DYNAMIC DISPATCH OF DIRECT LOAD CONTROL

by

Rahul Bhatnagar

Dissertation submitted to the Faculty of the

Virginia Polytechnic Institute and State University

in partial fulfillment of the requirements for the degree of

Doctor of Philosophy

in

Electrical Engineering

APPROVED:

S. Rahman, Chairman

L.L. Grigsby

F.C. Brockhurst

I.M. Besieris

W.H. Mashburn

June, 1985

Blacksburg, Virginia

DYNAMIC DISPATCH OF DIRECT LOAD CONTROL

by

Rahul Bhatnagar

S. Rahman, Chairman

Electrical Engineering

(ABSTRACT)

Direct Load Control (DLC) -- the direct control of customer loads by an electric utility for the economic and reliable operation of the power system, is an important and active element of Load Management(LM). Currently attention has focussed on the integration of DLC into system operations. However, as yet, DLC is regarded as a discretionary resource to be used by the system operator based on informed judegement. The integration process has therefore, concentrated on improving the informational inputs to the operator.

This dissertation extends the integration from that of a discretionary resource to a dispatchable system resource. The concept of the dynamic dispatch of DLC is formulated and defined to be an online evaluation and utilization of DLC for optimum benefit to the utility, as system conditions change. The concept envisages the use of DLC in an automated mode and coordinated with other system resources for optimum benefit.

An important and integral part of the research effort is the development of a cost characterization of DLC. A closed form solution, using a dynamic programming framework, has

been developed to estimate the costs of DLC dispatch. The derivation takes into account all operational constraints on the utilization of DLC -- payback characteristics, maximum on-times and minimum recovery times. The cost, defined as the difference in the fuel costs with and without DLC dispatch, were found to be dependent on the cost characteristics of the online generators and the load shape impacts of DLC dispatch.

The dynamic dispatch concept is concretized by a power system operations model which incorporates DLC dispatch for fuel cost minimization and peak load shaving. The two modes are toggled by the dispatch algorithm as system conditions change. Results from the model are presented for several combinations of system conditions and DLC system parameters.

ACKNOWLEDGEMENTS

I would like to take this opportunity to express my heartfelt gratitude and sincere appreciation of the help and guidance of Dr. Saifur Rahman. His constant support and encouragement, professional and otherwise, has been an important factor in my staying the course. He gave unstintingly of his time, knowledge and experience while providing an independence which has allowed me to develop professionally and personally. It has been, for me, a long and fruitful association and, I hope, for Dr. Rahman as well. It has also been and will always continue to be a pleasure to be associated with him and to work with him.

I would also like to thank my committee -- Dr. Grigsby, Dr. Brockhurst, Mr. Mashburn and Dr. Besieris, for their time, help and guidance during my Ph.D. program and otherwise. The entire committee has always been extremely helpful and willing to provide advice or guidance whenever I have required it.

It would not have been possible to complete this dissertation without the help of numerous friends and associates and I would like to take this opportunity to thank them all. In particular, has always allowed me to draw on his knowledge of the software at Va Tech. Scripting this dissertation as well as accomplishing the numerous tasks that are required for producing a 'deliverable product' would have been a much more difficult task without his help. Also, , and the other secretaries in the department deserve a vote of thanks, for their help during my graduate studies.

Finally, I would like to thank , my wife of one year and a friend of several years, for her support and understanding during my entire graduate program and specially during the last few months of my Ph.D. program.

TABLE OF CONTENTS

LIST OF ILLUSTRATIONS

CHAPTER I

INTRODUCTION

The primary focus of this dissertation is an investigation into the "dispatch" of loads directly under the control of an electric utility, otherwise known as Direct Load Control (DLC). The subject matter is, however, part of a broader spectrum of utility activities known as Load Management (LM). In order to understand the 'whys and wherefores' of this dissertation, it is necessary to present a short historical perspective on Load Management and Direct Load Control.

1.1 LOAD MANAGEMENT - A HISTORICAL PERSPECTIVE

The seeds of LM had been sown earlier, in Europe, in the late 1950's [1] and to some extent in the United States by utilities such as Detroit Edison (which has had an active DLC program since 1969) [2]. However, Load Management (LM) as it is practiced today by the electric utility industry started it's evolution in the mid-1970's, after a series of economic, legislative and social developments which have had a lasting impact on the electric utility industry.

The current emphasis on and involvement with LM is, in the final analysis, related to the negation of the advantages of economies of scale caused by spiralling operating and capital costs. The four primary reasons for this are:

1. The Arab Oil Embargo of 1973 which sent oil prices skyrocketing to several times their pre-embargo prices. The fuel bills of oil importing countries tripled and quadrupled during the space of a few months. For the electric utility industry in the United States and it's customers the consequences were rather grave. The increased fuel costs resulted in rate hikes which in turn prompted customers across the board to resort to energy conservation. On a closed loop basis, customer activities reflected back onto the utilities in the form of increased uncertainties in sales and peak load growth. Historical data was largely invalidated and previous prediction models outdated because of a need to include a host of new variables. For example, the rate of peak load growth across the country had been stable at approximately 8% prior to the Oil Embargo. Within a few years it fell to 3-4% and there was no data to predict its future behavior.
2. The high oil prices fueled an inflationary economy which resulted in rising interest rates. As interest rates spiralled upward, so did the capital costs of the electric utility industry, which is inherently a capital intensive industry.

3. The 1977 amendment to the Clean Air Act in response to societal pressures increased capital outlays for new plants and required further expenditures for retrofitting existing ones.
4. Superimposed on all the above economic and legislative developments was a general societal shift away from nuclear power. Public concern about the safety of nuclear power plants and the transference of the stigma attached to nuclear weapons to nuclear power plants has resulted in stringent design and safety regulations from the Nuclear Regulatory Commission.

The effect of the developments has been to increase the uncertainty in the planning process in terms of lead times, costs, applicable legislation that may be forthcoming, etc. and to increase operating and capital costs for the electric utility industry. For example, lead times for nuclear power plants have increased from 5-8 years to around 15 years or more. The resultant increases in projected costs have largely negated the economy of nuclear power. Cost overruns have caused utilities to abandon nuclear power plants in their construction stages. Lead times for large fossil fuel plants have also doubled requiring upward revisions of projected costs. For primarily oil and gas burning utilities which depend on cheaper nuclear power or large coal plants to serve their base load, the consequences are large increases in production costs, increased dependence on interchange and increased capital costs. In response to the above developments the industry has had to develop:

1. new planning models and strategies;
2. methods of improving system utilization; and
3. methods for limiting and/or controlling the rate of peak load growth.

The methods of the last two categories form the set of functions known as Load Management. The primary purpose of LM is to maximize resource utilization in all respects i.e. in terms of additional capacity required, reduction of operating costs, improvement of the revenue base, etc. without undermining service quality. While several definitions of Load Management have been forwarded in the literature, two which best represent the nature and task of LM are presented here:

The U.S. Department of Energy defines Load Management as "a systems concept of altering the real or apparent pattern of electricity use in order to (i) improve system efficiency, (ii) shift fuel dependency from limited to more abundant energy resources, (iii) reduce reserve requirements and (iv) improve reliability to essential loads" [3].

On a more practical note Comerford and Gellings [4] define Load Management as: Any deliberate reshaping of the behindthe-meter or customer side load curve resulting from any actions of the utility which impact the customer.

1.2 THE RATIONALE FOR LOAD MANAGEMENT

Traditionally as the demand for electric energy goes up, so does the peak electrical load (MW). Since generation capacity requirements are directly related to the peak load, there are strong incentives to reduce the peak load and contain its growth while meeting the demand for electric energy. This would result in retaining the revenue base while reducing the additional capacity that would be required. Load Management in its essential form is aimed at doing just that -- inhibiting the growth of peak loads while encouraging the use of electric energy. The apparently contradictory nature of the above statement is clarified below.

The ratio of electric energy served to the installed generation capacity required to serve it is reflected in the load factor of an electric utility. The load factor is defined as:

$$\text{Load Factor} = \frac{\int_{t_1}^{t_2} L(t)\, dt}{\Delta T * \text{Peak Load}} \qquad (1)$$

Thus, the load factor measures the ratio of the average real system load to the peak load. As the load factor approaches unity, the implications are:

1. the Generation, Transmission and Distribution (G,T&D) system is more effectively utilized, thus improving the economics;
2. either it becomes more economical to install new capacity if the load factor improvement was obtained by improving revenue sales during off-peak hours; or
3. additional capacity requirements have been reduced if the improvements were obtained by peak shaving.

LM aims at improving the load factor by both the above methods.

A generalized electric utility load curve is shown in Figure 1. The curve exhibits deep valleys and high peaks. If the peaks were reduced by peak load shaving and the valleys shallower by encouraging off-peak energy usage, then:

1. the peak load is reduced, requiring less on-line capacity to serve it. Further, if this reduction is constant over an extended period of time such as a planning horizon, then the additional capacity requirement is also reduced.
2. the average load is higher i.e. the load factor is closer to unity. As mentioned earlier, a high load factor is beneficial from an economic point of view. It should be mentioned though, that a load factor close to unity also creates scheduling and reserve problems. So, the desirable load factor increase is dependent on the system as a

whole. However, in general, a load factor rise indicates improved system utilization, which is one of the goals of LM.

3. if the cross hatched areas 1 are equal to the cross hatched areas 2, then, all electric energy requirements would have been met. If the areas 1 are greater than the areas 2, then, more electric energy has been served than before and the revenue base has been expanded.
4. in terms of energy sales, the off-peak energy sales have increased and the peak energy requirements have been reduced. Thus high cost energy from oil and gas has been replaced by low cost coal, nuclear or hydro energy.

Hence, the electric utility industry has been testing and assessing various alternatives for improving the load factor by peak load shaving and shifting energy consumption from peak to off-peak hours. This allows them to meet the ever increasing demand for electric energy with the minimum possible new generation and at the minimum cost. These alternatives are generically known as Load Management (LM).

1.3 THE SCOPE OF LOAD MANAGEMENT

The options available to a utility for Load Management include:

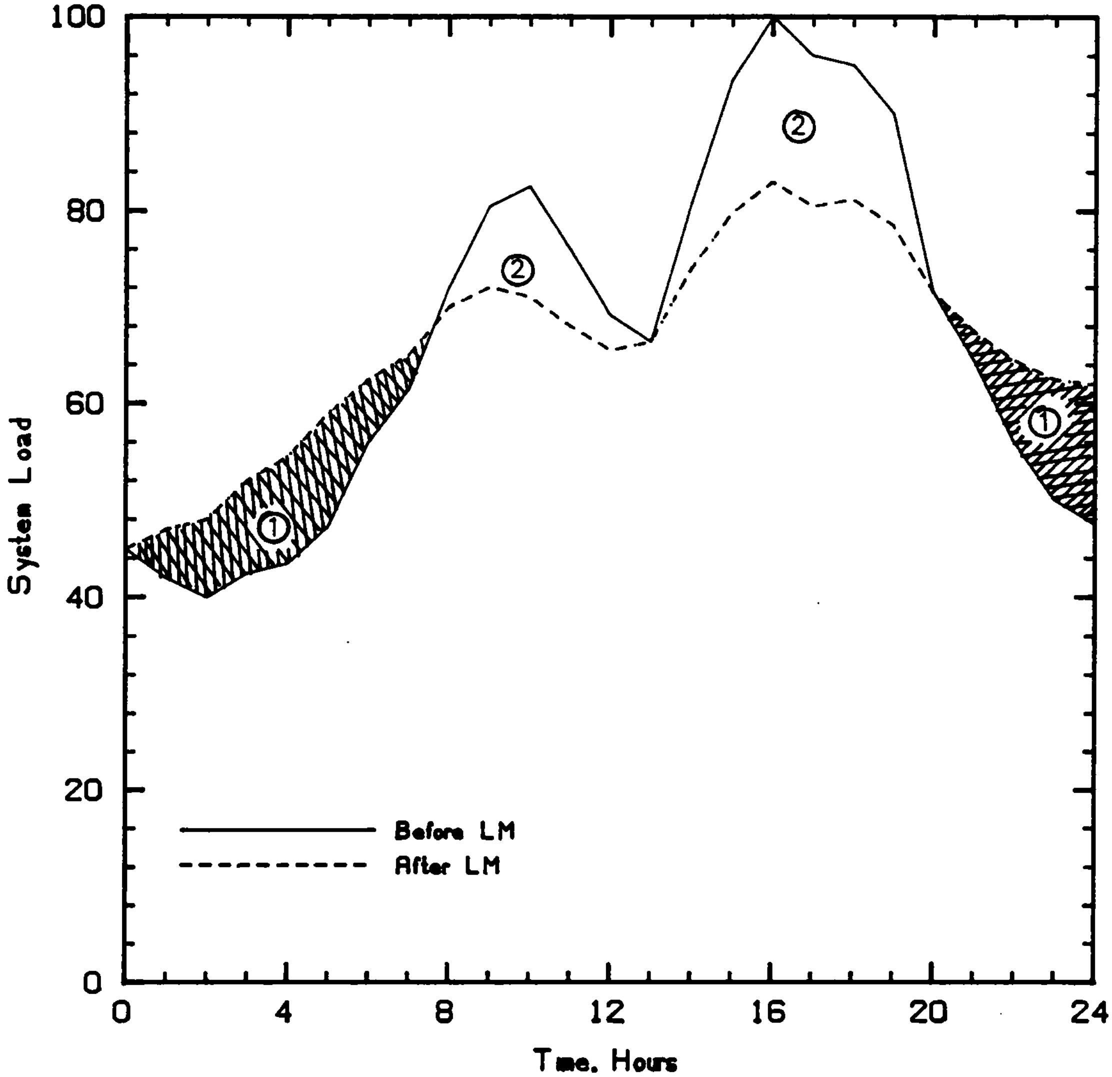

Figure 1. Desired Impact of Load Management on the Load Curve

1. encouragement of Electric Thermal Storage (ETS) devices for comfort conditioning. These devices store energy during off-peak hours and utilize it during peak hours, thus shifting energy use to off-peak hours.
2. institution of Time-of-Day (TOD) rates to encourage off-peak power usage.
3. demand management programs which encourage energy conservation and demand reduction by the customer.
4. institution of Time-of-day (TOD) rates to encourage off-peak energy usage.
5. direct control of customer appliances/equipment to limit peak demand and control peak hour demand.

The above list of alternatives excludes the following supply side alternatives:

1. voltage reduction programs to reduce the system load;
2. installation of pumped storage hydro to utilize relatively inexpensive base load generation for pumping during off-peak hours in order to displace peaking generation during peak hours.

While the U.S. Department of Energy (D.O.E.) definition of Load Management would permit the inclusion of the above two supply side alternatives within the scope of LM, they are attempts by the utility to "manage" their supply system and should not be included within LM. Hence, for the purposes of this research, the second definition of LM forwarded by Comerford and Gellings will be used.

In order to complete this discussion of the scope of LM, some benefits of LM accruing to the utility are listed below:

1. reduced peak loads;
2. deferral and/or reduction of additional capacity requirements;
3. off-peak energy utilization eliminating partial base load generator loadings and excess capacity problems;
4. higher load factors;
5. reduced production costs;
6. increase in revenue due to increased off peak energy sales;
7. increased availability of power for sale to interconnecting utilities;
8. reduced reserve requirements or substitution of DLC for reserves;
9. improved emergency control of the power system due to enhanced load shedding capability; and
10. ease of restorative operations after a power system emergency;

Finally, it should be emphasized that all LM programs are primarily aimed at controlling and shifting electrical demand

(MW). They assiduously try to avoid any reductions in energy sales. The reason quite simply, is economic.

1.4 ACTIVE AND PASSIVE LOAD MANAGEMENT

The four components of LM -- DLC, TOD, Demand Management and ETS all serve the basic goals of LM. However, they differ in the manner in which they do so and hence in the benefits that they provide the electric utility. While all components contribute to peak load reduction and shifting energy requirements from peak to off-peak hours, not all components can contribute to system reserve, aid in emergency control, etc. It will be recognized that such "need dependent" functions can only be fulfilled by a resource which can be directly and predictably controlled by the electric utility.

Demand Management by its very nature is dependent on customer motivation and efforts to reduce electric energy costs. While load research data and appropriate models can predict the effect of Demand Management programs on the utility's load curve, the load essentially remains outside the field of utility control i.e. it is not controllable as needs require. Similar considerations hold for the effect of Time-of-Day (TOD) pricing. The behavior of ETS loads is very predictable since they are set to charge at predetermined times, but they are not selectively controllable. ETS loads can be shed if required, but:

- they charge at off-peak hours when only a system emergency would require them to be shed; and
- all loads on a feeder would have to be shed, including non-ETS loads.

Thus, Demand Management, TOD and ETS can be considered as "passive" components of LM.

Direct Load Control (DLC) however, has all the requirements of a predictable and controllable component of LM. Loads under a DLC program can be quantified quite accurately and can be selectively controlled as needs require. Thus, DLC can be classified as an "active" component. The availability of an active component lends a flexibility to any LM program that can be of use in several situations.

1.5 DIRECT LOAD CONTROL -- DESCRIPTION

Direct Load Control involves the control of customer loads by an electric utility to achieve desirable load shape changes to meet Load Management objectives. The term 'direct' is used because the control is exerted directly by the utility using a communication link, as opposed to indirect control through pricing mechanisms or devices such as Electric Thermal Storage.

In the general scenario, the DLC mechanism consists of:

- centrally located signal transmitters;
- signal relaying stations (optional); and
- signal receivers and decoders located on the customer premises.

The signal transmitters are keyed in by the utility's LM system, located in the Energy Control Center, when control is desired. Transmitted signals are received and decoded by the devices located on the customer premises.

The receivers are organized in blocks and possibly, groups. Each block and group within the block is assigned a unique address. On receiving a signal to shed, the receivers addressed by the signal switch off the supply to the load. Normally they are preset to restore power after a predetermined interval, but the control interval can be extended by transmitting another shed signal.

The control interval and/or the time-of-day that control can be exercised is constrained by customer considerations. As far as possible, load control should not interrupt the customer's life style. Hence, limits are imposed on the maximum length of the control interval as well as the minimum time between control signals once control has been relinquished. In addition, the customers are given monetary incentives to participate in the program and as compensation for any inconvenience caused by the control scheme.

The organization of DLC capacity in blocks and groups then, allows selective control of DLC. This property of selective control provides DLC with the flexibility that is required for a system resource to be variably utilized to meet system requirements in an economical, reliable and efficient manner. The research presented here draws on this essential flexibility to study the "dispatch" of DLC for different objectives.

CHAPTER II

ISSUES IN PROGRAM DESIGN

As a preamble to the problem discussed in this dissertation, this chapter discusses some of the issues in the design of a Load Management program and presents the motivation for the research discussed.

Program design, in general, involves:

1. setting objectives for the program -- choosing from one or more of the set of desired objectives of Load Management, specifying desired penetration levels, etc.
2. determining a feasible set of alternatives for achieving the stated objectives of the program. This is constrained by:
   - customer reaction;
   - available technology; and
   - system characteristics such as planned and existing capacity mix, historical load shape, load factors, etc.
3. economic analysis of the set of feasible alternatives; and
4. choosing the most economic set of alternatives.

The process is inherently iterative in nature because many constraints which may be used at one step of the process reflect back onto a previous step. For example, customer reaction will also affect the economic analysis. The results of the economic analysis may then require a revision of the objectives because desired penetration levels may not be achieved. As an example, the American Electric Power Service Corporation (AEP) determined that a DLC program was not economic on their system. In order to make it economically feasible, customer incentives would have to be reduced. However, this reduction in incentives would lead to a drop in the expected participation rate in the program. The reduced penetration levels would make the program economically infeasible. Hence, AEP had to abandon the DLC program on a system wide basis. Individual member systems though, could study the feasibility of a DLC program on their system. The salient point here is not the conclusion of AEP, but the manner in which constraints and issues interact at different points of the program design process.

Probably the single most important issue is economics or the economic feasibility of a program. All other constraints and issues such as customer reaction and choice of technology depend, to a greater or lesser extent on the final economic analysis. For example, radio interference from a neighboring utility's load control program may require close coordination between the two programs or force the choice of a different technology altogether, such as power line carrier. But even so, economics may dictate the choice there. Similary, while customer reaction may depend on such intangibles as sensitivity to utility control of equipment, consciousness or need to save on utility costs and energy, etc. the bottom line is economics. Attractive incentive programs and proven savings may convert many a recalcitrant customer. However, can the overall economics of the program sustain the incentive program required?

This chapter will, therefore concentrate on the economic assessment methodologies used for LM programs. In the course of the discussion, the program formulation philosophy that has been followed by utilities will also be pointed out.

2.1 LOAD MANAGEMENT ASSESSMENT

The electric utility industry uses simulation and analytical models to study the impact of LM options on the load shape and economics and formulate policies regarding these alternatives. Usually, one or more of the LM options are used to formulate several alternative strategies based on informed judgement and load research tests and data. For example a startegy for a DLC program would define the control sequence in terms of time and length of control and the amount (MW) for a 24 hour representative load shape. The effect of these alternative strategies on the utility load shape and attendant economic effects are then assessed. The most economic strategy or combination of strategies is then chosen for implementation. One area of LM assessment that has not been investigated on a quantitative basis is the effect of various system characteristics on LM program goals. It has been shown qualitatively [5] that there is sufficient evidence and data to formulate effective relationships between system characteristics such as generation mix (existing and planned), historical load factor, load shape, etc. and the desired LM results. Such relationships would aid in screening out economically infeasible program options. In the absence of such aids, the formulation of LM programs proceeds on the basis of informed judgement and trial and error.

The exact assessment methodology differs from one utility to another. But the overall framework may be summarized as follows [6-16].

The overall costs of an LM program can be subdivided into two categories consisting of:

1. Utility Costs :

    a. capital and equipment costs together with associated carrying costs;
    b. possible drops in revenue due to lower energy sales;
    c. costs of incentives paid to participating customers;

d. costs of reprogramming system control/monitoring programs;
e. promotional costs; and
f. costs associated with upgrading the T&D system.

2. <u>Customer Costs :</u>

a. investment in new equipment such as an Energy Management System (EMS), ETS equipment, etc.;
b. for residential customers, the cost of adjusting life styles to accommodate energy conservation measures;
c. the cost of rearranging production schedules; and
d. possible increase in the cost of service, for non-participating customers.

The customer benefits of LM consist of reduced electric bills and any incentive payments made by the utility. The utility benefits are assessed by estimating the impact of a LM strategy on the load curve and estimating the production costs under the new scenario, while maintaining all system security and reliability constraints. Thus, all costs and benefits of an LM strategy accruing to the utility and its customers can be translated into financial considerations and revenue requirements. These, in turn, affect the rate structure, which again impacts on the customer. A closed loop is thus established, which is shown in Figure 2.

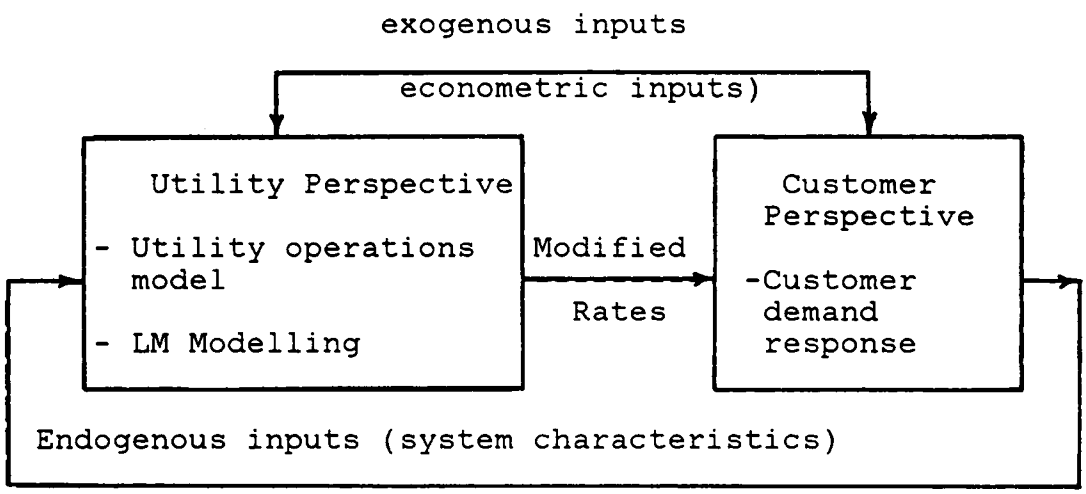

Figure 2. Closed Loop Load Management Assessment

Usually this loop is opened because it is difficult to quantify and measure the effect of exogenous inputs and changes therein. The open loop assessment scenario is divided into three perspectives:

2.1.1 Utility Perspective

This includes estimating the impact of a LM strategy on:

1. load curves;
2. generation, transmission and distribution expansion plans;
3. system production costs;
4. cost of incentives to be paid to customers;
5. program capital costs and carrying costs;
6. revenue requirements; and
7. rate structures.

This perspective is also the easiest to evaluate since all the items to be evaluated are tangibles and the required tools to do so have been developed extensively.

2.1.2 Customer Perspective

Includes assessing:

1. customer benefits; and
2. cost to customers.

This is a difficult task because of the large number of intangibles involved. First of all, each customer class -- residential, commercial and industrial has to be evaluated separately. Secondly, customer benefits in the case of such LM tools as TOD pricing or Demand Management are dependent strictly on the customers desire to save on utility costs and conserve energy -- a variable which is difficult to estimate at best. Also, some of the items mentioned earlier such as the cost of changing life styles are not amenable to quantification. So, the customer perspective costs and benefits are restricted to tangibles only. Based on the results of this evaluation expected customer reaction to a proposed LM program is estimated in terms of expected penetration levels. Additionally, the expected response of participating and non-participating customers to rate structures which incorporate the utility's costs of the LM program is also assessed.

2.1.3 Societal Perspective

This involves the assessment of:

1. environmental impacts;

2. reduced dependence on imported or scarce fuels;
3. costs of industrial relocations;
4. increased costs of off-peak hour concentrations of labor; etc.

This is, however, the most difficult perspective to evaluate because of the large number of intangibles involved. Usually, it is neglected in LM assessment methodologies.

The net effect of the application of such methodologies is the economic choice of a fixed LM strategy. The general scenario that evolves is amplified in [11] wherein combinations of controllable loads are cycled at specific times of the day. The most economically advantageous in terms of production cost savings, after accounting for the cost of the LM program, is selected. This strategy is then assumed to be implementable throughout the period that was simulated.

As mentioned earlier, several methodologies, operating within the general framework outlined above, have been reported in the literature. The predominance of the utility perspective is distinguishable in all these methodologies due to the well developed power system analysis and planning tools that can be used. The basic difference lies in the objectives that have been set for the LM program and the ways in which a particular utility will evaluate them. The most frequently used objectives sought from a LM program, as indicated by a survey of the literature [5], are:

1. peak load reduction;
2. production and fuel cost savings;
3. capacity deferrals/reductions;
4. load factor improvement;
5. reduction in system reserve requirements; and
6. system reliability improvement.

However, all except one of the methodologies reported [15] use traditional production costing algorithms employing Load Duration Curves (LDCs). Consequently, these methodologies suffer from one or more of the following defects:

1. the value and utility of LM is highly time dependent i.e. on the time-of-day, season of the year, etc. The use of LDCs for reliability and production costing obscures this effect;
2. LM strategies are considered fixed and not flexible. Therefore, LM is not considered on call 24 hours a day;
3. the dependency between generating unit availablity and the operation of other resources is not taken into account. For example, pumped storage hydro cannot be charged if base load capacity is not available.

The Load Management Strategy Testing Model [15] claims to correct these deficiencies. It requires production costs determined from a generation schedule derived from daily load curves for the entire time horizon. But, LMSTM suffers from several defects itself. The most significant of these are:

1. no power system calculations are performed by LMSTM. Generation schedules and similar data has to be input by the user. This makes data preparation and entry a lengthy and tedious task; and
2. it is, by and large, too general as evidenced by the above point. In order to retain generality, the program does not perform any scheduling, economic dispatch or unit commitment. The onus of its generality, therefore, falls on the user.

In concluding this section, it should be pointed out that, despite the limitations of LM assessment methodologies and the effort required to utilize them, many utilities have investigated the feasibility of LM and the majority have found LM to be economically advantageous. The proliferation of LM programs is hence a reasonable conclusion.

2.2 THE PARTIAL FALLACY OF DIRECT LOAD CONTROL

One important limitation that is placed on any LM program, specially one which includes Direct Load Control, is that of customer satisfaction. This can take two forms:

- ensuring minimum discomfort to customers, whether residential, commercial or industrial; and
- compensating them sufficiently for any discomfort caused.

The above considerations have prompted planners to place severe restrictions on their use of DLC. Control may be exercised on only five or six days in a season for peak load shaving. This leads to an underutilization of DLC resources and arises from the 'partial fallacy of DLC'. The 'partial fallacy of DLC' is the philosophy that DLC can only be used for peak load shaving. It is partial not because it is true to any extent, but because of a growing realization that DLC can be used for purposes other than peak load shaving alone.

Direct Load Control (DLC) offers the advantages of predictability and controllability and is hence, a tool that can be utilized not only for peak load shaving but for other purposes too. As mentioned in the section "Active and Passive Load Management" on page 11 DLC is an 'active' resource. It is, hence, an inherently more flexible resource than the 'passive' elements of LM such as TOD, ETS, etc. and not limited to one operating mode only. Thus, the program design philosophy described in the section "Load Management Assessment" on page 17 which limits the use of DLC would definitely not lead to the best use of the resource. Only recently have system planners taken cognizance of this attribute of DLC. Consideration has been given to the use of DLC for generation reserve and in system emergencies. However, given the flexibility of the resource and its attributes of predictability and controllability, it is surprising that until very recently, [16]-[21], little or no consideration has been given to integrating DLC into system operations. As pointed out by Kuliasha [22], "..this is unexpected considering the widespread interest in all forms of Load Management expressed by utilities and regulators".

