A TECHNIQUE TO INCORPORATE THE IMPACTS OF DEMAND SIDE MANAGEMENT ON GENERATION EXPANSION PLANNING

by

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(ABSTRACT)

Demand Side Management (DSM) has begun to emerge as a major component of utility planning, with more utilities than ever before using it to help meet their own needs and those of their customers. DSM encompasses utility and customer activities aimed at modifying load shape, which embodies the timing and level of customer electricity demand. Future load shapes will result from the combined effect of individual DSM programs seeking specific load shape objectives. Load Duration Curve (LDC) is the vehicle through which DSM impacts are incorporated into power system planning and operation. Models of the LDC is one of the most important tools in the analysis of electric power system. The DSM will affect the peak load, the base load and total energy demand of the load duration curve. Those three impacts have to be explicitly modeled into the load duration curve for properly representing the effects of demand side management activities. However, the available models cannot properly represent the impacts of demand side management into load duration curve, because they do not explicitly model those three variables into their load duration curve. A new model that can incorporate the effects of demand side management is needed by utilities to help them with planning and operation. A new way to directly model the inverted load duration curve (ILDC) is presented in this study thus facilitating the representation of DSM impacts.

Peak Load, base load and total energy demand are the variables of the new model. Using DSM activities as case studies, the new model produced good results compared to other widely used models, in term of reliability indices (LOLP and ENS) and total energy under the load duration curve. The flexibility, simplicity and the speed of execution of the new model in calculating the reliability indices are demonstrated. The capability of the new model to calculate the capacity credit is also presented. As a result of its ability to represent energy under load duration curve, the new model is inserted into WASP computer program to calculate the production cost. Results obtained from the new model (modified WASP) compared to results from original WASP are very close. Based on these capabilities it can be claimed that the new ILDC model is a better overall model and can be used as an alternative load model in utility planning and operation.

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CHAPTER I

Introduction

In the era of load growth and increasing constraints on new and existing generation capacity, Demand Side Management (DSM) options are being considered all over the world as possible bridges between these two apparently conflicting requirements. The high variability of load from one day to another, and from one hour to the next, may provide significant opportunities for demand side management. DSM include load management, identification and promotion of new uses, strategic conservation, electrification, customer generation, and adjustments in market share. There is a great deal of uncertainty in future demand, future prices, construction cost, availability and cost of power from other utilities, independent power producer, and the regulatory environment. This is leading electric utilities toward incorporating DSM concepts in their resource planning.

The main objective of implement DSM in power systems is to change the utility's load shape - i.e. changes in the time pattern and magnitude of utility's load. Changing the load shape as a result of demand side activities could change the peak load, base load and/or energy demand. Those three variables have to be explicitly modeled into the load duration curve for properly representing the effects of demand side management. For the available model that has been used widely, the hourly load data is an important part of the load duration curve. If one wants to modify the load duration curve, he has to go back to hourly load data, make some changes and perform the new load duration curve model with the modified data after DSM impacts are inserted. Since DSM has already been used as an available capacity in utility planning and operation, the frequency of changing the variables will be more often. A new model would eliminate the time delays and the errors that are common to the well known and much used models.

This study presents an efficient technique to model the system load such that the impact of demand side management on the power system can be easily and accurately evaluated. The impact of DSM will be manifested as higher or lower reliability levels. The proposed technique to model the load duration curve will facilitate the representation of DSM impacts on loss-of-load probability, energy not served, energy consumption and the capacity credit. This will provide an analytical method to study the impact of DSM on capacity requirement. To demonstrate the capability of the new model as a tool in power system planning and operation, the new model will be inserted into an available capacity expansion planning package (WASP). The modified WASP is then run with the new model representing the load duration curve. The results will be compared to the original WASP output where the same data are used.

Theoretical support for derivation of the new model that is going to be used in this study is presented briefly in chapter II. In the chapter III the overview of DSM is presented. From this chapter, it can be seen how the new model will be useful for incorporating the DSM impacts in the integrated planning process, because the available models cannot incorporate the impacts of DSM very easily. To appriciate how DSM can be treated as an alternative to generation options, an overview of integrated resource planning is presented in chapter IV. In this chapter, the need of a new model will be more obvious, because of difficulty of the available models to incorporate the DSM impact properly and easily. After presenting how DSM affects to the power system operation and planning, the new model is presented in chapter V. After showing that the new mathematical model is acceptable, some implementations of the new model are demonstrated in chapter VI. Those implementations include how the system reliability is affected by DSM activities, how production cost changes because of DSM activities, and the ranges of capacity credit of units under various assumptions. After demonstrating that the new model can be implemented and incorporated into available capacity expansion models, some advantages and recommendations for future research are presented in chapter VII which is the concluding chapter of this thesis.

CHAPTER II

Literature Review

2.1. Load Duration Curve (LDC)

A load-duration curve (LDC) is defined as showing the amount of time that any given overall load level is exceeded. By its definition the LDC is a function whose abscissa specifies the number of hours, in a given period (usually a year) during which a customer's demand for power equals or exceeds the associated demand level on the ordinate. By normalizing the time variable, the value at any point on the abscissa can be thought of as the probability of the corresponding load being equaled or exceeded.

A load duration curve is commonly used to represent the system load over an extended period of time. It has been utilized for various purposes, such as estimating the operating cost of a power system, predicting the amount of energy delivered by each unit, and calculating reliability measures. The LDC is one of the most important tools in the analysis of electric power system as explained by Jenkins and Joy [83]. It was found by Snyder [9] that load duration curves can be represented by fifth-order polynomials as shown in Figure 2.1. The coefficients of the fifth-order polynomial are,

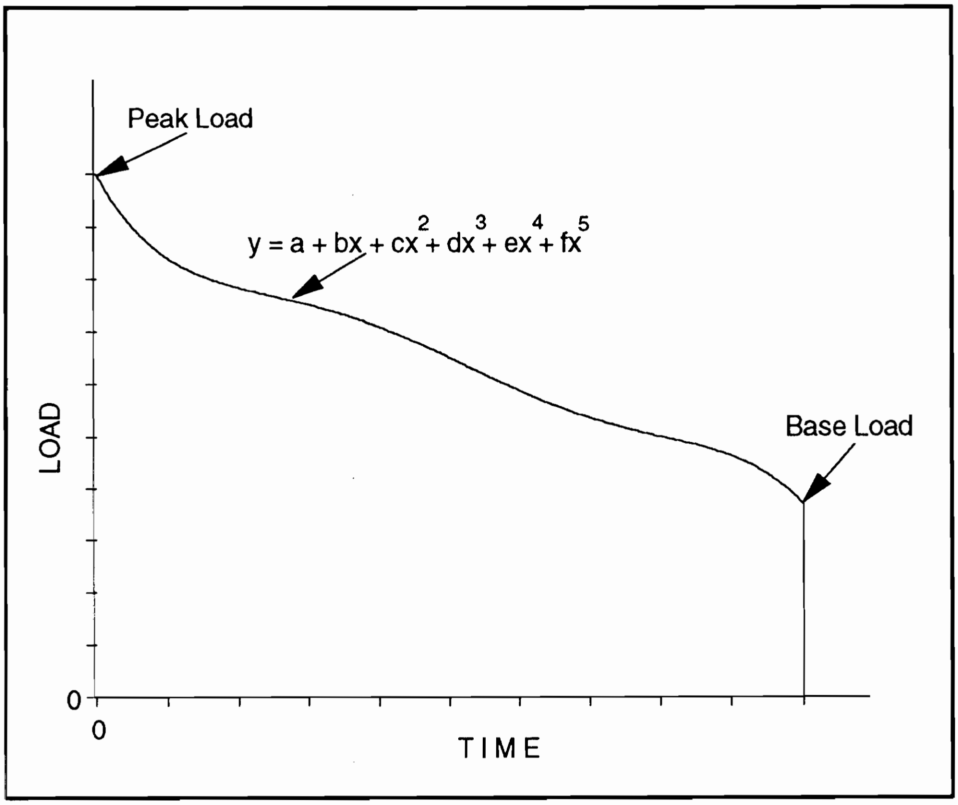

Figure 2.1. Load Duration Curve

in general, closely related to just two quantities: the ratio of minimum to maximum load during the period, and the ratio of average to maximum load. The following relationship was developed by Snyder [9].

2.1.1. Snyder Model

Snyder used a fifth-order polynomial to represent the load duration curve (LDC). The mathematical model is :

$$y = y_2-(1-y_1)(x-1/2)-3(1+y_1-2y_2)(x-1/2)^2+8(1-y_2)(x-1/2)^3 + 20(1+y_1-2y_2)(x-1/2)^4-32(1-y_2)(x-1/2)^5 \quad (2.1)$$

where

y = ratio of the load to the maximum load;

y_1 = ratio of the minimum to the maximum load;

y_2 = ratio of the average to the maximum load; and

x = fraction of the total hours in the period that the ratio of the load to the maximum load exceeds y.

By transforming equation (2.1) into a general expression, it becomes:

$$y = a_o + a_1 x + a_2 x^2 + a_3 x^3 + a_4 x^4 + a_5 x^5 \quad (2.2)$$

where

y = fraction of peak load

x = fraction of time

$a_0 = 1.$

$a_1 = 6(3y-y_1-2)$

$a_2 = -82y+27y_1+55$

$a_3 = 4(38y-10y_1-28)$

$a_4 = 20(-6y+y_1+5)$

$a_5 = 32(y-1)$

Based on equation (2.2), the coefficients of fifth-order polynomial can be calculated by using regression analysis or other techniques where hourly load data are needed.

By its definition the LDC is a function whose abscissa specifies the number of hours, in a given period, usually a year, during which customers' demand for power equals or exceeds the associated demand level on the ordinate. By normalizing the time variable, the value at any point on the abscissa can be thought of as the probability that the corresponding load will be equaled or exceeded. The Snyder's formula expressed that ratio of actual load to the maximum load is as a function of fraction of the total hour.

It is more convenient in probabilistic simulation work to use the load duration curve with the ordinate and abscissa reversed. This form of the curve is called the Inverted Load Duration Curve (ILDC). ILDC can be used to estimate the loadings of the various generation units by plotting the units on the curve. There are several ways to express the ILDC from load data, such as the Fourier series or the reversion series.

2.1.2. Fourier Series Expansion

A Fourier series is used to represent the inverted load duration curve. This method is used by WASP with the Fourier wave form analysis to invert the LDC to

ILDC. The curve is inverted numerically. The output of the numerical inversion is a table of 1000 equally spaced values on an inverted curve covering the range from 0 to the peak load, as explained by Jenkins and Vorce [89]. The range (peak load plus minimum load) is chosen to represent one-half the period of the fundamental frequency of the fitted Fourier series. Thus, the fitted curve will be periodic. For the probabilistic simulation the region of interest is limited to equivalent loads up to the peak load plus twice the minimum load. The abscissa values are originally in megawatts, but for computational reasons a normalized scale is established in which peak load is defined as 1.

The fitted Fourier series is an "even" function, i.e. f(x) = f(-x). For an even function with half wave symmetry the Fourier series has the form, Jenkin and Vorce [89]:

$$f(x) = \frac{a_o}{2} + \sum_{k=1}^{n} a_k \cos(\frac{2\pi.k}{T}.x) \qquad 2.3)$$

To fit this form to the 1000 point numerical representation of the inverted load duration curve it is necessary to evaluate the coefficients a_o and a_k. To evaluate the kth constant, a_k, we multiply through by $\cos(\frac{2\pi k}{T})$ and integrate over the range 0 to T/2. Since the integral of unlike harmonic cosine terms over the inverted is 0, only the terms with like frequency remain. This yields the general relationships :

$$a_o = \frac{4}{T} \int_0^{\frac{T}{2}} f(x)\ dx \qquad (2.4)$$

$$a_k = \frac{4}{T} \int_0^{\frac{T}{2}} f(x) \cos\left(\frac{2\pi.k.x}{T}\right) dx \tag{2.5}$$

for the coefficient values yielding the Fourier fit.

where

$\mathbf{a_k}$ = the coefficient for the kth harmonic of Fourier series

T = the period of the Fourier series in the same units as x

k = the harmonic whose coefficient is being determined

2.1.3. The Reversion Series Method

The reversion of series is used to invert the polynomial series into the inverted polynomial. The series is y as a function of x as shown in eqn.(2.6), and the reversion of eqn.(2.6) is as shown in eqn.(2.7).

$$y = ax + bx^2 + cx^3 + dx^4 + ex^5 + fx^6 + gx^7 + hx^8 + ix^9 + \ldots\ldots \tag{2.6}$$

The reversion is

$$x = Ay + By^2 + Cy^3 + Dy^4 + Ey^5 + Fy^6 + Gy^7 + Hy^8 + Iy^9 + \ldots\ldots \tag{2.7}$$

To calculate the coefficients in the reversion series, substitute eqn.(2.7) into eqn.(2.6), the result is shown below.

$$
\begin{aligned}
\mathbf{y} = {} & aA\mathbf{y} + (bA^2 + aB)\mathbf{y^2} + (cA^3 + 2bAB + aC)\mathbf{y^3} + (dA^4 + 3cA^2B + \\
& bB^2 + 2bAC + aD)\mathbf{y^4} + (eA^5 + 4dA^3B + 3cAB^2 + 3cA^2C + 2bBC + 2bAD \\
& + aE)\mathbf{y^5} + (fA^6 + 5eA^4B + 6dA^2B^2 + cB^3 + 4dA^3C + 6cABC + bC^2 + \\
& 3cA^2D + 2bBD + 2bAE + aF)\mathbf{y^6} + (gA^7 + 6fA^5B + 10eA^3B^2 + 4dAB^3 + \\
& 5eA^4C + 12dA^2BC + 3cB^2C + 3cAC^2 + 4dA^3D + 6cABD + 2bCD + 3cA^2E + \\
& 2bBE + 2bAF + aG)\mathbf{y^7} + (hA^8 + 7gA^6B + 15fA^4B^2 + 10eA^2B^3 + dB^4 + \\
& 6fA^5C + 20eA^3BC + 12dAB^2C + 6dA^2C^2 + 3cBC^2 + 5ej^4D + 12\,dA^2BD + \\
& 3cB^2D + 6cACD + bD^2 + 4dA^3E + 6cABE + 2bCE + 3cA^2F + 2bBF + 2bAG \\
& + aH)\mathbf{y^8} + (iA^9 + 8hA^7B + 21gA^5B^2 + 20fA^3B^3 + 5eAB^4 + 7gA^6C + \\
& 30fA^4BC + 30eA^2B^2C + 4dB^3C + 10eA^3C^2 + 12dABC^2 + cC^3 + 6fA^5D + \\
& 20eA^3BD + 12dAB^2D + 12dA^2CD + 6cBCD + 3cAD^2 + 5eA^4E + 12dA^2BE \\
& + 3cB^2E + 6cACE + 2bDE + 4dA^3F + 6cABF + 2bCF + 3cA^2G + 2bBG + \\
& 2bAH + aI)\mathbf{y^9} + \ldots\ldots\ldots\ldots + (\ldots\ldots\ldots\ldots)\mathbf{y^{81}}
\end{aligned}
\tag{2.8}
$$

Even though the degree of polynomial is 81, only the coefficient of the ninth-degree polynomial in eqn.(2.8) is needed for calculating coefficients A,B,C,D,E, F,G,H, and I in reversion equation (eqn.2.7). Because we just need 9 equations for calculating 9 unknown coefficients. Those coefficients are as a function of a,b,c,d,e,f,g,h, and/or i in original equation, eqn.(2.6). From those nine coefficients in eqn.(2.8), the coefficient A, B, C, D, E, F, G, H, and I can be calculated. The result is shown below :

$$A = \frac{1}{a}$$

$$B = -\frac{b}{a^3}$$

$$C = \frac{1}{a^5}(2b^2 - ac)$$

$$D = \frac{1}{a^7}(5abc - 5b^3 a^2 d)$$

$$E = \frac{1}{a^9}(6a^2bd + 3a^2c^2 + 14b^4 - a^3e - 21ab^2c)$$

$$F = \frac{1}{a^{11}}(7a^3be + 7a^3\ cd + 84ab^3c - a^4f - 28a^2bc^2 - 42b^5 - 28a^2b^2d)$$

$$G = \frac{1}{a^{13}}(8a^4bf + 8a^4ce + 4a^4d^2 + 120a^2b^3d + 180a^2b^2c^2 + 132b^6 - a^5g -$$

$$36a^3b^2e - 72a^3bcd - 12a^3c^3 - 330ab^4c)$$

$$H = \frac{1}{a^{15}}(-429b^7 + 1287ab^5c - 990a^2b^3c^2 + 165a^3bc^3 - 495a^2b^4d +$$

$$495a^3b^2cd - 45a^4c^2d - 45a^4bd^2 + 165a^3b^3e - 90a^4bce +$$

$$9a^5de - 45a^4b^2f + 9a^5cf + 9a^5bg + a^6h)$$

$$I = \frac{1}{a^{17}}(1430b^8 - 5005ab^6c + 5005a^2b^4c^2 - 1430a^3b^2c^3 + 55a^4c^4 +$$

$$2002a^2b^5d - 2860a^3b^3cd + 660a^4bc^2d + 330a^4b^2d^2 - 55a^5cd^2 -$$

$$715a^3b^4e + 660a^4b^2ce - 55a^5c^2e - 110a^5bde + 5a^6e^2 + 220a^4b^3f -$$

$$110a^5bcf + 10a^6df - 55a^5b^2g + 10a^6cg + 10a^6bh - a^7i)$$

2.2. Wien Automatic System Planning Package (WASP)

WASP is designed to find the economically optimal generation expansion policy for an electric utility system within user-specified constraints. It was developed by Jenkins and Joy [83], of The Tennessee Valley Authority (TVA) and the Oak Ridge National Laboratory (ORNL). It utilizes probabilistic estimation of reliability and of production costs and dynamic programming method of optimization. The modular structure of WASP permits the user to monitor intermediate results, so that any input data errors can be corrected before large amounts of computer time are wasted in simulating and optimizing with erroneous data. It also permits use of a relatively small computer, since the maximum core memory required by any one module is 158-166 kbytes (1246-1328 Kbytes) using the OS/VS1 system. WASP uses the fifth-order polynomial describing the period load duration curve ($y = a_o + a_1x + a_2x^2 + a_3x^3 + a_4x^4 + a_5x^5$), where x is the fraction of the time during the period that load equals or exceeds the fraction y of the period peak demand). WASP also uses the number of cosine term to be considered in Fourier series to express the inverted load duration curve (ILDC) as explained by Jenkins and Vorce [89,11]. A probabilistic simulation model is used to calculate production cost for all allowable configurations. The model includes the effect of unit forced outages and maintenance schedule.

Major features of WASP can summarized as:

. 100 multi-unit plants in the existing system, with normal hydro, emergency hydro and pumped storage, if any, each treated as a single composite plant;

. 20 expansion candidate plant types, with hydro treated as a single plant type consisting of up to 20 ranked candidate projects;

. 30 years in the study period;

. 200 alternative system configurations in any one year, with a limit of 2000 configurations in the study period;

. 5 hydro conditions; and

. up to 12 period per year.

Simulation of a 30 years fixed expansion with one period per year, one hydro condition and 20 Fourier coefficients takes less than 2 minutes of computation time using IBM 370/145. A full dynamic programming study with simulation of 3000 configurations would take as much as 10 - 20 hours of CPU time as mentioned in [11].

The original WASP has six inter-related code modules. After the improvement, the seventh module, REPROBAT, which produces a summary report on the first six module is added. The following paragraphs describe each of these modules :

Module 1, LOADSYS (load system description), processes information describing period peak loads and load duration curves for the power system over the study period. This module is assisted by a curve fit routine to calculate up to a 5th order polynomial fit for each period load duration curve.

Module 2, FIXSYS (fixed system description), processes information describing the existing generation system and any pre-determined additions or retirements. The required data for each unit, minimum and maximum operating capacities, heat rates, associated with these capacities, type of fuel, fuel cost, forced outage rate, and maintenance requirement.

Module 3, VARSYS (variable system description), processes information describing the various generating plants which are to be considered as candidates for expansion the generation system.

Module 4, CONGEN (configuration generation), calculates all possible year-to-year combinations of expansion candidate additions which satisfy certain input constraints and which in combination with the fixed system can satisfy the loads.

Module 5, MERSIM (merge and simulate), considers all configurations put forward by CONGEN and uses probabilistic simulation to calculate the associated operating cost and system reliability for each configuration. The module also calculates plant loading orders if desired and keeps track of all previously simulated configurations.

Module 6, DYNPRO (dynamic programming optimization), determines the optimum expansion program based on previously derived operating costs along with input information on capital cost, economic parameters and reliability criteria.

Module 7, REPROBAT (report writer code), writes a report summarizing the total or partial results for the optimum power system expansion program and for fixed expansion schedules.

