PEAK DEMAND

FORECAST METHODOLOGY

FORECASTING DEPARTMENT
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PEAK DEMAND FORECAST METHODOLOGY

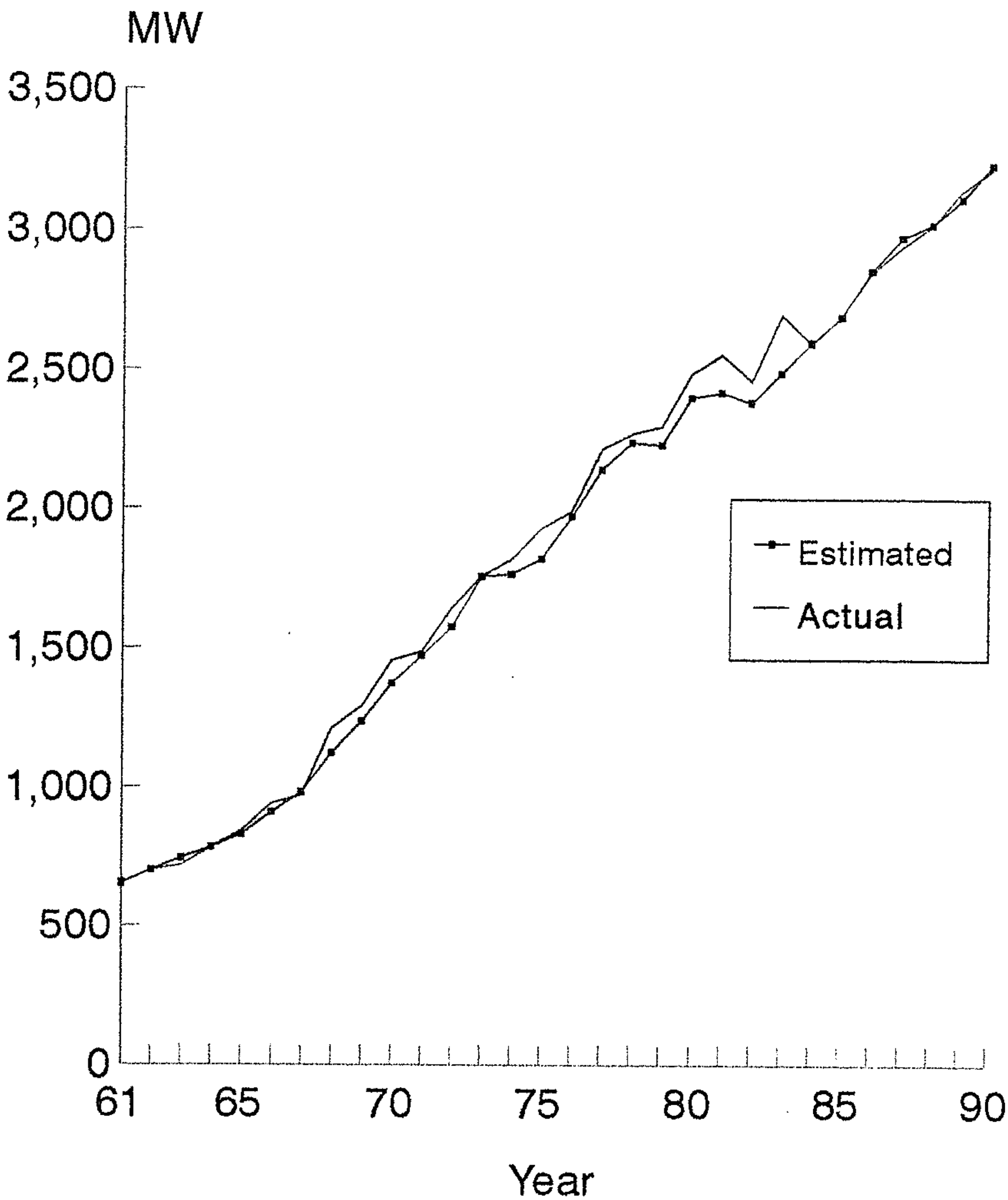
This paper describes the procedures used to create the long-range summer and winter peak demand forecasts. It also describes the methodology used to create monthly forecast peak demands. The development of the summer peak demand forecast will be discussed initially. This is followed by the construction of winter peaks, and concludes with a review of monthly peak demand development.

The forecast of annual summer peak demands was developed with a class load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and certain individual customer peaks are separately determined and then summed to a total.

