Load Management Direct Control: Fact or Simulation

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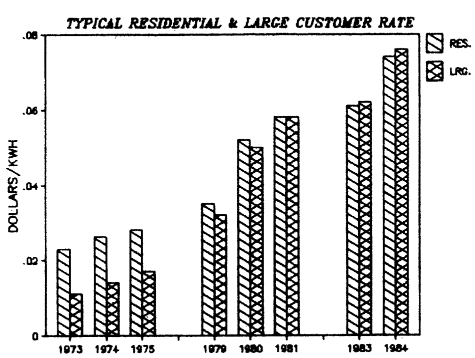
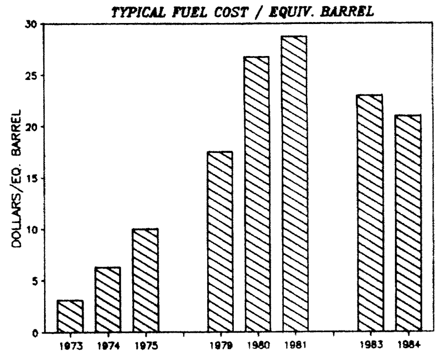
Abstract - This paper discusses Pacific Gas and Electric's experience with its five (5) major dispatchable load management programs from an operations viewpoint. Much of the existing industry literature concerning load management is written by Rate and Commercial Department personnel; however, this paper provides a unique insight into the operation and assessment of load management programs by those who directly utilize them. In addition to the in-depth analysis of PGandE's existing load management programs for heavy industrial, commercial, and residential customers, this paper presents criteria by which programs can be assessed in a continually changing utility environment.

INTRODUCTION

This presentation will discuss the vast experience of developing direct control load management programs at Pacific Gas and Electric Company (PGandE) from an operation's view. The service territory at PGandE covers the northern and central portions of California or approximately two-thirds of the state. We serve over 3.5 million electric customers and our 1984 System Peak was 16,225 MW on July 13, 1984. We are a summer peaking utility heavily influenced by agricultural pumping in the fertile central valley of California and air conditioning. We are fortunate to have the largest diverse mix of generation resources of any investor-owned utility in the U.S. However, the Arab oil embargo of 1973 reached its tenacious grip into California impacting the fuel cost of conventional fossil power plants. No longer were customer energy bills going down but instead were increasing at unprecedented rates and from rate forecasts energy bills will continue to increase beyond the year 2000.



Various actions began in the mid 70's to stem the tide of escalating customer energy bills. One of

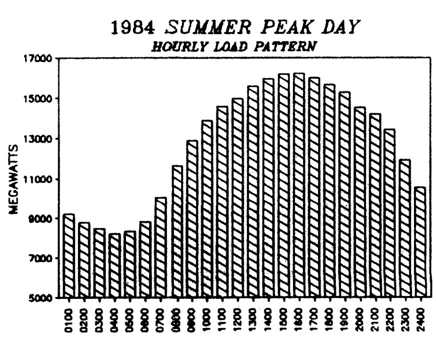


these areas was direct control of some customers loads during peak load times. The first PGandE program began in 1977 when 300 residential customers with central air conditioning were operated. This small beginning has grown to several load management programs. This paper will discuss PGandE's load management (LM) experience through 1984. All of these programs are considered experimental and not operational. The yearly operation criteria and parameters for each program is determined by representatives from our Rate, Customer Operations, and Electric Operations Departments prior to May 1. The decision to then operate any program for load relief is always the responsibility of the Power Control Department. The only exception may be some test operations.

Since all of our LM programs are voluntary, customer attitudes affect the direction of programs. For example, load management cannot be a viable resource without causing some inconvenience to the customer and customers do not want to be inconvenienced. Consequently, Power Control views these programs as a resource to be used sparingly thus keeping the number of operation days to a minimum. However, in order for these direct control LM programs to prove worthwhile they must successfully compete with other available resources. From an operation's viewpoint, let us take a look at the value of a resource.

A Power company must identify its projected electrical load demand prior to the time of need in order to have the necessary generation resources on line. The many segments of future planning for these resources runs from 10+ years in advance to the hour before the need. I will focus on the actions surrounding the availability and use of resources from 24 hours prior to the electrical demand.

