ELECTRICAL LOAD SHEDDING PROGRAM AT THE SALT CREEK FIELD UNIT

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ABSTRACT

This paper discusses a recently implemented electrical load shedding program at the Salt Creek Field Unit (SCFU) in Kent County, Texas. The project involves the interruption of SCFU electrical load during the wholesale utility's monthly peak load. By interrupting SCFU load during the utility's monthly peak, the SCFU electrical demand charge is reduced by $7.16 or $6.03 per interrupted kilowatt, depending on the time of year.

A dual demand electrical rate schedule makes the load shedding concept possible. With this rate schedule, the demand charge is divided into two components. One demand charge is based on the highest SCFU electrical load during the billing period while the other is based on the SCFU load during the wholesale utility's monthly peak. The goal of the load shedding program is to interrupt SCFU electrical load at the time of the utility's peak load thereby reducing one component of the demand charge.

A critical element to the load shedding program is the ability to predict when the wholesale utility's monthly peak load will occur. The utility's system load is highly dependent on the temperature in the utility's main load center which is located in and around Stephenville, Texas. By closely monitoring the utility's load and temperature/weather data in Stephenville, the time of the utility's peak load can be forecasted. Historical load and temperature/weather information are also utilized in peak load forecasting.

Another key element is the selection of SCFU electrical load to be interrupted during the utility's monthly peak. Currently, high pressure injection pumps and artificial lift installations are interrupted for load shedding purposes. Since the interruption of artificial lift installations results in deferred production, wells must be carefully prioritized for interruption so that lost revenue is minimized. Also, limiting total interruption time and frequency during each billing period is very important in minimizing lost revenue and cycling of lift equipment. Net profit of load shedding each artificial lift installation is determined by subtracting potential lost revenue from potential electrical savings.

This paper addresses the electrical rate schedule design, wholesale utility load forecasting, load shedding methodology, and results of the program to date.

INTRODUCTION

Since the mid-1980s, there has been increasing concern about the high electrical costs associated with oil and gas production. Mobil Exploration & Producing U.S. Inc. is currently using a dual demand electrical rate in combination with a load shedding program to lower electrical expenses at the Salt Creek Field Unit in Kent County, Texas. The load shedding program has been in operation since October, 1991 and has saved over $42,000 per month in electrical expenses in the first year.

The Salt Creek Field Unit (SCFU) currently produces 21,000 BOPD and 280,000 BWPD from the Canyon Reef formation at a depth of approximately 6200 ft. SCFU currently has 173 producing wells and 133 injection wells. Of the 173 producing wells, 138 wells are lifted with electrical submersible pumps and 35 wells are lifted with beam pump installations. The unit has an active waterflood with a current injection rate of approximately 325,000 BWPD. Total electrical demand at SCFU is currently 35,000 kilowatts with an electrical usage of 24,000,000 kilowatt-hours per month. Electrical demand and usage are expected to increase dramatically in the near future due to the commencement of a carbon dioxide enhanced recovery project.

RESULTS AND DISCUSSION

Dual Demand Rate

Most large commercial electrical rates contain three cost categories: 1) a customer or facilities charge; 2) an energy charge; and 3) a demand charge. The customer or facilities charge is the monthly flat rate charge designed to recover the expenses associated with the customer's individual account services and metering facilities. The energy charge is the cost for total consumption of electrical power used during the billing period. The energy charge is measured in kilowatt-hours (KWH) and is denoted by the area under the curve in Figure 1. The demand charge is the charge for the utility company to provide capacity to meet the customer's needs at any time and is measured in kilowatts (KW). The demand charge is based on the highest average load required by the customer during any consecutive 15 minute interval within the billing period. Some electrical rates may stipulate a different time interval and method for demand averaging. The electrical demand is denoted by the highest point on the curve in Figure 1.

The dual demand rate is a special power rate negotiated with the distribution cooperative which allows a direct pass-through of wholesale power costs from the wholesale power supplier to the customer. The wholesale power costs are passed to the customer in the same rate form that is used to sell wholesale power to the distribution cooperative. The dual demand rate form has the same cost categories as the normal commercial rate except that the demand charge is divided into two components - the non-coincident peak (NCP) demand charge and the coincident peak (CP) demand charge. The NCP demand basis is the same as the demand basis for the normal commercial rate but the cost, under the dual demand rate for SCFU, has been discounted from $9.00 to $1.56 per KW. The CP demand charge is an additional charge based on the wholesale utility's charges to the distribution cooperative. The CP demand charge for each billing period is based on the customer's highest average 15 minute load within the hour during which the wholesale utility's highest average hourly load for the billing period occurs. For SCFU, the CP demand charge varies with the time of year and the costs are $7.16 per KW in summer billing periods (May - October) and $6.03 per KW in winter billing periods (November - April). Figure 2 illustrates the difference between the NCP and CP demand charges.

For SCFU, changing from the old rate to the dual demand rate produced a guaranteed demand charge savings of $0.28 and $1.41 per KW for summer and winter billing periods, respectively. In addition to these guaranteed savings, the CP demand charge can be further reduced by forecasting the wholesale utility's average hourly peak load for the billing period and then shedding SCFU electrical load when the peak occurs. The load shedding process, if successful, can increase the savings by $7.16 per KW in summer billing periods and $6.03 per KW in winter billing periods. For example, a 15,000 KW reduction in the monthly CP demand will lower the CP demand charge by $107,400 per month in the summer months and $90,450 per month in the winter months.

Unlike other discounted electrical rates, such as an interruptible power rate, the dual demand rate allows the customer to control electrical interruptions. With the interruptible power rate, the power utility usually has the right to temporarily terminate electrical service to the customer at anytime and without warning. There may be multiple interruptions adding up to hundreds of hours per year with each interruption possibly lasting 12 hours or more depending on contract agreements. It should be noted that interruption time of load on interruptible service has been very low historically. The dual demand rate gives the customer the flexibility to decide the time, duration, magnitude, and type of load to be interrupted.