2.3. System Reliability

The ability of the power system to provide an adequate supply of electrical energy at any point in time is referred to as the reliability of the system. Due to the nature of electricity and the dependence of our society on its uninterrupted supply, reliability is one of the most important design criteria of electric power system as mentioned by Vardi and Patton [55,6]. And also, reliability assessments are a necessary part of power system studies in order to assist managerial decisions regarding how much should be expected on the system in order to improve or maintain the quality, the adequacy and reliability of the system; installation of additional capacity; timing of new installations; and operating guidelines.

Power system reliability has two primary components: system adequacy and system security as explained by Endrenyi et al. [50]. This study will deal primarily with system adequacy issues with focus on the steady state ability of a power system to provide uninterrupted service under both normal and the most plausible multiple contingencies. Security analysis addresses the issue of system performance degradation as a result of dynamic events in a system as explained by Sulivan and Endrenyi et al. [86,50].

2.3.1. Reliability Measures and Methods

Several measures have been devised to evaluate the reliability performance of a given electric power system. Two of them will be considered in this study. They are :

- Loss Of Load Probability (LOLP)
- Energy Not Serve (ENS)

According to Day et al. [43], loss of load probability is the simplest and most common of all. LOLP describes the expected accumulated amount of time in a given period, usually a year, during which the system will experience a shortage of energy of more than 0 kwh.

Energy not serve indicates the expected total amount of energy required by customers and not supplied because of the inability of the system to meet the demand for electric power as explained by Vardi [55].

2.4. Equivalent Load Duration Curve (ELDC)

The need for better analytical tools that will account in a more accurate manner for the random nature of electric systems due to forced outages has resulted in the development of a modified version of the load duration curve, known as the Equivalent Load Duration Curve (ELDC). The equivalent load duration curve was first presented by Baleriaux et al. [35], and was later refined by Booth [88], Joy and Jenkins [22]. and others.

The ELDC has been successfully applied to the calculation of expected operating cost of the system under a merit order loading, providing improved estimates of the expected generation requirements for each unit in the system. In its most general form, the ELDC contains four elements of demand :

(1) the deterministic component of customers' load

(2) the random component of customers' load

(3) requirements for forced outages

(4) requirements for maintenance

The ELDC is a convolution of customer load, the "demand" of capacity for maintenance, and the "demand of capacity for failure. Maintenance is regarded as another kind of demand for capacity with zero consumption of fuel. The main advantage of the convolution approach is that it incorporates into the ELDC outage probabilities, maintenance requirements, and random deviations of customers' load. Hence, any change in the characteristics of the system will also affect the ELDC as each such change contributes to different customer's demand or to different demand for maintenance and force outages. This property of the ELDC yields a tool which has the potential of being most powerful and versatile for electric power system analysis. Furthermore it is exploited here to derive a host of analysis by studying the impact of parameters of a system through its reflection on the ELDC.

The importance of these analyses to decision making is also demonstrated. For instance, based on the observation that any excess of combined demand over the installed capacity results in a shortage of power supply, the ELDC lends itself rather easily to reliability analysis, as has already been recognized by Joy and Jenkins [19], with regard to calculating the loss-of-load-probability and various sensitivity analyses. The ability to conveniently perform reliability analyses is an important feature in decisions regarding reserve requirements.

A major advantage of the ELDC as an aid in decision making is the fact that it has been formulated in an explicit analytical manner. Such a formulation will undoubtedly open up more potential applications of the ELDC and at the same time provide better insight into the system and its behavior. Developing a tool to analyze the system by computation rather than by simulation enables one to rigorously compute many important parameters of the system in an easy way. Various applications of these methods are described by Vardi [55] as the following:

- the expected number of hours that each individual unit will work;
- the expected fuel consumption of each individual unit for the case of incremental cost loading and fuel budget of the system;
- the effect of adding a unit on the reliability of the system;
- the effect of the size of a unit on the reliability of the system;
- the trade-off between better reliability of a unit versus the installed capacity required in a system for meeting a given criterion of system reliability;
- the loss-of-load probability;
- the distribution of capacity surplus;
- the distribution capacity deficiency;
- the expected amount of energy which cannot be supplied; and
- how different customers should share energy and capacity costs.

Joy and Jenkins [22,83] have demonstrated how the outage probabilities are convolved with the load density function to an equivalent load curve of customers' demand and forced outages. The resulting curve is then applied to calculate the expected operating cost of a power system, the amount of energy delivered by each unit, the LOLP and the ENS. The convolution method will be discussed in other sections.

The method of moments (or cumulants) was introduced by Schenk and Rau [58,59,76] as an efficient procedure for the evaluation of LOLP, expected energy

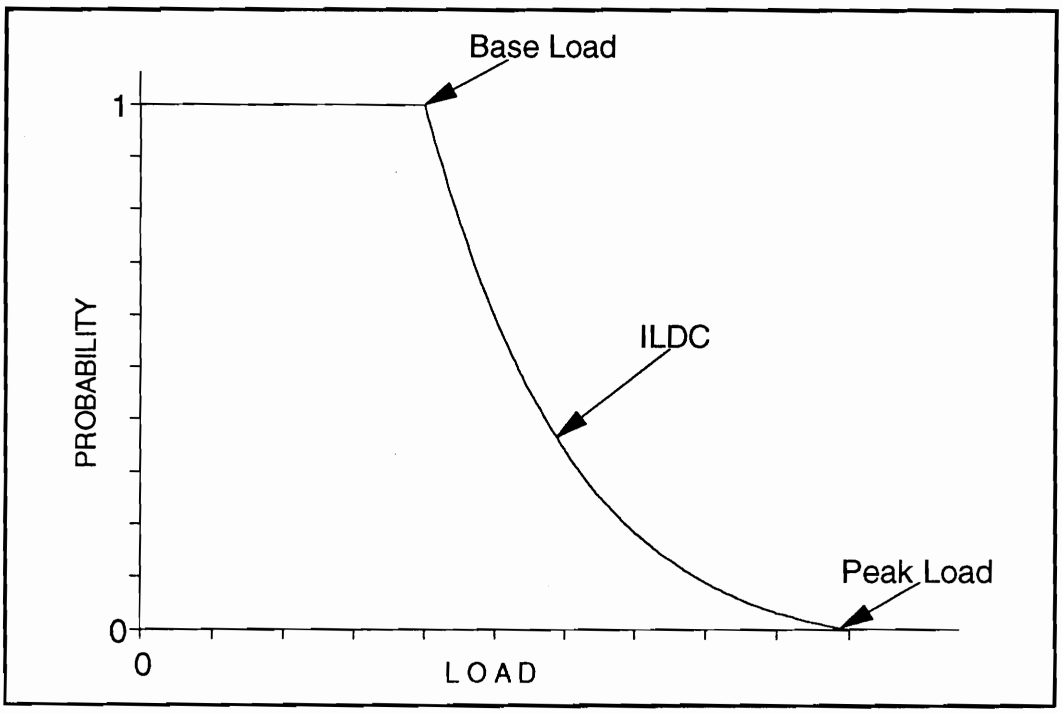

Figure 2.2. Inverted Load Duration Curve

generation and production costing for a system of generating units meeting a certain demand. The cumulant method is based on Gram-Charlier expansion as reported by Stremel et al.[47,41,44]. The cumulant uses the hourly load data to calculate ELDC as explained by Schenk and Bayless [56,115], where the convolution method use the inverted LDC to calculate ELDC.

2.4.1. The Convolution method

The basic model for this technique requires the following information:

- System load duration curve or inverted load duration curve;
- Loading order of units; and
- Generating unit characteristic.

The major advantage of this technique is its capability to simulate the effects of random events such as unit forced outages as explained by Joy and Jenkins, Vardi [22,55].

It is more convenient in probabilistic simulation work to use the load duration curve with ordinate and abscissa reversed. This form of the curve is called inverted load duration curve (ILDC), as shown in Figure 2.2. ILDC can be used to estimate the loadings of the various generating units by plotting the units on the curve as shown in Figure 2.3, and to estimate the expected generation of each unit by integrating the curve between the proper limits as mentioned by Jenkins and Joy [83].

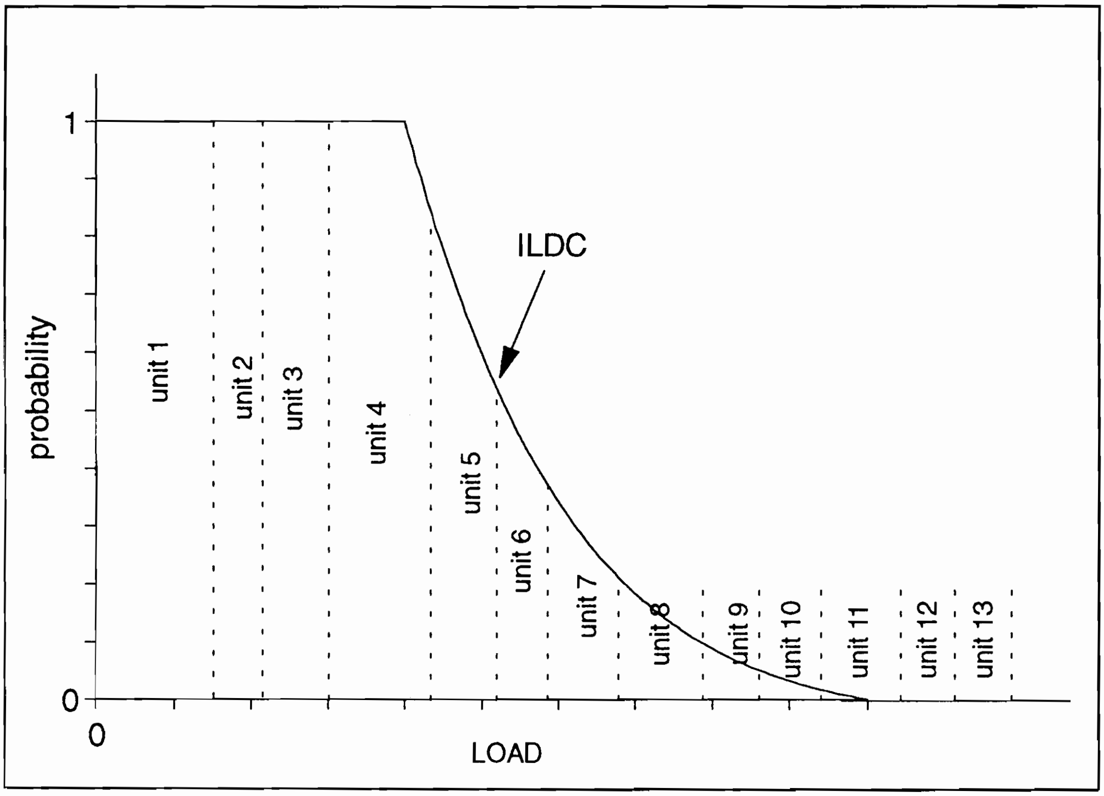

Figure 2.3. Unit Loading When All Units are 100% Available

$$E_i = T \int_{a_i}^{b_i} L(x) \; dx \tag{2.9}$$

where

E_i = expected generation on ith unit

T = time period represented by load duration curve

$L(x)$ = inverted load duration curve

a_i = system capacity for units 1,2,.....,i-1

b_i = system capacity for units 1,2,....,i

In order to perform this calculation, the order in which the units are to be loaded must be specified, and also whether the unit is available or unavailable to deliver power. Let p_i be the probability that unit i is available, and let q_i be the probability that the unit is not available. Since the unit must be in one of the two states,

$$p_i + q_i = 1.0 \tag{2.10}$$

The probability q_i is normally referred to as the forced outage rate and is frequently expressed as a percentage rather than a fraction. When unit 1 is not available, all units are shifted to the left by an amount equivalent to the capacity of unit 1 as shown in Figure 2.4. The amount of energy generated if unit 1 is available, would be equal to its area under the load duration curve L, Figure 2.3. Therefore, the expected average generation for unit 1 would be calculated by multiplying the area under curve L by the probability that this unit will be available. From eqn.(2.9) we get:

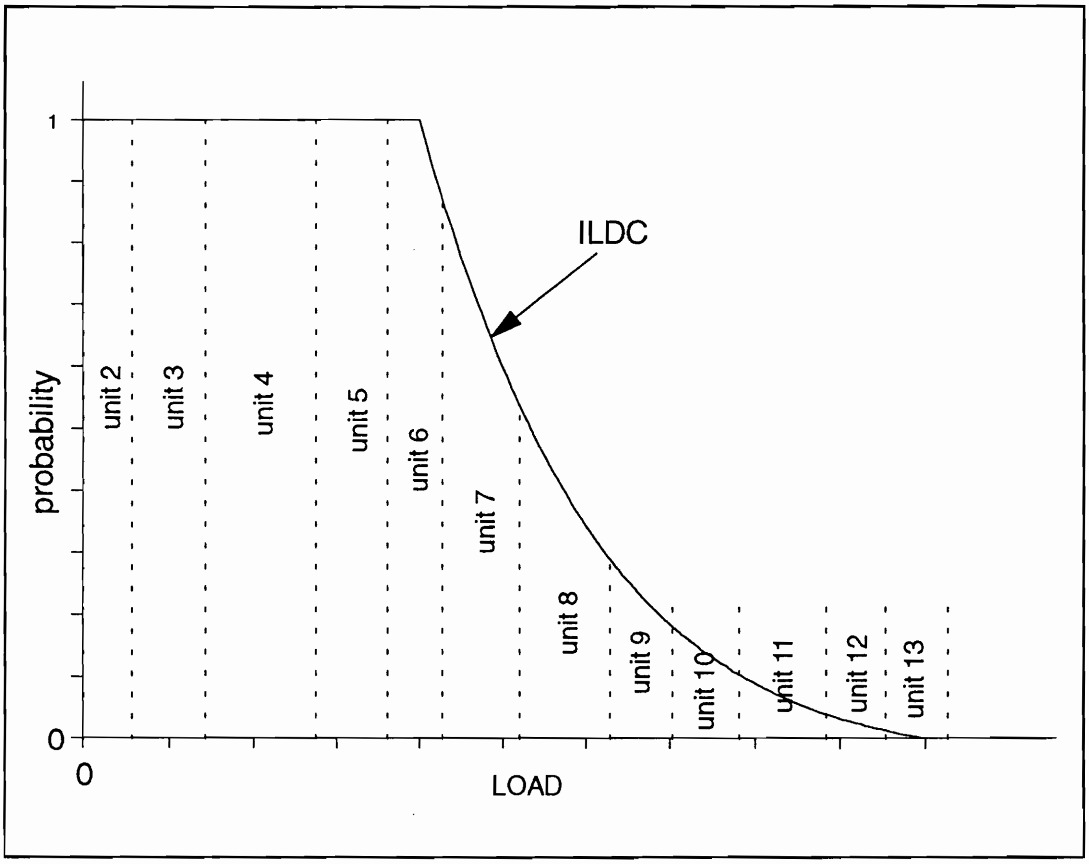

Figure 2.4. Unit Loading When Unit 1 is not Available

$$E_1 = p_1 T \int_{a_1}^{b_1} L(x) \; dx \tag{2.11}$$

Outages of other units in the system do not have any effect on unit 1 since the position of unit 1 under the curve L does not change when other units are removed from the system.

The operation of unit 2 is directly affected by any outage of unit 1 but is not affected by outages of unit 3, 4 etc. When unit 2 is unavailable, it would not be capable of generating any energy. Therefore, the expected generation of unit 2 would be :

$$E_2 = p_2 T[\, p_1 \int_{a_2}^{b_2} L(x)\, dx + q_1 \int_{c_2}^{d_2} L(x)\, dx \,] \tag{2.12}$$

where

a_2, b_2 = are integrating limits based on the type of loading shown in Figure 2.3

c_2, d_2 = are integrating limits based on the type of loading shown in Figure 2.4.

An alternative and equivalent representation of an outage of unit 1 is to leave unit 1 in its original position and shift the ILDC to the right by capacity of unit 1 as shown in Figure 2.5. Let L represent the original ILDC, and let L' be the shifted curve. From an examination of Figure 2.5, it becomes apparent that

$$L'(x) = L(x - MW_1) \qquad (2.13)$$

where

MW_1 = the capacity of unit 1

and hence

$$\int_{c_2}^{d_2} L'(x)\,dx = \int_{a_2}^{b_2} L(x - MW_1)\,dx \qquad (2.14)$$

The probability that unit 2 would be loaded by curve L is p_1, and the probability that unit 2 would be loaded by curve L' is q_1. By substituting eqn.(2.14) in to eqn.(2.12) and rearranging, the expected generation of unit 2 would be calculated by :

$$E_2 = p_2 T \int_{a_2}^{b_2} [p_1\, L(x) + q_1\, L(x - MW_1)]\,dx \qquad (2.15)$$

Equation (2.15) suggests that the effect of forced outages can be combined with the system load in a single variable, the equivalent load. Equivalent load is defined as :

$$EL_{i-1} = L + O_i \qquad \text{......} \; (2.16)$$

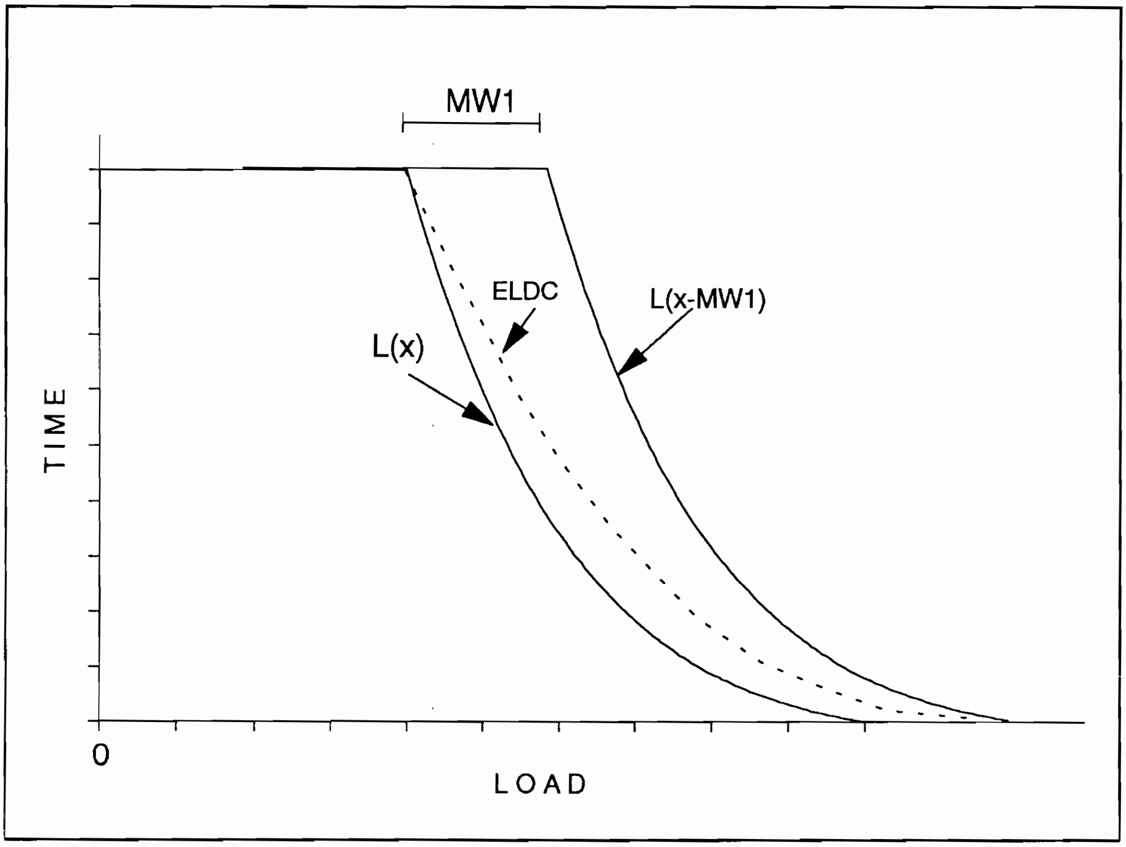

Figure 2.5. Shifted ILDC and ELDC

where

EL_{i-1} = equivalent load considering outages of units before unit i to be in the loading order units 1,2,...,i-1

L = system inverted load duration curve

O_i = additional operation required of unit i by outages of unit prior to unit i in the loading order unit 1,2,...,i-1

The operation of unit 2 caused by an outage of unit 1 would be represented by the difference between curves $L(x - MW_1)$ and $L(x)$:

$$O_i = [L(x - MW_i) - L(x)] \qquad (2.17)$$

The equivalent load curve for unit 2 (EL_1) would be evaluated by multiplying the additional load by the probability of having to serve the additional load.

