INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Thursday, September 10, 2020
TIME: 1:30 p.m. – 4:24 p.m.
DOCKET NOS.: E-7, Sub 1214; E-7, Sub 1213; E-7, Sub 1187
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-7, Sub 1213, In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program; E-7, Sub 1214, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-7, Sub 1187, In the Matter of Application of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 19

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, and Luhr

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DATE: Thursday, September 10, 2020

TIME: 1:30 P.M. - 4:24 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 19

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

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MCLAWHORN Exhibit JSM-1

Analysis of COS Methodologies

Total Energy Requirements by Jurisdiction and Customer Class

	System	NC Retail	Residential	SGS	LGS	Industrial	OPTG	OPTI/T	OL	TS
Energy (GWH)	94,330	62,148	23,794	4,792	5,391	2,145	13,360	11,940	715	11
System	100%	65.88%								
NC Retail		100%	38.29%	7.71%	8.67%	3.45%	21.50%	19.21%	1.15%	0.02%

Allocation of Production Plant by COSS Methodology

	System	NC Retail	Residential	SGS	LGS	Industrial	OPTG	OPTI/T	OL	TS
SWPA										
System	100%	66.57%								
NC Retail		100%	44.60%	8.31%	8.64%	3.26%	18.83%	15.63%	0.72%	0.01%
SCP										
System	100%	67.43%								
NC Retail		100%	45.96%	9.95%	9.28%	3.10%	18.21%	13.49%	0.00%	0.01%
WCP										
System	100%	67.02%								
NC Retail		100%	54.68%	7.86%	7.97%	3.06%	14.61%	11.20%	0.61%	0.01%
SWCP										
System	100%	67.22%								
NC Retail		100%	50.47%	8.87%	8.60%	3.08%	16.35%	12.31%	0.32%	0.01%
4CP										
System	100%	67.01%								
NC Retail		100%	47.78%	9.18%	9.12%	3.24%	17.21%	13.30%	0.16%	0.01%
12CP										
System	100%	66.67%								
NC Retail		100%	47.23%%	8.28%	9.19%	3.52%	17.32%	14.26%	0.19%	0.01%

/A

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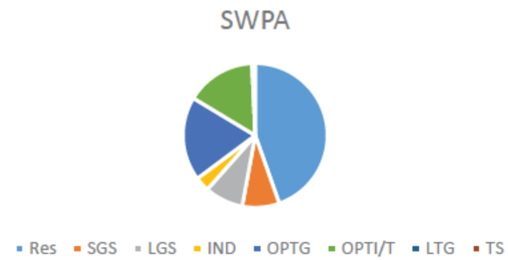
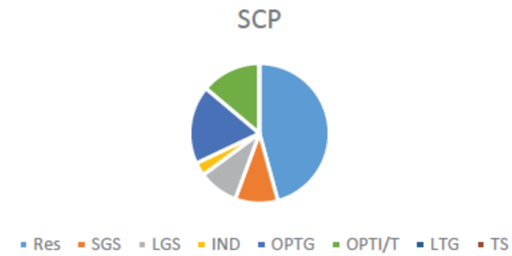
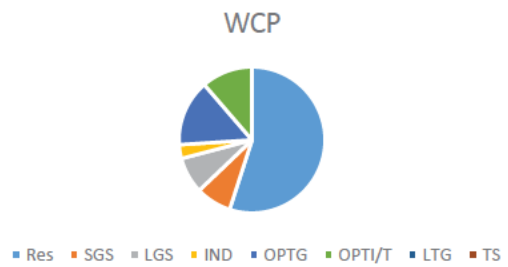
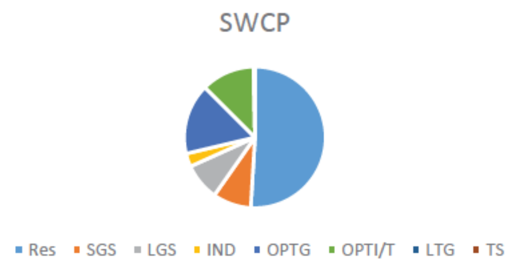
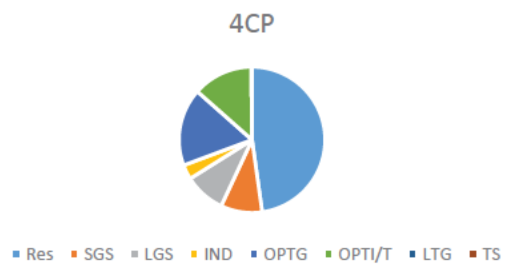
Analysis of COS Methodologies

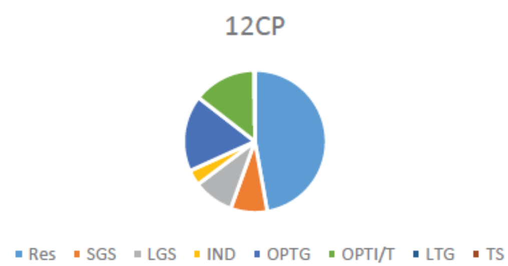












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MCLAWHORN JSM Exhibit 2

Rates of Return and Revenue Increases for SWPA, SCP, and WCP COS Methodologies

Rate of Return and % Increase	NC Retail	RES	SGS	LGS	IND	OPTG	OPTI/T	LTG	TS
SWPA									
Present Revenues Annualized ROR	5.51%	5.50%	9.36%	7.33%	7.82%	4.33%	3.74%	2.56%	-1.18%
Proposed Revenues ROR	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%
Revenue Increase to achieve 7.58%	8.95%	9.79%	-3.23%	2.62%	0.64%	11.85%	13.00%	29.95%	50.86%
SCP									
Present Revenues Annualized ROR	5.40%	5.25%	7.22%	6.22%	8.25%	4.45%	5.11%	3.97%	-0.92%
Proposed Revenues ROR	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%
Revenue Increase to achieve 7.58%	9.35%	10.77%	2.89%	5.98%	-0.52%	11.48%	8.49%	20.94%	48.51%

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Rates of Return and Revenue Increases
for SWPA, SCP, and WCP COS Methodologies

WCP

Present Revenues Annualized ROR	5.45%	3.81%	10.01%	8.34%	8.49%	7.22%	7.52%	2.69%	-0.89%
Proposed Revenues ROR	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%	7.58%
Revenue Increase to achieve 7.58%	9.19%	17.16%	-4.85%	-0.12%	-1.13%	3.18%	2.07%	29.11%	48.22%

/A

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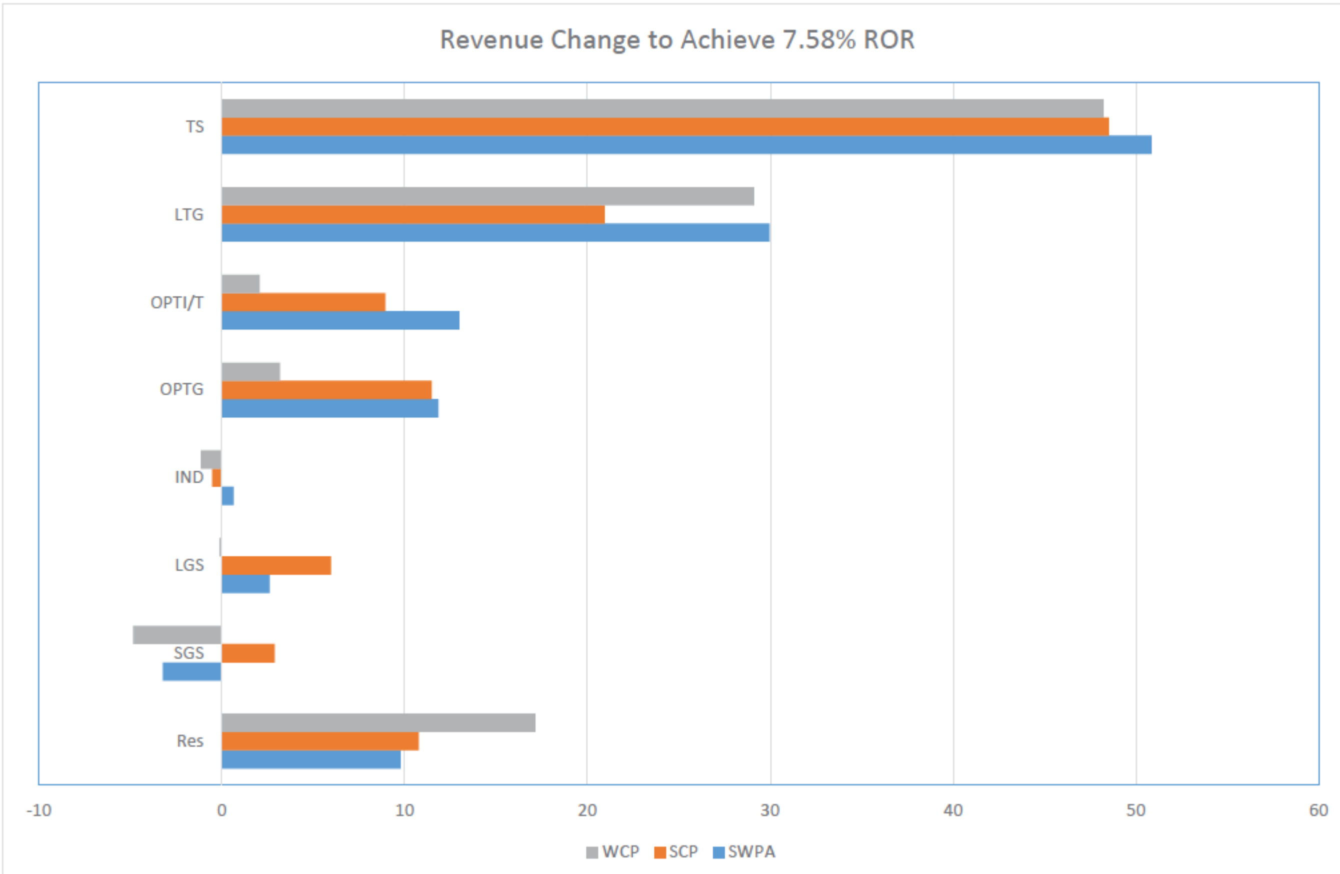
Rates of Return and Revenue Increases
for SWPA, SCP, and WCP COS Methodologies



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FLOYD EXHIBIT 1

PURPA SECTION 114 [16 U.S.C. 2624]

[16 U.S.C. 2623]

SEC. 114. LIFELINE RATES.

(a) LOWER RATES.—No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate for essential needs (as defined by the State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the standard referred to in section 111(d)(1).

(b) DETERMINATION.—If any State regulated electric utility or nonregulated electric utility does not have a lower rate as described in subsection (a) in effect two years after the date of the enactment of this Act, the State regulatory authority having ratemaking authority with respect to such State regulated electric utility or the nonregulated electric utility, as the case may be, shall determine, after an evidentiary hearing, whether such a rate should be implemented by such utility.

(c) PRIOR PROCEEDINGS.—Section 124 shall not apply to the requirements of this section.

[16 U.S.C. 2624]

SEC. 115. SPECIAL RULES FOR STANDARDS.

(a) COST OF SERVICE.—In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable—

(1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if—

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) TIME-OF-DAY RATES.—In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3) and the standard for time-based metering and communications established by section 111(d)(14), a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate

Floyd DEC Direct Exhibit 2
I/A

Public Staff
Floyd Exhibit 2

Docket No. E-7, Sub 1214

An Evaluation of A Lifeline Rate Alternative: The Supplemental Security income Rate

RTI Economics
September 1981

E-100, Sub 43

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RTI ECONOMICS

Research Triangle Institute

An Evaluation of A Lifeline Rate Alternative: The Supplemental Security Income Rate

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September 1981

Cooperative Agreement No. DE-FC-01-79-RG-10255/RTI Project No. 41U-2164

CONTENTS

CONTENTS (continued)

FIGURES

TABLES

TABLES (continued)

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The authors would like to thank the North Carolina Utilities Commission, the Public Staff, and Duke Power Company for their cooperation in this project. Mr. Robert Koger, Chairman of the Commission, has provided the impetus for the investigation of the Supplemental Security Income Rate. Mr. Tom Hatley, Vice President of Rates for Duke, has been more than generous with the resources of his department and the time of his staff--Mr. Ollie Frazier, Mr. Tom Taylor, Ms. Kathy Gann, and especially Mr. Bill Hooks. The Computer Services Department personnel, particularly Mr. Rick Ayres, Mrs. Metter Hodges and Ms. Nancy Dalgleish, have been most helpful. The Technical Officers at the Public Staff, Dr. Bill Watson and Dr. Robert Weiss, have provided the latitude necessary to carry out the study. We would also like to thank Mr. Robert Bennink and Mrs. Rhonna Jones for their contractual and administrative assistance on the project.

We gratefully acknowledge the funding support for this project through the Innovative Rates Program by the Office of Utility Systems of the U.S. Department of Energy.

1.0 INTRODUCTION AND SUMMARY

1.1 PROJECT BACKGROUND

The Duke Power Company's Supplemental Security Income (SSI) Rate Schedule was adopted in response to a North Carolina Utility Commission (NCUC) order issued on August 31, 1978, in Docket No. E-7, Sub 237. This order was issued approximately 8 weeks after the NCUC held a 3-day statewide "lifeline" conference in June 1978. This conference was held as one response to a resolution passed in the 1977 North Carolina General Assembly that required the NCUC to review, study, and consider the implementation of a lifeline rate for electric and gas service. Appendix A provides a detailed look at the relationship of the SSI rate to lifeline programs.

The NCUC ordered the establishment of the SSI Rate Schedule (shown in Table 1-1) as an experimental rate, initiated on the basis that this group of customers have electrical power usage characteristics that may differ substantially from those of the average residential customer. These characteristics may result in a smaller impact on utility system costs than the impact associated with the average residential customer. The rate was termed experimental in order to allow the NCUC to collect usage data on the customers to test whether or not they do have significantly different usage characteristics than the average residential customer, and to use these data to help develop a position on lifeline rates as required under the resolution in the 1977 North Carolina General Assembly. This project embraced these goals in developing its objectives and organizing its activities.

TABLE 1-1. SSI RATE DISCOUNTS[a]

Residential rate schedule	Rate (¢/month for first 350 kWh)	Maximum monthly discount ($/month)
RW (electric water heating)	2.9259	1.26
R (general service)	3.0059	.98
RA (all-electric)	3.0359	.88

[a]Effective June 16, 1980.

Several key features have influenced the overall design and execution of this project. Duke Power developed the sample design and drew the sample for the evaluation of the SSI rate discount before Research Triangle Institute (RTI) involvement in the project occurred. This was done at the request of NCUC staff, and some design considerations were ignored in order to fulfill the request in an expeditious manner.

Duke Power Company also indicated that their residential load research data were confidential and should not be released to RTI. RTI agreed to allow Duke to process and analyze the data under close supervision from the RTI project team. RTI provided Duke with computer software that facilitated Duke's efforts in processing the necessary data.

1.2 OBJECTIVES

The central objective of this study is to determine whether or not the electricity usage of customers on the SSI rate currently offered by Duke Power Company is different from the average residential customer on the Duke system in North Carolina. If SSI customer usage is different, the study will determine if the usage differences provide a cost-of-service justification for the SSI rate. A secondary objective is to assess the appropriateness of extending this rate to all low-use residential electric customers in North Carolina and the relationship of this rate to a generic lifeline rate.

1.3 SUMMARY OF RESULTS

The results of the comparative and covariance analyses employed in this study of electricity usage by SSI and non-SSI customers on the Duke Power System in North Carolina between June 1980 and March 1981 clearly showed that SSI customers used less electricity than non-SSI customers. On average, for all days and type of days, SSI customers used about half as much electricity as non-SSI customers. The differences were greatest during the winter months and smallest in the off season months, but were almost always of the same order of magnitude. When the usages of SSI and non-SSI customers were compared <u>within</u> each of the major residential customer rate classes, the differences were smaller but still significant in a large number of cases.

Even more important for purposes of rate analysis and costing is the profile of the electricity usage of SSI customers on critical system days and the load factors that characterize the shapes of the SSI electricity usage in any month. The study results demonstrate that SSI customers used less electricity (in many instances about half as much) than non-SSI customers on the system peak hours and peak days during the study period.

Monthly load factors, defined as the ratio of average to peak hourly usage for a class of customers during a month, were generally higher for SSI customers. This indicates that the load shapes of SSI customers were flatter than those of non-SSI customers. These results are less reliable than the usage results because the differences were statistically significant in only 3 months. They do, however, provide valuable information in that the load factors of SSI customers at a minimum are no worse than non-SSI customers' which suggests that the demand-related costs, and perhaps the energy costs of serving these customers, are lower.

Analysis of the customer survey results showed that there are distinct differences between SSI and non-SSI households in terms of their appliances and household characteristics. SSI customers had a lower proportion of most major electric appliances than did non-SSI customers. SSI customers tend to have smaller, less expensive homes and smaller family sizes.

The analysis of the survey data also showed that the sample means of several of the survey variables were substantially larger than the estimates of their population means due to a sampling design that oversampled larger users in each population. The effect of this was to increase the variance of the load estimates in the analyses. Sampling design limitations also precluded a direct comparison of SSI and low use non-SSI customers.

The analysis of covariance enabled a comparison of SSI and non-SSI customers by controlling for differences in appliances and other household characteristics. That is, by using a common set of covariate values (the SSI means) in both the non-SSI and SSI regressions, it was possible to attribute the resulting differences in the load estimates of non-SSI and SSI customers to behavioral differences between the two groups.

The results from the comparison for the combined rate classes in July indicated that SSI and non-SSI customers would use electricity at the same rate during the daytime but that SSI customers would use significantly less in the evening hours. One interpretation is that SSI customers are home during the day and use their discretionary appliances at those times but that non-SSI customers use theirs more intensively in the evening.

Using January's results to represent customer behavior during the heating season indicates that SSI customers would have significantly higher usage than their non-SSI counterparts during the daytime hours except during the evening and 6 a.m. to 8 a.m. when they use the same amount. SSI customers on the all electric rate used significantly more electricity at all hours of the day in January than the non-SSI customers. Likely explanations of these differences are the low penetration of wood stoves for the SSI customers, that SSI customers prefer higher indoor temperatures in the winter time, or that their homes are not as well insulated.

One important limitation in drawing inferences from the covariance analysis of the low use question is that no class of customers for rate purposes actually exists with SSI appliance profiles and non-SSI behavior. It does tell us, however, that when the effects of appliances and other household variables are controlled, there are behavioral differences between SSI and non-SSI customers and that these differences do <u>not</u> lead to lower electricity usage in all cases.

The costing analysis employed in this study focused on differences in energy costs between SSI and non-SSI customers measured in terms of both marginal and average costs. This represents a conservative estimate of the entire difference by not including differences in capital costs that could be attributed to lower SSI usage during key hours. The monthly average energy costs of SSI customers were approximately half those of non-SSI customers. Marginal energy costs of SSI customers ranged from one-third to one-half of those for the non-SSI customers.

Any final inferences for rate design that can be drawn from the results of this study require careful consideration of several important issues. It is clear from this study that SSI customers use less electricity and have lower costs than non-SSI customers. What is less clear is whether or not individuals receiving SSI payments require the implementation of an exclusive rate. There may be other subsets of residential customers who have usage patterns that are significantly different from the average residential customer and would require a special rate. If the North Carolina Utilities Commission feels that this particular class of customers should be granted special rate consideration, then there exist cost as well as social equity justifications for doing so.

2.0 SAMPLING DESIGN AND PROCEDURES

The basic purpose of Duke Power Company's SSI study is to determine if there is a cost-of-service justification for having a separate electricity rate for customers receiving Supplemental Security Income (SSI). The principal analytical objectives, therefore, involve comparisons of various usage characteristics of certain subsets of Duke Power Company's residential customers. To accomplish this objective, samples of non-SSI and SSI customers (accounts) were selected and 15-minute recording meters were installed on the selected residences. The non-SSI sample was selected from the population of N.C. residential customers having active accounts in August 1979 who:

1. Had consumed at least 1 kWh during the August 1978 billing period,
2. Had consumed at least 1 kWh during the January 1979 billing period,
3. Had consumed at least 1 kWh during the April 1979 billing period, and
4. Were not billed on the SSI rate in August 1979.

The SSI sample was selected from the population of N.C. residential customers having active accounts in August 1979 who:

1. Had consumed at least 1 kWh during the July 1978 billing period,
2. Had consumed at least 1 kWh during the January 1979 billing period,
3. Had consumed at least 1 kWh during the May 1979 billing period, and
4. Were billed according to the SSI schedule in August 1979.

The number of accounts eligible for inclusion in the sample, and the number ineligible (due to zero consumption in one or more of the prior

TABLE 2-1. CUSTOMER ACCOUNTS CONSIDERED FOR SAMPLING

Rate class	Population counts (August 1979)			
	Non-SSI customers		SSI customers	
	Eligible	Ineligible	Eligible	Ineligible
R	147,408	13,416	2,713	123
RA	198,684	18,430	421	142
RW	357,632	14,942	4,804	250
Total	703,724	46,788	7,938	515

months indicated above are shown in Table 2-1. Hence, the sampled populations constituted 93.8 percent of the 750,512 non-SSI customer accounts and 93.9 percent of the 8,453 SSI customer accounts that were classified as active in August 1979.

Each of the six rate-class-by-population categories was stratified into 64 strata by employing four usage groups during each of the three indicated months as stratification variables. For the non-SSI sample, one customer per stratum was then selected as a study participant. For the SSI sample, one customer was usually selected per stratum, though in some cases, zero, two, or three customers were selected. The overall structure of the sample design, along with the number of customers in each stratum, is shown in Tables 2-2 through 2-7. The design is highly imbalanced with respect to the numbers of customers per stratum. This feature, and the use of a single sample customer per stratum (in most cases), causes a number of analytical problems and necessitates an extensive amount of stratum collapsing for purposes of analysis.

The same sampling procedures were used by Duke for selecting the non-SSI and SSI samples. Within a given stratum, customers' data records were

TABLE 2-2. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS R

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-400	1-450	1-300	26,319
		301-600	14,335
		601-1000	5,574
		>1000	2,650
	451-1100	1-300	491
		301-600	599
		601-1100	363
		>1000	370
	1101-2000	1-300	23
		301-600	21
		601-1000	8
		>1000	20
	≥2001	1-300	7
		301-600	2
		601-1000	2
		>1000	2
401-700	1-450	1-300	2,935
		301-600	10,150
		601-1000	6,096
		>1000	5,598
	451-1100	1-300	1,095
		301-600	7,498
		601-1000	8,463
		>1000	10,212
	1101-2000	1-300	26
		301-600	54
		601-1000	30
		>1000	27
	≥2001	1-300	3
		301-600	7
		601-1000	3
		>1000	6
701-1400	1-450	1-300	434
		301-600	609
		601-1000	481
		>1000	544
	451-1100	1-300	693
		301-600	3,721
		601-1000	9,973
		>1000	21,223
	1101-2000	1-300	61
		301-600	122
		601-1000	359
		>1000	1,285
	≥2001	1-300	5
		301-600	5
		601-1000	11
		>1000	21
≥1401	1-450	1-300	96
		301-600	87
		601-1000	43
		>1000	57
	451-1100	1-300	138
		301-600	273
		601-1000	340
		>1000	891
	1101-2000	1-300	77
		301-600	172
		601-1000	329
		>1000	1,951
	≥2001	1-300	11
		301-600	19
		601-1000	33
		>1000	355

TABLE 2-3. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RA

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count	Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-1800	1-900	1-1000	27,807	3001-5000	1-900	1-1000	431
		1001-1600	6,563			1001-1600	367
		1601-2500	1,108			1601-2500	331
		>2500	123			>2500	93
	901-1600	1-1000	9,809		901-1600	1-1000	3,683
		1001-1600	6,169			1001-1600	4,754
		1601-2500	2,604			1601-2500	4,697
		>2500	331			>2500	822
	1601-2500	1-1000	619		1601-2500	1-1000	5,765
		1001-1600	545			1001-1600	10,674
		1601-2500	529			1601-2500	13,709
		>2500	128			>2500	4,685
	>2500	1-1000	65		>2500	1-1000	905
		1001-1600	52			1001-1600	2,244
		1601-2500	42			1601-2500	3,796
		>2500	21			>2500	2,556
1801-3000	1-900	1-1000	5,570	>5000	1-900	1-1000	24
		1001-1600	2,784			1001-1600	19
		1601-2500	748			1001-2500	41
		>2500	69			>2500	33
	901-1600	1-1000	18,291		901-1600	1-1000	73
		1001-1600	15,227			1001-1600	108
		1601-2500	7,727			1601-2500	235
		>2500	700			>2500	134
	1601-2500	1-1000	5,527		1601-2500	1-1000	290
		1001-1600	6,889			1001-1600	590
		1601-2500	5,855			1601-2500	1,506
		>2500	1,306			>2500	1,217
	>2500	1-1000	168		>2500	1-1000	346
		1001-1600	207			1001-1600	762
		1601-2500	278			1601-2500	2,029
		>2500	129			>2500	3,775

TABLE 2-4. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RW

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count	Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-700	1-700	1-600	67,343	1101-1900	1-700	1-600	1,034
		601-900	20,425			601-900	878
		901-1500	10,181			901-1500	1,065
		>1500	2,005			>1500	625
	701-1300	1-600	2,693		700-1300	1-600	2,780
		601-900	2,087			601-900	10,412
		901-1500	1,456			901-1500	32,065
		>1500	536			>1500	27,349
	1301-2500	1-600	190		1301-2500	1-600	543
		601-900	92			601-900	1,157
		901-1500	91			901-1500	8,244
		>1500	121			>1500	15,329
	>2500	1-600	10		>2500	1-600	8
		601-900	2			601-900	17
		901-1500	2			901-1500	47
		>1500	4			>1500	86
701-1100	1-700	1-600	12,523	>1900	1-700	1-600	263
		601-900	16,046			601-900	113
		901-1500	10,723			901-1500	125
		>1500	2,947			>1500	83
	701-1300	1-600	8,167		701-1300	1-600	491
		601-900	30,124			601-900	493
		901-1500	34,635			901-1500	925
		>1500	14,209			>1500	1,007
	1301-2500	1-600	208		1301-2500	1-600	487
		601-900	293			601-900	611
		901-1500	354			901-1500	2,415
		>1500	236			>1500	9,746
	>2500	1-600	12		>2500	1-600	50
		601-900	13			601-900	51
		901-1500	8			901-1500	118
		>1500	5			>1500	1,274

TABLE 2-5. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS R

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-300	1-250	1-300	803	451-600	1-250	1-300	17
		301-450	13			301-450	4
		451-600	4			451-600	4
		>600	0			>600	3
	251-500	1-300	253		251-500	1-300	43
		301-450	61			301-450	129
		451-600	4			451-600	69
		>600	1			>600	7
	501-900	1-300	26		501-900	1-300	1
		301-450	5			301-450	41
		451-600	0			451-600	64
		>600	1			>600	14
	>900	1-300	1		>900	1-300	0
		301-450	0			301-450	4
		451-600	1			451-600	6
		>600	0			>600	4
301-450	1-250	1-300	104	> 600	1-250	1-300	10
		301-450	23			301-450	3
		451-600	0			451-600	1
		>600	0			>600	4
	251-500	1-300	163		251-500	1-300	10
		301-450	256			301-450	39
		451-600	28			451-600	44
		>600	4			>600	18
	501-900	1-300	22		501-900	1-300	3
		301-450	52			301-450	23
		451-600	19			451-600	74
		>600	3			>600	140
	>900	1-300	3		>900	1-300	1
		301-450	4			301-450	3
		451-600	2			451-600	9
		>600	0			>600	65

TABLE 2-6. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RA

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-1500	1-1400	1-600	115	2501-4000	1-1400	1-600	8
		601-900	20			601-900	24
		901-1400	8			901-1400	34
		>1400	0			>1400	23
	1401-2500	1-600	0		1401-2500	1-600	0
		601-900	0			601-900	2
		901-1400	0			901-1400	7
		>1400	0			>1400	6
	2501-4000	1-600	0		2501-4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	1
		>1400	0			>1400	0
	>4000	1-600	0		>4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	0
1501-2500	1-1400	1-600	43	>4000	1-1400	1-600	0
		601-900	57			601-900	0
		901-1400	39			901-1400	7
		>1400	7			>1400	7
	1401-2500	1-600	2		1401-2500	1-600	0
		601-900	0			601-900	0
		901-1400	3			901-1400	2
		>1400	2			>1400	3
	2501-4000	1-600	0		2501-4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	1
	>4000	1-600	0		>4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	0

TABLE 2-7. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RW

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-500	1-450	1-350	995	801-1300	1-450	1-350	9
		351-600	428			351-600	19
		601-1000	14			601-1000	13
		>1000	1			>1000	3
	451-800	1-350	71		451-800	1-350	5
		351-600	188			351-600	107
		601-1000	10			601-1000	362
		>1000	0			>1000	23
	801-1300	1-350	7		801-1300	1-350	1
		351-600	16			351-600	20
		601-1000	2			601-1000	312
		>1000	0			>1000	89
	>1300	1-350	0		>1300	1-350	0
		351-600	1			351-600	3
		601-1000	0			601-1000	48
		>1000	0			>1000	31
501-800	1-450	1-350	90	>1300	1-450	1-350	2
		351-600	399			351-600	9
		601-1000	37			601-1000	5
		>1000	2			>1000	0
	451-800	1-350	24		451-800	1-350	0
		351-600	706			351-600	7
		601-1000	347			601-1000	22
		>1000	6			>1000	11
	801-1300	1-350	2		801-1300	1-350	0
		351-600	66			351-600	0
		601-1000	71			601-1000	33
		>1000	4			>1000	90
	>1300	1-350	0		>1300	1-350	1
		351-600	6			351-600	1
		601-1000	9			601-1000	7
		>1000	0			>1000	69

first ordered by geographical region. If N(h) customers occurred in the h^{th} stratum and if a sample (including alternates) of size n(h) was desired from this stratum, then n(h) equal-sized sets of contiguous records were identified. A random number between 1 and N(h)/n(h) was then selected in order to choose a customer from the first within-stratum set. Using a constant skip interval equal to N(h)/n(h), a customer was selected from each of the other sets. The initial household or set of households from stratum h to be included in the study was then randomly chosen (without replacement) from the n(h) customers previously selected.

Selected customers whose dwellings could not be metered or whose accounts had become inactive prior to the time of meter installation were replaced with a randomly chosen alternate from the same stratum. In addition, at any time after sample selection, selected SSI-rate customers were dropped whenever they no longer qualified for the SSI rate and were replaced with a randomly selected customer from the same stratum who was still eligible for this SSI rate.

Target numbers of customers sample to be metered were initially the following:

	Rate class			
	R	RA	RW	Total
Non-SSI	64	64	64	192
SSI	72	52	72	196

With the availability of additional meters during the fall of 1980, the SSI sample was enlarged slightly by selecting and metering some additional customers. Full implementation of the non-SSI sample metering also was not achieved until early autumn 1980.

Sample meter allocations as they existed in August 1980 for the SSI group are given in Table 2-8. The non-SSI sample consisted of one customer within each of the 64 strata for a given rate class.

TABLE 2-8. METER ALLOCATION FOR SSI SAMPLE AS OF AUGUST 1980, BY RATE CLASS AND PRIOR USAGE LEVELS

Rate class	Stratum (July 1978 kWh)	Sample count	Stratum (January 1979 kWh)	Sample count	Stratum (May 1979 kWh)	Sample count
R	1-250	16	1-300	13	1-300	16
	251-500	18	301-450	21	301-450	18
	501-900	18	451-600	16	451-600	17
	>900	14	>600	16	>600	15
RA	1-1400	38	1-1500	12	1-600	13
	1401-2500	11	1501-2500	15	601-900	11
	2501-4000	1	2501-4000	15	901-1400	13
	>4000	0	>4000	8	>1400	13
RW	1-450	18	1-500	12	1-350	15
	451-800	19	501-800	18	351-600	18
	801-1300	16	801-1300	21	601-1000	17
	>1300	14	>1300	16	>1000	17

3.0 DATA COLLECTION PROCEDURES

3.1 BACKGROUND ON SSI RATE PROGRAM ADMINISTRATION

The selection of the SSI subset of residential customers imposed a need to define the population and to develop procedures for contacting and verifying the SSI customers. Fulfilling these requirements imposed administration costs on Duke Power because the definition of customers was not available through normal billing information.

To qualify for the Duke Power Company SSI rate, an individual must be a Duke customer who is currently receiving Supplemental Security Income payments. In addition, this person must be the head of the household as defined by the Social Security Living Arrangement A in which the individual is responsible for household expenses or shares in them at least equally. To receive SSI payments, one must be either 65 years of age or older, legally blind, or disabled for a period of time expected to exceed 12 months. Further, household income cannot be greater than 125 percent of federal poverty guidelines.

As of December 1977, 139,500 adults and 4,964 children were receiving SSI payments in North Carolina. Of the adults, 65,033 were disabled and 3,200 were blind. Of the 71,267 in the entire state who would have qualified for the Duke Power Company SSI Rate on the basis of age, 83 percent were 70 or over and 28 percent had achieved or passed their 80th birthday.*

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*Statistical data on North Carolina Supplemental Security Income recipients were furnished by George V. Hess of the Social Security Administration, P. O. Box 27168, Raleigh, NC 27611. Information on the Duke Power Company SSI Rate program was provided by George E. Meier, Duke Power Company, Rate Department, Charlotte, NC 28242.

During 1977, the average SSI payment for all recipients was about $100 per month. Of the total number of SSI recipients, 56 percent also collected a regular Social Security benefit averaging $124 per month and 13 percent had unearned income, other than Social Security, averaging $40 per month. Approximately 4 percent reported an earned income of at least $94 per month.