As with interruptible rates, dual demand rate utilization benefits the wholesale power supplier as it provides a tool for flattening electrical generation requirements. Generation requirements are flattened because customers are given incentive to interrupt load during peak periods. Effective demand management allows the wholesale supplier to defer or eliminate costly power generation investments.

Forecasting the Wholesale Utility's Peak

In order to take full advantage of the dual demand rate, SCFU personnel must be able to accurately forecast the time of the wholesale utility's average hourly peak load for each billing period.

A key activity in forecasting the wholesale utility's peak load is the monitoring of current weather and temperature data in the utility's main load center which is located in and around Stephenville, Texas. The system load of the wholesale utility serving SCFU is driven by residential load. These residential loads are very predictable because they are primarily dependent on the weather (especially temperature) in the Stephenville area. Figure 3 illustrates the percent of the wholesale utility's total system load that is dependent on the weather for a typical summer day.

Historical load data for the wholesale utility is also very important in peak load forecasting. Figures 4, 5, and 6 illustrate typical load shapes for past summer, winter, and transitional billing periods. Load magnitudes are highest in the summer and winter months when temperatures are most severe and the use of air conditioning or space heating is increased. Historical load shapes are used to forecast both the time of day that the peak load will occur and the magnitude of the peak load.

In order to facilitate the forecasting of the wholesale utility's peak loads, a load forecasting computer model was developed for the SCFU load shedding program. The computer model is a database containing the last four years of hourly temperature and load data from the Stephenville weather station and the wholesale power utility. When furnished with temperature and time of year information, the computer model searches the database and develops a subset database which exhibits all the characteristics defined by the user. The model then calculates statistics based on the subset database and provides the user with a set of columnar and graphical data for that day's forecasted load shape. Using the statistical data, the model will forecast the time and magnitude of the daily peak load when provided with actual load data for the day being monitored. Figure 7 contains a typical output sheet from the computer model. The first three columns on the right-hand side of Figure 7 numerically represent the typical load shape for the temperature and time of year input criteria. Actual average hourly loads for the wholesale utility are input into column 4 as they become available during the day being monitored. The forecasted peak load for that day is then calculated in column 5 with an upper and lower boundary in columns 6 and 7. The graph in Figure 7 is the average load shape representing the temperature and time of year input parameters.

Load Forecasting Difficulties

Forecasting the wholesale utility's peak load can be very tricky at times.

One problem that can occur during a load shedding operation is shifting the utility's peak due to the interruption of too much load. This is best illustrated by example. Assume that the wholesale utility's daily peak load is forecasted to occur between 7:00 pm and 8:00 pm and the load shedding team interrupts 15,000 KW of SCFU load starting at 7:00 pm. Also, assume that the wholesale utility's average load from 6:00 pm to 7:00 pm was 840,000 KW while the load from 7:00 pm to 8:00 pm was 830,000 KW. The peak load for this hypothetical day would have been 845,000 KW and would have occurred from 7:00 pm to 8:00 pm if the 15,000 KW had not been interrupted. However, the peak load is shifted to 6:00 pm to 7:00 pm because 15,000 KW of load is removed from the system from 7:00 pm to 8:00 pm. This problem is most likely to occur in the higher temperature months because the utility's average hourly loads around the normal peak period are close in magnitude (see Figure 4). Chances of shifting the utility peak can be minimized by interrupting the desired load through the entire potential peak period or interrupting smaller magnitudes of load during the hour in which the peak is forecasted.

Another difficult problem of forecasting utility peak loads is changing weather conditions during a potential peak load day. An example of this is the passage of a cold front in the winter. If the cold front passes through the load center during and after the normal peaking period, the utility load may continue to increase throughout the day rather than the expected occurrence of a spike with a subsequent decrease in load. Similarly, in summer months, a thunderstorm passing through the load center during the peak period may suddenly decrease the temperature thereby reducing the utility load by a significant amount.

As more industrial operations utilize the dual demand rate on the same electrical system, forecasting becomes more difficult as more wholesale utility load is interrupted during peak days. With only one operation forecasting and shedding load, wholesale utility loads are dependent primarily on the temperature in the utility load center. With several operations forecasting and shedding load, utility loads become dependent on temperature and on the magnitude of load interruption that occurs on the system. The addition of another variable makes accurate forecasting more difficult.

The Load Shedding Process

Prior to each billing period, the load shedding team discusses unique characteristics of that billing period. From historical weather and load data, the team determines the portion of the billing period and the time of day that the wholesale utility's hourly peak load is likely to occur. The team also predicts the approximate magnitude of the peak load and the temperature in Stephenville at which the peak load is likely to occur. Each of these parameters will differ for each billing period in a given year. Figures 4, 5, and 6 illustrate how different months require different strategies. For example, Figure 4 indicates that the wholesale utility's peak load in the summer months will occur sometime between 4:00 pm and 8:00 pm. Conversely, Figure 5 indicates that the peak in the winter months will occur in the morning between 6:00 am and 9:00 am.

After a monthly strategy is formulated, a load shedding technician is assigned to monitor daily weather/temperature forecasts for Stephenville. If a peaking type day is projected, pertinent field personnel will be notified of a potential load shedding interruption. As the likely time of the system peak approaches, the technician will rigorously monitor Stephenville temperatures and wholesale utility loads. Pertinent data will be input into the load forecasting computer model to further refine the forecast of the peak load. If the technician believes that a system peak load will occur, proper operations personnel will be notified so that SCFU electrical load can be promptly interrupted during the hour of the peak. After the peak load has occurred, the technician will expedite the start-up of the affected load. The majority of the affected load can be turned on and off by the load shedding technician from the central production office. A typical load shedding interruption will last two to four hours. A typical billing period will have zero to four interruptions. All SCFU electrical load that is interrupted is thoroughly documented for future analysis. The technician also monitors and documents deferred production, artificial lift installation failures resulting from load shedding, and other important data.