1. Summer Peak Demand

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated and then utilized to estimate peak demands from projected energy consumption among these categories. Next, planning peaks were determined for six large special contract industrial customers. The demands of these customers were forecasted directly. Summing these class, rate, and individual customer demands provided a preliminary forecast of summer territorial peak demand. Incremental reductions in demand resulting from the Company's demand-side programs were then subtracted from the preliminary forecast. This calculation gave the final estimate of summer territorial peak demand, which was used for planning purposes.

CHART 1
CLASS LOAD FACTOR DEVELOPMENT VS. ACTUAL PEAK DEMANDS



whether or not an adjustment to forecast peak demands was required, a regression model was calculated. Actual annual summer peaks were regressed against two explanatory variables. The first of these was the weather occurring on the peak day, measured as the average of cooling degree days (CDD) in Columbia and Charleston. The second variable was the estimated summer peak based on 1990 load factors. Finally, a spline regression was modeled to allow for a changing regression coefficient in the second variable. This was used to account for the rapid growth in air-conditioning use over the period 1961-1984. The final version of the regression equations tested is shown below as Equation 1.

EQUATION 1

$$SPEAK = -191.120 + 1.003*LPEAK + 0.046*ADDFAC + 8.037*CDD$$
$$\qquad (-3.01) \qquad (118.01) \qquad (6.35) \qquad (2.50)$$

Estimation Period:
1961-1991

ADDFAC=ADDFAC*LPEAK
where
ADDFAC=1 for years prior to 1984, 0 otherwise

Where: SPEAK=Summer peak
LPEAK=Estimated summer Peak based on actual energy and average 1990 load factors
CDD=Average of cooling Degree Days for summer peak day, Columbia and Charleston

F-statistic: 5673.975
R^2: 0.998
Root MSE: 33.938
Dependent Mean: 1922.433
DW: 1.889

All of the independent variables were significant and the explanatory power of the overall equation was high, with an adjusted R^2 value of 0.998. The mean absolute percent error (MAPE) was 1.51%, representing as expected an improvement over the historic explanatory power of the load factor methodology alone.

For forecasting purposes, as opposed to explaining historic fluctuations in peak demand, the key coefficient in Equation 1 was that associated with the calculated load factor peak. The value of 1.003 indicated that an upward adjustment of 0.3% to the load factor peak was valid over the estimation period, which would translate into an increase of 10 to 14 MW for the forecast years 1992-2011.

In addition to the load factor adjustment, each additional CDD on the peak day added 8 MW to peak demand, so using the estimation period median value of 21 CDD (See Table 1) as a proxy for normal peak day weather, an additional 168 MW would be added to the forecast peak. However, when the negative intercept value of -191 was combined with these two positive adjustments the net result was a decrease to peak demand of 9 to 13 MW throughout the forecast horizon. This extremely small adjustment to the estimated load factor peaks implied that any revisions to the forecast values would be insignificant for planning purposes. Therefore, no changes were made as a result of explicitly incorporating weather, and the planning peaks remained as before.

TABLE 1

WEATHER STATISTICS FOR SUMMER PEAK DAYS

(1961-1991)

	Cooling Degree Days (CDD)
Maximum	26.5
75th Percentile	21.5
Median	21.0
Mean	20.9
25th Percentile	20.0
Minimum	16.0

NOTE: Cooling Degree Days are the average of Columbia and Charleston.

3. Load Factor Development

As mentioned above, load factors are required to estimate KW demand from KWH sales. The relationship among annual load factor, energy, and demand is shown in the following equation:

LOAD FACTOR = ENERGY/(DEMAND*8760)

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a load factor will range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This is the technique used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales. These were provided by the Load Research Department, which developed load factors by class and/or rate as required. Values were based on calendar year 1991, the most recent period for which load factors have been determined.