Eighty-six percent of all SSI recipients owned their homes. Eleven percent were members of another household, and the remaining three percent lived in Medicaid institutions. With regard to sex and race, approximately 64 percent were women and 51 percent were white and 43 percent black. Other races accounted for 1.5 percent with the remainder not reported.

In January of 1979 when the SSI rate was initiated, approximately 50,000 individuals living in the 37 counties of the Duke service area were identified as receiving SSI payments. The potential SSI rate population is somewhat less than this figure because a number of households within the Duke territory are served by municipalities and rural cooperatives. From January 1979 to February 1980, Duke received approximately 11,000 applications for the rate. Some 9,400 of these have qualified, and, as of February 1980, there were about 8,600 on the rate. Enrollment has remained fairly stable around this number.

At the origination of the SSI rate program, the Social Security Administration mailed application forms to SSI recipients living in the 37 counties of the Duke service area. With the Social Security Administration responsible for this initial contact, the SSI recipients' right to remain anonymous was not violated. Upon receipt of an application form, it became the individual's responsibility to complete and return the form to a local Duke Power office.

Procedures for contacting new SSI recipients were initiated by the North Carolina Department of Human Resources in June 1979. These procedures entail a periodic mailing of application forms to be completed and returned to Duke Power by the individual. Approximately 1,000 new recipients have been contacted each month in this effort.

To monitor the eligibility of those who receive billing on the SSI rate, Duke periodically prepares a computer tape containing their names and forwards this tape to the Department of Human Resources. There it is compared with a tape containing the names of all SSI recipients in North Carolina. An exceptions list of those who receive SSI rate billing but do not receive SSI assistance is then returned to Duke. Accounts on this list are reassigned by Duke to the appropriate residential rate schedule.

3.2 LOAD RESEARCH DATA

Duke Power Company provided 192 Westinghouse single-phase meters with two-channel recorders to record the pulse data in 15-minute intervals for the SSI sample customers. The control group customers were metered as part of Duke's Residential Load Research Program.

By January of 1980, Duke had installed the 192 recorders on the SSI sample customers. Duke changed its load research sample in March 1980 and did not have the meters in place on the new sample until June 1980. Recorded load data for this project were available for analysis from June 1980 through March 1981.

This standard load research practice at Duke of obtaining only 10 months of actual load data limited the data collection of the project. RTI project team members urged Duke to change its program to acquire a full year's data for future load analyses. Duke has subsequently resolved the difficulties that caused this problem and are conducting their load research programs are being conducted over the entire year.

Duke's metering department changed the recording cartridges on a monthly basis. They dispatched these tapes monthly to the central office for translation on a Westinghouse translater. Data from the translater were transferred to a computer-readable tape and analyzed in the Duke Load Research Department.

RTI and Duke developed procedures for providing summary information on data collection and reduction procedures to ensure the highest possible quality for the analysis. Appendix B provides details on Duke's data translation procedures.

3.3 CUSTOMER SURVEY DATA

The customer survey data provide detailed information on household characteristics and socioeconomic characteristics of the sample customers. Duke Power Company's marketing representatives acquired these data through personal interviews with each of the customers. Data on age of house and present market value of the house for the SSI customers were estimated by the representatives in a subsequent effort to provide consistent measures for both the control and experimental customers. The survey instruments used for acquiring data on both groups of customers are presented in Appendix C.

3.4 SYSTEM LOAD DATA

Table 3-1 presents a summary of the Duke Power Company system load data for the study period. The table provides summary statistics on the day, hour, and size of the monthly system peak and also the load factor of the system. The data are summarized from the actual operating data of the Duke Power Company system.

TABLE 3-1. SYSTEM LOAD CHARACTERISTICS

Month/year	Day	Hour	Monthly system peak (megawatt h)	Load factor
June 1980	8	18	8,784	.688
July 1980	16	15	10,364	.669
August 1980	6	18	10,239	.699
September 1980	3	15	9,590	.688
October 1980	30	19	7,835	.750
November 1980	20	8	9,038	.682
December 1980	4	8	9,068	.721
January 1981	12	8	10,530	.691
February 1981	4	8	10,395	.660
March 1981	19	20	9,086	.698

4.0 COMPARATIVE ANALYSIS OF LOAD RESEARCH DATA

Installation of recording meters on sample customers with and without the SSI rate was completed in June 1980. Monitoring of 15-minute kWh consumption continued on all sample customers through March 1981. Thus, 15-minute kWh consumption data were available for analysis for most sample customers over a 10-month period: June 1980 through March 1981. These data formed the basis for the comparative analyses described in this section.

The objectives of the comparative analyses are the following:

- To provide statistical estimates of various electricity consumption characteristics of the SSI-rate and non-SSI-rate residential customer populations;
- To make statistical comparisons of these populations with respect to the various usage characteristics;
- To provide such estimates and comparisons for each of the three basic rate classes:

  R = general residential service

  RA = all-electric residential service

  RW = water heating residential service.

The statistical inferences are made for the Duke Power Company North Carolina service territory as of the time of sampling (August 1979). The estimates/comparisons, however, must be treated with some caution, since the methodology involves a number of assumptions necessitated principally because of the sample design limitations and because of the lack of sufficient information on population dynamics during the study period.

4.1 DESCRIPTION OF ANALYSIS VARIABLES

The time frame for analyzing the 15-minute usage data is a calendar month. Therefore, all analyses are repeated for each of 10 months--June 1980 through March 1981. The parameters that were estimated for each month are identified in Table 4-1. These parameters were estimated for seven subsets of days within the month (day of system peak, weekdays, weekend days, all days, and days in which the system load exceeded 80 percent, 90 percent, or 95 percent of the annual system peak) for the population of North Carolina residential customers on the SSI rate and for the population not on the SSI rate. Corresponding parameters of each population were compared, via statistical tests, to determine if there were statistically significant differences in the usage patterns. Procedures for estimating the parameters and performing the statistical tests are given in Appendix D.

The first 24 parameters listed in Table 4-1 correspond to average hourly consumption values (for each of the 24 hours of the day) for the various subsets of days. Parameter 25 is the average daily kWh (or the sum of parameters 1-24). Parameters 26 and 27 are, respectively, the average 60-minute and 15-minute noncoincident demands. The 28th parameter is the class load factor based on the demand at the time of system peak. This parameter is estimated only for the day of system peak and for the month (i.e., all days). The last parameter is the estimated average hourly consumption over hours with "high" system load, using three alternative definitions of "high." In all, 194 parameters per month are estimated for each of the two populations. Similar estimates are determined by rate class (R, RA, RW).

TABLE 4-1. LIST OF PARAMETERS ESTIMATED FOR SPECIFIC SUBSETS OF DAYS IN CALENDAR MONTHS JUNE 1980 - MARCH 1981

Parameters[a]	Day of system peak	Weekdays	Weekend days	All days	Days with system load exceeding: 80 percent of annual peak	90 percent of annual peak	95 percent of annual peak
1. Average kWh in 0000-0100							
2. Average kWh in 0100-0200							
3. Average kWh in 0200-0300							
4. Average kWh in 0300-0400							
5. Average kWh in 0400-0500							
6. Average kWh in 0500-0600							
7. Average kWh in 0600-0700							
8. Average kWh in 0700-0800							
9. Average kWh in 0800-0900							
10. Average kWh in 0900-1000							
11. Average kWh in 1000-1100							
12. Average kWh in 1100-1200							
13. Average kWh in 1200-1300							
14. Average kWh in 1300-1400							
15. Average kWh in 1400-1500							
16. Average kWh in 1500-1600							
17. Average kWh in 1600-1700							
18. Average kWh in 1700-1800							
19. Average kWh in 1800-1900							
20. Average kWh in 1900-2000							
21. Average kWh in 2000-2100							
22. Average kWh in 2100-2200							
23. Average kWh in 2200-2300							
24. Average kWh in 2300-2400							
25. Average daily kWh							
26. Average 60-min noncoincident max demand							
27. Average 15-min noncoincident max demand							
28. Class load factor (based on demand at time of system peak)		N/A	N/A		N/A	N/A	N/A
29. Average hourly kWh during critical hours[b]	N/A	N/A	N/A	N/A	(1)	(2)	(3)

[a]Estimated on a per customer basis.

[b](1) Critical hours = hours with system load over 80 percent of annual system peak.
(2) Critical hours = hours with system load over 90 percent of annual system peak.
(3) Critical hours = hours with system load over 95 percent of annual system peak.

NA = not applicable.

4.2 DATA COMPILATION, REDUCTION, AND ANALYSIS PROCEDURES

The overall structure of the analysis process for the Duke SSI Rate Study involved four major data processing/analysis steps:

1. Creation of Billing Month Usage Files (BMUFs) from the raw data tapes;
2. Creation of Calendar Month Usage Files (CMUFs) from the BMUFs;
3. Data editing and creation of Analysis Files from the CMUFs;
4. Statistical analyses.

The initial raw data tapes contained 15-minute billing month data in the form of one record per customer per day for the period June 1980 through March 1981. In creating the Billing Month Usage Files, pulse counts were converted to 15-minute kWh values and the data were screened for duplicate records, data gaps, and overlaps with records from prior billing months.

After splicing together the start and stop days from consecutive billing months, the 15-minute usage records were split into the appropriate Calendar Month Usage Files, which contained one record per customer per day. In the next processing step, the 15-minute usage data were first aggregated to produce hourly usage data. Any missing 15-minute value within a particular hour was assumed to generate a missing value for the entire hour. The data for each customer were then aggregated to produce a data file containing average hourly usage values over the seven different time frames within each calendar month (see Table 4-1). During this stage of the processing, customers for whom large amounts of data were missing in a given month were excluded from further analysis. In addition, customers with unusual data patterns were identified for further manual examination; if warranted, such customers' data were also excluded (on a month-by-month basis). Table 4-2 shows, by month and rate class, the number of non-SSI and SSI customers who were

TABLE 4-2. SAMPLE SIZES AND NUMBER OF SAMPLE EXCLUSIONS, BY MONTH, RATE CLASS, AND POPULATION

		Number of sample customers								
		Providing some kWh data[a]			Excluded in editing[b]			Providing valid usage data[c]		
Population	Month	R	RA	RW	R	RA	RW	R	RA	RW
Non-SSI-customers	June 1980	44	49	50	7	11	12	37	38	38
	July	51	50	51	11	11	7	40	39	44
	August	54	52	52	8	15	9	46	37	43
	September	57	54	54	8	16	10	49	38	44
	October	59	59	58	13	9	16	46	50	42
	November	57	62	61	9	5	16	48	57	45
	December	57	63	62	7	6	17	50	57	45
	January 1981	59	63	49	16	4	12	43	59	47
	February	55	64	62	9	11	15	46	53	47
	March	58	64	59	10	13	7	48	51	52
SSI-customers	June 1980	73	53	69	24	11	15	49	42	54
	July	65	53	63	19	8	13	46	45	50
	August	62	57	62	15	15	10	47	42	52
	September	66	57	65	18	12	14	48	45	51
	October	67	56	67	15	17	15	52	39	52
	November	69	57	68	13	13	15	56	44	53
	December	74	58	71	13	12	13	61	46	58
	January 1981	75	55	70	14	8	11	61	47	59
	February	75	54	68	14	9	11	61	45	57
	March	73	54	67	11	12	11	62	42	56

[a]These totals exclude those customers with no data during the calendar month.

[b]Customers were excluded automatically if they had excessive amounts of missing data during the calendar month. Other customers were excluded if erroneous data were suspected or if the assigned rate schedule (e.g., SSI-R) was no longer appropriate.

[c]These sample sizes apply to those response variables associated with the weekend, weekday, or all-day time frames; for other time frames (e.g., day of system peak), the sample sizes may be slightly smaller than those shown here.

excluded by the statistical editing procedures, and the number providing valid usage data. The latter are the sample sizes used in the analyses for the R, RW, and RA rate classes (Section 4.4). Table 4-3 provides the same information as Table 4-2 after aggregating over these three rate classes.

The final step in creating the analysis variables involved examination of the sample sizes after data editing to determine if the number of customers providing data in each population/stratum combination was sufficient for estimating the desired parameters and their standard errors. Such estimation requires the assumption that, within each stratum and population, the final sample of respondents constitutes a random sample from the corresponding stratum of the particular population. Estimation of the standard errors also requires the availability of data from at least two customers per population per stratum. These requirements necessitated collapsing a large number of strata into single strata, since the sample design usually called for the selection of only one (or in some cases, two or three) customer per stratum.

In order to perform the analyses, the prior usage strata were collapsed in accordance with the season for which analyses were being performed. For example, for analyzing data from June, July, August, or September, prior summertime usage strata, within rate classes, were employed. Similarly, winter-month usage variables were analyzed using the prior wintertime usage strata (within rate classes). Table 4-4 identifies the particular stratification used in each of the monthly analyses as well as the number of customers in each such stratum. These counts indicate the weights attached to the strata means that were used to produce an overall estimated mean.

TABLE 4-3. SAMPLE SIZES AND NUMBER OF SAMPLE EXCLUSIONS, BY MONTH AND POPULATIONS[a]

Month	No. of sample customers providing some usage data		No. of sample customers excluded in editing		No. of sample customers with valid usage data	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
June 1980	143	195	30	50	113	145
July	152	181	29	40	123	141
August	158	181	32	40	126	141
September	165	188	34	44	131	144
October	176	190	38	47	138	143
November	180	194	30	41	150	153
December	182	203	30	38	152	165
January 1981	181	200	32	33	149	167
February	181	197	35	34	146	163
March	181	194	30	34	151	160

[a]Since entries in this table are obtained from Table 4-2 by adding over rate classes, the footnotes of Table 4-2 apply to this table as well.

TABLE 4-4. POPULATION COUNTS OF SSI AND NON-SSI CUSTOMERS, BY STRATA

SSI population rate class	June-September analyses		October-November analyses		December-March analyses	
	Stratum (July 1978 usage)	Population count	Stratum (January 1979 usage)	Population count	Stratum (May 1979 usage)	Population count
R	1-250	993	1-300	1,173	1-300	1,460
	251-500	1,129	301-450	683	301-450	660
	501-900	488	451-600	410	451-600	329
	>900	103	>600	447	>600	264
RA	1-1,400	392	1-1,500	143	1-600	168
	>1,400	29	1,501-2,500	153	601-900	103
			2,501-4,000	105	901-1,400	101
			>4,000	20	>1,400	49
RW	1-450	2,026	1-500	1,733	1-350	1,207
	451-800	1,889	501-800	1,769	351-600	1,976
	801-1,300	713	801-1,300	1,045	601-1,000	1,292
	>1,300	176	>1,300	257	>1,000	329
Non-SSI population rate class	Stratum (Aug. 1978 usage)	Population count	Stratum (January 1979 usage)	Population count	Stratum (Apr. 1979 usage)	Population count
R	1-450	76,008	1-400	50,786	1-300	32,414
	451-1,100	66,343	401-700	52,203	301-600	37,674
	1,101-2,000	4,565	701-1,400	39,547	601-1,000	32,108
	>2,000	492	>1,400	4,872	>1,000	45,212
RA	1-900	46,111	1-1,800	56,515	1-1,000	79,373
	901-1,600	75,364	1,801-3,000	71,475	1,001-1,600	57,954
	1,601-2,500	59,834	3,001-5,000	59,512	1,601-2,500	45,235
	>2,500	17,375	>5,000	11,182	>2,500	16,122
RW	1-700	146,379	1-700	107,238	1-600	96,802
	701-1,300	169,429	701-1,100	130,503	601-900	82,814
	1,301-2,500	40,117	1,101-1,900	101,639	901-1,500	102,454
	>2,500	1,707	>1,900	18,252	>1,500	75,562

With this assumption, which also involves an implicit nonresponse adjustment, a mean kWh (e.g., for a given hour or day) for the SSI population can be estimated by a weighted sum of strata means. For example, if Y_{hi} denotes the value of the particular kWh variable for the i^{th} sample member of the h^{th} SSI stratum, and if there are n_h sample customers providing values of Y_{hi}, then the particular stratum mean is estimated as

$$\hat{\bar{Y}}_h = \sum_{i=1}^{n_h} Y_{hi}/n_h \quad .$$

These means are then weighted according to the population counts N_h (as shown in Table 4-4) to produce an overall estimate for the SSI population:

$$\hat{\bar{Y}} = \sum_{h=1}^{H} N_h \bar{Y}_h / N$$

where

H = number of (collapsed) strata, and

$N = \sum_{h=1}^{H} N_h$ = total number of SSI customers.

The standard error of $\bar{Y}$ is estimated by taking the square root of

$$\mathrm{Var}[\hat{\bar{Y}}] = \left(\frac{1}{N}\right)^2 \sum_{h=1}^{H} \frac{s_h^2}{n_h} \left(N_h - n_h\right) N_h \quad ,$$

where

$$s_h^2 = \left(\sum_{h=1}^{n_h} Y_{hi} - \hat{\bar{Y}}_h\right)^2 \bigg/ \left(n_h - 1\right)$$

= variance of the Y_{hi} responses among the n_h sample customers in the h^{th} stratum.

Similar formulas are used to estimate the corresponding mean of the non-SSI population and the standard error of the estimate. If $\hat{\bar{X}}$ denotes this estimated non-SSI mean, then comparisons between the two true population means $\overline{X}$ and $\overline{Y}$, can be made using the test statistic

$$t = \left(\hat{\overline{X}} - \hat{\overline{Y}}\right)/[\mathrm{Var}(\hat{\overline{X}}) + \mathrm{Var}(\hat{\overline{Y}})]^{\frac{1}{2}} \quad .$$

Under the assumption that $\hat{\overline{X}}$ and $\hat{\overline{Y}}$ are approximately normally distributed with a common mean (the null hypothesis), this statistic will for large samples be approximately normally distributed with a zero mean. Hence, t can be used to provide an approximate test for differences in the population means.

4.3 OVERALL COMPARATIVE ANALYSIS RESULTS

A major objective of this study was to determine if, and to what extent, electricity usage patterns for SSI-rate customers differ from load patterns of customers not on the SSI rate. To achieve this objective, 15-minute kWh recording meters were used to monitor electricity usage on two samples of Duke's North Carolina residential customers--those with and those without the SSI rate (as of August 1979). This section describes the results of various analyses that were conducted to make this comparison of the load characteristics of the two populations.

The general analytical approach involved estimating certain parameters or load characteristics for the two populations, as indicated in Section 4.2, and then comparing these estimates, via statistical tests, to determine whether the difference could reasonably be attributed to chance or whether the difference was due to inherent differences in the populations with respect to the usage of electricity. The parameters estimated for each population in each calendar month were identified in Table 4-1.

Comparative analysis results for the day of system peak and hours of high system load in the months of June 1980 through March 1981 are given in

Section 4.3.1. Similarly, comparative analysis results for the average day for these calendar months are presented in Section 4.3.2. The next subsection presents monthly class load factors and the final subsection discusses usage patterns for the two groups during weekdays and weekend days. Detailed comparisons of the data summarized herein will be presented in a companion volume to this report.

4.3.1 Days and Hours of High System Load

Table 4-5 presents, for the day of monthly system peak, the percentage differences in electricity consumption for the populations of customers having and not having the SSI rate. Differences in consumption are expressed in terms of percentages relative to the population that was not on the SSI rate.

It is evident from the results given in Table 4-5 that customers on the SSI rate used significantly less electricity than those on the regular R, RA, or RW rates. For example, on the day in which the system peaked in January 1981, the daily difference in consumption (parameter 25) reached 58.5 percent. Similar, though somewhat smaller, differences in daily consumption were observed for the days of system peak in each of the other months. These daily differences reflect lower consumption by customers on the SSI rate throughout the 24-hour day (parameters 1-24); however, the largest percentage differences in the two populations generally appeared to occur during evening, nighttime, and early morning hours (from about 6 p.m. to 8 a.m.). The most pronounced differences appeared in the wintertime during early morning hours (midnight to 8 a.m.).

Both the 15- and 60-minute noncoincident maximum demands (parameters 26 and 27) for days of monthly system peak were significantly lower during all months of the study for the population of SSI-rate customers. The percent-

TABLE 4-5. COMPARISON OF AVERAGE USAGE PATTERNS OF NON-SSI AND SSI CUSTOMERS ON DAYS OF MONTHLY SYSTEM PEAKS, BY MONTH

Parameter	Percentage differences, by month[a]									
	1980							1981		
	Jun. 3	Jul. 16	Aug. 6	Sept. 3	Oct. 30	Nov. 20	Dec. 4	Jan. 12	Feb. 4	Mar. 19
1. Average kWh in 0000-0100	53.6	52.8	54.6	46.9	41.5	66.5	62.6	62.7	61.5	40.0
2. Average kWh in 0100-0200	44.3	44.4	45.7	45.3	41.7	66.8	58.0	64.0	63.4	48.2
3. Average kWh in 0200-0300	41.3	44.5	47.5	45.7	46.4	64.9	62.9	64.8	68.4	53.8
4. Average kWh in 0300-0400	50.3	40.5	46.6	40.4	45.3	65.0	59.0	65.2	66.6	52.8
5. Average kWh in 0400-0500	46.8	41.6	39.6	29.4	47.8	60.8	60.9	64.5	66.2	46.8
6. Average kWh in 0500-0600	43.7	42.7	41.5	42.6	53.5	68.0	58.9	67.2	67.6	50.0
7. Average kWh in 0600-0700	47.6	48.7	45.9	48.0	50.1	64.2	64.1	68.0	65.8	59.1
8. Average kWh in 0700-0800	48.9	45.5	52.0	43.4	34.8	61.3[b]	59.3[b]	61.9[b]	60.0[b]	53.9
9. Average kWh in 0800-0900	(23.6)	33.2	43.6	(29.7)	33.8	44.1	46.6	48.3	57.4	32.9
10. Average kWh in 0900-1000	(19.5)	(27.8)	49.2	(27.2)	(27.7)	40.9	43.5	50.6	50.3	36.9
11. Average kWh in 1000-1100	(17.1)	34.1	37.3	39.6	30.7	43.6	49.6	55.1	50.1	37.3
12. Average kWh in 1100-1200	(27.2)	44.1	39.6	34.5	38.8	44.7	42.6	46.6	43.3	41.9
13. Average kWh in 1200-1300	42.0	52.5	43.0	35.0	39.4	44.8	49.2	53.3	49.1	42.8
14. Average kWh in 1300-1400	42.9	54.9	41.2	39.6	48.7	49.3	57.2	53.2	45.9	50.6
15. Average kWh in 1400-1500	49.1	50.2[b]	44.7	37.3[b]	44.5	32.1	48.1	56.2	47.0	45.8
16. Average kWh in 1500-1600	35.9	47.5	44.8	39.8	39.3	35.7	41.5	51.7	41.0	40.1
17. Average kWh in 1600-1700	43.4	46.5	44.6	55.0	40.7	39.0	41.9	47.1	48.5	(25.7)
18. Average kWh in 1700-1800	49.7[b]	48.9	40.6[b]	53.6	41.9	54.6	50.4	55.5	51.2	40.3
19. Average kWh in 1800-1900	55.1	53.3	54.0	53.7	55.4[b]	56.1	53.8	59.1	53.1	54.8
20. Average kWh in 1900-2000	58.3	54.4	57.7	51.7	50.1	56.0	57.2	56.3	58.9	53.6
21. Average kWh in 2000-2100	57.6	59.7	55.6	39.3	60.0	61.1	58.8	60.0	55.9	56.6[b]
22. Average kWh in 2100-2200	53.7	57.7	49.3	54.3	60.4	61.9	63.6	60.6	61.3	58.9
23. Average kWh in 2200-2300	57.1	61.4	56.0	55.5	58.2	64.7	63.8	64.0	62.6	55.0
24. Average kWh in 2300-2400	59.4	57.7	51.1	55.8	52.5	62.5	62.8	64.9	60.1	49.9
25. Average daily kWh	46.8	49.4	47.5	44.7	45.6	55.5	55.5	58.5	57.0	47.8
26. Average 60-min noncoincident max demand	45.1	46.9	45.5	42.4	44.2	50.2	51.3	50.3	47.7	43.9
27. Average 15-min noncoincident max demand	36.5	40.3	39.0	34.9	41.1	46.3	44.2	46.2	41.0	39.9

[a]Percentage differences are calculated relative to the non-SSI population. Differences which are not statistically significant at the .01 level are shown in parentheses.

[b]Indicates hour of system peak.

age differences in these parameter estimates appeared most pronounced in the winter months--perhaps due to the disproportionately small number of all-electric customers in the SSI population (5 percent) as compared to the non-SSI population (28 percent).

The levels of consumption used in calculating the percentage differences shown in Table 4-5 will be given in a companion volume to this report.

Table 4-6 shows, for each month of the study period, the average electricity consumption (in watthours per customer per hour) over four subsets of hours, listed below.

Type of hour	Definition
1	Hour of system peak in the month
2	All hours in the month in which system load exceeded 95 percent of the annual system peak (10,530 MWh on January 12, 1981 at 7-8 a.m.)
3	All hours in the month in which system load exceeded 90 percent of the annual system peak
4	All hours in the month in which system load exceeded 80 percent of the annual system peak

The upper portion of the table shows the number of hours involved in the average, and the lower portion of the table gives the percent difference in the SSI and non-SSI consumption levels during the particular set of hours. All of the differences shown are statistically significant and most are around 50 percent, indicating that the SSI customers used about half as much electricity during these types of hours as did the non-SSI customers.

4.3.2 Average Day of the Month

In contrast to the previous section, which focused on consumption during the days and hours of a calendar month in which the system load was high, this section discusses consumption averaged over all days of the calendar month.

TABLE 4-6. COMPARISON OF SSI AND NON-SSI CUSTOMERS WITH RESPECT TO ELECTRICITY CONSUMPTION DURING HOURS OF HIGH SYSTEM LOAD

	Type of hour*	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Number hours:											
	1	1	1	1	1	1	1	1	1	1	1
	2	0	20	39	0	0	-	-	8	7	
	3	0	59	96	15	0	-	-	22	17	
	4	20	216	227	100	0	15	25	131	84	11
Average consumption per hour (watt hours):											
Non-SSI	1	1,845	2,038	2,438	1,572	2,174	3,159	2,968	3,460	3,175	2,401
SSI	1	928	1,014	1,447	986	969	1,221	1,208	1,320	1,271	1,042
Non-SSI	2	-	2,278	2,215	-	-	-	-	2,931	3,006	-
SSI	2	-	1,163	1,163	-	-	-	-	1,314	1,274	-
Non-SSI	3	-	2,155	2,145	1,874	-	-	-	2,793	2,671	-
SSI	3	-	1,117	1,118	968	-	-	-	1,271	1,249	-
Non-SSI	4	1,663	1,936	1,986	1,726	-	2,574	2,516	2,457	2,500	2,353
SSI	4	861	1,012	1,043	908	-	1,214	1,210	1,163	1,111	1,160
Percent difference:											
	1	49.7	50.2	40.6	37.3	55.4	61.3	59.3	61.9	60.0	56.6
	2	-	48.9	47.5	-	-	-	-	55.2	57.6	-
	3	-	48.2	47.9	48.4	-	-	-	54.5	53.2	-
	4	48.2	47.7	47.5	47.4	-	52.8	51.9	52.7	55.6	50.7

*1 = Hour of system peak in the month.
2 = All hours in the month in which system load exceeded 95 percent of the annual system peak (10,530 MWh on January 12, 1981, at 7-8 a.m.).
3 = All hours in the month in which system load exceeded 90 percent of the annual system peak.
4 = All hours in the month in which system load exceeded 80 percent of the annual system peak.

Table 4-7 summarizes, by month, differences in electricity consumption for the two populations of interest. Differences in consumption are expressed in terms of percentages relative to the non-SSI population.

It is obvious from the information given in Table 4-7 that the SSI customers used substantially less electricity than those who did not have the SSI rate. For the average day in January 1981, for instance, SSI customers consumed 54.4 percent less electricity (see parameter 25 for January in Table 4-7). Similar results were observed for the average day in November December, and February. During the warm-weather months, the percentage differences were slightly smaller (43 to 48 percent) but still highly significant. In August, for example, the average daily consumption for the SSI customers was 46.4 percent lower than that for the non-SSI population.

The average daily difference reflects a lower consumption by SSI customers throughout the 24-hour day (parameters 1-24 in Table 4-7). This is best illustrated by examining average daily load curves for the two populations. Figures 4-1 and 4-2 show these estimated load curves for August 1980 and January 1981, respectively.

4.3.3 Monthly Class Load Factors

Two types of monthly class load factors (MCLF) were estimated for the SSI and non-SSI customer populations:

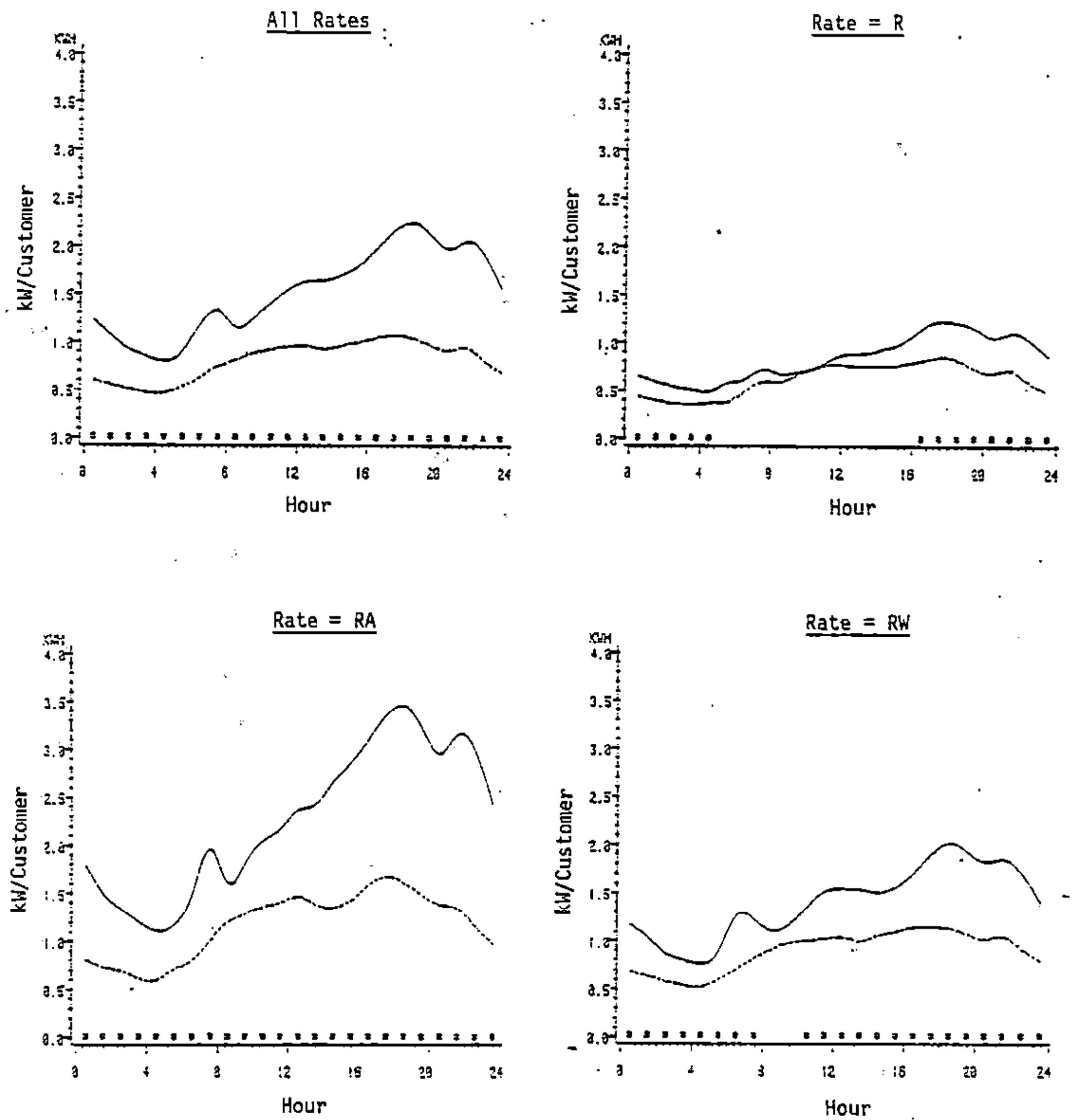
1. MCLF based on usage at time of monthly system peak; and
2. MCLF based on usage at time of monthly class peak.