Types and Sizes of SCFU Electrical Load

Electrical loads at SCFU consist of the following equipment: artificial lift units (electric submersible pumps and beam pumps); high pressure injection pumps; vapor recovery units; product/transfer pumps; and miscellaneous small loads such as office needs. Figure 8 illustrates the percent contribution of the major load types to the SCFU electrical demand.

Electric submersible pump (ESP) load comprises the largest single component of total demand at SCFU. ESP motors at SCFU range in size from 50-560 HP. High pressure injection pump load is the next largest power component. Currently, six injection pumps, all driven by 1500 HP motors, are active. The majority of other, less significant loads, such as beam pump installations, vapor recovery units, and product/transfer pumps, range in size from 1-100 HP.

Due to the large contribution to the total electrical demand at SCFU, ESP and injection pump load were initially targeted for load shedding. Beam pump installations were added to the load shedding strategy after ten billing periods.

Load Shedding of Artificial Lift Installations

Interruption of artificial lift installations for load shedding purposes has the following major concerns: 1) lost revenue resulting from deferred production and 2) the potential for higher maintenance costs resulting from excessive cycling of equipment. The key to minimizing both of these problems is to minimize interruption time and frequency.

When the evaluation of artificial lift load shedding began, the most critical unknown was how many interruptions would be necessary to assure that the CP demand was reduced significantly. As interruption time and, therefore, artificial lift downtime increases, lost revenue from deferred production also increases. High interruption frequency will impact surface and subsurface maintenance costs due to the increased cycling of lift equipment. For each producing well, a single, unique interruption time per month is associated with the break-even point at which potential electrical cost savings equals lost revenue plus increased maintenance costs. The key to successful load shedding of producing wells is to keep the total interruption time and frequency well below the break-even time.

Figure 9 illustrates the potential profit and risk of load shedding 10,000 KW of artificial lift load at various interruption times. The financial risk of load shedding is the lost revenue associated with deferred production and is represented by the dotted line below the break-even line. In calculating the financial risk of load shedding, it is assumed that the oil price is $20.00 per barrel and that maintenance expenses are not affected by load shedding. It is also assumed that production is deferred at the same rate that it is produced. In other words, a well producing 5 BOPH will lose 15 barrels if it is interrupted for three hours. The financial risk is the profit lost if load shedding does not reduce electrical expenses despite the interruption of load. The two lines above the break-even line in Figure 9 represent the estimated net profit from successful load shedding. The net profit is the difference between the electrical savings and the financial risk of load shedding. Net profit for summer billing periods is higher than that of winter billing periods because the CP demand charge is $7.16 and $6.03 per KW for summer and winter months, respectively. Although the above assumptions are somewhat simplified, Figure 9 illustrates an important point. At 4 hours of interruption time, the net profit from successful load shedding is $49,300 to $60,500 per month while the financial risk of interrupting production is only $11,100 per month. However, at 16 hours of interruption time, net profit is only $18,500 to $30,000 per month while the financial risk is $44,600 per month. Therefore, it is very important to minimize interruption time so that the ratio of potential net profit to financial risk is as high as possible.

Prior to beginning the SCFU load shedding program, an accurate estimation of interruption time and frequency was necessary to properly evaluate project economics. To estimate monthly interruption time and frequency that could be expected, a mock load shedding exercise was conceived. The mock exercise involved six past billing periods from 1991 and was conducted over a two day period. Although the six billing periods had already past, the exercise was designed so that the mock load shedding technician would have no prior knowledge of the hour in which the monthly utility peak loads occurred. The mock load shedding technician was provided with all information necessary to forecast peak load occurrences. This information included hourly load data from the wholesale utility, weather forecasts, and actual temperature data from Stephenville, Texas. For each day of the six billing periods, the mock load shedding technician reviewed the weather forecasts and temperature/load data, input parameters into the load forecasting computer model, and made artificial decisions on whether to interrupt operations. Since the mock load shedding technician had no prior knowledge of peak load occurrences, the artificial decision to interrupt operations was biased only by the weather/load data and the output of the forecasting model. The major conclusions from the mock load shedding exercise were: 1) zero to ten hours per month of interruption time could be expected from a load shedding program; 2) zero to four interruptions per month could be expected from load shedding; and 3) the monthly CP demand charge could be significantly reduced in 50-75% of the billing periods. From the simulation, it became apparent that there would be months in which the CP demand would not be reduced despite interruptions of SCFU load. Conversely, there would be months in which the CP demand would be reduced with only two hours of interruption time.

With only zero to ten hours per month of interruption time, lost revenue (at $20.00 per BO) from interruptions is well below potential electrical savings. Also, an interruption frequency of only zero to four times per month requires minimal cycling of lift installations; therefore, it is assumed that surface and subsurface maintenance costs are not impacted significantly.

Load Shedding of Injection Pump Load

Interruption of injection pump load has the following problems and concerns: 1) storage of water during load shedding interruptions; 2) nuisance shut-downs of engine-driven injection pumps; 3) deferred production resulting from disruption of target injection rates; and 4) additional pump/motor maintenance resulting from excessive cycling.

The problem of storing produced water during a load shedding operation is partially offset by interrupting high water producing lift installations at the same time that injection pumps are interrupted. This reduces the volume of produced water entering the injection facility and partially negates the need for water storage. During a typical load shedding interruption, producing wells are normally interrupted anyway since significant electrical savings are possible with the load shedding of lift installations. Even without a reduction of produced water entering the injection facility, adequate storage capacity is available to handle water during a load shedding interruption. Another concern associated with water storage is the ability to inject stored water after an interruption. The electric-driven injection pumps are centrifugal pumps; therefore, some stored water is injected due to increased injection rates resulting from lower field injection pressure after an interruption. When necessary, existing standby pump capacity is sufficient to remove the remainder of the stored water. Using standby pump capacity to inject stored water could potentially increase the NCP demand charge; however, at a NCP demand charge of only $1.56 per KW, the additional expense is minimal.