$$EL_1 = L(x) + q_1[L(x - MW_1) - L(x)] \qquad ..... (2.18)$$

which, on substitution of eqn. (2.18), becomes

$$EL_1 = p_1 L(x) + q_1 L(x - MW_1) \qquad ..... (2.19)$$

This is the dashed curve shown in Figure 2.5. Substituting eqn.(2.19) into eqn.(2.15) yields

$$E_2 = p_2 T \int_{a_2}^{b_2} EL_1(x)dx \qquad \text{...... (2.20)}$$

Effects of outages in both unit 1 and 2 must be considered in order to evaluate the expected generation of unit 3. The equivalent load curve (EL_1) incorporates the effect of forced outages for unit 1. Unit 3 is loaded according to EL_1 curve if unit 2 is available. If unit 2 is not available, the equivalent load curve would be shifted to the right by amount equal to the capacity of unit 2 (MW_2). These two curves can be combined into a single equivalent load curve (EL_2) by using eqn.(2.19) and replacing L with EL_1. Consider that the loading of unit 3 is subject to forced outages of unit 1 and 2. Four different cases must be considered :

(1) unit 1 and unit 2 both available, probability (p_1p_2)

(2) unit 1 available and unit 2 unavailable, probability (p_1q_2)

(3) unit 1 unavailable and unit 2 available, probability (q_1p_2)

(4) unit 1 and 2 both unavailable, probability (q_1q_2)

For case 1, unit 3 would be loaded according to the ILDC L(x). For case 2, unit 3 would be loaded by curve $L(x - MW_2)$, for case 3 by $L(x - MW_1)$, and finally by $L(x - MW_1 - MW_2)$ for case 4. Now the expected energy from unit 3 would be:

$$E_3 = p_3\, T[p_1p_2 \int_a^b L(x)dx + p_1q_2 \int_a^b L(x - MW_2)dx +$$

$$q_1 p_2 \int_a^b L(x\text{-}MW_1)dx + q_1 q_2 \int_a^b L(x\text{-}MW_1\text{-}MW_2)dx] \qquad (2.21)$$

The first and third terms in eqn.(2.21) can be rewritten as:

$$p_2 \int_a^b [p_1\, L(x) + q_1\, L(x - MW_1)]\, dx \qquad (2.22)$$

Referring to eqn.(2.19) the term inside the brackets is seen to be simply the definition of the equivalent load curve (EL_1) incorporating an outage of unit 1.

$$E_3 = p_3\, T[\, p_2 \int_a^b EL_1(x)\, dx + p_1 q_2 \int_a^b L(x - MW_2)\, dx +$$

$$q_1\, q_2 \int_a^b L(x\text{-}MW_1\text{-}MW_2)dx] \qquad (2.23)$$

Let $y = x - MW_2$; then, noting that $dx = dy$, the last two terms in eqn.(2.23) become

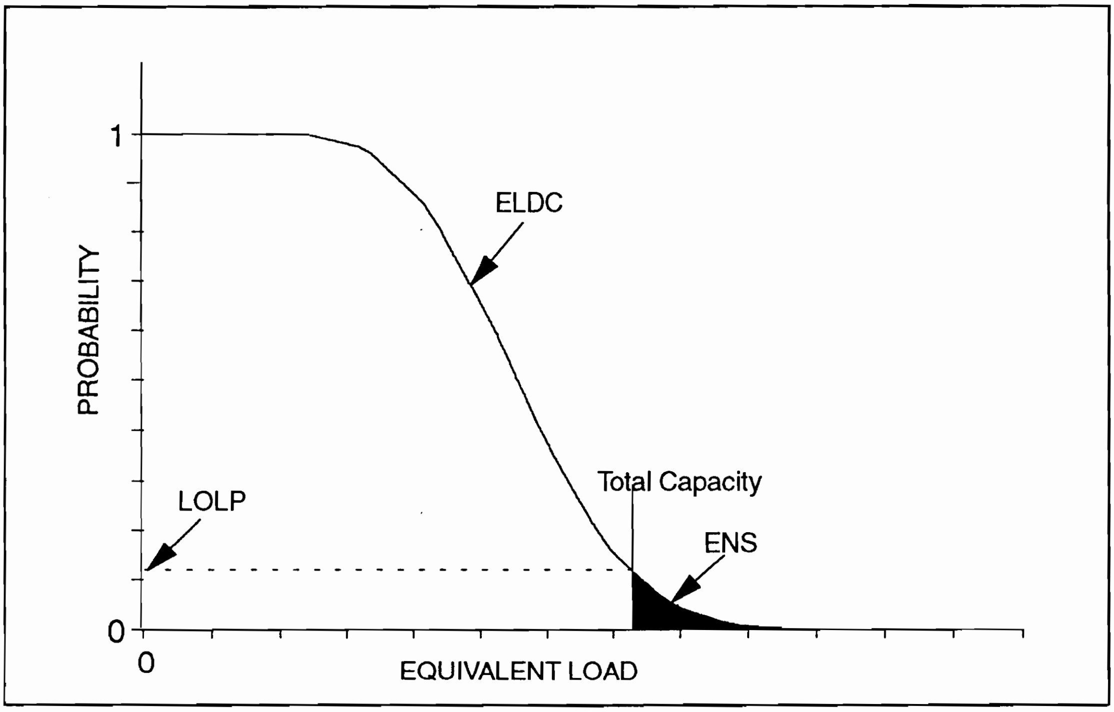

Figure 2.6. ELDC, LOLP and ENS

$$q_2 \int_a^b [p_1 L(y) + q_1 L(y - MW_1)]\, dy$$

Referring to eqn.(2.19), this is simply the equivalent load curve for y, $EL_1(y)$, when the outage of unit 1 is incorporated. Therefore

$$E_3 = p_3 T[\, p_2 \int_a^b EL_1(x)\, dx + q_2 \int_a^b EL_1(y)\, dy\,] \tag{2.24}$$

Now, replacing y with $(x - MW_2)$ and rearranging eqn.(2.24) yields

$$E_3 = p_3 T \int_a^b [p_2 EL_1(x) + q_2 EL_1(x - MW_2)]\, dx \tag{2.25}$$

Hence the energy to be generated by unit 3 would be calculated from a new equivalent load curve which is formed by incorporating the effect of outages of unit 2 into the original equivalent load curve;

$$E_3 = p_3\, T \int_a^b EL_2(x)\ dx \tag{2.26}$$

where

$$EL_2(x) = p_2\, EL_1(x) + q_2\, EL_1(x - MW_2) \qquad (2.27)$$

An Equivalent Load Duration Curve (ELDC) can be generated to include forced outages of any number of units by successively applying eqn.(2.27). The general form of the ELDC is in equation (2.28) below

$$EL_n(x) = p_n\, EL_{n-1}(x) + q_n\, EL_{n-1}(x - MW_n) \qquad (2.28)$$

The expected energy generation for each unit is :

$$E_n = p_n\, T \int_a^b EL_{n-1}(x)\, dx \qquad (2.29)$$

The LOLP can be calculated from ELDC as shown in Figure 2.6. The area under the ELDC to the right of the total capacity X_c (shaded area in Figure 2.6) represents the expected energy demand that the generating system would not be able to serve or Energy Not Serve (ENS).

$$ENS = T \int_{x_c}^{\infty} EL_{n-1}(x)\, dx \qquad (2.30)$$

2.4.2. Gram-Charlier Series

Gram-Charlier series is representation for the standardized equivalent load curve, and is used to estimate an area under the equivalent load curve. When the Gram-Charlier series is used to estimate a point on the equivalent load curve, a table is used to determine the value of standard cumulative normal distribution, because Gram-Charlier series starts with a basic normal distribution as mentioned by Stremel [45,46]. Before we end up with a formula, six steps of calculation have to be established.

Step 1 : Calculate the moment of distribution.

$$LM_j = \frac{1}{T} \sum_{t=1}^{T} (L_t)^j$$

for $j = 1,2,3,4$

where

LM_j = the jth moment of the load distribution

L_t = the hourly load at time t

Step 2 : Calculate the cumulant

$$LK_1 = LM_1$$

$$LK_2 = LM_2 - LM_1^2$$

$$LK_3.. = LM_3 - 3LM_2 LM_1 + 2LM_1^3$$

$$LK_4 = LM_4 + 6LM_2 LM_1^2 - 4LM_3 LM_1 - 3LM_1^4 - 3LK_2^2$$

where

LKj = the jth cumulant of the hourly load distribution.

Step 3 : Calculate the kth moment of outage distribution.

$$Mk_i = \sum_{j=1}^{m} P_{ij} \, (O_{ij})^k$$

where

Mki = the kth moment of outage distribution of the ith unit

Oij = the outage level of the ith generation unit in derating state j

Pij = the probability the ith generation unit is in derating state j

Step 4 : Calculate the cumulant for each unit which will determine the generation outage distribution for the system.

$$g_{1i} = M_{1i}$$

$$g_{2i} = M_{2i} - M_{1i}^2$$

$$g_{3i} = M_{3i} - 3M_{2i} M_{1i} + 2M_{1i}^3$$

$$g_{4i} = M_{4i} + 6M_{2i}\,M_{1i}^2 - 4M_{3i}\,M_{1i} - 3M_{1i}^4 - 3G_{2i}^2$$

Step 5 : Calculate mean, variance, skewness, kurtosis and normal distribution.

$$u = LK_1 + \sum_{i=1}^{n} g_{1i} \qquad \text{(mean)}$$

$$T^2 = LK_2 + \sum_{i=1}^{n} g_{2i} \qquad \text{(Variance)}$$

$$G_1 = \frac{1}{T^3}(LK_3 + \sum_{i=1}^{n} g_{3i}) \qquad \text{(skewness)}$$

$$G_2 = \frac{1}{T^4}(LK_4 + \sum_{i=1}^{n} g_{4i}) \qquad \text{(kurtosis)}$$

$$Z_1 = \frac{IC-u}{T}$$

$$N(Z_1) = \frac{1}{\sqrt{2pi}}\exp\left(\frac{-Z_1^2}{2}\right) \qquad \text{(normal distribution evaluated at } Z_1\text{)}$$

where

n = number of unit;

IC = installed capacity; and

Z1 = variable.

Step 6 : Calculate the derivatives of the normal.

$$N^{(2)}(Z_1) = (Z_1^2 - 1)\,N(Z_1)$$

$$N^{(3)}(Z_1) = (-Z_1^3 + 3Z_1)\,N(Z_1)$$

The Gram-Charlier representation of the Equivalent Load Duration Curve (ELDC) is :

$$\mathrm{LOLP}(Z_1) = 1 - \int_{-\infty}^{Z1} N(Z)\,dz + \frac{G_1}{3!}N^{(2)}(Z_1) - \frac{G_2}{4!}N^{(3)}(Z_1) \qquad \text{...... (2.31)}$$

2.5. Availability.

Availability of a generation unit is the probability that a certain portion of a unit's capacity will be available if called to generate. To calculate availability of the unit, a formula as explained by Mulvaney [122] will be used as shown below :

$$\mathrm{EAA} = \left(1 - \frac{\mathrm{PORdays}}{365\mathrm{days}}\right)\mathrm{x}\left(1 - \frac{\%\mathrm{ADU}}{100}\right)\mathrm{x}\left(1 - \frac{\%\mathrm{UOR}}{100}\right) \qquad \text{..... (2.32)}$$

where

EAA = Equivalent Annual Availability;

UOR = Unscheduled Outage Rate, represents full forced outages in percent;

ADU = Average Daily Unavailability, represents partial forced outages in percent; and

POR = Planned Outage Rate, represents the time during which a unit is removed from service for planned outages, such as scheduled overhaul or inspection, in days per year.

CHAPTER III

Demand Side Management

3.1. Introduction

Demand Side Management (DSM) is the planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape - i.e., changes in the pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand side management include : load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share. Demand side management encompasses the entire range of management functions associated with directing demand side activities, including program planning, evaluation, implementation and monitoring. Opportunities for demand side management can be found in all customer classes, including residential, commercial, industrial, and wholesale. DSM in its broadest definition, incorporates all kinds of action utilities take to modify their customers' demand for electricity. Those actions can include the implementation of programs that aim to reduce electricity use, programs that redistribute electricity demand to spread it more evenly throughout the hours of day, and even programs that encourage strategic load growth.

The above definition of demand side management contains two points that should emphasized. First, demand side management includes only those activities that involve a deliberate intervention by the utility in the marketplace to alert its load shape. Under this definition, for example, naturally occurring conservation, such as customer purchases of energy efficient refrigerators as a reaction to higher energy prices, would not be classified as demand side management. On the other hand, a utility initiated incentive or advertising program that encourages customers to install energy efficient refrigerators meets the definition of DSM. The second important point is that DSM extends beyond strategic conservation and load management to include programs designed specifically to build load in both peak and off-peak periods.

Implementing a DSM program could reduce sales, which decreases the company's revenues and profits. However, if a utility manages to reduce electricity demand, it can postpone the need to build expensive new power plants. And also, if one remembers that customers do not buy kilowatt-hours but buy the services that electricity provides, and if one recognizes these energy services as a utility's products, then DSM makes perfect sense. From this perspective, energy efficiency programs are not a means of unselling a utility's product but an opportunity to broaden the utility's business. Providing quality energy services is the essential ingredient of successful DSM.

DSM provides a workable solution to some of the major problems confronting the electric utility today. DSM offers a utility's management many alternatives which improve customer satisfaction and maintaining good customer relations in the increasingly competitive area of electricity supply--besides improving the utility's financial health. There is a great deal of uncertainty in future demand, fuel prices, construction cost, availability and cost of power from other utilities, independent power producers, and the regulatory environment are leading electric utilities toward incorporating DSM concepts into their resource planning. Utility programs falling under the umbrella of DSM include load management, identification and promotion of new uses, strategic conservation, electrification, customer generation and adjustments in market share. DSM encompasses planning, evaluation, implementation, and monitoring of activities selected from wide variety of DSM alternatives. The choice is further complicated since the attractiveness of alternatives is influenced strongly by utility specific factors, such as current generating mix, expected load growth, capacity expansion plans, generating-system reliability, load factor, load shapes for average and extreme days, regulatory climate, fuel cost outlook, and reserve margins, and last but not least, rate structures.

3.2. The Objectives of DSM

A key first step in selecting DSM alternatives is deciding what overall objectives are to be met by DSM. This step can be accomplished in hierarchical fashion :

1) establish strategic, utility-wide objectives
2) set tactical, operational objectives
3) determine load shape objectives

3.2.1 Strategic objectives

Strategic objectives are quite broad and generally include directions such as improving cash flow, increasing earnings, or improving customer and employee relations. Certain institutional constraints may limit the achievement of these objectives. These constraints represent the business environment that all utilities currently face: regulations, environmental considerations, and the obligation to provide service of reasonable quality to customers within their designated service area as explained by Broehl et al. vol 2 [52].

3.2.2. Operational Objectives

While strategic objectives provide important guidelines for utility long-range planning, the second level of tactical or operational objectives help and guide utility management to specific actions. At this operational or tactical level, DSM alternatives collectively are examined and evaluated against corresponding supply side alternative. According to Gelling and Ma [15,28] operational objectives that can be addressed by DSM alternatives include the following :

- Reduce the need for critical fuels;
- Reduce or postpone capital investment in construction programs;
- Mitigate electricity cost increase;
- Increase sales and/or revenues, and/or earnings;
- Provide customers with options that improve their control over their electricity bills;
- Reduce risks by investing in diverse alternatives;
- Increase operating flexibility and generating system reliability;
- Decrease unit cost through more efficient loading of existing and planned generating facilities;
- Satisfy regulatory constraints or rules;
- Minimize potential environment impacts; and

. Improve the image of the utility

3.2.3. Load Shape Objectives

In the third level, operational objectives are translated into load shape objectives. Six generic load shape objectives illustrate the range of possibilities:

1. **Peak Clipping**, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customer's appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.

2. **Valley Filling** is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of the electricity. Adding properly price off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.

3. **Load Shifting** is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water

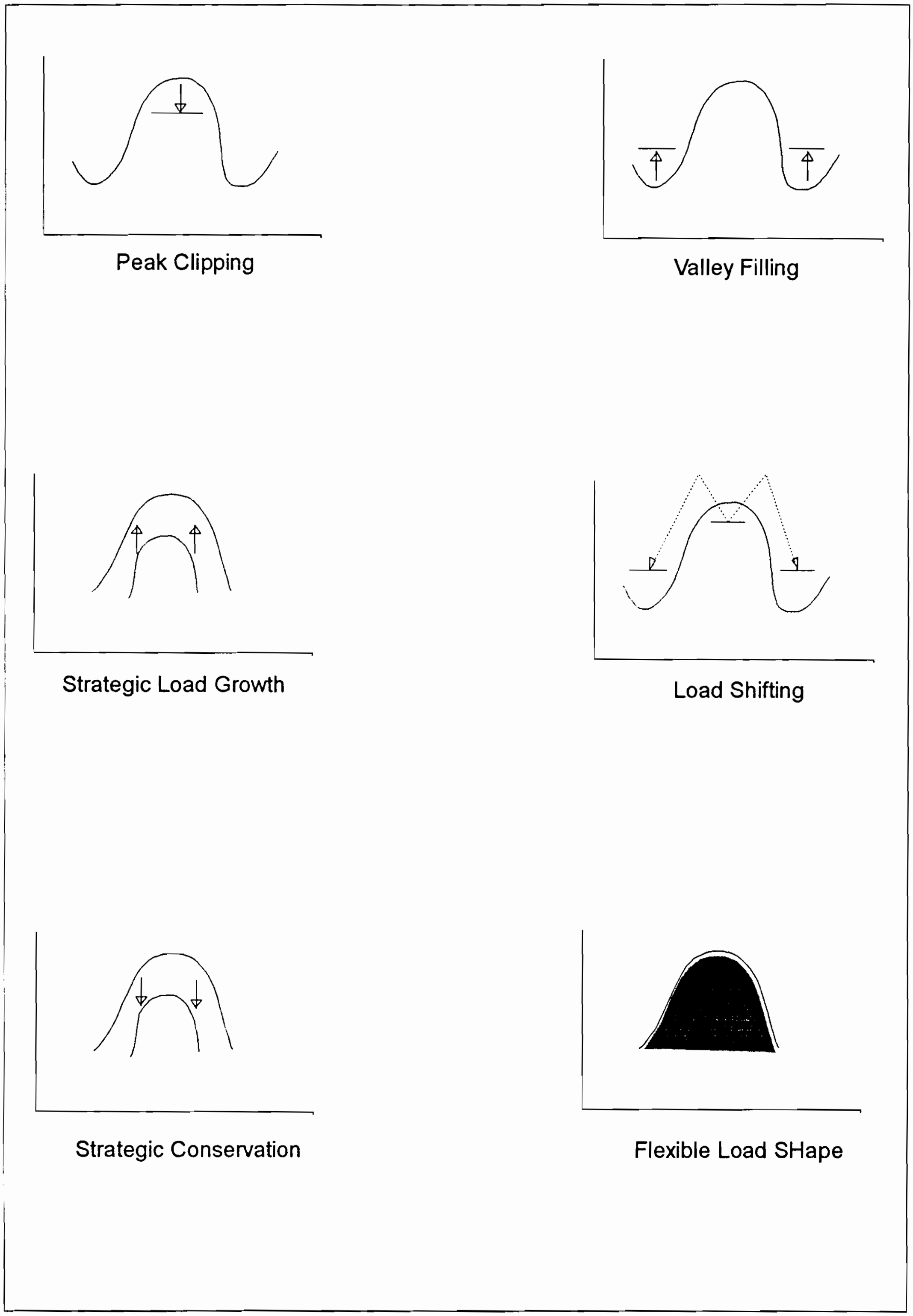

Figure 3.1. Load Shape Objectives

heating, storage space heating, coolness storage, and customer load shifts. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.

4. **Strategic Conservation** is the load shape change that results from utility-stimulated programs directed at end use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in sale as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.

5. **Strategic Load Growth** is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric's vehicles, industrial process heating, and automation. These have a potential increasing the electric energy intensity industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.

6. **Flexible Load Shape** is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible -- if customers are presented with options as to the variations in quality of service that

they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.

Once load shape objectives have been selected, an appropriate set of DSM programs needs to be identified. See Figure 3.1 for the load shape objectives. Additional issues that need to be addressed in selecting load shape objectives include the following :

- What would be the impact on supply capability ?. For example, a hydro system that is energy constrained must consider the loss of supply capability if it chooses to flatten peaks
- What will be the impact on maintenance cost?. For example, if seasonal valley-filling programs are successful, they can increase scheduled maintenance costs
- What will be the impact on transmission and distribution costs?. Rapid penetration of heat storage may create nighttime peaks that increase distribution costs, for example.

3.3. Demand Side Alternative

The concept of demand side management implies a utility/customer relationship that produces mutually beneficial results. To achieve these mutual benefits, a utility must carefully consider such factors as the manner in which the activity will affect the utility's load shape, the methods available for obtaining customer participation, and the likely magnitudes of costs and benefits to both utility and customer prior to attempting implementation. Because there are so many demand side alternatives, the process of identifying potential candidates can be carried out more effectively by considering several aspects of alternatives in an orderly fashion. These alternatives can, in turn, serve widely varying purposes and can be utilized over a broad range of conditions. We can structure the assessment of demand side alternatives by considering four key aspects or dimensions associated with each alternative: Load shape objectives, End-use, Technology alternatives, and Market implementation methods.