A utility must first determine its anticipated load demand on an hourly basis. This is done at PGandE around 5 p.m. of the day prior to the forecasted day. We are able to use a sophisticated computer program which utilizes key area temperatures and the previous 28 days system load data to forecast the next day hourly demand curve.



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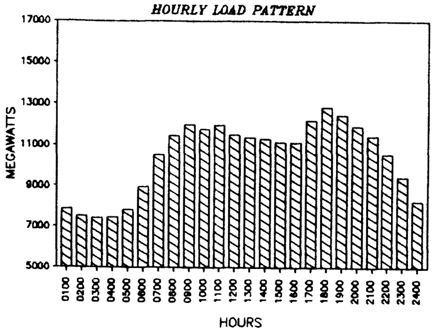
1984 *WINTER PEAK DAY*
HOURLY LOAD PATTERN



These graphs indicate a typical PGandE load curve for summer and winter periods. The dispatchers must determine what resources are available and then match these resources to the expected electrical need in the most economic and reliable manner. The mix of resources available to the system dispatcher vary in magnitude during the course of a year. General categories that we have available are nuclear, geothermal, PGandE hydro, other hydro, PGandE thermal, power purchases in California, and power purchases outside California. This resource mix must be scheduled in a varying manner to meet the hourly load curve demands. Some resources are more flexible and responsive than others. Critical characteristics of a resource that are considered are:

CHARACTERISTICS OF A RESOURCE

AVAILABILITY

RELIABILITY

SPEED OF RESPONSE

SIZE

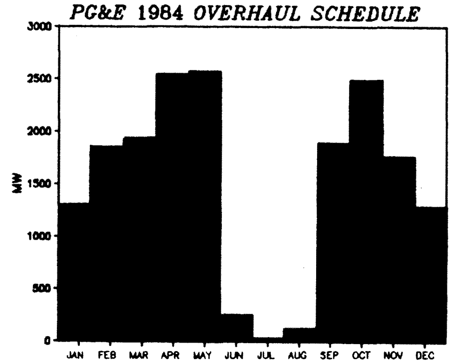
COST

ABILITY TO OBSERVE RESPONSE

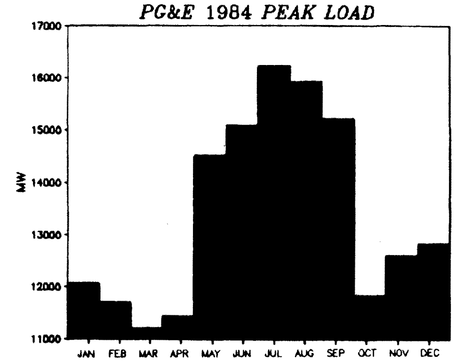
Based on the forecasted next days' hourly load, these resources are scheduled to meet the expected load plus provide a margin of safety to cover contingencies. This margin at PGandE is 7% at the peak hour. As shown on the above figure concerning resource characteristics, each type of resource must be planned (scheduled) based on its characteristics. For example, a nuclear plant is operated as a base load; our geothermal is run as a base load; hydro is run as a base load whenever you are in spill conditions and run as a peaking unit when water storage permits; fossil fueled steam plants are run as peaking units; however, due to the thermal stresses and long start-up times, it is not common practice on most systems to start up and shut down conventional steam units on a daily cycle; purchased power from others may be firm (guaranteed) or may be cancelled in an hour. Another characteristic in addition to the energy/capacity capability just described is the response of a generator to move quickly up or down in response to system conditions. This characteristic is very important to the dispatcher since his system must correct itself to 60 HZ and normal intertie schedules within 10 minutes. Steam plants are very slow responders because the steam requirements must be changed before the generator can respond. Typically a 330 MW steam unit can respond with 18-28 MW within the first minute and then 8 MW/minute -- as you can see this is slow to a large system. Hydro unit response varies widely and can go from zero load to full load in a matter of seconds or certain configurations may take a few minutes. A gas turbine which is a more expensive resource to run is used for short peaks and emergencies and can go from shutdown conditions to full load in approximately 6 minutes. The dispatchable load management programs at PGandE are not scheduled to meet the daily load but are utilized during peak periods when the margins are tight. However, when a load management program is being designed, it is being matched up to these resource characteristics to see if it is beneficial and practical. For example, an early option designed by one of our programs called for a 4-hour customer response time. In reality, this time frame was too long to respond to emergencies and, thus, was dropped. Presently some of our direct load control programs are more valuable than others because they have different capabilities just like our other power resources.