The demand levels used to create the load factors for the peak demand forecast were not one-hour coincident peaks. Instead, it was determined that use of an adjusted 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that over the past 23 years (1970-1992) all of the peaks had occurred between the hours of 2 and 6 PM, as shown in Table 2. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand contribution for the residential and commercial classes fluctuated widely depending on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined

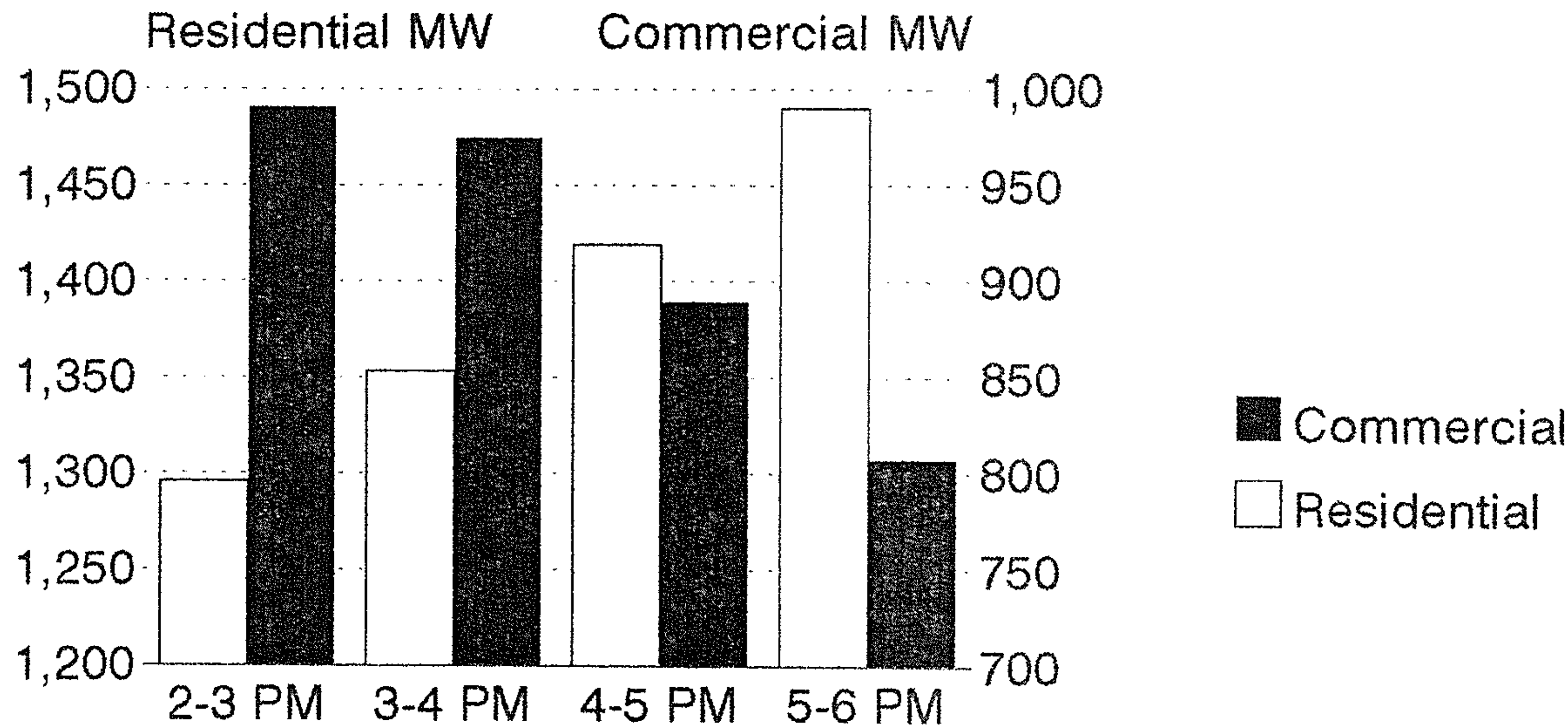
TABLE 2

LOAD RESEARCH AND DEMAND-SIDE PLANNING
ANNUAL SUMMER PEAK
1970 - 1992

	YEAR	MW	MONTH	DAY	HOUR	DAY OF WEEK
1.	1970	1,485	Aug.	31	5-6 P.M.	Mon.
2.	1971	1,489	Aug.	20	2-3 P.M.	Fri.
3.	1972	1,646	Aug.	4	3-4 P.M.	Fri.
4.	1973	1,762	Jul.	16	5-6 P.M	Mon.
5.	1974	1,819	Jul.	30	3-4 P.M.	Tue.
6.	1975	1,931	Aug.	26	2-3 P.M.	Tue.
7.	1976	1,994	Jul.	29	5-6 P.M.	Thu.
8.	1977	2,216	Jul.	20	4-5 P.M.	Wed.
9.	1978	2,271	Jun.	28	5-6 P.M.	Wed.
10.	1979	2,299	Aug.	9	3-4 P.M.	Thu.
11.	1980	2,489	Aug.	6	4-5 P.M.	Wed.
12.	1981	2,557	Jul.	14	4-5 P.M.	Tue.
13.	1982	2,463	Aug.	25	4-5 P.M.	Wed.
14.	1983	2,700	Aug.	22	4-5 P.M.	Mon.
15.	1984	2,596	Jun.	20	2-3 P.M.	Wed.
16.	1985	2,694	Jul.	10	5-6 P.M.	Wed.
17.	1986	2,853	Jul.	9	5-6 P.M.	Wed.
18.	1987	2,943	Aug.	10	2-3 P.M.	Mon.
19.	1988	3,021	Aug.	18	3-4 P.M.	Thu.
20.	1989	3,144	Jul.	11	5-6 P.M.	Tue.
21.	1990	3,222	Aug.	29	4-5 P.M.	Wed.
22.	1991	3,300	Jul.	23	3-4 P.M.	Tue.
23.	1992	3,380	Jul.	13	4-5 P.M.	Mon.

MONTH		HOUR		WEEKDAY	
Jun.	2	2-3	4	Mon.	5
Jul.	10	3-4	5	Tue.	5
Aug.	11	4-5	7	Wed.	8
	23	5-6	7	Thu.	3
			23	Fri.	2
					23

CHART 2
CHANGE IN RESIDENTIAL AND COMMERCIAL CLASS DEMANDS DURING PEAK HOURS (1991)



	2-3 PM	3-4 PM	4-5 PM	5-6 PM
Total	2,287	2,328	2,309	2,298
Commercial	991	975	890	808
Residential	1,296	1,353	1,419	1,490

(See Chart 2). Thus, load factors based on peaks occurring at, say, 2PM, would be quite different from those developed for a 5PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand for, say, municipals, was within 2% of the 1-hour coincident peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

Given that 4-hour average demands were used to construct the 1-hour coincident peak meant that a small difference of 39 MW occurred between the actual and developed coincident peaks for 1991. This difference was allocated to the residential and commercial classes, since those two categories drive the actual occurrence of the peak. It was these demands which were then applied to 1991 energies to derive class load factors for forecast development. Table 3 compares the 4-hour and 1-hour demands by class for the first year of the forecast, 1993, along with the adjustment for the residential and commercial sectors.