The first dimension of demand side alternatives involves the appropriate load shape objectives to ensure that desired result is consistent with utility goals and constraint. Load forecasts may indicate that existing and planned generating capacity will fall short of projected peak demand plus targeted reserve margin. Several supply side alternatives may be available to meet this capacity shortfall: additional peaking capacity can be built; extra power can be purchased as needed from other generating utilities; or, perhaps a reduction in reserve margin can be tolerated. There are also a number of demand side alternatives, including direct load control, interruptible rates, and residential thermal storage, that can augment the number of planning alternatives available to utility. Choosing between meeting the peak versus reducing the peak becomes a balance between the cost and benefits associated with the range of available supply side and demand side alternatives.

The second dimension involves identification of the end-uses whose energy demand and characteristics generally match the requirements of the load shape objectives. In general, each end use (e.g., residential space heating, commercial lighting) exhibits typical and predictable load patterns. The extent to which load pattern modification can be accommodated by a given end use is one factor used to select an end use for demand side management.

The third dimension of demand side alternatives deals with choosing appropriate technology alternatives for each target end-use. This process should consider the suitability of the technology for satisfying the load shape objective. Residential sector demand side technologies fall into four categories: building envelope options; efficient equipment and appliances; thermal storage equipment; and energy and demand control options. These four categories cover most of the currently available. Many of the individual options can be considered as components of an overall program and thereby offer a very broad range of possibilities for successful residential demand side program synthesis and implementation.

The fourth dimension of demand side alternatives covers various methods for encouraging customers to participate in the program. Market implementation alternatives vary for different technologies, but typical approaches involve some form of market evaluation and promotion. In some cases, direct customer contact can be made and incentives offered to gain customer participation; in others, merely increased customer awareness of the availability of alternatives is sufficient to initiate customer participation.

Taken in sequence, the four steps of activities described provide an orderly method for characterizing demand side management alternatives. The basic steps are :

- Establish the load shape objective to be met
- Determine which end uses can be appropriately modified to meet the load shape objective

- Select technology options that can produce the desired end use load shape change
- Identify an appropriate market implementation program.

The evaluation and selection of the most appropriate DSM alternatives is perhaps the most crucial question a utility faces. The question is difficult since the number of demand side alternatives from which to select is so large. In addition, because the relative attractiveness of alternatives depends upon specific utility characteristic, such as the load growth in its service area, the fuel price forecast, the system marginal cost of its generating resource mix, and the load shape (peak and base load). In other words, what is attractive to one utility may not be attractive to another. In order to be cost effective, incremental cost of DSM alternative must not exceed this system marginal cost. The system marginal cost of an electric utility characteristically represents its reliability, commitment, and dispatch criteria, and forms the basis for pricing the electric energy in various power purchase contracts.

3.4. Program Planning

Experience with field implementation of DSM programs has grown substantially over the past few years. The emphasis of most utilities has been on the screening, design, and implementation of DSM programs. Now, evaluation of in-place DSM programs is growing in importance. As with any sophisticated program, a demand side program should begin with an implementation plan. The plan includes a set of carefully defined, measurable, obtainable goals. A program logic chart can be used to identify the program implementation process from the point of customer response to program completion. For example, in a direct load control program, decision points, such as meeting customer eligibility requirements, completing credit applications, device installation, and post-inspection can be defined. Actual program implementation can be checked against the plan and major variances reviewed as they occur. The careful planning that characterizes other utility operations should carry over to the implementation of demand side programs.

The programs are expensive, but prudent planning will help assure program efficiency and effectiveness. The variety of activities and functional groups involved in implementing demand side programs further accentuates the need for proper planning. Ongoing program management is also extremely important. The need for cost accounting, monitoring employee productivity and quality assurance should be addressed; the use of direct incentives necessitate close monitoring of program costs.

3.4.1. Customer Acceptance

The electric utility industry has recently begun to apply a variety of market research techniques to assess customer preferences and behavior. Several insights are beginning to emerge about how customers make their energy usage and equipment purchase decisions. In general, customer acceptance of a utility's DSM programs depends on three factors: financing and economics; risk aversion; and time preference and comfort as explained by Gellings and Smith [15].

Customer acceptance can be enhanced considerably by utility promotional practices, such as low interest financing of specific end-use technologies; educational information on the costs and reliability of end-use products /services; and offering customers a choice of pricing options to accommodate their time preferences and comfort needs.

Customers do not purchase energy for the sake of consuming it but instead are interested in the service it provides. Potential customer interest in a demand side management program may be based on a number of factors including, price of electricity and competing fuels ; demographics (income, age, and education) ; appliance characteristic (saturation, usage, cost, and age) ; behavioral factors ; utility marketing/program availability ; and mandated standards

Increasing DSM activity is a crucial part of fundamental shift in the electric utility industry - a shift that is transforming utilities from commodity producers into service providers. Clearly this is no simple transition. As challenges like proving the impact of DSM programs indicate, the transition calls for significant changes in the way utilities conduct their business. Implementing DSM today means that utilities have to pay more attention not only to customers but to society at large.

3.4.2. The Incentive in DSM

As in most businesses, revenues of investor owned utilities have traditionally been linked to sales. That is, the more kilowatt-hours of electricity a utility sold, the more money it cloud make; conversely, the fewer it sold, the less it made. This type of business environment created a disincentive for utilities to implement energy efficiency programs and other types of demand side management. What's worse, under most traditional rate making formulas, some utilities could never fully recover money spent on DSM programs, nor could they recover revenues lost from decreased electricity sales.

situation changing due to environ- restriction

Just as a utility, customer may require an incentive like rebates to participate in energy efficiency programs, utilities also may need incentives to sponsor such programs. In an effort to give utilities at least the same incentives to use demand side resources as they have to use generating resources, regulators have been revamping traditional rate making formulas and implementing financial incentives. Regulatory command offers some degree of incentive for utility action on DSM. These incentives vary widely in form, which can make a significant difference in the extent to which they encourage DSM investment. Generally, the financial incentives fall into three categories: cost recovery, lost revenue recovery, and pure incentives.

Cost recovery incentives allow utilities to recover money spent on DSM programs. One typical method of cost recovery is to treat DSM as an investment rather than as an expense. This allows cost associated with DSM programs to be accumulated over a number of years and figured into the financial base upon which rates are determined. In this way, utilities can earn a return on DSM investments just as they do on power plants.

Revenue recovery incentives do away with the profit-sales link that causes utilities to lose revenues when they sell less electricity. This link can be broken in two ways. One method, called decoupling, simply divorces profits from sales in rate making formulas. The second method is to allow utilities to recover lost revenues after the fact.

Pure incentives, goes beyond offsetting costs associated with DSM programs to offer bonus profits for utilities. This money comes from the savings that otherwise would be fully reflected in customers' bills. In other words, pure incentives allow utilities to share some of the customers' savings. These incentives can be configured in a number of ways. Some regulators offer them as rewards for achieving conservation goals.

DSM resources involve less risk than most supply side options in part because they can be delivered in small increments. While a utility can build a DSM program gradually, it can not build and use a power plant in similar increments. Others simply offer a higher return on investment in the demand side than that allowed on supply side.

3.5. The Impact of DSM

As the needs and opportunities for DSM are discussed in the previous section, two issues become obvious. First , how to quantify the effects of these myriad options such that proper credits can be provided. This would ensure that the utility is not unfairly subsidizing one group of customers at the expense of the other. Second is, how to represent the impact of demand side management activities. A carefully analyses to represent the impacts of demand side management as mentioned in the second issue is the most important thing in implementing DSM. The load duration curve is a key in DSM impacts, since from load duration curve the peak and energy change can be analyzed. An other important component that has to be considered as the effect of the peak reduction is the base load. It is important to know because the utility have to realize how the increasing or decreasing of base load will affect the units which serve the base load.

3.5.1. The load shape change

As in its definition, demand side management focuses on deliberately changing the load shape so it can be served more efficiently. This focus may give the impression that the only load shape changes that occur are those induced by demand side management. Certainly this is not the case. System load shape changes can occur naturally due to fluctuations in customer mix, the entry of new industries into marketplace, the introduction of new process, and the growth of the end use stock in the residential and commercial sectors. Thus, to examine the impact of demand side alternatives, it is important to differentiate naturally occurring changes in the load shape and those changes resulting from demand side alternatives.

Recently, with the available models, the utilities induced the impacts of demand side management into load duration curve by modifying their hourly load data first, and using the modified data, the load duration curve is made. To modify the hourly load data to induce the impacts of DSM is not an easy job, specially reducing the energy demand as a result of demand side activities. Realizing on these difficulties, the existence of a new model that can induce the variables as they change directly to load duration curve (such as peak load, base load and total energy demand) after implementing DSM, is needed. A model that could do this would make the process of inducing DSM easier and more accurate, and ultimately be invaluable to the utility planner and operator.

Actually there are some factors which influence the system load shape. They are: demand side management, appliance and equipment turnover, regulation, reactions to energy prices, naturally occurring load growth. The load impacts of demand side alternatives may change over the planning horizon. Failure to recognize and account for this change can lead to serious future supply problems. Alternatives tend to interact making the estimation of changes in the load shape difficult. The important message is that the load shape is dynamic and changes over the planning horizon. The load shape change mentioned in this section means the change has happened in numerical data, where the available model cannot modify the load duration curve but change the numerical data and perform the load duration curve.

3.5.2. Transmission and Distribution Impacts

Taking into account the structure and behavior of the electric system, several objectives can be met through DSM implementation. A primary concern of utility management is generation expansion requirements. The capital-intensive nature of new generation provides a basis for significant savings due to unit deferral or cancellation. An appropriate DSM strategy choice might be the options which function in the manner as would the planned generation unit. For example, peak clipping DSM options would be candidates for the deferral of a combustion turbine unit, or strategic conservation options would be utilized to provide the capacity that would have been provided by a new coal-fired unit. These DSM options are implemented to realize a savings in generation will have the impacts on the T&D system. DSM might also be implemented for direct benefit of the T&D system itself. For instance, some portions of a utility's service area may impose geographical constraints which limit the number or size of feeders into the load center. In the extreme case, DSM might represent the only viable alternative to serving a constrained load in a reliable manner.

Historically the utility industry involvement in Demand Side Management (DSM) programs has been motivated by the desire to improve the utilization of generation and fuel resources and to increase customer value through the varied end uses of electrical energy. The impacts and opportunities for DSM on transmission and distribution (T&D) system have thus far been ignored or treated as inconsequential. It is becoming increasingly clear that prime opportunities exist to incorporate DSM into the T&D system planning process, particularly since many utilities are currently experiencing T&D construction budgets that outweigh the investment in generation expansion by significant margin. U.S. utilities are expected to spend nearly $12 billion more for T&D than for generation during the period of 1990 to 1994 as mentioned by Willis [38]. DSM can serve as a premier tool for achieving a T&D system which is optimally built and operated. This translates into reduced costs and enhanced revenues.

Implementation of a single DSM program option may not by itself achieve the full potential of T&D impact benefits. Rather, the utility case study showed that combining various DSM program options into strategic package is the best approach. Such an integrated program was evaluated by studying the simultaneous application of cool storage, weatherization, water heating control, and air condition control. The summer load was decreased by 64 MVA (over ten percent) while also reducing loadings uniformly throughout the T&D system [38].

A final opportunity is the utilization of DSM to optimize the T&D system. Such decisions must be based on an economic analysis which considers both capital and operating costs to appropriately determine the tradeoff between DSM options and T&D upgrade/new construction.

3.5.3. DSM and the environment

Pressures to improve the environment are among the leading forces propelling the DSM movement today. This is apparent in the statements and actions of regulators, environmentalist and others who are encouraging utilities to investigate DSM options.

DSM's environmental benefits are also now being recognized in the utility planning process, through the use of "externalities" in developing an Integrated Resource Planning (IRP). Externalities are the impacts - both positive and negative - of supply and demand side resources on society that are not reflected in the market prices of resource options. These impacts can be social, economic, or environmental, including issues of human health, recreational opportunities, and visual air quality. Since load-reducing DSM programs do not generate emissions, including environmental externalities in the IRP process gives this type of DSM a clear advantage over most supply side options.

Various techniques have been devised to account for environmental externalities in the development of least-cost plan. Some involve a ranking, or point, system that recognizes the attributes of all resource options and allows planners to weigh them against one another. Other methods give the externalities a relative value that can be either added to the cost of a DSM program. Still other techniques assign a specific dollar value (in cents per kilowatt-hour) to the cost of each resource option.

Clearly, assigning any sort of value to externalities is a difficult task. Making this task even more complex is the fact that the environmental impacts of various emissions are still being determined. As new information emerges, the cost that regulators attribute to externalities are likely to change. An added concern is that if externalities are incorporated into the electric utility IRP process, they should also be applied to all other fuels, so that electricity does not suffer an unfair competitive disadvantage. Despite these challenges, a number of utility action on DSM. Some utilities were motivated by other factors, such as a desire to postpone the construction of new power plants. In other case, activity was prompted by federal mandates requiring utilities to offer certain conservation programs.

One troublesome issue that externalities raise for electric utilities, is that they contribute to the perception that less electricity is better for environment. There are many situations in which more, not less, electricity is the answer to saving energy and improving the environment. Advanced end use technologies like computers and fax machines have clearly added to the demand for electricity. They also contributed to the enhancement of society and saved gasoline, postage, and time, among other things. In addition, there are a number of sophisticated electric technologies and processes that can be directly substituted for less efficient fossil fuel alternatives, resulting in significant overall reductions in primary energy use.

According to EPRI's figures, beneficial electric technologies have the potential to add as much as 700 billion kwh to electricity use by 2010. It is because of the efficiency gains these technologies offer their fossil fuel alternatives, the additional demand would result in a commensurate reduction in total energy use of 7.7 quadrillion Btu and a reduction in carbon dioxide emissions of offer 350 million tons.

3.6. DSM Program Evaluation

Demand side management evaluations are conducted primarily to verify how electricity use changes as a result of a given program and to determine how efficiently programs are administered. Three key elements of demand side management program evaluation are field data, engineering model and statistical model. These elements will be outlined bellow.

1) Field data include all kinds of information about customers and their energy use, such as that obtained from metering and customer surveys. Comprehensive and accurate field data are crucial to successful evaluations, but this information alone will not allow utilities to determine how effective programs are and how efficiently they are delivered. To complete the picture, field data must be plugged into the framework of tools like engineering model and statistical models.

2). Engineering models are computer models containing algorithms that can calculate the energy use of a building, given detailed information on the building and the end use technologies inside. The models can be used to determine which technologies will offer the biggest electricity savings for a particular customer or group of customers. To create a realistic picture of electricity use, information on weather patterns, hours of occupancy, and other factors affecting customers' electricity consumption must be input. Engineering models have seen widespread application within electric utilities for DSM program impact monitoring and evaluation, as well as program planning and screening. While engineering simulations have certain inherent limitations, they are used in one form or another throughout the impact evaluation process. It can be used to fill several different roles in impact evaluation projects. One function is as an independent, stand-alone estimate of program impacts. Engineering models can be a quick and inexpensive method to obtain information that does not justify more expensive statistical and end-use metering approaches. It can serve as a means of verification of statistical model. Engineering estimates are also important as a method for estimating the time differentiation of impacts; because statistical estimates are limited by the periods of available consumption data.

Because engineering models rely on many assumptions about behavior, they needs to be calibrated and benchmarked to actual consumption characteristics of typical participants in each customer class. Care must be taken in the assumptions used in developing engineering models. Other points to consider include using an appropriately detailed simulation model and/or algorithms and using personnel with an adequate understanding of the end-useds affected by the programs.

3). Statistical models are built around extensive customer information, including demographic and energy use data. These models can be used to determine what kind of program would be most successful in a given area, and they can also indicate the electricity savings attributable to a particular program already in place. While helpful in accounting for behavioral patterns, these models lack the technical detail provided by engineering simulations. There are a variety of such models, each with the potential to provide information on program impacts. Because there is no single correct model, this section reviews the strengths and weakness of alternative approaches so that the analyst can make reasonable choices between models. In general, the literature on conservation program evaluation has used two basic statistical approaches for estimating the energy savings attributable to a DSM program :

- Comparison approaches using in-house data -- the energy consumption of participants is compared with the energy consumption of non-participants; and,
- Multivariate regression approaches using customer specific data -- factors that affect energy use for both participants and non-participants are used as control variables in a statistical model.

The comparison approaches can produce useful information about the effects of a DSM program, while requiring minimal additional data collection. One problem with these comparison approaches is that the researcher will have limited information about the comparability of the participant and non-participant groups in terms of household demographics and appliance stocks. The only data available to confirm the similarity on the two groups are billing data and limited in-house information.

The multivariate regression approach discussed in this section uses a larger data set that typically includes survey data on individual customers. This approach is more flexible in its ability to control for non-program factors that may influence energy use and bias the estimates of program energy savings. While simple comparison approaches are potentially useful in DSM impact evaluations, the flexibility and power of multivariate regression models make this approach more attractive. Multivariate regression models can control for many of potentially confounding factors that alter changes in energy use, increasing the ability of the model to isolate impacts attributable to the DSM program. Conditional demand modeling, interaction variables, multicollinearity problems, auto correlation, and regression diagnostics are some of the multivariate modeling issues.

3.7. Summary

The total capacity that have to be provided by utility base on the peak of the customer load, however, the utilities get the revenue, base on the energy in kwh that customer used. This two variables, energy and peak load, have different effects on the utility planning. Because the effects of these two variables to utility planning are so important, the utility has to manage the customers load -- in other word to improve the load factor by implementing Demand side management. Demand side management influences customer use of electricity in ways that will produce desired changes in the utility's load shape.

The utility benefits from DSM by inducing changes in the time pattern and magnitude of electricity demand, maximizes the productive and cost effective use of the utility's resources. The customer benefits by being better able to control total energy cost and usage. Demand side alternatives are appropriate for consideration both by investor owned or public utilities. With the systematic application of demand side management principles by utilities throughout the nation (USA), there could be a peak demand savings by the year 2000 of more than 60,000 MW. This could represent a saving to all utility customers of more than 60 billion dollars. In addition, demand side management can increase sales which could decrease average prices 5 percent and/or increase net profits by 10 to 30 percent, depending upon the utility as reported by Keelin and Gellings [109].

The role of demand side management (DSM) in utility integrated resource plans has been growing over the past few years. Demand for electricity has exceeded forecasts, moving up the time when some utilities will be facing capacity shortfalls. The Integrated Resource Planning (IRP) will be discussed in the following chapter.

CHAPTER IV

Integrated Resource Planning

4.1. Introduction

In general, the electric utility planning process can be described as a method involving the energy forecast, yielding an expansion plan with associated financial analysis and resulting in construction programs. Every electric utility company performs both short-term and long-term planning. Short-range planning is defined as the analytical process that includes an assessment of the near future by evaluating alternative courses of action against desired objectives with the selection of a recommended course of action for the time period requiring immediate commitments. The Long-range planning is defined as the analytical process that includes an assessment of the future by evaluating alternative courses of action against desired objectives with the selection of a recommended course of action, extending beyond the time period requiring immediate commitments. In general, the Long-range planning cover 15-20 years into the future. However, the planning horizons are known to be 15-30 years for some power plant additions. Long-term planning is much more uncertain. Treatment of generation expansion planning under load forecast uncertainty is becoming more important for electric utility planning.

During the past several years, dramatic changes have affected the environment in which electric utility's plan. These changes include deregulation of electricity generation; greater access to transmission systems; competition for retail customers; changes in economic regulation; increased concern with the environmental consequences of electricity production and use; growing public opposition to construction of power plants and transmission lines; and considerable uncertainty about future load growth, fossil-fuel prices and availability, and the cost and construction times for different kinds of resources. These changes and a great deal of uncertainty in the future is leading electric utilities toward incorporating DSM concepts in their resource planning. The reasons for the transition to an integrated supply-demand analysis include recognition of the value of conservation, the rising cost of new power plants, a more competitive marketplace, and the promotion of greater efficiency in energy use. Resource planning practices today encompass both customer and utility actions. Consequently, utility planning now requires a broader perspective than that previously needed for traditional supply planning studies.

Traditional electric utility planning has consisted largely of matching expected load growth with the right kind of "supply-side" generating capacity or energy purchases. In recent years there has been an emergence of interest in planning methods which focus on alternatives to supply-side options. Two such approaches, Least-Cost Planing, and Demand Side Management, both address opportunities to modify the ways in which energy (especially electricity) is used to reduce the need for new generation sources. The term least-cost planning is sometimes used to describe the idea of balancing the mix of supply-side and demand-side alternatives to meet the energy needs at the "least-cost". A more descriptive and accurate term for this balancing is Integrated Resource Planning (IRP) as reported by Gellings et.al. [14].