Another resource characteristic sometimes overlooked in load management program design is the availability to respond throughout the year. Even though we are a summer peaking utility due to agricultural pumping and air conditioning loads, we can have tight periods at any time of the year. Thus, an air conditioning load management program is not as beneficial to the power system as another program which is available any time during the year (Example: large customer interruptible). The reason for tight periods during the spring and fall is due to the scheduled overhaul of units. PGandE schedules all of its major unit overhauls during a 9-month period and in that period also coordinates with Southern California Edison, San Diego Gas & Electric, and Los Angeles Department of Water and Power. We do not normally schedule overhauls during the months of June, July, and August. For example, our 1984 scheduled overhaul program and peak load are highlighted in the following graphs:

PG&E 1984 *OVERHAUL SCHEDULE*

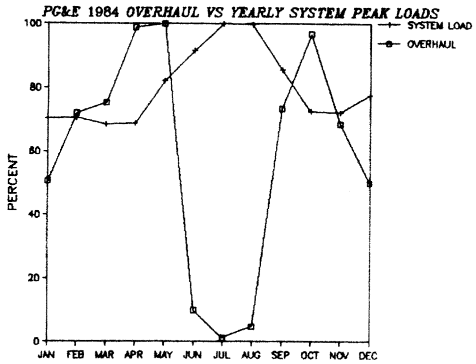


PG&E 1984 *PEAK LOAD*



By comparing the overhaul schedule with the monthly peak loads, you can see the potential for need exists during all 12 months of the year and especially shows how May and September are prime candidate months for tight margins. The available supply of capacity/energy from neighboring utilities is normally more available and least costly outside of the summer months which, therefore, provides more operating flexibility during these 9 months.

If we want to directly compare overhaul scheduling versus the peak loads, we can set the monthly maximum equal to 100% and compare as follows:



If we again look at the graph of the summer load day, we can compute the amount of resource needed to change the spinning reserve by 1% or 2%. As you can see, at PGandE, this is 163 MW and 325 MW, respectively. Can a load management program produce load reduction in a magnitude large enough to help the system? PGandE has under development and analysis a group of dispatchable programs.

PG&E MAJOR LOAD MANAGEMENT PROGRAMS

* DISPATCHABLE
  - LARGE INDUSTRIAL INTERRUPTIBLE
  - LARGE INDUSTRIAL CURTAILABLE
  - RESIDENTIAL AIR CONDITIONERS
  - AUXILIARY POWER SOURCES
  - GROUP LOAD CURTAILMENT
* TIME OF USE
* CEMP

Pacific Gas and Electric Company has a variety of volunteer load management (LM) programs available for most of its industrial, commercial, and residential customers. These programs can be separated into three (3) categories: (1) Dispatchable, (2) Time-of-Use (TOU), and (3) Community Electricity Management programs. The major distinction between categories one (1) and two (2) is that the dispatchable programs are controllable and can respond within 1 hour to some changes in system operating conditions within a well-defined operating window, whereas TOU programs are available 24 hours a day and year-round with customers altering their electricity usage based on cost. Indeed, the primary impact of TOU programs is the slowing of the growth rate of the system load curve for peak periods rather than directly affecting day-to-day system operations. In fact, TOU programs should be classified as non-dispatchable load management programs.

The Community Electricity Management Program (CEMP) is a group version of the TOU programs. The program is designed to encourage cities to reduce their normal energy usage. Therefore, CEMP is another program which should be classified as a non-dispatchable load management program.