In addition to the electric-driven injection pumps, the SCFU injection system consists of four engine-driven, centrifugal injection pumps. When the electric-driven injection pumps are interrupted for load shedding purposes, the SCFU field injection pressure decreases significantly. When the field pressure decreases, injection rates of the engine-driven pumps increase and high flow shut-downs occur. This problem is managed by manually imposing artificial head on the engine-driven pumps during load shedding operations so that flow rates will stay within the operating limits.

Deferred production from disruption of target injection rates during load shedding operations is another concern due to high formation communication between offsetting wellbores. With ten hours of interruption time per month, target injection rates are disrupted a maximum of only 1.4%. This deferred injection is partially offset by the injection of stored water after an interruption. For these reasons, it is assumed that overall production deferral from injection interruptions is minimal.

It is also assumed that maintenance due to increased cycling of injection pumps will not increase noticeably with zero to four interruptions per month.

Results of the SCFU Load Shedding Program

The SCFU load shedding program commenced October 21, 1991 and has been in progress for 12 billing periods as of this writing.

Figure 10 illustrates the effect of the load shedding program on the SCFU electrical bill. The gap between the average demand line and the CP demand line represents the total reduction in CP demand after the load shedding program commenced in October, 1991.

Table 1 is a summary of electrical billing data and results of the SCFU load shedding program from October 21, 1991 to October 20, 1992. For the first year, the CP demand charge was successfully reduced in nine billing periods. Total electrical cost reduction for the first year was approximately $510,000 while estimated revenue reduction and operating costs were $150,000; therefore, net profit from load shedding was $360,000. The effective reduction of the CP demand was estimated by subtracting the actual CP demand from the average demand for each billing period. For the first year of load shedding, average interruption time ranged from zero to ten hours per billing period while interruption frequency ranged from zero to four times per billing period.

In the two unsuccessful winter billing periods (November 21 to December 20 and January 21 to February 20), no interruptions occurred because the strategy was to wait for low temperatures which never occurred. Similarly, in the unsuccessful summer billing period (July 21 to August 20), no interruption occurred because the strategy was to wait for high temperatures which never occurred.

Analysis of Deferred Production

Production deferral resulting from SCFU load shedding interruptions was analyzed and quantified by two different methods. The first method, referred to as Method 1, compares potential production on load interruption days with potential production on normal, non-interruption days. Daily potential production is defined as the production possible if all wells at SCFU were producing for the entire 24 hour period. This number is generated by adding downtime production to actual measured daily production. Potential production on each load shedding interruption day is compared to the production potential on the closest non-interruption day (usually the prior day). Potential production on each interruption day was also compared to the average of potential production for the seven preceding non-interruption days. The second method, referred to as Method 2, is based on the assumption that the rate of deferred production for an interrupted well is equal to the normal producing rate. In other words, a well producing 5 BOPH will defer 15 barrels if it is interrupted for three hours. Normal producing rates of each well are determined from monthly well tests. With Method 2, total deferred production due to a load shedding interruption is the summation of production deferral of each well which is interrupted. It is also assumed, with Method 2, that interruption of water injection will have minimal impact on total production. Method 1 is considered the more accurate of the two because it involves the measurement of actual daily production rates and it accounts for the effects of water injection interruptions. The calculation of deferred revenue in Table 1 is based on deferred production estimates from Method 1.

Table 2 displays the estimated production change resulting from load shedding for the 18 days in which a load shedding interruption occurred. Also listed in the table are the average interruption times and the number of interrupted ESP's, beam pump installations, and injection pumps. In Table 2, a negative production change indicates that the load shedding interruption resulted in deferred production. A positive production change indicates that production increased because of the interruption. Positive production changes are indicated on 5 of the 18 interruption days. The indicated production increases are primarily the result of normal production fluctuations. Otherwise, the increased production on the five days is unexplained. It is very unlikely that a load shedding interruption would result in increased production rates; therefore, if a positive production change is indicated, it is assumed (for project economics and otherwise) that the production change is zero.

The listed production change for each interruption day in Table 2 is estimated from Method 1 and Method 2, above. Production change estimates from Method 1 include a comparison of interruption days with the preceding non-interruption day and with the average of the preceding seven non-interruption days. Average production change for the two Method 1 comparisons are within approximately two percent. The estimate of total deferred production from Method 1 is approximately twice as high as that of Method 2.

The magnitude and rate of deferred production per well are highly dependent on the number of interrupted wells and the interruption time of each well. Prior to a load shedding interruption, producing wells are prioritized for interruption according to the potential net profit from load shedding. Since lower priority wells generally have higher oil cuts, more prolific production is impacted as more and more wells are interrupted. Table 2 indicates that the magnitude of deferred production usually increases notably when more than 11 producing wells are interrupted. The rate of production deferral per well will also increase with interruption time due to increased wellbore loading. As wellbore loading time increases, the time it takes for a well to recover to the normal production rate will also increase. The occurrence of wellbore loading during load shedding interruptions is supported by the fact that deferred production estimates from Method 1 are twice as high as from Method 2.

Three load shedding operations involved the interruption of injection pumps only. Positive production changes are shown on two of these days. Although inconclusive, the data supports the assumption that injection interruptions have a minor effect on production.

The magnitude of deferred production during load shedding interruptions is very difficult to accurately quantify. Normal production fluctuations mask the effect of load shedding interruptions on total production. As more production data becomes available in the upcoming years, a more reliable statistical method of analysis will be possible.

Analysis of Maintenance Costs

To date, no ESP or injection pump failures can be directly attributed to the load shedding program. It is recognized that increased cycling of rotating equipment is detrimental to equipment life; however, analysis of failure data indicates no noticeable increases after the load shedding program began.