Kuliasha further observes that:

> An operating strategy which considers load dispatching as an alternative to power dispatching, subject to constraints on the power system (such as unit characteristics, system security, and energy limitations), and considers the operational characteristics and constraints on the load being controlled, is a more realistic approach capable of realizing all the benefits possible from an active load control system.

In addition, such a strategy would also effectively integrate DLC into system operations and place DLC resources under the system operator as opposed to the system planners alone. The resource could then be used flexibly, as and when required while still being retained in the planning process.

2.3 RECENT ADVANCES IN DLC UTILIZATION

Le, et al. [17], have shown that the savings from DLC are maximized if DLC is coordinated with other generation resources. The methodology employed was to run three scenarios:

1. Unit commitment and economic dispatch without DLC. Let C1 be the production costs and E1 be the energy generated in this scenario.
2. Unit commitment and economic dispatch with DLC. In this scenario the load curves were modified on an hourly basis to account for the chosen DLC strategy. and a conventional unit commitment and economic dispatch performed for the modified load curves. Let C2 and E2 be the production costs and energy generated in this scenario.
3. A unit commitment was performed on the unmodified load curves. The economic dispatch utilized the modified load curves.

Then, the savings due to DLC in the case of the second scenario can be computed as:

$$S = (C1 - C2) - (E1 - E2) * R \qquad (2)$$

where

R = average residential energy rate

Similarly, savings were computed for the savings due to DLC in the third scenario. These savings were found to be drastically reduced. However, the investigation by Le et al. did not take into account the following:

1. the unit commitment is drawn up based on a 24 hour load forecast. Weather uncertainties however, can change the conditions under which the the unit commitment has to operate.
2. increasing penetrations of solar assist and alternative technology equipment, specially in the residential sector, greatly magnify the effects of weather uncertainties and variations on the system load.
3. while production cost considerations are very important during normal system operations, the availability of DLC as a dispatchable resource allows the system operator greater flexibility in meeting system load and emergencies.

However, the investigation supports the assertion of Kuliasha [20] and the central theme of this dissertation that DLC benefits can be maximized if DLC is considered as a dispatchable resource, since coordinating DLC with other generation resources implies treating it as such. Recently attention has been focussed on integrating DLC into system operations and treating DLC as a dispatchable resource. However these efforts consider DLC to be a discretionary resource to be used or 'dispatched' by the system operator based on informed judgement DLC utilization policies of the utility. The integration process, therefore, concentrates on improving the informational inputs to the operator or to allow the operator greater flexibility in choosing the amount and period of load shed.

Stitt [18], discusses a proposed procedure for integrating DLC into system operations via an on-line unit commitment program. The inputs to the program will consist of 'aggregate load reduction curves' derived for various cycling strategies or load control options. The program will evaluate the load control options along with other capacity options and commit the DLC system based on these evaluations. The operator will simply initiate the best cycling strategy at the designated time.

Bischke and Sella [19] discuss the use of DLC as regulating margin and to reduce the cycling of conventional units during secondary valleys in the load curve. DLC is scheduled either for anticipated periods of load following or for shifting the load from the secondary peak to the ensuing valley period to avoid generator cycling.

England and Harrison [20] present the design of a Load Management system which will allow the operator to initiate or terminate load control actions based on company formulated guidelines for the utilization of DLC. The operator can access the DLC capacity in steps of 12.5% corresponding to the eight blocks in which the DLC capacity is organized. Stored cycling strategies are used to implement the operator's decision. Additional restrictions on the use of DLC are also stored to prevent the operator from making an inadvertent mistake. One major restriction is the use of DLC only when the system load is above 5000 MW or the system cost of generation is greater than 50 mils per KW-HR.

Finley et al. [21] discuss an algorithm for the operator initiated dispatch of DLC which is conceptually similar to that of England and Harrison. The algorithm requires the operator to input the amount of load to be shed and the length of the control time. A cycling strategy appropriate for the operator's decision is then chosen from a set of stored strategies and implemented.

The above methods suffer from one or more of the following drawbacks:

- require operator decisions regarding the use of DLC;
- require a pre-evaluation based on a 24-hour load forecast;
- primarily restrict DLC to peak load shaving; and
- place preformulated restrictions on the use of DLC;

In general, they regard DLC as a discretionary resource.

It is contended here that DLC can be classified as a system resource which, within operational constraints, can be dispatched in coordination with conventional generation to meet system load i.e., coordinated with the short term decision process of economic dispatch. The coordination process will depend on the current operational objective of DLC which may change with system conditions. The next chapter discusses, in depth, the resource characterization of DLC since the research work described here aims to investigate the integration and dispatch of DLC in a dynamic mode which will allow the use of DLC for interchangeable operating objectives.

CHAPTER III

CHARACTERIZATION AND CLASSIFICATION OF DLC

Implicit in the concept of dispatching DLC is the idea that DLC is available on a 24 hour basis to the system dispatcher as a resource. This chapter discusses the issues of resource characterization and classification of DLC.

3.1 DIRECT LOAD CONTROL -- RESOURCE CHARACTERIZATION

Resource characterization depends on the context in which the proposed resource would be utilized. Since the context that is being discussed is the use of DLC as a dispatchable resource, the characterization sought is that of a generation resource. In general, any electric system resource is required to fulfill some criteria that would ensure that it can be utilized in an optimum manner. Geier amd Samaniego [23], identify the major requirements of a resource as:

1. Availability in terms of when a resource is available to meet load, the magnitude of the resource and the response time of the resource.
2. Known Costs -- are required of any electric system resource if it is to be scheduled for the most efficient operation of the electric system.

3. Controllability -- so that the resource can be utilized in a manner that conforms to the overall efficient operation of the system.
4. Verifiability -- in order that the operator is assured that the resource is operating as required.
5. Known reliability -- in order to assure consistent and reliable performance and allow proper maintenance scheduling.
6. Scheduling and real time adaptability -- to ensure that the resource is integrable into system operations.
7. Accountability -- so that the resource can be logged into the accounting system.

The following subsections discuss the feasibility of characterizing DLC in the terms defined above. It should be mentioned that not all resource criteria are discussed individually, but the appropriateness of each criterion will be made clear.

3.1.1 Direct Load Control Capacity

Probably, the first question that is asked about a resource is: how much is available? While the question of availability also involves reliability, this section considers the question of DLC capacity.

The capacity available from DLC is governed by:

1. the available rated load under control;
2. customer usage patterns;
3. customer considerations which may affect cycling time lengths;
4. availability of other generation. For example load increases during periods of excess base load generation hardly need to be controlled, except in the case of system emergencies.

The above suggests that DLC capacity is a time varying function. Denoting this function as F(DLC;t), the magnitude and behavior will be governed by the above four factors.

In order to define the function F(DLC;t), it can be split into two components:

- a constant, maximum value C(DLC) which can be termed as the maximum DLC capacity;
- a time varying function that modifies the maximum DLC capacity to yield the actual, realizable DLC capacity at any time, t.

The maximum value of DLC can be defined as:

MAXIMUM DLC CAPACITY is the theoretically maximum load that can be shed and is equal to the rated load under control.

It can be computed quite simply as follows: Let,

the number of devices under control = N
the average rating of each device = R KW

Then,

the maximum DLC capacity, C(DLC) = N * R /1000. MW

The value C(DLC), however, can never be realized in practice. The reason being that at the time that control is initiated or during control, all the devices under control would not have been on or operating at their rated value. The realizable DLC capacity is then, the product of C(DLC) and the time varying function which can be denoted by D(t). Unfortunately, D(t) is not an analytically definable function and has to be determined empirically from load research data.

The requirements from D(t) are that it provide one of the following quantities:

- the probability that a load is on at any given time, t. This probability multiplied by the rating of a device will yield the per device contribution to the system load; or
- the average demand per device of the controlled load type at any given time t.

Load research data provides a means for determining the diversified demand of a load type. This quantity, as will be clarified by its definition, fulfills the second requirement listed above.

DIVERSIFIED DEMAND is the ratio of the observed demand of a load type to the maximum possible demand for that load type.

Mathematically, diversified demand can be defined as:

Div. Demand = Observed Demand/Number of Devices

The definition of diversified demand yields the average load per device at any given time t. Alternatively, if the diversified demand is divided by the rating per device, then, one obtains the probability that a load is on. This is termed the diversity fraction. In either case the time dependent function D(t) is obtained. The product of C(DLC) and D(t) then yield the realizable DLC capacity.

3.1.2 Availability of Direct Load Control

From a capacity point of view, the availability of DLC is defined by the realizable capacity, which, as has been shown earlier, is a time dependent function. From a reliability point of view, the literature reports that DLC has an approximately 99.0% availability [18,24,25]. Moreover, the current technology utilized at the receiver end allows test signals to be sent. These can determine whether a receiver is functioning or not thus facilitating prompt detection and repair of faulty units.

3.1.3 Controllability

Irrespective of the technology used, DLC capacity is organized in blocks with all units in a block being assigned a unique code. The number of blocks and hence the block size is determined by the addressing capability of the signal transmitter. Thus each block of load can be selectively controlled. The resolution of control therefore, depends on the block size. However, within the resolution afforded, the DLC capacity is variably controllable.

3.1.4 Observability

The actual load shed obtained via DLC can be observed if proper monitoring equipment is installed at the station and substation level. An additional advantage of such monitoring equipment would be that it could allow periodic 'nicking' tests to determine the diversified demand of the load under control. A 'nicking' test is a very short duration control signal. The drop in load is then measured against the load on a similar day. Knowing the number of devices that were controlled and the drop in load, the diversified demand could be easily calculated.

3.1.5 Response Rates

All electric system resources, such as conventional generation, have known response rates referred to as 'ramp rates'. For conventional units the ramp rates define the rate at which the units can increase or decrease their generation from the current operating point. At times when the slope of the load curve is very steep, the ramp rates can be crucial in determining whether the current set of online units can in fact change their generation fast enough to the new required operating point. Alternatively, the ramp rates define how long it will take a unit to ramp up or down to its new, desired operating point. The ramp rates, then, in a sense define the 'inertia' of the system to control.

In the case of DLC, the response of receivers to a control signal is immediate. Hence, the response time is related to the speed of propagation of the signals which is of the order of the speed of light. Thus, the ramp rate of DLC can be considered as 100%. This implies that in any time frame, 100% of DLC capacity can be shed or restored.

3.1.6 Costs

Of all the characteristics of DLC, the cost characterization is probably the most complex. It has been indicated in the literature that the primary and in most instances the only cost of DLC is the capital and O&M (operation and maintenance) cost. Since DLC does not consume any fuel, there are no fuel costs associated with it. Thus, the statement would appear to be valid. In fact, if peak load shaving is the only objective of a DLC program, the statement holds for all practical purposes. Since the objective of peak load shaving is the control of peak demand and the reduction and/or deferral of additional planned capacity, the fuel costs are a secondary issue. In addition, DLC scheduled for peak load shaving shifts energy use from the peak to the shoulder peak periods. Since a more economical set of generators is operating at the shoulder peaks, the costs of serving the shifted energy may be lower. Hence, in most cases, peak load shaving leads to some production cost savings.

But, if DLC is to be considered as a system resource which is available for objectives other than peak load shaving, then some cost characterization is necessary.

The costs of DLC arise from a phenomenon known as 'payback'.

PAYBACK is the <u>increase</u> in the diversified demand of a load type, over the normal diversified demand, as a consequence of load control. It arises due to efforts of the controlled load to restore the balance between set control limits, such as thermostat settings, and the controlled variable, such as temperature, which was disturbed during load control.

Loads under DLC are invariably loads which have some 'storage' capacity associated with them so that their control only minimally disrupts the service they provide. For example, comfort conditioning equipment (air conditioners and space heaters) has storage built into it in the form of the thermal inertia of the building and the indoor air mass. But during a control period the value of the variable controlled by the device may deviate beyond its control bandwidth. When supply is restored, the load will try to restore the controlled variable to a value within the bandwidth. This will cause an increase in the diversified demand of the load type due to the following reasons:

- controlling the loads will cause more than the normal number of devices to deviate from their control bandwidth; and

- the length of the control period may cause a significant deviation of the controlled variable from its bandwidth. In this case, the device will have to stay on longer in order to restore the balance. If the diversified demand is visualized as being due to some statistical duty cycle, it is easy to see that a disruption in the duty cycle will cause that cycle to change for some interval along the time line. This phenomenon gives rise to the term 'payback' because the energy that was not supplied during the control period has to be paid back.

The net effect of the payback is to increase the system load for the duration of the payback interval. It is therefore, important to coordinate any use of DLC if a new inadvertent peak is to be avoided. Further, the payback, as mentioned earlier, has an impact on the production costs which depends on the load shape during payback and the set of online generators. It is this dependence of the economic impact of DLC payback on the load shape and online generation that complicates any cost characterization of DLC. It is however, central to the issue of considering DLC as a system resource and integrating it into system operations.

3.2 DIRECT LOAD CONTROL — RESOURCE CLASSIFICATION

The previous section discussed the characterization of DLC based on criteria applied to any electric system resource. Two differences were notable:

1. available DLC capacity is a function of the time-of-day. This can be extended to include variations with the day of the week, seasons and as demographic characteristics change, years. Conventional generation sources have a fixed, known capacity; and
2. the operational costs of DLC are due to payback which is again a time varying function. They are, moreover, dependent on the load shape and the set of online generators. The cost characteristics of conventional generation sources are, on the other hand, clearly and analytically definable through the heat rate curves and unit fuel costs.

Historically, two approaches have been used for the classification of DLC:

1. The more widespread approach has been to treat DLC as 'negative load'. The concept of negative load is very useful in that it solves the problem of treating sources and/or resources that:

- are highly variable and exhibit large fluctuations in their instantaneous values, such as renewables;
- have low operational costs associated with them and so cannot be factored into economically based optimization processes such as economic dispatch; and
- cannot be included in firm capacity since their availability cannot be guaranteed.

The application of the concept of negative load requires that the instantaneous value of the source be subtracted from the system load and conventional generation be dispatched to meet the remaining load.

2. The second approach that has been used more recently [26] and on a limited basis is that of treating DLC as a limited resource similar to pumped storage hydro and scheduling it for maximum benefit -- maximum peak load shaving.

Based on discussions in this and the previous chapter, both the above approaches suffer from the following fallacies:

- the negative load approach depends on the diversified demand to estimate the instantaneous value of DLC that would be available for subtraction from the system load. Contradicting itself however, it does not regard that as being guaranteed or predictable capacity. Further, it will be shown that DLC may not always have a low cost. Thus, the basic premises for treating any resource as negative load are not applicable in the case of DLC.

- the basic premise of the second approach is that DLC has a limited time availability. This, as has been pointed out earlier, is one of the fallacies of DLC. DLC has a time-limited availability and not a limited time availability i.e., the availability of DLC is limited by or determined by the time-of-day that control is exercised but is not limited in its duration (except by operational constraints).
- finally, both the above approaches assume that the optimum utilization of DLC is for peak load shaving

The question then remains: what is the resource classification of DLC? Geier and Samaniego [23], forward the conclusion that DLC is system resource. Since the criteria on which they based their conclusion are ones which are used to judge generation resources, it would be reasonable to assume that they then regard DLC as a generation resource. However, their discussion of the cost characterization of DLC only mentions the need to determine the startup and operating costs of DLC so that "dispatching can be done in the most efficient manner using existing computer programs". As discussed in the previous section, the source of operating costs is the payback phenomenon translated into increased fuel costs. This, as was pointed out earlier, depends on the load shape and the cost characteristics of the online set of generating units. Since this set changes over time, the cost characterization also changes. Thus, for the same load reduction, different payback costs can be incurred depending on the unit commitment. This aspect of DLC costs considerably complicates it's cost characterization. A relatively simple analytical representation of the costs of DLC is difficult to foresee. Hence, it does not seem likely that DLC can be included strictly as a generation resource.

The most logical representation, then appears to be that of a "dispatchable load" . The concept of dispatchable load:

- allows the selective removal of the load from the system load;
- implies that the decision to selectively remove the load is dependent on some optimization process;
- permits the use of DLC for purposes other than peak load shaving by the simple expedient of changing the objective function of the optimization process;
- does not place any ad hoc limitation on the time of use of DLC since the decision to utilize DLC is the reult of an optimization process;
- requires all the criteria of a system resource such as observability, accountability, controllability, reliability and known availability to be satisfied. This

forces the compliance of DLC to the overall requirement of a system resource: it should be adaptable to the changing needs of the system; and

- finally, is not subject to the same cost specification process as generation resources to be included in the dispatch of resources.

In conclusion, then, the concept of "dispatchable load" permits the treatment of DLC as a system resource in its own right and subject to its own limitations and constraints. It also allows a broader view of DLC which permits the investigation of DLC for purposes other than peak load shaving. Finally, it establishes the framework for integrating DLC into system operations.

CHAPTER IV

A NEW APPROACH TO DLC UTILIZATION

This chapter presents the central theses of this dissertation. The previous chapters have attempted to provide a sufficiently detailed discussion of the development of Load Management and Direct Load Control and the state of the art as it exists today, vis-a-vis DLC utilization.

The research presented here is concerned entirely with investigating new methods of DLC utilization. Hence only issues affecting the philosophy of DLC utilization will be discussed. In this respect, the technology issue is not perceived as presenting any insurmounatble problems in the utilization of DLC for any systems operation objective. The state-of-the-art in communications and control technology should provide solutions to any technology barriers. In any event, the current methods of radio, power line carrier or ripple control can provide the means to selectively control DLC. The other main constraint on DLC — customer considerations, will be given due attention later in this chapter.

4.1 ESSENTIAL PROPOSITIONS

In order to develop the hypotheses of this dissertation, three propositions are necessary. These propositions derive from the discussions of the previous chapter but are stated here to clearly set the framework for the hypotheses of this dissertation.

1. Direct Load Control is a dispatchable resource;
2. Utilization of DLC for any system objective will be such as to ensure minimal customer dissatisfaction;
3. Direct Load Control is available to the system dispatcher on a 24 hour basis. This proposition may seem to follow from the classification of DLC as a system resource. However, it should be noted that the fulfillment of the criterion of known availability, for classification as a system resource, only requires a definition of known availability periods. It does not require a 24 hour availability. It is therefore, essential that this proposition be made and justified. The main reason that DLC has not been considered as being actively available on a 24 hour basis is simply that it has not been required to do so. The use of DLC for peak load shaving requires its availability on days when a system peak is expected and not on non-peak days. Customer considerations have been invoked, with some validity, to limit required DLC availability. It is contended here that the fulfillment of the second proposition can justify the use of DLC on a 24 hour basis, if required.

4. The maximum control times and DLC dispatch intervals are of a shorter duration. The major constraints on DLC utilization arise from customer considerations. Long control times are liable to cause customer discomfort and dissatisfaction. They would also prompt customers to possibly deny the utility control over loads during high usage times. Further, long control times are seen to be a factor in customer resistance to frequent load control. However, shorter load control times will improve customer attitudes to load control and grant the utility greater freedom in its utilization of DLC. As an example, it would seem logical that customers would respond more favorably to maximum control times of 30 minutes than to times of 2-4 hours, specially if the second proposition is satisfied.

4.2 HYPOTHESES

The hypotheses of the present research relate to the dispatch of DLC in conjunction with other system resources to satisfy system operation objectives.

The use of DLC has historically been constrained to peak load shaving. Proposals have been made in the literature and summarized in [16] to use DLC for system reserve and emergency system operation. But, in practice, DLC has primarily been limited to peak load shaving.

A novel approach has been proposed in [27] to make controlled load available on a spot pricing basis to member utilities of a power pool so that relatively inexpensive generation from another member can be used to meet the load instead of shedding it. This would improve the overall economics of the pool. While the validity of this approach is not being questioned, the subject lies outside the scope of this dissertation. The research detailed in this dissertation deals implicitly with single systems.

The literature however, does not indicate any LM programs where DLC has been implemented as a dispatchable resource. The idea of DLC as an operator dispatchable system resource has been proposed [20-23], but as yet there are no algorithms in the literature which attempt to effectively integrate DLC into system operations or study the viability of DLC for purposes other than peak load shaving or system reserve. The latter objective too has had limited exposure. England and Harrison [20], discuss the interface between the system operator and DLC dispatch. However:

- the algorithm is still in the development stage;
- the algorithm discussed primarily deals with the human factors aspects of the interface; and
- the paper does not mention the informational criteria on which the operator will be expected to make his decisions

i.e., how will the load and cost impacts made available to the operator be computed.

Finally, the overall scheme proposed is to allow the operator to make the decisions concerning when and how much DLC to dispatch based on load and cost impacts. The scheme necessarily depends on scenario type studies performed on a projected load curve. While this may be a viable scheme, it still classifies as a scheduling approach. Dispatchable system resources such as conventional generation are not scheduled in this manner. It is a hypothesis of this research that DLC can be dispatched online in much the same manner as generation resources. The algorithm should be able to determine the optimum DLC capacity to be dispatched to meet its set objective. This has two advantages:

- the scenario type algorithm proposed in [20] depends on a projected load curve. Deviations from the projected load curve, which could have severe impacts on the scenario analysis, would require a fresh evaluation. This slows down the response to the changing load situation. An online algorithm would be able to react faster and take full advantage of the response times of DLC.
- the algorithm can evaluate the best possible operating mode for DLC and switch modes accordingly.

The second point relates to the next hypothesis of this dissertation.

DLC can operate to fulfill one of several operational objectives. This is evidenced by the multiple uses that have been proposed for DLC, namely peak load shaving, system reserve capacity, regulating margin, emergency load shedding, aiding in gradual load restoral after an emergency, etc. If DLC capacity is available on a 24-hour basis, then it could be used for one objective or another. For example, when it is not required for peak load shaving, it can automatically be included in system reserve capacity. An online DLC dispatch could automatically perform this function. Hence, DLC can be utilized in several alternative 'modes' on the same system.

Finally, this dissertation forwards the hypothesis that DLC can be dispatched for fuel cost minimization -- a function that is also performed by the economic dispatch of conventional generation sources. The implication here is that DLC can be dispatched in conjunction with other generation sources to minimize fuel costs. This adds another dimension to the utilization of DLC.

The literature will show that production cost savings have been one of the objectives of a DLC program. However, these savings are sought as a consequence of peak load shaving. The process of peak load shaving also aims to shift peak hour energy use to the off-peak periods. Usually, the shift is from peak to shoulder peak periods. The reason is that the only way DLC shifts energy is through the payback phenomenon. If sufficient DLC capacity is not available to control the load beyond the shoulder peak period, the payback starts during that period. In any event, if the set of online units operating during the shoulder peak periods has a lower incremental cost then fuel cost savings will be realized. In addition savings on unit startup costs may accrue due to the lower peak load. But, fuel cost minimization is not the main objective. The savings on production costs that may accrue are a useful economic result of the main objective: peak load shaving.

This dissertation proposes fuel cost minimization as one of the objectives of dispatching DLC i.e., as one of the operating modes of DLC. There is no indication in the literature that this possible aspect of of DLC utilization has been investigated before.

Recapitulating, the four propositions under which DLC can be effectively integrated for maximum benefit are:

1. DLC is a dispatchable system resource;
2. DLC will be dispatched in a manner which will ensure minimal customer dissatisfaction; and
3. DLC will be available for dispatch on a 24 hour basis.

4. shorter DLC dispatch and maximum control times to improve DLC dispatch sensitivity to changing system conditions as well as reduce customer resistance to load control.

Under the above conditions, this dissertation offers the following hypotheses:

1. DLC can be most effectively integrated into system operations if the dispatch is online;
2. DLC can be utilized for several different objectives on the same system at different times of the day. Examples are:
   - fuel cost minimization;
   - peak load shaving;
   - system reserve contribution;
   - emergency load shedding;
   - reserve margin capacity; etc.

The above hypotheses, in one respect or the other, imply that:

- DLC is dispatched at regular intervals and not scheduled via a scenario analysis; and
- DLC dispatch is evaluated at regular intervals for the optimum benefit;

The term DYNAMIC DISPATCH OF DLC is forwarded here to encompass this online process of dispatching DLC. Dispatch, because DLC is considered as a selectively controllable system resource and dynamic, because not only is the control of DLC changing in terms of the amount dispatched but the operating objective of DLC is also being evaluated and changed as system needs change.

DYNAMIC DISPATCH OF DLC is the selective control of DLC based on an ongoing or dynamic evaluation of the optimum operating mode for DLC.

The general scenario that is envisaged is as follows:
At intervals of time ΔT evaluations are made of the 'best' operating mode of DLC. At smaller intervals Δt DLC is dispatched to fulfill its current operating objective. The magnitude of Δt would be of the order of a few economic dispatch intervals δT. The DLC dispatch interval is therefore small to allow sensitivity to changes in load and system requirements.

4.3 RESEARCH OBJECTIVE

The present research objective consists, therefore, of the task of proving the above hypotheses. The method adopted is to develop a model of power system operations tasks incorporating the dynamic dispatch of DLC. The successful development of such a model would demonstrate the viability of integrating DLC into system operations and its dispatch as a system resource. The model developed could then be used to investigate the dispatch of DLC for fuel cost minimization. Thus, on a practical note, the objective is to develop a model of power system operations which incorporates the dynamic dispatch of DLC.

4.4 DYNAMIC DISPATCH REQUIREMENTS

The system operations referred to are those performed on a daily basis. The time frame has to be restricted to 24 hours because of the variation of the diversified demand with the day of the week and the season. The sequence of operations in this time frame can be summarized as follows:

1. At the start of the daily operations cycle, the unit commitment is decided for the ensuing 24 hours. Some utilities may use a 48 hour unit commitment, but no loss of generality occurs if a 24-hour unit commitment is assumed. The unit commitment is decided on the basis of forecasted hourly loads, area interchange agreements, system reserve requirements, hydro availability (if applicable) and system security constraints. The objective

is to meet all the above requirements at minimum cost [28-31].

2. During the 24 hour time frame for which the unit commitment was drawn up, more accurate load forecasts are made at periodic intervals.
3. At fixed intervals of length δT (δT being in the range of 2.0 to 10.0 minutes) the available (committed) generation units are dispatched to meet the system load at the minimum cost. This economic dispatch provides the desired loading levels of the committed units for the interval δT.
4. At intermediate intervals δt (of the order of a few seconds) the Automatic Generation Control (AGC) system adjusts the generation to match the load, till the next economic dispatch computation is performed. The AGC is the system which actually implements the results of the economic dispatch. Further, intermediate control is required by the AGC during the economic dispatch interval δT because the load does vary on an instantaneous basis during δT and the equality of system generation and load has to be maintained for secure system operation and frequency maintenance.

The above four steps form a cycle.

In the context of the above description of online system operations, it is necessary that any methodology for the dispatch of DLC:

1. factor the availability of DLC into the unit commitment to obtain the maximum benefit of DLC dispatch. This requirement was shown to be essential in section "Recent Advances in DLC Utilization" on page 27.
2. interface DLC dispatch with the economic dispatch of system generation resources.
3. provide a fast DLC dispatch algorithm to satisfy the interface requirement.
4. take cognizance of any operational constraints on the utilization of DLC.

Satisfaction of the requirements will allow DLC to be integrated into the process of utilizing system resources for the optimum operation of the power system. In order to allow the dynamic dispatch of DLC, the additional requirements are that:

1. a cost characterization be provided for DLC; and
2. methods for the evaluation and choice of DLC objectives be incorporated.

The ensuing chapters discuss the model development.

CHAPTER V

UNIT COMMITMENT AND ECONOMIC DISPATCH

The principal task in integrating DLC dispatch into system operations is the development of an appropriate model of DLC which can be incorporated into or interfaced with the unit commitment and economic diaptch (ED) functions. The principal development of the model, to be detailed in the next chapter, is, however, focussed on the interface of DLC dispatch with the economic dispatch. The unit commitment process is performed once in 24 or 48 hours. The interface of DLC dispatch with unit commitment can be obtained without explicitly including DLC into the unit commitment (the exception is when DLC capacity is to be used for system reserves). The more urgent need is for integrating or interfacing the dispatch of DLC with the economic dispatch process.

This chapter discusses the unit commitment program used in the overall model developed for the dynamic dispatch of DLC. It also discusses the derivation of a fast, closed form solution to the constrained economic dispatch problem. The need for this derivation will be discussed and clarified in the next chapter. Suffice it to say here that, it is required for the cost characterization of DLC.

5.1 UNIT COMMITMENT

The function of unit commitment is to provide an hourly schedule of available online units for a 24-48 hour period. Unit commitment is a required function because:

- all dispatchable and most peaking units have start-up times which determine how long it takes the unit before it can be expected to be online and ready to serve the load; and
- all units have maximum up-time and minimum down-time constraints which have to be observed.

Thus, the constraints on the units have to be maintained while ensuring that at any hour of the day there is sufficient online capacity to:

1. meet the expected load plus losses;
2. satisfy the system reserve requirements; and
3. provide a sufficient regulating margin;

When all the above requirements are placed within the unit constraints, it is evident that a scheduling function is required which will coordinate unit startups and shutdowns in a manner which meets all the requirements and satisfies all the constraints in the most economical manner. This is the function of unit commitment.

Several algorithms have been discussed in the literature for thermal and hydrothermal unit commitment. References [28-31] discuss some representative approaches to the problem.