Our concern is with evaluating the operational benefits of load management programs, and we must consider only those programs that directly effect the day-to-day system operations which are the major dispatchable load management programs. These programs provide a mechanism (phone lines, radio signal, distribution lines), which allow for corrective actions in the event of an unexpected system operation need such as spinning reserve less than 7%, an unexpected rise in temperature, generation unit outage, and transmission outage. These programs are:

1. A-18, large industrial customers with 500 kw or more of <u>interruptible</u> load.
2. A-22, large industrial customers with 500 kw or more of <u>curtailable</u> load.
3. Residential air conditioner radio switch direct control.
4. Auxiliary Power Sources (customer generators - non-parallel operations).
5. Group load curtailment - commercial buildings and small industrial customers with 300 kw or more of curtailable load.

In addition to these major programs, there are some small experimental dispatchable load management programs:

- Interruptible Agricultural Pumps
- Residential Air Conditioners Controlled by Signals Transmitted over Distribution Lines (Power Line Carrier, Ripple)

However, these programs will only be briefly discussed because they are very small pilot programs and have not demonstrated significant amounts of load relief.

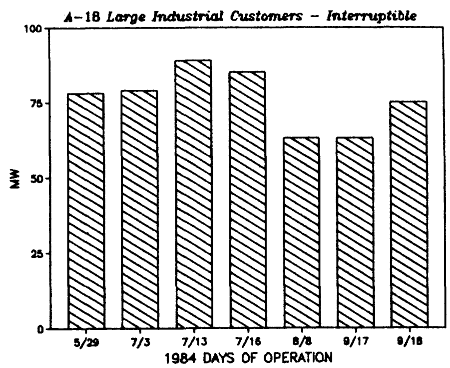
These small pilot projects are designed to evaluate the technical feasibility, customer acceptance, and cost effectiveness of each program. In addition, it is the Operating Department's responsibility to evaluate the quality of each program's resource characteristics. However, not all of these characteristics are easily assessed. For example, the Agricultural Interruptible Program, started in 1983, and had 30 customers with an estimated total of 0.5 MW of load relief. However, long-term forecasts predict available load relief of 10 MW in 1986, 21 MW in 1992, and 224 MW in 1998 which is a considerable increase from the present estimated 0.5 MW. The reliability of these forecasts are questionable in light of potential adverse customer reaction to actual operating conditions. It is important to note that experimental design criteria for operating these pilot programs may vary considerably from actual operations and, therefore, may adversely impact on the actual amount of load relief available at some future date. Forecasted load relief may be reduced considerably under actual operating conditions, thereby reducing the overall value of the program.

<u>Large Industrial Interruptible (A-18)</u>

The first program to be discussed is called A-18 for large industrial customers with an <u>interruptible</u> load of 500 kw or more. These customers must reduce their electric demand to zero (or to emergency service load only) within 10 minutes upon request, via telephone, from PGandE. The request is issued when it is determined by PGandE that a system condition exists or may exist which will impair PGandE's ability to meet the demands of its other customers. The program is most likely to be operated when the forecasted system spinning reserve is less than 7% and greater than 5%. In addition, these customers have automatic underfrequency relays which are set to operate when frequency excursions of 59.75 Hz or less occur. The non-automatic operating constraints for the A-18 program are that full interruption shall not exceed 320 hours in any year, once per day, 8 hours per interruption, and 40 times per year.

A-18 History

The interruptible program for large industrial customers began in 1983 with 19 customers, and ten (10) operations; load reductions ranged from 39 MW to 67 MW and the average load reduction was 55 MW at the time of the peak. In 1984, there were 28 customers and (7) operations; load reductions ranged from 63 MW to 89 MW and the average load reduction was 76 MW. Some of the initial problems in operating the program were the lack of rapid, verifiable assessment of customer performance, and delay in program dispatch due to intra-company communications problems. However, many of these problems were resolved during the 1984 operating season.