Initial and Operating Costs

Initial cost required to start the SCFU load shedding program was approximately $40,000. This cost included: 1) the development of the load forecasting computer model; 2) computer hardware and other software necessary for load shedding; and 3) the development of historical temperature and load information.

Minimum operating costs required for the SCFU load shedding program include: 1) time required from the load shedding technician and operating personnel; 2) acquisition of weather forecasts and data; and 3) periodic updating of the load forecasting computer model and other historical data. The load shedding technician and other operating personnel spend 1 to 15 hours per week on monitoring actual loads and weather data, forecasting the wholesale utility's peaks, and expediting load shedding operations when necessary. Weather data is accessed daily via a computer weather network which costs $400 to $500 per month. Annual updates of forecasting software and supporting data are projected to cost $3000 per year.

CONCLUSIONS

1) The dual demand rate in combination with a load shedding program is an effective method of reducing electrical expenses.

2) The time of the wholesale utility's monthly system peak can be consistently predicted by monitoring pertinent load and weather data.

3) Interruption time resulting from the SCFU load shedding program has ranged from zero to nine hours per billing period. Interruption frequency has been zero to four times per billing period.

4) The SCFU load shedding program has successfully reduced electrical costs in 9 of the first 12 months. The SCFU electric bill has been reduced by $510,000 in the first full year of load shedding. Deferred revenue and operating costs have totalled approximately $150,000. Total net profit for the first year is $360,000 or approximately $30,000 per billing period.

5) Deferred production resulting from SCFU load shedding operations has ranged from 0 to 1678 BO per interruption day. The rate of deferred production per well increases as interruption time of the affected wells increases. Accurate estimates of deferred production are difficult and will require more data for improved statistical analysis.

6) Increased cycling of artificial lift equipment and injection pumps due to SCFU load shedding operations has not noticeably increased maintenance costs.

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Table 1 - Results of Load Shedding Program at SCFU

Billing Period	Billing Data: CP Demand (KW)	Billing Data: NCP Demand (KW)	Billing Data: Avg. Demand (KW)	Financial Data: CP Demand Reduct. (KW)	Financial Data: CP Demand Reduct. ($)	Financial Data: Defer. Revenue ($)	Financial Data: Oper. Cost ($)	Financial Data: Net Profit ($)
6/21-7/20	28140	29199	26441	—	—	—	—	—
7/21-8/20	28280	32763	28573	—	—	—	—	—
8/21-9/20	29520	32996	30503	—	—	—	—	—
9/21-10/20	32560	33820	30608	—	—	—	—	—
10/21-11/20	20800	33540	31133	10333	62308	49	571	61688
11/21-12/20	31940	34357	31839	0	0	0	338	-338
12/21-1/20	18400	33968	29815	11415	68832	34565	467	33800
1/21-2/20	30300	32789	28909	0	0	0	7128	-7128
2/21-3/20	21640	33113	30014	8374	50495	0	426	50069
3/21-4/20	23120	32387	28677	5557	33509	7701	477	25331
4/21-5/20	18520	31778	29239	10719	76748	41191	415	35142
5/21-6/20	18540	32944	28461	9921	71034	16912	417	53705
6/21-7/20	25800	33229	32371	6571	47048	9919	397	36732
7/21-8/20	28560	33916	31648	0	0	0	424	-424
8/21-9/20	27400	34888	32927	5527	39573	26707	480	12386
9/21-10/20	24980	35355	33422	8462	60588	572	496	59520
Total					510135	137616	12036	360483

Table 2 - Effect of Load Shedding on SCFU Oil Prod

Load Shed Date	ESP Data: Avg. Shed Time (Hrs)	ESP Data: No.of ESP's Shed	Beam Pump Data: Avg. Shed Time (Hrs)	Beam Pump Data: No.of Beam Pumps Shed	Inj. Pump Data: Avg. Shed Time (Hrs)	Inj. Pump Data: No.of Pumps Shed	* Prod. Change (BO)	** Prod. Change (BO)	*** Prod. Change (BO)
10/24/91	0	0	0	0	2.6	3	+378	-238	0
11/01/91	3.1	9	0	0	2.2	4	+350	-471	-148
11/03/91	3.2	7	0	0	2.8	3	-3	-195	-129
11/08/91	2.4	8	0	0	2.1	4	+893	+85	-116
01/14/92	4.0	20	0	0	3.7	3	-1491	-1269	-549
01/16/92	4.0	25	0	0	3.0	3	-1102	-1493	-674
02/26/92	2.1	18	0	0	3.8	3	+836	+59	-244
03/23/92	2.3	11	0	0	4.5	3	-347	-135	-205
04/03/92	2.0	9	0	0	2.3	3	-213	-236	-139
05/11/92	3.8	16	0	0	4.2	3	-1056	-882	-377
05/12/92	3.9	19	0	0	3.3	4	-1678	-1504	-576
06/19/92	2.5	21	0	0	3.9	5	-1053	-1094	-370
07/14/92	3.0	29	0	0	4.8	4	-633	-806	-576
08/25/92	2.4	5	2.4	29	3.0	4	-459	-346	-287
09/07/92	0	0	0	0	3.0	5	+209	+415	0
09/08/92	0	0	2.0	28	3.0	5	-897	-691	-142
09/09/92	0	0	0	0	1.0	4	-380	-174	0
09/21/92	2.3	5	2.2	28	2.6	6	-37	+330	-259

* Production on day of interruption compared with production on first preceding non-interruption day (Method 1)

** Production on day of interruption compared with average production of preceding seven non-interruption days (Method 1)