The basic single area unit commitment problem requires that:

$$N_{max} \geq L + X + S_r$$

$$N_{min} \leq L + X$$

where

N_{max} = sum of maximum generator capacities

N_{min} = sum of minimum generator capacities

L = real system load plus losses

X = net area power interchange

S_r = spinning reserve requirement

[29-31] discuss algorithms utilizing dynamic programming to select the least cost generator combination which will meet the above constraints. They differ basicaaly in the methods employed for reducing the feasible set of solutions. Shoults, et al., [28], present a priority based approach where gener-

ators are prioritized based on their operating costs at some fraction of their capacity. Then depending on the hourly capacity requirement, generators are committed or decommitted in the inverse order of their priority. From [30] and personal communication, it appears that a priority method is quite adequate. Hence, in the development of a model for integrating the dispatch of DLC, a priority based unit commitment program was used. The specific program used is the "Unit Commitment and Production Costing Program (GPUC)" developed by Boeing Computer Services for the Electric Power Research Institute (EPRI), [32,33]. A brief discussion of the program is given below, details can be found in [32,33].

5.1.1 EPRI's Unit Commitment Program

The program is designed to analyze the operations of generation and transmission systems consisting primarily of thermal dispatchable generating units and with possible additional capacity in the form of non-dispatchable combustion turbines, pumped storage hydro and hydro units. Its main function is to schedule generation and interchange on an hourly basis for periods ranging upto a week. Given a profile of the expected integrated hourly loads, a description of the generation system and a set of scheduling constraints, the program generates a unit commitment schedule such that the expected system load is met at suitably low cost without violating any of the numerous operating constraints. Once a schedule has been determined, the total production costs (fuel plus any start-up costs) are estimated. The program also monitors fuel consumption by generating unit, station and fuel type and compares this usage with any fuel usage constraints.

The following subsections highlight the scheduling process used by the program.

5.1.1.1 Input Data

The input data required by GPUC consists of:

- processing options such as spinning reserve requirements, priority list generation options, load specification option, etc.
- unit identification, cost and performance data such as unit id, heat rate curve, startup time, minimum downtime, maximum up time, boiler cool down time, etc.
- load models for a week. The load for each 24 hour period is assumed to start at 8:00 a.m. and the loads specified have to be hourly integrated loads.
- manual scheduling data for hydro, pumped hydro and thermal units and interchange.
- transmission loss data appropriate to the option exercised. GPUC allows three options for this purpose:

- ignore transmission losses;
- compute transmission losses using the B-constants provided; or
- use a quadratic function of the load for computing losses.

5.1.1.2 Priority List Generation

Commitment of dispatchable units proceeds on the basis of a single priority list which may be provided by the user or generated by GPUC. The priority list generation is based on the operating cost of a unit at a user specified fraction of the generator set capacity. Units are removed from the set as their priorities are assigned. The process stops when the capacity of the reduced generator set is a specified fraction of the total generation capacity. The units remaining in the set are then assigned priorities based on the relative operating costs at their maximum capacity.

5.1.1.3 Hourly Generation Maximum Capacity

This quantity is central to the scheduling of non-dispatchable capacity. It is determined as the summation of:

1. the maximum capacities of all online dispatchable units

2. the maximum capacities of any combustion turbines which are user scheduled to be online; and
3. any user scheduled interchange and hydro capacity.

5.1.1.4 Reserve capacity From Non-Dispatchable Sources

All non-dispatchable sources contribute to two types of reserves (ten minute and spinning reserves) as a function of the unit type and status during the hour. The reserve capacity from non-dispatchable sources is required in order to compute:

1. the ten minute and spinning reserve capacity from such sources; and
2. an estimate of the additional reserve capacity from the dispatchable sources.

5.1.1.5 Precommitment of Peaking Units

The purpose of this process is to schedule combustion turbines and interchange on an hourly basis such that, for each hour:

1. there is sufficient online generating capacity and interchange to meet the expected load plus losses;

2. if possible there is sufficient capacity and interchange to meet the load plus losses and reserve requirements; and
3. if desired by the user, peaking units are scheduled to displace the more expensive thermal units.

For each hour, two inflated estimates of required capacity are made:

1. an estimate of load plus losses computed by multiplying the hourly load by a user specified factor. This estimate is denoted as TLOAD1.
2. TLOAD1 is further inflated to TLOAD2 by the addition of
   - a user specified non-negative factor called ADDPK which can cause GPUC to schedule combustion turbines to displace the more expensive dispatchable units; and
   - a measure of potential spinning reserve deficit for the hour.

Peaking capacity or interchange is then scheduled according to whether GMAX, the hourly maximum dispatchable capacity, lies above, below or between TLOAD2 and TLOAD1.

5.1.1.6 Hourly Regulation Requirement

GPUC does not require ramp rate inputs for the generating units. However, it attempts to provide sufficient regulating margin during periods of load pickup. The policy followed in the program is, that 'in the average system, bringing additional capacity online at a given hour, equal to the load pickup the next hour, should ensure a system response rate sufficient to meet the increased demand'. The regulation requirement for hour h is found by calculating the increase in the dispatchable load, DELPWR.

DELPWR = (FL(h+1) - FL(h))*GENMIN + PNON(h) - PNON(h+1) (3)

and

DISREG(h) = REGFAC*DELPWR, for DELPWR > 0 (4)

or

DISREG(h) = 0 for DELPWR < 0

where

FL(I) = the integrated MW load for hour I

PNON(I) = the total non-dispatchable generation for hour I

DISREG(I) = regulation requirement for hour I

REGFAC = user input regulation factor.

5.1.1.7 Dispatchable Unit Commitment Schedule

The dispatchable unit commitment schedule is basically arrived at by considering a shutdown decision for each unit on an hour by hour basis. The default status of all dispatchable units is the Economic Run status. Then at every hour a decision is made whether to shut down a unit or not. The decision is first based on a comparison of GMAX versus the load, loss, reserve and regulation requirement for each hour that the unit would be shutdown, upto its minimum down time. If this comparison allows the unit to be shut down, an economic comparison is made. This done by prorating the unit's startup cost over the shutdown period and the up-time. A comparison of an hour's fuel costs plus the hour's prorated value of start-up costs will allow the determination of the most economical set of online generators.

Once the schedule of dispatchable and non-dispatchable units has been determined, an economic dispatch is done and production costs are calculated and fuel usage is logged.

5.1.1.8 Interfacing DLC to the Unit Commitment

From the point of view of interfacing DLC to the unit commitment process, an offline estimation of the impact of DLC dispatch can be used to input a modified load profile to the program. This should be able to provide a unit commitment schedule which reflects the load shape impacts of DLC. If DLC is to be used solely for system reserve, then, it can be treated as negative load and used to modify the load shape accordingly. This will serve the purpose of lowering system reserve and regulation requirements, thus leading to an appropriately modified unit commitment which reflects the presence of DLC. [In this instance, since DLC is being used primarily for system reserve, which is a static utilization of DLC, treating it as negative load would be an appropriate and convenient approach.] However, if DLC is to be dispatched, the above approach cannot be used because it does not reflect the payback effects due to load control. Moreover, DLC cannot be represented as a generator of limited availability since the cost of DLC is dependent on the set of online conventional generators. Thus, for the dynamic dispatch of DLC, an interface with the unit commitment process poses a number of problems.

The approach adopted in this dissertation is to perform an offline simulation of the dynamic dispatch of DLC to obtain a modified load curve. This is then input to GPUC to obtain a new unit commitment.

5.2 THE ECONOMIC DISPATCH PROBLEM

The classic problem of economic dispatch is the calculation of generator outputs from online units to satisfy the system load plus losses at the minimum cost. If the fuel cost of each generator is generalized as $C_i(P_i)$, P_i being the power output of the generator, then the economic dispatch problem can be stated as

$$\text{Minimize COST} = \Sigma\ C_i\ (P_i) \tag{5}$$
$$\text{such that } \Sigma\ P_i - \text{sytem load} - \text{losses} = 0$$

Knowing the cost characteristics of the generating units, the above can be solved as an unconstrained minimization problem using the Lagrange multiplier method, leading to the well known λ-dispatch. λ is then the system incremental cost or the cost of generating one additional MW. The λ-dispatch leads to the principle that the most economic solution to the problem is one where all generators are operating at equal incremental cost, so that the cost of generating an additional MW is the same for all units.

The algorithm for the λ-dispatch is usually an iterative one since in general the cost curves of the generating units can be polynomials of any degree. Ramanathan, [34], develops a closed form solution for the limitedly constrained economic dispatch problem defined above. However, [34] assumes that the generator cost curves are available in the form:

$$P_i = \alpha_i + \beta_i(IC_i) + \gamma_i(IC_i^2) \tag{6}$$

where

(IC_i) = incremental cost of generator i ($/MW-HR)

While the method developed in [34] is applicable to cost curves of any degree, [35-37] indicate that:

- a quadratic polynomial representation of the cost curves is usually considered adequate; and
- the cost curves are usually of the form:

$$C(P) = \alpha + \beta(P) + \gamma(P)^2 \tag{7}$$

i.e. the curves are a function of the generator output. If the cost curves are quadratic, it is possible to convert them to the form of Equation 6 on page 71. If the cost curves are assumed to be quadratic, then it is not necessary to convert them to the form of Equation 6 on page 71. The closed form solution to the economic dispatch can be obtained without the conversion.

The derivation of the closed form solution is presented below:

Given quadratic cost curves of the form:

$$F_i(P_i) = \alpha_i + \beta_i P_i + \gamma_i P_i^2 \tag{8}$$

The limitedly constrained economic problem can be stated as follows:

$$\text{Min.} \quad C = \sum_{i=1}^{N} F_i(P_i) \tag{9}$$

$$\text{such that} \quad \sum_{i=1}^{N} P_i - P_d - P_l = 0$$

N = number of online generators.

P_d = real system load in MW.

P_l = real system losses in MW.

This can now be converted into an unconstrained minimization problem using a Lagrange multiplier:

$$\text{Min.} \quad C = \sum_{i=1}^{N} F_i(P_i) - \lambda \left[\sum_{i=1}^{N} P_i - P_d - P_l \right] \tag{10}$$

Application of the Kuhn-Tucker theorem yields the condition that:

$$\delta C/\delta P_i = \beta_i + 2\gamma_i P_i = \lambda\, (1 - \delta P_l/\delta P_i) \tag{11}$$

Then

$$P_i = \lambda\, (1 - ITL_i)/2\gamma_i - \beta_i/2\gamma_i \tag{12}$$

ITL_i = incremental transmission losses, $\delta P_l/\delta P_i$

Substituting into the power balance equation (the constraint on the minimization problem):

$$\lambda \sum_{i=1}^{N} (1 - ITL_i)/2\gamma_i \quad - \quad \sum_{i=1}^{N} \beta_i/2\gamma_i + P_d + P_l = 0 \qquad (13)$$

Equation 13 is a constant coefficient equation and can be solved for λ, the equal incremental cost at which all generators should operate.

The above formulation and solution only account for the power balance equation. There are four other constraints imposed on the economic dispatch by reliability and reserve requirements and the generator capacity and ramping limitations. Thus, the complete set of constraints on the economic dispatch consists of:

1. the power balance constraint;
2. generator capacity limits;
3. generator ramping limits in the raise and lower directions;
4. system spinning reserve requirements; and
5. ten minute reserve requirements.

References [38-40] and references cited therein, discuss linear programming techniques for solving the fully constrained economic dispatch problem. Waight et al. [38] also refers to the conventional two pass λ dispatch which checks for capacity violations in the second pass. However, ramp rates are not accounted for in this method. Stadlin, [40], discusses a method for the economic allocation of the reserve margin over the online generator set. This is done by extending the concept of incremental costs to that of regulating margin costs. This leads to a two λ dispatch formulation of the problem which is solved iteratively. Ramp rates and spinning reserves are not accounted for in this formulation. Happ, [35], refers to security function methods for solving the security constrained economic dispatch. These methods also, are iterative in nature.

Since, as stated earlier, a fast economic dispatch method is required for the cost characterization of DLC, the iterative methods would not be appropriate. Therefore, a new closed form solution of the economic dispatch problem is derived here.

5.2.1 A Closed Form Economic Dispatch Solution

The closed form solution derived follows the same principal logic as the closed form solution derived earlier. The point of departure lies in the inclusion of the generator capacity and ramp rate limits in the solution methodology. The assumptions under which the solution is derived are:

1. generator costs are characterized by quadratic polynomials which are functions of the generator output; and
2. the reserve and regulating margin constraints are excluded on the basis that they are accounted for in the unit commitment.

Ramp Rates.: The ramp rates of a generator impose limits on how much the output of the generator can change from its present output level. Given that a generator is operating at an output level P_i, the ramp rates impose the constraints that:

$$+ \Delta P_i = k_{1i} P_i \ \Delta t \tag{14}$$
$$- \Delta P_i = k_{2i} P_i \ \Delta t \tag{15}$$

where

k_{1i} = raise ramp rate in percent output/min
k_{2i} = lower ramp rate in percent output/min
Δt = time available for changing the output (usually the economic dispatch interval.

Capacity Limits: The capacity limits on each generator are of the type:

$$P_{min,i} \leq P_i \leq P_{max,i}$$

The economic dispatch is performed based on a forecast of load δT minutes in the future. Then, given that the generators are operating at levels P_i, the ramp rate and capacity limits can be combined as follows:

For the next load forecast, the outputs of the generators can only vary between modified maximum and minimum limits defined by:

$$P'_{max,i} = \text{Min. } [\ P_{max,i}\ , (1 + k_{1i}\Delta t)] \tag{16}$$

$$P'_{min,i} = \text{Max. } [\ P_{min,i}\ , (1 - k_{2i}\Delta t)] \tag{17}$$

To yield the constraint:

$$P'_{min,i} \leq P_i \leq P'_{max,i} \tag{18}$$

Now, given the modified limits $P'_{max,i}$ and $P'_{min,i}$, the new generator output will lie within these limits. Specifically,

$$\begin{aligned} P_{op,i} &= P'_{min,i} + x_i(P'_{max,i} - P'_{min,i}) \\ &= (1 - x_i)\ P'_{min,i} + x_i P'_{max,i} \end{aligned} \tag{19}$$

Substituting the above expression into the quadratic expression for the generator cost and simplifying:

$$F(P_{op,i}) = (\alpha_i + \beta_i P'_{min,i} + \gamma_i P'^{2}_{min,i} + 2\gamma_i P'_{min,i} P'_{max,i}) \tag{20}$$

$$+ [\beta_i \Delta MW_i - 2\gamma_i P'^2_{min,i} - 2\gamma_i P'_{min,i} P'_{max,i}]\, x_i$$
$$+ \gamma_i (P'^2_{max,i} + P'^2_{min,i})\, x_i^2$$
$$= \bar{\alpha}_i + \bar{\beta}_i x_i + \bar{\gamma}_i x_i{}^2$$

$\bar{\alpha}_i$, $\bar{\beta}_i$, $\bar{\gamma}_i$ are in (dollars/hr.)

$\Delta MW_i = P'_{max,i} - P'_{min,i}$

λ' = equivalent equal incremental cost.

The cost equation has now been transformed to account for the capacity and ramp rate limits. The economic dispatch problem can now be formulated in the usual way.

$$\text{Min. } C = \sum_{i=1}^{N} (\bar{\alpha}_i + \bar{\beta}_i x_i + \bar{\gamma}_i x_i^2)$$
$$- \lambda' \left[\sum_{i=1}^{N} (P'_{min,i} + x_i \Delta MW_i) - P_d \right]$$

Then, applying the Kuhn-Tucker theorem:

$$\delta C/\delta x_i = \bar{\beta}_i + 2\bar{\gamma}_i x_i - \lambda' \Delta MW_i = 0 \tag{21}$$

$$\delta C/\delta \lambda' = \sum_{i=1}^{N} (P'_{min,i} + x_i \Delta MW_i) - P_d = 0 \tag{22}$$

The above equations imply that all generators have to operate at x_i such that λ' is the same for all units. This result is analogous to the conventional equal incremental cost criterion. The modified criterion can be justified as follows:

1. the cost of operating the generators at $P'_{min,i}$ is reflected in the modified cost coefficients.
2. from Equation 21 on page 78 we obtain:

$$x_i = \lambda' \quad \Delta\ MW_i\ 1/2\bar{\gamma}_i\ -\ \bar{\beta}_i/2\bar{\gamma}_i \tag{23}$$

Since, x_i and $\bar{\beta}_i\ /\bar{\gamma}_i$ are non-dimensional, the units for λ' are seen to be (\$/MW-HR). Thus, the set of equations, Equation 21 and Equation 22 are seen to be a modified equal incremental cost criterion operating on the x_i Substituting Equation 23 into Equation 22 yields:

$$\lambda' \sum_{i=1}^{N} \Delta MW_i^{\,2}/\ 2\bar{\gamma}_i - \{\sum_{i=1}^{N} \Delta MW_i\bar{\beta}_i/2\bar{\gamma}_i + P_d - \sum_{i=1}^{N} P'_{min,i}\} = 0 \tag{24}$$

Equation 24 can then be solved for λ'. Once λ' is known, the x_i and P_i can be calculated for all i.

This, then, is the derivation of a closed form λ dispatch incorporating the generator capacity and ramp rate limitations and satisfying the power balance equation. This form of the economic dispatch will be implemented in the overall model of power systems operations that will be developed for dispatching DLC. In addition, the concepts of the above closed form solution will also be used for deriving a closed form expression for the cost characterization of DLC.

CHAPTER VI

MODELLING DISPATCHABLE DIRECT LOAD CONTROL

The DLC model required is that of a dispatchable system resource, clearly defining available capacity, reliability, response rates, costs and other operational characteristics. The basic framework for an appropriate DLC model had been established in Chapter III. In the interests of continuity and completeness, some of the material will be reviewed here. But the overall emphasis in this chapter is on deriving an expression for the operational costs and savings due to DLC.

The requirements for any resource to be classified as a system resource, as opposed to negative load, were that the resource:

1. have known and predictable availability and capacity;
2. have definable response rates;
3. be accountable in the system;
4. be controllable and observable; and
5. have definable costs;

In considering DLC as a dispatchable system resource, it was shown that:

- The maximum capacity of DLC could be defined as the product of the number of devices of each load type under control and the average rating of a device of that load type.
- the realizable DLC capacity was a time varying function, D(t), which could be obtained from load research data in the form of diversified demand of each load type under control.
- for dispatchable purposes, the response rate of DLC is instantaneous. The time delay involved in the reception of the control signal by the receivers at the customer load site and the load shedding or restoration is insignificant.
- DLC, by reason of being organized in individually controllable blocks satisfies the controllability criterion.
- observability, it was pointed out, is achieved through appropriate station and substation metering equipment, which, in turn, can be employed for verifying realizable DLC capacity.

Thus, DLC was shown to satisfy most of the requirements of a dispatchable system resource. The only requirement that was postulated to be definable but not discussed in specific terms was the cost characterization of DLC. This chapter, as mentioned earlier, will derive an expression for determining the costs or savings accruing from DLC dispatch.

6.1 DLC CONSTRAINTS

The classification of DLC as a dispatchable system resource of the form of 'dispatchable load' and the subsequent postulation of the hypotheses of this dissertation was based on considering DLC as being available to the system dispatcher on a 24 hour basis. However, once DLC dispatch is initiated, constraints on its use, arising from customer considerations have to be observed. In fact, one of the propositions underlying the hypotheses stated in Chapter IV was that customer discomfort arising from DLC utilization be minimized. It is logical, then that any model of DLC or algorithm for dispatching DLC incorporate these constraints.

DLC exercises control over customer loads to satisfy utility objectives of efficient, reliable and economic system operation without disrupting, as far as possible, customer schedules or lifestyles. Consequently, the loads controlled are those that have some inherent storage. However, a consequence of load control is the payback phenomenon discussed earlier. Apart from the load shape and economic impacts of DLC, the causes of payback provide a guide to the operational constraints of DLC which would ensure minimal customer discomfort or dissatisfaction.

Load control disrupts the normal duty cycle of the load (reflected in the diversified demand) and forces a new duty cycle. This interruption in the natural diversity of the load, if continued, will cause a degradation in the service provided by the load, such as loss of hot water supply, increase in room temperatures, etc. Hence, there has to be an upper limit on the control time. This implies that any block of DLC can be dispatched for no longer than than this upper limit. Once the upper limit on the control time has been reached, the loads in that block have to be allowed to recover i.e. re-establish their internal balance and their natural diversity. This, then implies a minimum on-time constraint which has to be satisfied to allow the load sufficient time to recover. The satisfaction of these two constraints — maximum control time and minimum on time will ensure customer satisfaction.

An analogy can be drawn from conventional generation sources which have maximum up-time and minimum down-time constraints associated with them. The maximum control time constraint, then, represents the maximum up-time allowable each time DLC is dispatched. The minimum down-time is represented by the minimum on time constraint.

6.2 DETERMINING OPERATIONAL CONSTRAINTS ON DLC

The maximum up-time constraint on DLC is determined by:

- The characteristics of the loads being controlled, which determines the inherent storage incorporated in them;
- time-of-day that control is exercised — determining how frequently the services performed by the load are utilized. This has an impact on how fast the inherent storage will be depleted; and
- customer perceptions of discomfort thresholds.

The literature surveyed (and cited earlier) indicated that, in general the maximum control times are of the order of 2-3 hours for water heaters and 7-1/2 to 15 minutes for air conditioners. The disparity in control times is due, not only to the differences in the load types, but also to the time-of-day that control has been exercised. The primary use of DLC for peak shaving has dictated control during peak hours. At these times, the diversified demand of water heaters has been low, indicating low usage. Hence water heater control can be exercised for longer periods. Air conditioner diversified demand is high during peak periods (in fact it is a strong contributor to the system peak). Therefore, even though higher load reductions can be obtained from air conditioner control, its high usage dictates smaller control times.

It is expected however, that the dynamic dispatch of DLC will require a revision of these control times, specially for water heaters. As water heater control is exercised during periods of high diversified demand customer considerations will dictate a smaller control period to ensure customer satisfaction. In addition, shorter control times will inherently:

- cause smaller paybacks;
- minimize customer discomfort. If the disruption in the supply to the load is for a shorter period, there is less probability of its service being interrupted.

The minimum down-time constraint is determined by the magnitude and length of the payback. This in turn is dependent on the load characteristics, the control time and the time-of-day that control is exercised. Models of payback have been developed by various researchers using regression and correlation analyses on load research data and computer simulations of physically based models of the loads [19,42-46]. These models are well defined functions which can be used to yield statistically accurate estimates of payback magnitude and length.

6.3 COST CHARACTERIZATION OF DLC

The cost characterization of DLC actually consists of determining:

1. the savings in fuel costs during the control period due to the lower system load being served; and
2. the increase in fuel costs during the payback period due to the higher system load encountered.

The net fuel cost or saving due to DLC is then the difference of the two quantities. In the ensuing discussion, only the term costs will be used, with the understanding that negative costs imply savings.

DLC COSTS can be defined as the net difference of the increased fuel costs incurred by the utility during the payback period and the fuel cost savings during the control period.

The implementation of the above definition, then, requires an evaluation of the fuel costs with and without DLC over a period of time equal to the control period plus the payback period. The fuel costs, in turn, are determined by the economic dispatch. This implies that a number a economic dispatch calculations, for the two scenarios, have to be performed every time a DLC dispatch decision has to be made. The computational burden of such a calculation can be quite high. For a control interval of one hour and an expected payback period of one hour, too, the number of economic dispatch calculations required, for an economic dispatch interval of 10 minutes, is 24. Superimposed on this computational requirement is the constraint that the above computations be performed in a time suitable for online implementation. It is obvious, then, that either:

- the computational burden be reduced; or
- the speed of the computation be extremely fast.

In the DLC cost determination algorithm that is developed here, attention is focussed on the second alternative. Some reduction in the computational burden is also achieved due to the approach adopted.

The above discussion of the cost definition of DLC and its computational requirements suggests a multistage organization of the problem for the two cases. At each stage, an economic dispatch is performed and fuel costs obtained. The stage wise organization of the problem, in turn, suggests a dynamic programming formulation. The next section, therefore, discusses some dynamic programming concepts. The cost derivation will be resumed after that.

6.3.1 Dynamic Programming Concepts

Dynamic programming, rather than being an algorithm, is a conceptual framework for the solution of complex optimization problems. Optimization implies finding a solution that in some way is the best solution to the problem. The dynamic programming concept is based on Bellman's principle of optimality [47], which states that:

> An optimal policy has the property that whatever the initial state and final decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision.

From Nemhauser [48]:

> A proof of the priciple of optimality (by contradiction) simply states that if the remaining decisions were not optimal, then the whole policy could not be optimal.

Bellman's principle of optimality is most suitable to multistage decision processes where an optimal decision has to be made at each stage of the process to obtain an overall optimal decision.

While the derivation of the dynamic programming concept and an application algorithm has been developed by several authors [47-50], a brief discussion, derived from Nemhauser is given below.

Each stage of a multistage process can be characterized in terms of the following factors:

1. the set of inputs X which describes the state of the system at the beginning of the stage;
2. the set of outputs Y which desribes the state of the system at the end of the state;
3. The decision variables D which control the operation of the stage;
4. The stage return, r, that measures the utility of the decisions and is a function of the inputs, decisions and outputs:

   $$r = r(D,X,Y)$$

5. the stage transformation, t, which expresses each output from the stage as a function of the input variables, X and the decisions, D.

   $$Y = t(X,D)$$

For the single stage characterized above and pictorially shown in Figure 3(a):

$$Y = t(X,D) \tag{25}$$

$$\text{and } r = r(X,D,Y)$$

Substituting the functional dependence of Y into the function for the stage return:

$$r = r(X,D,t(X,D)) \tag{26}$$

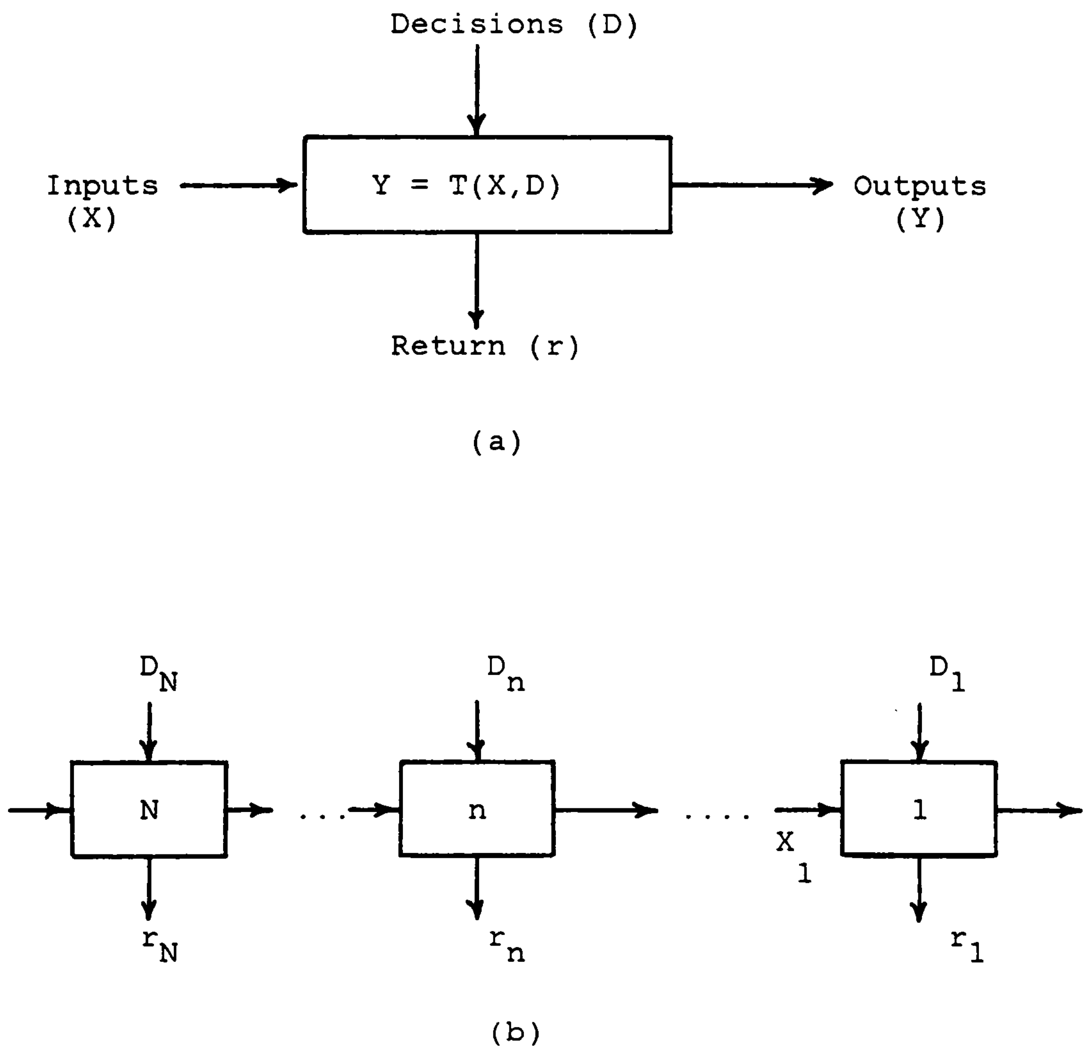

Figure 3. Dynamic Programming Framework

The above equation implies that the stage return is a function of the independent variables D, and the input state of the system only. The one stage initial state optimization problem is to find the maximum stage return as a function of the input state. Denoting f(X) as the optimal return and D^* as the optimal decision policy:

$$f(X) = r(X, D(X)) = r(X, D^*) \tag{27}$$
$$= \max_{D} r(X, D)$$

Extending the above process to serial multistage systems yields the recursive equations that form the essential applications form of the dynamic programming concept. A serial multistage system, shown in Figure 3(b) consists of a series of single stage processes connected such that the output of one stage is the input to the next stage. For the general stage n, (n=1,2,....,N) of an N-stage system, the stage transformation is:

$$X_{n-1} = t_n(X_n D_n) \tag{28}$$

and the stage return is:

$$r_n = r_n(X_n D_n) \tag{29}$$

No limitations are placed on the form of the functions r_n and t_n, but the structure of the serial multistage process implies that:

- X_n depends only on the decisions made prior to stage n, i.e.

  $$\begin{aligned} X_n &= t_{n+1}(X_{n+1}, D_{n+1}) \\ &= t_{n+1}(t_{n+2}(X_{n+2}, D_{n+2}), D_{n+1}) \\ &= \ldots = t_{n+1}(X_n, D_N, \ldots\ldots, D_{n+1}) \end{aligned}$$

  It then follows that the return from stage n depends only on the decisions $(D_n, D_{n+1}, \ldots, D_N)$ and X_n

  $$\begin{aligned} r_n &= r_n(X_n, D_n) \\ &= r_n(t_{n+1}(X_n, D_N, \ldots, D_{n+1}), D_n) \\ &= r_n(X_n, D_N, \ldots., D_n) \end{aligned}$$

- The total return R_N from stages 1 to N is some function of the individual stage returns:

  $$R_N(X_N, \ldots, X_1, D_N, \ldots, D_1) = g[r_N(X_N, D_N), \ldots, r_1(X_1, D_1)]$$

However, $(X_{N-1},\ldots,X_1)$ can be eliminated from the individual stage returns and consequently from the total return, leading to the alternate expression for R_N as:

$$R_N(X_N,D_N,\ldots,D_1) = g[r_N(X_N,D_N),r_{N-1}(X_N,D_N,D_{N-1}),\ldots,r_1(X_N,D_N,\ldots,D_1)] \tag{30}$$

The N-stage initial state optimization problem is to maximize the N-stage return R_N over the variables $D_1,\ldots,D_N$; that is to find the optimal return as the function of the initial state X_N. Denoting $f_N(X_N)$ as the maximum N-stage return, and $D_n{}^* = D_n(X_N)$, $X_n{}^* = t_n(X_N)$ as the optimal decisions and states, the following expression is obtained for $f_N(X_N)$,

$$\begin{aligned} f_N(X_N) &= g[r_N(X_N,D_N^*),r_{N-1}(X_{N-1},D_{N-1}^*),\ldots,r_1(X_1,D_1^*)] \\ &= \max_{D_N,\ldots,D_1} g[r_N(X_N,D_N),\ r_{N-1}(X_{N-1},D_{N-1}),\ \ldots,r_1(X_1,D_1)] \end{aligned} \tag{31}$$

subject to $X_{n-1} = t_n(X_n,D_n)$, $n=1,\ldots,N$

This formulation contains N decision variables, N state variables and N constraints, if there is one decision variable and one state variable at each stage. However, the above formulation can be transformed into N problems, each containing one decision and one state variable. The requirements that are sufficient for the decomposition are that the problem possess:

1. Separability. If:

$$g[r_N(X_N,D_N),\ldots,r_1(X_1,D_1)]$$
$$= g_1[r_N(X_N,D_N),\ g_2(r_{N-1}(X_{N-1},D_{N-1}),\ \ldots,r_1(X_1,D_1))]$$

where g_1 and g_2 are real valued functions, then the problem is separable.