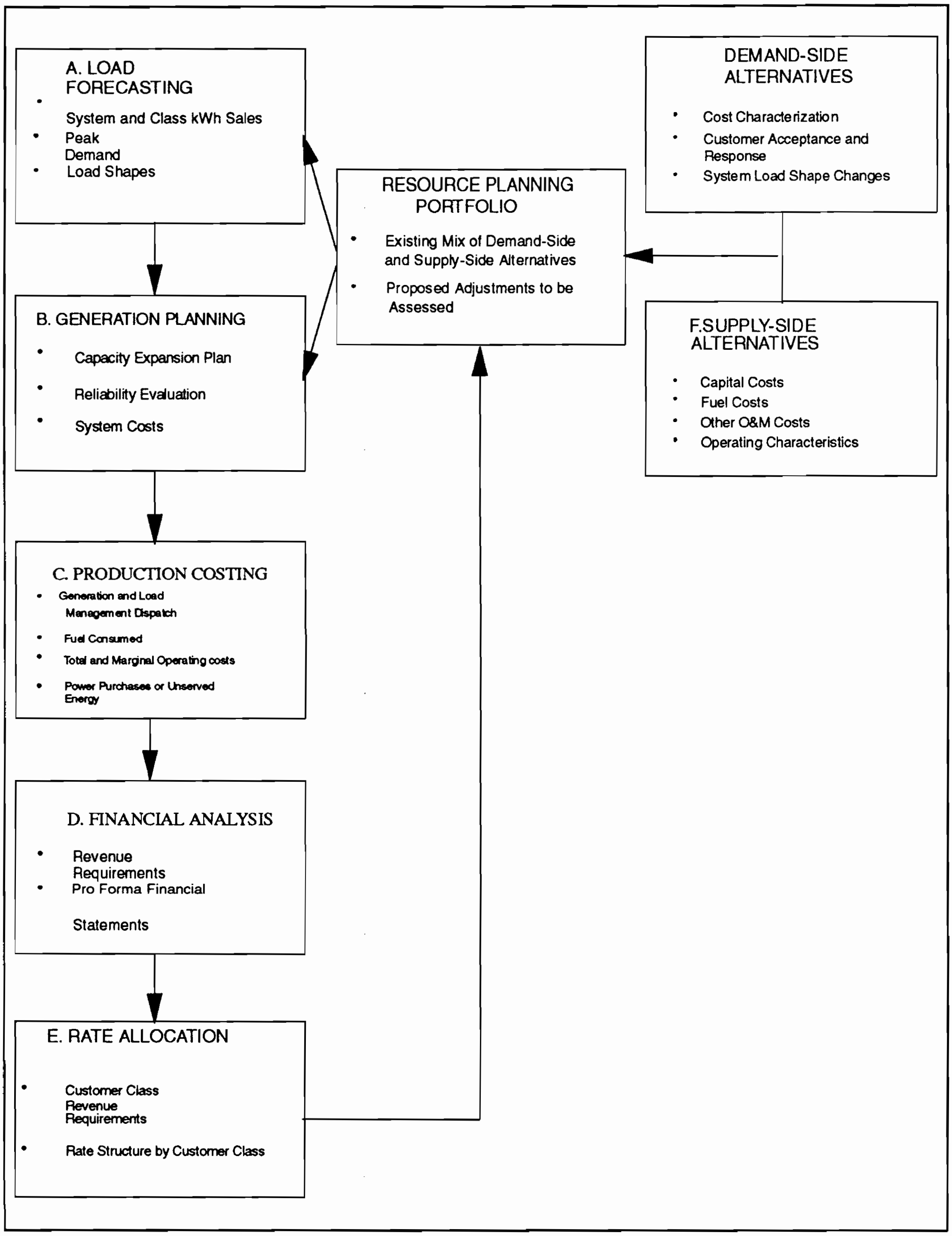

Figure 4.1. Utility Framework Including D S M

Integrated Resource Planning is important to utilities and their customers primarily because of problems that arose with traditional planning methods. These problems included a narrow focus on central station power plants limited consideration of uncertainty, and little public involvement. Typically, a utility begins its IRP process by developing alternative load forecasts to generation planning, production costing, and financial and rate analysis as shown in Figure 4.1. The fundamental aspect of IRP is that the planner seeks to find the combination of demand-side and supply-side which maximizes the attainment of some objectives (such as providing energy requirements at minimum cost).

The integrated resource plan also serves important functions within a utility. Preparation of the plan encourages cooperation and communication among several departments within the utility. The resource-planning process helps the utility to develop and communicate internally its plan to provide electric energy resources for future. IRP is also a powerful way for utilities to provide desired energy services to their customers at reasonable cost. It includes a broad array of supply and demand resources, explicit treatment of uncertainty, environmental costs as well as direct economic cost, and public involvement. Because of these features, IRP is likely to yield a better mix of resources and fewer protracted controversies among the utility, its regulator, and the public than would traditional planning approaches. IRP differs from traditional utility planning because of the following :

- Explicitly includes energy-efficiency and load management programs as energy and capacity resources;
- Considers environmental and social factors as well as direct economic costs;
- Involves public participation;

- Carefully analyzes the uncertainties and risks posed by different resource portfolio and external factors; and
- Helps utility executives decide which resources to acquire, what amount to acquire, and when to acquire those resources.

In contrast, implementing DSM program reduces sales, which decreases the company's revenues and profits. Utilities are also concerned with potential price increases (caused by the need to spread fixed cost over fewer kwh sales) that would reduce their competitiveness. These disincentives are the driving forces in on going debates over the need to reform the rate making process. Proponents of reform argue that IRP is likely to be successful only if ways are found to align the financial interest of the utilities with the goals of integrated resource planning.

According to Buttorff, et. al. [124], the "new" integrated resource planning concept is broader that the old capacity planning concept in several ways. Such as :

- Both supply-side and demand-side options must be considered in developing the least cost expansion plan;
- Supply-side options must include both traditional sources (i.e., gas turbines, combined cycles, and steam units) as well as alternative resources (i.e., life extension and repowering of existing units, renewable energy and cogeneration);
- Demand side options must consider the full potential of all cost effective conservation, strategic marketing and load management programs; and
- The least cost plan must integrate the supply side and demand side.

4.2. Overview of DSM Resources

DSM involves the planning and implementation of utility's activities designed to influence the time pattern and/or amount of electricity demand in ways that will increase customer satisfaction, and coincidentally produce desired changes in the utility's system load reduction strategies, as well as load growth strategies and flexible energy service options. Given their broad applicability across a range of utility situations, DSM alternatives warrant consideration by all types of utilities, including those involved with ambitious construction programs, those with high reserve margins, and those facing high marginal costs. Demand side management programs are designed to meet the utility's mix of strategic utility load shape objectives. Given the emphasis on reducing peak demand, the accuracy of the peak demand impact of a DSM forecast is a critical factor.

Demand side management such as load management and conservation can be integrated into the planning process in several distinct ways; these can be generally grouped into two categories as explained by Gellings et al. [16]. The first is one which generally incorporates demand side management into the energy forecast. In this method it is assumed that the decision to be involved with a particular demand side activity is made independently of the basic planning process. In this case, the forecast is made of "business as usual" without regard to utility intervention in the market place. Subsequent forecasts are made of each planned demand side activity. The second method involves a true integrated planning process wherein combinations of supply side and demand side options are evaluated jointly. In each combination, iterations of the forecast are required to capture the interrelationships between demand side management programs and naturally occurring consumer behavior. In order to fully and effectively capture its benefits, DSM has to be integrated into overall electric utility planning and operation. Demand side resources should be treated in a fashion that is both substantively and analytically consistent with the treatment of supply resources so that demand and supply resources compete head to head. The existing utility planning system may be used in the detailed analysis and evaluation of demand side programs.

For demand side management considerations, the major issue in this type of analysis is the ability to determine time-differentiated rates that can reflect the impact of the time-of-use rates. This requires that customer cost be broken down into several time periods (e.g., peak, off-peak) reflecting varying costs of operation as determined by the production costing model. DSM resources that are slightly more expensive than supply resources under baseline conditions should not automatically be rejected at this point. Because these DSM options may later turn out to be attractive

4.3. Overview of Supply Resource

Traditional resource planning was essentially confined to preparing load forecasts and matching load with new generating capacity to achieve a pre-set reserve margin or a reliability index. The incremental capacity to generate electricity would be derived from a limited number of supply options. The recommended expansion plan would be that which incurred the lowest total cost over the planning horizon.

One principal objective in planning is to provide sufficient generation capacity to supply the system load, with reasonable reliability, minimal cost, and acceptable for environment and regulation standards. While the regulated utility is obliged to expand its facilities to accommodate new customers, it must do so in a manner which minimizes customers' rates while protecting investors' interest. Analysis of customer supply options, such as self generation, needs to be consistent with the load forecast. The same issues of agreement arise here as do in analysis of DSM resources. The list of supply resources considered should be as complete as possible, including purchased power (from other utilities, facilities that qualify under the federal public utility Regulatory Policies Act, and other independent power producers), alternative energy sources (such as photovoltaics, wind and geothermal), life extension an repowering of existing plants, as well as utility construction of power plants. New or upgraded transmission facilities should be include also. The criteria used to screen supply resources and to select those for further analysis (in the integration phase) should be consistent with the criteria used for demand side programs.

Supply side resources are commonly represented in planning models with forced outage rates to provide a probabilistic representation of their resource value and to assess reserve margins. It has been clear that cost minimization alone cannot guide the decision to build capacity. The reliability of the system must also be considered. Otherwise, the cheapest decision would always be not add capacity, even demand is rising rapidly.

Once the generating plan has been optimized to meet forecasted loads, it is necessary to simulate the dispatch of the generating units within the system. The purpose of this activity is to forecast production cost, system reliability, and loadings of individual generating units (including pumped hydro or other storage and power purchased from outside the system) for shorter periods of time such as days, weeks or months.

4.4. Load Forecast

The prime directive of any regulated electric utility is to provide adequate and reliable electricity supplies to consumers at reasonable cost. Due to the long lead times needed to bring new generating systems on line, providing adequate electricity supplies requires long range forecasts of energy sales and peak demand. The peak demand forecast is needed as a reference for the capacity planning, it is needed most for technical reason. Technical reason include, how much reserve margin have to be prepared and how much capacity have to be available for reliability reason. The energy sale forecast is needed most for financial consideration, such as how much the income of the utility will be, how long the investment will be returned, and as the result how to rate the energy sale for the customers. The interrelation between the annual energy and peak load forecast is crucial information. Some utilities develop detailed energy forecasts, while the peak load forecast is based on a simple model that is not coupled to annual energy used.

End use forecasts are desirable because they provide much more detailed estimates of future electricity use than do traditional econometric model. This detail is needed to assess the effects of past and current DSM programs and the likely effects of future programs. An infinite number of possibilities and interrelationships could exist within DSM forecast. The assessment of demand side management alternatives place some special requirements on the forecasting methodology. In broad terms, the following characteristics facilitate the evaluation: level of detail of forecast, distinction between the market penetration or stock of energy-using activities or equipment and the intensity of usage, and finally, emphasis on load shapes rather than only peak demand.

Another important interrelationship between load forecast and DSM forecasting is through the forecasting of peak demand and demand impacts. The most common load shape objectives utilized by utility are "peak clipping" or "load shifting". With expected utility growth, the strategies are :

- Increase utility operating efficiencies by shifting a greater proportion of production cost to the base load unit from peaking load unit; and
- Decrease the future need of additional generation supply.

Since the whole objective of demand side management is to alter the system load shape, a load shape forecasting capability within the load forecasting system is a very desirable feature. Projections of only peak demand are not sufficient since many programs are designed to meet objectives such as shifting the load or filling a valley. Once a load forecast has been established by an electric utility, the next step in the planning process is to determine the timing and type of supply and demand side resources that can most cost effectively meet that demand. Consideration must be given to such variables as seasonal load shapes, maintenance schedules, plant retirements, the capital and operating costs of various types of generating plants, and forced outage rates.

4.5. Least Cost Planning

The least-cost planning was first coined by Roger Sant in 1979 as mentioned by Gelling, et al.[14] in the context of asking a question : " How much energy efficiency (and how little conventional electricity, gas, coal, and oil consumption) could we achieve if all the potential end use energy efficiency were achieved which is economically competitive with conventional forms of energy.?". Least-cost planning has evolved to a broad spectrum of integrated planning. There have been many different definitions of least-cost planning, least-cost resources, and cost-effectiveness. Generally, the study of energy efficient technology potential has been considered a fundamental component of least-cost planning. Gellings [14] presents the four basic steps to the early view of least-cost planning. Those are :

- Understand how energy is used (i.e. end-use of energy);
- Identify the technical potential for improved end-use efficiency in energy using technology and equipment ;
- Evaluate the benefits and costs from a societal perspective of adopting some or all of that technical potential; and
- Apply engineering and economic analysis to calculate the optimum amount of improved energy efficiency which should occur to reduce the total costs of meeting energy requirements.

Many analyses of least cost planning have focused on reducing the total new dollar investment required to build new electric generating units. It is important to note the basic concept of least-cost was introduced to persuade energy planners and public policy makers that there was sizable potential to produce new energy resources through efficiency improvements, where these could be achieved at a lower cost than many supply-side investment. Improving the energy efficiency of end-use devices is viewed as the primary means to accomplish the economic objective. Utilities are now comparing and evaluating supply and demand side options to assemble a least-cost resource strategy in a way that reflects the definition of DSM.

4.6. Uncertainty in Planning Process

This deterministic representation obscures the uncertainty inherent in DSM programs and may lead to biased resource selection; most importantly it may also result in a less reliable system. The use of deterministic approaches has proved to be unacceptable to supply planning as well as for analysis of DSM alternatives. The treatment of uncertainty is also very important because uncertainties affect utility resource-acquisition decisions and affect customer electricity costs. Uncertainty about the external environment include economic growth, inflation rates, fossil-fuel prices, and regulation. The uncertainty analysis should also consider uncertainties about the cost and performance of different demand and supply resources.

There is substantial uncertainty as to how much peak demand reduction will be realized at the particular time when load management is needed and implemented. Another major concern is that customers, who initially participate in load management programs because of the financial incentives, may decides once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of the interruption outweighs the cost savings and withdraw from the programs. The uncertainty about customer acceptance, penetration level, and inconvenience level that can cause the cancellation of their participation, have to be analyze carefully.

4.7. Technical Support

The electric utility resource planning process has evolved from evaluating the economics and timing of future unit installations to a much more sophisticated analysis of all practical alternative resources, including those that reduce electricity consumption. The term "resources" now connotes a wide range of demand side and supply side options. The amount of information that must be processed to prepare integrated resource plans is big enough. Computer models are routinely used to manage these data for load forecasting; screening of demand and supply resources; and analysis of production cost, revenue requirements, electricity rates, and other financial parameters. These models are used to analyze a wide range of plausible futures (scenarios) and resource mixes (strategies) in developing the utility's preferred resource portfolio.

A variety of technical problems complicate IRP. One important methodological issue is the proper choice and use of computer models to screen individual resources, to develop resource portfolios, and to conduct detailed analysis of a few attractive resource portfolios. The Electric Power Research Institute (EPRI) has developed several screening tools and integrated planning models. These integrated computer models encompass the functions of previously separate load forecasting, capacity expansion, production costing and financial planning models as mentioned by Hirst and Goldman [23]. A major input to the planning process is a full characterization of supply and demand side alternatives; direct measurement and experimentation are the most widely known techniques for developing the necessary data, and engineering simulation models play a major role when new technologies are involved.

Engineering models are available to simulate both supply and demand side options. Engineering models are used in two ways: to approximate the energy producing or energy consuming performance of a device without actual installation or field tests and to evaluate changes in the performance of the device that result from changes in its configuration or the conditions under which it operates. Utility planning models should be reviewed and compared in terms of their technical capabilities, relevance to different aspects of the planning process, ease of use, data requirements, costs, and their factors. Such a review would aid utility planners in their selection of suitable computer models.

4.8. Environmental and Social Factors

Failure to consider external factors is an important shortcoming of current IRP practices. This failure often leads to outcomes that are socially suboptimal because many resource options entail significant social costs . Moreover, there are significant differences in the environmental effect (e.g., on air quality, water quality, and land use) of various electricity supply options. The need to reduce environmental impacts may require a planning approach that includes environmental as well as other costs. Ultimately, the specter of global warming may lead to dramatic changes in IRP practices. For example, future utility planners may be required to develop resource plans that achieve specific carbon dioxide reduction targets. This is also apparent in the direction some environmental legislation has taken. For instance, the Clear Air Act Amendments of 1990 include an incentive for utilities to invest in DSM programs that promote the increased use of efficient technologies. The analyses should be conducted of different electricity supply and demand strategies to reduce emissions of acid-rain precursors and of carbon dioxide to see how least-emissions strategies differ in cost and environmental effects from least-cost strategies as explained by Geller et al. [39].

4.9. Summary

Because of differences between demand and supply resources in unit size, capital cost, construction time, operating cost, reliability, and dispatch ability, integrating DSM resources into the resource plan is difficult. Moreover, because the amount and quality of data on demand and supply resources differ so much, more efforts are need to enhance the information used in IRP. However, successful development and implementation of integrated resource plans can save billions of dollars a year; reduce the need to build large, expensive generation and transmission facilities; improve the financial performance of utilities; reduce emissions of green-house gases and other pollutants; enhance national security; improve economic productivity; and smooth relations between utilities and their commissions and customers.

As mentioned in the previous section, load shape forecasting is needed since the whole objectives of DSM is to alter the system load shape. To forecast the load shape is not an easy task; the available models use the hourly load data to perform fifth degree polynomial as a mathematical model of load duration curve. So, the hourly load data become an important component to incorporate the demand side management (DSM) forecast into utility load forecast and also be used to incorporate the impacts of conservation and load management into the system load profile for this case. Therefore, we have to forecast the hourly load data to have the forecasting of load shape. However, there are some drawbacks of this model. The drawbacks are:

- The model does not recognize the value of the base load. Where the value of the base load of the model is depended upon how the fifth degree polynomial fits into the actual hourly load data. So, the value of the base load in mathematical model could be more or less than the actual value.

- The model does not use energy as its variable. The total energy demand will be calculated after the equation is performed from load data. Because of this, the total energy demand, under load duration curve, will be more or less than the actual total energy.
- In the case that one of three variables (base load, peak load and total energy) has to be changed for load management, the mathematical expression has to be changed. We have to go back to the hourly load data, make some changes and perform the mathematical model again. This iteration could create error and be time consuming.

Because of the drawbacks mentioned above, a new load model is needed which can be used directly for generating reliability indices. The idea come from the variables that can change the shape of load duration curve. There are three components that have to be considered that could change the load duration curve. These variables are base load, peak load and total energy demand. Those three components are likely to be affected if demand side management is implemented in planning and operation. The new model is presented in the next Chapter.

CHAPTER V

Proposed Analytical Model For ILDC

5.1. Introduction

The main objective of implementing Demand Side Management (DSM) in power systems is to change the utility's load shape - i.e. changes in the time pattern and magnitude of utility's load. Changing the load shape as a result of demand side activities could change the peak load, base load and/or energy demand. Those three variables have to be explicitly modeled into the load curve for properly representing the effects of demand side management. The impact of DSM will result in a change in reliability levels. Once the expected impacts of demand side activities on the system load are estimated, ways have to be found to represent these in the load curve model. Moreover, DSM activities will manifest themselves in three different ways : changes in base load, peak load and energy served.

The proposed technique to model the load duration curve will facilitate the representation of DSM impacts on loss-of-load probability, energy not served and energy consumption. This will provide an analytical method to study the impact of DSM on capacity requirements. So far iterative methods have been applied to study these impacts.

5.2. The Impact of DSM in Load Curve

An LDC is commonly used to represent the system load over an extended period of time. As with a chronological hourly load curve, the area under the load duration curve represents the total system energy requirement. There are several models that try to express the LDC mathematically, one of them is Snyder [9]. Snyder model represents the LDC with a fifth-order polynomial, where the coefficients of the polynomial are closely related to two quantities : the ratio of the minimum to the maximum load during the period, and the ratio of the average load to the maximum load. There are other models, such as the Wien Automatic System Planning Package (WASP), which try to model the LDC with a fifth-order polynomial obtained by fitting the hourly load data [11]. In such cases, it is difficult to represent the changes to peak load, base load and energy usage in the load curve. And also the Cumulant method try to calculate the reliability measures directly from load data without using LDC or ILDC.

The load duration curve (LDC) is the vehicle through which DSM impacts are incorporated into power system planning and operation. Models of the LDC are one of the most important tools in the analysis of electric power systems. They have been utilized for various purposes, such as estimating the operating cost of a power system, predicting the amount of energy delivered by each unit, and calculating reliability measures.