TABLE 3

1993 PEAK DEMANDS

(MW)

	4-Hour	Adjustment	1-Hour
Residential	1,473	1.017	1,498
Commercial	959	1.018	976
Industrial	730	---	730
Municipalities	158	---	158
Cooperatives	41	---	41
Other	95	---	95
DSM Adjustment	(93)	---	(93)
TOTAL	3,364		3,405

Note: Detail may not add to total due to rounding.

The effect of system line losses was embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections. Combining sales-level load factors and line loss multipliers, then, resulted in the generation-level load factors shown in Table 4.

TABLE 4

SYSTEM-LEVEL LOAD FACTORS USED TO DEVELOP CLASS/RATE PEAK DEMANDS

Class/Rate	Annual Load Factor
Residential:	
Space Heating:	
Good Cents	0.338
Conservation Rate	0.540
Regular	0.380
Non-Space Heating:	
Good Cents	0.313
Conservation Rate	0.473
Regular	0.452
Commercial[1]	0.550
Industrial[1]	0.777
Municipalities	0.574
Cooperatives	0.525
Miscellaneous (OPA and Company use)	0.357

[1]Excludes customers that were directly forecasted.

As shown in Table 4, the residential class was divided into two categories, space and non-space heating. This was done to allow for the different usage characteristics between the two groups. Within the space heating and non-space heating categories, residential customers were further subdivided into Good Cents, Conservation and Regular classifications. It should also be noted that the industrial sector load factor excluded six large special contract customers, whose peaks were determined separately.

4. Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. However, it would not be proper to directly use the final energy sales projections described earlier in the chapter, because those values already reflected DSM program impacts. The load factors developed earlier were exclusive of any incremental DSM impacts, and therefore should be applied to sales levels which also exclude incremental DSM programs. A separate sales forecast was thus developed which met this requirement by eliminating the incremental impact of DSM from the energy forecast. These revised projections were then utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

5. Unadjusted Peak Demands

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The six large industrial customers whose peak demands were developed separately were also added to this estimate. Finally, any new loads not contained in the energy sales projections were added. The complete unadjusted peak demand forecast is shown as part of Table 5.