*** Production loss estimated by assuming that production is lost at the same rate that it is produced (Method 2)

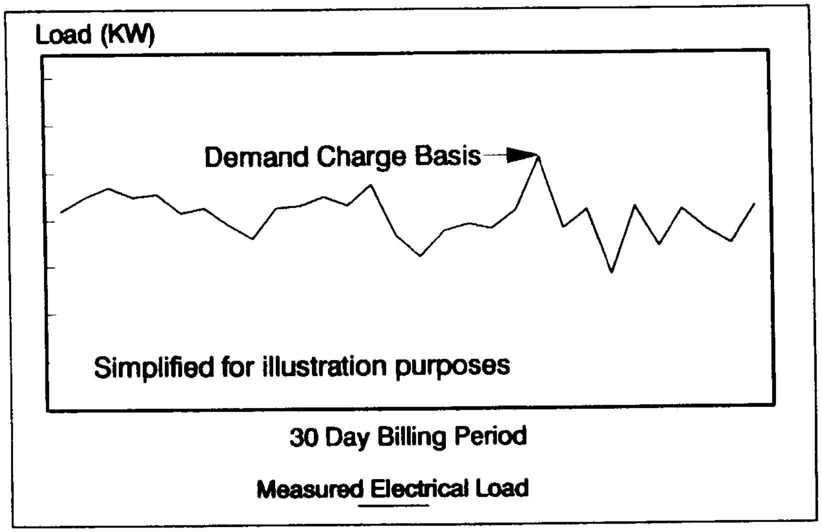


Figure 1 - Electrical demand for normal commercial electrical rate

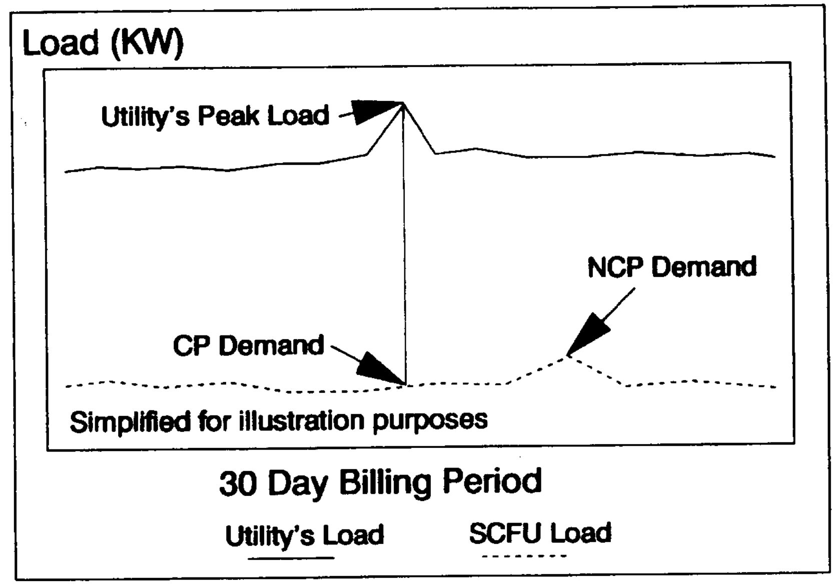


Figure 2 - Electrical demand for dual demand electrical rate

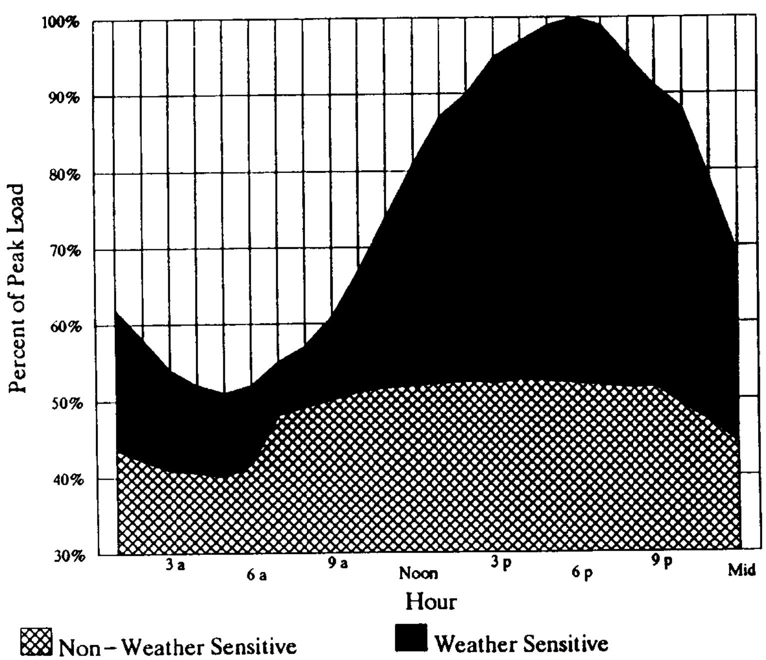


Figure 3 - Weather dependence of wholesale utility's system load

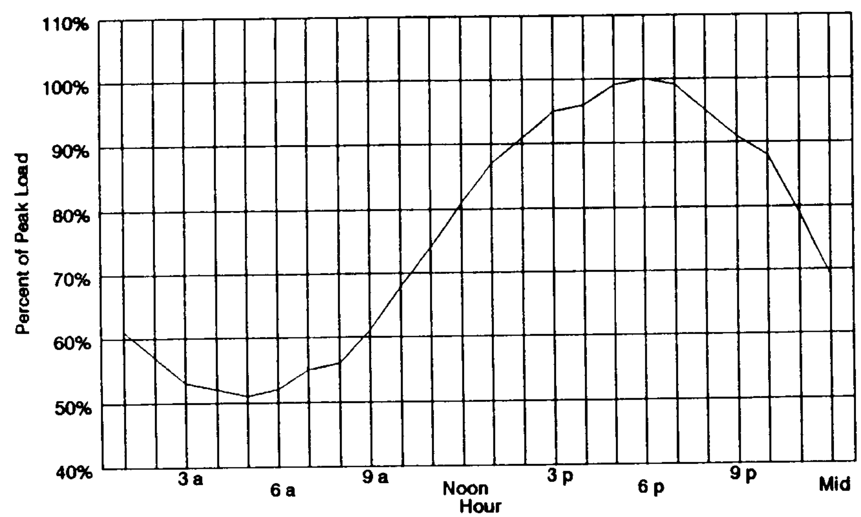


Figure 4 - Load shape for typical summer billing period

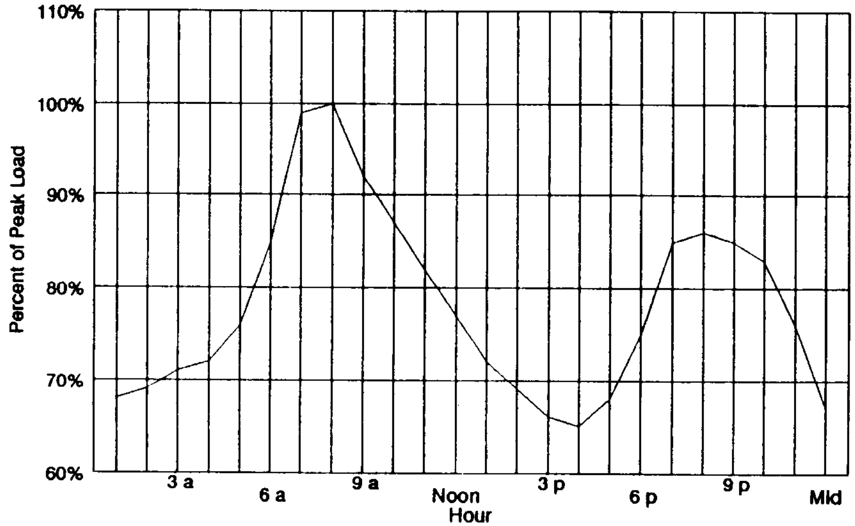


Figure 5 - Load shape for typical winter billing period

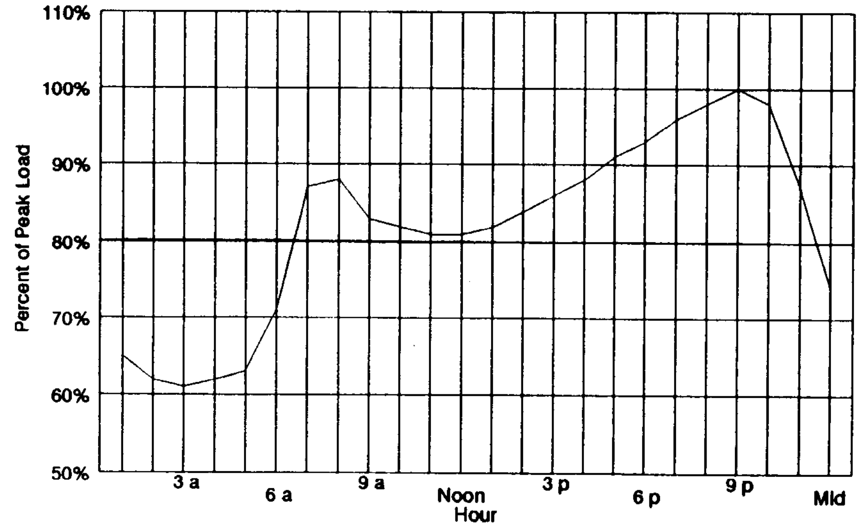


Figure 6 - Load shape for typical transitional billing period

Mobil Exploration & Production, U.S.

Salt Creek Load Forecasting System

Date: 03/31/92

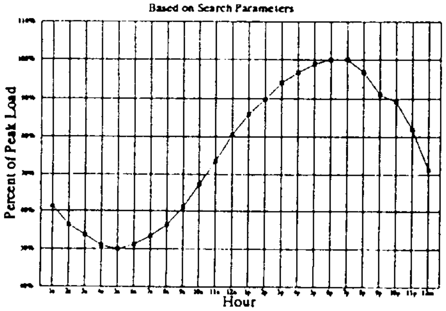
Version 3.0 Search Parameters:

Date Beg	601	MaxTmp1	95
Date End	731	MaxTmp2	100
WD=1,WE=2	1	MinTmp1	-110
PK=1,All=0	1	MinTmp2	110
		TempType	1

N = 20

Typical Load Shape

Based on Search Parameters



Hour	Avg Load Shape %	Avg Load Shape Mw	Actual Load	Forecast Peak Load	Peak Forecast Boundaries Upper	Peak Forecast Boundaries Lower
1a	0.6126	487	0	0	0	0
2a	0.5630	448	0	0	0	0
3a	0.5364	427	0	0	0	0
4a	0.5096	405	0	0	0	0
5a	0.5005	398	0	0	0	0
6a	0.5119	407	0	0	0	0
7a	0.5336	425	0	0	0	0
8a	0.5629	448	0	0	0	0
9a	0.6112	486	0	0	0	0
10a	0.6740	536	0	0	0	0
11a	0.7355	585	0	0	0	0
12n	0.8058	641	0	0	0	0
1p	0.8579	683	0	0	0	0
2p	0.8981	715	0	0	0	0
3p	0.9413	749	760	807	850	765
4p	0.9670	769	780	807	837	776
5p	0.9882	786	790	799	816	783
6p	1.0000	796	800	800	813	787
7p	0.9996	795	802	802	812	793
8p	0.9684	770	0	0	0	0
9p	0.9109	725	0	0	0	0
10p	0.8918	710	0	0	0	0
11p	0.8200	652	0	0	0	0
12m	0.7122	567	0	0	0	0