5.3. The proposed model

The analytical model of an inverse of the load duration curve is, in many ways, a more advantageous guide than its predecessors. The model represents the Inverted Load Duration Curve (ILDC) directly as a function of peak load (P), base load (B) and total

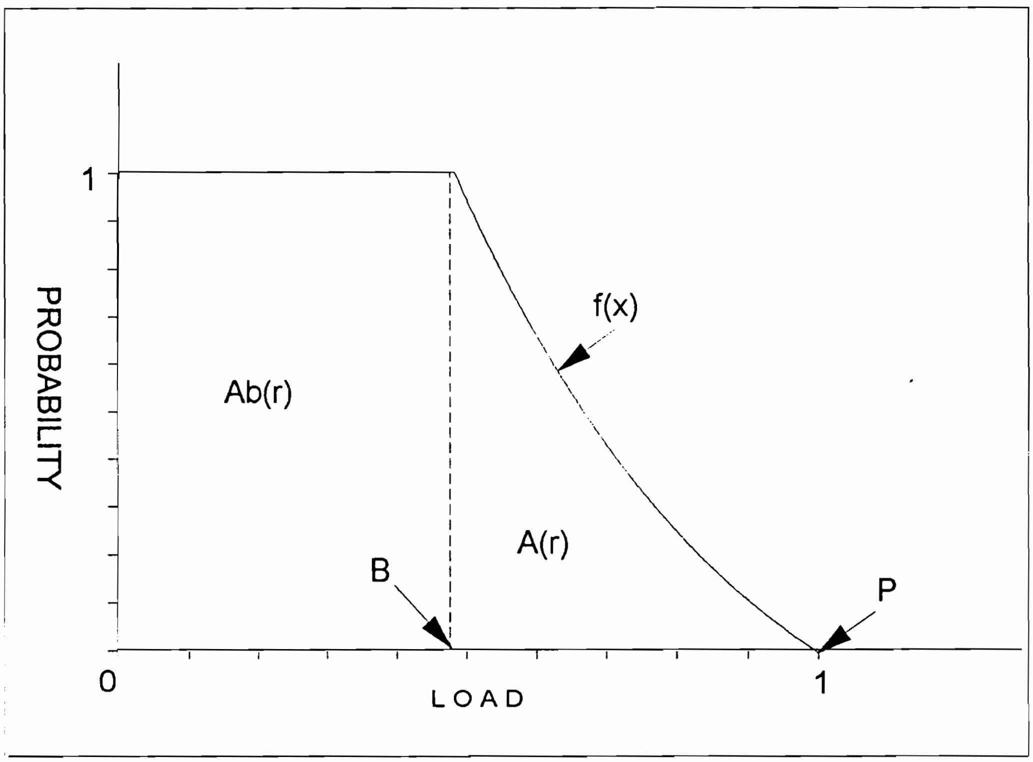

Figure 5.1. VPI Model

energy (E) as shown in Figure 5.1. This is a more accurate model of the load shape for use in planning and operation activities, especially after incorporating demand side management alternatives. The model is expressed as

$$f(x) = \left(1 - \frac{X-B}{P-B} \right) \exp\left(C \frac{X-B}{P-B} \right) \tag{5.1}$$

where

B = base load;

P = peak load;

C = a variable; and

X = load.

Among the four variables in equation (5.1), the variable 'C' is unspecified. So, we need to find the relationship between variable 'C' and the other variables. The next section derives the formula for variable C.

5. 3.1. Derive a Formula for Variable C

In equation (5.1), the variable C is a coefficient of exponential part. This coefficient will influence the slope of the curve f(x). The area under the curve f(x) multiply by total hours is the energy served. So, the total energy served will be related to the variable C. We will find out how variable C relates to the energy served analytically. Referring to equation (5.1), we have:

$$f(x) = (1 - \frac{X}{P-B} + \frac{B}{P-B}) \exp(\frac{CX}{P-B} - \frac{CB}{P-B})$$

$$f(x) = (1 + \frac{B}{P-B})\exp(\frac{CX}{P-B} - \frac{CB}{P-B}) - (\frac{X}{P-B})\exp(\frac{CX}{P-B} - \frac{CB}{P-B})$$

$$f(x) = (1+\frac{B}{P-B})\exp(-\frac{CB}{P-B})\exp(\frac{CX}{P-B}) - (\frac{X}{P-B})\exp(-\frac{CB}{P-B})\exp(\frac{CX}{P-B})$$

$$f(x) = \exp(\frac{-CB}{P-B})[(1 + \frac{B}{P-B}) \exp(\frac{CX}{P-B}) - (\frac{X}{P-B}) \exp(\frac{CX}{P-B})] \tag{5.2}$$

Referring to Figure 5.1, area under the curve f(x), which is A(r), is the integral of f(x) with the limit from the base load (B) to the peak load (P) as shown below.

$$A(r) = \int_B^P f(x)\, dx \tag{5.3}$$

In equation (5.2), there are two parts that have to be considered in integration of f(x) :

$$f_1(x) = \exp(\frac{CX}{P-B}) \tag{5.4}$$

and

$$f_2(x) = (\frac{X}{P-B})\exp(\frac{CX}{P-B}) \tag{5.5}$$

The integration of equation (5.2) after substitution equation (5.4) and (5.5) into equation (5.2) yields :

$$\int_B^P f(x)\,dx = \exp(-\frac{CB}{P-B})[(1+\frac{B}{P-B})\int_B^P f_1(x)\,dx - \int_B^P f_2(x)\,dx] \qquad (5.6)$$

To simplify the integration of equation (5.6), we integrate $f_1(x)$ and $f_2(x)$ separately where

$$\int_B^P f_1(x)\,dx = \int_B^P \exp(\frac{CX}{P-B})\,dx = [\frac{\exp(\frac{CX}{P-B})}{\frac{C}{P-B}}]_B^P$$

$$\int_B^P f_1(x)\,dx = (\frac{P-B}{C})[\exp(\frac{CP}{P-B}) - \exp(\frac{CB}{P-B})] \qquad (5.7)$$

and,

$$\int_B^P f_2(x)\,dx = \int_B^P \frac{X}{P-B}\exp(\frac{CX}{P-B})\,dx = \frac{1}{P-B}\int_B^P X\exp(\frac{CX}{P-B})\,dx$$

$$= \left(\frac{1}{P-B}\right)\left[\frac{\exp\left(\frac{CX}{P-B}\right)}{\frac{C^2}{(P-B)^2}} \left(\frac{CX}{P-B} - 1\right) \right]_B^P$$

$$= \left(\frac{1}{P-B}\right) \frac{\left[\left(\frac{CP}{P-B}-1\right) \exp\left(\frac{CP}{P-B}\right) - \left(\frac{CB}{P-B}-1\right) \exp\left(\frac{CB}{P-B}\right)\right]}{\frac{C^2}{(P-B)^2}}$$

$$\int_B^P f_2(x)\, dx = \left(\frac{P-B}{C^2}\right)\left[\left(\frac{CP}{P-B}-1\right)\exp\left(\frac{CP}{P-B}\right) - \left(\frac{CB}{P-B}-1\right)\exp\left(\frac{CB}{P-B}\right)\right] \tag{5.8}$$

The total integration for the area under f(x) is found by substituting equation(5.7) and equation(5.8) into equation(5.6). The result is

$$\int_B^P f(x)\, dx = \exp\left(-\frac{CB}{P-B}\right) \left\{\left(1+\frac{B}{P-B}\right)\left(\frac{P-B}{C}\right) \left[\exp\left(\frac{CP}{P-B}\right) - \exp\left(\frac{CB}{P-B}\right)\right]\right.$$

$$\left. -\left(\frac{P-B}{C^2}\right) \left[\left(\frac{CP}{P-B}-1\right)\exp\left(\frac{CP}{P-B}\right) - \left(\frac{CB}{P-B}-1\right)\exp\left(\frac{CB}{P-B}\right)\right]\right\}$$

$$= \exp\left(-\frac{CB}{P-B}\right)\left\{\left[\left(\frac{P}{C}\right)\exp\left(\frac{CP}{P-B}\right) - \left(\frac{P}{C}\right)\exp\left(\frac{CB}{P-B}\right)\right]\right.$$

$$\left. -\left[\left(\frac{CP-P+B}{C^2}\right)\exp\left(\frac{CP}{P-B}\right)-\left(\frac{CB-P+B}{C^2}\right)\exp\left(\frac{CB}{P-B}\right)\right]\right\}$$

$$\int_{B}^{P} f(x)\,dx = \left(\frac{P-B+B}{C}\right)[\exp(C)-1] - \left[\left(\frac{P}{C}-\frac{P-B}{C^2}\right)\exp(C)-\left(\frac{B}{C}-\frac{P-B}{C^2}\right)\right] \qquad (5.9)$$

Since equation (5.9) represents the area under f(x), (referring to equation (5.3)), we have

$$A(r) = \left(\frac{P}{C}\right)[\exp(c)-1] - \left[\left(\frac{P}{C} - \frac{P-B}{C^2}\right)\exp(C) - \left(\frac{B}{C}-\frac{P-B}{C^2}\right)\right]$$

$$A(r) = \left[\left(\frac{P}{C}\right)\exp(C) - \left(\frac{P}{C}\right)\right] - \left[\left(\frac{PC-P+B}{C^2}\right)\exp(C) - \left(\frac{BC-P+B}{C^2}\right)\right]$$

$$A(r) = \left(\frac{P-B}{C^2}\right)\exp(C) - \left(\frac{PC-BC+P-B}{C^2}\right)$$

$$A(r) = (P-B)\left[\frac{-(C+1) + \exp(C)}{C^2}\right]$$

We arrange all of the variable C in the right hand side, the result is as shown bellow :

$$\frac{A(r)}{P-B} = -\frac{1}{C} - \frac{1}{C^2} + \frac{\exp(C)}{C^2} \qquad (5.10)$$

From equation (5.10) we can see that $\frac{A(r)}{P-B}$ is the function of C, Such as

$$\frac{A(r)}{P-B} = f(C)$$

To analyze the relationship between variable C and the other variables, we first find 'C' as a function of $\frac{A(r)}{P-B}$

$$C = f(\frac{A(r)}{P-B}) \tag{5.11}$$

The exponential part in equation (5.1) , that is exp(C), is transformed into series form as shown bellow :

$$\exp(C) = (1 + C + \frac{C^2}{2!} + \frac{C^3}{3!} + \dots + \frac{C^n}{n!}) \tag{5.12}$$

Substitute equation (5.12) into equation (5.10), we find

$$\frac{A(r)}{P-B} = -\frac{1}{C} - \frac{1}{C^2} + \frac{(1 + C + \frac{C^2}{2!} + \frac{C^3}{3!} + \dots + \frac{C^n}{n!})}{C^2}$$

$$= -\frac{1}{C} - \frac{1}{C^2} + \frac{1}{C^2} + \frac{1}{C} + (\frac{1}{2!} + \frac{C}{3!} + \frac{C^2}{4!} + \dots + \frac{C^{n-2}}{n!})$$

$$\frac{A(r)}{P\text{-}B} = \frac{1}{2!} + \frac{C}{3!} + \frac{C^2}{4!} + \ldots + \frac{C^{n-2}}{n!} \qquad (5.13)$$

Simplify the equation (5.13) yields

$$\left(\frac{A(r)}{P\text{-}B} - \frac{1}{2!}\right) = \frac{C}{3!} + \frac{C^2}{4!} + \ldots + \frac{C^{n-2}}{n!} \qquad \ldots\ldots (5.14)$$

The right hand side of eqn.(5.14) is a series that can be expressed as a formula. To make the expression simpler, let m = n - 2. By simplifying equation (5.14), we will end up with,

$$\left(\frac{A(r)}{P\text{-}B} - 0.5\right) = \sum_{m=1}^{9} a_m C^m \qquad (5.15)$$

where: $a_m = \frac{1}{(m+2)!}$, m= 1,2,3,....,7

Using the reversion series method as discussed in chapter 2, we can find the expression of 'C' as a function of $\left(\frac{A(r)}{P\text{-}B} - 0.5\right)$

$$C = \sum_{m=1}^{9} A_m \left(\frac{A(r)}{P-B} - 0.5\right)^m \tag{5.16}$$

where:

$$A_1 = \frac{1}{a_1}$$

$$A_2 = -\frac{a_2}{a_1{}^3}$$

$$A_3 = \frac{1}{a_1{}^5}(2a_2{}^2 - a_1a_3)$$

$$A_4 = \frac{1}{a_1{}^7}(5a_1a_2a_3 - a_1{}^2a_4 - 5a_2{}^3)$$

$$A_5 = \frac{1}{a_1{}^9}(6a_1{}^2a_2a_4 + 3a_1{}^2a_3{}^2 + 14a_2{}^4 - a_1{}^3a_5 - 21a_1a_2{}^2a_3)$$

$$A_6 = \frac{1}{a_1{}^{11}}(7a_1{}^3a_2a_5+7a_1{}^3a_3a_4+84a_1a_2{}^3a_3-a_1{}^4a_6-28a_1{}^2a_2{}^2a_4 - 28a_1{}^2a_2a_3{}^2-42a_2{}^5)$$

$$A_7 = \frac{1}{a_1{}^{13}}(8a_1{}^4a_2a_6+8a_1{}^4a_3a_5+4a_1{}^4a_4{}^2+120a_1{}^2a_2{}^3a_4+132a_2{}^6+180a_1{}^2a_2{}^2a_3{}^2-a_1{}^5a_7$$
$$-36a_1{}^3a_2{}^2a_5 72a_2{}^3a_2a_3a_4-12a_1{}^3a_3{}^3-330a_1a_2{}^4a_3)$$

$$A_8 = \frac{1}{a^{15}}(-429b^7 + 1287ab^5c- 990a^2b^3c^2 + 165a^3bc^3 - 495a^2b^4d +$$
$$495a^3b^2cd - 45a^4c^2d - 45a^4bd^2 + 165a^3b^3e - 90a^4bce +$$
$$9a^5de - 45a^4b^2f + 9a^5cf + 9a^5bg + a^6h)$$

$$A_9 = \frac{1}{a^{17}}(1430b^8 - 5005ab^6c + 5005a^2b^4c^2 - 1430a^3b^2c^3 + 55a^4c^4 +$$

$$2002a^2b^5d - 2860a^3b^3cd + 660a^4bc^2d + 330a^4b^2d^2 - 55a^5cd^2 -$$

$$715a^3b^4e + 660a^4b^2ce - 55a^5c^2e - 110a^5bde + 5a^6e^2 + 220a^4b^3f -$$

$$110a^5bcf + 10a^6df - 55a^5b^2g + 10a^6cg + 10a^6bh - a^7i)$$

Referring to Figure 5.1, the total energy served is the area under the curve multiplied by total hours, such as

$$\text{Energy} = [A_b(r) + A(r)] \times h \qquad (5.17)$$

where

$A_b(r)$ = area at base load = 1 x B;

$A(r)$ = area under the curve; and

B = base load.

We want to find that $A(r)$ is a function of energy. By algebraic manipulation of equation (5.17) we can write

$$A(r) = \frac{\text{Energy}}{\text{hour}} - A_b(r)$$

$$A(r) = \frac{E}{h} - B$$

$$A(r) = \frac{E - Bh}{h} \qquad (5.18)$$

Substituting equation (5.18) into equation (5.16) and letting n = m. We end up with the formula for variable 'C' as shown below :

$$C = \sum_{n=1}^{9} A_n \left[\frac{E - (h.B)}{h.(P-B)} - 0.5 \right]^n \qquad \text{..... (5.19)}$$

where

E = energy;

h = hour;

P = peak load; and

B = base load.

From equation (5.19) we can see that variable 'C' is a function of peak load (P), base load (B), and total energy served (E). Substituting the equation (5.19) above into equation (5.1), we obtain the proposed model for load duration curve :

$$f(X) = \left(1 - \frac{X-B}{P-B}\right) \exp\left\{\left(\frac{X-B}{P-B}\right) . \sum_{n=1}^{9} A_n \left[\frac{E-h.B}{h.(P-B)} - 0.5\right]^n\right\} \qquad \text{..... (5.20)}$$

Equation (5.20) above is a direct mathematical representation of ILDC in terms of peak load, base load and total energy, and has been named the "VPI model". The VPI model mathematically represents the amount of time (normalized) a certain level of load is present. The VPI model will be compared to other available models that are widely used in power system planning and operations. In Figure 5.2., the VPI Model is compared to actual data. Before we compare the proposed model to others, we have to test the derived formula. The formula will be tested in the next section.

5.4. Validation of the Formula

In this section, we will test two of the formulas that were derived in the previous section. The first one is the formula for variable 'C', and the second is the VPI model's mathematical expression. We will also prove the insignificant changes for the value of series power if we use more than 7. In this case, the result of using series power 7 will be compared to series power 9.

5.4.1. Test the proper series power for the model

The proof that the series power greater than 7 insignificant relatively straight forward. In this proof, we choose n = 7. Using equation (5.19) the value of variable 'C' is calculated. With the calculated variable 'C', the LOLP and ENS are calculated using eqn.(5.20) with the convolution method. After that we choose n = 9 and calculate the value of variable 'C', LOLP and ENS again with the same formula. The comparison can be shown in Table 5.1. From this table we can see that the result of a power of 9 is not significantly different than that of a power of 7. As shown in chapter 2, the coefficients for a power of 7 of a series are simpler than that of a power of 9. Since the difference is not significant, for the calculation in the next section, power of 7 series will be used.

Table 5.1. Comparison Power Series of 7 and 9

Variable C		LOLP		ENS (MWh)	
7	9	7	9	7	9
-0.037150182820	-0.037150182820	0.0119149	0.0119149	5692.25	5692.25
-0.348239654399	-0.348239690393	0.0005312	0.0005312	176.84	176.84
0.039972551539	0.039972551539	0.0170320	0.0170319	8704.77	8704.77
-1.813811652737	-1.815856040947	0.0018813	0.0018790	787.13	786.09
-0.485647893947	-0.485648305274	0.0055455	0.0055455	2463.07	2463.07
-0.483721562390	-0.483721962096	0.0011172	0.0011172	400.84	400.84
-0.365433102156	-0.365433153610	0.0201061	0.0201061	10864.30	10864.30
-0.703401147845	-0.703406752132	0.0012961	0.0012961	490.99	490.99
-0.243760080727	-0.243760083191	0.0064251	0.0064251	2876.30	2876.30
-0.389049903374	-0.389049985066	0.0016913	0.0016913	629.79	629.79
-0.269174470434	-0.269174475658	0.0258518	0.0258518	14222.23	14222.23
-1.463314850633	-1.463923825017	0.0033998	0.0033985	1511.50	1510.89

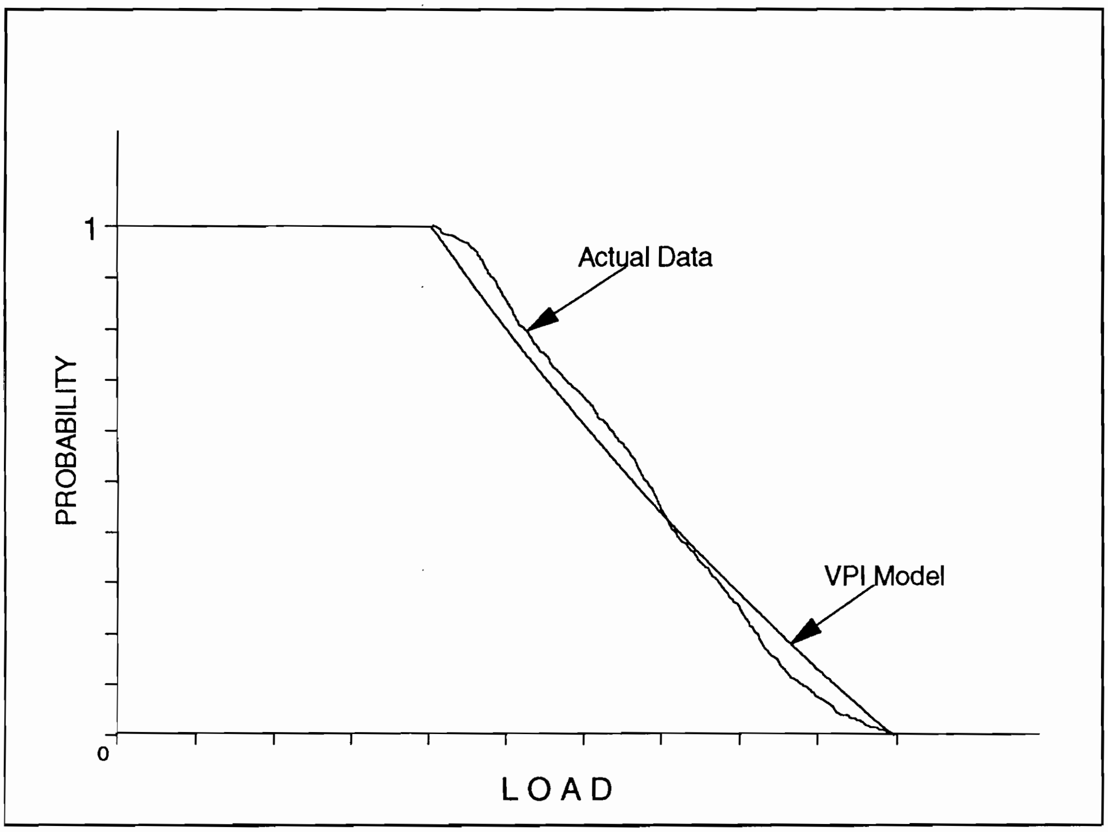

Figure 5.2. VPI Model vs Actual Data

5.4.2. Test the Formula for Variable 'C'

To test the formula for variable 'C', first, we choose a value for 'C'. And use equation (5.1) to calculate the area under the curve f(x) using mathematical integration with the chosen value for 'C'. After multiplying by total hour, we get the total energy under the curve f(x). Second, using equation (5.19) we calculate the value of 'C' using the same values as the first calculation, such as peak load (P), base load (B) and the calculated total energy served. We compare the chosen value of variable 'C' with the calculated value as shown in Table 5.2. From the Table 5.2, we can conclude that the formula for variable 'C' is reasonable estimate for the purpose of our proposed model.