2. Monotonicity. If g_1 is a monotonically non-decreasing function of g_2 for every r_N, then the problem satisfies the monotonocity requirement.

In the event that the problem satisfies the above two requirements, it can be decomposed as follows:

$$\max_{D_N,\ldots,D_1} g[r_N(X_N,D_N),\ r_{N-1}(X_{N-1},D_{N-1}),\ \ldots,r_1(X_1,D_1)] \tag{32}$$
$$= \max_{D_N} g_1[r_N(X_N,D_N),\ \max_{D_{N-1}..D_1} g_2(r_{N-1}(X_{N-1},D_{N-1}),\ldots,r_1(X_1,D_1))]$$

Finally, it is stated here without proof that problems with additive stage returns, i.e.

$$R_N = r_N(X_N,D_N) + r_{N-1}(X_{N-1},D_{N-1}) + \ldots + r_1(X_1,D_1) \tag{33}$$

can always be decomposed.

Then, a problem that can be decomposed into the form of Equation 32 can be solved by the following recursive procedure:

$$f_n(X_n,D_n) = \text{optimal return from stage } n \text{ , } n= 1,..,N \qquad (34)$$
$$= \max_{D_n} Q_n(X_n,D_n)$$

$$Q_n(X_n,D_n) = r_n(X_n,D_n), \qquad n=1 \qquad (35)$$
$$= r_n(X_n,D_n) \text{ o } f_{n-1}(t_n(X_n,D_n)) \text{ , } n=2,....,N$$

where

o = decomposition operator (additive, multiplicative, etc.)

Before concluding this section it should be noted that the above procedure can be used for both, forward or backward recursion by a simple redefinition of inputs and outputs

6.3.2 Operational Costs/Savings From DLC

With the dynamic programming background of the last section, a closed form solution in terms of the cost characteristics of the online generators will be derived.

Consider the three stage problem shown in Figure 4. The objective is to determine a least cost solution to the problem of serving the system load at each of the stages subject to the power balance and machine constraints. Thus an economic dispatch has to be done at each stage.

At any stage, n:

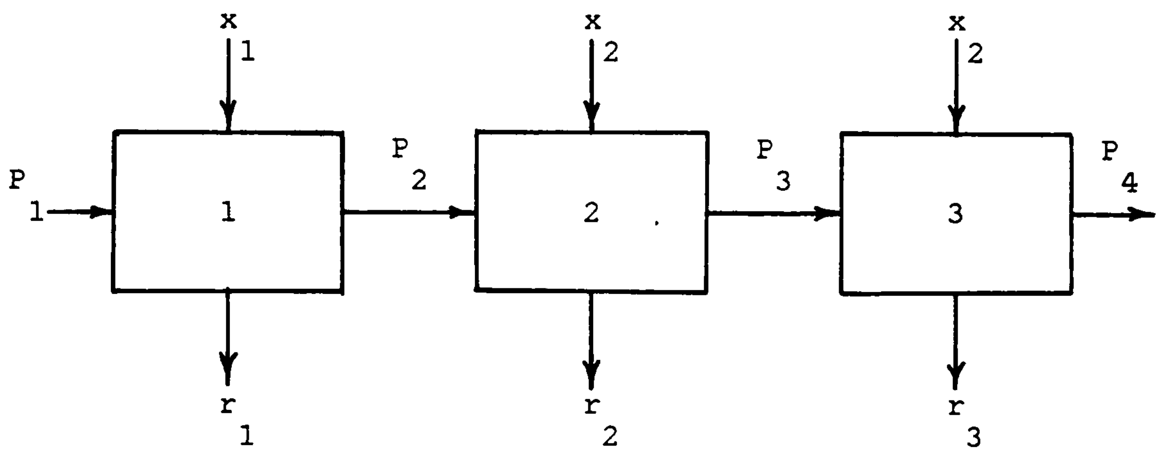

Figure 4. Multistage DLC Cost Determination

1. the input state of the system is described by the vector of generator outputs, $\underline{P}_n$.
2. the decision variables are the set or vector of fractions $\underline{x}_n$ of the economic dispatch solution, which will determine the change in the output of each generator.
3. the constraint is the power balance equation.
4. the output consists of the vector of new generator outputs, $\underline{P}_{n+1}$
5. the return from each stage is the minimum fuel cost.

Dropping the vector notation, the stage transformation is given by:

$$P_{n+1,1} = P_n(1-LRR_i) + (x_{n,i}P_{n,i}SRR_i) \qquad (36)$$

where

LRR_i = lower ramp rate of unit i

SRR_i =sum of thge raise and lower ramp rates of unit i

i = represents online units

Then at stage n:

$$f_n = \min_{x_n} Q_n \qquad (37)$$

where

$$Q_n = \sum_{i=1}^{N_n} (\alpha_i + \beta_i [P_{n,i}(1-LRR_i) + x_{n,i}P_{n,i}SRR_i] \quad (38)$$

$$+ \gamma_i (P_{n,i}(1-LRR_i) + x_{n,i}P_{n,i}SRR_i)^2)$$

such that

$$\sum_{i=1}^{N_n} [P_{n,i}(1-LRR_i) + x_{n,i}P_{n,i}SRR_i] - P_{d_n} = 0$$

Converting the above formulation into an unconstrained minimization problem,

$$Q_n' = \sum_{i=1}^{N_n} [\alpha_i + \beta_i (P_{n,i}(1-LRR_i) + x_{n,i}P_{n,i}SRR_i) \quad (39)$$

$$+ x_{n,i}P_{n,i}SRR_i)^2] - \lambda_n [\sum_{i=1}^{N_n} (P_{n,i}(1-LRR_i)$$

$$+ x_{n,i}P_{n,i}SRR_i) - P_{d_n}$$

Applying the Kuhn-Tucker theorem:

$$\delta Q_n'/\delta x_{n,i} = P_{n,i}\beta_i SRR_i + 2\gamma_i P_{n,i}^2 (1-LRR_i)SRR_i \quad (40)$$

$$+2\gamma_i P_{n,i}^2 SRR_i^2 x_{n,i} - \lambda_n P_{n,i}SRR_i = 0$$

or

$$x_{n,i} = (\lambda_n - \gamma_i)/(2\gamma_i P_{n,i}SRR_i) - (1 - LRR_i)/SRR_i \quad (41)$$

And

$$\delta Q_n/\delta \lambda_n = \sum_{i=1}^{N_n} [x_{n,i}P_{n,i}SRR_i + P_{n,i}(1-LRR_i)] - P_{d_n} = 0$$

Substituting above for $x_{n,i}$ and simplifying:

$$\lambda_n = (P_{d_n} + b_n)/c_n \tag{42}$$

where

$$b_n = \sum_{i=1}^{N_n} \beta_i/2\gamma_i$$

$$c_n = \sum_{i=1}^{N_n} 1/2\gamma_i$$

Then,

$$x_{n,i,opt} = (P_{d,n} + b_n)/(2\gamma_i c_n P_{n,i}SRR_i) + \beta_i/2\gamma_i P_{n,i}SRR_i - (1 - LRR_i)/SRR_i \tag{43}$$

And, therefore

$$f_n = \sum_{i=1}^{N_n}[\alpha_i + \beta_i(P_{n,i}(1-LRR_i) + x_{n,i,opt}P_{n,i}SRR_i) + \gamma_i(P_{n,i}(1-LRR_i) + x_{n,i,opt}P_{n,i}SRR_i^2)] \tag{44}$$

Substituting for $x_{n,i,opt}$ and simplifying,

$$f_n = a_n + b_n P_{d,n}/c_n - \frac{1}{2}\sum_{i=1}^{N_n} \beta_i^2/2\gamma_i + P_{d,n}^2/2c_n + b_n^2/2c_n \tag{45}$$

where

$$a_n = \sum_{i=1}^{N_n} \alpha_i$$

Thus the optimal solution at each stage is dependent only on the stage load and the cost characteristics of the online generators. Therefore, since the optimal solution is independent of the previous stages, the optimum solution over M stages is just the sum of the optimal solution for each of the stages. This is given by,

$$F_N = \sum_{j=1}^{M} [a_j + b_j^2/2c_j + b_j P_{d,j}/c_j - 1/2 \sum_{i=1}^{N_j} \beta_i^2/2\gamma_i + P_{d,j}^2/2c_j] \tag{46}$$

In the problem of determining the cost or savings due to DLC, let

T = the length of the economic dispatch interval in minutes

T_1 = the length of the DLC dispatch interval

Also, let $T_1 \geq T$ and an integer multiple of T. Then define

M_1 = number of economic dispatch stages in the DLC dispatch interval

Similarly, let M_2 be the integral number of economic dispatch stages in the payback period.

The problem of determining the fuel costs or savings of DLC then consists of determining the fuel costs over (M_1 + M_2) stages for the two scenarios — with DLC dispatch and without it. A closed form solution has been derived for the overall minimum fuel cost over M stages. This can be directly used for the case when no DLC is dispatched. For the case where DLC is dispatched, the stage loads can be modified as follows:

During the control period:

$$P'_{d,n} = P_{d,n} - X_{DLC}$$

And during the payback period,

$$P'_{d,n} = P_{d,n} + (f - d)*X_{DLC}$$

where

$P'_{d,n}$ = DLC modified load

X_{DLC} = amount of DLC dispatched in MW.

f = total restrike demand per MW of DLC

d = normal diversified demand per MW. of DLC

Then the equations for the minimum cost over $(M_1 + M_2)$ stages for the two cases are:

$$F_{w/o} = \sum_{j=1}^{M_1+M_2} [a_j + (b_j^2 + P_{d,j}^2)/2c_j - \sum_{i=1}^{N_j} \beta_i^2/2\gamma_i + b_j/c_j] \tag{47}$$

$$F_w = \sum_{j=1}^{M_1} [a_j + (b_j^2 + P'^2_{d,j})/2c_j + b_j/c_j - \sum_{i=1}^{N_j} \beta_i^2/2\gamma_i] + \sum_{j=M_1+1}^{M_1+M_2} [a_j + (b_j + P'^2_{d,j})/2c_j - \sum_{i=1}^{N_j} \beta_i^2/2\gamma_i + b_j/c_j] \tag{48}$$

The net difference is the fuel cost or savings due to DLC. Since savings are expected from the dispatch of DLC, define:

$$DLC_{cost} = F_{w/o} - F_w$$

$$= X_{DLC}\{\sum_{j=1}^{M_1} (P_{d,j} + b_j)/c_j - \sum_{j=M_1+1}^{M_1+M_2} (f_j - d_j)(b_j + P_{d,j})/c_j\} - X_{DLC}^2\{\sum_{i=1}^{M_1} 1/2c_i + \sum_{i=M_1+1}^{M_1+M_2} (f_i - d_i)^2/2c_i\} \tag{49}$$

In simplified form, the above equation can be written as:

$$DLC_{cost} = (A_1 - A_2)*X_{DLC} - (B_1 + B_2)*X_{DLC}^2 \quad (50)$$

The above equation can be used in one of two ways:

1. the equation can be used to determine the net savings or cost due to dispatching X_{DLC} amount of DLC. Then, based on the economics the dispatch could actually be made or not. Since the blocksize is known for DLC and hence the MW capacity of each block, this method could be used for a block by block dispatch decision.
2. differentiating the above equation and solving for X_{DLC} yields the DLC capacity to maximize savings. [The second derivative of the above equation is negative, thus indicating a maximization.]

Either approach is equivalent.

Thus, in concluding this section, a closed form solution for the cost/savings due to DLC dispatch has been developed in terms of the system loads (modified and unmodified) and the cost characteristics of the online generators. Therefore, it accounts for both, the load shape and economic impacts of DLC.

The implementation of the solution requires a computation of the stage parameters a_i, b_i, c_i, but if the set of generators does not change, then the computational burden can be reduced by using the values calculated for a previous stage. This should render the method extremely fast.

CHAPTER VII

IMPLEMENTATION OF DYNAMIC DLC DISPATCH

This chapter discusses the algorithms for the dynamic dispatch of DLC for the objectives of fuel cost minimization and peak load shaving. Details of the program used to implement these algorithms are also provided.

7.1 BASIC DISPATCH SEQUENCE

The basic dispatch scheme consists of two decisions:

- the best possible dispatch mode for DLC; and
- the optimal amount of DLC to dispatch to achieve the objectives of the chosen mode.

The points in time at which the decisions are made are termed as the DLC dispatch points. The interval between two points — the DLC dispatch interval. Therefore, the two decisions have to be made at each DLC dispatch point. The decisions taken at each point hold for the ensuing DLC dispatch interval. Therefore, the dispatch decision is used to modify the load curve for the ensuing DLC dispatch interval.

The modified load curve for the next DLC dispatch interval, then, forms the input to the economic dispatch. Thus, the inherent assumption is that the economic dispatch interval is less than or equal to the DLC interval. This assumption was also introduced in the previous chapter and used in defining the number of stages to be considered in th calculation of DLC cost.

In the framework of the basic dispatch sequence outlined above, the reason becomes clear. If the DLC dispatch interval was less than the economic dispatch interval, then the load and fuel cost impacts of DLC dispatch could not be factored into the economics of system operation. Since economics is one of the primary considerations in system operations, it is essential for DLC integration that its cost impacts be taken into account. Once this is achieved, the dispatch of DLC can be coordinated with other system operations and accounted for in terms of load, energy and economics.

The cycle of DLC dispatch decisions followed by one or more economic dispatch calculations till the next DLC dispatch point, then, forms the basic dispatch scheme.

<u>Coordination With Unit Commitment:</u> The coordination of DLC dispatch with unit commitment is obtained quite simply by simulating the DLC dispatch over 24 hours to obtain a modified load curve. The modified load curve is then input to GPUC, EPRI's unit commitment program discussed in Chapter V, to obtain the new unit commitment which would be the operative unit commitment for the online dispatch of DLC.

7.2 DLC DISPATCH FOR PEAK LOAD SHAVING

During the course of a 24 hour operating period DLC could also be dispatched for peak load shaving. Peak load shaving can produce production cost savings, as mentioned in Chapter II. But the primary goal of peak load shaving is to produce a reduction and/or deferral of planned capacity additions. This is therefore, a long term goal which is dependent on the consistency with which the system peak can be limited to a target level. For example, if only water heaters are controlled in a DLC program, the amount of peak shaving that will be obtainable in summer and winter, the normal peaking seasons, will be different and dependent on:

- the water heater diversified demand during summer and winter. In general, the water heater demands are greater in winter than in summer.
- the peak diversified demand during the two seasons; and
- the coincidence of the system peak with the diversified demand peak.

In a case study by an electric utility, [45], the winter system peak coincided with the peak water heater diversified demand. Hence, high load relief was obtained from the DLC program. However, in summer, the water heater diversified did not coincide with the peak water heater diversified demand.

Then, in such a situation, if the summer peak was much higher than the winter peak, the effective load reduction for capacity purposes would be the summer reduction. Furthermore, apart from the magnitude, the load reduction has to be consistent over the years that the capacity reduction or deferral is sought.

The above discussion was aimed at highlighting the fact that the utility of peak load shaving cannot be quantified within the time frame of daily system operations. The implication for dynamic DLC dispatch is that there is no quantifiable basis for weighing peak load shaving versus fuel cost minimization. The two modes can be considered independent in the sense that it is not possible to dynamically decide which mode is of greater utility at any given DLC dispatch point. The decision that can be made dynamically is when to switch from one mode to the other, since this can be made based on the anticipated load.

7.3 PEAK LOAD SHAVING ALGORITHM

The requirement of peak load shaving is that the system load be consistently limited to some target load. The length of the peak shaving period and the load relief obtainable is dependent on:

- the amount of DLC capacity available;

- the shape of the system peak;
- the up-time and down-time constraints on DLC dispatch; and
- the diversified demand of the controlled loads over the peak shaving period.

The DLC model for peak shaving is quite straightforward: during the anticipated peak shaving period the available DLC capacity is given by,

Peak Shave Capacity = NBAVL * BLKSIZE * DIVD

where:

NBAVL = the number of blocks available for dispatch during the current DLC dispatch interval

BLKSIZE = the capacity of each block in terms of the number of loads (in '000s)

DIVD = the diversified demand per device (in KW.)

Then, the task of any peak shaving program is to determine:

1. the target load;
2. the length of the peak shaving period; and

3. the block dispatch sequence i.e. how many blocks are to be dispatched at each DLC dispatch point.

The load to be reduced to the target load (TLD) will be the sum of the expected system load and payback from previously dispatched blocks. Denoting this by $SYSLD_{eff}$, the number of blocks required is

NBREQ = (SYSLD + PBLD - TLD)/(DIVD * BLKSIZE)

where:

NBREQ = number of blocks required for the current DLC dispatch interval

SYSLD = expected system load

PBLD = payback load from previously dispatched blocks

It should be noted that the quantity, PBLD, depends on past decisions concerning blocks dispatched and the length of the payback. The payback magnitude and length are in turn dependent on the length of the control period and the time-of-day that control is exercised. Further, NBREQ cannot exceed the number of blocks available (NBAVL) during the dispatch interval, NBAVL being defined by:

NBAVL = NBLK - NPBK

where:

NBLK = total number of DLC blocks

NPBK = number of blocks in payback mode

Since the payback is time dependent, NPBK is also time dependent. Therefore, the number of available blocks and the DLC capacity are dependent on time and the sequence of past decisions.

If the peak shaving problem is considered as an optimization problem with the objective of maximizing the peak load reduction, the natural structure of the problem is organized in several stages. Thus, once again a dynamic programming framework emerges. But the following factors posed a problem to finding a solution:

- the number of stages in the problem is variable. The number of DLC dispatch stages involved is dependent on when the load exceeds TLD and then drops below TLD. Since the objective is to find TLD, the number of stages and the objective are interdependent.
- the number of feedforward loops required to account for the effect of previous decisions, is dependent on the length of the payback period. This, in turn, is dependent on the time-of-day that control is exercised.

- the magnitude of the payback is a major factor in the determination of TLD, since the total peak shaving period can be expected to be greater than the maximum up-time for a DLC block. Therefore, payback from blocks dispatched at a previous dispatch point will also have to be shaved. This again, reflects on the TLD that can be achieved.

Thus, all three parameters for peak shaving — target load, length of peak shaving period (the number of DLC dispatch intervals), and the block dispatch sequence are interdependent and time variable. In terms of the decomposition criteria for dynamic programming:

1. the peak shaving problem consists of two subproblems -- the determination of the number of DLC dispatch intervals over which peak shaving can be sustained and the block dispatch sequence. These two subproblems are not separable;
2. the overall objective of the peak shaving algorithm is to maintain a flat load profile. The objective over the stages is therefore, not monotonically increasing.

Since the problem cannot be decomposed, dynamic programming concepts cannot be applied for the peak shaving algorithm.

Therefore, a simple linear search technique was utilized. The objective of the search was to find a target load between two well defined end-points such that the total system load (normal plus any payback effects) was always limited to the target load for as long as the total system load was greater than the target load. Such a search technique, which is inherently iterative could be computationally burdensome. But in the approach adopted, the end points were used to define maximum ranges and facilitate the preprocessing of the payback calculations. This would reduce the computational burden and improve the speed of the algorithm.

The endpoints were defined by the maximum and minimum target loads achievable. These can be computed as:

$$TLD_{min} = SYSPK - NBLK*DIVD*BLKSIZE$$

$$TLD_{max} = SYSPK$$

where

TLD_{min} = minimum target load achievable

TLD_{max} = maximum target load

SYSPK = pre DLC dispatch system peak

NBLK = total number of blocks in the DLC system

BLKSIZE = the number of devces in each block

The minimum target load, TLD_{min}, assumes that all the blocks are available at the time of the system peak for peak shaving. However, this will not be the case since some blocks would have been dispatched earlier and be in the payback mode at the time of the system peak. Hence, TLD_{min} serves as an effective lower bound on the target load. Then, a quick review of the load curve determines the times between which the system load is above TLD_{min}.

The search is then conducted in the usual fashion:

1. determine the midpoint of the current interval;
2. determine the return at the midpoint (also at the endpoints if the iteration count is one);
3. redefine the end-points to choose the interval which contains the optimal solution;
4. If the change in the return is less than some specified tolerance, the search is complete; else go to step 1.

In the search for TLD_{opt}:

1. the current interval is the one which is bounded at one end by a violation of the availability constraint and at the other end by a satisfaction of the constraints;
2. The stopping criterion is that the current interval be less than or equal to the resolution of control, which

is the load reduction obtainable from one block, coincident with the system peak;

3. the return is therefore, the satisfaction or violation of the availability constraints over the entire peak shaving interval.

The determination of the return at each new point, then involves:

1. fixing the value of the target point as TLD;
2. determining the number of DLC dispatch stages for that target load;
3. for each stage, j:
   a. determine the effective system load as:

      $SYSLD_{eff} = SYSLD_j + \Sigma PB_{ij} * NBDISP_i$

      where:

      PB_{ij} = payback at stage j from a block dispatched at stage i

      $NBDISP_i$ = number of blocks dispatched at stage i
   b. determine the number of blocks required at the stage j:

      $NBREQ_j = (SYSLD_{eff} - TLD)/(BLKSIZE*DIVD_j)$
   c. determine the number of available blocks, NBAVL as the difference between NBLK and all blocks in payback mode;

d. if $NBREQ_j$ is less than or equal to NBAVL, then proceed to stage (j+1); else log a violation and proceed to a new TLD.

It is obvious from the above discussion that at every new target point paybacks have to be calculated at all stages. Since over the interval spanned by TLD_{min} the time-of-day of control remains the same, the same payback calculation is being made every time the same stage is encountered. Since the payback calculations form the major computational burden, preprocessing of the payback calculations would considerably reduce the computation time.

This preprocessing is done as follows:

1. from TLD_{min} determine the total number of possible stages, M;
2. for 1 block dispatched at any stage n ($1 \le n \le M$) for the maximum control period, determine the payback magnitudes and the stages over which the payback takes place.
3. store this information in a vector. Thus, if the control period encompasses m stages and the payback lasts over m_1 stages, the payback vector will indicate payback magnitudes from stage n over stages (n+m+1) to ($n+m+m_1$). Now it can be determined how many prior stages are paying back over any given stage and the magnitudes of those

paybacks. A single vector can be constructed to store this information.

Once the vector of paybacks has been determined, the total payback effect at any stage can be easily calculated during the search.

The target load search described above forms the peak load shaving algorithm.

7.4 FUEL COST MINIMIZATION ALGORITHM

The fuel cost minimization algorithm utilizes the DLC cost equation for a block by block dispatch of DLC capacity. Blocks are dispatched based on a non-negative value for the cost i.e. a savings. After each block is dispatched, the load curve is modified. The modified load curve forms the basis for the economic calculation for the next available block.

One overriding concern in the dispatch of DLC for fuel cost minimization is that the system peak (or the target load in the dual mode case) should not be exceeded at any time. Hence, when a block is considered for dispatch, a scan ahead feature is used to ensure that the payback at no time causes a new system peak. If a new peak is perceived, then the block is not dispatched.

When a block is dispatched or is in payback mode, its up-time and down-times are logged and tracked. When any of the constraints are satisfied, the block mode is switched. If the block was in payback (i.e. unavailable for dispatch) it becomes available; if it was in dispatch, it is switched to payback mode. Some blocks are switched to payback mode because of economic reasons. In this case, the load curve is modified for the payback. Blocks may also be switched because of the up-time constraint. Since it is easy to foresee the switching of these blocks, the algorithm switches them to the payback mode and modifies the load curve before considering the dispatch of any other blocks. In this way, the economic effect of the uptime constraint is taken into account in the dispatch of any more blocks for the subsequent DLC dispatch points.

7.5 IMPLEMENTATION

The above dispatch algorithms for fuel cost minimization and peak load shaving were implemented in a program called DLCDISP. In accordance with the dynamic DLC dispatch philosophy of this dissertation, the program once started needs no other inputs from the user. Decisions are made and acted upon by the program.

DLCDISP allows the user the choice of specifying whether DLC is to be used for:

1. Fuel cost minimization alone; or
2. Peak shaving alone; or
3. Both, peak load shaving and fuel cost minimization.

This section briefly describes program actions for each of the above choices and the overall operation of the program.

7.5.1 Input Data

DLCDISP requires data on:

1. the generation system :- this data is essentially the same as that required by GPUC. Specifically, the program requires data on:
   - unit identification — name and unit numbers;
   - unit type — dispatchable or non-dispatchable;
   - fuel type — coal, gas or oil;
   - quadratic heat rate curves;
   - per unit fuel costs ($/MBTU-HR)
   - unit minimum and maximum capacities; and
   - ramp rates;
2. the DLC system :- the DLC system is described by:
   - the total number of blocks;
   - the blocksize — specified in terms of the number of devices in one block;
   - the maximum control time for a block; and

- the DLC dispatch interval.

3. the expected load curve and the diversified demand curve for the 24 hour period.
4. the unit commitment for dispatchable units;
5. the economic dispatch interval for dispatchable units;
6. loss data. Currently the only option supported is a representation of the losses as a percentage of the load.

The data can either, be input from a file or entered interactively. In the latter case, an input data file is created for subsequent runs.

Input Processing: The program performs minimal input processing. The only processing required consists of:

1. initialization of arrays and variables;
2. interpolation and storage of the load and diversified demand curves at economic dispatch intervals; and
3. rearranging of the unit commitment schedule output from GPUC in the form that it will be used. The unit commitment is stored in a matrix of dimension (NUNIT+2)*24, where NUNIT is the total number of units in the generation system. Actual storage used for any hour is (NCOM+2), where NCOM is the total number of units scheduled for the hour. The first element of of the vector for every hour contains the number of dispatchable units

committed for the hour and the second contains the number of non-dispatchable units scheduled.

7.5.2 Program Processing

The program operates on two nested time intervals — the DLC dispatch interval and the economic dispatch interval. At each DLC dispatch interval, program processing depends on the user option exercised. Briefly:

Fuel Cost Minimization: for this mode, at each DLC dispatch point, the program uses the DLC cost equation to dispatch DLC blocks for fuel cost minimization. Down-times and up-times are logged for each block and used to enforce the appropriate constraints.