The A-18 program is, from an operation's perspective, the best of the presently available dispatchable load management programs. It provides the greatest amount of load reduction and operating flexibility. However, it should be noted that the CPUC has placed a limit of 300 MW of interruptible load for this program. In addition, there are some aspects which could be improved to enhance program operations. One of these is in minimizing the time delay between obtaining the initial load reduction estimates and the actual load reduction measurements. These measurements are needed to promptly review customer performance to determine whether the customer was in compliance during the interruption. Also, this information is vital to forecast potential load reduction for subsequent operations. In the future, after thorough testing of this program's viability (i.e., significant and consistent load relief, cost effectiveness, operating flexibility), there may be real-time monitoring of customers' load which would provide for prompt feedback of customer performance and load relief.

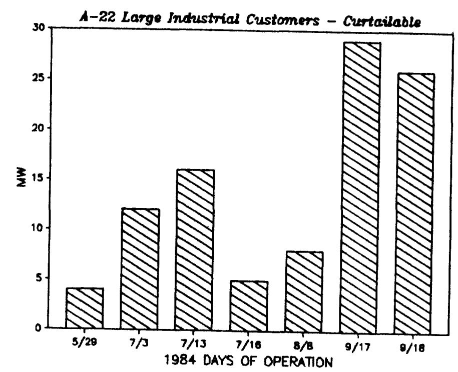
Large Industrial Curtailable (A-22)

The second program is called A-22 for large industrial customers that are willing to curtail a minimum of 500 kw of load. A-22 is similar to the A-18 program in that the request for curtailment is issued when it is determined by PGandE that a system condition exists or may exist which will impair its ability to meet the demands of its other customers (i.e., forecasted spinning reserve less than 7%). Program initiation is, also, via telephone. However, the similarity between A-22 and A-18 ends at this point. Instead of interruption, the A-22 customer is only required to limit electric demand usage to a contractually agreed upon level. Therefore, by shutting off selected or non-essential electrical loads, the customer decreases its electric load to a prescribed level called the Firm Service Level (FSL).

Another difference between A-22 and A-18 Program is that A-22 customers have an hour to be at or below their FSL after a curtailment notification. The 1-hour response time significantly lessens the value of this program to respond to rapidly changing system conditions. In addition, this program can only be operated 10 days per year and 6 hours per operation. One can quickly surmise utilizing the criteria of availability and response time that the curtailable program has serious shortcomings with respect to its operational viability. In all likelihood this program will require serious changes in the response and availability criteria to improve its operating characteristics.

A-22 History

Program operation began in 1981 with one customer and operated three times to obtain experimental data. The program was not operated in 1982 because the spinning reserve forecast was always at 7% or greater; but it was operated 10 times in 1983 with 13 customers. The average load relief was 22 MW, and ranged from 4 MW to 42 MW. In early 1984, the customer population declined to 3 members due to a tariff change requiring customers to provide guaranteed curtailable load (GCL). However, after this adverse customer reaction to the GCL it was changed to be an option. During the 1984 operating season, there were seven curtailments. The average load reduction was 13 MW and ranged from 4 MW to 29 MW.



Residential Air Conditioner

The third program is the residential central air conditioner radio switch program.

The present level of customer participation is at approximately 65,000 A/C switches located in 8 of PGandE's 13 divisions. These switches cover the length of most of the Company's service area from Red Bluff in the north to 450 miles south to Bakersfield and are located primarily in the warm central valley of California.

The radio switch control system is computer controlled. Predetermined commands are input at the operations terminal (CRT) and processed by the control computer. These commands are then transmitted via PGandE's microwave communication system to the ten primary transmitter site locations and then broadcast by the transmitter. Once the radio signal is received by the radio switch, it is activated and the A/C is cut off for a prescribed time depending on a predetermined control strategy.

A/C History

When the program began in 1977, there were only 300 customers which increased to about 1,000 in 1979. However, in June of 1979 the California Energy Commission mandated that PGandE install approximately 55,000 radio switches on residential central air conditioners. This goal was achieved and surpassed until it reached approximately 70,000 customers. Initially the program's cycling strategies were 9 minutes off/30 minutes and then 12 minutes off/30 minutes. This did not provide "significant" load relief without extremely high temperatures. In 1983, the adoption of increasingly severe strategies 15 minutes off/30 minutes and 18 minutes off/30 minutes occurred. However, the adoption of these "severe" strategies has not been without controversy. The matter of sacrificing customer comfort and, thereby, unfavorably impacting customer acceptance in order to maximize load relief has brought to the forefront the questions of whether load management programs should be designed to obtain the maximum amount of demand relief or provide customers with service options to reduce energy bills. From an operation's perspective maximum load relief should be the major underpinning of any effective load management program. However, to completely ignore the question of customer acceptance (i.e., how much can the customer take) would, also, run counter to achieving maximum load relief because of the high number of customer dropouts that would occur.