5.4.3. Test Study of the VPI Model

The formula for variable C has been tested, and the series power of 7 has been proved reasonable for calculations. Now, in order to show how well the VPI model represents the actual load of a system under different circumstances, test case were formulated and analyzed under various conditions. The actual load data from a Virginia utility were used to test the model. 12 monthly load duration curves are represented in Table 5.3. The generation data from an EPRI report [125] as shown in Table 5.4, represents the generating unit data for the test system. The data will be used to compare the VPI model to Snyder model, WASP, Cumulant model and the actual data. The comparison of the VPI model to other models are :

- the ILDC comparison
- the ELDC comparison
- the total energy, LOLP and ENS comparison

Table 5.2. Coeficient 'C' Comparison

No	The True Value	The Formula Calculation
1	1.0	1.001
2	0.0	0.000
3	-1.0	-0.999
4	-2.0	-1.996

Table 5.3. Load Data

No.	MONTH	Peak Load (MW)	Base Load (MW)	Total Energy (MWh)
1	Jan.88	7011.55	3060.85	3728901.23
2	Apr.88	5033.60	2399.15	2571077.60
3	Jul.88	7382.05	2596.10	3735832.75
4	Oct.88	6524.70	2679.30	2842369.46
5	Jan.89	6600.75	3114.80	3427458.45
6	Apr.89	5525.00	2594.80	2767919.05
7	Jul.89	7764.25	2873.00	3754270.65
8	Oct.89	5686.20	2740.40	2917258.50
9	Jan.90	6604.00	3077.10	3500956.55
10	Apr.90	5731.05	2763.15	2927772.90
11	Jul.90	7873.45	3209.70	3977202.45
12	Oct.90	6802.25	2812.55	3055495.95

Table 5.4. Generation Unit Data for Reliability Analysis

No.	Name	No. of Unit	Size (MW)	Availability
1	Nuclear	2	1200	0.711613
2	Nuclear	2	1000	0.711613
3	Nuclear	2	800	0.711613
4	Coal	1	1000	0.661192
5	Coal	1	800	0.676184
6	Coal	1	600	0.700571
7	Oil	2	800	0.704106
8	Hydro	2	1200	0.947025
	Total unit = 13			

5.4.3.1. The ILDC Comparison

As a sample, a data point is taken from Table 5.3 for demonstrating the closeness between the VPI model and the actual data.

The data:

Virginia July 1989.

Total energy	:	5,775,801	Mwh
Peak load	:	11945	MW
Base load	:	4420	MW
Total hour	:	744	Hour

Using equation (5.20), the model of Inverted Load Duration Curve (ILDC) is expressed as

$$\text{ILDC} = \left(1 - \frac{x-4420}{11945-4420}\right)\exp\left(-0.365\frac{x-4420}{11945-4420}\right) \tag{5.21}$$

The ILDC expression in equation (5.21) is plotted and compared to the actual load as shown in Figure 5.2. Using the same data, Four ILDC's, generated by inverted Snyder model, WASP, VPI model (equation (5.21)) and the actual data, are plotted in Figure 5.3. The close match between these curves show that the VPI model can be used to express the ILDC as a function of the peak load, base load, and total energy demand. As we mentioned before, the cumulant method does not need ILDC in the process of calculating the reliability indices; therefore there is no cumulant based ILDC in this comparison.

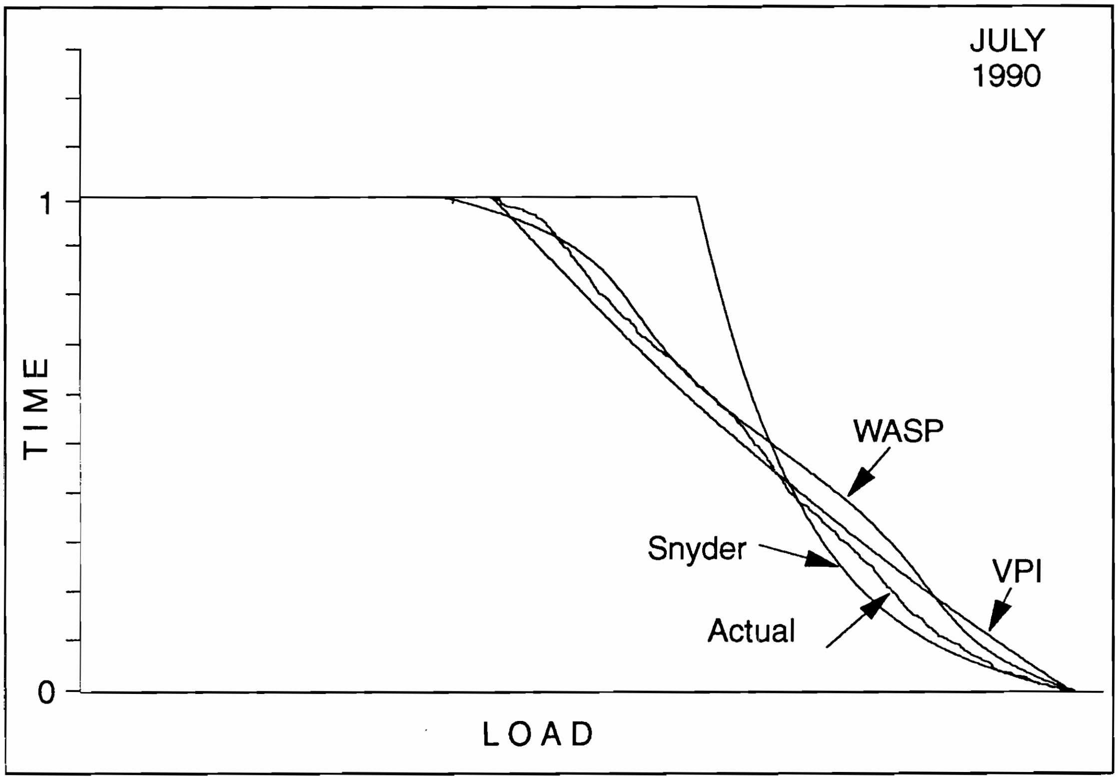

Figure 5.3. ILDC Comparison

The next step is to check how well the VPI model represents the equivalent load duration curve (ELDC), where the expected total energy demand, the system loss-of-load-probability (LOLP), and energy not served (ENS) is calculated based on the ELDC.

5.4.3.2. The ELDC comparison

The performance of the VPI model is compared to several available models. For this purpose, one needs to represent the equivalent load duration curve (ELDC), which is the result of convolution of LDC and generator failure rates. The equation for ELDC is given in equation (5.22) below, and the inverted LDC's (ILDC) for VPI, WASP and Snyder models are given in equations (5.20),(5.23) and (5.24) respectively.

Where :

$$\begin{aligned}ELDC=&p_1p_2p_3f(x_i)+p_1p_2q_3f(x_i-MW_3)+p_1q_2p_3f(x_i-MW_2)+\\&q_1p_2p_3f(x_i-MW_1)+q_1q_2p_3f(x_i-MW_1-MW_2)+\\&q_1p_2q_3f(x_i-MW_1-MW_3)+p_1q_2q_3f(x_i-MW_2-MW_3)\\&q_1q_2q_3f(x_i-MW_1-MW_2-MW_3)\end{aligned} \tag{5.22}$$

where

p_j = the probability that the unit j is available

q_j = the probability that the unit j is not available

$f(x_i)$ = the ILDC of model i

The ILDC representation for the WASP model is

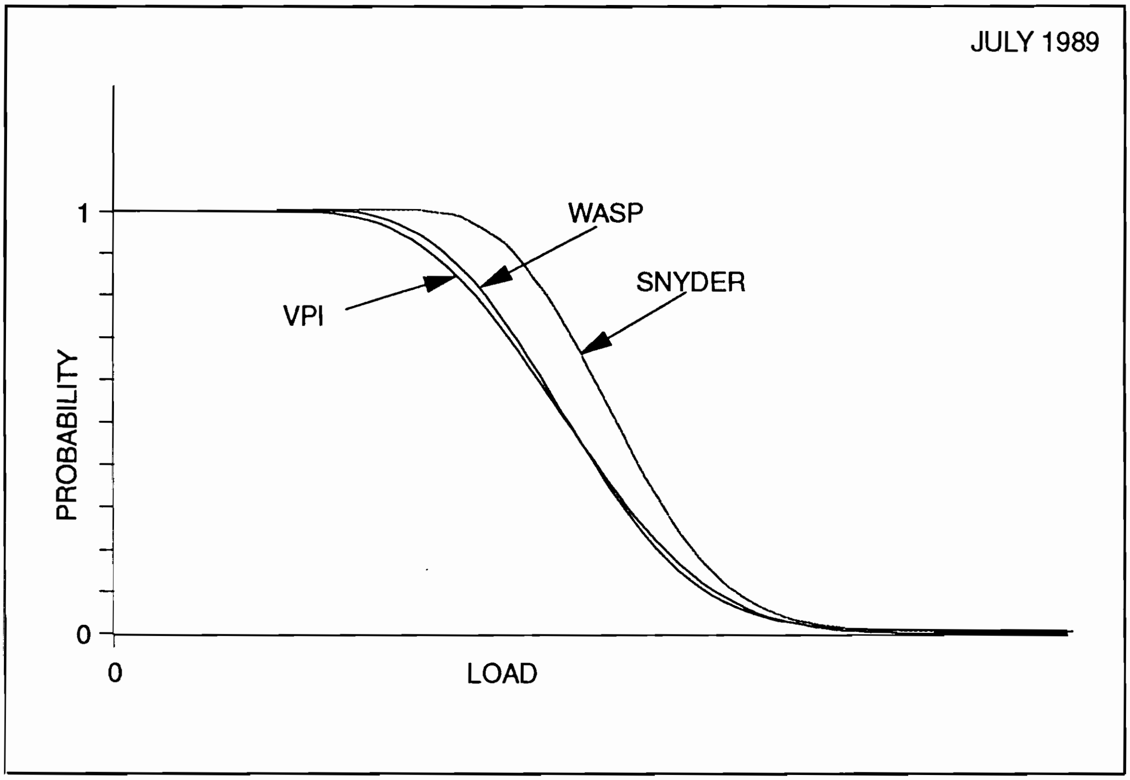

Figure 5.4. ELDC Comparison

$$f(x_i) = \frac{a_o}{2} + \sum_{k=1}^{n} a_k \cos(\frac{2(\pi)k}{T} x) \tag{5.23}$$

where

a_k = the coefficients for the kth harmonic of the Fourier series, k = 0,1,2, ... ,100 (max.)

T = the period of the Fourier series

The ILDC representation for the Snyder model is as follows

$$f(x_i) = A_1(x-1)+A_2(x-1)^2+A_3(x-1)^3+A_4(x-1)^4+A_5(x-1)^5 \tag{5.24}$$

where

A_i = the coefficients of the polynomial.

For conciseness, the analytical expression for ELDC is derived for three units only. However, the data for all 13 generating units are used for the results shown in Figure 5.4. From these curves we can see that the VPI model closely resembles the WASP model at the top of the ELDC curve, where the top is important for calculating the LOLP and ENS. The WASP model is based on the Booth-Baleiaux [35] technique of convolving ILDC and generator failure rates. Since WASP is widely used model and VPI model closely represents the WASP model performance, one can see that VPI model is a good model for representing the load. The next step is to show how close the VPI model to others in term of total energy, LOLP and ENS.

Table 5.5. Energy Comparison

No.	MONTH	Actual Data	VPI Model	VPI dif.from actual	WASP Model	WASP dif.from actual	Snyder Model	Snyder dif.from actual
1	Jan.88	3728901.23	3728901.23	0.00	3729138.63	237.40	4059844.04	330942.81
2	Apr.88	2571077.60	2571077.48	0.12	2574772.60	3695.00	2681687.57	110609.97
3	Jul.88	3735832.75	3735832.82	0.07	3735933.15	100.40	4191170.91	455338.16
4	Oct.88	2842369.46	2842369.88	0.42	2842555.62	186.16	2069025.10	773344.36
5	Jan.89	3427458.45	3427458.64	0.19	3427393.97	64.48	3515974.36	88515.91
6	Apr.89	2767919.05	2767919.14	0.09	2771802.74	3883.69	2844440.51	76521.46
7	Jul.89	3754270.65	3754270.78	0.13	3754278.36	7.71	3949121.68	194851.03
8	Oct.89	2917258.50	2917258.80	0.30	2917091.51	166.99	2853952.19	63306.31
9	Jan.90	3500956.55	3500956.51	0.04	3512053.70	11097.15	3696153.88	195197.33
10	Apr.90	2927772.90	2927772.02	0.88	2931254.80	3481.90	3037922.15	110149.25
11	Jul.90	3977202.45	3977202.52	0.07	3984918.36	7715.91	4219848.83	242646.38
12	Oct.90	3055495.95	3055495.29	0.66	3090251.89	34755.94	2415988.97	639506.98

5.4.3.3. The Energy, LOLP and ENS Comparison

In this comparison we will include one more model, the cumulant model. The cumulant model is used also in some power system planning packages. For the energy comparison, the ILDC as shown in Figure 5.1 is used to calculate the total energy by integrating the ILDC curve. Since the LOLP and ENS are calculated by using the ELDC, we used the ELDC curve as shown in Figure 5.4. Also from Figure 2.6, we can see how LOLP and ENS calculated from ELDC curve. For analyzing the comparison, we ran 12 cases. The load data for 12 cases and generation unit data are shown in Table 5.3 and 5.4. For the VPI model, Snyder model and WASP model, the convolution method is used to calculate LOLP and ENS or to perform the ELDC. The Cumulant model used Cumulant method to calculate LOLP and ENS. The result of this calculation is shown in Table 5.5 for energy comparison, Table 5.6 for LOLP comparison and Table 5.7 for ENS comparison.

From Table 5.5, one can see that total energy under the VPI model is closer to the actual data than total energy of WASP, which is widely used as a reference. In Table 5.6, the LOLP values computed using four different models are shown. These include the Cumulant method, which provides a direct representation of LOLP without convolution process. There are no "actual values" of LOLP for use as reference. However, the Snyder model is known to provide the best LOLP, because it models the tip of ILDC most accurately (see Figure 5.3). Results show that the VPI model comes the closest to the Snyder model in terms of LOLP as shown in Table 5.6.

The cumulant method is also an efficient method to calculate the LOLP. This method is used in the EPRI generation expansion model, EGEAS [5]. However, it

Table 5.6. LOLP Comparison

No.	Model			
	VPI	Snyder	WASP	Cumulant
1	0.011915	0.010185	0.009010	-0.018772
2	0.000527	0.000388	0.004485	0.000897
3	0.016088	0.014366	0.011804	0.004433
4	0.001881	0.001322	0.005018	0.001286
5	0.005546	0.003775	0.006499	0.039479
6	0.001107	0.000757	0.005077	-0.001433
7	0.020106	0.012924	0.013724	-0.002637
8	0.001296	0.000839	0.006734	-0.000645
9	0.006425	0.004868	0.011203	0.010663
10	0.001677	0.001209	0.007630	0.004295
11	0.025852	0.018423	0.021446	0.069394
12	0.003399	0.002167	0.008750	0.000872

demonstrates some instability when the largest unit in the system represents a significant percentage of the total load. This was the case some of the examples presented in this study; several of the cumulant generated LOLP values came out to be negative, see Table 5.6. The cumulant method is discussed in references [44,45,46,47].

Table 5.7 provides a comparison of energy not served as computed by WASP, Snyder and VPI models. Again we do not have a reference. However, the Snyder model, because of its more accurate LOLP representation, is also expected to give the best estimate for energy not served. Results of the VPI model come close to that of the Snyder model for this parameter as well. Since some of the LOLP values from the Cumulant method came out to be negative, it may not be very meaningful to compute energy not served (ENS) under these conditions. ENS readings from the Cumulant method are, therefore, not shown in Table 5.7.

Now that the accuracy of the VPI model in comparison to the other well established models has been demonstrated, it can be shown how convenient it is to study different load shape impacts, and compare the resulting LOLP and ENS indices. In order to demonstrate the flexibility and the fast response time of the VPI model, a reference and three test cases were set up. These are shown in Table 5.8. The reference case shows no DSM activity. The three indices need to define the load curve are shown; B1,P1 and E1 represent the reference case values. In case 2 (peak clipping), the peak is reduced by 10% and energy by 5%. The resulting LOLP and ENS show significant improvement. In case 3 (load shifting), the energy use is kept constant, but the base load is increased by 5% and peak load is decreased by 10%. Improvements from the base case are apparent. Finally in case 4 (valley filling), the peak load is kept constant, but the base and energy use are increased by 5% each. Resulting increases in the LOLP and ENS indices are as expected.

Table 5.7. ENS Comparison

No.	Model		
	WASP (GWh)	VPI (GWh)	Snyder (GWh)
1	2.91	5.68	4.92
2	1.16	0.18	0.14
3	1.42	8.70	7.29
4	1.55	0.79	0.61
5	2.33	2.46	1.72
6	1.49	0.40	0.29
7	5.69	10.86	6.96
8	2.26	0.49	0.34
9	4.05	2.87	2.22
10	2.54	0.63	0.47
11	8.81	14.22	10.01
12	3.15	1.51	1.04

Table 5.8. Comparative Analysis of LOLP and ENS under Different Scenario

No	Base Load (MW)	Peak Load (MW)	Energy (MWh)	DSM Activity	LOLP	ENS (GWh)
1	B1 3209.70	P1 7873.45	E1 3977202.45	No	0.02585	14.22
2	B2=B1 3209.70	P2=0.9P1 7086.11	E2=0.95E1 3778342.33	Peak Clipping	0.01291	6.19
3	B3=1.05B1 3370.19	P3=0.9P1 7086.11	E3=E1 3977202.45	Load Shifting	0.01622	7.89
4	B4=1.05B1 3370.19	P4=P1 7873.45	E4=1.05E1 4176062.57	Valley Filling	0.03186	17.60

5.5. Summary

The VPI model, as a function of peak load, base load and total energy demand, provides a straightforward means to study the effects of demand side management. This model can now be used in capacity expansion planning models to study the effects of DSM under different conditions of weather, load, and program penetrations. It can also be used to help the operator in the control center to study the effects of energy sale/purchase on system reliability. The VPI model is more convenient and equally accurate (if not more) for expressing the system load curve. This is because:

- One does not have to deal with the hourly load data every time a change is effected in the load shape.
- The model is already in the form of ILDC. This means that the ILDC does not have to be calculated by inverting the LDC, which could create errors.
- This model is not only related to the peak load, but also to the base load and the energy. This results in a more realistic as well as comprehensive reflection of DSM impacts.
- This model also provides a direct method to study the load factor impacts.

As it can be seen in comparison of LOLP, ENS and total energy served, some of the WASP values for LOLP and ENS are significantly different from the values obtained from VPI and Snyder models. One of the reasons for this significant difference is the cosine element in the representing ILDC by using the Fourier series expansion. One of the extreme case is as shown in Figure 5.5. In this figure we can see that at the base load (part A) and the peak load (part B), the curve is not precisely as it should be.

The cumulant value for LOLP is negative in some cases. It is the drawback of this method in calculating the LOLP. It was also shown by Hill and Jenkins [80], that at the top ELDC could overshoot or have a negative value. A value of ELDC will cause the LOLP to be negative also.