Statistical comparisons between the two groups are carried out only for the first type of MCLF, since the second type is a parameter that is defined only at the class level and, consequently, a parameter for which appropriate variance estimates cannot be determined from a single sample of a given

TABLE 4-7. COMPARISON OF AVERAGE DAILY USAGE PATTERNS OF NON-SSI AND SSI POPULATIONS, BY MONTH

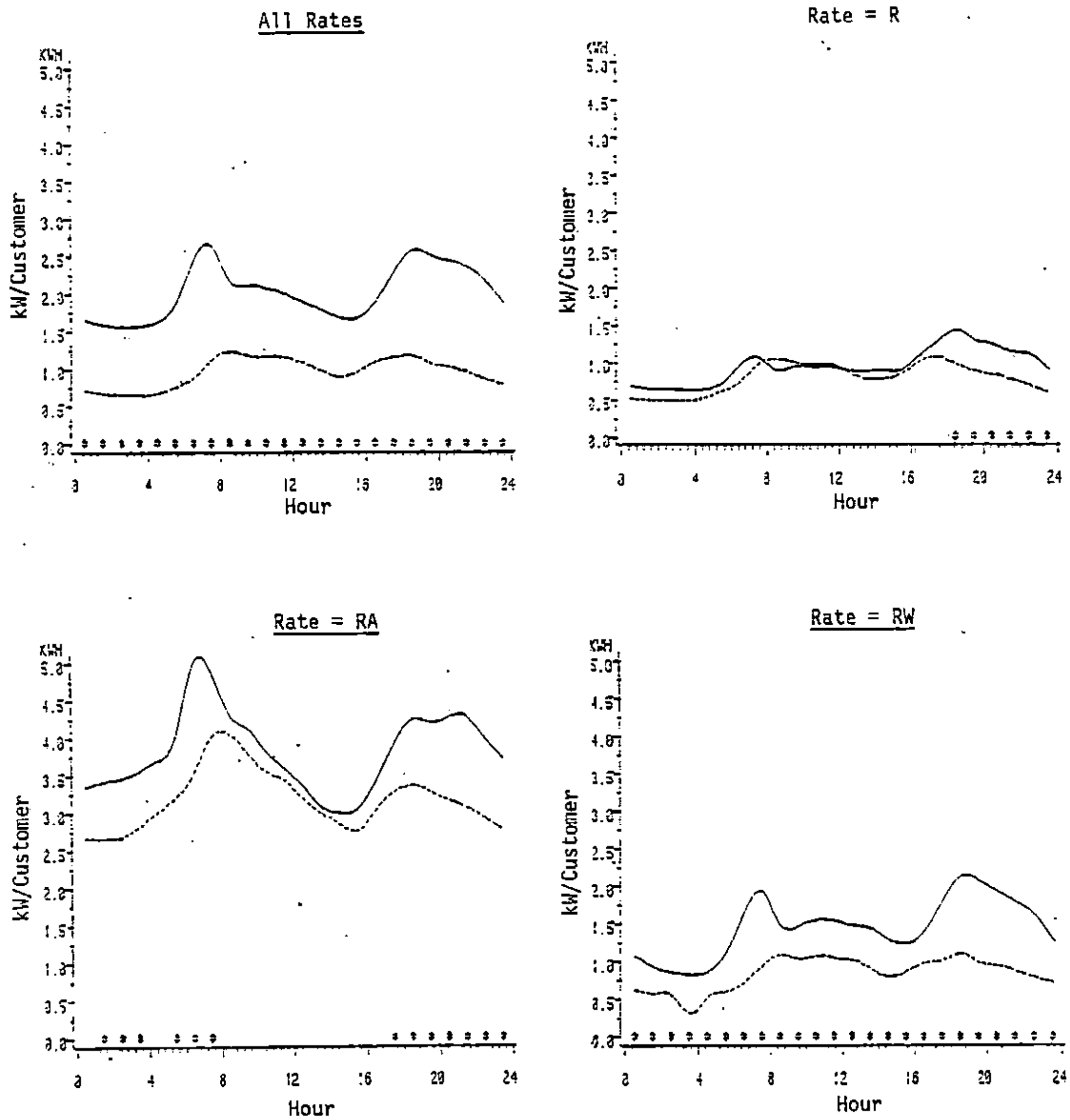
Parameter	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
	Percentage differences, by month[a]									
	1980							1981		
1. Average kWh in 0000-0100	46.8	53.0	48.2	43.7	44.1	58.3	59.5	58.3	57.8	49.3
2. Average kWh in 0100-0200	43.1	49.3	45.9	40.5	44.3	56.3	58.6	58.8	58.9	52.3
3. Average kWh in 0200-0300	41.3	46.0	45.0	38.2	42.8	56.4	58.2	59.4	60.6	53.3
4. Average kWh in 0300-0400	42.4	45.1	41.0	37.4	43.8	57.5	59.3	59.9	60.5	55.2
5. Average kWh in 0400-0500	39.0	42.2	36.3	30.6	43.1	58.8	60.6	59.9	60.2	55.1
6. Average kWh in 0500-0600	43.4	41.5	40.2	37.6	51.5	60.3	61.2	60.3	61.7	58.0
7. Average kWh in 0600-0700	48.0	45.0	47.0	46.0	49.3	58.0	62.2	63.8	62.8	58.6
8. Average kWh in 0700-0800	39.7	41.9	40.3	40.0	40.8	49.5	56.2	56.7	56.5	50.8
9. Average kWh in 0800-0900	32.2	33.4	34.7	24.9	30.0	42.2	47.3	45.6	47.6	39.9
10. Average kWh in 0900-1000	35.1	34.0	36.8	28.8	33.9	44.5	48.4	48.4	47.9	42.3
11. Average kWh in 1000-1100	39.1	39.0	36.7	32.5	35.8	44.9	49.6	47.1	47.8	41.6
12. Average kWh in 1100-1200	39.5	42.0	43.3	33.3	35.7	45.5	48.9	46.4	45.3	40.8
13. Average kWh in 1200-1300	43.3	43.7	43.2	38.1	40.8	47.4	50.5	48.0	47.5	41.7
14. Average kWh in 1300-1400	45.1	46.4	45.1	42.0	42.6	47.0	51.0	49.8	51.0	44.5
15. Average kWh in 1400-1500	46.8	46.2	46.1	41.2	41.2	46.0	48.6	50.1	47.1	42.3
16. Average kWh in 1500-1600	45.1	48.1	45.2	43.4	40.4	44.8	47.0	48.0	45.4	41.0
17. Average kWh in 1600-1700	46.9	50.5	47.4	46.7	40.8	42.2	47.8	46.9	44.2	39.7
18. Average kWh in 1700-1800	51.0	52.9	48.5	49.7	44.8	49.0	54.7	51.9	50.6	48.0
19. Average kWh in 1800-1900	54.3	53.8	52.1	53.2	48.8	53.5	56.7	55.5	56.1	52.5
20. Average kWh in 1900-2000	55.8	54.2	54.2	51.0	50.4	55.1	57.2	57.5	58.5	53.6
21. Average kWh in 2000-2100	53.9	54.0	53.2	50.4	51.4	57.7	58.0	57.9	58.5	52.7
22. Average kWh in 2100-2200	53.6	54.2	52.6	52.9	56.1	58.0	60.4	59.3	59.8	55.9
23. Average kWh in 2200-2300	56.3	57.3	54.5	53.1	54.2	59.1	61.1	60.4	60.4	54.1
24. Average kWh in 2300-2400	52.4	56.2	51.7	50.0	50.9	59.2	60.9	59.3	57.8	51.1
25. Average daily kWh	46.6	48.1	46.4	43.4	44.1	51.8	55.0	54.4	54.4	49.0
26. Average 60-min noncoincident max demand	42.3	44.2	42.7	37.7	39.9	44.7	42.9	45.6	44.7	40.3
27. Average 15-min noncoincident max demand	32.5	35.2	35.7	34.1	38.7	42.6	39.2	40.1	40.2	39.3

[a]Percentage differences are calculated relative to the non-SSI population. All differences are statistically significant at the .01 level.



Key: ——— Non-SSI
------ SSI
# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 4-1. Comparison of estimated hourly usage of SSI and non-SSI customers — July weekdays.



Key: ——— Non-SSI
------ SSI
\# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 4-2. Comparison of estimated hourly usage of SSI and non-SSI customers — January weekdays.

population. It should be emphasized that MCLF's are <u>not</u> estimated with high precision since they depend on the estimated average usage at a single hour.

Table 4-8 shows the results for each month during the study period for the MCLF based on usage at the hour of system peak (see Table 3-1). Statistical significance (at the .05 level) between the non-SSI and SSI MCLFs was detected only for the months of October, November, and January.

Table 4-9 shows the results for the second type of MCLF.

4.3.4 Weekdays/Weekend Days

Electricity consumption patterns for the non-SSI and SSI were derived separately for weekdays and weekend days within each calendar month. In each case, SSI-rate customers used less electricity than the non-SSI-rate customers. The patterns of differences were very similar to those described in Subsections 4.3.1 and 4.3.2, i.e., consumption was substantially less for the SSI population during each hour of the 24-hour day and the largest percentage differences in usage occurred during the winter months. Percentage differences appeared to be slightly larger for the weekend days than for the weekdays. Population estimates and results of statistical tests for these time periods are summarized in Table 4-10.

4.4 COMPARATIVE ANALYSIS RESULTS FOR SPECIFIC RATE CLASSES

Sample customers for the SSI rate study were selected from among North Carolina residential accounts in the Duke service area as of August 1979. These accounts were separated into the two primary populations of interest (SSI-rate and non-SSI-rate customers) as well as the three basic residential rates (R, RA, and RW). The number of accounts in the six categories are shown in Table 4-11, along with the percentage distributions.

TABLE 4-8. COMPARISON OF MONTHLY CLASS LOAD FACTORS, BASED ON USAGE AT HOUR OF SYSTEM PEAK, FOR NON-SSI AND SSI CUSTOMERS

Month	Population	Estimated average hourly kWh during month	Estimated average hourly kWh at hour of system peak	Estimated monthly class load factor (MCLF)	Estimated standard error of MCLF
1980:					
June	Non-SSI	1.250	1.845	.678	.056
	SSI	0.668	0.928	.720	.062
July	Non-SSI	1.547	2.038	.759	.048
	SSI	0.793	1.014	.782	.049
August	Non-SSI	1.541	2.438	.632	.032
	SSI	0.824	1.447	.569	.042
September	Non-SSI	1.266	1.572	.805	.053
	SSI	0.728	0.986	.738	.082
October	Non-SSI	1.321	2.174	.608	.037
	SSI	0.733	0.969	.756[a]	.043
November	Non-SSI	1.706	3.159	.540	.034
	SSI	0.823	1.221	.674[b]	.050
December	Non-SSI	2.000	2.968	.674	.034
	SSI	0.900	1.208	.745	.058
1981:					
January	Non-SSI	2.081	3.460	.601	.025
	SSI	0.949	1.320	.719[b]	.044
February	Non-SSI	1.851	3.175	.583	.029
	SSI	0.841	1.271	.662	.051
March	Non-SSI	1.594	2.401	.664	.029
	SSI	0.813	1.042	.780	.057

[a]Significantly different from the non-SSI MCLF at the .01 level.

[b]Significantly different from the non-SSI MCLF at the .05 level.

TABLE 4-9.
COMPARISON OF MONTHLY CLASS LOAD FACTORS,
BASED ON CLASS PEAK USAGE
FOR NON-SSI AND SSI CUSTOMERS

Month	Estimated class peak during month (kWh)		Estimated class load factor	
	Non-SSI	SSI	Non-SSI	SSI
1980:				
June	2.779	1.126	.45	.59
July	2.884	1.351	.54	.59
August	2.776	1.442	.55	.57
September	2.387	1.346	.53	.53
October	2.341	1.554	.57	.48
November	3.382	1.707	.50	.48
December	3.642	1.548	.55	.58
1981:				
January	3.460	1.486	.60	.64
February	3.175	1.271	.57	.60
March	2.524	1.269	.61	.62

TABLE 4-10. ESTIMATED AVERAGE DAILY ELECTRICITY USAGE FOR NON-SSI AND SSI CUSTOMERS, BY MONTH AND TIME OF WEEK

	Estimated average kWh (per customer, per day)[a]						Percentage differences[b]		
	Weekdays		Weekend days		All days				
Month	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Weekdays	Weekend	All days
1980:									
June	28.2	15.7	34.2	16.9	30.0	16.0	44	51	47
July	36.3	19.2	38.9	19.3	37.1	19.2	47	51	48
August	37.1	20.1	36.6	19.3	37.0	19.8	46	47	46
September	29.9	17.2	32.0	17.4	30.5	17.3	42	46	43
October	31.4	17.8	33.1	17.8	31.8	17.8	43	46	44
November	40.3	19.8	41.9	19.7	41.0	19.7	51	53	52
December	46.1	21.0	52.1	22.8	48.0	21.6	54	56	55
1981:									
January	48.1	22.5	53.7	23.3	49.9	22.8	53	57	54
February	44.2	20.3	44.9	20.2	44.4	20.2	54	55	54
March	37.9	19.4	39.1	19.8	38.3	19.5	49	50	49

[a] All differences between the non-SSI and SSI customers are statistically significant at the .05 level.

[b] Percentage differences are calculated as 1 - Y/X times 100 percent, where X and Y denote, respectively, the estimates for the non-SSI and the SSI populations.

TABLE 4-11. CATEGORIES OF ACCOUNTS

Rate class	Sample-eligible customers not on SSI rate		Sample-eligible customers on SSI rate	
	No.	%	No.	%
R	147,408	20.9	2,713	34.2
RA	198,684	28.2	421	5.3
RW	357,632	50.8	4,804	60.5
Total	703,724	100.0	7,938	100.0

The disparity between the two distributions shown in Table 4-11 is sufficient to have explained many of the differences described in the previous section. For example, suppose a particular parameter had values of 1, 5, and 2 for the R, RA, and RW rate classes, respectively, and suppose that these values held for both the SSI and non-SSI customers. Then the overall parameter values (i.e., combining over rate classes as in Section 4.4) for the SSI and non-SSI customers would be the following:

Non-SSI: .209(1) + .282(5) + .508(2) = 2.635
SSI: .342(1) + .053(5) + .605(2) = 1.817.

There is a 31-percent difference in these overall parameter values, even though there was no difference in the values assumed for the three specific rate classes. This simple example indicates that it is important to consider the separate rate classes, and to understand to what extent the distributional differences of the two populations over rate classes account for the differences described and presented in Section 4.4. This is the purpose of this section. Detailed results will be presented in a companion volume to this report.

Table 4-12 presents estimates, by rate class, of the average usage of non-SSI and SSI customers on the day of monthly system peak. The results of

TABLE 4-12. COMPARISON OF AVERAGE ELECTRICITY CONSUMPTION OF NON-SSI AND SSI CUSTOMERS ON DAYS OF MONTHLY SYSTEM PEAKS, BY MONTH AND RATE CLASS

Rate class	Estimate	1980 Jun. 3	Jul. 16	Aug. 6	Sept. 3	Oct. 30	Nov. 20	Dec. 4	1981 Jan. 12	Feb. 4	Mar. 19
R	Non-SSI kWh:	18.6	22.4	27.6	18.9	23.3	25.0	22.0	25.7	22.0	18.4
	SSI kWh:	12.9	15.0	17.3	15.8	12.7	13.8	16.9	21.3	18.2	16.7
	Difference:[a]	5.7	7.4	10.4	3.0	10.6	11.2	(5.2)	(4.5)	(3.8)	(1.7)
	% Difference:	30.6	33.1	37.5	16.0	45.7	44.7	23.4	17.4	17.4	9.1
RA	Non-SSI kWh:	51.8	64.4	59.8	48.5	56.3	88.9	85.7	134.7	119.0	80.6
	SSI kWh:	26.4	31.9	30.7	25.4	59.3	70.7	60.3	104.7	93.9	64.9
	Difference:[a]	25.3	32.5	29.2	23.1	(-3.0)	(18.2)	25.4	30.0[b]	25.1[b]	15.7[b]
	% Difference:	48.9	50.4	48.7	47.6	5.4	20.5	29.7	22.3	21.1	19.4
RW	Non-SSI kWh:	28.2	39.3	41.3	31.7	30.7	38.4	37.3	38.2	35.4	31.1
	SSI kWh:	19.3	24.5	25.4	19.7	20.4	22.6	20.3	21.9	21.5	21.5
	Difference:[a]	8.9	14.8	15.9	12.0	10.4	15.7	17.0	16.2	13.9	9.6
	% Difference:	31.6	37.6	38.5	37.9	33.8	40.9	45.5	42.5	39.3	31.0
All	Non-SSI kWh:	32.9	42.8	43.7	33.8	36.4	49.9	47.8	62.8	56.2	42.4
	SSI kwh:	17.5	21.7	22.9	18.7	19.8	22.2	21.3	26.1	24.2	22.1
	Difference:[a]	15.4	21.2	20.8	15.1	16.6	27.6	26.5	36.7	32.0	20.3
	% Difference:	46.8	49.4	47.5	44.7	45.6	55.5	55.5	58.5	57.0	47.8

[a]Difference between the non-SSI and SSI customers are statistically significant at the .05 level unless otherwise designated. Differences which are not significant at the .01 level are shown in parentheses.

[b]Differences between the non-SSI and SSI customers are statistically significant at the .10 level.

this table clearly indicate that the distributional difference described above is responsible for part of the difference between the two populations, since the overall difference is generally larger (on a percentage basis) than the differences for the individual rate classes. For the day of annual system peak (January 12, 1981), for instance, the differences for the R and RA classes are 17.4 percent and 22.3 percent, respectively (the former is not statistically significant, and the latter is significant at the .05 level), as compared to the overall difference of 58.5 percent. Thus, although there generally appear to be differences between the two populations even when evaluated on a rate-specific basis, these differences tend to be smaller in magnitude than the overall differences and are frequently not statistically significant.

5.0 ANALYSIS OF CUSTOMER SURVEY DATA

This chapter presents an analysis of the customer survey data described in Section 3.2. The appliance, profile, and household characteristics of the participating customers are the key elements in these data. The objectives of this analysis are to determine:

1. How the SSI and non-SSI populations differ in terms of their respective appliance saturations and household characteristics, and
2. How the sample characteristics of the SSI and non-SSI customers differ from the likely population characteristics of these groups of customers.

The comparative analysis of usage data presented in Chapter 4 showed large differences between the loads of the typical SSI and typical non-SSI customer. Objective one will determine if the load differences result from the two groups of customers having significantly different appliance saturations and household characteristics. In order to use the survey data to achieve objective one, it is necessary to compute weighted means and variances of the survey variables to estimate the population characteristics. The weights are defined in such a way that each weighted mean would, to the extent possible, estimate its corresponding population mean. This chapter also provides details of the weighted means computations and potential sources of inaccuracy caused by sample design peculiarities.

The second objective is important for evaluating the reliability of the covariate regression results that are presented in Chapter 6. Regression estimates are most precise when computed at the sample means of the explanatory variables. In Chapter 6, however, regression estimates are computed at the estimated population means computed in this chapter. If any of these population means differ substantially from their corresponding sample means, then a considerable loss of precision in the load estimates will result. In addition, the potential for estimation bias resulting from model misspecification is increased when estimates are computed at noncentral values of the explanatory variables.

5.1 Description of the Analysis Variables

The survey variables that will be used here to characterize the SSI and non-SSI populations are defined in Table 5-1. Apart from the three quantitative household characteristics variables at the bottom of the table, the remaining variables in Table 5-1 are indicator variables. The first 14 are appliance indicators, the next 3 are indicators for type of dwelling, and the final 3 are indicators for secondary heat sources.

5.2 Data Compilation and Reduction

The survey data consist of the responses from 199 SSI and 154 non-SSI customers. This is the entire set of customers who participated in the survey and includes customers who dropped out of the study, their replacements, and also those with incomplete hourly usage records.* The total of 353 customers is roughly 50 percent larger than the totals available for the monthly analyses of the load data. The reason for using the responses of all 353 customers, rather than just those eligible for the load analysis, is simply that the larger data set will yield more precise population estimates (i.e., weighted means) of the survey variables.

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*Many customers' usage records were missing due to meter failure.

TABLE 5-1. DEFINITIONS OF APPLIANCE AND DEMOGRAPHIC SURVEY VARIABLES

Variable Name	Definition
Appliances	
<u>Cooling</u>	
CAC	Indicator for central air conditioner
WAC	Indicator for one or more window air conditioners
<u>Heating</u>	
HEAT PUMP	Indicator for heat pump
EL._FURN	Indicator for electric furnace
RM_BY_RM	Indicator for electric room by room heat
<u>Discretionary</u>	
HOTW	Indicator for electric water heater
RANGE	Indicator for electric range
WASH	Indicator for electric clothes washer
DRY	Indicator for electric clothes dryer
DISH	Indicator for electric dishwasher
<u>Nondiscretionary</u>	
FF_FREZ	Indicator for frost-free freezer
NFF_FREZ	Indicator for non-frost-free freezer
FF_REF	Indicator for frost-free refrigerator
NFF_REF	Indicator for non-frost-free refrigerator
Household Characteristics	
<u>Type of Dwelling</u>	
HOUSE	Indicator for house
MOBILE	Indicator for mobile home
APT	Indicator for apartment
<u>Secondary Heat Source</u>	
FPL	Indicator for fireplace
WST	Indicator for woodstove
SPC	Indicator for portable space heater
<u>Other Household Characteristics</u>	
SIZE_RES	(Size of residence in square feet)/1000
VAL_RES	(Value of residence in dollars)/1000
NOHHMEM	Number of household members

5.2.1 Collapsing the Original Strata

The computation of variances using data from stratified samples requires that there be at least two sample members from each stratum. The sampling design prepared by Duke Power Company and utilized in this study called for the selection of only one customer from each stratum, but there were several strata in the SSI population that failed to contain a single household. Before weighted sample means and variances could be computed, the original 192 strata constituting each of the customer classes had to be collapsed into a smaller set of superstrata ("cells") each of which contained at least two customers. See Chapter 2 for details of the sample design.

While any number of collapsing schemes might have been chosen, the scheme used here combined the four off-season strata into a single stratum, leaving only 48 strata per customer class as shown in Table 5-2. If none of the originally defined strata were empty, there would have been at least four households in each cell.* Some of the original strata, however, contained none of the sample households and some sample households were also missing survey information, which caused some cells to have less than four households. In addition, there were still less than the minimum number of two households for a few cells, which required some additional collapsing (also shown in Table 5-2).

The additional collapsing was performed by joining that cell adjacent to the zero- or one-member cell that caused the selection probability in the newly formed cell to be as near as possible to the selection probability

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*Since replacement were included in the dataset, there could be more than four households supplying data in some cases.

TABLE 5-2. POPULATION AND SAMPLE CELL COUNTS OF SUMMER AND WINTER STRATIFICATION

SSI — Rate = R

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	820 7	319 7	32 4	2 0
2	127 4	451 4	46 7	9 5
3	28 4	248 7	120 5	14 4
4	18 4	111 4	240 4	78 6

non-SSI — Rate = R

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	48,878 3	1,823 4	72 3	13 2
2	24,779 3	27,268 4	137 3	19 3
3	2,068 3	35,610 4	1,827 3	42 2
4	283 4	1,642 0	2,529 4	418 4

SSI — Rate = RA

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	143 11	0 0	0 0	0 0
2	146 13	7 4	0 0	0 0
3	89 10	15 5	1 1	0 0
4	14 5	5 3	1 0	0 0

non-SSI — Rate = RA

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	35,601 3	18,913 4	1,821 2	180 2
2	9,171 4	41,945 4	19,577 4	782 4
3	1,222 4	13,956 3	34,833 3	9,501 4
4	117 2	550 4	3,603 2	6,912 3

SSI — Rate = RW

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	1,438 6	269 5	25 5	1 0
2	52 4	1,083 6	143 4	15 4
3	44 7	497 5	422 4	82 5
4	16 3	40 4	123 3	78 6

non-SSI — Rate = RW

Winter	Summer 1	Summer 2	Summer 3	Summer 4
1	99,954 4	6,772 3	494 4	18 1
2	42,239 3	87,135 3	1,091 3	38 4
3	3,602 3	72,606 4	25,273 3	158 3
4	584 4	2,916 4	13,259 4	1,493 2

Note: Collapsed cells indicated by boxes.

Stratum boundaries are illustrated in Tables 2-2 through 2-7.

that existed in the zero- or one-member cell prior to collapsing. Stated formally, let C_o be a cell with n_o sample members and N_o population members where $n_o = 0$ or 1. Also, let C^j, $j = 1,\ldots,k$ ($k \leq 4$) be k adjacent cells having sample and population sizes of n_j and N_j, respectively. For $j = 1,\ldots k$, compute Δj, the jth difference in the selection probabilities, where

$$\Delta_j = \left| \frac{n_o}{N_o} - \frac{n_o + n_j}{N_o + N_j} \right| \qquad (5\text{-}1)$$

Then combine cell C_o with that cell C_j for which the value of Δ_j is the smallest. Application of the collapsing scheme described above led to a partitioning of the 353 survey households into the 44 SSI plus 46 non-SSI cells shown in Table 5-2.

A word of caution is necessary as a result of the collapsing that had to be performed prior to the computation of the weighted means and variances. There is no guarantee that collapsing any two strata is valid since combining strata is equivalent to assuming no differences in the compositions of customers within each of the strata being combined. Should substantial differences exist in the distribution of, say, a particular appliance within two strata being combined, and if the selection probabilities differed for these two strata, then there will be some bias introduced into the computation of the estimated population saturation of that appliance.

Several collapsing schemes were tested before it was decided to collapse over the off-season strata to minimize the probability of serious biases occurring. For example, collapsing over the summer strata was rejected due to an uneven distribution of air-conditioners among these strata. Similarly, winter collapsing was rejected due to differing saturations of electric heating among these strata.

5.2.2 Computation of Weighted Means and Variances

Given the collapsed strata (cells) indicated in Table 5-2, weighted means and variances are computed as follows. Let n_j and N_j be the sample and population size of the jth cell and let N equal ΣN_j. Let y_{ij}, i = $1,\ldots,n_j$ be the n_j sample values for this cell for an arbitrary survey variable Y. Then the jth cell mean of Y is $\bar{y}_j = n_j^{-1} \sum_i y_{ij}$ and the weighted estimate of the population mean of Y is

$$\bar{y}_w = N^{-1} \sum_j N_j \bar{y}_j \qquad (5\text{-}2)$$

Similarly, the weighted estimate of the population variance of Y is

$$s_w^2 = N^{-2} \sum_j \frac{S_j^2}{n_j} (N_j - n_j)N_j \qquad (5\text{-}3)$$

where

s_j^2 is the sample variance of Y for the jth stratum,

5.2.3 Results

The estimated population means and their standard errors computed according to Equations (5-2) and (5-3) for the survey variables defined in Table 5-1 are shown in Table 5-3. The unweighted sample means of these variables also are shown in Table 5-3.

Objective one is concerned with how the SSI and non-SSI populations differ with regard to their appliance saturations and the other household characteristics covered in the survey. Table 5-3 shows that for a large number of the survey variables, the weighted means differ significantly between the two populations. In all cases the differences point toward higher average per household usage in the non-SSI class than in the SSI class.

Among the electric appliances, the non-SSI class has a significantly higher saturation of central air conditioners, heat pumps, room by room

TABLE 5-3. ESTIMATED POPULATION MEANS AND UNWEIGHTED SAMPLE MEANS OF 23 SURVEY VARIABLES

	Unweighted Sample Means			Estimated Population Means		
	Non-SSI	SSI	Difference[a]	Non-SSI	SSI	Difference[a]
Central Air	.384	.093	.291**	.237	.029	.208**
Window Air	.340	.275	.065	.307	.172	.135
Heat Pump	.109	.025	.084	.062	.007	.055**
Electric Furnace	.077	.064	.013	.073	.011	.062
Room by Room Heat	.192	.181	.011	.147	.035	.112**
Water Heater	.788	.730	.058	.853	.709	.144**
Range	.871	.833	.038	.832	.805	.026
Washer	.789	.554	.235**	.680	.473	.207*
Dryer	.635	.216	.419**	.449	.145	.304**
Dishwasher	.455	.049	.406**	.265	.006	.259**
Freezer, frost-free	.192	.083	.109**	.116	.073	.043
Non-frost-free	.288	.328	-.040	.379	.355	.024
Refrig. frost-free	.763	.441	.322**	.732	.345	.387**
Non-frost-free	.231	.539	-.308**	.251	.634	-.383**
House	.815	.672	.143**	.844	.758	.086
Mobile Home	.134	.127	.007	.100	.065	.035
Apartment	.051	.186	-.135**	.055	.150	-.095
Fireplace	.211	.093	.118**	.137	.116	.021
Woodstove	.179	.181	-.002	.148	.235	-.087
Space Heater	.032	.059	-.027	.006	.112	-.106*
Square Feet of Residence	1.484	.899	.585**	1.317	.894	.423**
Value of Residence	44.347	17.717	26.630**	35.686	14.045	21.641**
Number of Household Members	2.968	2.005	.963**	2.849	1.676	1.173**

[a] A single asterisk (*) indicates the difference in weighted means is statistically significant at the 10 percent level, a double asterisk (**) at the 5 percent level.

heating systems, water heaters, washers, dryers, dishwashers, and frost-free refrigerators. Members of the non-SSI customer class have homes that average 423 more square feet and $21,000 more value than their SSI counterparts. The typical non-SSI household has approximately one more family member than the typical SSI household.

The important issue is how these significant differences might contribute to the differences in the loads of these two groups of customers. In the summer months, a large differential in average air conditioning usage per household is certain to exist, since about 54 percent of all non-SSI households have some form of air conditioning compared to about 20 percent of SSI households. A similar situation exists for electric heat usage in the winter months with the total saturations of the various primary electric heat systems equal to about 30 percent among the non-SSI households, but only about 5 percent among the SSI households.

Water heater usage is most likely a major year-round source of differing usage between the two customer classes. Not only is the electric water heater saturation about 15 percent higher among non-SSI customers, but the major appliances that draw hot water--namely, clothes washers and dishwashers--have saturations in the non-SSI population of 21 percent and 26 percent, respectively, in excess of those in the SSI population. If these major appliances are utilized at similar rates by both customer classes, then the average per household water heater usage will be much higher in the non-SSI class. One other major appliance, the electric clothes dryer, is also much more prevalent among non-SSI households (45 percent ownership) than among SSI households (15 percent ownership).

The survey data show these many sources that contribute to greater non-SSI than SSI usage. It is not surprising that the comparative analysis presented in Chapter 4 estimates that indicated SSI households typically had loads about 50 percent less than those of non-SSI households. The survey results reinforce the importance of presenting both a comparative and a covariate analysis in this study.

The second objective of determining if large differences exist between any pairs of sample and weighted means can be achieved by analyzing the results of Table 5-3. There is a danger that the contribution to the load as estimated by a regression analysis will be unreliable for variables that have large differences between sample and weighted means. Errors in prediction due to errors in specification and estimation will be magnified when the weighted means deviate substantially from the sample means.

There are some variables for which fairly large deviations exist between the sample and weighted means because high users and some rate classes were oversampled. For the non-SSI population, the sample saturations are more than 10 percent greater than the estimated population saturations for the central air conditioners, washer, dryer, and dishwasher. For the SSI population, differences this large occurred for the air conditioning, electric heat, and refrigerator variables. On net, these discrepancies widen the confidence limits for the regression load estimates relative to what they would have been if the estimates were computed at the sample means.

An effort was made to compute the weighted means and variances with as little bias as possible; however, some bias may be present in the estimates. This is because the stratified sampling design prepared by Duke Power Company called for the selection of only one customer per stratum, which is insufficient for the computation of variances. Strata had to be combined to complete variances; therefore bias is possible in the weighted means.

The analysis of customer survey data has shown that the population of non-SSI households has a significantly higher proportion of many major electric appliances than does the SSI population. The non-SSI customers also tend to have larger, more expensive residences and larger family sizes.

The sample means of several of the survey variables were substantially larger than the corresponding estimates of their population means due to the oversampling of larger users in each of the populations being sampled. The effect of the differing sample and population means is to increase the variance of the load estimates presented in the covariance analysis of Chapter 6.

6.0 COVARIANCE ANALYSIS

In this chapter the information obtained from the customer survey is utilized to develop a behavioral model of hourly electricity demand for SSI and non-SSI households. The survey data consist of information on the appliance holdings, secondary heat sources, household size and value, and family size of each participating household. Together, these variables are referred to as "covariates" because they correlate with electricity usage. The model developed for this analysis is a linear regression model of hourly usage and a collection of independent variables constructed from the customer survey data presented in Chapter 5.

The objectives of the covariance analysis are:

1. To determine whether the usage of SSI customers is different from non-SSI customers when influences of covariate variables are included;

2. To determine whether SSI customers differ from other "low use" customers.

These objectives will be achieved by using the regression models to carry out three important activities. These activities are:

1. Compare the estimated hourly per household loads of the SSI and non-SSI customer classes;

2. Estimate average hourly usage per household of a hypothetical non-SSI class having appliance and demographic compositions identical to those of the SSI population and compare the hypothetical non-SSI load with that estimated for the SSI customer class; and,

3. Perform the above-mentioned estimations and comparisons separately for the three rate classes (R, RA, and RW).

The first set of comparisons listed above has already been made in the comparative analysis of Chapter 4. The covariance results of these comparisons/estimations tend to verify the comparative analysis results. An added benefit from performing these estimations is that the precision of the estimates may be improved over that achieved in the comparative analysis.

The second and third activities are necessary to separate differences in the typical load patterns of SSI and non-SSI households into those portions attributable to appliance and demographic differences and those attributable to differing appliance utilization habits. If the SSI households can be shown to use electricity in a different manner from non-SSI households, controlling for differences in appliance saturations and demographic characteristics, then the case for placing them on a separate rate schedule is strengthened. On the other hand, if it is found that the large differences in the load patterns of typical SSI and non-SSI households can be attributed almost entirely to differences in the covariates, then it can be assumed that SSI and non-SSI households behave alike, and the case for placing them on a separate rate is weakened.

6.1 DATA COMPILATION AND REDUCTION

The covariance results are presented for four different "day types": nonholiday weekdays, holidays and weekend days, the summer and winter system peak days, and days in the peak summer and winter months containing an hour for which system usage was at least 90 percent of the seasonal peak. Weekends and holidays are treated separately from weekdays because the patterns of hourly loads for these two day types differ and it is important to develop load curves that realistically characterize particular days. The system peak days of each month are of interest since the utility's cost of service is greatest on these days. Analyzing a single day of usage, however, will produce load estimates having high variances. "Near peak" days, such as those days for which the system peak was greater than 90 percent of the seasonal system peak, are a compromise solution that provides more precise estimates. In July and January, nine and seven days, respectively, fell into this "90 percent of peak" category.