Because of adverse customer reaction to the 18 minutes off/30 minutes strategy and 3 consecutive operating days, this strategy was eliminated from 1984 operations.

However, in 1984 a shed strategy (A/C off for 4 hours) in the 3 warmest areas was offered to approximately 9,000 cycling customers with about 3,700 accepting. The shed strategy was offered as a direct result of:

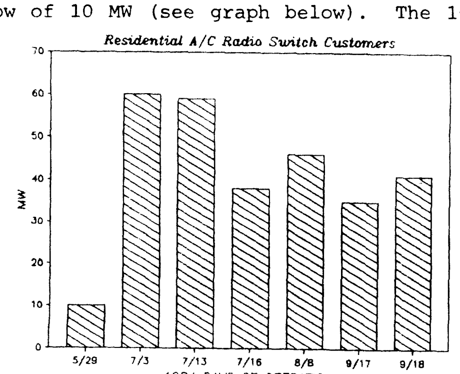
1. California Energy Commissions mandate to utilize more severe A/C control strategies in 1984.

2. Independent market survey of an existing group of shed customers determined that customer acceptance of the shed program was at a level of 93%.

3. Substation monitoring experiment which determined that shed strategies provide more than double the load relief provided by 15-minute cycling.

The present ability of the operating department to report, usually the day after an operation, is due to the substation monitoring experiment. This has resulted in a significant improvement in program performance, capability, and reliability. From an operation's perspective, it is important to continue to monitor available load relief to detect any abrupt changes in A/C customer usage patterns.

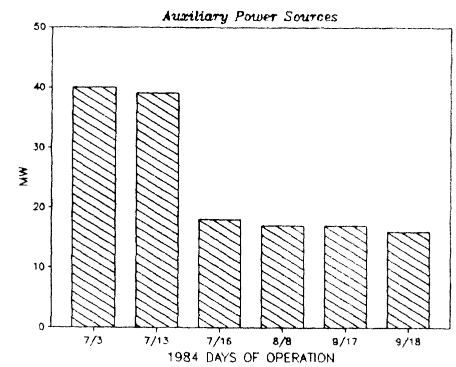
The criteria for operating the A/C program is that the forecast spinning reserve is below 7% and that the combined weighted temperatures from four of PGandE's warmest areas is approximately 99°F or greater. When these two criteria are met, then Power Control department has the discretion to implement the program for load relief. During 1984 the program was operated on 7 occasions (in conjunction with the other major LM programs) with an average of 41 MW and a high of 60 MW and a low of 10 MW (see graph below). The 10 MW was



the direct result of computer software problem which resulted in two-thirds of the A/C customers not being cycled. The reasons for the spinning reserve forecasts below 7% was generally attributed to high temperatures and/or unscheduled outages of large thermal generating plants.

Auxiliary Power Sources (APS)

This program was first utilized for load management in 1984 under the same spinning reserve criteria used by the other LM programs. This program was previously designed to operate under a state-wide Electrical Emergency Plan (spinning reserve of 3% or less). Upon request via phone, these customers are required to separate from the electric system and utilize their auxiliary generators in 1984. There were 32 customers and the program was operated 6 times. Based on customer reports, the average load reduction was 25 MW, with a high of 40 MW and a low of 16 MW. However, these load reduction numbers must be verified.