6. Adjusted Peak Demands

Derivation of the planning peak required that the impact of DSM programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet expected demand, which includes the reductions attributable to DSM. However, the adjustments to peak demand for DSM were not just a straight reduction to the unadjusted peak demand first created. For example, the residential class forecast was assumed to already incorporate the demand reductions from the Good Cents and Rate 7 programs, since these were projected separately as part of the energy forecast. Therefore, marketing estimates of demand reductions for these programs were not used to develop adjusted demands.

Calculation of the impact of DSM programs on peak demand was done in the following way. First, cumulative KW reduction estimates were obtained from the Marketing Department. Second, the Good Cents and Conservation Rate impacts were excluded from

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEVELOPMENT BY CLASS
BASED ON 4-HOUR 1991 LOAD FACTORS, WITH RESIDENTIAL AND COMMERCIAL
LOAD FACTORS ADJUSTED TO INCREASE TOTAL LOAD BY 1.2%
(MW)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
RESIDENTIAL										
GOOD CENTS	64	81	89	99	108	118	128	138	147	157
CONSERVATION RATE	59	62	64	67	70	72	75	78	80	83
REGULAR	1,374	1,399	1,418	1,443	1,469	1,494	1,521	1,545	1,570	1,593
RESIDENTIAL TOTAL	1,498	1,541	1,572	1,609	1,646	1,684	1,724	1,761	1,798	1,832
COMMERCIAL TOTAL	976	1,000	1,027	1,059	1,093	1,127	1,164	1,198	1,233	1,266
REGULAR INDUSTRIALS	566	578	587	597	610	625	636	647	659	671
INTERRUPTIBLE CUSTOMERS (INCLUDING SRP)	164	164	164	164	164	164	164	164	164	164
TOTAL INDUSTRIAL	730	742	751	760	773	788	799	810	823	835
MUNICIPALITIES	158	163	209	214	219	225	230	236	241	246
COOPERATIVES	41	43	44	45	46	47	48	49	50	51
MISCELLANEOUS (OPA, CO. USE, STATE LINE)	95	98	101	104	107	110	113	116	119	122
UNADJUSTED DEMAND	3,498	3,587	3,703	3,791	3,884	3,981	4,078	4,170	4,264	4,353
LESS:										
INCREMENTAL DSM PROGRAMS	20	51	68	86	104	122	141	159	176	194
STAND-BY GENERATORS	25	34	38	42	46	50	54	58	63	67
INTERRUPTIBLE LOAD	48	48	48	54	54	54	54	54	54	54
TOTAL DEMAND REDUCTIONS	93	133	154	182	204	226	249	271	293	315
ADJUSTED DEMAND	3,405	3,455	3,549	3,609	3,680	3,755	3,829	3,899	3,971	4,039

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SOUTH CAROLINA ELECTRIC AND GAS COMPANY
TERRITORIAL SUMMER PEAK DEVELOPMENT BY CLASS
BASED ON 4-HOUR 1991 LOAD FACTORS, WITH RESIDENTIAL AND COMMERCIAL
LOAD FACTORS ADJUSTED TO INCREASE TOTAL LOAD BY 1.2%
(MW)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
RESIDENTIAL										
GOOD CENTS	166	176	187	196	206	216	226	236	246	257
CONSERVATION RATE	86	88	91	94	96	99	102	105	108	110
REGULAR	1,617	1,644	1,671	1,695	1,719	1,744	1,769	1,793	1,818	1,844
RESIDENTIAL TOTAL	1,869	1,909	1,949	1,985	2,021	2,060	2,097	2,134	2,172	2,211
COMMERCIAL TOTAL	1,301	1,340	1,379	1,415	1,452	1,491	1,529	1,568	1,608	1,649
REGULAR INDUSTRIALS	684	696	707	718	730	741	752	762	772	781
INTERRUPTIBLE CUSTOMERS (INCLUDING SRP)	164	164	164	164	164	164	164	164	164	164
TOTAL INDUSTRIAL	848	860	871	882	894	905	916	926	936	945
MUNICIPALITIES	252	257	263	268	274	279	284	290	295	301
COOPERATIVES	52	53	54	55	56	57	58	59	60	61
MISCELLANEOUS (OPA, CO. USE, STATE LINE)	126	129	133	136	139	143	147	150	154	158
UNADJUSTED DEMAND	4,447	4,548	4,649	4,741	4,836	4,934	5,030	5,127	5,225	5,325
LESS:										
INCREMENTAL DSM PROGRAMS	212	230	249	267	286	304	323	342	361	382
STAND-BY GENERATORS	71	75	79	83	87	92	96	100	104	108
INTERRUPTIBLE LOAD	54	54	54	54	54	54	54	54	54	54
TOTAL DEMAND REDUCTIONS	337	359	382	404	427	450	473	496	519	544
ADJUSTED DEMAND	4,111	4,189	4,267	4,337	4,409	4,484	4,557	4,631	4,706	4,781