The number of customers that could be used in the monthly regression analyses varied from month to month. In June (the first month of the experiment for which some data are available), several of the customers had not had meters installed causing the analysis sample to be somewhat smaller than that of the other months. Customers periodically dropped out of the study and were subsequently replaced by Duke Power Company. Since relatively complete data throughout a full month was necessary for inclusion of a customer in the analysis, the number of customers eligible for each month's analysis varied. Occasional meter failures that caused a customer's usage values to be invalid or missing for a period of time created additional fluctuations in the number of customers. A summary of customer deletions and inclusions for the comparative analysis was provided earlier in Table 4-3. Table 6-1 provides data on additional deletions due to missing appliance and demographic data and final count of customers available for the monthly covariance analyses.

6.2 MODEL SPECIFICATION

This section describes the process of specifying the covariate regression model. The study considered only linear models, but numerous possible specifications remained. The model of electricity demand required:

TABLE 6-1. DEMOGRAPHIC EDITS AND FINAL SAMPLE SIZES BY MONTH FOR COVARIANCE ANALYSIS

Month	Appliance and Demographic Edits[a]		Final Sample Size	
	Non-SSI	SSI	Non-SSI	SSI
June 1980	16	18	97	127
July	18	19	105	122
August	15	17	111	124
September	18	19	113	125
October	28	17	110	126
November	35	16	115	137
December	37	20	115	145
January 1981	31	20	118	147
February	32	18	114	145
March	32	19	119	141

[a]Values shown are the number of customers excluded from the covariance analyses of a given month due to lack of data on one or more of the covariates.

1. Specification of the dependent variable--find a transformation of kWh such that the variance of the transformed variable is approximately constant over its range.

2. Specification of independent variables--using the information provided in the survey data, construct a concise set of independent regression variables that correlate significantly with the transformed usage variables in at least some hours.

3. Specifications of differences in SSI and non-SSI customers--determine the manner and extent to which the regression relationships will be allowed to differ between SSI and non-SSI households.

6.2.1 Specification of Dependent Variable

A plot of usage against its predicted values from preliminary regression results indicated that the variance of the residuals increased over the range of the predicted variables. This type of heteroskedasticity is typical of variables with a finite lower bound (in this case, zero) and has been noted in most econometric analyses of electricity consumption data. The standard procedure used to reduce the heteroskedasticity is to adopt the natural logarithmic transformation (ln). The ln(kWh+1) transformation was used to avoid difficulties for usage values of zero. A subsequent preliminary analysis of the ln(kWh+1) values confirmed that there was no longer significant heteroskedasticity.

6.2.2 Formation of the Independent Variables

The 23 covariates available from the survey data consist of 14 electric appliance variables and 9 nonappliance variables. The electricity used by a household is the sum of the electricity used by the various appliances within the household, therefore each independent variable was defined with the intention that it would correlate with the usage of a specific type of appliance. Often, one or more nonappliance variables were incorporated into the definitions of an appliance-usage variable when this would increase its correlation with the end-use of that appliance. Table 6-2 summarizes the appliance-usage variables that were formed from the survey data.

The rationale for the variable constructions shown in Table 6-2 is as follows: AC (air conditioning) usage should be roughly proportional to the size of the cooled area; therefore the dummy variable for central air conditioning is multiplied by the square feet of the residence. Window air conditioners are assumed to cool about one-fifth of the residence. The logarithmic (log) transformation of the cooling variable is used to correspond to the log transformation of usage.

Hot water use is assumed to increase linearly with the number of household members. Again, the log of the positive values of this variable was taken to correspond to the log transformation of the dependent variable. The clothes-washing and clothes-drying variables are defined also as the product of indicator variables and the log of the number of household members.

The electric heat variable was defined as the product of the efficiency of the type of heat used and the square feet of the residence. The relative efficiencies of the heat pump, room-by-room system, and electric furnace were taken from Taylor (1979, p. E.11).

The refrigerator-freezer variable was constructed by weighting the indicator variables of frost-free and non-frost-free refrigerators and freezers by the estimated kW demand of each unit. The kW estimates were taken from Miedema et al. (1980, p. 79).

6.2.3 Modeling Differences in SSI and Non-SSI Appliance Utilization

There are basically three options in allowing the utilization rates of the appliance (i.e., the regression coefficients) to differ between SSI and

TABLE 6-2. DEFINITION OF COMPOSITE VARIABLES USED IN COVARIATE REGRESSION ANALYSIS

Variable	Definition[a]
L_AC	LOG [(1/1000) * SIZE_RES]*(CAC + 0.2*WAC)
HOTW_USE	HOTW * LOG (NOHHMEM + 1)
EF	.4167*HEATPUMP + .7708*RM_BY_RM + .9167*EL_FURN
L_HEAT	(1/1000) * (EF * LOG (SIZE_RES))
L_REFRZ	LOG (0.7*NFF_REF + 1.8*FF_REF + 1.32*NFF_FREZ + 2.0*FF_FREZ)
WASHING	WASH*HOTW*LOG(NOHHMEM + 1)
DRY_USE	DRY*LOG(NOHHMEM + 1)

[a]The survey variables appearing in these definitionns are defined in Table 5-1.

non-SSI households. The first option is to pool the SSI and non-SSI customers into a single regression and then allow separate regression coefficients for each group by including interactions of all of the independent variables with an SSI indicator variable. The second option is to include only that subset of interaction variables that are deemed important. The third option is to run separate regressions for the SSI and non-SSI groups. The first and third options yield identical estimates of the appliance coefficients of each group, but different estimates of the standard errors of these coefficients. Choosing between these two options is a matter of assessing the validity of pooling the two samples. The third option should be chosen when pooling is inappropriate. If pooling is appropriate, then one of the first two options should be chosen.

The test for the appropriateness of pooling compares the variance of the regression residuals from the SSI and non-SSI regressions (option 3). If, through an F-test, the hypothesis that the variances are equal can be rejected, then the data should not be pooled.

Table 6-3 shows F-tests that were performed from the results of selected hourly summer and winter peak day regressions. In several hours, the SSI and non-SSI variances differed at the 5-percent level of significance. These results indicated that pooling was inappropriate and separate regressions were run for the SSI and non-SSI samples. While the possibility exists that the F-tests might not be rejected when applied to the average weekday regressions, a common model was adopted for all the day types considered. The extended decision was not to pool to the entire set of regressions.

TABLE 6-3. TESTS FOR EQUAL VARIANCES BETWEEN SSI AND NON-SSI REGRESSIONS[a,b]

Hour	F(Summer)[c]	F(Winter)[c]
8	1.826**	1.408**
10	1.533**	1.208
12	1.533**	1.332*
14	1.630**	1.617**
18	1.116	1.131
20	1.111	1.512**

[a]F-statistics were computed for peak day regressions of each season.

[b]Statistical significance at the 10 percent level is denoted by a single asterisk (*); at the 5 percent level, by a double asterisk (**).

[c]These F-statistics were computed as:

$$F_{df_1, df_2} = \frac{\text{Residual Variance from Non-SSI Regression}}{\text{Residual Variance from SSI Regression}}$$

where in the summer $(df_1, df_2) = (111,140)$

and in the winter $(df_1, df_2) = (99,116)$

6.2.4 Final Model Specification

The decisions made thus far have been: to run separate linear regressions for the SSI and non-SSI groups, to use ln(kWh+1) as the dependent variables, and to use independent variables--some subset of the survey variables listed in Table 5-1 and the composite variables defined in Table 6-2. To arrive at a final model specification, the independent variables to include in this subset must be determined.

The method of selecting the final list of independent variables was to run preliminary hourly regressions using the summer and winter peak day data in which the following variables were included:

Summer: L_AC, HOTW_USE, L_REFRZ, RANGE, WASHING, DRYING, VAL_RES

Winter: L_HEAT, WST, HOTW_USE, L_REFRZ, RANGE, WASHING, DRYING, VAL_RES

The coefficients of these variables given by the estimated regressions were examined; whenever a particular variable was consistently nonsignificant at the 10-percent level, that variable was dropped from the specification. Consistent nonsignificance in both the summer and winter sets of regressions occurred only for the variable WASHING. Careful inspection of the coefficients, however, revealed a high negative correlation between the VAL_RES and L_AC coefficients. It was then discovered that the correlation between VAL_RES and L_AC variables was 0.711, which explained the negative correlation of the regression coefficients. Since air conditioning use was regarded as an important end-use to estimate, the VAL_RES variable was dropped to eliminate its effects on the L_AC estimates.

The final model adopted is shown in Equation 6-1.

$$\ln(\mathrm{kWh}^s_{it} + 1) = a^s_t + \sum_{j=1}^{k} b^s_{jt} Z_j + e^s_{it} , \qquad (6\text{-}1)$$

where

kWh^s_{it} = kilowatthours consumed in hour t (t=1, 2,..., 24) by the ith household in the SSI sample (s=1) or non-SSI sample (s=2)

Z_j = jth independent variable

a^s_t, b^s_{jt} = regression coefficients, and

e^s_{it} = random error term.

For the summer regressions (June-October),

{Z_j} = {L_AC, HOTW_USE, L_REFRZ, RANGE, DRY_USE} and

for the winter regressions (November-March),

{Z_j} = {L_HEAT, WST, HOTW_USE, L_REFRZ, RANGE, DRY_USE} .

The final number of independent variables included in the regressions (five in the summer; six in the winter) is small in comparison with the much larger number of survey variables available for the analysis. The reasons for using such a small number are:

1. The five major appliance types included usually account for at least 90 percent of a household's total electricity consumption. It is very difficult to obtain accurate estimates of the smaller appliance effects when the large appliances are this dominant.

2. Because significant correlations existed among many of the survey variables, only the essential variables were included to minimize the effects of multicollinearity on the estimated coefficients and thereby increase the precision of the estimated loads.

The sample correlations of the included independent variables are shown in Table 6-4. Note that many statistically significant correlations exist among these variables, but that none are greater than 0.430. While the presence of these correlations will tend to decrease the accuracy and precision of the estimates of the individual appliance effects, it should have

TABLE 6-4. CORRELATIONS AMONG INDEPENDENT REGRESSION VARIABLES[a,b]

	Summer (July peak day sample)				
	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE
L_AC	-	.029	.273**	.123	.389**
HOTW_USE	-.020	-	.096	.296**	.326**
L_REFRZ	.094	.231**	-	.108	.358**
RANGE	.079	.218**	.188**	-	.337**
DRY_USE	.124	.327**	.323**	.089	-

	Winter (January peak day sample)					
	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE
L_HEAT	-	.271**	.430**	.257**	.299**	.314**
WST	-.111	-	.229**	.174	.094	.314**
HOTW_USE	.334**	-.016	-	.083	.299**	.177*
L_REFRZ	.231**	.176**	.226**	-	.190**	.290**
RANGE	.209**	-.061	.235**	.133	-	.297**
DRY_USE	.248**	.044	.410**	.281**	.104	-

[a]Correlations below each diagonal pertain to SSI sample; those above the diagonals pertain to non-SSI sample.

[b]Significance at 10 percent level is denoted by a single asterisk (*); at 5 percent level, by a double asterisk (**).

little effect on the estimate of total consumption and the precision with which total consumption is estimated.

6.3 RESULTS

The regression model of Eq. (6-1) was estimated for the SSI and non-SSI samples using consumption data from each month of the experiment. For all months, weekdays and weekend days are considered separately. Regressions were estimated also for the peak summer and winter months (July and January), peak day and "nearly peak day."

6.3.1 Appliance Effects

Tables 6-5 and 6-6 show the regression results for average July and January weekdays. These are illustrative of the results for all the regression analyses. Each table presents the hourly estimated regression coefficients, the number of customers supplying data for the regression, and the regression R-square. The results for SSI customers are shown in the top half of the tables; the non-SSI results in the bottom half. Coefficients significantly different from zero at the 10-percent level are indicated by a single asterisk (*) while those significant at the 5-percent level are identified by a double asterisk (**). Tables for the other regressions will be presented in a companion volume to this report.

The L_AC variable was statistically significant for all hours except from about 6 a.m. to 8 a.m. from June through September for both SSI and non-SSI households. The magnitude of the coefficients from the SSI regressions was much larger (about double) than that from the non-SSI regressions because of a much higher ratio of window to central air conditioners in the SSI sample and smaller residences for SSI customers. The larger coefficient on L_AC for this class simply means that the change in usage per unit change

TABLE 6-5 ESTIMATED HOURLY REGRESSION COEFFICIENTS, SAMPLE SIZE, AND REGRESSION R-SQUARE FOR JANUARY WEEKDAY ANALYSIS[a]

Non-SSI

HR	INTERCEP	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.4249**	0.9381**	-0.5638**	0.1764**	0.0365	-0.0303	0.1542**	118	.6038
2	0.3977*	0.9776**	-0.5342**	0.1819**	0.0302	-0.0476	0.1585**	118	.6162
3	0.3874*	1.0201**	-0.4945**	0.1711**	0.0098	-0.0376	0.1690**	118	.6212
4	0.3845*	1.0691**	-0.4785**	0.1638*	0.0304	-0.0684	0.1673**	118	.6266
5	0.3784*	1.0652**	-0.4823**	0.1804**	0.0459	-0.0806	0.1678**	118	.6190
6	0.3083	1.0323**	-0.4716**	0.2127**	0.1151	-0.0095	0.1591**	118	.6175
7	0.3587	0.9244**	-0.3207**	0.2981**	0.1503	-0.0623	0.1599*	118	.5718
8	0.4434*	0.9151**	-0.3535**	0.2599**	0.1634	-0.0080	0.1228	118	.5200
9	0.4773*	1.0479**	-0.4746**	0.2018**	0.1463	-0.0971	0.1384*	118	.5686
10	0.3416	0.9647**	-0.4756**	0.2029**	0.2307	-0.0606	0.1540*	118	.5874
11	0.2494	0.8376**	-0.4872**	0.2075**	0.2630*	-0.0062	0.1769**	118	.5728
12	0.2162	0.7412**	-0.4044**	0.2301**	0.2712*	-0.0317	0.2052**	118	.5726
13	0.2171	0.7154**	-0.4232**	0.2176**	0.2701*	-0.0127	0.1784**	118	.5652
14	0.1706	0.6436**	-0.4027**	0.2082**	0.2711*	0.0438	0.1715**	118	.5492
15	0.2374	0.6738**	-0.3690**	0.1712**	0.2087	0.0553	0.1671**	118	.5447
16	0.2665	0.6704**	-0.3863**	0.1622**	0.1868	0.0522	0.1854**	118	.6025
17	0.3616*	0.6332**	-0.3429**	0.1559**	0.1103	0.1348	0.1910**	118	.5748
18	0.4152**	0.5927**	-0.3316**	0.1884**	0.1109	0.1285	0.2163**	118	.6077
19	0.4737**	0.5767**	-0.3172**	0.2243**	0.0936	0.1148	0.2104**	118	.6028
20	0.5399**	0.5955**	-0.3020**	0.2538**	0.0677	0.0134	0.2053**	118	.5763
21	0.5469**	0.6751**	-0.3434**	0.2557**	0.0753	-0.0692	0.2325**	118	.5973
22	0.5261**	0.7313**	-0.2904**	0.2532**	0.1062	-0.1152	0.2141**	118	.5957
23	0.4994**	0.8041**	-0.3327**	0.2256**	0.1142	-0.1087	0.1847**	118	.5775
24	0.4503**	0.9016**	-0.4359**	0.1976**	0.0875	-0.0916	0.1782**	118	.6120

SSI

HR	INTERCEP	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.3987**	1.4734**	-0.1458	0.1841**	-0.0852	0.0363	-0.0087	147	.6125
2	0.4108**	1.5150**	-0.1371	0.1764**	-0.0831	0.0215	-0.0130	147	.6177
3	0.4159**	1.5470**	-0.1305	0.1773**	-0.0826	0.0007	-0.0071	147	.6326
4	0.3881**	1.6404**	-0.1315	0.1579*	-0.0660	0.0107	0.0285	147	.6735
5	0.3943**	1.6982**	-0.0872	0.1767**	-0.0715	0.0052	0.0028	147	.6754
6	0.4572**	1.6915**	-0.0520	0.2033**	-0.1145	0.0075	0.0381	147	.6774
7	0.4912**	1.6390**	-0.0757	0.2707**	-0.0859	-0.0325	0.0686	147	.6867
8	0.5743**	1.6605**	-0.0035	0.1975**	-0.1224	0.0814	0.0921	147	.6443
9	0.5862**	1.6133**	-0.0121	0.1375*	-0.1056	0.1483	0.0907	147	.6416
10	0.6273**	1.6021**	-0.0462	0.1194	-0.1365	0.1387	0.0690	147	.6398
11	0.5997**	1.4721**	-0.0734	0.1496*	-0.1229	0.1479	0.0685	147	.6228
12	0.5618**	1.4342**	-0.0181	0.1688*	-0.1006	0.1273	0.0780	147	.6277
13	0.5262**	1.3816**	-0.1037	0.1816**	-0.0509	0.0928	0.0429	147	.6370
14	0.4774**	1.3012**	-0.0725	0.1607**	-0.0387	0.1021	0.0301	147	.6414
15	0.4436**	1.3668**	-0.0302	0.1378*	-0.0196	0.0916	0.0608	147	.6468
16	0.4585**	1.3121**	-0.0099	0.1294*	-0.0283	0.1216	0.0384	147	.6134
17	0.5624**	1.3018**	0.0036	0.1196	-0.0683	0.1199	0.0722	147	.5951
18	0.5326**	1.3353**	-0.0301	0.1547*	-0.0102	0.1096	0.0705	147	.6241
19	0.5566**	1.3536**	-0.0520	0.1983**	-0.0445	0.0820	0.0656	147	.6388
20	0.5399**	1.3938**	-0.0595	0.2060**	-0.0626	0.0583	0.0858	147	.6571
21	0.5272**	1.3909**	-0.0870	0.2225**	-0.0715	0.0446	0.0934	147	.6506
22	0.5135**	1.4067**	-0.1017	0.2053**	-0.0685	0.0355	0.0918	147	.6436
23	0.4873**	1.4446**	-0.1423	0.1843**	-0.0785	0.0393	0.0666	147	.6386
24	0.4536**	1.4523**	-0.1466	0.1753**	-0.0807	0.0437	0.0259	147	.6286

[a] A single asterisk (*) denotes the associate regression coefficient was different from zero at the 10 percent level of significance; a double asterisk (**), at the 5 percent level.

TABLE 6-6 ESTIMATED HOURLY REGRESSION COEFFICIENTS, SAMPLE SIZE, AND REGRESSION R-SQUARE FOR JULY WEEKDAY ANALYSIS[a]

Non-SSI

HR	INTERCEP	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.2379	0.5470**	0.0361	0.2124*	0.0845	0.0456	105	.5509
2	0.2364	0.5019**	0.0018	0.2150*	0.0713	0.0332	105	.5034
3	0.1969	0.4605**	0.0010	0.1959*	0.0834	0.0446	105	.5056
4	0.1479	0.3971**	-0.0094	0.1964*	0.1219	0.0607	105	.4656
5	0.1939	0.3451**	-0.0033	0.1781*	0.0721	0.0730	105	.4326
6	0.1682	0.2951**	0.0256	0.2074*	0.1361	0.0287	105	.3092
7	0.0907	0.3033**	0.1371*	0.2377*	0.2369*	-0.0539	105	.3019
8	0.0600	0.3677**	0.1366*	0.3122**	0.2497*	-0.0594	105	.3659
9	0.2224	0.3881**	0.0563	0.2417*	0.1111	0.0519	105	.3857
10	0.2775	0.4309**	0.0338	0.2169	0.0845	0.1224	105	.4134
11	0.2977	0.4558**	0.0090	0.2283	0.1082	0.1577*	105	.4336
12	0.4126*	0.4969**	0.0223	0.2032	0.0474	0.1506*	105	.4465
13	0.4854**	0.5457**	0.0080	0.1779	0.0046	0.1899**	105	.5183
14	0.4917**	0.6166**	0.0013	0.1654	0.0138	0.1799**	105	.5467
15	0.6086**	0.6344**	-0.0068	0.0830	-0.0379	0.2364**	105	.5754
16	0.5998**	0.6595**	-0.0145	0.1124	-0.0630	0.2676**	105	.6191
17	0.5920**	0.6250**	0.0082	0.1360	-0.0060	0.2508**	105	.5895
18	0.5124**	0.6422**	0.0362	0.1801	0.0803	0.2120**	105	.6081
19	0.5477**	0.6536**	0.0264	0.2062	0.0696	0.1778**	105	.5992
20	0.5768**	0.6411**	0.0233	0.1933	0.0575	0.1498*	105	.5797
21	0.5213**	0.6174**	0.0389	0.2270*	0.0048	0.1429*	105	.5984
22	0.4859**	0.5605**	0.0962	0.2328*	-0.0208	0.1582**	105	.5734
23	0.4777**	0.5331**	0.1393*	0.2323*	-0.1151	0.1482*	105	.5423
24	0.4229**	0.5368**	0.0889	0.2040	-0.0594	0.1042	105	.5234

SSI

HR	INTERCEP	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.1397	0.4201**	0.0959	0.2106**	0.0676	0.0734	122	.2631
2	0.1510	0.3734**	0.0919	0.1872**	0.0383	0.0768	122	.2609
3	0.1425	0.3057**	0.0698	0.1826**	0.0385	0.0995*	122	.2737
4	0.1445*	0.3041**	0.0571	0.1737**	0.0233	0.1088*	122	.2862
5	0.1009	0.3413**	0.0640	0.1913**	0.0401	0.1101*	122	.3422
6	0.1205	0.2057	0.0874	0.2042**	0.0493	0.0972	122	.2564
7	0.1584*	0.1751	0.0880	0.1977**	0.0906	0.0617	122	.2302
8	0.1804*	0.3086**	0.0971*	0.1977**	0.1203*	0.0449	122	.3071
9	0.1895*	0.5297**	0.1503**	0.2015**	0.0834	0.0792	122	.3979
10	0.2714**	0.6449**	0.1530**	0.1563*	0.0748	0.1157*	122	.4225
11	0.3604**	0.7070**	0.1513**	0.1401*	0.0175	0.1178*	122	.3875
12	0.3562**	0.8194**	0.1323*	0.1875*	0.0210	0.0830	122	.4006
13	0.3652**	0.8798**	0.1734**	0.2064**	-0.0442	0.0794	122	.4303
14	0.3116**	0.9902**	0.1185*	0.2605**	-0.0247	0.0704	122	.4706
15	0.3056**	1.0147**	0.1187*	0.2866**	-0.0202	0.0400	122	.4727
16	0.2823**	1.0168**	0.1213*	0.3127**	-0.0059	0.0626	122	.4721
17	0.3090**	1.0541**	0.1229*	0.3012**	0.0009	0.1093	122	.4884
18	0.3331**	1.0007**	0.1100	0.3046**	0.0033	0.1132	122	.4743
19	0.2820**	1.0201**	0.1288*	0.3051**	0.0220	0.0994	122	.5073
20	0.2456**	0.9662**	0.1187*	0.2916**	0.0453	0.0986	122	.4961
21	0.2658**	0.8515**	0.1079*	0.2718**	0.0276	0.1252*	122	.4919
22	0.2742**	0.7160**	0.1203*	0.2592**	0.0420	0.0995	122	.4243
23	0.1847*	0.5985**	0.1518**	0.2395**	0.0699	0.0817	122	.3786
24	0.1426	0.5333**	0.1340*	0.2385**	0.0582	0.0962	122	.3378

[a] A single asterisk (*) denotes the associate regression coefficient was different from zero at the 10 percent level of significance; a double asterisk (**), at the 5 percent level.

in L_AC is larger within the range of L_AC for SSI households than it is within the broader range of the L_AC for non-SSI households.

Considerable hourly and monthly variability was exhibited by these AC coefficients, but they were generally larger in the winter than in the summer. This is because the water heater must work harder in cold weather than in warm weather to maintain the desired hot water temperature. In the winter, the coefficients for both groups of customers were always significantly positive, while in the summer significance was attained from about 7 a.m. to midnight for the SSI class and only from 6 a.m. to 9 a.m. for the non-SSI class.

The pattern of coefficients of L_REFRZ for SSI customers, showing significance for virtually all hours in the summer and for very few hours in the winter, reflects the relationship that refrigerator and freezer electricity demands are greater when the household temperature is higher (i.e., in the summer). For non-SSI customers, a similar pattern existed except that for the hottest months the significance declined, perhaps because the extra air-conditioning usage reduced the share of refrigerator-freezer usage below a statistically detectable level.

The RANGE coefficients tended to be nonsignificant, with the following exceptions: breakfast hours during June and July for non-SSI customers, breakfast and lunch hours from October through December for SSI customers, and lunch and dinner hours from October through December for non-SSI customers. The patterns of significance were roughly the same for weekdays and weekends.

The coefficients on the DRY_USE variable had distinctly different patterns of significance for each group. For the SSI group, significance occurred only in the morning and early afternoon hours and only in the summer and fall. The coefficients from the non-SSI regressions were significant mainly in the afternoon and evening hours in the winter as well as in the summer and fall.

For all winter months the L_HEAT coefficients were statistically significant during all hours of the day. The magnitude of the SSI coefficients tended to be nearly twice that of the non-SSI coefficients. About 57 percent of the non-SSI electric heat customers had wood stoves, while only about 11 percent of the SSI electric heat customers had wood stoves, which increases the relative difference in the coefficients. The SSI class had older, less expensive homes than the non-SSI class and, as a result, probably had poor insulation. The size of the coefficient may also be influenced by the construction of the L_HEAT variable that incorporated the house size and thus limited the range of the variable for the SSI customers. There may also be behavioral differences in desired thermostat settings that influence the coefficient.

The WST variable was only important in the non-SSI analysis since such a small percentage of SSI customers with electric heat also had a wood stove. The WST coefficients were significant for nearly all hours of the non-SSI regressions while significance was almost never attained for WST in the SSI regressions. As expected, the magnitude of the significant non-SSI WST coefficients was greatest during the coldest months (December and January) and during the coldest hours (midnight to 10 a.m.) of each month.

6.3.2 Predicted Non-SSI and SSI Population Load Curves

The estimated population means developed in Chapter 5 were used to evaluate the estimated regressions to give predicted per-household load curves for the non-SSI and SSI customer classes. These same load curves were estimated in Chapter 4 via a weighted means analysis. By controlling for variations in usage due to variation in household appliance and demographic mixes, it is conceivable that the precision of the predictions developed here will be greater than that of the predictions developed in Chapter 4. To some extent this will depend on how much precision is lost due to differences between the sample means and the weighted population means of the independent variables.

For both weekday and weekend usage for each of the 10 months, 24 sets of regressions were estimated. Peak day and "near-peak" day usage was estimated in July and January. Estimated bad curves are shown only for July and January weekdays (Table 6-7). Each table provides estimates of the hourly non-SSI and SSI per-household loads, their standard errors, 95 percent confidence limits, the differences in the hourly load estimates, and the standard errors of these differences.

The monthly predicted loads from the covariance analysis are similar to those from the weighted means analysis. For each month, however, the predicted non-SSI loads from the covariance analysis are slightly less than those given by the comparative analysis of the means. The percentage difference ranges from 0 to 30 percent and is nearly always proportional to the magnitude of the predicted load. In the peak hour of the peak winter day, the comparative analysis estimated that the average non-SSI customer used 3.46 kWh, while the estimate for the covariance analysis was 2.49 kWh, a differ-

TABLE 6-7. PREDICTED HOURLY PER HOUSEHOLD LOADS FOR NON-SSI AND SSI POPULATIONS

Hour	Non-SSI kWh Mean	Non-SSI Std. Error	Non-SSI 95% Conf. Limits Lower	Non-SSI 95% Conf. Limits Upper	SSI kWh Mean	SSI Std. Error	SSI 95% Conf. Limits Lower	SSI 95% Conf. Limits Upper	Difference[a] (Non-SSI/SSI)	Std. Error of Diff.
JULY WEEKDAYS										
1	1.1504	0.0696	1.0251	1.2980	0.6230	0.0463	0.5342	0.7156	0.5353**	0.0836
2	1.0150	0.0649	0.8907	1.1452	0.5613	0.0403	0.4839	0.6417	0.4537**	0.0764
3	0.9052	0.0574	0.7952	1.0202	0.5193	0.0358	0.4504	0.5907	0.3859**	0.0677
4	0.8385	0.0555	0.7321	0.9497	0.4808	0.0329	0.4175	0.5463	0.3576**	0.0645
5	0.8094	0.0526	0.7065	0.9146	0.4699	0.0313	0.4094	0.5323	0.3395**	0.0612
6	0.9014	0.0633	0.7004	1.0284	0.5394	0.0303	0.4657	0.6158	0.3620**	0.0739
7	1.1306	0.0772	0.9833	1.2859	0.6324	0.0396	0.5561	0.7115	0.4982**	0.0860
8	1.3005	0.0851	1.1381	1.4718	0.7265	0.0394	0.6505	0.8051	0.5740**	0.0938
9	1.2030	0.0805	1.0495	1.3649	0.7879	0.0443	0.7027	0.8762	0.4151**	0.0918
10	1.2885	0.0919	1.1137	1.4738	0.8741	0.0479	0.7820	0.9696	0.4144**	0.1036
11	1.4171	0.1023	1.2227	1.6237	0.9307	0.0532	0.8285	1.0371	0.4863**	0.1153
12	1.5628	0.1079	1.3578	1.7808	0.9884	0.0570	0.8791	1.1024	0.5744**	0.1220
13	1.6468	0.1060	1.4451	1.8605	0.9963	0.0582	0.8846	1.1128	0.6505**	0.1209
14	1.6640	0.1077	1.4592	1.8813	0.9539	0.0563	0.8460	1.0665	0.7101**	0.1215
15	1.7043	0.1086	1.4977	1.9233	0.9901	0.0579	0.8790	1.1061	0.7142**	0.1231
16	1.7629	0.1084	1.5565	1.9814	1.0250	0.0616	0.9070	1.1485	0.7379**	0.1247
17	1.9645	0.1195	1.7372	2.2054	1.0902	0.0649	0.9660	1.2202	0.8742**	0.1359
18	2.1237	0.1221	1.8912	2.3697	1.1290	0.0657	1.0031	1.2607	0.9947**	0.1387
19	2.2045	0.1247	1.9670	2.4557	1.0784	0.0611	0.9612	1.2006	1.1261**	0.1388
20	2.1404	0.1206	1.9107	2.3833	0.9978	0.0575	0.8875	1.1127	1.1427**	0.1336
21	1.9697	0.1060	1.7659	2.1844	0.9559	0.0526	0.8549	1.0609	1.0138**	0.1190
22	1.9916	0.1100	1.7817	2.2130	0.9684	0.0542	0.8643	1.0767	1.0232**	0.1227
23	1.8365	0.1070	1.6326	2.0518	0.8311	0.0516	0.7320	0.9343	1.0054**	0.1188
24	1.5073	0.0901	1.3352	1.6886	0.7152	0.0500	0.6193	0.8153	0.7921**	0.1031
JANUARY WEEKDAYS										
1	1.2904	0.0881	1.1226	1.4678	0.6414	0.0557	0.5349	0.7533	0.6490**	0.1042
2	1.2275	0.0859	1.0639	1.4006	0.6107	0.0547	0.5061	0.7205	0.6168**	0.1018
3	1.1920	0.0860	1.0283	1.3653	0.5990	0.0534	0.4968	0.7062	0.5930**	0.1012
4	1.1845	0.0870	1.0190	1.3598	0.5829	0.0512	0.4850	0.6856	0.6015**	0.1009
5	1.2251	0.0909	1.0523	1.4084	0.6108	0.0531	0.5091	0.7174	0.6143**	0.1053
6	1.4388	0.1021	1.2448	1.6449	0.7047	0.0566	0.5965	0.8182	0.7341**	0.1167
7	1.8157	0.1289	1.5715	2.0766	0.8306	0.0607	0.7145	0.9524	0.9851**	0.1424
8	2.0236	0.1460	1.7476	2.3197	1.0500	0.0738	0.9091	1.1985	0.9736**	0.1636
9	1.7159	0.1232	1.4825	1.9653	1.1277	0.0742	0.9860	1.2767	0.5883**	0.1438
10	1.6717	0.1139	1.4553	1.9019	1.0881	0.0712	0.9519	1.2311	0.5836**	0.1344
11	1.6267	0.1096	1.4104	1.8479	1.0938	0.0705	0.9591	1.2353	0.5329**	0.1303
12	1.6066	0.1052	1.4065	1.8108	1.0780	0.0681	0.9477	1.2145	0.5207**	0.1253
13	1.5464	0.0993	1.3574	1.7464	1.0043	0.0627	0.8842	1.1300	0.5421**	0.1174
14	1.4866	0.0947	1.3061	1.6774	0.9279	0.0586	0.8156	1.0454	0.5587**	0.1114
15	1.4221	0.0902	1.2501	1.6036	0.8784	0.0556	0.7718	0.9896	0.5437**	0.1059
16	1.4240	0.0881	1.2708	1.5846	0.9266	0.0585	0.8144	1.0437	0.4974**	0.0992
17	1.6132	0.0891	1.4429	1.7921	1.0609	0.0644	0.9375	1.1901	0.5523**	0.1100
18	1.8754	0.0938	1.6959	2.0635	1.1269	0.0663	1.0000	1.2597	0.7485**	0.1148
19	2.0639	0.1017	1.8693	2.2681	1.1147	0.0655	0.9892	1.2459	0.9493**	0.1210
20	2.0298	0.1063	1.8268	2.2434	1.0223	0.0620	0.9036	1.1464	1.0075**	0.1230
21	1.9549	0.1064	1.7519	2.1688	0.9702	0.0619	0.8515	1.0943	0.9848**	0.1231
22	1.8931	0.1072	1.6888	2.1088	0.9057	0.0607	0.7894	1.0274	0.9875**	0.1232
23	1.7393	0.1060	1.5375	1.9520	0.7969	0.0582	0.6856	0.9135	0.9424**	0.1209
24	1.4858	0.0934	1.3078	1.6738	0.7174	0.0560	0.6103	0.8297	0.7684**	0.1089

[a] A double asterisk signifies that the difference is statistically significant at the 5% significance level.

ence of 28 percent. On the other hand, for this same hour of the average September weekday, the means analysis predicted an average usage of 1.37 kWh, while the covariance analysis predicted 1.26 kWh, a difference of just 8 percent.