Peak Load Shaving: for peak load shaving, DLCDISP operates in two modes — preview and on-line and allows shaving of the global or 24 hour peak and local peaks.

In the preview mode, the program will scan the input load curve for peaks, determine target loads and the block dispatch sequence. The results are displayed on the screen of a video terminal. The preview is performed at the start of the 24 hour period and every hour. At the start of the 24 hour period, the results for all peaks to be shaved are displayed.

At hourly intervals, only the results for the next upcoming peak are displayed.

The hourly update is independent of the starting preview so that the peak shaving results can be updated as the load forecast is updated. This allows the program to be responsive to changing system needs.

The online mode is for the dispatch of blocks to achieve the target load established by the hourly calculation. The only input from the hourly calculation is the target load. The independence of the on-line mode from the previous modes allows the program to be responsive to short term load variations on a DLC dispatch interval basis.

The on-line peak shaving module calculates the number of blocks to be dispatched every DLC dispatch interval. If there is a shortage of blocks due to higher than expected loads, the target load is temporarily set to a new value and reset to the original value when possible. In any event, if the peak shaving period spans across hourly boundaries, the hourly update will also revise the target load as the system load varies from the expected values.

This organization allows the program to be sensitive to load changes and to adjust the DLC dispatch to those changes. In essence, it is dynamic in its dispatch for peak load shaving.

Dual Mode: In the dual mode, the program will toggle between the fuel cost minimization and peak load shaving mode. The default mode is the fuel cost minimization mode. However, in the default mode, the program scans ahead to determine the onset of a peak shaving period. The scanning period is equal to the longest payback period for all currently dispatched blocks plus one DLC dispatch interval. If a peak shaving period is detected, the program will switch the operating mode, stop the dispatch of blocks for fuel cost minimization and allow the currently dispatched blocks to recover.

At the end of the peak shaving period, detected when the effective system load decreases below the target load, the operating mode automatically switches back to fuel cost minimization.

The modified load curve over the ensuing DLC dispatch interval is then the input to the economic dispatch intervals nested within the DLC dispatch. At each economic dispatch point, the dispatchable load is calculated as the difference of the modified load and the non-dispatchable generation. Thus a predispatch of non-dispatchable generation is performed before the economic dispatch. The economic dispatch method used is the closed form solution derived in Chapter V.

Predispatch of Non-Dispatchable Generation: The non-dispatchable generation requirement is determined as the difference of the system load and the maximum available dispatchable generation. Since non-dispatchable sources do not have an adjustable output, as many units are predispatched as are required to cover the dispatchable generation shortfall.

7.5.3 Program Outputs

Reports are generated by the program for every DLC dispatch point. each report contains the following information:

1. time;
2. DLC operating mode;
3. number of blocks dispatched;
4. estimated cost savings;
5. original (expected) and modified system loads;
6. the current economic dispatch;
7. total, dispatchable and non-dispatchable generation;
8. system incremental cost i.e. the system λ; and
9. total generation costs for the current economic dispatch;

Additional reports are generated for:

1. the preview mode of the program — starting the 24 hour period and the hourly updates;
2. summary report for the 24 hour period, indicating:

- system peak before and after DLC dispatch;
- total energy served before and after DLC dispatch;
- difference in energy served
- total energy deferred due to DLC dispatch; and
- total system fuel cost for the 24 hour period.

Extracts from program reports are provided in Appendix A.

CHAPTER VIII

RESULTS AND DISCUSSION

Program DLCDISP was used to study a number of simulated scenarios in order to investigate the effect of various DLC characteristics on fuel savings and peak load shaved and thus illustrate the need for the dynamic dispatch of DLC Results of these simulations are presented and discussed in this chapter. However, in order to investigate DLC effects alone and to filter out extraneous effects, it was necessary to synthesize a test system for use in the simulations. Details of the test system are given and precede the results.

8.1 TEST SYSTEM

The major requirement in synthesizing the test system was that it reflect, as closely as possible, a real utility system. Since all the data required was not available from a single source, it was necessary to draw on several data sources — published and personal communications, to synthesize a test system which would meet the 'realistic system' criterion. While it is not possible to specify exactly what constitutes a real utility system, it was felt that if the data was drawn from actual systems or industry standard systems, and merged together in a consistent manner, then a realistic synthetic utility system would emerge. The data finally employed was drawn from two main sources — the EPRI Regional Systems [38] and a neighboring south eastern utility.

The EPRI Regional Systems were synthesized to provide standard systems for the testing of power system programs. There are six Regional Systems, roughly corresponding to the six NERC regions of the continental United States. The following data is provided for each system:

1. generation technology mix;
2. number and capacities of all unit types;
3. heat rate curves and other operating data;
4. load duration curves;
5. load factors;
6. weekly and seasonal load profiles;
7. peak load data; and
8. unit availabilities.

The regional systems, however, are large systems with total generating capacity in the range of 20GW. Therefore, any chosen system has to be scaled down.

Simultaneously, actual operating data was available from a neighboring electric utility which has a generating capacity in the range of 9,000 MW. Therefore, data from the utility was combined with data from the South Eastern EPRI region to synthesize the test system. The specific data items drawn from each source are listed below:

1. load data was drawn from the EPRI Regional System in the form of load profiles and peak data;
2. generating unit data was obtained from the utility;
3. generator ramp rates were obtained from guidelines discussed in Sullivan, [51];
4. fuel costs were supplied by the utility based on their current fuel prices;
5. diversified demand data for the DLC loads was obtained from the Conservation and Load Management Department, Carolina Power and Light Co., [45].
6. the distribution of generator sizes was determined from the EPRI Soth Eastern region data and followed as closely as possible; and
7. the fuel mix was the same as that of the utility supplying the data.

The system that emerged was a winter peaking system with a peak demand of 7800 MW. All generating capacity is nuclear or fossil fuel with coal being the predominant fuel type (approximately 70% of capacity). Details of the test system are provided in the sample input attached in Appendix B.

The DLC system was synthesized completely. Since DLC parameters were to be the variables in the investigation, realistic would be inherent in the range. In addition, since a new approach to DLC utilization was being investigated, it was not necessary to be to be confined by any criterion of 'realistic systems'.

8.2 SIMULATION OBJECTIVES

The simulation objectives were as much to investigate the effect of DLC parameters such as blocksize, control times, capacity, etc. as to provide a proof of concept of the dynamic DLC dispatch philosophy. In terms of the latter objective, it was sought to demonstrate that:

- DLC could be modelled as a dispatchable system resource and coordinated with the dispatch of system resources;
- DLC could be utilized for several different objectives as system conditions changed;
- DLC utilization can be optimized by dispatching it dynamically — allowing online decisions to be made and acted upon for the utilization of DLC; and
- a viable (working) algorithm could be developed to dynamically dispatch DLC by integrating it into the process of efficient, economic system operation.

The former objective was to utilize the algorithm to investigate the effects of DLC:

1. maximum control times;
2. dispatch interval length; and
3. available capacity,

on fuel cost savings and peak load shaved and demonstrate the utility of and need for dynamic dispatch.

8.3 SIMULATION DETAILS

Simulations for studying the effect of DLC parameters on DLC objectives were carried out on two seasonal shapes —

1. a winter load shape, since the system peak of the synthesized system occurred in winter; and
2. a spring/fall load shape since these can be considered to be moderate seasons in terms of peak demand and energy consumption. Since the effect of DLC is expected to vary with seasons, it would provide a 'control' load shape for comparing results obtained from a peaking season load shape.

The load shapes used are shown in Figure 5. As can be seen from the figure, the winter load variation is greater, has a higher average load and has a well defined system peak for the 24 hours. The spring load shape, on the other hand, has a flatter profile and exhibits smaller load variations.

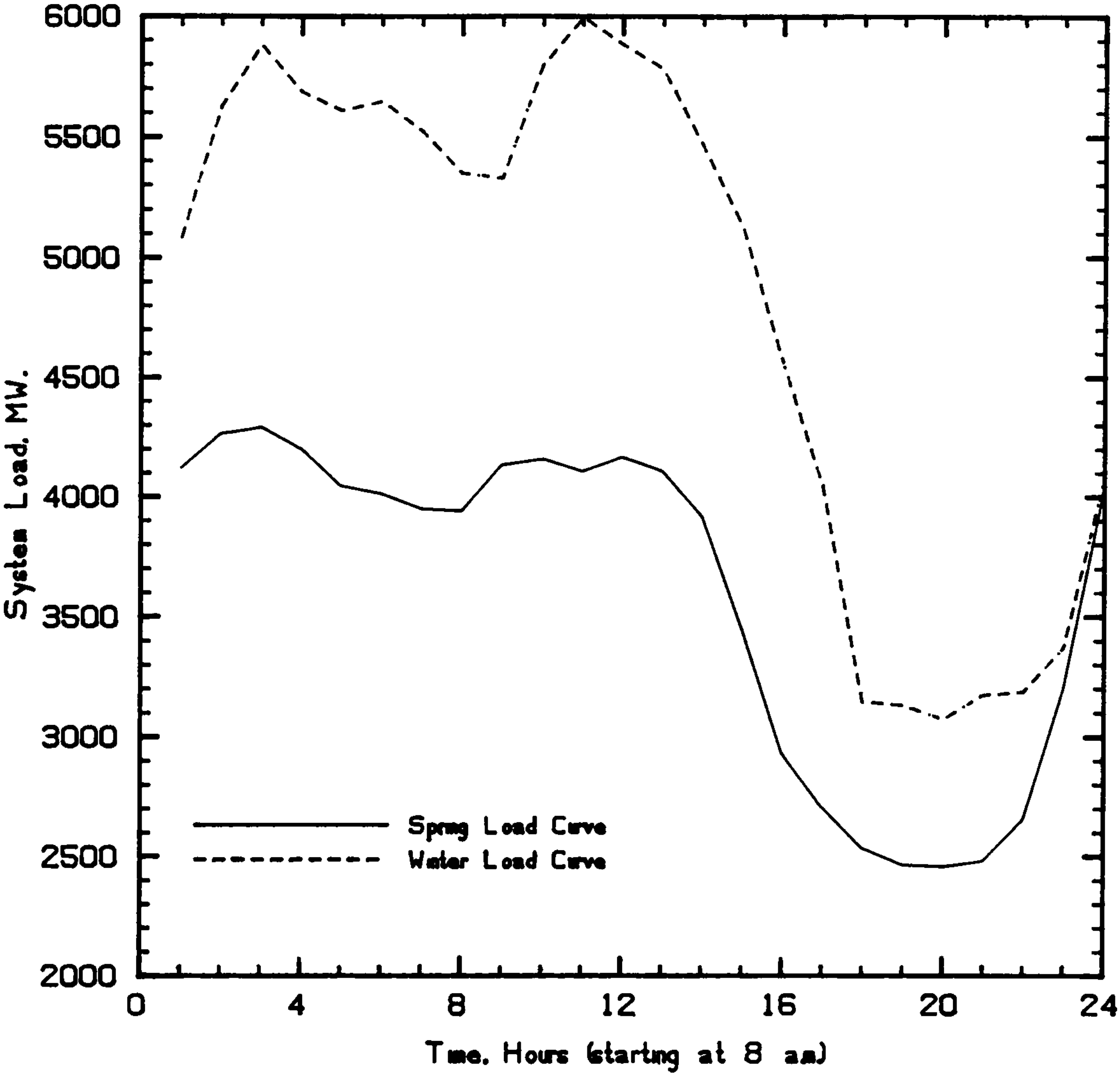

Figure 5. Spring and Winter Load Shapes

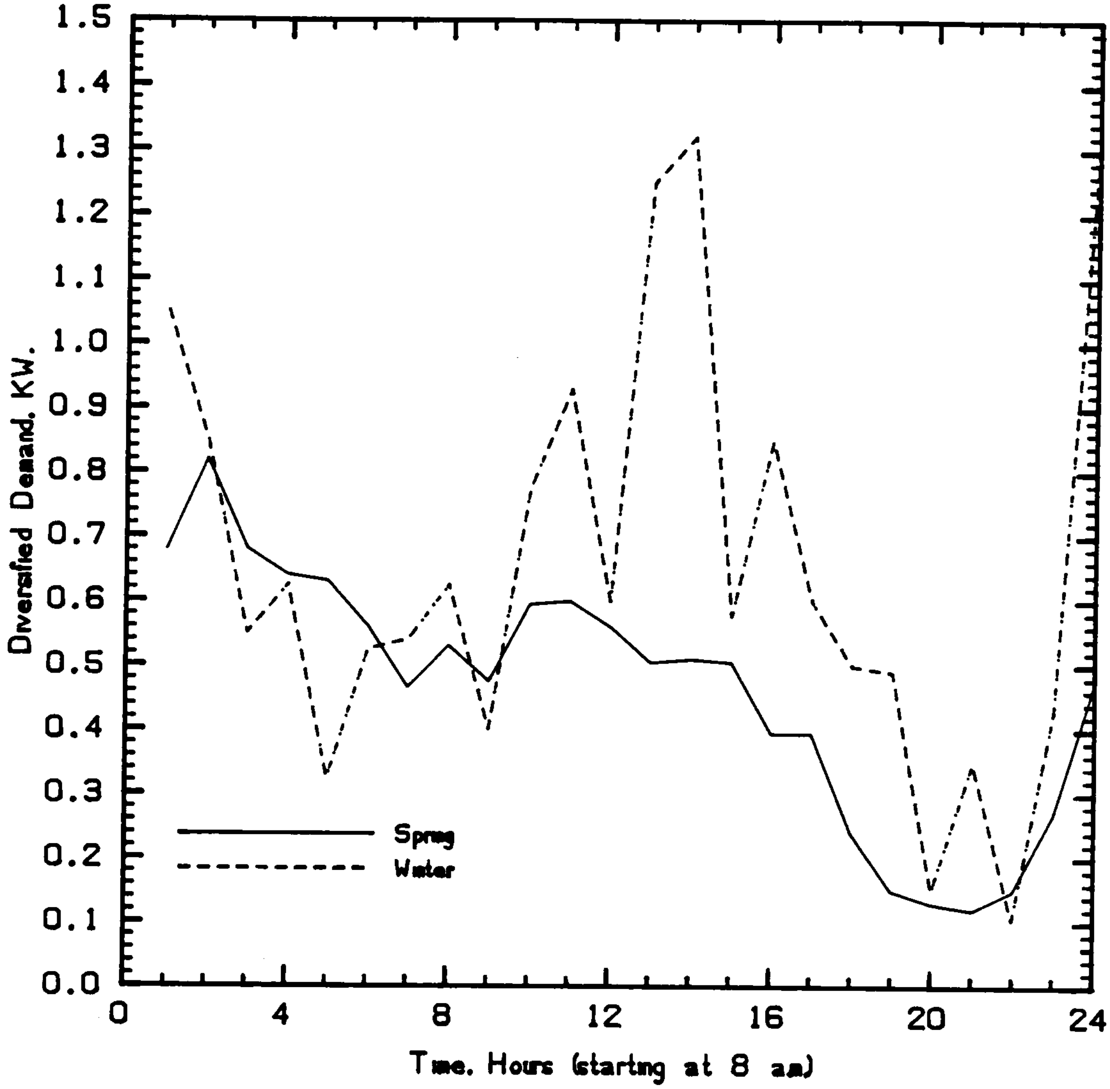

Figure 6. Spring and Winter Diversified Demands

Loads Controlled: The controlled loads in the DLC system consist of water heaters only. The water heater diversified demand curves corresponding to the seasonal load shapes are shown in Figure 6. The characteristics of the seasonal system load shapes is clearly reflected in the diversified demand curves too.

The payback function used for the water heaters is drawn from [45]. While a number of payback models have been proposed, most are derived in terms of the control time only, [19,44] give representative examples. However, these models neglect an important facet of load control — the time-of-day that control is exercised. So even though the control time based models are statistically correct for the data on which they are based, they fail to represent the actual phenomenon — the payback occurs essentially due to the energy that is not supplied to the load during the control period to maintain its internal balance. The amount of energy deferred will inherently be determined by the length of the control period. Furthermore, an energy based model will account for the actual device usage. The implication of the control-time based models is that the payback length and magnitude will be the same irrespective of whether DLC is used at periods of low demand or high demand. In point of fact, during a period of low diversified demand, indicating low energy use and hence a lower average demand per device, the payback will be less severe than during a period of high diversified demand.

Hence, the payback model proposed in [45] will be used. The payback model is given by:

$$\text{Restrike Demand} = 0.673 + 1.819E - 0.359E^2 \quad (0 \le E \le 2.53)$$
$$= 2.98 \quad (E > 2.53)$$

where:

Restrike Demand = normal demand + payback (KW.)

E = energy deferred (KW-HR)

8.4 RESULTS

Figure 7 shows the results of dispatching 200 MW of DLC for fuel cost minimization alone and in the dual mode. Results are shown for the fuel cost savings, system peak, load factor and the energy not served as a percentage of the energy served in the base case. In all categories, the dual mode indicates improved results. The fuel savings of the fuel cost minimization mode are combined with the peak reduction of the peak shaving mode. This:

- reduces the system peak load;
- yields higher fuel cost savings;
- improves the system load factor; and
- improves the overall percentage of energy served.

	Base Case	Fuel Cost Min.	Dual Mode
Fuel Cost Savings	0.000	5620.000	8989.000
System Peak	4292.633	4293.434	4266.016
Load Factor(%)	71.100	70.890	71.400
Energy Not Served (%)	0.000	0.268	0.245

Figure 7. Dispatch of 200 MW DLC

Thus, the dual mode has yielded a higher utilization of DLC and benefits to the utility. Overall, the economic and capacity benefits of DLC dispatch will depend on the load shapes, diversified demands and the coincidence between the two. Thus, the system peak coincident diversified demand is 0.68 KW. The average rating of each water heater, as reflected in the payback equation is 2.98 KW. Thus the system peak coincident demand is 22.8% of the average rating. However, the peak load reduction is 26.5 MW which is 13.25% of the DLC capacity. The lower percentage is due to:

- the lower diversified demand. The effective DLC capacity is the product of the number of blocks, the number of devices in each block and the diversified demand at that time. For the simulation case of Figure 7 this is 45.63 MW. Then, the peak shave percentage is 58.07%.
- the length of the peak shave period. Since the peak shave period is larger than the maximum off-time, the entire DLC capacity is not available at the instant of the system peak.

The following results are simulation studies of the effect of DLC subsystem parameters on the DLC operating objective. The results will be clearly seen to highlight the variation in the objective functions with changing DLC parameters; thus, illustrating the need for dynamic dispatch of DLC as well as giving indications of the relationships which exist between DLC parameters, system parameters and the DLC operating objective. If simulation studies could be used to derive the correlations between the above mentioned variables, the dynamic dispatch could be extended to the process of deciding on the optimum parameters. The simulation results are presentsed and discussed in the remainder of this section.

Figure 8 and Figure 9show the effects of varying DLC capacity on fuel cost savings, obtained from DLCDISP and GPUC, for spring and winter respectively. Three different trends are noticeable:

1. the overall difference in the results from GPUC and DLCDISP;
2. the differences in the results from GPUC and DLCDISP for both, the winter and spring load shapes;
3. the difference in the results from DLCDISP for the two load shapes.

The essential difference in the results from the two programs is that the savings from GPUC are consistently higher and diverging from the results obtained from program DLCDISP. In order to understand the differences, it should be pointed out that GPUC requires an integrated hourly load shape i.e., the expected energy requirement for the hour, as shown in

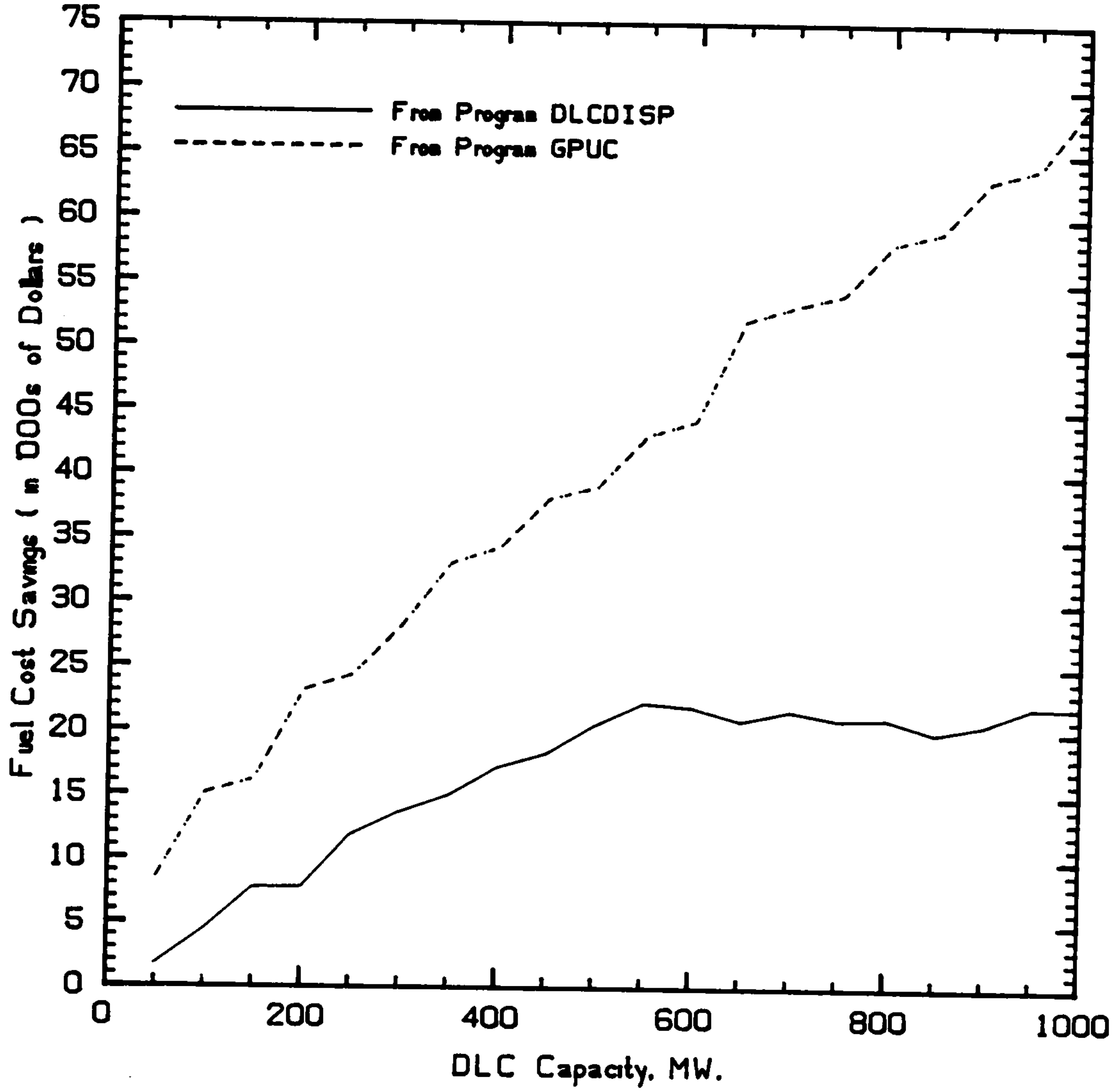

Figure 8. Fuel Cost Savings Versus DLC Capacity (Spring)

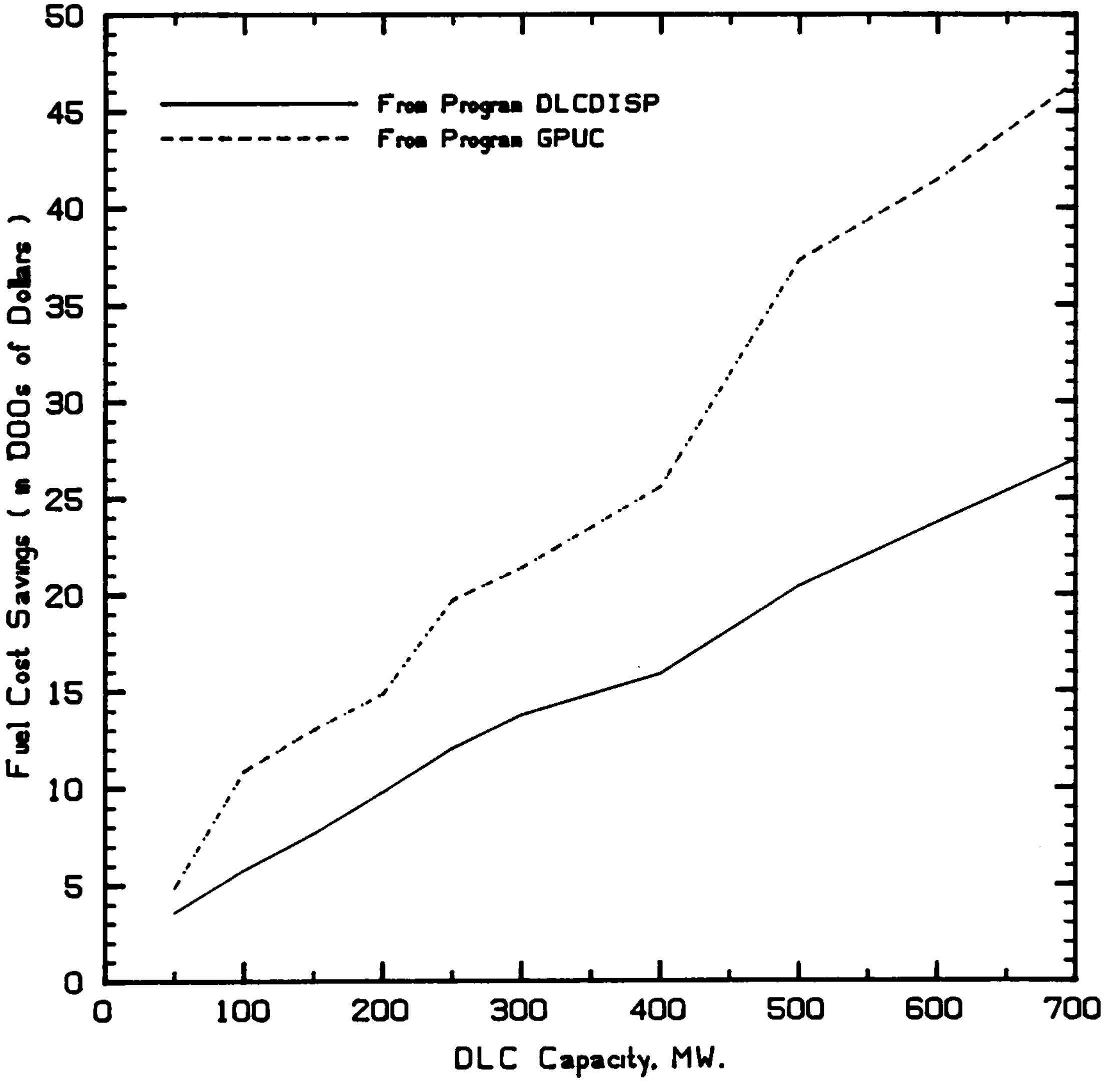

Figure 9. Fuel Cost Savings Versus DLC Capacity (Winter)

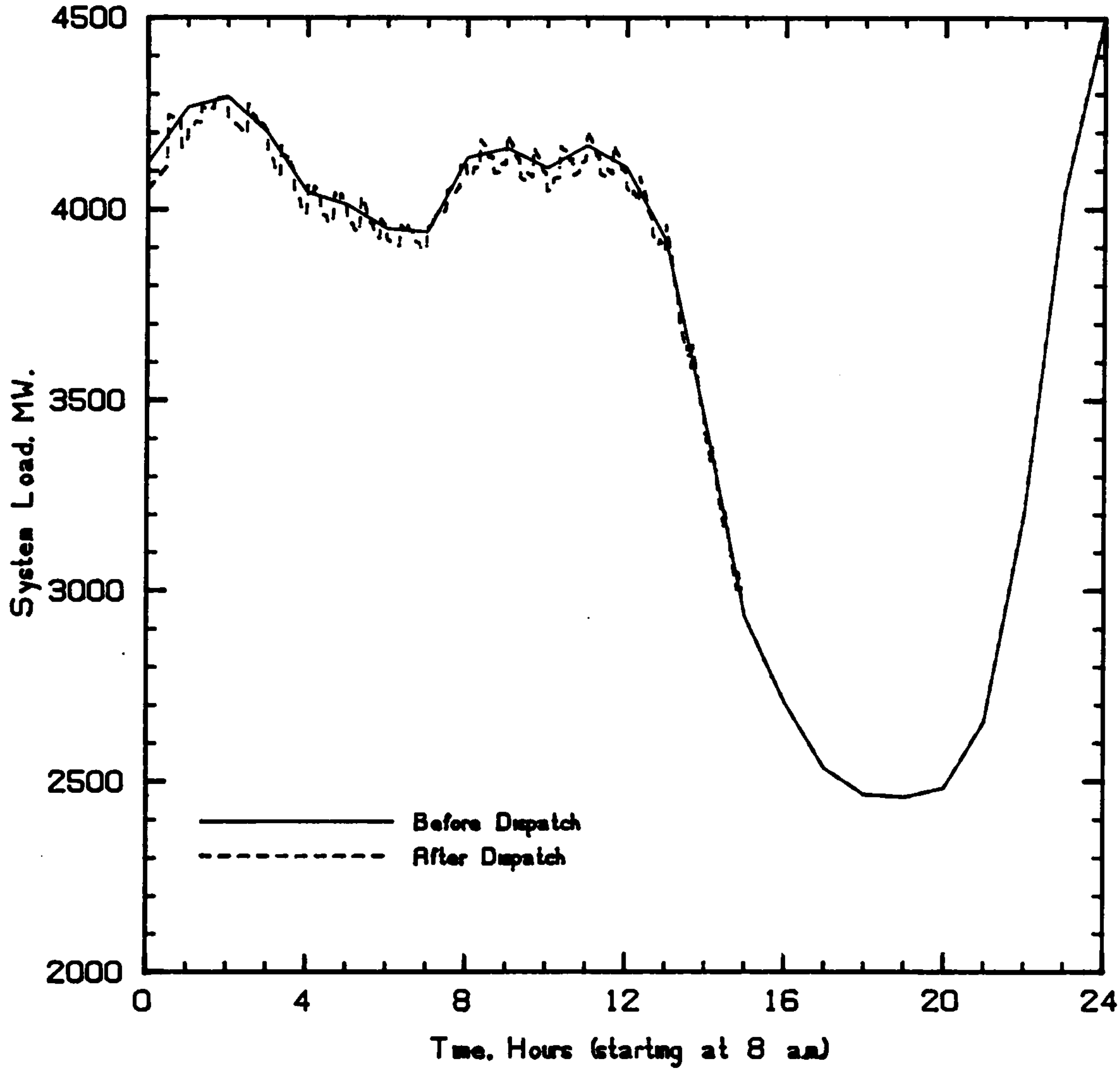

Figure 10. System Load Curves Before and After DLC Dispatch (300 MW. Capacity)