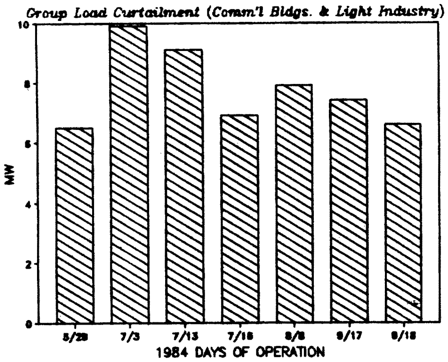
Group Load Curtailment (GLC)

The GLC program consists of four groups of customers with large commercial office buildings and/or industrial facilities, joined together in computerized network that allows treatment of their individual electric loads as a single load by PGandE. Each group member identifies which of their respective loads that can be curtailed.

The sum of these individual loads is the group's guaranteed curtailable load which is the minimum amount of load reduction the group agrees to provide during a curtailment request from PGandE. Customers are notified via a computer controlled communications system over leased phone lines. This communication system provides the GLC operator and customers with real-time load monitoring of all building's loads. Each customer can also monitor its group's curtailment performance. In addition, members can send messages to the system operator and other members within their respective group. In 1985 this communication scheme will be improved with the installation of customer notification alarms. The alarms will provide better customer response to curtailment requests.

GLC History

In the summer of 1981, the first GLC group was established in San Francisco with 17 buildings participating. The second group formed in Oakland with 8 buildings. In 1982, two additional groups joined the program. One group in Oakland, with one building, and three industrial facilities. The other group is in San Francisco with ten participating buildings. The plans for 1985 are to add new members to the existing groups and also to create a new group in the San Jose area. In 1981 GLC Group 1 was operated 5 times with an average load relief of 3.9 MW. In 1982 Groups 1 through 4 were operated four times with an average of 10.8 MW; in 1983 the 4 groups were operated 9 times with an average of 5.9 MW of load relief and in 1984 there were 7 operations with an average of 7.8 MW of load relief. How would you evaluate this program's value to date in contributing load relief to a power system with peak loads of 10,000 to 16,000 MW?



1984 Operations Summary

158.7 MW is the average load reduction for the 7 operations in 1984. Below is a table which lists each program's average contribution to the 1984 operating season:

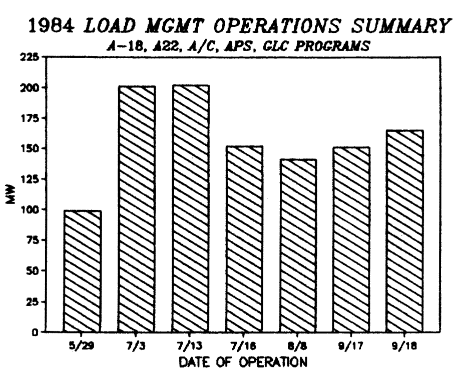
1984 Load Reduction (MW)

Program	High	Low	Average
A-18	89	63	76
A/C	60	10	41
A-22	29	4	13
APS	40	17	18
GLC	9.9	6.5	7.8

Each of these programs remain experimental as opposed to operational. However, part of the experiment is to determine if these programs can provide significant and consistent load relief under actual operating conditions.

It is clear that the programs must provide a significant available load relief when needed (approximately 100 MW per program) to contribute to PGandE's Electric System. The 1984 results, clearly show that none of the programs achieved this on an individual basis, but collectively they did exceed the 100 MW target. This 100 MW target is due to our large system load and the need to add resources of this size and larger. The size needed to help your utility may **be smaller, but if load management is to help a power system, it must be of sufficient SIZE. Very small programs will not help the power system due to their diversity, unknown response, and negligible effect upon the system.**

The following is a summary of load relief during 1984 operations:



Objective of the 80's and Beyond

The primary objective of PGandE during the remainder of the 1980's is to continue to test, evaluate and improve a broad range of LM service options that can be rapidly expanded in the event currently planned generation resources are unavailable. From a planning perspective, there is no present need for any major expansion of the load management program in light of our nuclear units at Diablo Canyon and our three pump storage units at Helms. However, Diablo with approximately 2,200 MW of baseload generation will have considerable system impacts in the event of a unit(s) relay or unscheduled outage.