Both analysis methods produced nearly identical predictions of average per-household SSI-customer usage in all months. This suggests that the discrepancy between the methods is due to differences in predicted non-SSI usage. There was virtually no difference in the standard errors of the estimates given by each procedure for both the SSI and non-SSI estimates, which suggests that the additional precision obtained in the covariance analysis by controlling for cross-sectional appliances and demographic differences was just offset by the loss of precision incurred by evaluating the regressions at the weighted, rather than the sample, means.

The main benefit provided by the covariance results is that it indicates that sensible load estimates can be obtained from the regression equations when they are computed at values of the independent variables that are in some cases quite different from the sample means. Table 5-3 presented in Chapter 5, illustrates the magnitude of these differences. As a consequence of this "resiliency" of the regression equations, the analyses of individual rate classes and low-usage customers that follow can be approached with greater confidence.

6.3.3 Comparisons Within Individual Rate Classes

Consumption of non-SSI and SSI customers by rate class has already been predicted in the comparison of weighted means analysis of Chapter 4, which showed that percentage differences between usage of non-SSI and SSI customers tended to be smaller within rate classes than for all rate classes combined. Individual rate class means were estimated using only individuals belonging to the rate class under consideration. However, when these within-rate-class comparisons are made using the covariance analysis results, the entire sample of customers figures into the calculations. This is because the entire sample was used to estimate the regression relationships. The individual rate class samples are only used to obtain within-rate-class covariate means for use in evaluating the estimated regressions.

The resulting non-SSI and SSI load estimates for the R, RA, and RW rate classes show similar percentage differences to those found in the comparative analysis. Table 6-8 illustrates the similarities between these results and those found in Chapter 4, by comparing the percentage differences in total consumption between non-SSI and SSI customers for each rate class found by each analysis method.

The results of the covariance analysis confirm the finding of the comparative analysis that, in general, percentage differences within rate classes are not as large as they are for the combined population. The actual percentage differences estimated by the covariance analysis for July were remarkably close to those computed from the comparative analysis. The January percentage differences, however, were not as close, being smaller for the RA and RW classes and larger for the R class.

6.4 COMPARISON OF USAGE BETWEEN SSI AND "LOW USE" CUSTOMERS

The analysis of covariance permits usage of the two customer classes to be compared, controlling for differences in appliance saturations and other household characteristics. By using a common set of covariate values to evaluate both the non-SSI and SSI regressions, the difference found in the resulting load estimates of non-SSI and SSI customers can be attributed to behavioral differences between the two groups (assuming the validity of the regression models).

TABLE 6-8. COMPARISON OF PERCENTAGE DIFFERENCES IN TOTAL DAILY CONSUMPTION BETWEEN SSI AND NON-SSI CUSTOMERS FOUND BY WEIGHTED MEANS ANALYSIS AND COVARIANCE ANALYSIS

Rate Class	July 1980		January 1981	
	Weighted Means Analysis	Covariance Analysis	Weighted Means Analysis	Covariance Analysis
R	33	33	17	24
RA	50	49	22	8
RW	38	36	43	36
All	49	45	59	45

The load analyses have shown that non-SSI customers use more electricity than SSI customers in all three rate classes, in all months and in every hour of the day, with the only exception occurring between non-SSI and SSI RA customers in some January daytime hours. It is not known, however, to what extent the predominantly greater non-SSI usage is due to a higher saturation of appliances, larger homes, etc., and to what extent it is due to greater appliance utilization rates.

The objective of this section is to determine if the label "low use" often applied to the SSI class can be interpreted to mean that a typical SSI customer will use appliances less than a typical non-SSI customer, or whether the correct interpretation is simply that the typical SSI household uses relatively little electricity because they have fewer appliances.

To shed some light on this question, the weighted means of the independent variables computed for the SSI class were inserted into the regression equation estimated for the non-SSI customers to predict what the typical non-SSI load would be if that class had the same appliance and demographic mix as the SSI class. The exercise was conducted using the overall SSI population means and also the three individual SSI rate class means. The four sets of means are shown in Table 6-9. The appliances for which major differences in saturation occurred among the rate classes were the water heater and electric heat since the rates were defined according to ownership of these appliances.* In addition to the water heater and primary electric heat variables, the RA class generally has higher saturations of the other

*Recall that the estimated 34.2 percent saturation of electric water heaters in the R class is due mainly to customers having water heaters too small to qualify them for the RW rate and also to the failure of certain customers who acquired (qualifying) water heaters to identify themselves to the utility prior to the time the survey was conducted.

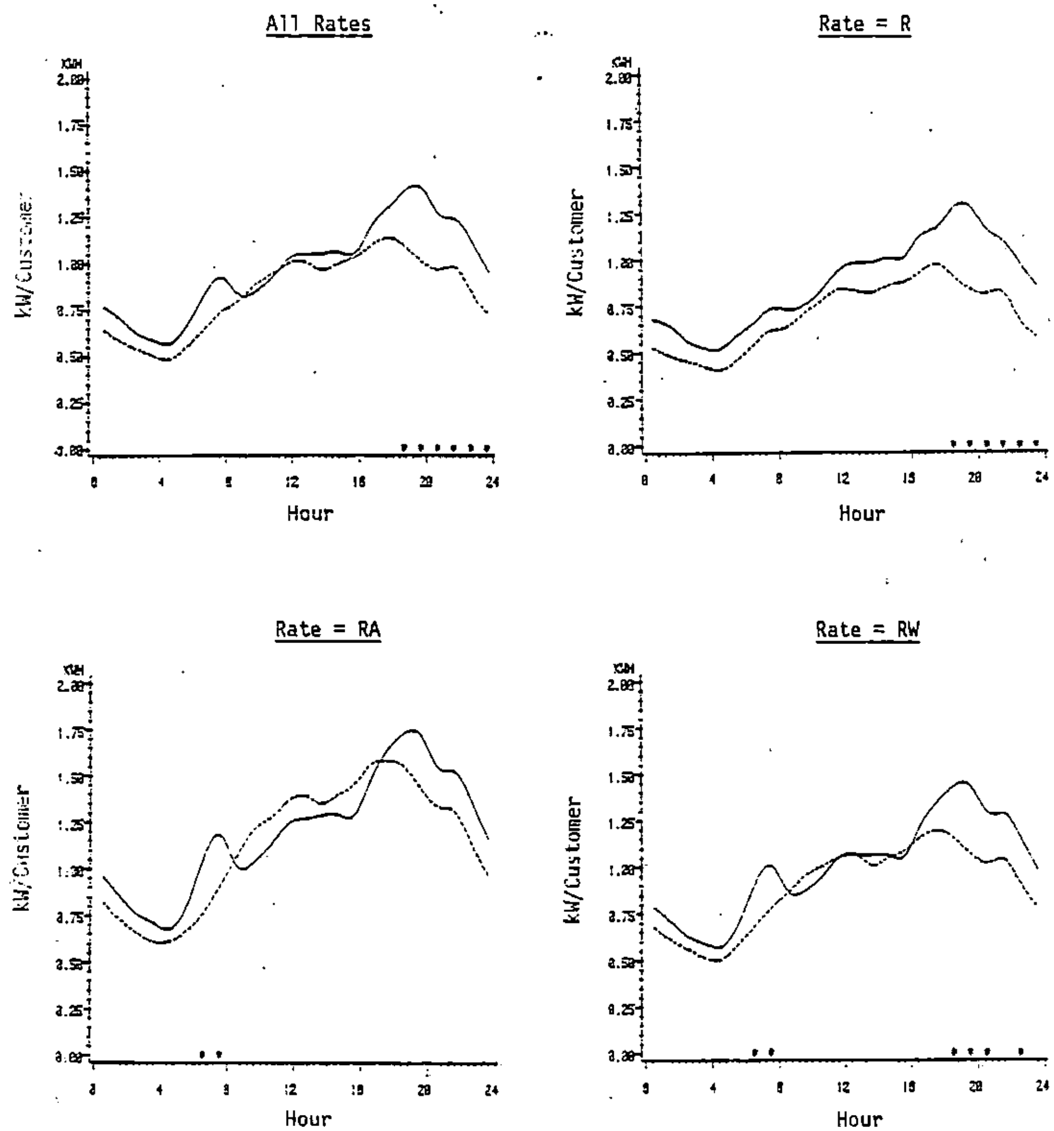
TABLE 6-9. APPLIANCE SATURATIONS AND DEMOGRAPHIC CHARACTERISTICS BY RATE CLASS FOR SSI POPULATION

Variable	Weighted Mean			
	R	RA	RW	Combined
CAC	.006	.254	.023	.029
WAC	.151	.289	.174	.172
HEATPUMP	.000	.140	.000	.007
EL_FURN	.000	.201	.000	.011
RM_BY_RM	.003	.594	.003	.035
HOTW	.342	.997	.892	.709
REFRZ	1.617	1.700	1.712	1.679
RANGE	.650	.966	.879	.805
WASH	.449	.596	.475	.473
DRY	.095	.251	.164	.145
DISH	.001	.100	.001	.006
WST	.233	.081	.250	.235
NOHHMEM	1.689	1.775	1.659	1.676
SIZE_RES	.745	.865	.980	.894

appliances as well. This is especially true for central air conditioning, where the RA saturation is estimated to be 25.4 percent as opposed to 2.3 percent for the RW class and just 0.6 percent for the R class. These differences must be kept in mind when interpreting the results among the three rate classes.

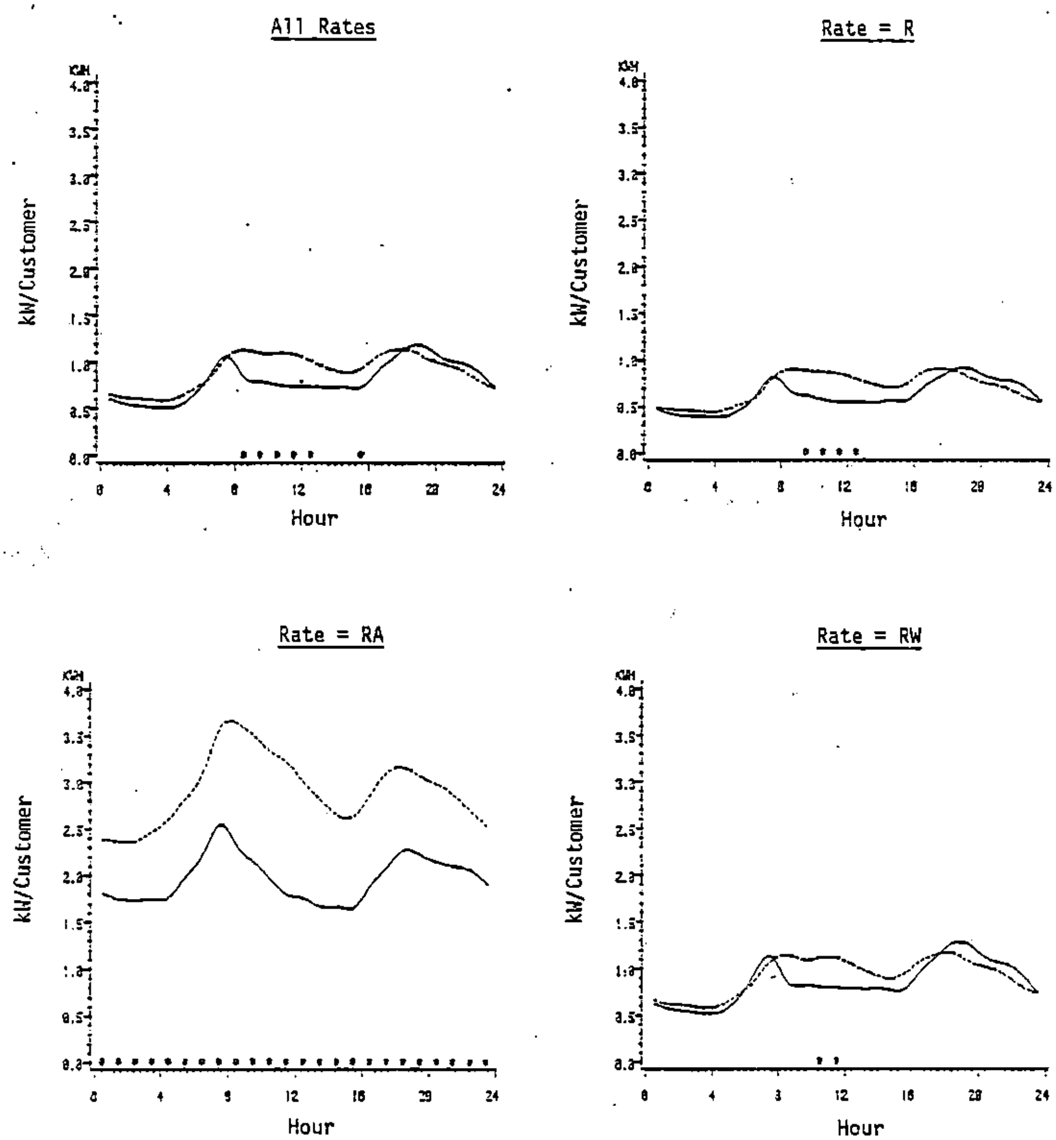
The results of comparing the utilization habits of SSI and non-SSI customers on a rate by rate basis are shown in Figures 6-1 and 6-2. The July analysis for the combined rate classes indicates that the groups use electricity at nearly the same rate except from 6 p.m. to midnight when non-SSI utilization is significantly greater. The individual rate classes reveal more variability between the utilization rates of non-SSI and SSI customers. Assuming an appliance and demographic mix corresponding to that of the SSI R-rate population yields consistently positive differences between non-SSI and SSI utilization, again with the largest differences occurring from 6 p.m. to midnight.

The comparisons, however, are quite different for RA type customers. In this case the only significant positive differences occur in the morning, from 6 a.m. to 8 a.m. Significant differences were found for no other hours, but from 8 a.m. until 5 p.m. SSI utilization was predicted to be greater than non-SSI utilization for this mix of customers. The trend reversed itself in the evening. Many of the positive (5 p.m.-12 p.m.) and negative (8 a.m.-5 p.m.) differences, while not significant at the 10 percent level, were still greater than zero by more than one standard deviation. Comparisons generated by assuming identical mixes of RW customers showed significantly greater non-SSI utilization in the morning (6 a.m.-8 a.m.), in the evening (6 p.m.-10 p.m.), and 11 p.m. to midnight. The daytime differences were again mostly negative, but very nearly zero.



Key: ——— Non-SSI
------ SSI
\# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 6-1. Comparison of estimated hourly usage of SSI and "Low-Use" customers – July weekdays.



Key: ——— Non-SSI
------ SSI
\# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 6-2. Comparison of estimated hourly usage of SSI and "Low-Use" customers — January weekdays.

An explanation for the three different ways in which non-SSI and SSI utilization compared may be that more SSI customers are home during the day (9 a.m.-5 p.m.) so that their use of the discretionary appliances (range, washer, dryer, dishwasher) is spread fairly evenly throughout the day and their use of air conditioning must occur in the daytime as well as nighttime hours. If so, then relatively fewer non-SSI customers are home during the day so that they would tend to concentrate their usage of discretionary appliances in the morning and evening hours. This would explain the significant positive utilization differentials detected during the morning and evening hours for R and RW households, as well as the negative differentials found for the RA customer comparisons (since they would use less air conditioning during the daytime hours).

The results for January are quite interesting. For the three rate classes combined, SSI usage is estimated to be significantly greater than non-SSI usage from 8 a.m. to 1 p.m. and from 3 p.m. to 4 p.m. when evaluating the regressions at the SSI means. In the remaining hours the differences are not significant. The sign pattern, however, is negative (indicating greater SSI usage) for all hours except 6 a.m. to 8 a.m. and 6 p.m. to 11 p.m. The comparisons within rate classes show that the combined results are very similar to those for the R and RW rates and much different from those for the RA rate.

The lack of influence of the RA results on the combined rate results is due to the small proportion of SSI customers on the RA rate (only 5.3 percent of the total SSI population). The results, however, indicate that usage of SSI households on the RA rate is significantly greater than usage of non-SSI households on the RA rate during all hours of the day in January. Possible explanations for these differences are a lower saturation of wood stoves, a preference for warmer household temperatures, and more poorly insulated homes within the SSI class in comparison to the general population.

The significantly higher estimated usage in the daytime by the R and RW customers may again be reflective of a relatively larger portion of the SSI class being at home during these hours. This hypothesis is supported by comparing the shapes of the estimated load curves of the SSI and non-SSI customers. The SSI customers consume electricity at a fairly constant rate from 7 a.m. to 8 p.m. whereas the non-SSI customers have an early morning peak from 7 a.m. to 8 p.m. and an evening peak from 5 p.m. to 11 p.m.

7.0 COST ANALYSIS OF LOAD DIFFERENCES

The primary objective of this chapter is to translate the differences between SSI and non-SSI customer usage that were presented in the comparative analysis of Chapter 4.0 into differences in the Duke Power system energy costs. To accomplish this objective, an analysis framework that describes a utility's cost in terms of marginal and average energy costs has been developed.

A major assumption is that the differences in capital costs and costs associated with transmission and distribution are of lesser consequence than those of energy costs, which implies that the cost estimates represent a conservative estimate of the total difference in the cost of serving SSI and non-SSI customers. The costing procedure will show the relative magnitude of the energy cost differences, which is essential to determine if the SSI rate is cost-justified.

Section 7.1 presents an overview that highlights various costing methodologies and illustrates both the theoretical and empirical problems associated with the methodologies. The data compilation and reduction procedures used in the costing analysis are discussed in Section 7.2. The methodology used in the cost analysis is developed in Section 7.3 and the results are presented in Section 7.4.

7.1 OVERVIEW OF COSTING METHODOLOGIES

In recent years researchers in electricity economics have devoted considerable attention to the issue of the most appropriate measure of the cost of producing electricity. No clear consensus has been reached but a pragmatic interpretation of the relevant issues will provide a much needed background for the methodology employed in this chapter to assess the cost implications of the differences between SSI customers and non-SSI customers.

Embedded or average cost and marginal cost approaches are the two primary classifications, or methodologies, for measuring the cost of producing electricity. Average cost techniques focus primarily on the recovery of the investment and operating costs incurred in the production of electricity. Marginal cost techniques measure the incremental or additional cost of producing one more unit of electricity. Average cost reflects the cost of producing electricity averaged or weighted over an entire time period; marginal costs are forward looking, sending signals to producers and consumers based on the most recent unit produced.

Unfortunately, average cost versus marginal cost has become a hotly debated issue in which proponents of each technique argue the significance of following their method. This discussion is blurred even more by arguments among the proponents of each methodology as to the appropriate (correct) interpretation of the theoretical concepts that are the underpinnings of each approach.

Average cost techniques combine the capital cost of previously purchased equipment, the cost of new investment, and the variable costs of producing electricity--fuel, operation, and maintenance--into a comprehensive measure of the cost of producing electricity. The primary concern of average cost techniques is to provide a method to recover the costs of producing electricity. Variable costs are easily allocated to the units responsible, even differentiated by the time that they were incurred. The main problem in electricity pricing is to allocate the capital costs that are common to all customers. The average cost methods divide customers into broad classes and then allocates costs across these classes according to various criteria. Table 7-1 summarizes the most frequently used criteria for allocating capital costs.

The peak responsibility method allocates demand costs for an electric utility on the assumption that capacity requirements are determined by the peak load. Capital costs are allocated either totally to the demand component or are adjusted to compensate for those customer classes that have higher load factors and impose lower costs. These additional measures recognize the effect on total capacity requirements of maintenance scheduling and other system operation factors in addition to the importance of the peak load. The range of measures will also indicate any sensitivity to the system load characteristics.

The effectiveness of the peak responsibility method for allocating demand-related costs is hindered by the fact that it does not provide any benefit to the positive impacts of load diversity and by the major shifts in cost allocation that arise when peaks shift. The former effect is mitigated by using peak averages and the latter can be reduced by using the load factor excess demand adjustment to account for diversity.

The average of the maximum demands combines maximum class demands, calculates their average, and uses this average to allocate capital costs. Noncoincident demand techniques use the group maximum demands that do not occur at the same time the system maximum occurs. Both of these techniques can be adjusted in the same way as the peak responsibility technique to incorporate the benefits of diversity.

TABLE 7-1. CRITERIA FOR ALLOCATING CAPITAL COSTS

1. Peak responsibility

   a. 100% to demand component
   b. Load factor--excess demand

2. Average of maximum demands

   a. 100% to demand component
   b. Load factor--excess demand

3. Noncoincident demand

   a. 100% to demand component
   b. Load factor--excess demand
   c. Load factor--diversity factor

Four basic shortcomings limit the usefulness of the average or embedded cost techniques. The methods reflect a primary accounting goal of recovering sunk costs, imply that resources can be used in the future as in the past, consider equity in the very narrow terms of an allocated share of accounting cost, and provide no incentive effects. Turvey and Anderson (1977) have pointed out that the relevant costs for efficiently allocating resources are the additional costs of meeting extra usage. The costs should be a signal that is related to the value of the resource used or saved. Primarily, prices should be forward looking.

Marginal costs overcome the primary weaknesses of the average cost techniques by providing signals that are forward looking and reflect the existing situation in the marketplace and that of the electric utility itself. Marginal costs, however, present the analyst with a perplexing array of problems that limit their widespread application in utility rate design.

Marginal cost is the cost incurred by producing one more unit or the cost avoided by producing one less unit. Economic efficiency requires that marginal costs should equal prices because the incremental value that consumers place on a unit should just be equal to the additional opportunity cost incurred in producing that unit. Marginal cost equal to price should also serve as a rule of thumb for the electric utility in that it pays the utility to continue to produce and sell as long as incremental revenues cover incremental costs.

Economic efficiency is not an equity criterion and provides no implications for the fairness of an existing distribution of income. In theoretical terms, if marginal cost pricing is not achieved in all markets, economic welfare may not improve by achieving it in one market. From a practical policy perspective, however, regulators who encourage movements toward marginal cost pricing will improve efficiency within the regulatory arena that they govern.

Problems also arise in defining marginal costs, which, in turn, has lead to numerous interpretations in an attempt to solve these problems. In a recent series of works,* several analysts compared and critiqued the alternative methodologies for implementing marginal cost pricing for an electric utility. We will draw from this work to illustrate the problems in defining marginal costs but will not provide a detailed critique of each method.

To carry out a marginal costs analysis, one must specify the time perspective that is relevant. Marginal costs consider only those costs that are variable and ignore the costs that are already sunk into the enterprise. The length of the selected time horizon will determine the percentage of costs that are variable and thus are included in the analysis.

In specifying the length of the time horizon, most of the major marginal cost techniques have tended to define the time horizon to allow changes in plant capacity, arguing that long-run marginal costs are a more workable measurement. Short-run marginal costs, which do not allow for changes in plant capacity, have high variability and may yield the electric utility

*Two of the most relevant works are Temple, Barker, Sloan. An Evaluation of Four Costing Methodologies, Electric Power Research Institute (EPRI). Electric Utility Rate Design Study (Report #66), July 13, 1979 and the Comments on an Evaluation of Four Costing Methodologies, by Temple, Barker Sloan, et al., EPRI, Electric Utility Rate Design Study. (Report #67), June 12, 1980.

revenues that are either too high or too low. The Cicchetti, Gillen and Smolensky (CGS) method employs the long-run marginal cost definition arguing that in a "planning" sense, capacity can be varied and is fixed only when viewed as "bricks and mortar."

The Ernst and Whinney method assumes that all factors of production are flexible and that any new technology can be incorporated into the cost analysis. Utilities are assumed to have full adaptability and are not restricted to using capacity from the preceding period. This method is less valuable as a practical means of measuring marginal cost than as a means of comparing the idealized marginal costs of two different production strategies.

The National Economic Research Associates (NERA) method and the Gordian Associates (Gordian) method constrain the utilities to their current expansion plans for a relevant time horizon for costing, but draw heavily on personal expertise rather than rigorous definitions for their methods. The Gordian model, however, allows for up to 100 different future expansion plans and compares the discounted costs of each in order to select that plan with the lowest discounted costs of producing the predicted future demands.

Turvey and Anderson (1977) suggests that from a practical standpoint, defining the time horizon is not a major problem. Prices should reflect both long-run and short-run marginal costs to the extent that each is important for the utility or policymaker. If long-run signals are more important, then greater weight should be given to the long-run cost measure and vice versa.

Marginal cost techniques must also solve the problem of specifying the appropriate incremental unit. CGS solves this problem by specifying the incremental unit as the change in the timing of expansion planned by a utility attributable to an increase in production. NERA, on the other hand, defines the marginal unit as the next combustion turbine that is brought on line by an increase in output. It is clear that in solving this problem the analyst must balance the practical with the theoretical ideal.

Marginal cost analyses must still find some means of allocating the costs that are common and that cannot be easily attributed to a customer. This involves defining a peak period and then developing a rationale for allocating the common costs (primarily capital costs) across the peak period. Problems that arise here are very similar to the capital allocation problems that plague embedded cost analyses.

In summary, there are problems in employing either marginal costs or average costs to determine the appropriate prices for electricity. Marginal costs do provide important signals to producers and consumers that are disguised in average cost estimates, which is critical from the rate design standpoint. For the purposes of this chapter, however, both provide a rationale for developing a practical methodology to portray the cost differences between SSI and non-SSI customers.

7.2 DATA COMPILATION AND REDUCTION

Hourly load data of Duke Power Company for the period June 1980 through March 1981 (summarized in Section 3.1) were the main source of data for this analysis. Detailed information on Duke Power production capability, including plant capacity, fuel use, heat rate, and production cost for the units, was provided by Duke Power for inclusion in the GLiMPS production costing model. GLiMPS is a power system production costing model that estimates costs based on sequential hourly simulation of the system's operation. The SSI rate study used a modified version of GLiMPS that minimized the operational costs but still produced reliable production costing results. This version modified the Monte Carlo simulation of the power system stochastics and used 20 production histories in simulating production costs.

GLiMPS determines optimum daily operating configurations at hourly intervals using unit commitment and economic dispatch criteria. GLiMPS uses an optimal unit commitment subroutine to determine the hourly operating schedule of available units. Standard utility dynamic programming techniques that consider starting cost and operating cost provide the basis for the unit commitment process. Variable operating and maintenance costs are not considered because they are small compared to fuel costs. Unit loading and fuel costs are determined by the LaGrange multiplier economic dispatch method that provides a cost minimum operation decision.

GLiMPS estimates the hourly production for an average weekday and an average Saturday and Sunday. A simple average of Saturday and Sunday costs was calculated to provide an estimate comparable with the usage data for an average weekend day from the comparative analysis.

The GLiMPS model dispatches only conventional fuels and does not provide for any hydro capability. Because the Duke System has substantial hydro capability, a linear programming routine was employed to adjust the system load data by using the pumped hydro to shave the peaks and fill the valleys in the system load profile. More detailed documentation of this linear programming model is presented in Appendix E.

7.3 METHODOLOGY FOR COSTING ANALYSIS

The basic objective of the costing methodology is to provide a means for expressing the differences in load between non-SSI and SSI customers in terms of the cost of producing electricity. As we have demonstrated earlier, there is no clear consensus on the most appropriate means for accomplishing this task.

The key to developing a workable methodology is to focus on those cost components that are most relevant to differences between SSI and non-SSI customers. Figure 7-1 indicates the possible sources of cost differences and the one chosen for this study.

At the system level, transmission and distribution costs should be essentially the same for the two groups because they require the same equipment and impose the same requirements on the system. Ignoring these sources of potential differences in cost should have little effect on our results. At the substation level, the more diverse load of the SSI customers should result in some small amount of savings, but this analysis is concerned only with system level costs.

Administrative costs should also be essentially the same for the two groups except for the requirement that SSI customers must be identified and verified by Duke Power Company and the Social Security Administration. This is an added cost for Duke, but the order of magnitude is probably small now that program startup costs are sunk, and therefore it is excluded by the costing methodology.

Differences in generation costs should constitute the largest component of the cost differential between serving SSI and non-SSI customers and this is the primary focus of the costing methodology. These differences are due to both capital and energy elements. Differences in capital costs are excluded because of the arbitrary nature of attributing costs of capital to different residential customers and measurement problems in actually determining capital costs. This exclusion suggests that because SSI customers

COST CATEGORIES

	Generation	Transmission	Distribution	Administration
Non-SSI Customers	√	•	•	•
SSI Customers	√	•	•	•

√ Measured by Costing Methodology

• Not Measured by Costing Methodology

Figure 7-1. Costing methodology and cost categories.

use less energy than non-SSI customers and have at least as high a load factor, the costing methodology will provide a lower bound estimate of the difference in the cost of service.

The costing methodology that has been adopted measures the short-run marginal and average energy costs of serving SSI and non-SSI customers. Long-run considerations are excluded because of the small effect the SSI customers have on system load and any system expansion plans. Since short-run energy costs are the largest source of cost differences, the use of these energy costs achieves the primary objective of measuring the cost differential that results from the usage differences between SSI and non-SSI customers.

7.4 RESULTS

Table 7-2 presents the average hourly energy costs for SSI and non-SSI customers for a typical weekday. The same costs for a typical weekend day are presented in Table 7-3. The cost estimates are based on estimated hourly production costs provided by the GLiMPS production costing model and estimated hourly usage from the comparative analysis presented in Chapter 4.

The data indicate that the cost of serving SSI customers, measured in terms of hourly energy costs, are approximately half of those for serving non-SSI customers. The calculated hourly energy costs follow the system load profile for both winter and summer by increasing as the system moves toward peak production. In the off season months, the cost differential is not quite as great, reflecting the smaller difference in usage in these non-critical months.

The average monthly energy costs of a typical weekday and weekend day for this study are presented in Table 7-4. For the typical weekday, average

TABLE 7-2. AVERAGE HOURLY WEEKDAY ENERGY COSTS
SSI AND NON-SSI CUSTOMERS--mils/kWh
(June 1980 - March 1981)

Average cost in	June 1980		July 1980		August 1980		September 1980		October 1980	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	7.95	4.31	12.06	5.76	12.23	6.38	8.49	4.83	7.78	4.44
0100-0200	6.48	3.70	10.11	5.13	10.35	5.58	7.09	4.24	6.84	3.89
0200-0300	5.44	3.22	8.58	4.63	9.15	5.00	6.32	3.96	6.70	3.85
0300-0400	5.23	2.99	7.74	4.27	8.24	4.77	5.99	3.63	6.69	3.74
0400-0500	4.93	3.04	7.25	4.25	7.73	4.94	5.87	4.05	7.20	4.08
0500-0600	6.96	3.93	8.36	4.88	9.04	5.31	7.87	4.67	10.24	4.88
0600-0700	11.12	5.51	11.55	6.10	12.74	6.38	12.13	6.22	16.80	8.25
0700-0800	13.27	7.63	13.70	9.66	14.89	8.50	14.69	8.37	19.54	11.06
0800-0900	11.90	8.18	12.36	8.67	14.00	9.40	11.84	9.16	16.19	11.36
0900-1000	12.07	8.41	13.79	9.72	14.96	10.24	11.07	8.63	15.12	10.39
1000-1100	12.64	8.35	15.86	10.35	16.10	10.80	11.61	8.54	13.89	9.52
1100-1200	12.48	8.51	17.67	10.83	18.34	11.15	12.54	9.23	13.68	9.35
1200-1300	10.96	6.78	16.06	9.39	17.07	10.20	12.13	8.06	11.78	7.46
1300-1400	10.63	6.07	15.74	8.83	17.40	9.86	12.36	7.65	11.01	6.65
1400-1500	10.68	6.07	15.98	9.01	17.97	9.99	12.05	7.66	10.11	6.35
1500-1600	10.98	6.48	16.69	9.23	18.01	10.16	12.51	7.61	10.68	6.72
1600-1700	12.30	7.08	18.23	9.62	20.02	10.72	14.89	8.17	12.46	7.74
1700-1800	14.02	7.33	20.29	9.96	21.65	11.29	17.14	8.77	14.91	8.47
1800-1900	15.75	7.64	21.98	10.15	23.96	11.30	19.35	8.95	17.33	8.81
1900-2000	15.83	7.29	22.10	9.98	23.89	10.75	19.73	9.53	17.87	8.74
2000-2100	15.76	7.54	21.27	9.85	23.95	11.25	19.48	9.65	17.49	8.31
2100-2200	16.92	7.95	22.82	10.43	23.89	11.12	18.30	8.66	17.13	7.41
2200-2300	15.70	6.90	21.75	9.12	21.58	9.70	16.03	7.33	14.70	6.66
2300-2400	12.27	6.06	17.93	7.89	17.92	8.53	12.60	6.22	11.71	5.76

TABLE 7-2 (con.)