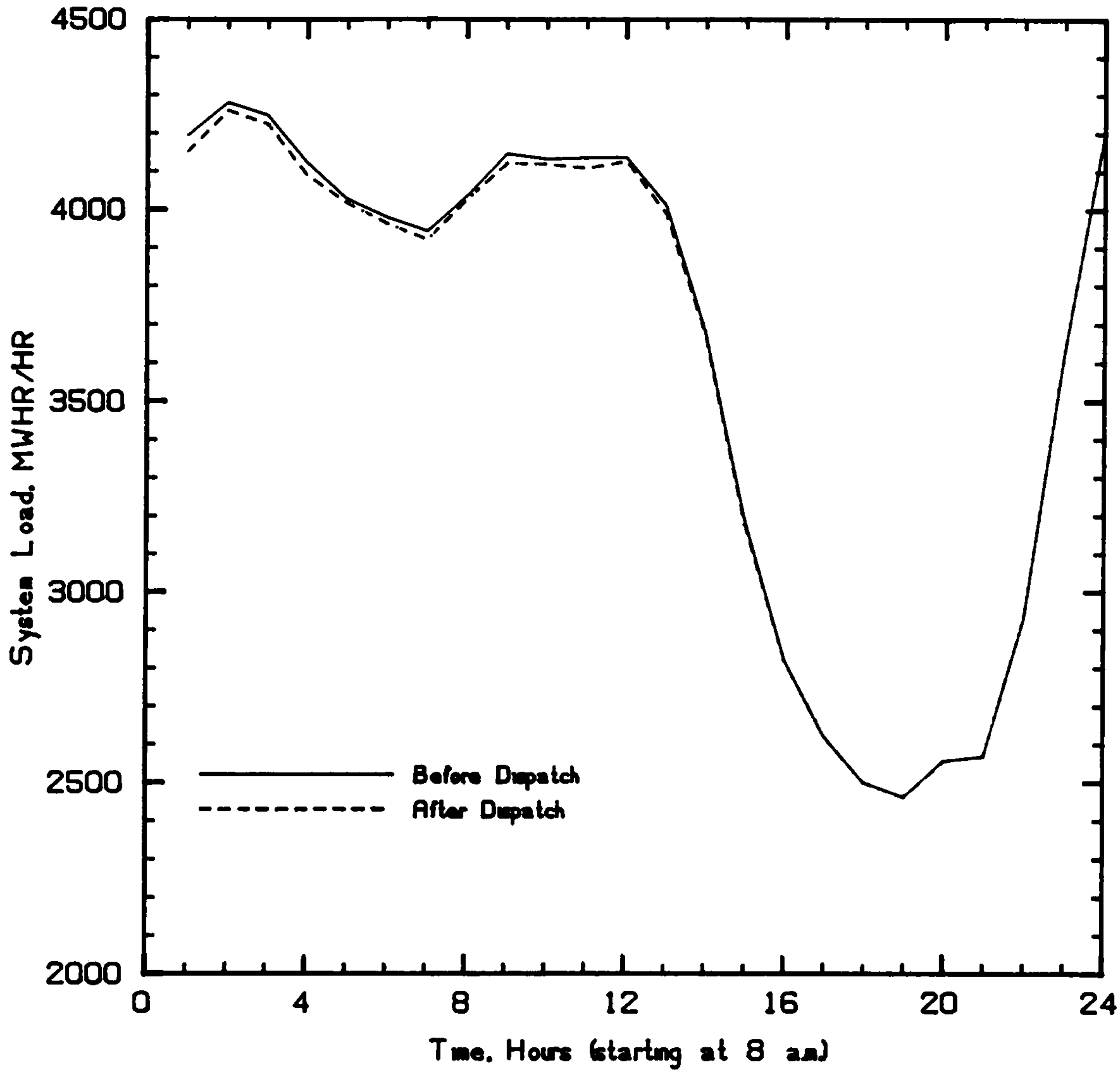

Figure 11. Integrated Hourly Curves For GPUC (Before and After 300 MW Dispatch)

Figure 11 which is a plot of the per unit (base = system peak) integrated hourly values for the two scenarios — with and without DLC dispatch. Thus it does not see the instantaneous load variation that is evident in Figure 10 and which is encountered by DLCDISP. The implications are that:

- GPUC dispatches generation based on the average hourly load. This will allow the program to utilize more dispatchable generation than DLCDISP.
- As shown in Figure 11, the consistently lower average energy requirement will lead to greater fuel cost savings

If the two figures, Figure 10 and Figure 11, are examined, the contrast becomes very apparent. Even if the same energy is supplied by GPUC and DLCDISP, the savings will be lower for the latter, because the dispatch and hence the fuel costs are based on the instantaneous values. It is evident from the nature of the dotted curve in Figure 10, that the sharp variations in the load will require the use of greater amounts of fast ramping capacity which can only be provided by non-dispatchable sources such as combustion turbines.

In addition, the ramp rate constraints incorporated in DLCDISP limit the maximum available dispatchable generation. Such a constraint does not exist in GPUC. The smooth curve before DLC dispatch allows a constant ramp-up or ramp-down of units in DLCDISP, leading to larger amounts of available dispatchable generation as compared to the case after DLC dispatch where the sharp variations may severely limit the the dispatchable generation. Therefore the savings will be reduced. The divergence of savings from GPUC and DLCDISP is caused by the difference in the load input format. As more DLC is dispatched, the load variations will increase, thus requiring more non-dispatchable generation.

There is however, one more difference between DLCDISP and GPUC that needs comment. The fuel costs from GPUC are consistently higher. The reason for this lies in the manner in which the two programs utilize combustion turbines. GPUC considers all combustion turbines scheduled for an hour to be producing at their maximum capacity. DLCDISP, on the other hand will only utilize combustion turbines to the extent of the dispatchable generation shortfall.

The third effect is the seasonal variation in savings for the two programs.

1. For GPUC, the trend is a monotonically increasing function for both the seasons. The savings too, are of similar magnitude. Any differences are attributable to the changes in the unit commitment caused by changes in the input load profile.
2. For DLCDISP, the seasonal variation is quite dramatic. While the fuel cost savings for the spring load curve level off at approximately 550 MW of DLC capacity, they

continue to rise for the winter load shape. The explanation for this depends on three factors:

- the payback percentage. The payback percentages for the winter load shape were in the range of 22-26%, while for the spring load shape they were in the range of 32-35% . The higher payback for the spring load shape is caused by the nature of the diversified demand curve, shown in Figure 6, which exhibits a constantly decreasing trend. It will be remembered that the payback demand was defined to be the <u>increase</u> in the normal diversified demand due to control. Therefore, when a payback occurs, the decreasing trend of the diversified demand curve allows the payback to occur for a longer period. In contrast, the winter diversified demand increases from hour 5 to hour 14. The increasing trend during the first part of the 24 hour period causes payback times to be shorter, thus lowering the payback percentage. It should be noted though, that the peak payback magnitudes will be higher for the winter load shape because of the higher diversified demands.
- the load shape. the spring load shape has a flatter profile causing the unit commitment to remain constant over a longer period of time. Since the economics of DLC depends on the cost characteristics of the on-line generators, the economics for the winter

load shape has higher variations. This could possibly lead to higher savings. Further, the average load during winter is higher which requires greater amounts of expensive capacity. Reduction of the load will lead to higher savings.

- the diversified demand profiles. The spring load shape and its diversified demand peaks have a higher coincidence than the winter curves. This, principally, has implications for the payback percentage, as discussed earlier.

Figure 12 plots the fuel cost savings versus DLC control resolution. The results for GPUC show a maximum variation of 0.9% . This can be considered negligible as evidenced by the plot, and attributed to round off errors. The maximum variation for DLCDISP is of the order of 6.0%. It would be expected that the error would decrease with increasing resolution. But this does not occur. The only explanation that can be forwarded is that the resolution causes differences in the dispatch decisions. The variations in the sequence of decisions could cause a higher (lower) number of blocks to be dispatched at particular instances, leading to greater or lower savings. But this effect shows no clear trends. With the available data, it is not possible to comment any further on this variation.

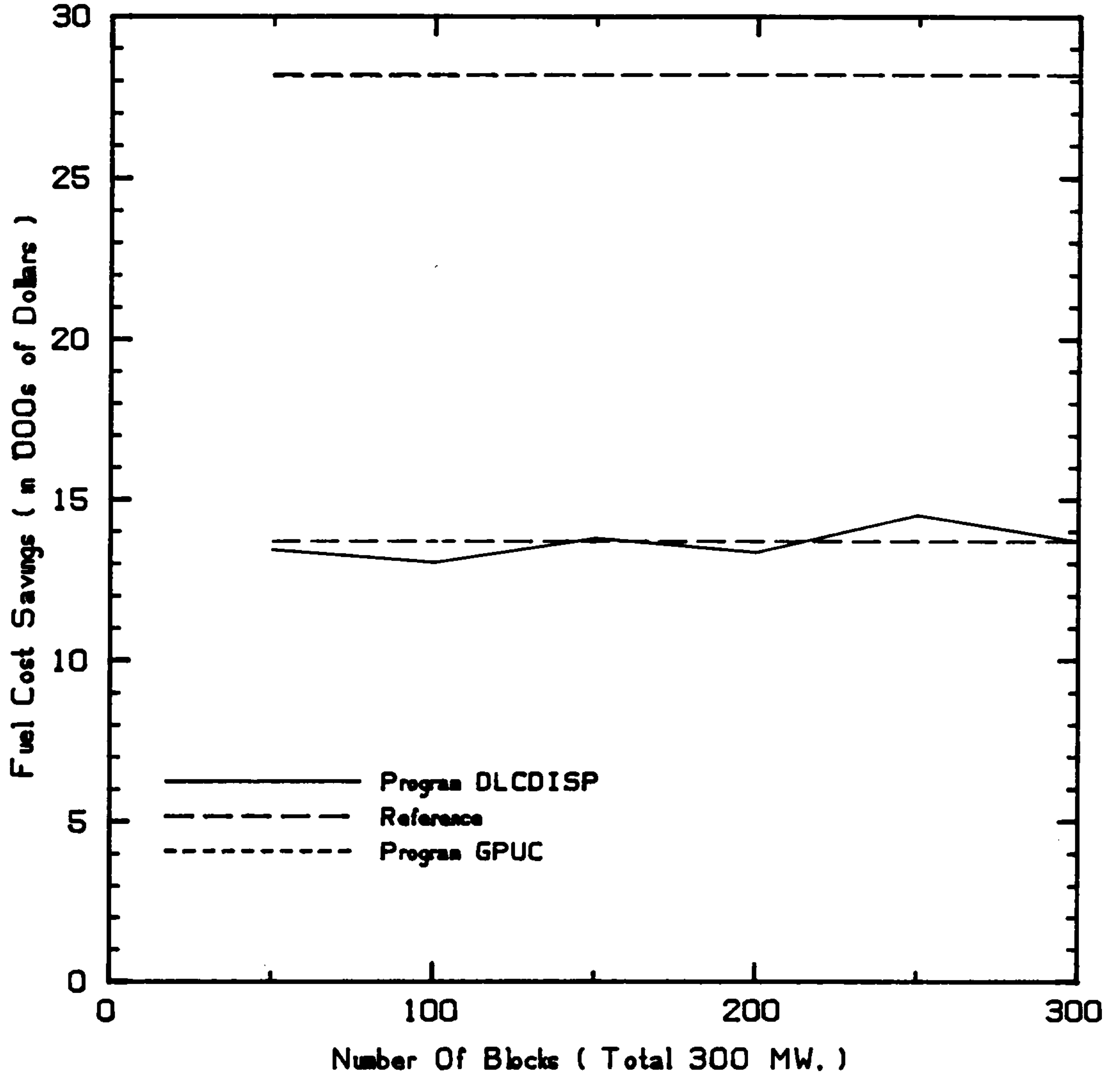

Figure 12. Fuel Cost Savings Versus Control Resolution. (Variable Number of Blocks at Constant Capacity)

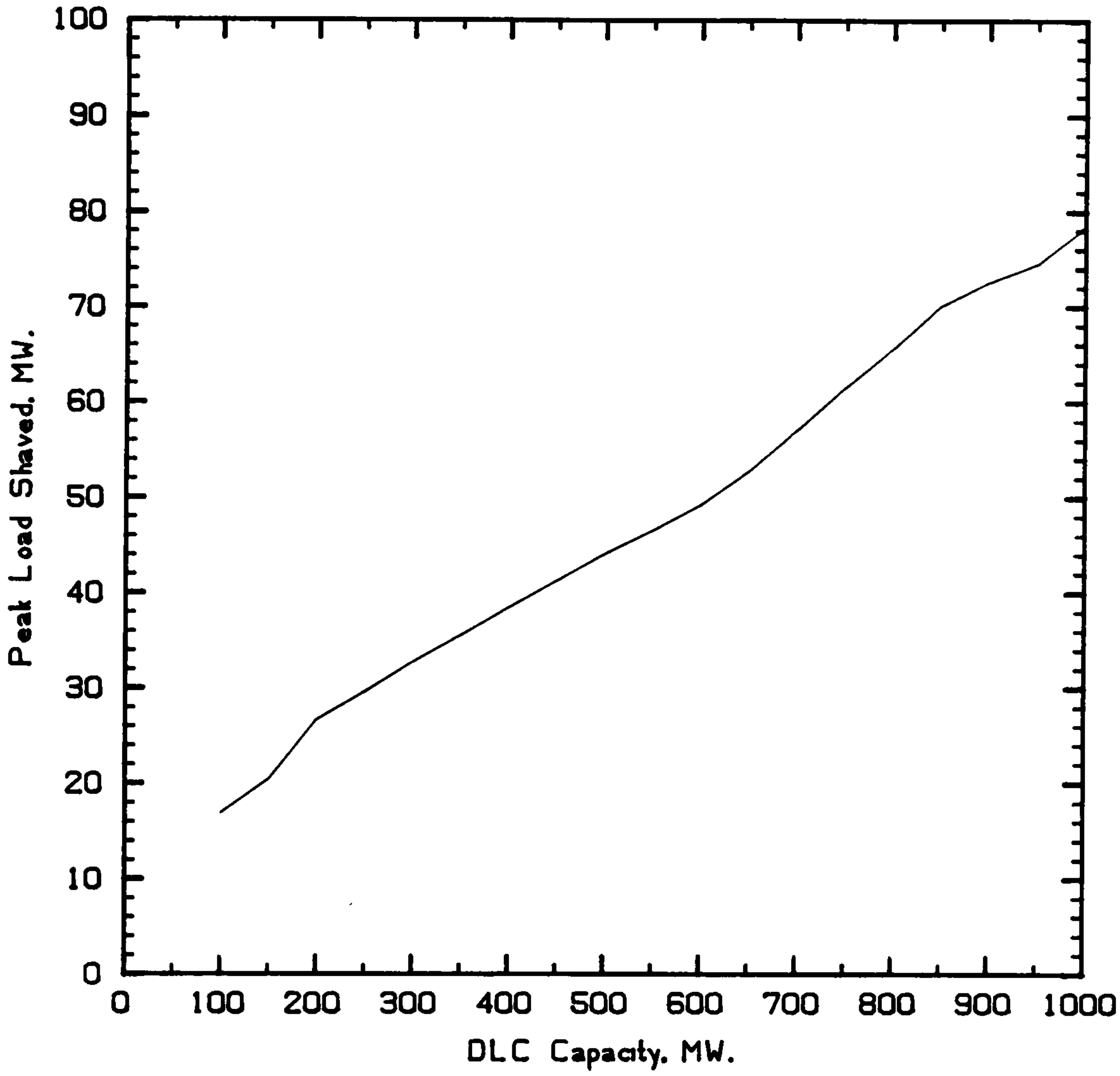

Figure 13. Peak Load Shaved Versus DLC Capacity Using Spring Load Curve. (Maximum Control Time Fixed at 30 Minutes)

Figure 13 shows the variation of peak load shaved versus DLC capacity for the spring load shape. It would be expected that increasing DLC capacity would allow increasing load relief and the expectation is borne out by the data.

It should be mentioned here that the peak load shaved by DLCDISP is less than those reported for comparable capacity. The reason is that in past uses of DLC for peak load shaving, the primary purpose has been to limit the load for the duration of the system peak. Smaller secondary peaks do get established during the payback period. DLCDISP strictly enforces the criterion of a flat load profile and secondary peaks are not allowed to form during payback. The only exception to this is when there is a shortage of available blocks.

The effect of the maximum control time on peak load shaved was also studied. The results are shown in Figure 14 and Figure 15. Well defined peak shaving maxima appear for a control interval of 80 minutes in spring and of 40 minutes in winter. Coincidentally, these intervals are equal to the period over which the maximum peak shaving occurs. For example, in spring the maximum peak shaving of 38 MW occurs over a 80 minute interval. Similarly, in winter, the maximum peak shave of 62 MW occurs over a 40 minute interval.

The previous paragraph would imply a definite relationship between the maximum control time and peak load shaved. Figure 16shows a family of curves for varying DLC capacity

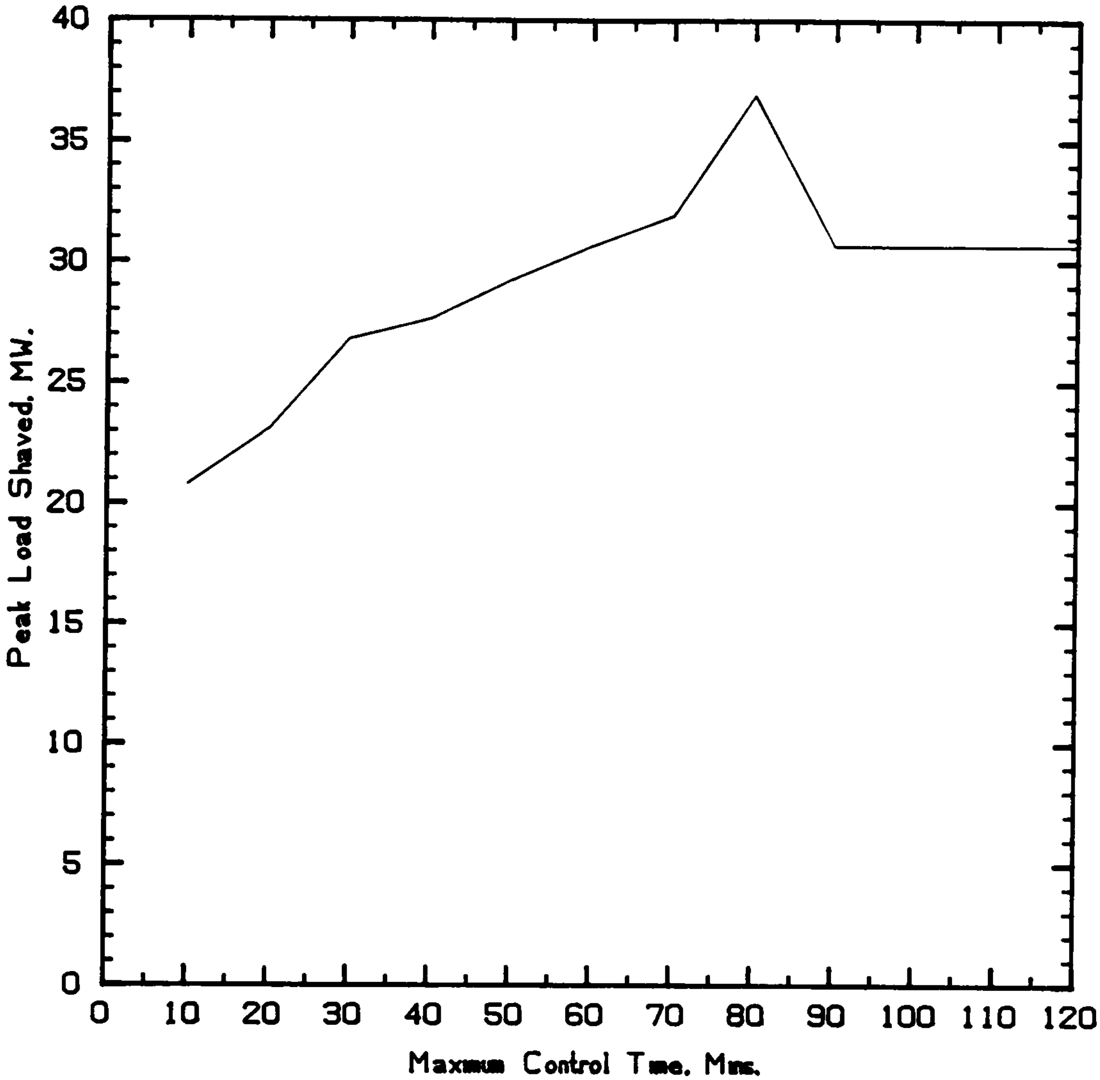

Figure 14. Peak Load Shaved Versus Maximum Control Time (Spring)

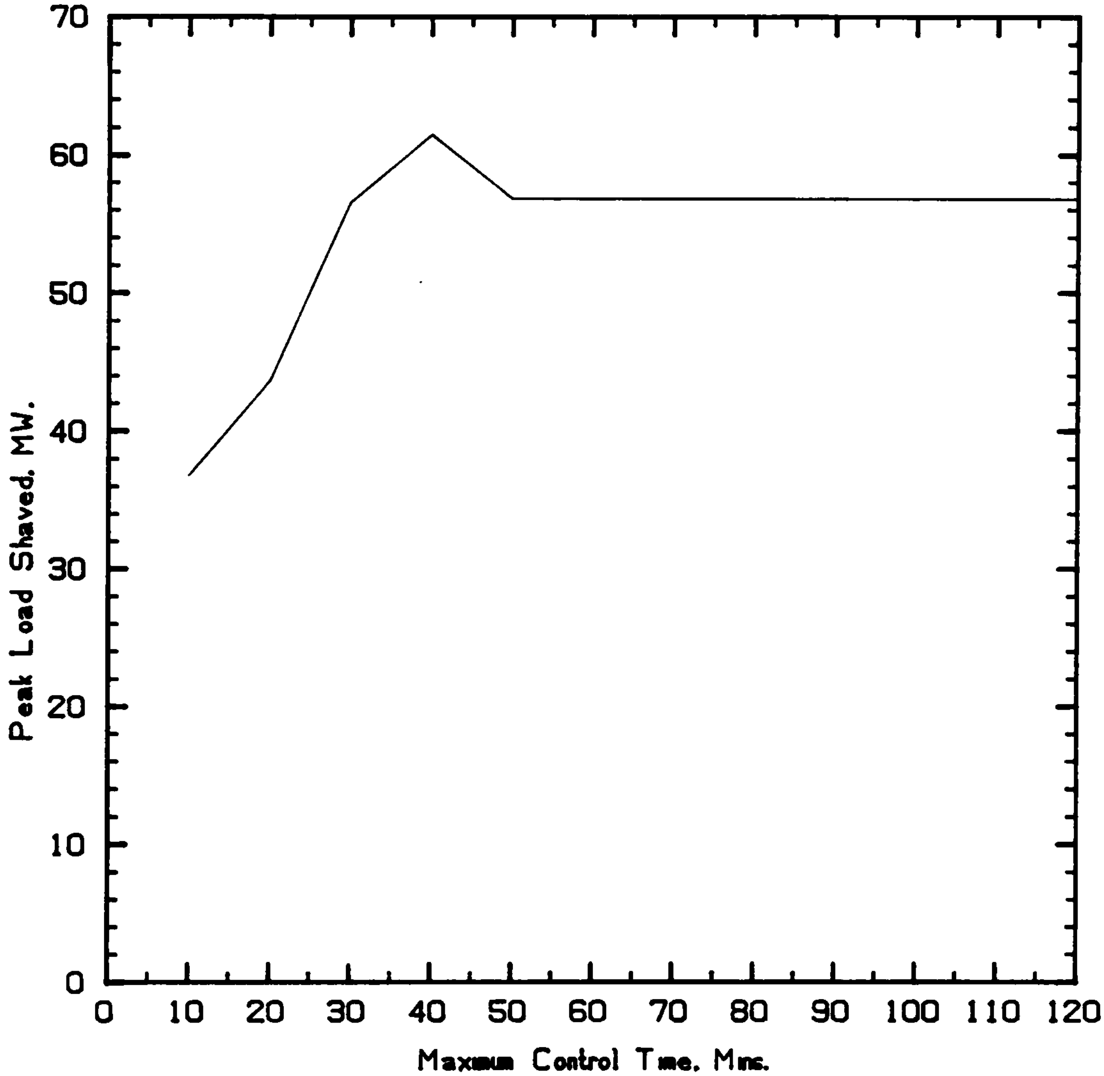

Figure 15. Peak Load Shaved Versus Maximum Control Time (Winter)

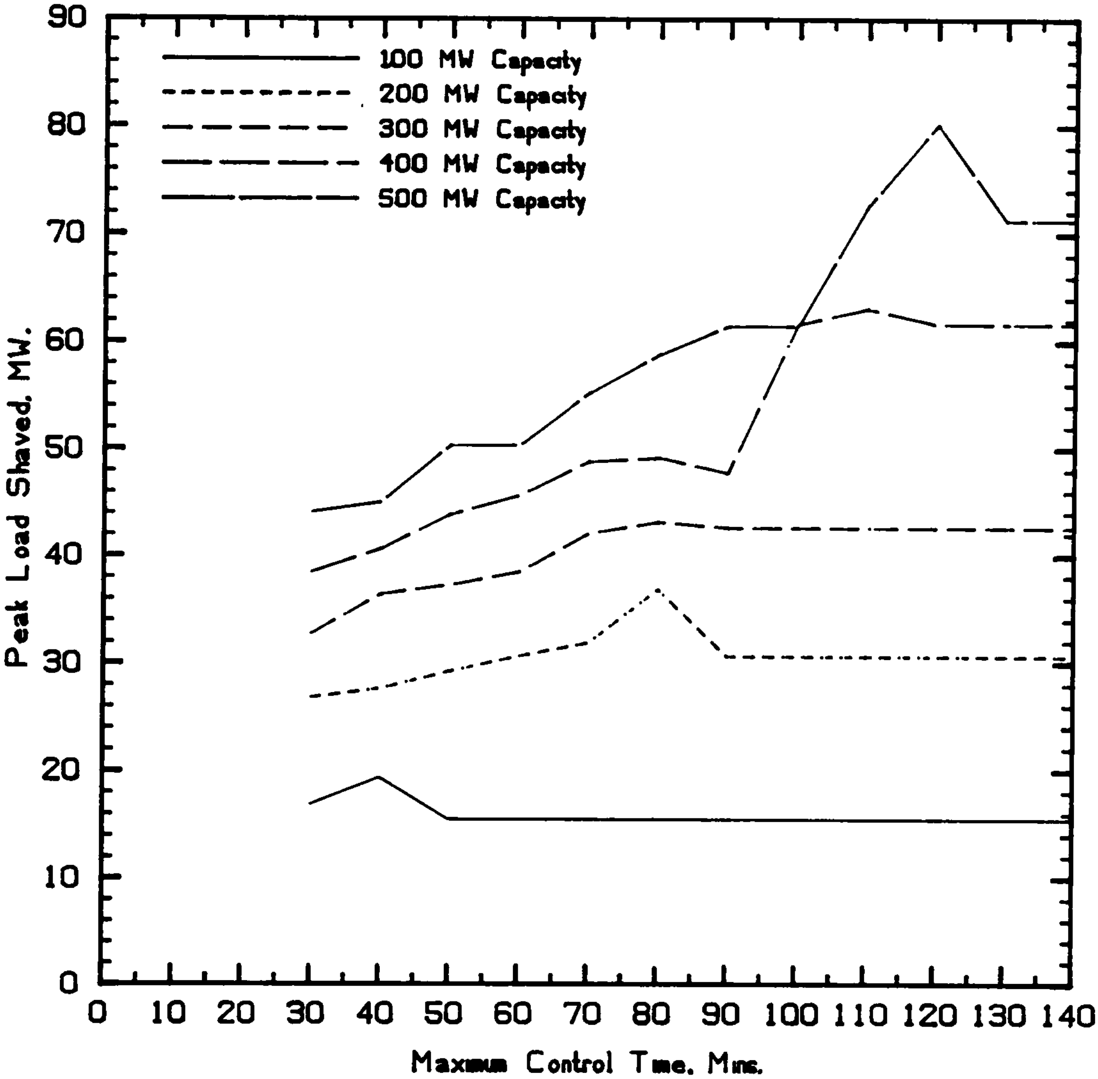

Figure 16. Variation of Peak Load Shaved Versus Maximum Control Time and DLC Capacity

DLC Capacity (MW)	Maximum Peak Shave Interval	Maximum Control Time
100.00	050.00	040.00
200.00	080.00	080.00
300.00	080.00	080.00
400.00	110.00	110.00
500.00	130.00	120.00

Figure 17. Maximum Peak Shave Interval Vs. Maximum Control Time

and maximum control times. While the well defined maxima are still visible, the length of the peak shaving period at the maxima, as shown in Figure 17 do not always exhibit a correspondence with the maximum control time. Examination of the load curve indicates that the slope of the load curve in the region of the peak shaving period also determines the length and magnitude of the peak shave. This illustrates the system load dependent characteristic of DLC dispatch. [It has already been shown that the savings or cost due to DLC dispatch depends on the cost coefficients of the set of on-line generators].