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consideration as discussed above. Third, using 1993 as the base year, the difference was calculated between each year's reduction and the 1993 value, for all programs which were in effect prior to 1993. This was to account for the fact that currently existing programs were embedded in the actual KWH values used to project sales. Removing these decrements to sales once more would have overstated the impact of the DSM programs, so only the incremental DSM impacts from 1993 were used to determine the adjusted peak demands from existing programs. Conversely, all of the savings from new DSM programs introduced in 1992 and thereafter were included as reductions to peak demand.

Fourth, once the proper KW savings, full or incremental, were determined, they were increased to represent system-level savings. Marketing estimates are for sales-level units, and a one KW deferral at the customer level represents a greater than one KW deferral at generation level. System line losses were used to increase the KW impact of each marketing program, based on the customer group impacted. Finally, the sum of all included DSM program impacts was determined, and this accumulated value was used to reduce the unadjusted peak demand to its final adjusted peak demand. These estimates are also shown in Table 5, and are the values used to represent the planning peak.

7. Winter Peak Demand

Although SCE&G historically has been a summer-peaking utility, estimation of its future winter peak demands is also required for various planning functions. To project winter peaks a regression model was developed based on the 26-year period 1965-1991. Actual winter peak demands were related to three primary explanatory variables: the summer peak; weather during the day of the winter peak's occurrence; and residential space-heating customers.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in the summer peak reflects economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors which cause winter peak demand to change. It should be noted that the winter peak for any given year occurs by definition after the summer peak for that year. For peak demand forecasting, the winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970.

In addition to economic factors, weather also causes winter peak demand to fluctuate. Weather was represented by the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston. When the forecast of winter peak demand was calculated, the median value of heating degree days over the sample period was used, so no growth in the winter peak is attributable to future changes in weather. Finally, although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the relative number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to over 153,000 in 1990, a 14.7% annual growth rate. Inclusion of this variable thus provided further explanatory power in the regression analysis.

A number of exploratory regression models were tested before the final version containing the above variables was selected. A dummy variable was also added for the years 1984 and 1985, which experienced severe winter weather. The results of the regression analysis are shown following in Equation 2.

EQUATION 2

$$WPEAK = \underset{(-1.58)}{-129.375} + \underset{(11.52)}{0.694*SPEAK} + \underset{(6.25)}{306.430*D8485} + \underset{(4.89)}{8.720*HDD} + \underset{(3.63)}{0.003*CUSTSH}$$

Estimation Period:
1965-1991

F-statistic: 991.026
R^2: 0.994
Root MSE: 55.259
Dependent Mean: 1858.615
DW: 1.695

Where: WPEAK=Winter Peak
SPEAK=Summer Peak
D8485=1 for years 1984 and 1985, 0 otherwise
HDD=Average of Heating Degree Days for winter peak day, Columbia and Charleston
CUSTSH=Residential space-heating customers

The adjusted R^2 and F-statistic indicated that winter peak was strongly related to the combination of explanatory variables chosen, and the t-statistics for the individual variables also confirmed their inclusion in the regression equation. The MAPE over the estimation period was 2.6%, showing a close fit of actual to predicted winter peak demands.

Forecasting the winter peak demand utilizing the above equation required projections of summer peak, heating degree days, and residential space-heating customers. The planning peaks shown in Table 3 were used for the summer peak, while heating degree days were based on the median for the estimation period 1965-1991, which was 31 HDD (See Table 6). Finally, projections of residential space-heating customers developed as part of the energy sales forecast were used as that variable's forecast input. The result of this process is shown in Table 7. Winter peak demand is expected to grow from 3,049 MW in 1993 to 4,396 MW in 2012, a compound annual growth rate of 1.9%. The slightly higher rate of increase in winter peak demand causes the ratio of winter to summer peaks to increase from 0.896 in 1993 to 0.919 by 2012. As discussed above, this result should be expected because of the projected growth in space-heating customers.