Presently only the large industrial interruptible customers can respond quickly enough via underfrequency relays which operate at 59.75 Hz. Even though these customers can provide an immediate response, the present size of potential load relief (63-89 MW) remains insignificant with respect to the loss of a major unit. In the coming years, it might be prudent to increase the amount of available load relief (300 MW or more) to respond to underfrequency conditions. This underfrequency response could apply, also, for Residential Air Conditioners which could be automatically dispatched during underfrequency conditions, but only when temperatures are 100°F or greater.

If load management programs become a proven resource and thereby become operational, then the dispatch of these programs would most likely occur via equipment (CRT's, printers) installed in the System Dispatch Center. Presently, all load management equipment is located outside of the Dispatch Center and there are no communication links between the dispatch computer and the various load management control equipment. Even though the decision to operate these programs resides with the system operations department, coordination of operations is now achieved through the actions of support operations engineering personnel.

One can conclude that the future direction of dispatchable load management programs is still wide open. Our programs remain experimental because we have not determined that these programs are viable resources, nor have we developed the optimum dispatch criteria. We will continue to move toward this criteria through continued operation of programs that show potentially significant load relief. However, achieving significant load relief may be thwarted by changing attitudes among customers who no longer consider the "energy supply" a problem. For example, a 1979 California poll listed "energy supply" as the #2 concern of Californians (inflation was #1). In 1984, "energy supply" is now ranked #14 out of 16 categories. Because customers now perceive continuous energy supply as a resolved issue, they are less willing to sacrifice personal comfort, or alter their plant operations. This change in customer attitudes can sometimes be overcome by paying greater monetary incentives, although this makes other resources more economical.

Ultimately, LM programs could proceed with the objective of solely providing customer rate options with small load reduction and minor inconveniences or it could develop into a program that can be considered a power system resource. A utility must be careful when considering load management as a resource in their short- or long-term capacity plans. These programs are still under development and widely influenced by customer support and should not be treated as a proven resource.

As noted all PGandE programs are implemented only during system emergencies. The current attitudes of customers and the desire to develop these programs with a positive acceptance by the public guides the Public Utilities Commission. These inputs are reflected in the tariffs which are changed from time to time. It is interesting to note that sometimes these restrictions influencing the tariff requirements can diminish the demand-side program effectiveness. However, these same all inclusive issues are present during the planning of all resources such as new generation, new transmission facilities, etc.

In conclusion let me say that at PGandE we achieved modest resource support to our power system during 1983 and 1984. This modest amount of load relief (100 - 200 MW) was helpful but will need to be increased significantly in size and improved time response to be counted as a viable resource. Whether this will happen is still unknown because the customer willingness to respond in the way a power system resource must respond is changing. As stated earlier customer attitude has a big impact upon the success of a load management program. Remember the criteria for a power system resource: AVAILABILITY, RELAIBILITY, SPEED OF RESPONSE, SIZE COST, AND ABILITY TO OBSERVE RESPONSE. While all of these characteristics are important, the ability to measure the actual load relief response has been the most important one for load management programs at PGandE. Measuring total program response is most desirable but sometimes impossible. The best example to support this statement occurred in the residential A/C program. Initially a large amount of analysis went into trying to determine the individual customer household load characteristics. Even tape demand meters were installed on a small sample of customers and used to project the aggregate result. This information led to certain conclusions regarding the expected amount of load relief. People were not sure if we were really obtaining these results because no system meter could show results. It was not until we installed special substation metering systems at selected transformer banks that we could determine the actual response. The ability to measure aggregate response from any program is a definite requirement. Seeing the measured results can be instantaneous or the next day or the next week.

It is important to actually measure the aggregate response as completely as possible. If you create a program and just depend upon calculated values, then I would say you are headed for trouble. Design your measurement capability to best reflect your power system measuring requirements.

This concludes my presentation of what is required from direct load control programs if they are to become a viable permanent tool in the hands of a system dispatcher. Remember the benefits to the system dispatch is the programs ability to respond similarly as other available resources.

I would like to acknowledge the significant contribution of my collegue Isaac W. Moore, Power System Engineer, in the preparation of this paper. Mr. Moore has been involved in the operation for many of these programs. He has contributed toward the development of more valuable operating criteria and the elimination of ineffective operating criteria.