Average cost in	November 1980		December 1980		January 1981		February 1981		March 1981	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	12.32	5.15	14.52	5.92	17.92	7.56	16.17	6.73	12.11	6.16
0100-0200	11.41	5.01	13.01	5.50	17.11	7.14	15.43	6.34	11.83	5.69
0200-0300	11.27	4.81	12.61	5.33	16.80	6.98	15.18	5.93	11.78	5.49
0300-0400	11.30	4.80	12.92	5.21	16.97	6.88	15.42	6.04	12.29	5.46
0400-0500	12.46	5.14	13.94	5.59	17.80	7.22	16.00	6.35	12.96	5.81
0500-0600	15.87	6.03	16.85	6.60	21.06	8.46	19.06	7.30	16.30	6.96
0600-0700	22.73	9.25	23.24	8.66	29.26	10.41	27.43	7.82	24.64	9.70
0700-0800	25.38	12.33	26.54	11.45	33.10	13.91	31.11	13.09	26.28	12.28
0800-0900	21.11	12.66	23.11	12.65	26.99	15.29	25.20	13.58	21.17	12.96
0900-1000	19.44	11.73	21.72	11.83	26.04	14.31	22.51	12.53	19.12	11.72
1000-1100	18.00	10.66	20.76	11.03	25.29	14.26	21.60	11.93	18.06	11.19
1100-1200	16.93	10.31	19.70	10.49	24.19	13.81	21.02	11.84	17.06	10.56
1200-1300	14.42	8.35	16.77	8.73	20.62	11.68	17.98	9.67	14.74	8.96
1300-1400	12.87	7.38	15.40	7.94	19.34	10.45	16.94	8.61	13.78	7.89
1400-1500	12.29	7.23	14.54	7.92	18.22	9.64	15.42	8.47	13.04	7.76
1500-1600	12.39	7.39	14.77	8.38	18.19	10.33	16.00	9.08	13.21	8.24
1600-1700	14.90	9.24	17.23	9.71	20.87	11.95	18.23	10.66	14.99	9.57
1700-1800	19.61	10.44	22.94	10.54	25.88	12.98	22.37	11.28	18.89	10.04
1800-1900	23.73	10.97	26.86	11.49	30.84	13.97	28.57	12.56	23.21	10.97
1900-2000	23.06	10.11	26.14	10.99	31.44	13.28	29.99	12.19	24.58	11.25
2000-2100	22.19	9.38	25.19	10.37	30.37	12.62	28.28	11.63	23.62	10.86
2100-2200	21.27	8.79	24.52	9.62	29.01	11.60	27.58	10.79	22.67	9.63
2200-2300	19.70	7.88	22.20	8.54	26.50	10.42	24.75	9.57	19.26	8.56
2300-2400	17.00	6.89	19.12	7.39	22.75	9.38	20.86	8.67	15.85	7.64

TABLE 7-3. AVERAGE HOURLY WEEKEND ENERGY COSTS
SSI AND NON-SSI CUSTOMERS--mils/kWh
(June 1980 - March 1981)

Average cost in	June 1980		July 1980		August 1980		September 1980		October 1980	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	9.45	4.85	12.41	5.64	11.87	6.04	8.31	4.57	8.17	4.29
0100-0200	7.15	4.03	9.91	5.00	9.68	5.27	7.05	4.13	7.59	4.02
0200-0300	6.38	3.70	8.35	4.50	8.43	4.72	6.05	3.64	6.52	3.69
0300-0400	5.72	3.36	7.64	4.17	7.32	4.51	5.50	3.68	6.39	3.65
0400-0500	5.50	3.28	7.04	3.94	7.04	4.45	5.20	3.65	6.45	3.72
0500-0600	5.91	3.36	6.93	4.09	7.08	4.41	5.53	3.95	7.30	3.78
0600-0700	6.89	4.14	7.77	4.82	7.83	4.82	6.40	4.12	8.50	4.93
0700-0800	8.57	5.90	9.47	6.11	9.43	6.30	8.53	5.94	11.18	7.90
0800-0900	11.38	7.51	13.27	7.91	13.03	8.06	11.57	8.15	15.24	10.62
0900-1000	14.80	8.41	16.55	9.59	13.79	9.54	14.06	8.49	17.63	10.57
1000-1100	16.28	8.52	19.14	10.18	18.54	10.57	14.91	8.60	17.28	9.46
1100-1200	17.49	8.53	19.72	10.12	20.50	10.18	15.74	8.55	16.95	9.37
1200-1300	15.73	7.64	18.51	9.64	18.35	9.45	14.65	7.86	16.09	8.14
1300-1400	14.72	7.57	18.16	8.83	17.91	9.21	14.22	7.21	14.21	7.25
1400-1500	15.01	7.11	17.81	8.64	17.53	8.87	14.15	7.11	13.20	6.62
1500-1600	14.38	6.84	18.04	8.09	17.34	8.96	14.62	7.12	13.08	6.83
1600-1700	15.18	6.84	18.83	7.97	17.17	8.70	15.00	7.52	13.39	6.91
1700-1800	16.04	6.88	19.36	8.25	18.02	9.02	15.56	7.49	14.48	7.39
1800-1900	16.46	6.60	18.82	8.71	17.51	8.72	15.77	7.57	14.95	7.81
1900-2000	16.14	6.55	17.65	8.40	17.52	8.37	15.22	7.70	15.10	7.80
2000-2100	16.00	6.83	18.52	8.40	18.02	8.34	16.85	8.37	15.39	7.97
2100-2200	17.09	7.73	19.90	9.15	18.62	9.22	16.08	7.52	15.43	7.09
2200-2300	16.06	6.96	19.24	8.57	17.37	8.11	13.98	6.94	13.85	6.50
2300-2400	14.36	6.36	17.35	7.50	14.79	7.41	11.96	6.18	11.39	5.58

TABLE 7-3 (con.)

Average cost in	November 1980		December 1980		January 1981		February 1981		March 1981	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	12.40	5.16	16.50	6.60	20.08	8.20	16.23	7.04	12.78	6.43
0100-0200	11.20	4.88	15.10	6.00	18.74	7.53	15.41	6.34	11.90	5.56
0200-0300	10.53	4.74	14.07	5.78	18.36	7.11	14.94	6.01	11.59	5.46
0300-0400	10.75	4.56	13.84	5.75	18.14	7.13	14.77	5.95	11.82	5.40
0400-0500	11.24	4.64	15.07	5.74	18.73	7.32	15.11	6.05	12.26	5.47
0500-0600	12.21	5.22	16.24	6.19	19.95	7.73	16.31	6.25	13.90	5.57
0600-0700	13.98	6.27	17.98	7.05	22.86	8.65	18.45	7.11	16.01	7.72
0700-0800	17.19	9.35	22.28	10.11	26.20	12.15	21.56	10.32	19.38	11.00
0800-0900	21.46	11.77	27.07	13.30	30.67	15.46	25.76	12.66	22.82	13.17
0900-1000	23.55	11.72	28.97	13.63	32.16	14.79	26.63	12.00	23.72	12.05
1000-1100	22.68	11.41	27.66	12.78	31.82	15.05	25.38	11.72	22.21	11.46
1100-1200	21.75	10.32	25.97	12.56	30.48	14.63	23.68	12.17	20.61	11.12
1200-1300	19.18	8.98	22.97	10.48	27.61	12.34	21.66	10.81	18.22	9.81
1300-1400	17.02	8.21	21.29	9.61	25.80	11.44	20.54	9.36	16.75	8.74
1400-1500	15.56	7.56	19.56	9.14	24.15	10.90	18.34	8.96	15.16	8.18
1500-1600	15.18	7.61	18.73	8.76	23.68	10.53	17.83	8.91	15.10	7.92
1600-1700	16.14	8.43	20.54	9.27	23.97	10.96	18.40	9.12	15.47	8.12
1700-1800	18.56	8.86	23.15	10.19	27.65	12.19	20.26	9.50	17.23	8.45
1800-1900	19.52	9.17	24.19	10.76	29.61	12.67	22.72	9.97	19.00	9.17
1900-2000	19.14	8.94	24.64	10.93	29.18	12.56	22.64	9.96	20.05	9.64
2000-2100	19.75	8.36	24.90	10.87	29.28	12.70	23.01	9.83	20.31	10.37
2100-2200	18.62	8.02	24.80	10.02	29.45	12.38	21.92	9.46	19.43	9.43
2200-2300	17.17	7.26	22.89	9.13	27.14	10.92	20.21	8.53	17.35	8.65
2300-2400	15.08	6.21	20.83	8.31	24.92	9.90	18.35	8.08	14.96	7.59

TABLE 7-4. AVERAGE MONTHLY ENERGY COSTS FOR NON-SSI AND SSI CUSTOMERS--WEEKDAYS AND WEEKENDS

Month/year	Average weekday cost (¢/kWh)		Average weekend cost (¢/kWh)	
	Non-SSI	SSI	Non-SSI	SSI
June 1980	1.1	0.6	1.3	0.6
July 1980	1.5	0.8	1.5	0.7
August 1980	1.6	0.9	1.4	0.8
September 1980	1.3	0.7	1.2	0.7
October 1980	1.3	0.7	1.2	0.7
November 1980	1.7	0.8	1.7	0.8
December 1980	1.9	0.9	2.1	0.9
January 1981	2.4	1.1	2.5	1.1
February 1981	2.2	1.0	2.0	0.9
March 1981	1.8	0.9	1.7	0.9

monthly energy costs for SSI customers are approximately half those of non-SSI customers in the summer and off-season months but are less than half in the winter months. This suggests that when the costs are assessed for all the SSI customers together, they are considerably less than those for the non-SSI customers. The cost pattern for the typical weekend day is essentially the same as that for the typical weekday, indicating that SSI energy costs are about half those of non-SSI customers on the weekend.

The comparative analysis result that within-rate usage differences between SSI and non-SSI customers are smaller than the overall differences provides a guide for evaluating the within-rate cost implications. A costing analysis for within rate classes would show the same general pattern as the comparative results because the same hourly production costs would be used to calculate the differences within rate classes. No detailed cost estimates are provided because the relative relationship is already established.

Table 7-5 presents the marginal energy costs at the hour of monthly system peak for SSI and non-SSI customers. These costs are calculated by multiplying peak hour usage for each group by the system marginal energy cost for the last unit dispatched to meet load.

The marginal energy costs for the non-SSI customers are considerably larger than those for the SSI customers. Non-SSI marginal energy costs exceed those for SSI customers by slightly less than a 2 to 1 margin in the closest month, September, to almost a 3 to 1 margin in January. These large margins reflect the substantially lower consumption of SSI customers at the hour of monthly system peak.

The cost of serving SSI customers, measured in either marginal or average energy costs, are substantially less than those of serving non-SSI

TABLE 7-5. MARGINAL ENERGY COST[a] AT HOUR OF MONTHLY SYSTEM PEAK--
NON-SSI AND SSI CUSTOMERS

Month/year	System marginal energy cost (¢/kWh)	Non-SSI customers		SSI customers	
		Peak usage (kWh)	Marginal cost (¢/kWh)	Peak usage (kWh)	Marginal cost (¢/kWh)
June 1980	7.6	1.845	14.02	0.928	7.05
July 1980	8.5[b]	2.038	17.32	1.014	8.62
August 1980	8.5[b]	2.438	20.72	1.447	12.30
September 1980	8.5	1.572	13.36	0.986	8.38
October 1980	8.5	2.174	18.48	0.969	8.24
November 1980	8.5	3.159	26.85	1.221	10.38
December 1980	8.5	2.968	25.23	1.208	10.27
January 1981	8.5	3.460	29.40	1.320	11.22
February 1981	8.5	3.175	26.99	1.271	10.80
March 1981	8.5	2.401	20.41	1.042	8.86

[a] Production cost of the last unit dispatched in each month to meet load.

[b] Power purchases were required to meet load this month. The cost of the last unit dispatched must be at least equal to the cost of purchased power.

customers. This suggests that the SSI rate may be justified on the basis of a lower cost of serving these customers. Determination of a permanent rate for SSI customers requires careful consideration of its overall rate design implications by both Duke Power Company and the North Carolina Utilities Commission.

REFERENCES

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Turvey, Ralph, and Dennis Anderson, Electricity Economics, Baltimore: Johns Hopkins University Press for the World Bank, 1977.

APPENDIX A

RELATIONSHIP OF THE SSI RATE TO LIFELINE RATES IN THE UNITED STATES

Source: W. H. Desvousges, D. H. Brown, M. P. McGivney, Lifeline Rates and Alternatives: A Program Survey, Cooperative Agreement No. DE-FC-01-79-RG-10255, June 1981.

APPENDIX A

RELATIONSHIP OF THE SSI RATE TO LIFELINE RATES IN THE UNITED STATES

The SSI rate in North Carolina is best viewed in the larger context of lifeline rates. The Public Utilities Regulatory Policies Act of 1978 required States to assess the feasibility of lifeline rates. These rates are derived from the premise that a certain amount of energy is required to sustain life, but, unfortunately, the term lifeline lacks a universal definition. The purpose of a lifeline rate is either to create lower-than-average rates for groups of electricity consumers or provide all residential customers a certain usage at rates lower than the cost of serving them.

Lifeline rate programs are established in two ways: (1) the program may be developed on a marginal cost basis, and (2) it may be designated on the basis that it subsidizes the energy consumption of certain users. The marginal cost justification is based on the economic efficiency criterion that the consumer's valuation of the incremental unit of a good should be equal to the additional (marginal) cost of producing that unit. Lifeline rates that provide a lower charge for the initial units of energy consumed are efficient if the lower rates reflect the marginal cost of energy production.

Lower rates on the initial units of consumption are based on the reasoning that users who consume small amounts of energy impose lower marginal costs than other users. This rationale, however, overlooks the fact that the time of use is as important as total use in determining costs. Small users may add significantly to costs if their consumption occurs at utility peak periods. Large users may add very little to costs if their consumption occurs at times of excess utility capacity. Regulators should consider both the amount of consumption and the time of consumption in determining if lifeline rates are cost-justified. Indeed, most state commissions have argued that lifeline rates should be implemented only if cost-justified. New York, for example, supports a 300-kWh lifeline block of electricity as a move toward marginal cost pricing. This project employs both use and time-of-use evaluation measures to determine if the SSI discount can be justified on a cost-of-service basis.

The second rationale in various states for lifeline rates is that utilities can subsidize certain individuals. These programs are generally identified as those lowering rates to groups based on income, family, and age characteristics. It is argued that assistance is needed by these individuals to purchse some basic level of energy. Rates are purposely set below marginal costs in these cases. The resulting transfers of income are best evaluated by the political process, but the use of lifeline rates to transfer income is questionable because of the costs involved. The actual amount of assistance is usually small yet high administration costs may be incurred. These transfers in many cases could be accomplished by existing government programs in a more cost-effective manner that would not affect the energy price signals to consumers.

Because of various identification problems, it is often difficult to determine if a state has a lifetime program. Some problems arise because the direction of the correlation between income and energy consumption is unknown. Depending on the direction of this correlation, a program designed for low-use customers may be classified as lifeline program. If low-income consumers use inefficient heating and cooling equipment and have poorly insulated homes and high-income consumers have more efficient equipment, better insulation, and spend a great deal of time away from home, then a negative correlation of income and usage exists. Programs aimed at low-use consumers will thus have a perverse effect on the existing income distribution because low-income households will be subsidizing consumption by high-income households.

Alternatively, as income increases, consumers may buy larger homes or more energy-intensive appliances, causing a positive correlation of electricity usage and income. If this situation exists, then low-use subsidies will be analogous to low-income subsidies. These programs, however, would still adversely affect those low-income families that do consume large amounts of energy.

The second problem in the identification of lifeline programs is the determination of the groups eligible for reduced rates. Eligibility requirements range from specific age and income limits to statewide programs for all residents. The State of California instituted the first statewide lifeline rate in 1975 for all residential customers. The program provided residents with reduced rates on a basic allowance of electricity and natural gas with increases for specific energy uses such as water heating, air conditioning, and space heating. In 1980, Michigan passed a bill requiring utilities to design lifeline rates for residents using less than 350 kWh per month of electricity. Montana requires each utility to establish a lifeline rate for residents who use under 15 thousand cubic feet (Mcf) per month of natural gas. Some individual utilities in Georgia, Washington, D.C., Minnesota, South Carolina, and Vermont offer lifeline rates to all residential customers.

Age and income requirements are usually specified in lifeline programs. Maine's demonstration project limited special rates to residents 62 years old with annual incomes of less than $5,000. Programs aimed at specific groups tend to conform with the basic income transfer premise of lifeline rates because household income is the limiting constraint in the purchase of a minimum amount of energy.

The amount of consumption subsidized also varies by state and season of the year. The breakoff points range from 150 kWh for Vermont to 1,000 kWh for South Carolina. The typical breakoff is usually between 350 and 650 kWh. For natural gas the lifeline breakoff point ranges from 26 therms per month for California to approximately 150 therms (15 Mcf) per month for Montana. Assistance actually received by residents under these programs is difficult to calculate. Subsidies vary with household characteristics and consumption and between seasons. Household savings range from almost zero to almost $9.00 per month for Maine.

Several states offer a fixed amount of assistance for all energy payments as a substitute for lower rates for certain types of energy. These payments in many cases tend to be larger than the true lifeline rate subsidies. Montana, Kentucky, New Jersey, Indiana, and Ohio offer payments of from $40 to $200 per heating season with the amount of assistance varying between seasons and with the type of fuels used. Payments are either credited to a household's utility bill or deducted from taxes. In Kentucky, however, individuals receive the assistance payment directly. Assistance is offered to specific residential groups; for instance, recipients must be receiving Supplemental Security Income checks in Indiana and New Jersey to receive the energy payments assistance. The most important difference between reduced lifeline rates and fixed payments is that fixed energy payments are usually subsidized by general tax revenue while lifeline rates are subsidized by other utility customers.

The West Virginia Public Service Commission in a May 1981 rate case provided a special rate to SSI recipients in the Appalachian Power Company territory on a trial basis. The PSC approved the rate because the SSI customers were easily identifiable and their small number would have a minimal effect on revenues. The PSC order stated that residential class customers will bear the costs of the SSI rate.

Because of the disagreement in interpreting the Public Utilities Regulatory Policies Act (PURPA) of 1978, considerable inconsistency exists in the implementation of lifeline rates. PURPA recommends to state commissions that rates be cost based but also requires states to consider lifeline rates. The only consistent interpretation of PURPA requires that lifeline rates be implemented only if they are cost-justified. This interpretation, however, is inconsistent with the lifeline premise of providing some necessary amount of energy at a low cost. The problem is compounded by court cases in several states that have questioned the constitutionality of reduced rates to a certain group of customers. These court cases have caused the termination of assistance programs in Colorado, Utah, and Idaho.

Lifeline rate issues will continue to be a difficult policy issue for both regulatory and legislative officials. The cross-currents produced by the conflicting goals of cost-based pricing and minimum energy needs at reasonable cost will only worsen as the cost of energy production rises. The difficulty of the issue is heightened by the lack of sound data on the cost justifications for lifeline rates and the confusion over the correlation between energy usage and income. This report provides empirical evidence in an attempt to shed some light on these facets of the lifeline controversy.

APPENDIX B

DATA HANDLING PROCEDURES AT DUKE POWER COMPANY

Libby

MOST COMMON PROBLEMS WITH FIELD TAPES
FOUND IN TRANSLATION PROCESS

1. Multiplier changed
2. Low Usage
3. Erratic Timing
4. Split Intervals
5. Recorder Failure
6. Switched Channels
7. Bad Tape
8. Bad Information on Cards
9. Light Source
10. Undetermined Outage
11. Blank Tape
12. Recorder not Tracking
13. Missing Data on Channel ______
14. PO/PU
15. Missing Data & Intervals

Load Research Operations
Rate Department
1-16-79

LOAD RESEARCH OPERATIONS' DEFINITIONS OF
MOST COMMON PROBLEMS WITH FIELD TAPES
FOUND IN TRANSLATION PROCESS

1. Multiplier Changed - This problem would occur when the bill meter, watthour meter, or recorder constants have been changed to something other than the constants reported on the original installation sheet.

2. Low Usage - Tapes having less than 100 Kwh usage are given special consideration. If the comparison of Pulse Meter to Billing Meter is close or the difference is not more than twice the largest multiplier then the tape is accepted, regardless of percentage. If the translation falls outside of these considerations, it is reported as missing data. The comparison on all reports will remain a rejected status 2 eventhough the operater will transfer the data to 1600 BPI tape.

3. Erratic Timing - Timing channel reflects the amount of tape travel in units of milli-seconds. Each 15 minute recorder would produce 15 minute intervals of approximately 30 milli-seconds. Each 30 minute recorder would produce 30 minute intervals of approximately 60 milli-seconds. If at the time of translation, the timing channel reflects intervals of extremely high or low values, then the problem would be flagged as erratic timing. This would be caused by the recorder motor changing speed. (KR possible codes: DE, RP, RR).

Ex: Normal 15 min. pattern		Erratic timing pattern	
2967	1 hr.	2967	1 hr.
2943		609	
2959		4078	
2980		2001	

4. Split Intervals - The timing length for 15 or 30 minute recorders is predetermined at approximately 30 milli-seconds and 60 milli-seconds, respectively. Split or broken intervals are the result of recorder malfunction. This can be determined by the timing channel values. (possible KR codes: DE, CI)

Ex A: Normal 15 min. pattern					Ex B: Split interval 15 min.				
1	2967	5	2979	2 hrs.	1	2967	5	2979	2 hrs.
2	2943	6	2947		2	2943	6	2620	
3	2959	7	2952		3	2629	7	327	
4	2980	8	2952		4	330	8	2952	

As you can see in Ex. B, the values of interval #3 & #4 should be added together to reach a normal value of 2959. Intervals #6 & #7 should also be combined to give a value of 2947. Split intervals differ from erratic timing in that they can be combined for a valid data value. Erratic timing has no pattern and cannot be corrected.

5. Recorder Failure - The tape for a given period was short on data and intervals expected. The tape was verified and found good. No outages occurred and power was connected. Usually, the data pulses are good until a certain point (which may be several hours or days short of expected time) after that point, there are no intervals or data. This shows the same affect that would result if all power were removed at once. (possible KR codes: DE, RP, CI)

6. Switched Channels - Data channels on 4 track recorders that are wired incorrectly. This indicates data which should actually be on channel C is recorded on B and vice versa.

7. Bad Tape - The tape has been verified and could not read expected data. At this point, the tape is discarded. No trouble report will be sent.

8. Bad Information on Cards - Part or all of the start and stop dates, times, and readings were incorrect or omitted.

9. Light Source - Light source is suspected when a tape for a customer that usually has a regular pattern shows a splotchy pattern and is missing a large amount of expected data. (possible KR codes: DE, RP, RR)

10. Undetermined Outage - At the time the tape is changed, outage is checked on the ID card or a note is made on the back that power was off for x number hours with no dates given. Data would be purged.

11. Blank Tape - Tape was translated but found no data pulses or timing intervals.

12. Recorder not Tracking - When readings from both a pulse generator meter and a watthour meter are written on the ID card, they are expected to show a similar total. If this is not the case and one total is far greater or smaller than the other, and the translation shows the same comparison, then we report a tracking problem.

13. Missing Data on Channel - Missing data indicates the translation found fewer pulses than expected. The expected pulse count was determined by the start and stop meter readings and the meter constants on the ID card.

14. PO/PU (Post-Purge) - PO/PU indicates the data on that particular tape was not usable but that the stop date, time, and readings were retained for use on the next tape.

15. Missing Data & Intervals - Fewer data pulses and intervals found in translation than expected from information on ID card.

ADVANCED WLT-40

OPERATIONS MANUAL

DUKE POWER COMPANY

Charlotte, North Carolina

Westinghouse Electric Corporation • Meter & LVIT Division • Raleigh, N. C.

Code	Action
DE	Delete Intervals.
AD	Add intervals. The start and stop times may not cover more than 38 intervals. The system will determine how many interval values are required to cover the start thru stop time, and request them, eight at a time, for each channel: CH Z: XX TO YY — where Z is A, B, or C; XX and YY are interval number offsets from the correction start time. If an invalid interval value is entered, INTERVAL XX INVALID is typed and the values beginning, with the incorrect one, must be re-entered. In all cases, the system will specify the interval numbers it expects. A value entry of "GO" will imply that the last value entered is to be repeated thru the correction stop time. If it is entered for the first correction interval value, a pulse count of zero is assumed for the entire correction period.
RP	Replace intervals. Number of intervals limit and interval value entry is the same as for the AD type. In addition, a value entry of "NC" will tell the system that <u>N</u>o <u>C</u>hange is desired for the specified interval.
RA	Repetitive Add intervals. One value only is requested for each channel, and that one value is inserted for indicated interval. No limit is placed on the correction time span.
RR	Repetitive Replace intervals. One value or "NC", indicating No Change, is requested for each channel and that one value replaces the value for each indicated interval. No limit is placed on the correction time span.
CI	Combine Intervals. All intervals between the start and stop times will be combined, and the subsequent intervals skewed.

APPENDIX C

SURVEY INSTRUMENTS FOR SSI AND
RESIDENTIAL LOAD RESEARCH CUSTOMERS

SUPPLEMENTARY SECURITY INCOME DEMOGRAPHIC SURVEY

LOAD RESEARCH REFERENCE NUMBER

1. Group No. ____
2. Strata No. ___
3. Ident. No. ____________
4. Soc. Sec. No. ___ __ ____

5. TYPE OF RESIDENTIAL STRUCTURE
   - ☐ House
   - ☐ Apartment
   - ☐ Mobile Home
   - ☐ Condominium
6. SIZE OF STRUCTURE ____
7. NUMBER OF PERSONS IN HOUSEHOLD __
8. NUMBER OF PERSONS IN HOUSEHOLD RECEIVING SSI PAYMENTS __
9. TYPE OF HEATING SYSTEM
   - ☐ Electric Room by Room System
   - ☐ Electric Furnace
   - ☐ Heat Pump
   - ☐ Gas, Oil or Coal Central System
   - ☐ Gas, Oil or Coal Space Heater
   - ☐ Other________
10. ARE ANY OF THE FOLLOWING NORMALLY USED TO HELP HEAT THE STRUCTURE?
    - ☐ Solar
    - ☐ Portable Electric Heaters
    - ☐ Fireplace
    - ☐ Wood Stove
    - ☐ Other________
11. CENTRAL ELECTRIC AIR CONDITIONING
    - ☐ Yes
12. "WINDOW TYPE" AIR CONDITIONERS
    - ☐ Yes
13. WATER HEATING
    - ☐ Electric
    - ☐ Gas
    - ☐ Oil
    - ☐ Solar
    - ☐ None
14. INDICATE ANY OF THE FOLLOWING MAJOR APPLIANCES IN THE STRUCTURE
    - ☐ Electric Range
    - ☐ Frost-Free Refrigerator
    - ☐ Non Frost-Free Refrigerator
    - ☐ Frost-Free Freezer
    - ☐ Non Frost-Free Freezer
    - ☐ Clothes Washer
    - ☐ Electric Clothes Dryer
    - ☐ Gas Clothes Dryer
    - ☐ Dishwasher
    - ☐ Waste Disposal
    - ☐ Trash Compactor
    - ☐ Microwave Oven

Notes:________

Res. Rep. ________

Date________

SSI SUPPLEMENTAL SURVEY

Sample

CALDWELL, ODESSA
R14 MOORES CHPL RD
CHARLOTTE, NC 28208
01261402351
03

EDP FILE REFERENCE

3. Ident. No. 0 1 0 2 3 5 0 3 1 1 1 1

This questionnaire should be completed for each SSI household currently being monitored for load research purposes. A personal interview is not recommended. Estimates should be obtained by simply driving by the residence. If the address is an apartment for which the owner can be easily identified, a phone call should be placed to the owner to obtain the rent for 1, 2, and 3 bedroom living units.

All questionnaires should be completed and returned to Ben Christenbury by November 1, 1980.

15. Year house built

____ 1930 or before
____ 1931 to 1940
____ 1941 to 1950
____ 1951 to 1960
____ 1961 to 1970
____ 1971 to 1980

16. Present market value

____ $10,000 or below
____ $10,001 to $20,000
____ $20,001 to $30,000
____ $30,001 to $40,000
____ $40,001 to $50,000
____ $50,001 to $60,000
____ $60,001 to $70,000
____ $70,001 to $80,000
____ $80,001 to $90,000
____ $90,001 to $100,000
____ $100,001 or above

If the housing unit is a duplex, please indicate an estimate for one side or one housing unit.

17. If the housing unit is an apartment, please determine monthly rental from owner or manager, if possible (not tenant).

1 Bedroom __________
2 Bedroom __________
3 Bedroom __________
Other __________

Surveyed by __________

Date __________

Comment __________

9/5/80

RESIDENTIAL MARKET RESEARCH SURVEY

Load Research Reference Number

1. Group No. |_|_|_|_|
2. Strata No. |_|_|
3. Ident. No. |_|_|_|_|_|_|_|_|_|_|_|_|

(Circle Number For The Proper Answer Or "Fill-in" All Spaces)

A. TYPE STRUCTURE
1. House
2. Apartment
3. Mobile Home
4. Condominium
5. Summer Home

B. YEAR BUILT 19 4 C

C. STYLE OF STRUCTURE
1. One Level
2. Two Level
3. Tri-Level (or more)
4. Double Wide

D. SIZE OF STRUCTURE
1 _ _ _ Sq. ft.

E. IS THIS AN EES STRUCTURE?
1. Yes
2. No

F. MEMBERS OF HOUSEHOLD
1. Under 6 years old ___
2. From 6 through 18 years ___
3. From 19 through 65 years 1
4. Over 65 years old 2

G. HOW MANY MEMBERS SHOWN IN QUESTION F ARE LIVING AWAY FROM HOME AT COLLEGE OR OTHER TYPES OF SCHOOLS? 0

H. DO YOU LIVE
1. Inside the city limits of a town or city
2. Within a residential sub-division but outside the city limits
3. In a rural area
4. On a farm

I. PRIMARY HEATING FUEL
1. Electric
2. Gas
3. LP Gas
4. Oil
5. Other
6. None

J. TYPE OF PRIMARY HEATING SYSTEM
1. Room-by-Room Electric
2. Electric Furnace
3. Heat Pump
4. Fossil Central System
5. Fossil Space Heater
6. None

K. ARE ANY OF THE FOLLOWING NORMALLY USED TO HELP HEAT YOUR HOME?
1. Solar
2. Portable Electric Heaters
3. Fireplace
4. Wood Stove
5. Range
6. Other ________
7. None

L. AIR CONDITIONING
1. Central Electric
2. Central Gas
3. Window Units
4. None

M. YEAR INSTALLED 19__ __
(Latest year if window units)

N. TOTAL NUMBER IF WINDOW UNITS IN L ______

O. IS THERE A "HEAT RECLAIM" DEVICE ON THE CENTRAL AIR CONDITIONING?
1. Yes

P. WATER HEATING
1. Electric
2. Gas
3. Other
4. None

Q. SOLAR WATER HEATING
1. Yes
2. No

R. ELECTRIC WATER HEATER SIZE
1. 80 gal.
2. 66 gal.
3. 50 gal.
4. 40 gal.
5. 30 gal.
6. Smaller

S. WHAT IS THE LARGEST SIZE ELECTRIC WATER HEATER THAT CAN BE INSTALLED AT THE PRESENT LOCATION?
1. 80 gal. (64"H x 26"W)
2. 66 gal. (64"H x 25"W)
3. 50 gal. (60"H x 22"W)
4. 40 gal. (48"H x 22"W)
5. Tank size cannot be increased

T. ELECTRIC WATER HEATER LOCATIO
1. Basement
2. Crawl Space
3. Storage Area
4. Living Area
5. Attic
6. Other

U. MICROWAVE OVEN
1. Yes
2. No

V. PERCENT OF MEALS PREPARED BY MICROWAVE OVEN

1. 10% or less
2. 11% - 20%
3. 21% - 30%
4. 31% - 40%
5. over 41%

W. TOTAL MEALS PER WEEK ___

X. RANGE

1. Electric
2. Gas
3. Other
4. None

Y. PRIMARY REFRIGERATION

1. Side by Side
2. Other Types of Frost Free
3. Non-Frost Free
4. None

Z. SECONDARY REFRIGERATION

1. Side by Side
2. Other Types of Frost Free
3. Non-Frost Free
4. None

AA. PRIMARY FREEZER

1. Frost Free
2. Other
3. None

BB. SECONDARY FREEZER

1. Frost Free
2. Other
3. None

CC. CLOTHES WASHER

1. Yes
2. No

DD. DISHWASHER

1. Yes
2. No

EE. DISPOSAL

1. Yes
2. No

FF. CLOTHES DRYER

1. Electric
2. Gas
3. None

GG. TRASH COMPACTOR

1. Yes
2. No

HH. TELEVISIONS

__1__ Total Number

II. HAVE YOU ADDED HOME INSULATION WITHIN THE LAST 12 MONTHS?

1. Ceiling
2. Sidewall
3. Floor
4. Storm Windows
5. None

JJ. ARE YOU AWARE OF DUKE POWER'S ENERGY EFFICIENT APPLIANCE PROGRAM?

1. Yes
2. No

KK. APPLIANCES PURCHASED IN THE LAST 12 MONTHS

1. Refrigerator
2. Electric Water Heater
3. Dishwasher
4. Room Air Conditioner
5. None of the above

LL. WERE THEY ENERGY EFFICIENT APPLIANCES?

1. Refrigerator
2. Electric Water Heater
3. Dishwasher
4. Room Air Conditioner
5. No

MM. WHAT PERCENT OF YOUR HOME DO YOU HEAT?

1. 100%
2. 80%
3. 60%
4. 50%
5. Less than 50%

NN. WHAT IS YOUR NORMAL THERMOS SETTING FOR HEATING?

___ °F

OO. WHAT IS YOUR NORMAL THERMOS SETTING FOR HEATING AT NIGHT?

___ °F

PP. WHAT TIME IS THE HEATING "SET BACK"?

(Military time) ____

QQ. WHAT TIME IS IT "SET UP"?

(Military time) ____

RR. DO YOU LET YOUR AIR CONDITIONI OPERATE DURING THE DAY, IF YOU ARE NOT AT HOME?

1. Yes
2. No

SS. WHAT IS THE NORMAL THERMOSTA SETTING FOR YOUR AIR CONDITIONI

___ °F

TT. WHAT PERCENT OF THE HOME DO YOU AIR CONDITION?

1. 100%
2. 75%
3. 50%
4. 25%
5 Less than 25%

UU. COULD WE INSTALL A RECORDING METER ON YOUR HOME IF REQUIRE BY REGULATORY BODIES?