TABLE 6

WEATHER STATISTICS FOR WINTER PEAK DAYS

(1965-1991)

	Heating Degree Days (HDD)
Maximum	50.5
75th Percentile	38.0
Median	31.0
Mean	33.5
25th Percentile	28.5
Minimum	23.0

NOTE: Heating Degree Days are the average of Columbia and Charleston.

TABLE 7

WINTER TERRITORIAL PEAK DEMANDS

(MW)

Year	Winter Peak
1993	3,049
1994	3,099
1995	3,182
1996	3,244
1997	3,314
1998	3,387
1999	3,461
2000	3,530
2001	3,601
2002	3,668
2003	3,739
2004	3,815
2005	3,891
2006	3,960
2007	4,031
2008	4,104
2009	4,176
2010	4,248
2011	4,322
2012	4,396

8. Monthly Peak Demand

The creation of monthly peak demands was based on the relationship of historic monthly peaks for the period 1986-1992. This provided seven observations for each month, yet was current enough to avoid using irrelevant historic data. First, the data was broken down into two seasons: winter and summer, with summer defined as the months of May through October, and winter defined as all other months. A ratio was then calculated for each month within these groupings, with the monthly peaks in each year divided by its respective seasonal peak. Thus, one month in each winter and summer category for each year had a ratio of 1.00, corresponding to the month in which the seasonal peak occurred.

The ratios were next assembled into ranked categories by season, with a total of six groupings (one for each month) within each season. The highest ranked category had seven observations with a value of 1, while the second ranked category also had seven observations, but with different ratio values. To eliminate any distortion from extreme values, the high and low observations within each category were deleted. The impact of this process was to eliminate any "outliers" which might have occurred in the historic sample period, and resulted in 5 observations for each ranked category. A mean category ratio was then calculated using 5 observations for each category. At this stage of the analysis, then, there were two sets of ratios: one for summer and one for winter, with these ratios ranked by size into categories.

For the second stage of the process, the original monthly ratios were grouped by month and season. For example, there were 7 monthly ratios for August and each of the other summer months. The high and the low observations for each month were then dropped for the reasons described earlier, and monthly average ratios were then calculated. The months were then categorized by the magnitude of their average ratio, so July, for example, was assigned a category value of 1, since its average ratio was higher than the other summer months. It should be noted, however, that the monthly July ratio was not 1.0, since the seasonal peak did not always occur in that month.

The categories of ratios determined in the first stage of the process, i.e., grouped ratios irrespective of months, were then merged with the monthly ratio categories for each season. Again, consider July; since it had the highest monthly ratio, it was matched with the highest ratio category, which had a value of 1.0. At this point, it was possible to compare the monthly ratios with those ratios created by the ranking process only. In general, there was an extremely close match between ratios calculated in each fashion. For example, the ratio for the third highest ranked summer category estimated independent of month was 0.94, while the ratio for the third highest ranking month ratio (June) was also 0.94. This close match stems from the stable relationship between monthly and annual peaks, and provides a measure of reassurance that such a relationship will continue into the future.

In the final step, the ranked categories, irrespective of month, were assigned to their corresponding months to develop projected monthly peaks and are shown in Table 8. These ratios were then multiplied by their respective seasonal peaks to create the final monthly peaks shown in Table 9.

TABLE 8

RATIOS APPLIED TO SEASONAL PEAKS TO CREATE MONTHLY PEAKS

SUMMER		WINTER	
July	1.00	January	1.00
August	0.98	December	0.97
June	0.94	February	0.90
September	0.91	March	0.87
May	0.84	November	0.82
October	0.70	April	0.73

TABLE 9

MONTHLY SYSTEM PEAKS

(MW)

	(ACTUAL) 1992	1993	1994	1995
JANUARY	2,799	3,017	3,049	3,099
FEBRUARY	2,473	2,722	2,751	2,796
MARCH	2,393	2,620	2,647	2,691
APRIL	2,328	2,206	2,230	2,266
MAY	2,569	2,852	2,894	3,972
JUNE	3,054	3,193	3,240	3,328
JULY	3,380	3,405	3,455	3,549
AUGUST	3,166	3,339	3,388	3,481
SEPTEMBER	2,962	3,082	3,127	3,212
OCTOBER	2,140	2,367	2,401	2,467
NOVEMBER	2,495	2,495	2,536	2,604
DECEMBER	2,663	2,952	3,001	3,081