Figure 18 shows the effect of DLC control resolution on peak load shaved for the spring load shape. The variations, again, show no clear trend and the explanation forwarded for the variation of fuel cost savings with DLC control resolution is reiterated here.

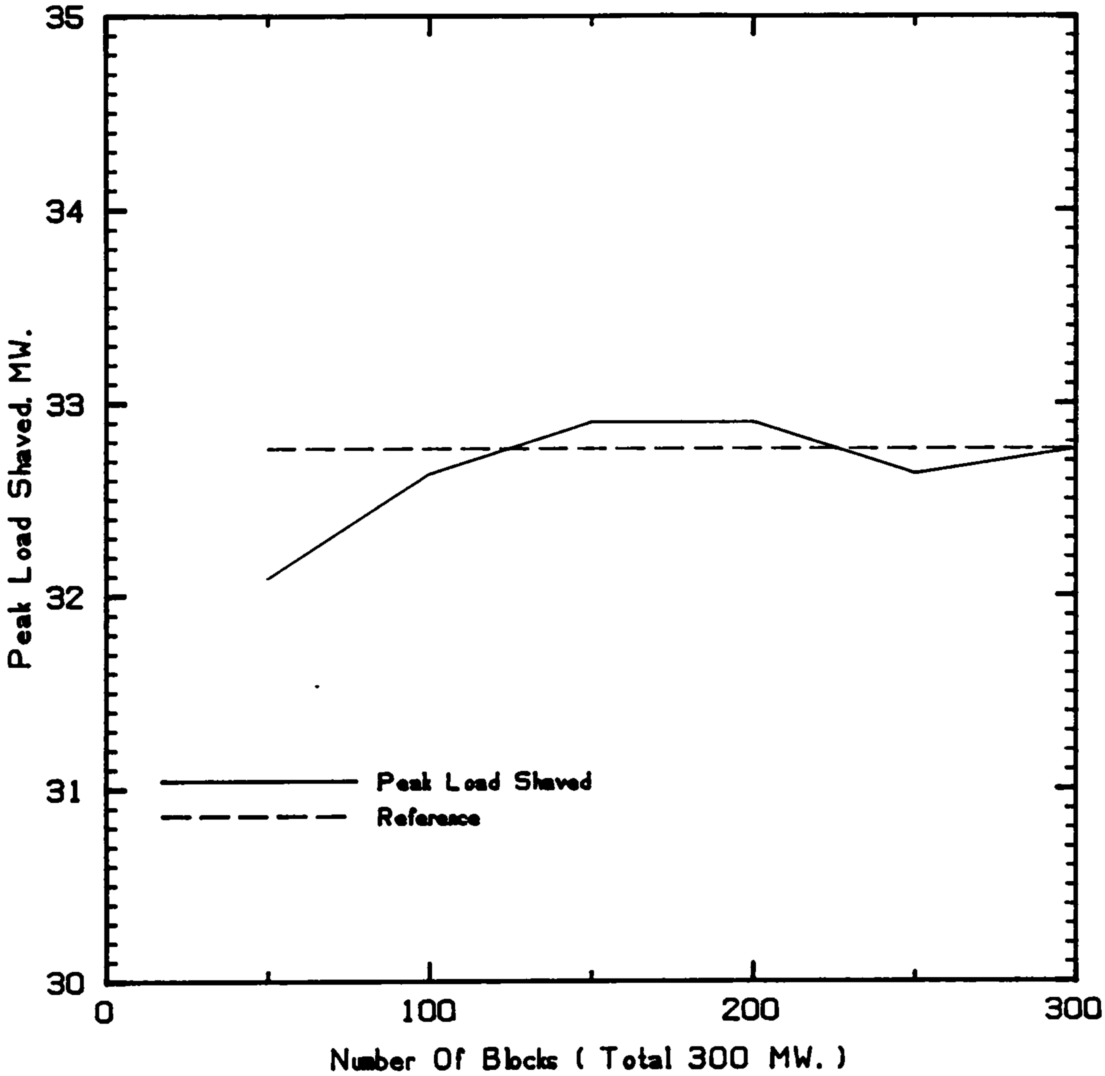

Figure 18. Peak Load Shaved Versus DLC Control Resolution. (Variable Number of Blocks at Constant Capacity)

CHAPTER IX

CONCLUSIONS AND RECOMMENDATIONS

Conceptually, the idea of the dynamic dispatch of DLC has been forwarded and defined as an ongoing process of evaluation and utilization of DLC to meet operational objectives on a 24 hour basis. Recent efforts in the industry have focussed on integrating DLC into system operations. However, at this point in the development of DLC, these efforts, as yet, view DLC as a discretionary resource to be utilized by the system resource, based on informed judgement. The integration efforts, therefore, are aimed at improving the informational bases for the operator's decisions.

This dissertation extends the idea of the integration of DLC to that of a dynamic process where DLC is utilized as an active resource, rather than as a discretionary one. Essentially, the idea developed here allows for the utilization of DLC for multiple objectives with the decisions regarding the optimum operating objective and state (defined by the amount under dispatch, idle and in payback) being evaluated throughout the 24 hour operations cycle. The characteristics of DLC are suitable for such an application.

One of the central concepts that was developed for the purpose of dynamic DLC dispatch is the cost characterization of DLC. During normal system operation, security and reliability being satisfied, economics is the major factor which dictates the use of resources. The definition of the operational cost (or savings) of DLC allows the comparison of DLC with other system resources in deciding the optimum economic resource utilization. While the concept of DLC operational costs has been speculated on in the literature, a concrete formulation has not yet been forthcoming. The cost definition (conceptual and mathematical) that has been developed here has been shown to be a viable concept which takes cognizance of all relevant factors -- operating constraints, payback, relative cost of other generation and load shape impacts.

Finally, a generation resource type of utilization for DLC -- dispatch for fuel cost minimization, has been formulated and demonstrated. The utility of DLC for such an objective will of course depend on the system characteristics -- capacity mix, load shape, demand diversity, coincidence of diversified demand with system peak, etc. It is beyond the scope of this dissertation to provide any conclusions on the benefits of DLC dispatch for fuel cost minimization. But it provides a concrete example of the concept of dynamic dispatch of DLC that has been developed here.

Further, the utility of dynamic dispatch of DLC has been demonstrated through the dual mode dispatch of DLC. The results proved that the online dispatch responded to system needs as well as provided greater benefits than could be expected from a single mode.

Simulation results from the model have also been presented to demonstrate the need for dynamic DLC dispatch by illustating the variations and relationships between DLC subsystem parameters, system characteristics and DLC operational objectives. Based on the data presented and the discussion of the previous chapter, it can be concluded that:

- The effect of DLC parameters is strongly dependent on the load shapes, the diversified demand curves and the coincidence between them.
- Indications are that fuel cost savings show a saturation with increasing DLC capacity. The saturation point is not fixed and depends on the load shape and the diversified demands.
- peak load shaving increases with the DLC capacity.
- The optimum control period for peak shaving is related to the period of the maximum of peak shave. This, in turn, is related to the available capacity.

In non-exact terms, the effect of DLC parameters depends on the capacity of the system to utilize DLC. Definite saturation and maximum points are indicated for fuel cost minimization and peak load shaving. Furthermore, all the variables of the problem of determining the optimum DLC strategy are interlinked. For example, the optimum maximum control periods for peak shaving were indicated as being 80 minutes for the spring load shape and 40 minutes for the winter load shape. [These optima were seen to change as the DLC capacity varied.] It was also pointed out that these times were equal to the length of the maximum peak shaving period. Consider if the maximum control time was increased to 50 minutes for the winter load shape. Then either of two events would take place:

1. the dispatch interval will increase, thus requiring greater capacity to obtain the same load reduction, else the amount shaved will decrease; or
2. if the interval remains the same, then all blocks can be dispatched to achieve a significant load reduction. But, the resulting payback may cause a second peak.

The inter-relationships apparent here, in fact highlight the requirement for a dynamic dispatch approach to DLC where on-line decisions can be made and revised as system load conditions change. This vindicates the contention and philosophy underlying this dissertation, that DLC utilization can be optimized by considering it as a dispatchable system resource and allowing its operation to be decided dynamically.

The successful simulation results also provide the proof of concept that was stated as one of the goals of this research. It has been shown that:

1. DLC can be modelled and dispatched as a system resource; and
2. it can be effectively integrated into online calculations for system operations.

9.1 RECOMMENDATIONS

The concepts developed here are part of an emerging philosophy of DLC utilization. As with any new concepts, those presented here, require considerable development, testing, and refining. Efforts have been made to develop a model of power system operations incorporating the dynamic dispatch of DLC. The model, while serving to concretize the ideas presented and providing a proof-of-concept, requires considerable more development to be regarded as an operational tool. The concept of dynamic dispatch itself, needs to be explored further in terms of possible uses of DLC and the criteria and algorithms for making the optimum decision.

Some issues which need to be researched further are:

- a unit commitment algorithm which would be more responsive to instantaneous load variations;

- the incorporation of an algorithm which could factor DLC into system reserve in an on-line mode. One possible method to do this is to examine the projected load from a future time equal to the start-up time of a unit which has the same capacity as DLC at that time. The set of possible units can be reduced considerably by the capacity matching requirement. Then, a preview of the operational cost savings of DLC from an objective such as fuel cost minimization and the savings from including DLC in the spinning reserve (equal to the costs incurred for the startup and operation of the unit) could provide the criterion for deciding between the two alternatives.
- on non-system peak days, peak shaving may provide capacity relief, reduce interchange requirements, etc. But since it would not contribute to the capacity deferral/reduction objective, trade-offs may be possible with other objectives of DLC such as fuel cost savings, system reserve contribution, regulating margin, etc. Research is required to determine methods of revaluating these trade-offs.
- a major concern is that as DLC is used more extensively the diversity of loads is going to change. Models are required for estimating the new diversity curves and the effect of DLC on the diversified demand.
- effect of DLC utilization on transmission and distribution planning;

- the long term effect of dynamic DLC utilization on system operation and planning. Reliability effects of DLC are one area in which further work needs to be done. Several concepts have been forwarded to account for the effect of DLC on system reliability such as Capacity Response Ratio. This ratio is a measure of the capacity equivalency of DLC for reliability purposes. But if DLC is also being utilized for other objectives then what is its contribution to system reliability?
- the dynamic dispatch concept developed here has dealt with the macroscopic or complete DLC system. However, it may be possible to utilize the same concept on a microscopic level to mitigate the effects of localized variations in the system load. For example, weather extremes in parts of the service territory could cause an unexpected peak in the system load. DLC could then be used in the 'problem' area to negate the effects of the weather extremes.

Finally, the effect of DLC system parameters and their relationship to the power system characteristics needs to be investigated further.

CHAPTER X

REFERENCES

1. Systems Control Inc.,"Critical Analysis of European Load Management Practices", NTIS/CONS/1168-1, Jan 1977.

2. B.F. Hastings,"Ten Years of Operating Experience With a Remote Controlled Water Heater Load Management System at Detroit Edison", IEEE Transactions on PAS, July/Aug 1980, pp.1437-1441.

3. U.S. Department of Energy,"Program Plan for Research, Development and Demonstration of Load Management on the Electric Power System", DOE/ET/0004, January 1978.

4. R.B. Comerford and C.W. Gellings,"The Application of Classical Forecasting Techniques to Load Management", IEEE Transactions on PAS, December 1982, pp.4656-4664.

5. R. Bhatnagar and S. Rahman,"Direct Load Control: Relationships Between Electric Utility Experiences/Assessments and System Characteristics", IEEE PES Winter Meeting, New York, February 1985, paper WM-012-0.

6. IEEE Load Management Working Group,"Economic Issues Related to Assessing Load Management in Electric Utilities", IEEE Transactions on PAS, June 1983, pp.1771-1777.

7. American Electric Power Service Corporation,"The Economic Feasibility of Direct Control of Residential Load Management on The AEP System", Report to the AEP Service Corporation, November 1982.

8. Myron D. Adams,"American Electric Power System Electric Thermal Storage Program: An Evaluation of the Impact On the Generation System", IEEE Transactions on PAS, April 1982, pp.836-694.

9. J. Flitter, L. Markel and P. Grimsrud,"A Load Management Feasibility Study for South Carolina Electric & Gas Co.", IEEE Transaction on PAS, October 1982, pp.3877-3883.

10. L. Finley, et al.,"Houston Lighting and Power's Preliminary Economic Analysis of Load Management",IEEE Transactions on PAS, December 1982, pp.4697-4702.

11. G.S. Fiske, E.T.K. Law and D.Q. Seeto,"The Economic Analysis of Load Management: The Case of A/C Cycling", IEEE Transactions on PAS, December 1981, pp.4725-4732.

12. C.W. Gellings, A.C. Johnson and P. Yatcko, "Load Management Assessment Methodology at P.S.E.& G.", IEEE Transactions on PAS, September 1982, pp. 3349-3355.

13. M.R. Minnick and R.E. Runnels,"Load Management Assessment: An Oil Burning Utility's Perspective", IEEE Transactions on PAS, October 1982, pp.3870-3876.

14. S.M. Barrager, C.E. Clark, et al.,"Load Management Strategy Testing Model", NTIS-EPRI-EA2396, May 1982.

15. IEEE Committee Report,"Impact of Major Load Management Projects", IEEE Transactions on PAS, October 1982, pp.3885-3891.

16. IEEE Committee Report,"Load Management -- How Will Operators Want to Use It", IEEE 1983 PES Winter Meeting, paper 83-WM-060-1.

17. K.D. Le, R.F. Boyle, et al.,"A Procedure for Coordinating Direct Load Control Strategies to Minimize System Production Costs", IEEE Transactions of PAS, June 1983, pp.1843-1849.

18. J.R. Stitt,"Implementation of a Large Scale Direct Load Control System. Some Critical Factors", IEEE Transactions on PAS, July 1985, pp.1663-1669.

19. R.F. Bischke and R.A. Sella,"Design and Controlled Use of Water Heater Load Management", IEEE Transactions on PAS, June 1985, pp. 1290-1293.

20. W.A. England and L.W. Harrison,"Integrating the Load Management Function into the Energy Control Center: A Case History", IEEE Transactions on PAS, June 1985, pp.1281-1285.

21. L.A. Finley, T.R. Standish and R.C. Phillips,"Optimizing System Performance Through Dynamic Load Shed Scheduling", IEEE Transactions on PAS, June 1985, pp.1286-1289.

22. M.A. Kuliasha, A Dynamic Model of Power System Operation Incorporating Load Control, Oak Ridge National Laboratory, October 1980, NTIS/ORNL-5655.

23. D.L. Geier and G.M. Samaniego,"Evaluation of Load Management as an Electric System Resource", 1985 PES Summer Meeting, Vancouver, July 1985, paper number 85 SM 475-9.

24. Argonne National Laboratory, Benefits and Costs of Load Management: A Technical Assistance and Resource Material Handbook, ANL/SPG-12, June 1980.

25. Energy Utilization Systems, Inc., Survey of Utility Load Management and Energy Conservation Projects, ORNL/SUB-77/13509/4, 1978.

26. S. Finger, Electric Power System Production Costing and Reliability Analysis Including Hydroelectric, Storage and Time Dependent Power Plants, MIT Energy Laboratory Technical Report, No. MIT-EL-79-006, February 1979.

27. IEEE Committee Report,"Spot Pricing of Surplus Energy by the Sharing of Interruptible Loads in a Regional Power Pool", IEEE Transactions on PAS, February 1985, pp.328-336.

28. R.R. Shoults, S.K. Chang, et al.,"A Practical Approach to Unit Commitment, Economic Dispatch and Savings Allocation for Multiple Area Operation With Import/Export Constraints", IEEE Transactions on PAS, March/April 1980, pp.625-635.

29. C.K. Pang and H.C. Chen,"Optimal Short Term Thermal Unit Commitment" , IEEE Transactions on PAS, July/August 1976, pp.1336-1346.

30. C.K. Pang, G.B. Sheble and F. Albuyeh,"Evaluation of Dynamic Programming Methods and Multiple Area Representation for Thermal Unit Commitment", IEEE Transactions on PAS, March 1981, pp.1212-1218.

31. L. Engles and R.E. Larson, Dynamic Programming Applied to Hydro And Thermal Generation Scheduling, IEEE Tutorial Course: Application of Optimization Methods in Power Systems Engineering, 76 CH1107-2-PWR.

32. Boeing Computer Services Company, EPRI Generating-Unit Commitment and Production-Costing Program -- User's Guide, NTIS/EPRI/EL-455, June 1982.

33. Boeing Computer Services Company, EPRI Generating-Unit Commitment and Production Costing Program -- Programmer's Guide, NTIS/EPRI/EL-455, June 1982.

34. R. Ramanathan, Multiprocessing With Microprocessors for Power Flow Analysis, Ph.D. Dissertation, V.P.I.& S.U., Blacksburg, VA., May 1982.

35. H.H. Happ, "Optimal Power Dispatch -- A Comprehensive Survey", IEEE Transactions on PAS, May/June 1977, pp.841-851.

36. A.M. Sasson and H.M. Merrill, "Some Applications of Optimization Techniques to Power System Problems", Proc. of the IEEE, Vol. 62, Number 7, July 1974, pp.959-972.

37. EPRI, The EPRI Regional Systems, NTIS/EPRI/P-1950-SR, July 1981.

38. J.G. Waight, A. Bose and G.B. Sheble, "Generation Dispatch With Reserve Margin Constraints Using Linear Programming", IEEE PES Winter Meeting, New York, February 1980.

39. C.M. Shen and M.A. Laughton, "Power System Load Scheduling With Security Constraints Using Dual Linear Programming", Proc. of the IEEE, November 1980, pp.2117-2127.

40. W.O. Stadlin, "Economic Allocation of Regulating Margin", IEEE Transactions on PAS, January 1971.

41. C.W. Brice, S.K. Jones, et al., Physically Based Stochastic Models of Power System Loads, Final Report, U.S. Department of Energy, June 1982.

42. D. Nelson, D. Newman, et al., A Physically Based Methodology for Constructing Load Models of Power Systems, Final Report, U.S. Department of Energy, June 1982.

43. S.H. Lee and C.L. Wilkins, "A Practical Approach to Appliance Load Control Analysis : A Water Heater Case Study", IEEE Transactions on PAS, April 1983, pp.1007-1013.

44. F.C. Schweppe, "Quantifying the A/C Component of Cold Load Pickup", IEEE Transactions on PAS, September 1983.

45. Conservation and Load Management Department, Water Heater Control Pilot Program Evaluation, Raleigh, North

Carolina, Carolina Power & Light Company, Raleigh, North Carolina, August 1982.

46. M.R. McRae, R.M. Scheer and B.A. Smith,"Integrating Load Management Programs Into Utility Operations and Planning With a Load Reduction Forecasting Program", IEEE Transactions on PAS, June 1985, pp.1321-1325.

47. R.E. Bellman,Dynamic Programming, Princeton University Press, Princeton, N.J., 1957.

48. G.L. Nemhauser,Introduction to Dynamic Programming, John Wiley and Sons, 1966.

49. D.J. White,Dynamic Programming, Oliver and Boyd, London, 1969.

50. R.E. Larson,State Increment Dynamic Programming, American Elsevier Publishing Company, New York, 1968.

51. R.L. Sullivan,Power System Planning, Mcgraw-Hill, New York.

APPENDIX A

SAMPLE OUTPUT REPORT : DUAL OPERATING MODE

```
****************************************
*                                      *
*         SAMPLE OUTPUT REPORT         *
*                                      *
*          DUAL OPERATING MODE         *
*                                      *
*                                      *
****************************************

****************************************
*                                      *
*        NUMBER OF BLOCKS = 200        *
*                                      *
*        TOTAL CAPACITY   = 200 MW.    *
*                                      *
*        MAXIMUM CONTROL  =  30 MINS.  *
*                                      *
****************************************
```

***** TIME ***** 0: 0 *****

***** PEAK ***** GLOBAL *****

***** PRELIMINARY RESULTS *****

>> SUGGESTED TARGET LOAD 4265.89

>> EXPECTED STARTING TIME 1: 0

BLOCK DISPATCH SEQUENCE FOR PEAK SHAVING

TIME	NUMBER
1: 0	1
1:10	17
1:20	35
1:30	54
1:40	87
1:50	117
2: 0	144
2:10	103

1

***** TIME ***** 0: 0 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 200

>> LOAD REDUCTION (MW.) = 45.638

>> COST SAVINGS ($) = 154.214

>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.039

>> SYSTEM LOAD BEFORE DISPATCH = 4121.703

>> SYSTEM LOAD AFTER DISPATCH = 4075.805

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	60.8048
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000

DISPATCHABLE GENERATION = 4075.8047

NON-DISPATCHABLE GENERATION = 0.0000

TOTAL SYSTEM GENERATION = 4075.8047

SYSTEM DEMAND = 4075.8052

SYSTEM LAMBDA = 30.1287

TOTAL SYSTEM COST = $ 86943.4375

1

***** TIME ***** 0:10 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 200
>> LOAD REDUCTION (MW.) = 47.181
>> COST SAVINGS ($) = 118.787
>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.040

>> SYSTEM LOAD BEFORE DISPATCH = 4145.781
>> SYSTEM LOAD AFTER DISPATCH = 4098.125

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000

8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	66.1248
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
34	BLEWET1A	GAS	2	17.0000

DISPATCHABLE GENERATION = 4081.1248

NON-DISPATCHABLE GENERATION = 17.0000

TOTAL SYSTEM GENERATION = 4098.1211

SYSTEM DEMAND = 4098.1250

SYSTEM LAMBDA = 30.5146

TOTAL SYSTEM COST = $ 88614.1250

1

***** TIME ***** 0:20 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 200

>> LOAD REDUCTION (MW.) = 48.792

>> COST SAVINGS ($) = 66.579

>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.041

>> SYSTEM LOAD BEFORE DISPATCH = 4169.863

>> SYSTEM LOAD AFTER DISPATCH = 4120.645

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000

20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	73.6441
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
40	LEEICT 2	GAS	2	32.0000

DISPATCHABLE GENERATION = 4088.6440

NON-DISPATCHABLE GENERATION = 32.0000

TOTAL SYSTEM GENERATION = 4120.6406

SYSTEM DEMAND = 4120.6445

SYSTEM LAMBDA = 31.0601

TOTAL SYSTEM COST = $ 90014.8125

1

***** TIME ***** 0:30 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 0
>> LOAD REDUCTION (MW.) = 0.000
>> COST SAVINGS ($) = 0.000
>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.042

>> SYSTEM LOAD BEFORE DISPATCH = 4193.945

>> SYSTEM LOAD AFTER DISPATCH = 4229.102

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	69.1012
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000

DISPATCHABLE GENERATION = 4084.1011

NON-DISPATCHABLE GENERATION = 145.0000

TOTAL SYSTEM GENERATION = 4229.0977

SYSTEM DEMAND = 4229.1016

SYSTEM LAMBDA = 30.7305

TOTAL SYSTEM COST = $ 97432.5000

1

***** TIME ***** 0:40 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 0
>> LOAD REDUCTION (MW.) = 0.000
>> COST SAVINGS ($) = -19.976

>> SYSTEM LOAD BEFORE DISPATCH = 4218.027
>> SYSTEM LOAD AFTER DISPATCH = 4230.527

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000

9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	70.5268
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000

DISPATCHABLE GENERATION = 4085.5266

NON-DISPATCHABLE GENERATION = 145.0000

TOTAL SYSTEM GENERATION = 4230.5234

SYSTEM DEMAND = 4230.5273

SYSTEM LAMBDA = 30.8340

TOTAL SYSTEM COST = $ 97476.4375

1

***** TIME ***** 0:50 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED	=	0
>> LOAD REDUCTION (MW.)	=	0.000
>> COST SAVINGS ($)	=	0.000

>> SYSTEM LOAD BEFORE DISPATCH	=	4242.109
>> SYSTEM LOAD AFTER DISPATCH	=	4242.109

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000

20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	67.1091
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
40	LEEICT 2	GAS	2	32.0000

DISPATCHABLE GENERATION = 4082.1089

NON-DISPATCHABLE GENERATION = 160.0000

TOTAL SYSTEM GENERATION = 4242.1055

SYSTEM DEMAND = 4242.1094

SYSTEM LAMBDA = 30.5860

TOTAL SYSTEM COST = $ 98540.6250

1

***** TIME ***** 1: 0 *****

***** PEAK ***** GLOBAL *****

***** PRELIMINARY RESULTS *****

>> SUGGESTED TARGET LOAD 4265.89

```
>> EXPECTED STARTING TIME      1: 0

BLOCK DISPATCH SEQUENCE FOR PEAK SHAVING

TIME       NUMBER
----       ------


 1: 0         1

 1:10        17

 1:20        35

 1:30        54

 1:40        87

 1:50       117

 2: 0       144

 2:10       103

1
***** TIME *****   1: 0   *****



***** PEAK SHAVING MODE *****


>> NUMBER OF BLOCKS DISPATCHED   =         1
>> LOAD REDUCTION (MW.)          =     0.275
>> COST SAVINGS ($)              =     7.685
```

>> SYSTEM LOAD BEFORE DISPATCH = 4266.191

>> SYSTEM LOAD AFTER DISPATCH = 4265.914

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.9135
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.9133

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.9102

SYSTEM DEMAND = 4265.9141

SYSTEM LAMBDA = 30.3542

TOTAL SYSTEM COST = $ 101151.1870

1

***** TIME ***** 1:10 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 17
>> LOAD REDUCTION (MW.) = 4.547
>> COST SAVINGS ($) = 23.915

>> SYSTEM LOAD BEFORE DISPATCH = 4270.598
>> SYSTEM LOAD AFTER DISPATCH = 4266.016

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000

3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	64.0150
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4079.0149

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4266.0117

SYSTEM DEMAND = 4266.0156

SYSTEM LAMBDA = 30.3616

TOTAL SYSTEM COST = $ 101154.3120

1

***** TIME ***** 1:20 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 35

>> LOAD REDUCTION (MW.) = 9.079

>> COST SAVINGS ($) = 41.175

>> SYSTEM LOAD BEFORE DISPATCH = 4275.004

>> SYSTEM LOAD AFTER DISPATCH = 4265.844

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000

15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.8434
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.8433

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.8398

SYSTEM DEMAND = 4265.8437

SYSTEM LAMBDA = 30.3492

TOTAL SYSTEM COST = $ 101149.0620

1

***** TIME ***** 1:30 *****

***** PEAK SHAVING MODE *****

```
>> NUMBER OF BLOCKS DISPATCHED   =        54
>> LOAD REDUCTION (MW.)          =    13.591
>> COST SAVINGS ($)              =    57.601


>> SYSTEM LOAD BEFORE DISPATCH   =  4279.410
>> SYSTEM LOAD AFTER DISPATCH    =  4265.895
```

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.8943
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000

28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.8943

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.8906

SYSTEM DEMAND = 4265.8945

SYSTEM LAMBDA = 30.3528

TOTAL SYSTEM COST = $ 101150.6250

1

***** TIME ***** 1:40 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 86
>> LOAD REDUCTION (MW.) = 20.980
>> COST SAVINGS ($) = 74.066

>> SYSTEM LOAD BEFORE DISPATCH = 4283.820
>> SYSTEM LOAD AFTER DISPATCH = 4265.937

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.9370
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.9368

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.9336

SYSTEM DEMAND = 4265.9375

SYSTEM LAMBDA = 30.3559

TOTAL SYSTEM COST = $ 101151.9370

1

***** TIME ***** 1:50 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 116
>> LOAD REDUCTION (MW.) = 27.365
>> COST SAVINGS ($) = 91.395

>> SYSTEM LOAD BEFORE DISPATCH = 4288.227
>> SYSTEM LOAD AFTER DISPATCH = 4265.750

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000

11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.7494
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.7493

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.7461

SYSTEM DEMAND = 4265.7500

SYSTEM LAMBDA = 30.3423

TOTAL SYSTEM COST = $ 101146.2500

1

***** TIME ***** 2: 0 *****

***** PEAK ***** GLOBAL *****

***** PRELIMINARY RESULTS *****

>> SUGGESTED TARGET LOAD 4265.89

>> EXPECTED STARTING TIME 1: 0

BLOCK DISPATCH SEQUENCE FOR PEAK SHAVING

TIME	NUMBER
1: 0	1
1:10	17
1:20	35
1:30	54
1:40	87
1:50	117
2: 0	144
2:10	103

1

***** TIME ***** 2: 0 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 144
>> LOAD REDUCTION (MW.) = 32.859
>> COST SAVINGS ($) = 78.481