1. Yes
2. No

VV. ESTIMATE THE FOLLOWING

1. For Rental Living Unit, the Monthly Rent $____
2. For Others, Present Market Value $0 0 ____

HEAT GAIN AND HEAT LOSS
FOR
1979 RESIDENTIAL MARKET RESEARCH SURVEY

9. NO. PEOPLE [illegible]

10. TEMP. DIFF. HTG. [illegible]   11. ROOF LT (Lt. or Dk.)   12 DUCT INS. 0 Inch (es)

13. DUCT LOCATION [illegible]
A - Attic C - Crawl Space
N - None

FOR FIELD USE ONLY

Table for Calculating Shaded & Unshaded Glass Areas				
1. Direction Window Faces				
2. Total Window Area Sq. Ft.				
3. Width of Window, Ft.				
4. Shaded Area Per Foot of Overhang - Table B - 1, Sq. Ft.				
5. Width of Overhang, Ft.				
6. Total Area of Shaded Glass, Sq. Ft. (Line 4) X (Line 5)				
7. Total Area of Unshaded Glass, Sq. Ft. (Line 2) — (Line 6)				

	TYPE OF EXPOSURE		Const. No.	HTM Htg	HTM Clg	Area or Length
20	Gross Walls	a				110[illegible]
21	Windows and Glass (Htg)	a	131A			0018
		b				
		c				
22	Windows and Glass (Clg)	a	North			
		b	North			
		c	E&W or NE&NW			
		d	E&W or NE&NW		15.6	[illegible]
		e	South or SE&SW		30.0	[illegible]
		f	South or SE&SW			
23	Doors	a	19C			[illegible]
		b				
		c				
24	Net Exposed Walls and Partitions	a	1C1A			[illegible]
		b				
		c				
		d				
25	Ceilings	a	1[illegible]A			1C[illegible]
		b				
26	Floors	a	17B			1C[illegible]
		b				

Res. Rep:

Date:

APPENDIX D

STATISTICAL ESTIMATION AND TESTING METHODOLOGY

APPENDIX D

STATISTICAL ESTIMATION AND TESTING METHODOLOGY

The design of the Duke Power Company SSI Rate Study involves the use of two stratified random samples. The first sample was selected from the population of North Carolina residential customers not on the SSI rate in August 1979. Members of the second sample were drawn from the population of North Carolina residential customers served by the SSI rate at that time.* Because of the relatively simple designs, the estimation methodology is straightforward if stratum sizes are assumed known. This assumption is made throughout.

Notation and Parameters of Interest

The first population of interest, consisting of sample-eligible, non-SSI, North Carolina residential customers in the Duke service area, is denoted by I=1; and the second population, by I=2. Define the following:

$N(I,h)$ = the number of customers in the h^{th} stratum of the I^{th} population, $h = 1, 2, \ldots, H_I$;

$$N(I) = \sum_{h=1}^{H_I} N(I,h) = \text{number of customers in the } I^{th} \text{ population;}$$

$n(I,h)$ = the number of sample customers selected from the h^{th} stratum of the I^{th} population;

$r_Y(I,h)$ = the number of sample customers in the h^{th} stratum of the I^{th} population who provide "valid" data on a given response variable, Y.

* Some exclusions prevented some of the residential customers from being eligible for either of these samples.

Let Y and Z represent two arbitrary response variables. For instance, Z might represent "kWh consumed during the hour of system peak load of a particular month", and Y might represent "average hourly kWh consumed during the particular month." Let Y(I,h,i) and Z(I,h,i) denote the values of such variables for the i^{th} customer of the h^{th} stratum in the I^{th} population. The parameters of interest are of two types:

$$\text{Averages:} \quad \overline{Y}(I) = \sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Y(I,h,i) \ / \ N(I)$$

$$\text{Load Factors:} \quad \frac{\overline{Y}(I)}{\overline{Z}(I)} = \frac{\sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Y(I,h,i) \ / \ N(I)}{\sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Z(I,h,i) \ / \ N(I)} .$$

Estimation of these two types of population parameters is described in the following sections. To facilitate that discussion, it is convenient to define the following for each sample member:

$X_Y(I,h,i)$ = 1, if the i^{th} sample member in the h^{th} stratum of population I provides valid data on the arbitrary response variable Y, and
= 0, otherwise.

Note that

$$r_Y(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i) .$$

Estimation of Population Averages

Estimates of $\overline{Y}(I)$ are obtained as weighted averages of the sample stratum means:

$$\hat{\overline{Y}}(I) = \sum_{h=1}^{H_I} \frac{N(I,h)}{N(I)} \ \hat{\overline{Y}}(I,h)$$

where

$$\hat{\bar{Y}}(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\ Y(I,h,i)\ /\ r_Y(I,h).$$

It should be noted that this estimate (and subsequent estimates) involve an implicit imputation when $r_Y(I,h) < n(I,h)$, i.e., when some sample customers fail to provide valid data on the particular response variable.

It is assumed that $r_Y(I,h) \geq 2$ for all I and h*; hence, the standard error of the estimated average $\hat{\bar{Y}}(I)$ is obtained by taking the square root of

$$\widehat{\mathrm{Var}}\left[\hat{\bar{Y}}(I)\right] = \sum_{h=1}^{H_I} \left[\frac{N(I,h)}{N(I)}\right]^2 s_Y^2(I,h)\ f_Y(I,h)\ /\ r_Y(I,h),$$

where $f_Y(I,h) = 1 - r_Y(I,h)\ /\ N(I,h)$ is the finite population correction factor for the h^{th} stratum of population I, and $s_Y^2(I,h)$ is the variance of Y among the $r_Y(I,h)$ respondents in the h^{th} stratum of the I^{th} population, i.e.,

$$s_Y^2(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\ \left[Y(I,h,i) - \hat{\bar{Y}}(I,h)\right]^2/\left[r_Y(I,h)-1\right].$$

Estimation of Population Load Factors

Assume that $X_Y(I,h,i) = X_Z(I,h,i)$; that is, assume that those sample customers providing valid data on Y also provide valid data on another response variable Z.** With appropriate definitions of Y and Z, and assuming a known fixed time for which the load factor is to be

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* When this fails to hold, customers in the affected strata are grouped with those in an adjacent stratum. Some bias in the estimates, as well as decreased precision, can be expected to result from collapsing strata in this fashion.

** Otherwise, the data file is restricted to such customers and the definition of $X_Y(I,h,i)$ is modified accordingly.

determined (e.g., the hour of system peak), the estimate of a load factor for the Ith population, R(I), has the form

$$\hat{R}(I) = \frac{\hat{\bar{Y}}(I)}{\hat{\bar{Z}}(I)} ,$$

where both the numerator and denominator are estimated in the manner of the previous section.

The estimated variance of $\hat{R}(I)$ is approximated as

$$\widehat{Var}\ [\hat{R}(I)] = \frac{1}{\hat{\bar{Z}}(I)^2}\left\{\widehat{Var}\ [\hat{\bar{Y}}(I)] + [\hat{R}(I)]^2\ \widehat{Var}[\hat{\bar{Z}}(I)] - 2\hat{R}(I)\ \widehat{Cov}[\hat{\bar{Y}}(I),\hat{\bar{Z}}(I)]\right\},$$

where

$$\widehat{Cov}[\hat{\bar{Y}}(I),\hat{\bar{Z}}(I)] = \sum_{h=1}^{H_I} \left[\frac{N(I,h)}{N(I)}\right]^2 \frac{f_Y(I,h)}{r_Y(I,h)}\ s_{YZ}(I,h)$$

and

$$s_{YZ}(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\ [Y(I,h,i) - \hat{\bar{Y}}(I,h)]\ [Z(I,h,i)-\hat{\bar{Z}}(I,h)]/[r_Y(I,h)-1].$$

Estimation and Comparison of Population Differences

Differences in the non-SSI and SSI population parameters are of two types:

1. Differences in population averages: $\bar{Y}(1) - \bar{Y}(2)$; and
2. Differences in population load factors: $R(1) - R(2)$.

Such differences are estimated, respectively, as $\hat{\bar{Y}}(1) - \hat{\bar{Y}}(2)$ and as $\hat{R}(1) - \hat{R}(2)$. Under the assumption that these estimates are approximately normally distributed, approximate tests of significance can be performed to determine if differences exist in the population averages or load factors. In the first case, (i.e., comparison of population averages), the form of the test statistic is

$$T = \frac{\hat{\bar{Y}}(1) - \hat{\bar{Y}}(2)}{\sqrt{\widehat{Var}[\hat{\bar{Y}}(1)] + \widehat{Var}[\hat{\bar{Y}}(2)]}} .$$

Statistically significant differences (at the α level) are determined when this T value exceeds the $(1-\alpha/2) \times 100$ percentage point of the t distribution having degrees of freedom equal to

$$\sum_{I=1}^{2} \sum_{h=1}^{H_I} [r_Y(I,h) - 1].$$

The test statistic for comparing population load factors is of identical form, with $\hat{R}(I)$ replacing $\hat{\overline{Y}}(I)$ in the formula.

<u>Estimation of Effects of Various Penetration Levels of SSI Customers</u>

Let P, $0 \leq P \leq 1$, represent the proportion of Duke's North Carolina residential customers not on the SSI rate at some point in time. The electricity consumption during a particular time frame for the residential class as a whole can therefore be represented by

$$\overline{Y}_p = P\overline{Y}(1) + Q\overline{Y}(2),$$

where $Q = 1-P$ and where $\overline{Y}(I)$ is the average consumption during the particular time frame for the I^{th} population. An estimate of $\overline{Y}_p$ is given by

$$\hat{\overline{Y}}_p = P\hat{\overline{Y}}(1) + Q\hat{\overline{Y}}(2).$$

Under the assumption of no population growth, the assumption that "new" SSI customers exhibit usage patterns like those of current (i.e., at the time of sampling) SSI customers, and the assumption that the remaining non-SSI customers exhibit usage patterns like those of current non-SSI customers, such estimates provide projected population estimates for the Duke North Carolina residential class as a whole (with the exception of those customers ineligible for either sample). Assuming that P is a known constant, the variance of $\hat{\overline{Y}}_p$ is estimated as

$$\widehat{\mathrm{Var}}(\hat{\bar{Y}}_p) = P^2 \, \widehat{\mathrm{Var}}[\hat{\bar{Y}}(1)] + Q^2 \, \widehat{\mathrm{Var}}[\hat{\bar{Y}}(2)].$$

Under the same assumptions, projected load factors, R_p, for the residential class can also be estimated. These estimates take the form

$$\hat{R}_p = \hat{\bar{Y}}_p \, / \, \hat{\bar{Z}}_p,$$

where the time frame for the numerator variable is chosen to be an average hour over a day (or month) and the time frame for the denominator variable is chosen as some specific hour during the day (or month). An approximate variance of the estimated load factor is estimated as

$$\widehat{\mathrm{Var}}(\hat{R}_p) = \frac{1}{\hat{\bar{Z}}_p^2} \left[\widehat{\mathrm{Var}}(\hat{\bar{Y}}_p) + \hat{R}_p^2 \, \widehat{\mathrm{Var}}(\hat{\bar{Z}}_p) - 2\hat{R}_p \, \widehat{\mathrm{Cov}}(\hat{\bar{Y}}_p, \hat{\bar{Z}}_p) \right]$$

where

$$\widehat{\mathrm{Cov}}(\hat{\bar{Y}}_p, \hat{\bar{Z}}_p) = P^2 \, \widehat{\mathrm{Cov}}[\hat{\bar{Y}}(1), \hat{\bar{Z}}(1)] + Q^2 \, \widehat{\mathrm{Cov}}[\hat{\bar{Y}}(2), \hat{\bar{Z}}(2)].$$

APPENDIX E

GENERAL DESCRIPTION OF THE HYDRO MODEL

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HYDRO is a FORTRAN implementation of a series of models which simulate the dispatch of all forms of hydroelectric generating capacity on a month-by-month basis. Inputs to the model are of two forms:

1. Information (in GLiMPS format) which is used to construct unit fuel costs of power from non-hydroelectric generating capacity.

2. The system load curve (time-sequential) for the utility for an arbitrary number of months, in EEI format.

Output of the model is an EEI format load curve (time-sequential) for the same months' input, which has been revised to include the effects of the dispatch of the following forms of hydroelectric generating capacity.

1. Run-of-the-river

2. Conventional (behind-the-dam) storage

3. Pumped storage

It should be noted that in its present form, HYDRO is applicable only to Duke Power Company, and strictly applicable only to months in the period 1/1/80 through 12/3/95. Descriptions of hydroelectric facilities are internal to the model, i.e., embedded in the FORTRAN code. Generalization of the model can be obtained by revising the code to accept these data from external sources.

For each month, the system load curve is read into the program, and average hourly run-of-the-river power is removed.

Next, conventional storage hydro is dispatched, based on the total energy available from this source in a given month. The load curve for all hours in which demand exceeds a particle level (Y*) is reduced to that level, subject to the constraint imposed by the maximum rate at which energy can be delivered. For Duke Power this rate is taken to be 812 MW.

Y* is determined by the model as a function of the total energy in the month and the load duration curve for the month, shown in Figure E-1.

Finally, the energy to be shifted from peak to base by pumped hydro storage is determined and this capacity is dispatched.

This is the most complex section of the model. Consider Figure E-2. The curve B represents the gross benefit to the utility from displacing high cost generating capacity from peak hours. Curve C represents the gross cost of providing that power. Thus, the net profit to the utility is given by the (vertical) distance between these two curves. Economic theory suggests that this profit will be at a maximum at the point where the marginal benefit is equal to marginal cost (E*). If the cost and benefit curves can be represented by equations, finding the optimum is easy.

However, the available data represent the curves as piece-wise linear approximations, so that the value of E* can only be approximated in the normal case. The method used is as follows:

1. The highest-cost plant being used to meet demand is found.
2. The lowest-cost plant having unused capacity in the base period is found.
3. If the ratio of low-cost to high-cost of the plants (correcting for energy efficiency of the pumping process) is less than one, the current estimates of E* lie to the left of E* in Figure E-2. A better solution is possible. Two estimates of Y* are found, associated with the high-cost and low-cost plants, respectively. From these values the amounts of energy (E*) that can be shifted are found, and another plant is considered on the peak or base periods, whichever is smaller.

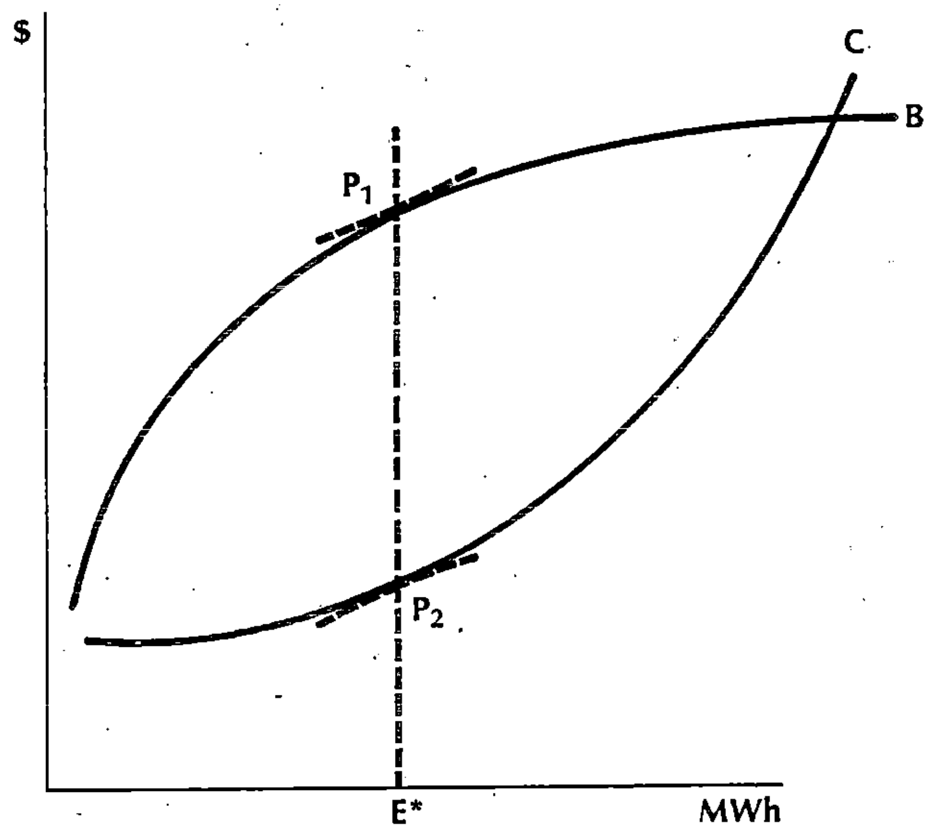

Figure E-1. Optimum energy supplied from pumped storage and associated pricing points.

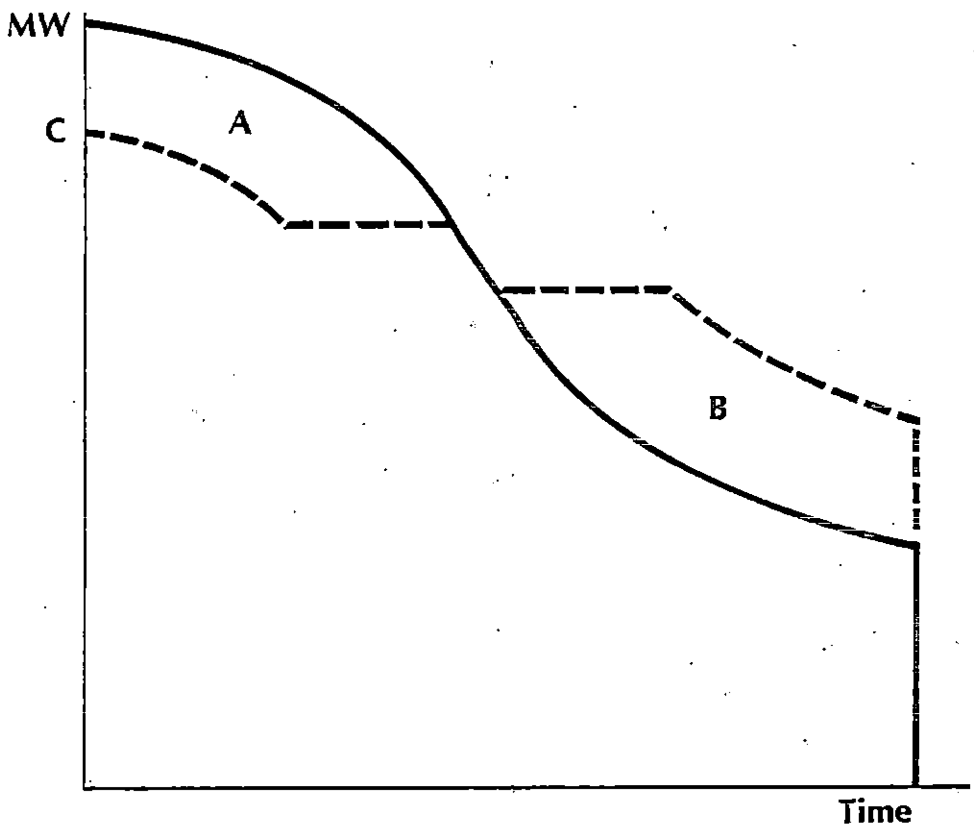

Figure E-2. Energy shifting with pumped storage subject to capacity and energy constraints.

4. If the ratio of low-cost to high-cost is greater than one, the current estimates of E^* are economically suboptimal, i.e., they lie to the right of the best value of E^* in Figure E-2.

   In this case, the previous solution is taken to be the best approximation of Y^*. The smaller amount of energy in the peak or base is the binding constraint, and the value of Y^* at the other end of the load duration curve is adjusted until its associated E^* is equal to the smaller amount.

5. The load curve for the month is then revised to the levels $\overset{*}{YP}$ and $\overset{*}{YB}$, constrained by the maximum charge and discharge rate of the system. This value is 610 representing Jocassee, and rises to 1610 MW by April 1991 as the Bad River facilities become available.

No check is made of possible capacity constraints of pumped hydro in the model, but our examination of the data suggests that no such constraint is binding.

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List of Web Links for Programs in Other States Related to Low-Income Electric Rates and Assistance

1. Office of Legislative Research – "Utility Rate Discounts for Low-Income Customers in Other States, February 2018
https://www.cga.ct.gov/2018/rpt/pdf/2018-R-0051.pdf

2. ASPE – "Approached to Low-Income Energy Assistance Funding in Selected States," April 2014
https://aspe.hhs.gov/system/files/pdf/180296/rb_LIHEAP.pdf

3. Choose Energy – Compilation of Resources in Various States
https://www.chooseenergy.com/blog/energy-tips/summer-energy-assistance-programs/

4. National Grid Rhode Island - Rate discount for Eligible Low-Income Customers on Food Stamps, LiHEAP, or receiving SSI.
https://www.nationalgridus.com/RI-Home/Bill-Help/Discount-Rates

5. SMUD Low-Income Assistance and Non-Profit Discount
https://www.smud.org/en/Rate-Information/Low-income-and-nonprofits

6. Lite-Up Texas – Texas program that provided rate discounts to eligible low-income customers. Program was terminated in August 2017.
https://www.puc.texas.gov/consumer/lowincome/assistance.aspx

7. PECO – Customer Assistance Program provides monthly credits to eligible low-income customers.
https://www.peco.com/MyAccount/CustomerSupport/Pages/CAPRate.aspx
https://www.peco.com/MyAccount/CustomerSupport/Pages/AssistancePrograms.aspx

8. Pennsylvania Public Utility Commission – Summary of Energy Assistance Programs
http://www.puc.state.pa.us/consumer_info/electricity/energy_assistance_programs.aspx

9. Salt River Project – Flat discount of $23/month for eligible customers.
https://www.srpnet.com/prices/economy.aspx
https://www.srpnet.com/community/liprograms.aspx

10. ConEdison – Discount program for low-income customers who already have qualified for specific governmental assistance programs. https://www.coned.com/en/accounts-billing/payment-plans-assistance/help-paying-your-bill

11. City of Seattle – Rate Discount program for income-qualified customers. https://www.seattle.gov/light/assistance/

12. New Hampshire Public Utilities Commission - Electric Assistance Program provides discounts to low-income eligible customers https://www.puc.nh.gov/consumer/electricassistanceprogram.htm

13. Georgia Service Commission – Senior Citizen discount of up to $24 per month on electric bill for qualifying customers. https://psc.ga.gov/about-the-psc/consumer-corner/consumer-advisories/senior-citizens-discounts/

14. California Alternative Rates for Energy – Bill discount program. https://www.cpuc.ca.gov/General.aspx?id=976

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Floyd Exhibit 4

Docket No. E-7, Sub 1214

Electric Utility Residential Customer Charges Minimum Bills

Jim Lazar
Regulatory Assistance Project
November 2014

RAP™ Energy solutions for a changing world

Electric Utility Residential Customer Charges and Minimum Bills:

Alternative Approaches for Recovering Basic Distribution Costs

By Jim Lazar[1]

Electric utilities have certain costs that do not vary with the usage of electricity. It is generally accepted that these include the costs of metering, billing, and payment processing. These costs are most often recovered through what is variously called a "customer charge" or a "service charge" or a "basic charge." In the United Kingdom, this is known as a "standing charge."

Regardless of the title, it is a charge (usually less than $10/month for residential service) that is levied each month regardless of electricity usage, with additional charges applying for each kilowatt-hour of electricity consumed. For most utilities in the US, the customer charge covers the cost of billing and collection, and perhaps other customer-specific costs like meter reading, but not the costs of distribution facilities like poles, conductors, or transformers.

Nearly all electric utilities worldwide bundle the cost of distribution service, as well as the power supply cost, into a usage charge, calculated as a price per kilowatt-hour. This is consistent with how competitive firms price their products, whether it is gasoline, groceries, or hotel rooms: the price per unit recovers all of the costs involved in producing, transporting, and retailing of goods and services.

Some rate analysts argue that a portion of the distribution system – poles, wires, and transformers – constitute a fixed cost that does not vary with sales and should be included in the fixed customer charge. Some recent proposals from electric utilities reflect this view. This is controversial.

Many state regulatory authorities rejected this approach when they held hearings and made determinations under the Public Utility Regulatory Policies Act of 1978.[2] The Washington Utilities and Transportation Commission, for example, explicitly rejected the concept that distribution costs were customer-related in nature:

> *In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies.*[3]

However, as sales have flattened or declined in recent years, and as more customers install on-site generating resources but remain dependent on grid services for some service, the concept of recovering distribution network costs in fixed charges has experienced resurgence.

Utility sales volumes in some regions have stagnated or declined as appliances, homes, equipment and systems become more efficient. Sales volumes also vary with weather, declining in mild years. Many state net-metering laws allow consumers installing rooftop solar arrays to incur net-bills for zero or very few kilowatt-hours, depending on the geographic location and the design of the net-metering tariff. To improve revenue stability, and to collect distribution system costs from PV customers, some utilities are arguing that "fixed" costs should be recovered in fixed customer charges. Some utilities are seeking customer charges of $20/month or more. In one extreme case, Madison Gas and Electric Company proposed a $69/month customer charge, to recover all costs except for fuel and purchased power expenses.[4] The Wisconsin PUC recently voted 2-1 to approve an increase in the customer charge to

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1 Rich Sedano, Janine Migden-Ostrander, Brenda Hausauer and Camille Kadoch provided reviews.

2 Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§2601-2645 (1978). Available at: http://www.gpo.gov/fdsys/pkg/STATUTE-92/pdf/STATUTE-92-Pg3117.pdf.

3 WUTC v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, P. 71, 1990.

$19/month for Wisconsin Public Service Company.[5]

An electric utility has a defined revenue requirement, determined by their regulator. A higher customer charge therefore means a lower per-kWh rate will be required. This has important impacts on the utility and its customers. Utility revenue is stabilized by a high customer charge, independent of weather, conservation, or other impacts on sales. However, the impacts on customers of high customer charges can be inconsistent with policy objectives:

- Small-use customers, such as apartment dwellers, low-income households, and second homes will receive much higher electric bills; the vast majority of low-income consumers are also low-use consumers. This is anathema to public policy objectives that normally tend to protect low-income customers and/or reward low usage;
- Urban area residents who use natural gas for space and water heat will receive much higher electric bills;
- Large-use customers, including large single-family homes in suburban and rural areas without access to natural gas most often will receive lower electric bills, depending on the existing utility rate design; and
- The lower per-kWh prices that result when a significant portion of costs are recovered in a fixed monthly customer charge will stimulate consumption. This creates consequences for incremental utility investment and for the environment. It also reduces the economic incentive for careful customer energy management practices and investment in energy efficiency measures by increasing pay-back periods.

There are several ways besides high fixed charges to address utility revenue stability issues:

- **Financial Reserves:** The traditional approach has been to set rates in a manner that recovers distribution and power costs in a per-kWh charge, and expect utilities to have adequate financial reserves to manage the volatility that occurs with weather. This is reflected in the 40% – 50% equity ratios allowed for electric utilities in determining the cost of capital.
- **Frequent rate cases**: If regulators hold rate proceedings every year or two, there is little time for sales volumes to deviate far from the level used to set volumetric rates.
- **Revenue Decoupling:** Many regulators have adopted revenue regulation mechanisms that calculate a true-up at the end of the month or year to align actual revenues with allowed revenues.

All of these methods allow the per-kWh charge to continue to reflect substantially all of the costs of service. By structuring rates this way, regulators preserve the consumer incentive to use electricity wisely.

Rate Designs with Minimum Bill Charges

One alternative to address utility concerns for revenue adequacy in addition to Revenue Regulation and frequent rate cases is a concept known as a "minimum bill." A minimum bill guarantees the utility a minimum annual revenue level from each customer, even if their usage is zero. The vast majority of customers, who consume the overwhelming majority of energy, have usage that exceeds those low thresholds. For these customers, a minimum bill "disappears" when the usage passes that level, and the customer effectively pays a volumetric rate to cover both power supply and distribution costs.

It is important to understand that a very small number of customers will be adversely affected by the minimum bill, because a large majority of all customers have usage in excess of the minimum billed amount. Figure 1 compares the number of customers served at each usage level, and the kilowatt-hours used by those customers at each usage level. Only a few percent of the customers, using less than one percent of the energy, have usage below 150 kWh per month in this illustrative example, and are arguably not making a meaningful contribution to system costs when those costs are built into the per-kWh charge.

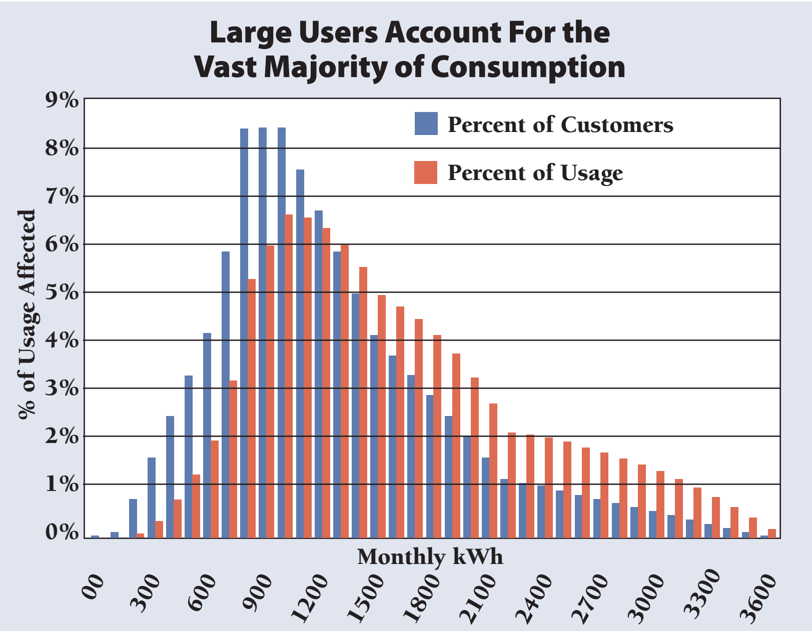
Table 1 compares three example residential rates, all designed to produce the same total level of residential revenue for an illustrative utility with average usage for this example of 1,000 kWh/month/customer.

- **Low Customer Charge:** $5/month, to cover billing and collection
- **High Customer Charge:** $20/month, to cover billing, collection, and a portion of distribution costs
- **Minimum Bill:** $5.00/month to cover billing and collection, with a minimum bill of $20 (which applies if usage falls below 150 kWh/month).

4 Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates, Docket 3270-UR-120, April 9, 2014. Available at: http://psc.wi.gov/apps40/dockets/content/detail.aspx?dockt_id=3270-UR-120.

5 Content, T. (2014, November 6). State regulators approve 83% increase in Green Bay utility's fixed charge. *Milwaukee Journal-Sentinel*. Retrieved from: www.jsonline.com.

Figure 1



This shows that for the average customer, the three rate designs produce almost identical bills. With a high customer charge rate design, because the $20 customer charge is collecting $15 more than the $5 low customer charge, the price per kWh is lower by $0.015/kWh. For the minimum bill rate design, however, less than 1% of kWh sales will typically be to those customers using under 150 kWh/month. This group has historically been limited to unoccupied dwellings; more recently, it has come to include customers with solar PV systems that produce as many kilowatt-hours as they consume, but remain dependent on the grid to serve as a "battery" taking excess production during the day, and supplying power when the sun is not shining.

Therefore, there will not be a lot of revenue recovered by the minimum bill charge, leaving most of the revenue requirement recovered by the volumetric charge. The per-kWh rate would only be reduced by about $0.001/kWh (1%) as a result. Under this rate design, very small-use customers, such as PV customers whose panels produce as many kilowatt-hours as the house uses, would pay slightly higher bills. However, as nearly all usage by customers remains priced at a cost-based rate that includes all of the costs of producing and distributing electricity, the low-use PV customer would have negligible usage charges.

Table 1

	kWh	Low Customer Charge	High Customer Charge	$20 Minimum Bill*
Customer Charge		$5.00	$20.00	$5.00
Minimum Bill				$20.00
Per-kWh Charge		$0.10	$0.085	$0.099
	10 kWh	$6.00	$20.85	$20.00
	100 kWh	$15.00	$28.50	$20.00
Customer Bills	200 kWh	$25.00	$37.00	$24.80
	500 kWh	$55.00	$62.50	$54.50
	1,000 kWh	$105.00	$105.00	$104.00
	1,500 kWh	$155.00	$147.50	$153.50
	2,000 kWh	$205.00	$190.00	$203.00

**The minimum bill will only apply when customer's usage is so low that their bill falls below $20.*

Impact on Usage

Electricity usage varies with the price paid. Higher kWh charges create greater incentives for consumers to turn out unneeded lights, manage thermostat settings, and invest in more efficient appliances, windows, and insulation. There is an economic science tool, price elasticity, which measures the expected change in consumption if prices change. Economists variously estimate the price elasticity of demand for electricity in the range of -0.1 to -0.7, with some long-run estimates going higher. An elasticity of -0.2, meaning that a 1% increase in price results in a 0.2% decrease in the quantity demanded, is considered a conservative estimate of long-run price elasticity.

The high customer charge rate design results in a 15% lower price per kilowatt-hour compared to the low customer charge rate design. Assuming an elasticity of -0.2, that would imply that customers would consume about 3% more electricity (-0.2 elasticity x 15% change in rate = 3% change in usage) as a result of the lower per-kWh price.

The minimum bill rate form, on the other hand, only reduces the price per kWh by 1% compared to the low customer charge rate design; assuming the same elasticity factor, the minimum bill design would increase usage by only about 0.2% among customers using more than the minimum billed quantity, when compared with their usage under the low customer charge rate form.