Figure 7 - Output of load forecasting computer model

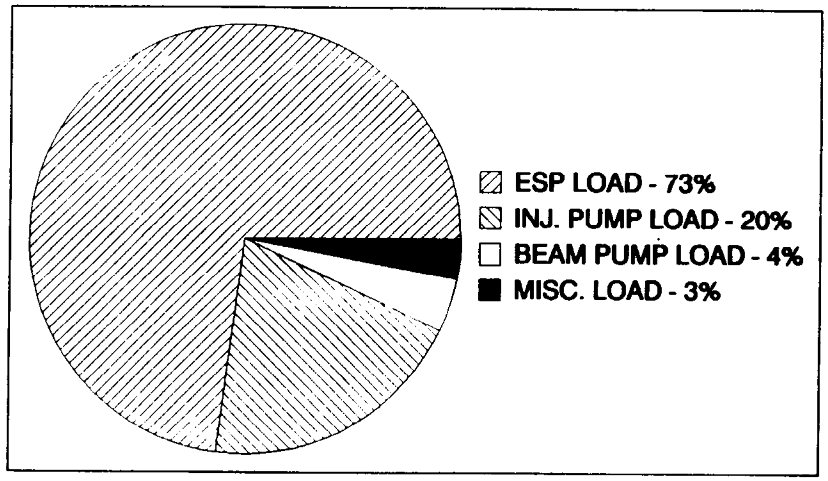


Figure 8 - Electrical load distribution at SCFU

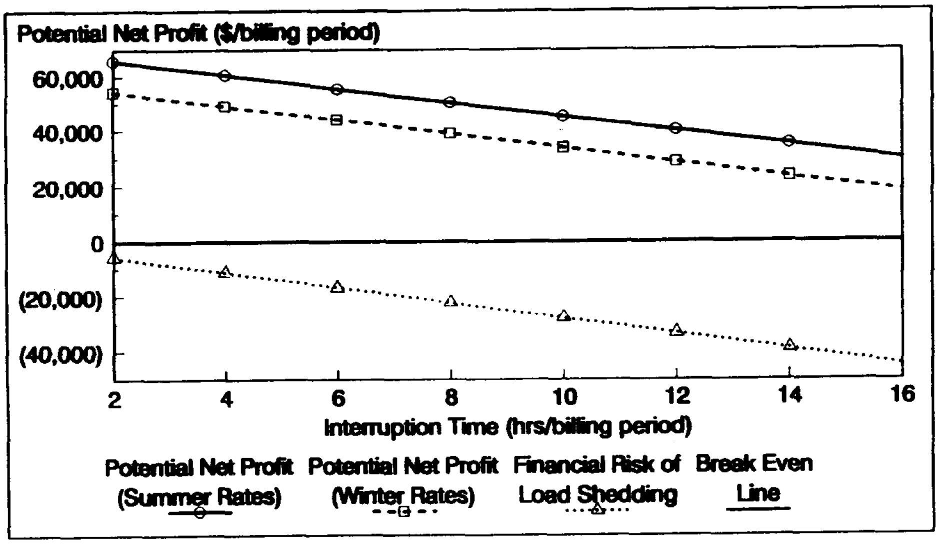


Figure 9 - Potential profit and risk of load shedding at SCFU

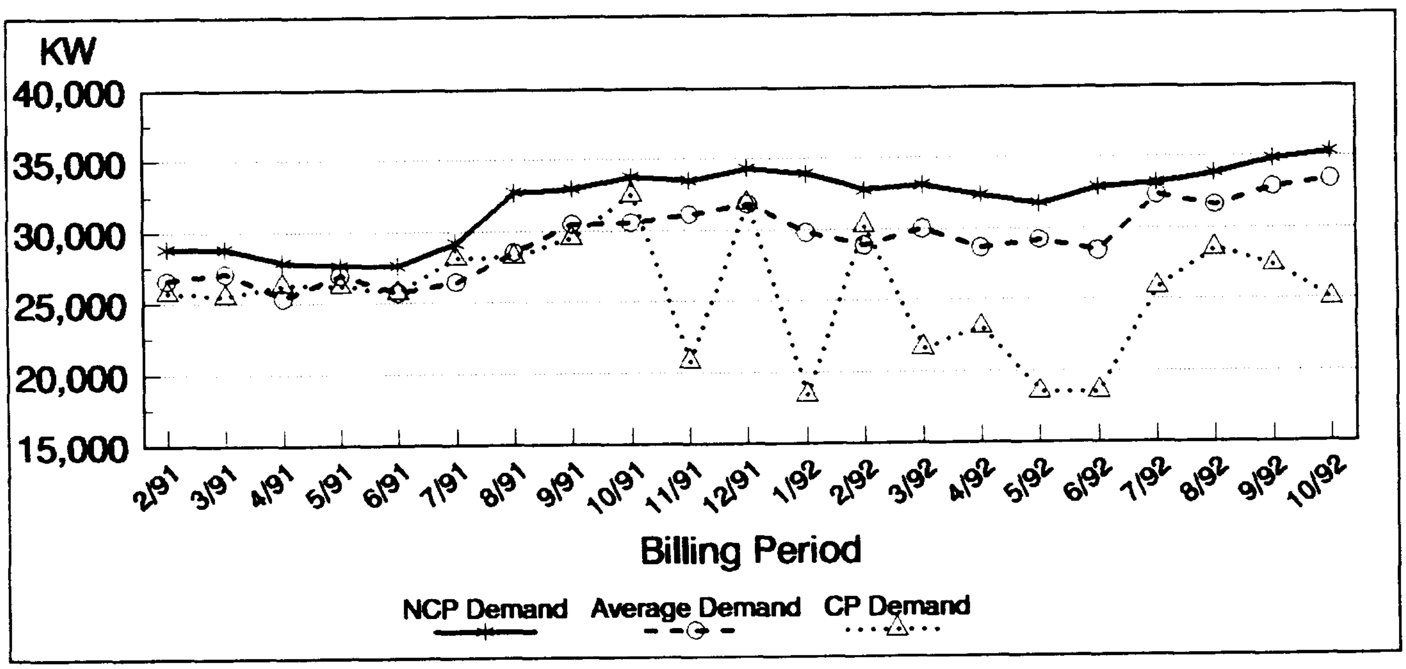


Figure 10 - Recent demand history for SCFU