>> SYSTEM LOAD BEFORE DISPATCH = 4292.633
>> SYSTEM LOAD AFTER DISPATCH = 4265.648

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000

19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.6481
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.6479

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.6445

SYSTEM DEMAND = 4265.6484

SYSTEM LAMBDA = 30.3350

TOTAL SYSTEM COST = $ 101143.1250

1

***** TIME ***** 2:10 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 102
>> LOAD REDUCTION (MW.) = 23.036
>> COST SAVINGS ($) = 19.123

\>> SYSTEM LOAD BEFORE DISPATCH = 4277.207

\>> SYSTEM LOAD AFTER DISPATCH = 4265.965

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.9643
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.9641

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.9609

SYSTEM DEMAND = 4265.9648

SYSTEM LAMBDA = 30.3579

TOTAL SYSTEM COST = $ 101152.7500

1

***** TIME ***** 2:20 *****

***** PEAK SHAVING MODE *****

>> NUMBER OF BLOCKS DISPATCHED = 48
>> LOAD REDUCTION (MW.) = 10.744
>> COST SAVINGS ($) = -38.728

>> SYSTEM LOAD BEFORE DISPATCH = 4261.785
>> SYSTEM LOAD AFTER DISPATCH = 4265.895

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000

3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	63.8940
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
38	WTSPNIC1	OIL	2	42.0000

DISPATCHABLE GENERATION = 4078.8938

NON-DISPATCHABLE GENERATION = 187.0000

TOTAL SYSTEM GENERATION = 4265.8906

SYSTEM DEMAND = 4265.8945

SYSTEM LAMBDA = 30.3528

TOTAL SYSTEM COST = $ 101150.6250

1

***** TIME ***** 2:30 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 155
>> LOAD REDUCTION (MW.) = 34.329
>> COST SAVINGS ($) = 104.975
>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.037

>> SYSTEM LOAD BEFORE DISPATCH = 4246.359
>> SYSTEM LOAD AFTER DISPATCH = 4226.227

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000

14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	66.2263
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000

DISPATCHABLE GENERATION = 4081.2261

NON-DISPATCHABLE GENERATION = 145.0000

TOTAL SYSTEM GENERATION = 4226.2227

SYSTEM DEMAND = 4226.2266

SYSTEM LAMBDA = 30.5220

TOTAL SYSTEM COST = $ 97344.5000

1

***** TIME ***** 2:40 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 200

>> LOAD REDUCTION (MW.) = 43.825

>> COST SAVINGS ($) = 87.121

>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.036

>> SYSTEM LOAD BEFORE DISPATCH = 4230.934

>> SYSTEM LOAD AFTER DISPATCH = 4190.621

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	61.6207
23	CFHREC 1	COAL	1	80.0000

24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
34	BLEWET1A	GAS	2	17.0000
41	SUTONIC2	OIL	2	33.0000

DISPATCHABLE GENERATION = 4076.6206

NON-DISPATCHABLE GENERATION = 114.0000

TOTAL SYSTEM GENERATION = 4190.6172

SYSTEM DEMAND = 4190.6211

SYSTEM LAMBDA = 30.1879

TOTAL SYSTEM COST = $ 95999.1250

1

***** TIME ***** 2:50 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 45
>> LOAD REDUCTION (MW.) = 9.770
>> COST SAVINGS ($) = 16.280
>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.036

>> SYSTEM LOAD BEFORE DISPATCH = 4215.508
>> SYSTEM LOAD AFTER DISPATCH = 4226.250

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000
10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	51.2496
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000
40	LEEICT 2	GAS	2	32.0000

DISPATCHABLE GENERATION = 4066.2495

NON-DISPATCHABLE GENERATION = 160.0000

TOTAL SYSTEM GENERATION = 4226.2461

SYSTEM DEMAND = 4226.2500

SYSTEM LAMBDA = 29.4356

TOTAL SYSTEM COST = $ 98064.6875

1

***** TIME ***** 3: 0 *****

***** FUEL COST MINIMIZATION *****

>> NUMBER OF BLOCKS DISPATCHED = 0
>> LOAD REDUCTION (MW.) = 0.000
>> COST SAVINGS ($) = 0.000
>> ENERGY DEFERRED PER BLOCK (MWHR) = 0.036

>> SYSTEM LOAD BEFORE DISPATCH = 4200.086
>> SYSTEM LOAD AFTER DISPATCH = 4213.504

UNIT NO.	UNIT ID.	FUEL	TYPE	OUTPUT (MW.)
2	ROXBORO4	COAL	1	760.0000
3	ROXBORO1	COAL	1	420.0000
4	ROBNSON1	COAL	1	190.0000
5	ROBNSON2	COAL	1	190.0000
6	LEEUNIT3	COAL	1	270.0000
8	ASHEVLE2	COAL	1	210.0000
9	SUTTON 2	COAL	1	115.0000

10	SUTTON 3	COAL	1	450.0000
11	SUTTON 4	COAL	1	450.0000
12	SUTTON1B	COAL	1	110.0000
13	SUTTON 1	COAL	1	110.0000
14	SUTTON1A	COAL	1	90.0000
15	WTHSPN 1	COAL	1	55.0000
16	WTHSPN 2	COAL	1	55.0000
17	WTHSPN 3	COAL	1	85.0000
18	WTHSPN 4	COAL	1	55.0000
19	WTHSPN 5	COAL	1	55.0000
20	LEE UNT2	COAL	1	90.0000
21	LEE UNT1	COAL	1	90.0000
22	BLEWETT1	COAL	1	70.5035
23	CFHREC 1	COAL	1	80.0000
24	WTHSPN 7	COAL	1	85.0000
28	DRLNGTN1	OIL	2	64.0000
29	DRLNGTN2	OIL	2	64.0000

DISPATCHABLE GENERATION = 4085.5034

NON-DISPATCHABLE GENERATION = 128.0000

TOTAL SYSTEM GENERATION = 4213.5000

SYSTEM DEMAND = 4213.5039

SYSTEM LAMBDA = 30.8323

TOTAL SYSTEM COST = $ 95966.3125

********** SUMMARY REPORT **********

ENERGY SERVED BEFORE DLC	=	73251.250
ENERGY SERVED AFTER DLC	=	73071.375
DIFFERENCE ENERGY SERVED	=	179.875
TOTAL ENERGY DEFERRED	=	249.699
SYSTEM PEAK BEFORE DLC	=	4292.633
SYSTEM PEAKAFTER DLC	=	4266.016
TOTAL GENERATION COSTS	=	1580383.000
GENERATION COST SAVINGS	=	3269.804
FUEL COST SAVINGS (PEAK SHAVING)	=	296.780

APPENDIX B

INPUT DATA FOR DLCDISP

```
            **********************************************
            *                                            *
            *           DATA INPUT FOR DLCDISP           *
            *                                            *
            *         (SPRING UNIT AVAILABILITY)         *
            *                                            *
            *  (FILE CREATED BY INTERACTIVE INPUT PROGRAM) *
            **********************************************
**                       **
** SIMULATION TIME IN MINS.**
**                       **
1200.00

**                                                                     **
** TOTAL NUMBER OF UNITS, NUMBER OF DISPATCHABLE UNITS, NUMBER OF CTS **
**            (NUCLEAR BASE LOAD UNITS EXCLUDED)                      **
**                                                                     **
41 24 17

**                                            **
** UNIT NUMBER, UNIT ID, UNIT TYPE, FUEL TYPE **
**                                            **
 1 ROXBORO3  1 COAL
 2 ROXBORO4  1 COAL
 3 ROXBORO1  1 COAL
 4 ROBNSON1  1 COAL
 5 ROBNSON2  1 COAL
 6 LEEUNIT3  1 COAL
 7 ASHEVLE1  1 COAL
 8 ASHEVLE2  1 COAL
 9 SUTTON 2  1 COAL
10 SUTTON 3  1 COAL
11 SUTTON 4  1 COAL
12 SUTTON1B  1 COAL
13 SUTTON 1  1 COAL
```

14	SUTTON1A	1	COAL
15	WTHSPN 1	1	COAL
16	WTHSPN 2	1	COAL
17	WTHSPN 3	1	COAL
18	WTHSPN 4	1	COAL
19	WTHSPN 5	1	COAL
20	LEE UNT2	1	COAL
21	LEE UNT1	1	COAL
22	BLEWETT1	1	COAL
23	CFHREC 1	1	COAL
24	WTHSPN 7	1	COAL
25	MOREHD1A	2	GAS
26	ROBNSN1A	2	OIL
27	ROXBRO1A	2	GAS
28	DRLNGTN1	2	OIL
29	DRLNGTN2	2	OIL
30	DRLNGTN3	2	OIL
31	DRLNGTN4	2	OIL
32	DRLNGTN5	2	OIL
33	DRLNGTN6	2	OIL
34	BLEWET1A	2	GAS
35	BLEWET2A	2	GAS
36	BLEWET3A	2	GAS
37	BLEWET4A	2	GAS
38	WTSPNIC1	2	OIL
39	LEEICT 1	2	GAS
40	LEEICT 2	2	GAS
41	SUTONIC2	2	OIL

** **

** COST COEFFICIENTS AND UNIT FUEL COSTS **

** **

680.941472	7.189709	0.001852	2.110
702.962766	7.681645	0.001371	2.110
401.805713	7.245143	0.004253	2.110

118.276158	8.117995	0.004253	2.110
120.276158	8.117995	0.004483	2.110
162.333586	7.643047	0.003265	2.110
269.422099	6.091183	0.009388	2.110
248.665264	6.544131	0.010109	2.110
156.272943	6.122496	0.025779	2.110
391.128891	7.463225	0.003063	2.110
396.128891	7.463225	0.003063	2.110
117.296959	7.903477	0.015792	2.110
117.296959	7.903477	0.015792	2.110
49.930167	13.002987	0.004356	2.110
32.600426	10.016945	0.013248	2.110
32.600426	10.016945	0.013248	2.110
85.080842	7.489352	0.017369	2.110
32.600426	10.016945	0.013248	2.110
32.600426	10.016945	0.013248	2.110
118.552580	7.590891	0.027030	2.110
103.900210	7.517778	0.027613	2.110
52.503344	12.188683	0.017189	2.110
47.585357	8.994592	0.017462	2.110
85.080842	7.489352	0.017369	2.110
87.876000	9.217000	0.000000	5.900
87.468000	9.245000	0.000000	5.530
87.036000	9.258000	0.000000	5.900
236.716000	8.631000	0.000000	5.530
236.716000	8.631000	0.000000	5.530
236.716000	8.631000	0.000000	5.530
236.716000	8.631000	0.000000	5.530
236.716000	8.631000	0.000000	5.530
236.716000	8.631000	0.000000	5.530
71.181000	10.862000	0.000000	5.900
71.181000	10.862000	0.000000	5.900
71.181000	10.862000	0.000000	5.900
71.181000	10.862000	0.000000	5.900
291.830000	9.745000	0.000000	5.530

87.876000	9.217000	0.000000	5.900
135.828000	9.943000	0.000000	5.900
262.112000	9.363000	0.000000	5.530

** **

** RAISE AND LOWER RAMP RATES, MIN. & MAX. CAPACITY **

** **

0.030	0.030	250.00	760.00	0.10
0.030	0.030	174.00	760.00	0.10
0.050	0.050	125.00	420.00	0.10
0.070	0.070	50.00	190.00	0.10
0.070	0.070	50.00	190.00	0.10
0.050	0.050	65.00	270.00	0.10
0.050	0.050	70.00	210.00	0.10
0.050	0.050	70.00	210.00	0.10
0.070	0.070	35.00	115.00	0.10
0.030	0.030	136.00	450.00	0.10
0.030	0.030	136.00	450.00	0.10
0.070	0.070	35.00	110.00	0.10
0.070	0.070	35.00	110.00	0.10
0.100	0.100	25.00	90.00	0.10
0.100	0.100	25.00	55.00	0.10
0.100	0.100	25.00	55.00	0.10
0.100	0.100	33.00	85.00	0.10
0.100	0.100	25.00	55.00	0.10
0.100	0.100	25.00	55.00	0.10
0.100	0.100	35.00	90.00	0.10
0.100	0.100	35.00	90.00	0.10
0.100	0.100	25.00	76.00	0.10
0.100	0.100	25.00	80.00	0.10
0.100	0.100	33.00	85.00	0.10
1.000	1.000	0.00	18.00	1.00
1.000	1.000	0.00	18.00	1.00
1.000	1.000	0.00	18.00	1.00
1.000	1.000	0.00	64.00	1.00

```
 1.000  1.000     0.00    64.00     1.00
 1.000  1.000     0.00    64.00     1.00
 1.000  1.000     0.00    64.00     1.00
 1.000  1.000     0.00    64.00     1.00
 1.000  1.000     0.00    64.00     1.00
 1.000  1.000     0.00    17.00     1.00
 1.000  1.000     0.00    17.00     1.00
 1.000  1.000     0.00    17.00     1.00
 1.000  1.000     0.00    17.00     1.00
 1.000  1.000     0.00    42.00     1.00
 1.000  1.000     0.00    18.00     1.00
 1.000  1.000     0.00    32.00     1.00
 1.000  1.000     0.00    33.00     1.00

**                             **
** ECONOMIC DISPATCH INTERVAL **
**                             **
 2.000

**                                                                **
** NUMBER OF BLOCKS, BLOCK CAPACITY (NUMBER OF DEVICES/1000), **
**                MAXIMUM CONTROL TIME                            **
200  0.33557 030.000

**                        **
** DLC DISPATCH INTERVAL **
**                        **
10.000

**                                                       **
** NUMBER OF LOAD AND DIVERSIFIED DEMAND DATA POINTS **
**   (SIMULATION TIME/ECONOMIC DISPATCH INTERVAL)       **
**                                                       **
721
```

**

** EXPECTED SYSTEM LOAD AND DIVERSIFIED DEMAND **

** **

3925.431	0.680
3930.018	0.685
3934.605	0.689
3939.192	0.694
3943.779	0.699
3948.366	0.703
3952.953	0.708
3957.540	0.713
3962.126	0.717
3966.714	0.722
3971.301	0.727
3975.887	0.731
3980.474	0.736
3985.062	0.741
3989.648	0.745
3994.235	0.750
3998.822	0.755
4003.409	0.759
4007.996	0.764
4012.583	0.769
4017.170	0.773
4021.757	0.778
4026.344	0.783
4030.931	0.787
4035.518	0.792
4040.105	0.797
4044.692	0.801
4049.279	0.806
4053.866	0.811
4058.453	0.815
4063.040	0.820
4063.879	0.815

4064.719	0.811
4065.558	0.806
4066.398	0.801
4067.237	0.797
4068.076	0.792
4068.916	0.787
4069.755	0.783
4070.595	0.778
4071.434	0.773
4072.274	0.769
4073.113	0.764
4073.952	0.759
4074.792	0.755
4075.631	0.750
4076.471	0.745
4077.310	0.741
4078.150	0.736
4078.989	0.731
4079.829	0.727
4080.668	0.722
4081.507	0.717
4082.347	0.713
4083.186	0.708
4084.026	0.703
4084.865	0.699
4085.705	0.694
4086.544	0.689
4087.383	0.685
4088.223	0.680
4085.285	0.679
4082.347	0.677
4079.409	0.676
4076.471	0.675
4073.533	0.673
4070.595	0.672

4067.656	0.671
4064.719	0.669
4061.781	0.668
4058.843	0.667
4055.905	0.665
4052.967	0.664
4050.028	0.663
4047.090	0.661
4044.152	0.660
4041.214	0.659
4038.276	0.657
4035.338	0.656
4032.400	0.655
4029.462	0.653
4026.524	0.652
4023.586	0.651
4020.648	0.649
4017.710	0.648
4014.772	0.647
4011.834	0.645
4008.896	0.644
4005.958	0.643
4003.020	0.641
4000.082	0.640
3995.135	0.640
3990.188	0.639
3985.242	0.639
3980.295	0.639
3975.348	0.638
3970.402	0.638
3965.455	0.638
3960.508	0.637
3955.562	0.637
3950.615	0.637
3945.668	0.636

3940.721	0.636
3935.775	0.636
3930.828	0.635
3925.881	0.635
3920.935	0.635
3915.988	0.634
3911.041	0.634
3906.094	0.634
3901.148	0.633
3896.201	0.633
3891.254	0.633
3886.308	0.632
3881.361	0.632
3876.414	0.632
3871.468	0.631
3866.521	0.631
3861.574	0.631
3856.627	0.630
3851.681	0.630
3850.632	0.628
3849.582	0.625
3848.533	0.623
3847.484	0.621
3846.434	0.618
3845.385	0.616
3844.336	0.614
3843.286	0.611
3842.237	0.609
3841.188	0.607
3840.138	0.604
3839.089	0.602
3838.040	0.600
3836.990	0.597
3835.941	0.595
3834.892	0.593

3833.843	0.590
3832.793	0.588
3831.744	0.586
3830.695	0.583
3829.646	0.581
3828.596	0.579
3827.547	0.576
3826.498	0.574
3825.448	0.572
3824.399	0.569
3823.350	0.567
3822.300	0.565
3821.251	0.562
3820.202	0.560
3818.193	0.557
3816.185	0.554
3814.176	0.550
3812.167	0.547
3810.158	0.544
3808.150	0.541
3806.141	0.538
3804.133	0.535
3802.124	0.531
3800.115	0.528
3798.106	0.525
3796.098	0.522
3794.089	0.519
3792.081	0.516
3790.072	0.512
3788.063	0.509
3786.054	0.506
3784.046	0.503
3782.037	0.500
3780.029	0.497
3778.020	0.493

3776.011	0.490
3774.002	0.487
3771.994	0.484
3769.985	0.481
3767.977	0.478
3765.968	0.475
3763.959	0.471
3761.950	0.468
3759.942	0.465
3759.672	0.467
3759.402	0.469
3759.132	0.471
3758.863	0.474
3758.593	0.476
3758.323	0.478
3758.053	0.480
3757.783	0.482
3757.513	0.484
3757.243	0.487
3756.974	0.489
3756.704	0.491
3756.434	0.493
3756.164	0.495
3755.894	0.497
3755.625	0.500
3755.355	0.502
3755.085	0.504
3754.815	0.506
3754.545	0.508
3754.275	0.510
3754.005	0.513
3753.736	0.515
3753.466	0.517
3753.196	0.519
3752.926	0.521

3752.656	0.523
3752.386	0.526
3752.117	0.528
3751.847	0.530
3758.038	0.528
3764.229	0.526
3770.419	0.524
3776.610	0.523
3782.801	0.521
3788.992	0.519
3795.183	0.517
3801.374	0.515
3807.565	0.513
3813.756	0.512
3819.946	0.510
3826.137	0.508
3832.328	0.506
3838.519	0.504
3844.710	0.502
3850.901	0.501
3857.092	0.499
3863.282	0.497
3869.473	0.495
3875.664	0.493
3881.855	0.491
3888.046	0.490
3894.237	0.488
3900.428	0.486
3906.618	0.484
3912.809	0.482
3919.000	0.480
3925.191	0.479
3931.382	0.477
3937.573	0.475
3938.352	0.479

3939.132	0.483
3939.911	0.487
3940.691	0.491
3941.470	0.495
3942.250	0.499
3943.029	0.503
3943.809	0.507
3944.588	0.511
3945.368	0.515
3946.147	0.519
3946.927	0.523
3947.706	0.527
3948.486	0.531
3949.265	0.535
3950.045	0.539
3950.824	0.543
3951.604	0.547
3952.383	0.551
3953.163	0.555
3953.942	0.559
3954.722	0.563
3955.501	0.567
3956.281	0.571
3957.060	0.575
3957.840	0.579
3958.619	0.583
3959.399	0.587
3960.178	0.591
3960.958	0.595
3959.309	0.595
3957.660	0.595
3956.011	0.595
3954.362	0.596
3952.713	0.596
3951.064	0.596

3949.416	0.596
3947.767	0.596
3946.118	0.596
3944.469	0.597
3942.820	0.597
3941.171	0.597
3939.522	0.597
3937.873	0.597
3936.224	0.598
3934.575	0.598
3932.927	0.598
3931.278	0.598
3929.629	0.598
3927.980	0.598
3926.331	0.599
3924.682	0.599
3923.033	0.599
3921.384	0.599
3919.735	0.599
3918.086	0.599
3916.437	0.600
3914.789	0.600
3913.140	0.600
3911.491	0.600
3913.365	0.599
3915.238	0.597
3917.112	0.596
3918.986	0.595
3920.860	0.593
3922.733	0.592
3924.607	0.591
3926.481	0.589
3928.354	0.588
3930.228	0.587
3932.102	0.585

3933.976	0.584
3935.849	0.583
3937.723	0.581
3939.597	0.580
3941.470	0.579
3943.344	0.577
3945.218	0.576
3947.092	0.575
3948.966	0.573
3950.839	0.572
3952.713	0.571
3954.587	0.569
3956.460	0.568
3958.334	0.567
3960.208	0.565
3962.082	0.564
3963.955	0.563
3965.829	0.561
3967.703	0.560
3965.859	0.558
3964.015	0.556
3962.171	0.554
3960.328	0.553
3958.484	0.551
3956.640	0.549
3954.796	0.547
3952.953	0.545
3951.109	0.543
3949.265	0.542
3947.421	0.540
3945.578	0.538
3943.734	0.536
3941.890	0.534
3940.046	0.532
3938.202	0.531

3936.359	0.529
3934.515	0.527
3932.671	0.525
3930.827	0.523
3928.984	0.521
3927.140	0.520
3925.296	0.518
3923.452	0.516
3921.609	0.514
3919.765	0.512
3917.921	0.510
3916.077	0.509
3914.234	0.507
3912.390	0.505
3906.364	0.505
3900.338	0.505
3894.312	0.505
3888.286	0.506
3882.260	0.506
3876.234	0.506
3870.208	0.506
3864.182	0.506
3858.156	0.506
3852.130	0.507
3846.104	0.507
3840.078	0.507
3834.052	0.507
3828.026	0.507
3822.000	0.507
3815.974	0.508
3809.948	0.508
3803.923	0.508
3797.896	0.508
3791.871	0.508
3785.845	0.508

3779.819	0.509
3773.793	0.509
3767.767	0.509
3761.741	0.509
3755.715	0.509
3749.689	0.509
3743.663	0.510
3737.637	0.510
3731.611	0.510
3716.651	0.510
3701.691	0.510
3686.731	0.509
3671.771	0.509
3656.811	0.509
3641.851	0.509
3626.891	0.509
3611.931	0.509
3596.971	0.508
3582.011	0.508
3567.051	0.508
3552.091	0.508
3537.131	0.508
3522.171	0.508
3507.210	0.507
3492.250	0.507
3477.290	0.507
3462.331	0.507
3447.371	0.507
3432.411	0.507
3417.450	0.506
3402.490	0.506
3387.531	0.506
3372.570	0.506
3357.610	0.506
3342.650	0.506

3327.690	0.505
3312.730	0.505
3297.770	0.505
3282.810	0.505
3266.471	0.501
3250.132	0.498
3233.793	0.494
3217.454	0.490
3201.115	0.487
3184.775	0.483
3168.436	0.479
3152.097	0.476
3135.758	0.472
3119.419	0.468
3103.080	0.465
3086.741	0.461
3070.402	0.457
3054.062	0.454
3037.723	0.450
3021.385	0.446
3005.045	0.443
2988.706	0.439
2972.367	0.435
2956.028	0.432
2939.689	0.428
2923.350	0.424
2907.011	0.421
2890.672	0.417
2874.333	0.413
2857.993	0.410
2841.655	0.406
2825.315	0.402
2808.976	0.399
2792.637	0.395
2785.502	0.395

2778.366	0.395
2771.231	0.395
2764.096	0.395
2756.961	0.395
2749.825	0.395
2742.690	0.395
2735.555	0.395
2728.420	0.395
2721.285	0.395
2714.149	0.395
2707.014	0.395
2699.879	0.395
2692.744	0.395
2685.608	0.395
2678.473	0.395
2671.338	0.395
2664.203	0.395
2657.068	0.395
2649.932	0.395
2642.797	0.395
2635.662	0.395
2628.527	0.395
2621.391	0.395
2614.256	0.395
2607.121	0.395
2599.986	0.395
2592.850	0.395
2585.715	0.395
2578.580	0.395
2573.109	0.390
2567.637	0.385
2562.166	0.379
2556.695	0.374
2551.223	0.369
2545.752	0.364

2540.280	0.359
2534.809	0.354
2529.338	0.348
2523.866	0.343
2518.395	0.338
2512.924	0.333
2507.452	0.328
2501.981	0.323
2496.510	0.318
2491.038	0.312
2485.567	0.307
2480.095	0.302
2474.624	0.297
2469.153	0.292
2463.681	0.287
2458.210	0.281
2452.739	0.276
2447.267	0.271
2441.796	0.266
2436.324	0.261
2430.853	0.256
2425.382	0.250
2419.910	0.245
2414.439	0.240
2412.250	0.237
2410.062	0.234
2407.873	0.231
2405.685	0.228
2403.496	0.225
2401.308	0.222
2399.119	0.219
2396.931	0.216
2394.742	0.213
2392.553	0.210
2390.365	0.207

2388.177	0.204
2385.988	0.201
2383.799	0.198
2381.611	0.195
2379.422	0.192
2377.234	0.189
2375.045	0.186
2372.857	0.183
2370.668	0.180
2368.480	0.177
2366.291	0.174
2364.103	0.171
2361.914	0.168
2359.726	0.165
2357.537	0.162
2355.348	0.159
2353.160	0.156
2350.971	0.153
2348.783	0.150
2348.570	0.149
2348.357	0.149
2348.144	0.148
2347.931	0.147
2347.719	0.147
2347.506	0.146
2347.293	0.145
2347.080	0.145
2346.867	0.144
2346.654	0.143
2346.441	0.143
2346.229	0.142
2346.016	0.141
2345.803	0.141
2345.590	0.140
2345.377	0.139

2345.164	0.139
2344.951	0.138
2344.738	0.137
2344.526	0.137
2344.313	0.136
2344.100	0.135
2343.887	0.135
2343.674	0.134
2343.461	0.133
2343.248	0.133
2343.035	0.132
2342.823	0.131
2342.610	0.131
2342.397	0.130
2343.164	0.130
2343.932	0.129
2344.699	0.129
2345.467	0.129
2346.234	0.128
2347.002	0.128
2347.769	0.128
2348.537	0.127
2349.304	0.127
2350.072	0.127
2350.839	0.126
2351.607	0.126
2352.375	0.126
2353.142	0.125
2353.909	0.125
2354.677	0.125
2355.444	0.124
2356.212	0.124
2356.979	0.124
2357.747	0.123
2358.514	0.123

2359.282	0.123
2360.050	0.122
2360.817	0.122
2361.584	0.122
2362.352	0.121
2363.119	0.121
2363.887	0.121
2364.655	0.120
2365.422	0.120
2370.908	0.121
2376.395	0.122
2381.881	0.123
2387.367	0.124
2392.854	0.125
2398.340	0.126
2403.826	0.127
2409.313	0.128
2414.799	0.129
2420.285	0.130
2425.772	0.131
2431.258	0.132
2436.744	0.133
2442.231	0.134
2447.717	0.135
2453.203	0.136
2458.690	0.137
2464.176	0.138
2469.662	0.139
2475.149	0.140
2480.635	0.141
2486.121	0.142
2491.608	0.143
2497.094	0.144
2502.580	0.145
2508.067	0.146

2513.553	0.147
2519.039	0.148
2524.526	0.149
2530.012	0.150
2547.325	0.154
2564.639	0.158
2581.952	0.162
2599.266	0.166
2616.579	0.170
2633.893	0.174
2651.206	0.178
2668.520	0.182
2685.833	0.186
2703.146	0.190
2720.460	0.194
2737.773	0.198
2755.087	0.202
2772.400	0.206
2789.714	0.210
2807.027	0.214
2824.341	0.218
2841.654	0.222
2858.968	0.226
2876.281	0.230
2893.595	0.234
2910.908	0.238
2928.222	0.242
2945.535	0.246
2962.848	0.250
2980.162	0.254
2997.475	0.258
3014.789	0.262
3032.102	0.266
3049.416	0.270
3076.083	0.277

3102.750	0.284
3129.417	0.290
3156.085	0.297
3182.752	0.304
3209.419	0.311
3236.086	0.318
3262.753	0.325
3289.421	0.331
3316.088	0.338
3342.755	0.345
3369.422	0.352
3396.089	0.359
3422.757	0.366
3449.424	0.372
3476.091	0.379
3502.758	0.386
3529.425	0.393
3556.093	0.400
3582.760	0.407
3609.427	0.413
3636.094	0.420
3662.761	0.427
3689.429	0.434
3716.096	0.441
3742.763	0.448
3769.430	0.454
3796.097	0.461
3822.765	0.468
3849.432	0.475
3864.032	0.479
3878.632	0.484
3893.233	0.488
3907.833	0.493
3922.433	0.498
3937.034	0.502

3951.634	0.507
3966.234	0.511
3980.834	0.516
3995.435	0.520
4010.035	0.525
4024.635	0.529
4039.236	0.533
4053.836	0.538
4068.437	0.542
4083.037	0.547
4097.637	0.551
4112.234	0.556
4126.836	0.560
4141.437	0.565
4156.035	0.569
4170.637	0.574
4185.238	0.578
4199.836	0.583
4214.437	0.587
4229.039	0.592
4243.637	0.596
4258.238	0.601
4272.840	0.605
4287.441	0.610

The vita has been removed from the scanned document