There is, however, a chance that the very small users might increase their usage up to the 150 kWh minimum. With this $20 minimum bill, customers using less than

150 kWh per month would see no change in their bills if they increased usage up to 150 kwh. But, since only a small percentage of customers use that little power, even if they did so, usage would not increase very much.

Evaluating a choice between a $20 fixed customer charge and a $20 minimum bill charge, we would expect about 15 times as much additional usage under the $20 fixed charge as under the $20 minimum bill charge.

Impact on PV Customers

Part of the concern that is raised by utilities is that customers with solar PV systems are "net-metering" to zero kWh, and paying only the customer charge in a monthly bill. These customers remain dependent on the grid for storage and shaping of their daytime energy production. Solar advocates argue that the grid is receiving a more valuable product – daytime renewable energy – than it is providing to the customers at night from conventional generation, and that this is a form of rough equity.

A minimum bill would ensure that a PV customer with net consumption of zero would still contribute to system costs. In the example, these customers would pay $20 per month. But, rather than distort the rate design for all customers, only the low-consumption consumers would be affected, allowing rates that continue to reflect all system costs to be applied to the overwhelming majority of energy sales.

Advantages and Disadvantages

A rate design that uses a customer charge combined with a kWh charge is simple to understand and administer. It provides a clear price signal for each kWh. If the customer charge is lower, the per-kWh charge is higher. However, the public is used to doing business for other purchases with a zero customer charge – grocery stores, gas stations, and virtually all other retailers only charge customers for what they buy, not for the privilege of being a customer (membership warehouse clubs are exceptions, with fees designed to weed out "browsers" from their stores.) There may also be conflict with intended outcomes for low use customers.

A minimum bill rate design has an advantage in that the per-kWh price is higher, more closely reflecting long-run marginal costs (all costs are variable in the long run). This rate design encourages prudent usage, better aligned with investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and, importantly, energy-related investments, will be informed by electricity prices that reflect long run grid value. The disadvantage is that, for the very small number of customers whose usage is below the "minimum," this rate design provides no disincentive at all to using the minimum amount of electricity. It can be perceived to have a disadvantage of encouraging additional usage by those users with usage below the minimum billed amount, but there are very few of these customers, and their prospective additional usage increase is minimal. Users in this group may argue that the minimum bill is unfair to them.

Finally, a minimum bill rate form ensures that second-homes, which may have no consumption during the off-season, contribute to utility revenues. This is sometimes presented as an economic justice issue, since second homes are generally held only by upper-income consumers.

Conclusion

The primary purpose of utility regulation is to enforce the pricing discipline on monopolies that competitive markets impose on most firms. Competitive firms nearly always recover all of their costs in the price per unit of their products. Therefore, any fixed monthly charge for electricity service represents a deviation from this underlying principle of utility regulation. The most commonly applied customer charges recover only customer-specific costs, such as billing and collection, in a fixed customer charge, leaving all costs of the shared system to be recovered in usage charges.

A regulator seeking to increase the contribution to utility system costs from those customers with minimal consumption can do so with either a higher customer charge, or establishing a minimum bill. The minimum bill option will ensure that all customers contribute to distribution costs, but without significantly stimulating consumption by higher-use customers or raising the bills of lower-income, low-use customers.

Forthcoming in Second Quarter, 2015: *Electric Rate Design for the Utility of the Future*. Watch for this on our website, www.raponline.org

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.65%		1.00	2.64%	-5.67%
Residential	6.56%		0.99	4.08%	-5.03%
General Service	7.67%	**	1.15	-2.73%	-8.66%
Lighting	4.96%	**	0.75	4.62%	-8.07%
Industrial	8.45%	**	1.27	-3.26%	-8.36%
OPT	6.20%		0.93	4.21%	-4.25%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental
Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SWPA Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.65%		1.00	2.64%	-5.67%
Residential	6.65%		1.00	3.76%	-5.36%
General Service	9.49%	**	1.43	-1.75%	-7.68%
Lighting	3.39%	**	0.51	4.61%	-8.08%
Industrial	8.34%	**	1.26	-1.51%	-6.62%
OPT	5.32%	**	0.80	3.91%	-4.55%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on WCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.65%		1.00	2.64%	-5.67%
Residential	5.09%	**	0.77	4.64%	-4.48%
General Service	10.73%	**	1.61	-0.64%	-6.57%
Lighting	3.57%	**	0.54	4.64%	-8.05%
Industrial	10.21%	**	1.54	2.69%	-2.42%
OPT	8.03%	**	1.21	1.25%	-7.20%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended +/- 10% band of reasonableness.

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Base Case - No Revenue Change -SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,254	$ 885,750	$ 126,724	$ 157,155	$ 1,367,662
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 1,009,285	$ 487,229	$ 234,230	$ 26,135	$ 42,242	$ 219,448
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 1,009,285	$ 487,229	$ 234,230	$ 26,135	$ 42,242	$ 219,448
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,505,221	$ 2,811,975	$ 616,537	$ 453,269	$ 4,245,142
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,512,151	$ 2,814,266	$ 617,039	$ 453,639	$ 4,248,601
8	**Rate of Return (before change)**	6.07%	5.73%	8.33%	4.24%	9.32%	5.17%
9	**Rate of Return Index (before change)**	1.00	0.94	1.37	0.70	1.54	0.85
10	**Rate of Return (after change)**	6.06%	5.72%	8.32%	4.24%	9.31%	5.17%
11	**Rate of Return Index (after change)**	1.00	0.94	1.37	0.70	1.54	0.85
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Equal Rates of Return for all Classes - SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,254	$ 885,750	$ 126,724	$ 157,155	$ 1,367,662
2	**Proposed Revenue Change**	$ 126,799	$ 102,677	$ (61,842)	$ 19,470	$ (15,843)	$ 82,337
3	**Net Income Before Increase**	$ 1,009,285	$ 487,229	$ 234,230	$ 26,135	$ 42,242	$ 219,448
4	**Change in Net Income**	$ 96,822	$ 78,403	$ (47,222)	$ 14,867	$ (12,098)	$ 62,871
5	**Total Net Income**	$ 1,106,107	$ 565,633	$ 187,008	$ 41,002	$ 30,144	$ 282,320
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,505,221	$ 2,811,975	$ 616,537	$ 453,269	$ 4,245,142
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,512,151	$ 2,814,266	$ 617,039	$ 453,639	$ 4,248,601
8	**Rate of Return (before change)**	6.07%	5.73%	8.33%	4.24%	9.32%	5.17%
9	**Rate of Return Index (before change)**	1.00	0.94	1.37	0.70	1.54	0.85
10	**Rate of Return (after change)**	6.65%	6.65%	6.65%	6.65%	6.65%	6.65%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	2.64%	4.52%	-6.98%	15.36%	-10.08%	6.02%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Class Revenue Changes Equal to NC Retail Change - SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,254	$ 885,750	$ 126,724	$ 157,155	$ 1,367,662
2	**Proposed Revenue Change**	$ 126,799	$ 102,677	$ (61,842)	$ 19,470	$ (15,843)	$ 82,337
3	**Net Income Before Increase**	$ 1,009,285	$ 487,229	$ 234,230	$ 26,135	$ 42,242	$ 219,448
4	**Change in Net Income**	$ 96,822	$ 78,403	$ (47,222)	$ 14,867	$ (12,098)	$ 62,871
5	**Total Net Income**	$ 1,106,107	$ 565,633	$ 187,008	$ 41,002	$ 30,144	$ 282,320
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,505,221	$ 2,811,975	$ 616,537	$ 453,269	$ 4,245,142
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,512,151	$ 2,814,266	$ 617,039	$ 453,639	$ 4,248,601
8	**Rate of Return (before change)**	6.07%	5.73%	8.33%	4.24%	9.32%	5.17%
9	**Rate of Return Index (before change)**	1.00	0.94	1.37	0.70	1.54	0.85
10	**Rate of Return (after change)**	6.65%	6.26%	8.96%	4.65%	10.01%	5.81%
11	**Rate of Return Index (after change)**	1.00	0.94	1.35	0.70	1.51	0.87
12	**Percent Change in Base Revenue**	2.64%	2.64%	2.64%	2.64%	2.64%	2.64%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Public Staff Recommended Revenue Distribution- SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,254	$ 885,750	$ 126,724	$ 157,155	$ 1,367,662
2	**Proposed Revenue Change**	$ 126,799	$ 92,677	$ (24,165)	$ 5,851	$ (5,116)	$ 57,551
3	**Net Income Before Increase**	$ 1,009,285	$ 487,229	$ 234,230	$ 26,135	$ 42,242	$ 219,448
4	**Change in Net Income**	$ 96,822	$ 70,767	$ (18,452)	$ 4,468	$ (3,907)	$ 43,945
5	**Total Net Income**	$ 1,106,107	$ 557,997	$ 215,778	$ 30,603	$ 38,335	$ 263,394
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,505,221	$ 2,811,975	$ 616,537	$ 453,269	$ 4,245,142
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,512,151	$ 2,814,266	$ 617,039	$ 453,639	$ 4,248,601
8	**Rate of Return (before change)**	6.07%	5.73%	8.33%	4.24%	9.32%	5.17%
9	**Rate of Return Index (before change)**	1.00	0.94	1.37	0.70	1.54	0.85
10	**Rate of Return (after change)**	6.65%	6.56%	7.67%	4.96%	8.45%	6.20%
11	**Rate of Return Index (after change)**	1.00	0.99	1.15	0.75	1.27	0.93
12	**Percent Change in Base Revenue**	2.64%	4.08%	-2.73%	4.62%	-3.26%	4.21%
13	**Staff's Proposed EDIT-2 Credit**	$ (399,343)	$ (207,067)	$ (52,544)	$ (16,074)	$ (8,025)	$ (115,634)
14	**Percent Change in Revenue with EDIT-2 Credit**	-5.67%	-5.03%	-8.66%	-8.07%	-8.36%	-4.25%

Floyd DEC Corrected First Supplemental Exhibit 3

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 3

Base Case - No Revenue Change - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,352	$ 886,057	$ 126,662	$ 157,139	$ 1,367,335
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 1,009,285	$ 496,474	$ 256,857	$ 18,957	$ 40,803	$ 196,194
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 1,009,285	$ 496,474	$ 256,857	$ 18,957	$ 40,803	$ 196,194
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,443,384	$ 2,580,550	$ 690,101	$ 466,883	$ 4,451,228
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,450,264	$ 2,582,652	$ 690,663	$ 467,263	$ 4,454,854
8	**Rate of Return (before change)**	6.07%	5.88%	9.95%	2.75%	8.74%	4.41%
9	**Rate of Return Index (before change)**	1.00	0.97	1.64	0.45	1.44	0.73
10	**Rate of Return (after change)**	6.06%	5.88%	9.95%	2.74%	8.73%	4.40%
11	**Rate of Return Index (after change)**	1.00	0.97	1.64	0.45	1.44	0.73
12	**Percent Change in Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 3
Page 2 of 4

Equal Rates of Return for all Classes - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,352	$ 886,057	$ 126,662	$ 157,139	$ 1,367,335
2	**Proposed Revenue Change**	$ 126,799	$ 85,185	$ (111,630)	$ 35,277	$ (12,773)	$ 130,739
3	**Net Income Before Increase**	$ 1,009,285	$ 496,474	$ 256,857	$ 18,957	$ 40,803	$ 196,194
4	**Change in Net Income**	$ 96,822	$ 65,046	$ (85,240)	$ 26,937	$ (9,753)	$ 99,831
5	**Total Net Income**	$ 1,106,107	$ 561,520	$ 171,617	$ 45,895	$ 31,050	$ 296,025
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,443,384	$ 2,580,550	$ 690,101	$ 466,883	$ 4,451,228
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,450,264	$ 2,582,652	$ 690,663	$ 467,263	$ 4,454,854
8	**Rate of Return (before change)**	6.07%	5.88%	9.95%	2.75%	8.74%	4.41%
9	**Rate of Return Index (before change)**	1.00	0.97	1.64	0.45	1.44	0.73
10	**Rate of Return (after change)**	6.65%	6.65%	6.65%	6.65%	6.65%	6.65%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Revenue**	2.64%	3.75%	-12.60%	27.85%	-8.13%	9.56%

Class Revenue Changes Equal to NC Retail Change - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,352	$ 886,057	$ 126,662	$ 157,139	$ 1,367,335
2	**Proposed Revenue Change**	$ 126,799	$ 85,185	$ (111,630)	$ 35,277	$ (12,773)	$ 130,739
3	**Net Income Before Increase**	$ 1,009,285	$ 496,474	$ 256,857	$ 18,957	$ 40,803	$ 196,194
4	**Change in Net Income**	$ 96,822	$ 65,046	$ (85,240)	$ 26,937	$ (9,753)	$ 99,831
5	**Total Net Income**	$ 1,106,107	$ 561,520	$ 171,617	$ 45,895	$ 31,050	$ 296,025
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,443,384	$ 2,580,550	$ 690,101	$ 466,883	$ 4,451,228
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,450,264	$ 2,582,652	$ 690,663	$ 467,263	$ 4,454,854
8	**Rate of Return (before change)**	6.07%	5.88%	9.95%	2.75%	8.74%	4.41%
9	**Rate of Return Index (before change)**	1.00	0.97	1.64	0.45	1.44	0.73
10	**Rate of Return (after change)**	6.65%	6.42%	10.64%	3.11%	9.41%	5.02%
11	**Rate of Return Index (after change)**	1.00	0.97	1.60	0.47	1.42	0.76
12	**Percent Change in Revenue**	2.64%	2.64%	2.64%	2.64%	2.64%	2.64%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 3

Public Staff Recommended Revenue Distribution- SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,272,352	$ 886,057	$ 126,662	$ 157,139	$ 1,367,335
2	**Proposed Revenue Change**	$ 126,799	$ 85,380	$ (15,483)	$ 5,836	$ (2,373)	$ 53,437
3	**Net Income Before Increase**	$ 1,009,285	$ 496,474	$ 256,857	$ 18,957	$ 40,803	$ 196,194
4	**Change in Net Income**	$ 96,822	$ 65,195	$ (11,823)	$ 4,457	$ (1,812)	$ 40,804
5	**Total Net Income**	$ 1,106,107	$ 561,669	$ 245,034	$ 23,414	$ 38,991	$ 236,998
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 8,443,384	$ 2,580,550	$ 690,101	$ 466,883	$ 4,451,228
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 8,450,264	$ 2,582,652	$ 690,663	$ 467,263	$ 4,454,854
8	**Rate of Return (before change)**	6.07%	5.88%	9.95%	2.75%	8.74%	4.41%
9	**Rate of Return Index (before change)**	1.00	0.97	1.64	0.45	1.44	0.73
10	**Rate of Return (after change)**	6.65%	6.65%	9.49%	3.39%	8.34%	5.32%
11	**Rate of Return Index (after change)**	1.00	1.00	1.43	0.51	1.26	0.80
12	**Percent Change in Revenue**	2.64%	3.76%	-1.75%	4.61%	-1.51%	3.91%
13	**Staff's Proposed EDIT-2 Credit**	$ (399,343)	$ (207,067)	$ (52,544)	$ (16,074)	$ (8,025)	$ (115,634)
14	**Percent Change in Revenue with EDIT-2 Credit**	-5.67%	-5.36%	-7.68%	-8.08%	-6.62%	-4.55%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd (Corrected) Supplemental Exhibit 4

Base Case - No Revenue Change -WCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,809,545	$ 2,270,880	$ 886,264	$ 126,641	$ 157,164	$ 1,368,597
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 1,009,285	$ 399,345	$ 268,488	$ 19,884	$ 42,658	$ 278,910
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 1,009,285	$ 399,345	$ 268,488	$ 19,884	$ 42,658	$ 278,910
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,632,145	$ 9,409,941	$ 2,459,647	$ 681,346	$ 448,860	$ 3,632,351
7	**Staff's Proposed Rate Base**	$ 16,645,696	$ 9,417,608	$ 2,461,651	$ 681,901	$ 449,226	$ 3,635,310
8	**Rate of Return (before change)**	6.07%	4.24%	10.92%	2.92%	9.50%	7.68%
9	**Rate of Return Index (before change)**	1.00	0.70	1.80	0.48	1.57	1.27
10	**Rate of Return (after change)**	6.06%	4.24%	10.91%	2.92%	9.50%	7.67%
11	**Rate of Return Index (after change)**	1.00	0.70	1.80	0.48	1.57	1.27
12	**Percent Change in Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Floyd DEC Supplemental Exhibit 1

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental
Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT Credit
NC Retail	7.04%		1.00	6.21%	-0.72%
Residential	6.80%		0.96	7.69%	0.05%
General Service	7.72%		1.10	0.80%	-4.22%
Lighting	7.04%		1.00	8.15%	-1.59%
Industrial	9.25%	**	1.31	0.79%	-3.44%
OPT	6.85%		0.97	7.66%	0.64%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended

+/- 10% band of reasonableness.

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental
Exhibit No. 1
Page 2 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SWPA Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT Credit
NC Retail	7.04%		1.00	6.21%	-0.72%
Residential	6.90%		0.98	7.43%	-0.21%
General Service	9.25%	**	1.31	0.64%	-4.36%
Lighting	5.26%	**	0.75	8.15%	-1.61%
Industrial	8.73%	**	1.24	1.05%	-3.19%
OPT	6.12%	**	0.87	8.15%	1.13%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

Duke Energy Carolinas, LLC

Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental
Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on WCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT Credit
NC Retail	7.04%		1.00	6.21%	-0.72%
Residential	5.29%	**	0.75	8.21%	0.55%
General Service	11.11%	**	1.58	4.20%	-0.80%
Lighting	5.46%	**	0.78	8.20%	-1.57%
Industrial	10.32%	**	1.47	4.24%	0.01%
OPT	8.72%	**	1.24	4.25%	-2.75%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

Floyd DEC Supplemental Exhibit 2

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 2

Base Case - No Revenue Change -SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,070	$ 850,346	$ 133,855	$ 153,683	$ 1,336,477
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 971,306	$ 459,610	$ 215,822	$ 35,891	$ 41,768	$ 218,216
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 971,306	$ 459,610	$ 215,822	$ 35,891	$ 41,768	$ 218,216
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,647,579	$ 2,859,041	$ 626,856	$ 460,856	$ 4,316,196
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,663,263	$ 2,864,227	$ 627,993	$ 461,692	$ 4,324,024
8	**Rate of Return (before change)**	5.74%	5.31%	7.55%	5.73%	9.06%	5.06%
9	**Rate of Return Index (before change)**	1.00	0.93	1.31	1.00	1.58	0.88
10	**Rate of Return (after change)**	5.73%	5.31%	7.54%	5.72%	9.05%	5.05%
11	**Rate of Return Index (after change)**	1.00	0.93	1.31	1.00	1.58	0.88
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 2

Equal Rates of Return for all Classes - SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,070	$ 850,346	$ 133,855	$ 153,683	$ 1,336,477
2	**Proposed Revenue Change**	$ 290,241	$ 196,993	$ (18,510)	$ 10,909	$ (12,123)	$ 112,973
3	**Net Income Before Increase**	$ 971,306	$ 459,610	$ 215,822	$ 35,891	$ 41,768	$ 218,216
4	**Change in Net Income**	$ 221,625	$ 150,422	$ (14,134)	$ 8,330	$ (9,257)	$ 86,265
5	**Total Net Income**	$ 1,192,931	$ 610,032	$ 201,687	$ 44,221	$ 32,510	$ 304,480
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,647,579	$ 2,859,041	$ 626,856	$ 460,856	$ 4,316,196
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,663,263	$ 2,864,227	$ 627,993	$ 461,692	$ 4,324,024
8	**Rate of Return (before change)**	5.74%	5.31%	7.55%	5.73%	9.06%	5.06%
9	**Rate of Return Index (before change)**	1.00	0.93	1.31	1.00	1.58	0.88
10	**Rate of Return (after change)**	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	6.21%	8.96%	-2.18%	8.15%	-7.89%	8.45%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 2

Class Revenue Changes Equal to NC Retail Change - SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,070	$ 850,346	$ 133,855	$ 153,683	$ 1,336,477
2	**Proposed Revenue Change**	$ 290,241	$ 196,993	$ (18,510)	$ 10,909	$ (12,123)	$ 112,973
3	**Net Income Before Increase**	$ 971,306	$ 459,610	$ 215,822	$ 35,891	$ 41,768	$ 218,216
4	**Change in Net Income**	$ 221,625	$ 150,422	$ (14,134)	$ 8,330	$ (9,257)	$ 86,265
5	**Total Net Income**	$ 1,192,931	$ 610,032	$ 201,687	$ 44,221	$ 32,510	$ 304,480
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,647,579	$ 2,859,041	$ 626,856	$ 460,856	$ 4,316,196
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,663,263	$ 2,864,227	$ 627,993	$ 461,692	$ 4,324,024
8	**Rate of Return (before change)**	5.74%	5.31%	7.55%	5.73%	9.06%	5.06%
9	**Rate of Return Index (before change)**	1.00	0.93	1.31	1.00	1.58	0.88
10	**Rate of Return (after change)**	7.04%	6.51%	8.94%	6.73%	10.63%	6.51%
11	**Rate of Return Index (after change)**	1.00	0.92	1.27	0.96	1.51	0.92
12	**Percent Change in Base Revenue**	6.21%	6.21%	6.21%	6.21%	6.21%	6.21%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 2

Public Staff Recommended Revenue Distribution- SCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,070	$ 850,346	$ 133,855	$ 153,683	$ 1,336,477
2	**Proposed Revenue Change**	$ 290,241	$ 169,028	$ 6,769	$ 10,909	$ 1,221	$ 102,313
3	**Net Income Before Increase**	$ 971,306	$ 459,610	$ 215,822	$ 35,891	$ 41,768	$ 218,216
4	**Change in Net Income**	$ 221,625	$ 129,068	$ 5,169	$ 8,330	$ 933	$ 78,125
5	**Total Net Income**	$ 1,192,931	$ 588,679	$ 220,990	$ 44,221	$ 42,701	$ 296,341
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,647,579	$ 2,859,041	$ 626,856	$ 460,856	$ 4,316,196
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,663,263	$ 2,864,227	$ 627,993	$ 461,692	$ 4,324,024
8	**Rate of Return (before change)**	5.74%	5.31%	7.55%	5.73%	9.06%	5.06%
9	**Rate of Return Index (before change)**	1.00	0.93	1.31	1.00	1.58	0.88
10	**Rate of Return (after change)**	7.04%	6.80%	7.72%	7.04%	9.25%	6.85%
11	**Rate of Return Index (after change)**	1.00	0.96	1.10	1.00	1.31	0.97
12	**Percent Change in Base Revenue**	6.21%	7.69%	0.80%	8.15%	0.79%	7.66%
13	**Staff's Proposed EDIT Credit**	$ (323,929)	$ (167,963)	$ (42,622)	$ (13,038)	$ (6,509)	$ (93,797)
14	**Percent Change in Revenue with EDIT Credit**	-0.72%	0.05%	-4.22%	-1.59%	-3.44%	0.64%

Floyd DEC Supplemental Exhibit 3

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 3

Base Case - No Revenue Change - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,501	$ 851,683	$ 133,585	$ 153,613	$ 1,335,049
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 971,306	$ 468,949	$ 238,897	$ 28,690	$ 40,311	$ 194,458
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 971,306	$ 468,949	$ 238,897	$ 28,690	$ 40,311	$ 194,458
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,584,707	$ 2,623,742	$ 701,651	$ 474,697	$ 4,525,731
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,600,277	$ 2,628,501	$ 702,924	$ 475,558	$ 4,533,939
8	**Rate of Return (before change)**	5.74%	5.46%	9.11%	4.09%	8.49%	4.30%
9	**Rate of Return Index (before change)**	1.00	0.95	1.59	0.71	1.48	0.75
10	**Rate of Return (after change)**	5.73%	5.45%	9.09%	4.08%	8.48%	4.29%
11	**Rate of Return Index (after change)**	1.00	0.95	1.59	0.71	1.48	0.75
12	**Percent Change in Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 3

Equal Rates of Return for all Classes - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,501	$ 851,683	$ 133,585	$ 153,613	$ 1,335,049
2	**Proposed Revenue Change**	$ 290,241	$ 178,955	$ (70,468)	$ 27,249	$ (8,937)	$ 163,443
3	**Net Income Before Increase**	$ 971,306	$ 468,949	$ 238,897	$ 28,690	$ 40,311	$ 194,458
4	**Change in Net Income**	$ 221,625	$ 136,648	$ (53,809)	$ 20,807	$ (6,825)	$ 124,803
5	**Total Net Income**	$ 1,192,931	$ 605,597	$ 185,088	$ 49,497	$ 33,487	$ 319,262
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,584,707	$ 2,623,742	$ 701,651	$ 474,697	$ 4,525,731
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,600,277	$ 2,628,501	$ 702,924	$ 475,558	$ 4,533,939
8	**Rate of Return (before change)**	5.74%	5.46%	9.11%	4.09%	8.49%	4.30%
9	**Rate of Return Index (before change)**	1.00	0.95	1.59	0.71	1.48	0.75
10	**Rate of Return (after change)**	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Revenue**	6.21%	8.14%	-8.27%	20.40%	-5.82%	12.24%

Class Revenue Changes Equal to NC Retail Change - SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,501	$ 851,683	$ 133,585	$ 153,613	$ 1,335,049
2	**Proposed Revenue Change**	$ 290,241	$ 178,955	$ (70,468)	$ 27,249	$ (8,937)	$ 163,443
3	**Net Income Before Increase**	$ 971,306	$ 468,949	$ 238,897	$ 28,690	$ 40,311	$ 194,458
4	**Change in Net Income**	$ 221,625	$ 136,648	$ (53,809)	$ 20,807	$ (6,825)	$ 124,803
5	**Total Net Income**	$ 1,192,931	$ 605,597	$ 185,088	$ 49,497	$ 33,487	$ 319,262
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,584,707	$ 2,623,742	$ 701,651	$ 474,697	$ 4,525,731
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,600,277	$ 2,628,501	$ 702,924	$ 475,558	$ 4,533,939
8	**Rate of Return (before change)**	5.74%	5.46%	9.11%	4.09%	8.49%	4.30%
9	**Rate of Return Index (before change)**	1.00	0.95	1.59	0.71	1.48	0.75
10	**Rate of Return (after change)**	7.04%	6.67%	10.63%	4.98%	10.01%	5.69%
11	**Rate of Return Index (after change)**	1.00	0.95	1.51	0.71	1.42	0.81
12	**Percent Change in Revenue**	6.21%	6.21%	6.21%	6.21%	6.21%	6.21%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 3

Public Staff Recommended Revenue Distribution- SWPA

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,198,501	$ 851,683	$ 133,585	$ 153,613	$ 1,335,049
2	**Proposed Revenue Change**	$ 290,241	$ 163,423	$ 5,487	$ 10,887	$ 1,606	$ 108,839
3	**Net Income Before Increase**	$ 971,306	$ 468,949	$ 238,897	$ 28,690	$ 40,311	$ 194,458
4	**Change in Net Income**	$ 221,625	$ 124,788	$ 4,190	$ 8,313	$ 1,226	$ 83,108
5	**Total Net Income**	$ 1,192,931	$ 593,737	$ 243,087	$ 37,003	$ 41,538	$ 277,567
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 8,584,707	$ 2,623,742	$ 701,651	$ 474,697	$ 4,525,731
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 8,600,277	$ 2,628,501	$ 702,924	$ 475,558	$ 4,533,939
8	**Rate of Return (before change)**	5.74%	5.46%	9.11%	4.09%	8.49%	4.30%
9	**Rate of Return Index (before change)**	1.00	0.95	1.59	0.71	1.48	0.75
10	**Rate of Return (after change)**	7.04%	6.90%	9.25%	5.26%	8.73%	6.12%
11	**Rate of Return Index (after change)**	1.00	0.98	1.31	0.75	1.24	0.87
12	**Percent Change in Revenue**	6.21%	7.43%	0.64%	8.15%	1.05%	8.15%
13	**Staff's Proposed EDIT Credit**	$ (323,929)	$ (167,963)	$ (42,622)	$ (13,038)	$ (6,509)	$ (93,797)
14	**Percent Change in Revenue with EDIT Credit**	-0.72%	-0.21%	-4.36%	-1.61%	-3.19%	1.13%

Floyd DEC Supplemental Exhibit 4

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 4

Base Case - No Revenue Change -WCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,192,070	$ 852,587	$ 133,493	$ 153,722	$ 1,340,559
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 971,306	$ 369,357	$ 250,928	$ 29,521	$ 42,203	$ 279,297
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 971,306	$ 369,357	$ 250,928	$ 29,521	$ 42,203	$ 279,297
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 9,567,442	$ 2,500,816	$ 692,750	$ 456,373	$ 3,693,148
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 9,584,794	$ 2,505,351	$ 694,006	$ 457,201	$ 3,699,846
8	**Rate of Return (before change)**	5.74%	3.86%	10.03%	4.26%	9.25%	7.56%
9	**Rate of Return Index (before change)**	1.00	0.67	1.75	0.74	1.61	1.32
10	**Rate of Return (after change)**	5.73%	3.85%	10.02%	4.25%	9.23%	7.55%
11	**Rate of Return Index (after change)**	1.00	0.67	1.75	0.74	1.61	1.32
12	**Percent Change in Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Equal Rates of Return for all Classes - WCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,192,070	$ 852,587	$ 133,493	$ 153,722	$ 1,340,559
2	**Proposed Revenue Change**	$ 290,241	$ 400,170	$ (97,580)	$ 25,338	$ (13,107)	$ (24,580)
3	**Net Income Before Increase**	$ 971,306	$ 369,357	$ 250,928	$ 29,521	$ 42,203	$ 279,297
4	**Change in Net Income**	$ 221,625	$ 305,566	$ (74,511)	$ 19,348	$ (10,009)	$ (18,769)
5	**Total Net Income**	$ 1,192,931	$ 674,923	$ 176,417	$ 48,869	$ 32,194	$ 260,528
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 9,567,442	$ 2,500,816	$ 692,750	$ 456,373	$ 3,693,148
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 9,584,794	$ 2,505,351	$ 694,006	$ 457,201	$ 3,699,846
8	**Rate of Return (before change)**	5.74%	3.86%	10.03%	4.26%	9.25%	7.56%
9	**Rate of Return Index (before change)**	1.00	0.67	1.75	0.74	1.61	1.32
10	**Rate of Return (after change)**	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Revenue**	6.21%	18.26%	-11.45%	18.98%	-8.53%	-1.83%

Class Revenue Changes Equal to NC Retail Change - WCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,192,070	$ 852,587	$ 133,493	$ 153,722	$ 1,340,559
2	**Proposed Revenue Change**	$ 290,241	$ 400,170	$ (97,580)	$ 25,338	$ (13,107)	$ (24,580)
3	**Net Income Before Increase**	$ 971,306	$ 369,357	$ 250,928	$ 29,521	$ 42,203	$ 279,297
4	**Change in Net Income**	$ 221,625	$ 305,566	$ (74,511)	$ 19,348	$ (10,009)	$ (18,769)
5	**Total Net Income**	$ 1,192,931	$ 674,923	$ 176,417	$ 48,869	$ 32,194	$ 260,528
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 9,567,442	$ 2,500,816	$ 692,750	$ 456,373	$ 3,693,148
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 9,584,794	$ 2,505,351	$ 694,006	$ 457,201	$ 3,699,846
8	**Rate of Return (before change)**	5.74%	3.86%	10.03%	4.26%	9.25%	7.56%
9	**Rate of Return Index (before change)**	1.00	0.67	1.75	0.74	1.61	1.32
10	**Rate of Return (after change)**	7.04%	4.94%	11.63%	5.17%	10.83%	9.27%
11	**Rate of Return Index (after change)**	1.00	0.70	1.65	0.73	1.54	1.32
12	**Percent Change in Revenue**	6.21%	6.21%	6.21%	6.21%	6.21%	6.21%

Duke Energy Carolinas, LLC
Docket No. E-7, Subs 1213 and 1214

Public Staff
Floyd Second Supplemental Exhibit 4

Public Staff Recommended Revenue Distribution- WCP

		NC Retail	RES	GS	Lighting	IND	OPT
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 4,672,431	$ 2,192,070	$ 852,587	$ 133,493	$ 153,722	$ 1,340,559
2	**Proposed Revenue Change**	$ 290,241	$ 180,007	$ 35,812	$ 10,945	$ 6,525	$ 56,951
3	**Net Income Before Increase**	$ 971,306	$ 369,357	$ 250,928	$ 29,521	$ 42,203	$ 279,297
4	**Change in Net Income**	$ 221,625	$ 137,452	$ 27,346	$ 8,358	$ 4,982	$ 43,487
5	**Total Net Income**	$ 1,192,931	$ 506,809	$ 278,273	$ 37,879	$ 47,185	$ 322,785
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 16,910,528	$ 9,567,442	$ 2,500,816	$ 692,750	$ 456,373	$ 3,693,148
7	**Staff's Proposed Rate Base**	$ 16,941,199	$ 9,584,794	$ 2,505,351	$ 694,006	$ 457,201	$ 3,699,846
8	**Rate of Return (before change)**	5.74%	3.86%	10.03%	4.26%	9.25%	7.56%
9	**Rate of Return Index (before change)**	1.00	0.67	1.75	0.74	1.61	1.32
10	**Rate of Return (after change)**	7.04%	5.29%	11.11%	5.46%	10.32%	8.72%
11	**Rate of Return Index (after change)**	1.00	0.75	1.58	0.78	1.47	1.24
12	**Percent Change in Revenue**	6.21%	8.21%	4.20%	8.20%	4.24%	4.25%
13	**Staff's Proposed EDIT Credit**	$ (323,929)	$ (167,963)	$ (42,622)	$ (13,038)	$ (6,509)	$ (93,797)
14	**Percent Change in Revenue with EDIT Credit**	-0.72%	0.55%	-0.80%	-1.57%	0.01%	-2.75%