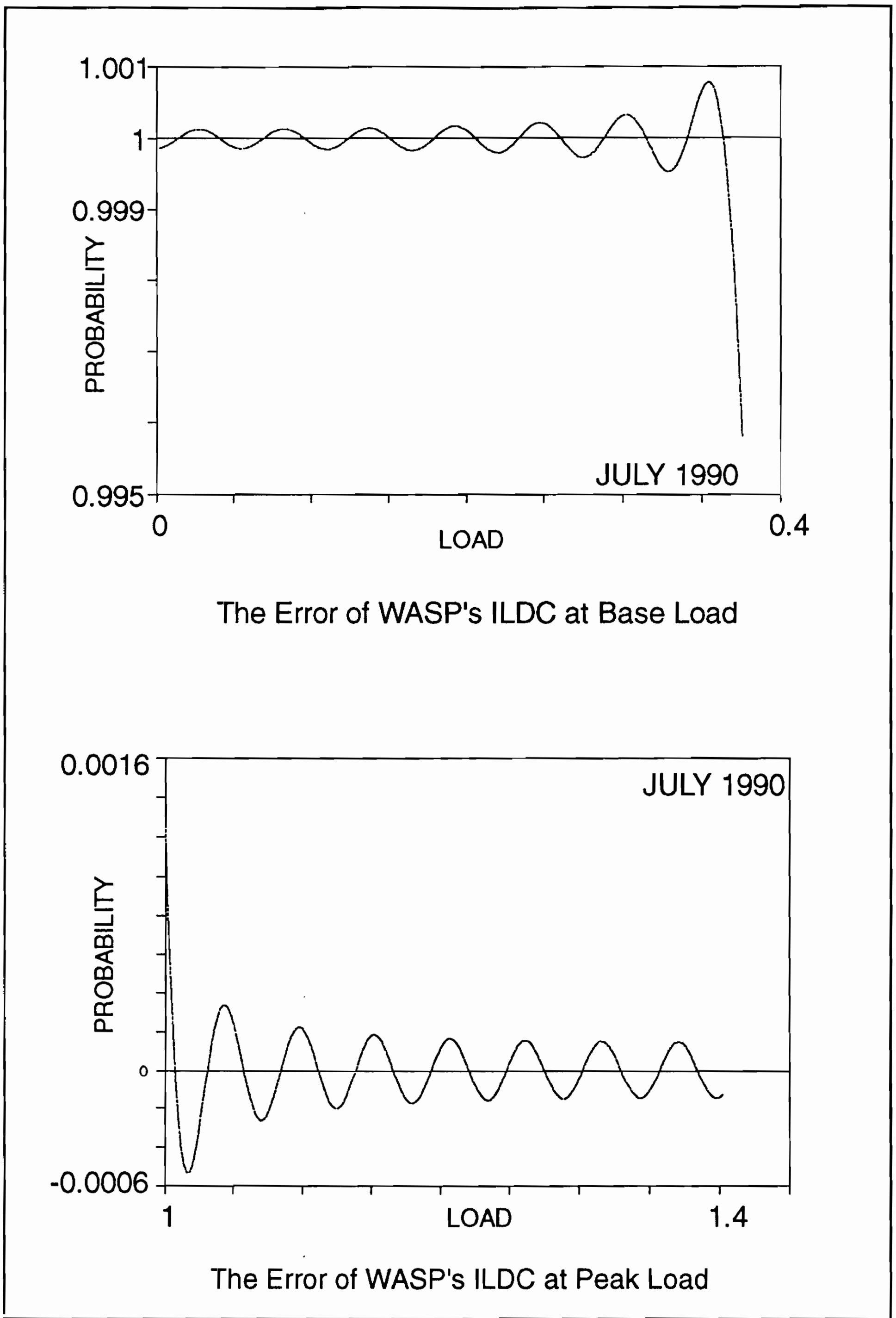

Figure 5.5. The Possible Errors of WASP's ILDC

CHAPTER VI

The Application of The VPI Model

6.1. Introduction

In Chapter 5, the mathematical expression of the VPI model was derived and tested. It was also compared to other available models that have been widely used recently in power system planning and operation. The comparisons, in terms of LOLP, ENS and total energy demand were calculated from load duration curve (LDC). As proven in the comparison in the Chapter 5, the VPI model is close to the available model in terms of the three aforementioned values. Based on the result of the comparison, we can say that the VPI model is a reasonable model to use as a new tool in power system planning and operation. In this chapter we are going to demonstrate the possibility of applying the VPI model in power system operation and planning.

While the VPI model is comparable to other models in terms of LOLP, ENS and total energy, this model surpasses other models in its reliability of calculation and ease

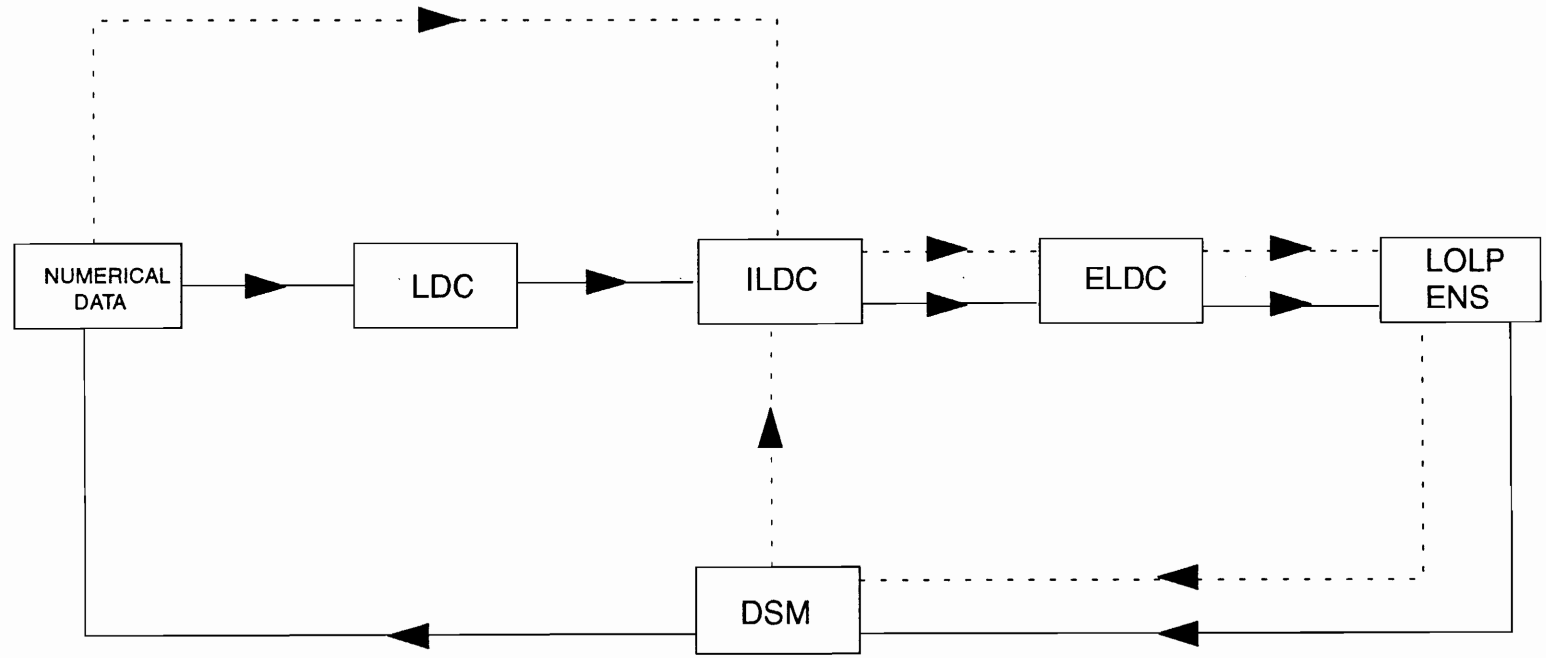

Figure 6.1. Flowchart for LOLP Calculation

of modification if one of the variable, such as peak load, base load and total energy demand, is changed. Those variables are intended to change in the operation and the planning process, especially when DSM is employed in both operation and planning. Each time one of those three variables is changed, the shape of the load duration curve will change, and the mathematical expression of the load duration curve will also be changed.

As mentioned before, the available models used the hourly load data to generate the fifth degree polynomial of the load duration curve, where as the VPI model with the peak load, base load, and total energy demand as its variables, performed the Inverted Load Duration Curve (ILDC) directly. The expression of ILDC directly, without going to LDC first, is another advantage of the VPI model compared to other models. In other models, ILDC is performed by inverting the LDC mathematical model (fifth degree polynomial). The inversion of the fifth degree polynomial contributes to errors as were seen in chapter 5. Especially, if the convolution method is used in the process of calculating the reliability indices; the calculation will be simpler if the VPI model is used. With the VPI model, the modification of the load duration curve could be done directly with the mathematical expression of ILDC. This direct process cannot be done in other models. If we compare the reliability calculation process of the VPI model (see dashed line in Figure 6.1) to the other models, the VPI model is more explicit than the other models (the solid line). Because with the VPI model, we do not have to go back to the numerical data if there is a change in the variables.

The convolution method is widely used in calculating reliability indices. In the convolution method, the ILDC mathematical expression is needed for the process. Using Fourier series expansion, WASP performs ILDC from fifth degree polynomial load duration curve. Transforming LDC to ILDC creates some errors (Chapter 5). The VPI model is simpler and reduces the possible errors. There is another method, the cumulant method, which tries to overcome the drawbacks of the convolution method in terms of the time consumed in the calculation process; the convolution method consumes more time than cumulant method. However, the Cumulant method is unstable in some cases, as mentioned in the previous chapter. Because of the potential instability of the cumulant method, it is believed that the convolution method is more accurate and the result can be trusted. Therefore, in this study, the convolution method was used for the calculation of the reliability indices and to perform the Equivalent Load Duration Curve (ELDC), so as not to sacrifice the accuracy of the result by reducing the total time consumed

For a more realistic approach, and to show the advantages of the VPI model, a computer program was developed using the convolution method and the VPI model as the mathematical expression for ILDC. The program is called VPIDSM. The program was made for analyzing the reliability of the system and the capacity credit of a unit. For production cost analysis, the WASP computer program was modified by inserting the VPI model in the MERSIM module. The function of the VPI model in WASP is to replace the ILDC, performed by Fourier series expansion and to replace the function of LDC (fifth degree polynomial) for calculating the total energy demand and the energy produced by each unit. This replacement will affect the total production cost calculation, and also, it will affect the LOLP calculation. So, the VPI model (ILDC expression) in the modified WASP has two functions: first, replacing the function of LDC to calculate total energy demand and second, replacing the ILDC function in LOLP and ENS calculation using the convolution method. The purpose of modifying WASP was for the study in the Virginia Tech Energy System Laboratory and is not going to be used for other purposes.

6.2. Computer Program

The menus available in the VPIDSM program are for reliability calculation of the DSM activities, such as peak clipping, valley filling, load shifting, strategic load growth, strategic conservation and the calculation of the capacity credit of a unit. It took only 18 seconds on 80486 PC to solve LOLP and ENS calculations in each case study with 13 units and different peak and base loads, and total energy served. The time consumption of the capacity credit calculation of a unit is dependent on the first guess peak load input. It will be discussed later in another section. The flowchart of the VPIDSM program is shown in Figure 6.2.

In the VPIDSM computer program, input files for generation unit data are needed. Those files are for the availability data, the units size data of each generator, and the total hours in the period of the load duration curve. The variables that are going to be changed many times, such as peak load (P), base load (B) and total energy demand (E), are input by the user. The outputs of the results are sent to a file and will also be output to the screen. Because in the production cost calculation more data are needed, such as heat rate, fuel cost etc., we add those data into Table 5.4. And the new table of the generation units data for production cost is shown in Table 6.1. Where the load data for this production cost calculation is the same as in the reliability calculation as in Table 5.3.

With the available menus, we are going to study how the DSM activities influence the reliability of the system; how the DSM activities influence the total energy sale that will change the production cost of the system; and how the DSM activities have to be used in operation and planning activities. Furthermore, we will see how the reliability, the weather, and the unit commitment will affect of the capacity credit of a unit. We believe

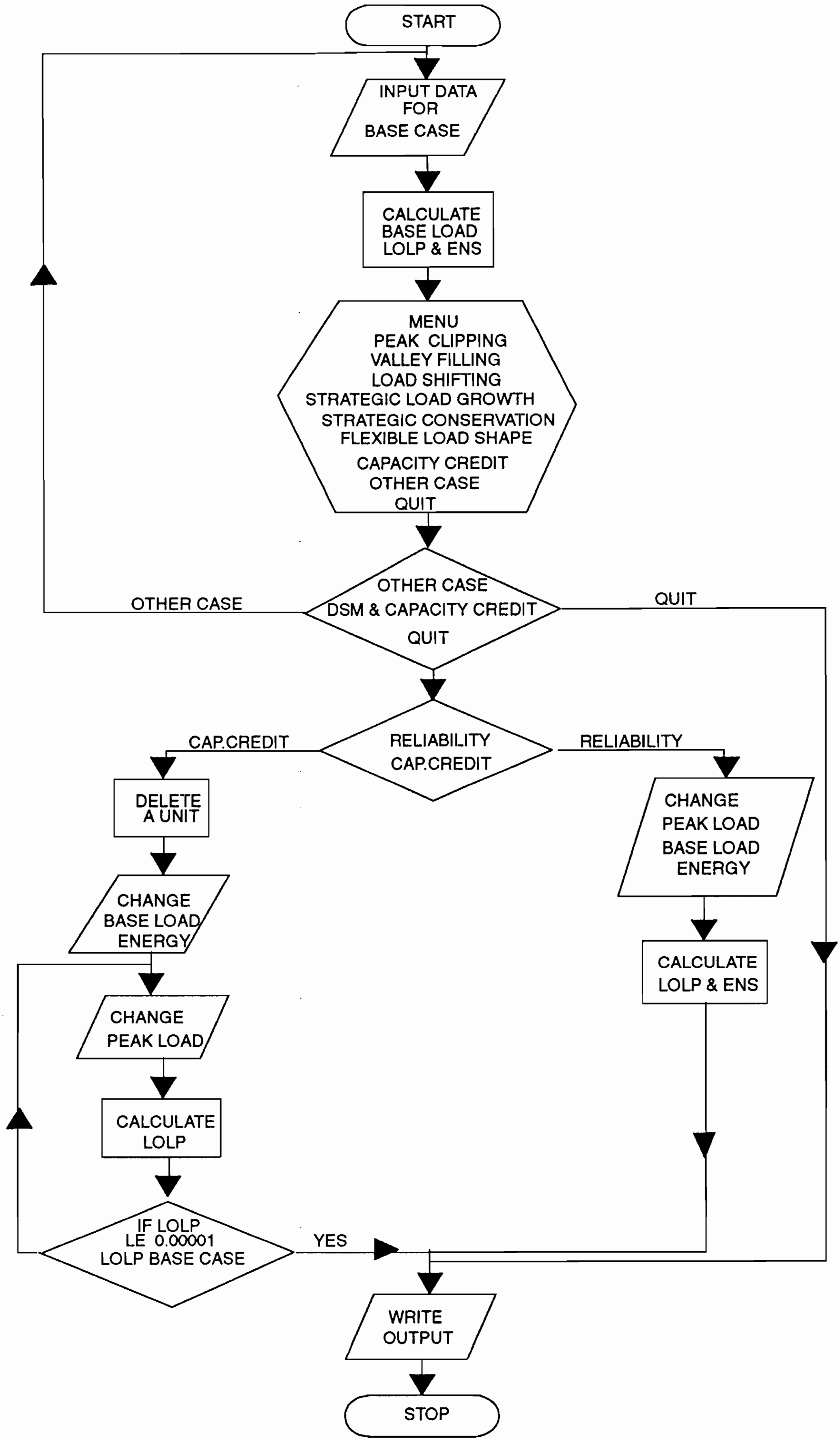

Figure 6.2. Flowchart of VPIDSM Program

Table 6.1 Generation Unit Data For Production Cost Analysis

No.	Name	# of Unit	Size (MW)	Availability	Heat Rate at Min. Operation	Average Incr. Hate Rate	Fuel Cost c/10^6kcal	O&M Cost ($/MWh)
1	Nuclear	2	1200	0.711613	10950	10700	85	0.30
2	Nuclear	2	1000	0.711613	10950	10700	85	0.79
3	Nuclear	2	800	0.711613	10950	10700	85	1.30
4	Coal	1	1000	0.661192	10950	10700	160	1.52
5	Coal	1	800	0.676184	12865	10390	160	1.71
6	Oil	1	600	0.700571	12480	10030	615	0.85
7	Oil	2	800	0.704106	12680	10090	615	0.79
8	Oil	2	1200	0.947025	14390	14000	815	0.79

that the result of analyzing those cases will be valuable for the utilities in operation and planning.

6.3. Reliability Analysis

The purpose of the reliability analysis, as mentioned above, is to know the reliability characteristics if one of the variable is changed. In the reliability analysis, we are going to use demand side activities as the cases, such as peak clipping, valley filling, load shifting, strategic load growth, strategic conservation, and several cases for flexible load curve. The reason we used the DSM activities as the case study is because most of the utilities have already used DSM as a part of their effort to increase the reliability and to meet the capacity need. Increasing the reliability means that the value of the LOLP is decreased, or if the value of LOLP increases, means the reliability of the system is decreased.

6.3.1. Peak Clipping

The peak clipping activity is to reduce the peak load by controlling the customer's load. It could be done by direct load control or indirect load control. There are several reasons for reducing the peak load in operation and planning of power systems, such as reliability problems, economic considerations, security problems, and environmental considerations. The reliability problems could occur when load growth is too fast and cannot be followed by the construction of new units. Economic considerations occur because of the investment in a new unit is more expensive than pursuing load management. So, instead of adding a new unit, utilities choose to do load management,

Table 6.2. Peak Clipping

No	MONTH	LOLP		ENS	
		Base Case	Peak Clipping	Base Case	Peak Clipping
1	Jan.88	0.011915	0.005773	5692.25	2450.18
2	Apr.88	0.000527	0.000257	176.84	78.85
3	Jul.88	0.016088	0.008135	8704.77	3689.44
4	Oct.88	0.001881	0.000837	787.13	315.65
5	Jan.89	0.005546	0.002652	2463.07	1051.25
6	Apr.89	0.001107	0.000523	400.84	173.78
7	Jul.89	0.020106	0.009824	10864.30	4655.33
8	Oct.89	0.001296	0.000617	490.99	211.93
9	Jan.90	0.006425	0.003087	2876.30	1233.05
10	Apr.90	0.001677	0.000810	629.79	273.80
11	Jul.90	0.025852	0.012909	14222.23	6192.30
12	Oct.90	0.003399	0.001562	1511.50	616.71
Peak Clipping : Base load-unchanged, Peak load-110%, energy-95%					

in this case the peak clipping. In the case that a unit is already too old and is not reliable anymore, it is possible that the unit has to be retired from operation. If this happens, load management can to be used to keep the reliability of the system in a certain level. Sometimes, it is difficult to get approval for a new nuclear power plant or coal unit, and also without using a good technology for cleaning the emission gases is also hard to get approval for, which often means the new unit can not be constructed. If this happens, the utilities also have to do load management to meet the customer load growth and maintain the reliability of the system at a certain level. The question now is: how much does the peak load have to be reduced if a unit is not in operation or the reliability of the system has to be improved? It is an important question that has to be addressed by the operator or planner before the peak reduction has to be done. Because reduction in the peak load is not free of cost, and also the peak reduction could be more or less than what it should be, the operator or planner has to know the capacity credit of the postponed unit exactly. With the VPI model, the capacity credit calculation can be done easily. The capacity credit study will be discussed in another section.

For the peak clipping case, the peak load will be reduced by 10%, where the energy is reduced by 5% and the base load remains constant as the base case value. Using the VPIDSM program, we calculated the reliability of the peak clipping case and compared it to the base case reliability, as shown in Table 6.2. We can see from Table 6.2 that the reliability of the system is lower than the base case reliability. It is because the peak load and the total energy are reduced. In the next sections, the most influence between peak load and total energy to the reliability will be shown.

6.3.2. Valley Filling

Valley filling encompasses building off-peak loads. Valley filling can be accomplished in several ways, one of the most popular is new thermal energy storage (water heating and/or space heating) which displaces loads served directly by fossil fuels. In this analysis, the base load is increased by 10% and the energy is increased by 5%, where the peak load is kept constant as the base case value. The result of this case is shown in Table 6.3. The reliability is decreased in the valley filling case , because the total energy demand is increased. We also ran the valley filling case with the base and the peak load remaining constant and increasing the energy by 5%. This condition could be happen when the increased energy fills the off-peak load and off-base load period. If we calculate the reliability of this case, the result is shown in Table 6.4. The system reliability of the second case, as shown in Table 6.4, is lower than the system reliability of the first case, as shown in Table 6.3. It is because the 5% increase in energy in the second case did not change the base load. In the first case, the 5% increase in energy increased the base load. Because of this result, if the base load is increased the value of LOLP will be decreased or the system reliability will be increased, we say that the base load has a positive effect to the system reliability.

6.3.3. Load Shifting

Load shifting is to shift the load from peak load to off-peak load periods. The shifting of the load can be accomplished by using storage water heating, storage space heating, cool storage, and customer load shifts. Load shifting also reduces the customer peak load, where the customer energy payback could be 100%. If the energy payback is 100%, it means the total energy demand remains constant as the base case value. Since the energy remains constant but the energy is shifted from the peak load period to the

Table 6.3. Valley Filling

No	MONTH	LOLP		ENS	
		Base case	Valley Filling	Base case	Valley Filling
1	Jan.88	0.011915	0.014287	5692.25	6853.43
2	Apr.88	0.000527	0.000639	176.84	213.47
3	Jul.88	0.016088	0.020042	8704.77	10290.40
4	Oct.88	0.001881	0.002135	787.13	890.39
5	Jan.89	0.005546	0.006652	2463.07	2964.86
6	Apr.89	0.001107	0.001339	400.84	481.81
7	Jul.89	0.020106	0.023621	10864.30	12817.09
8	Oct.89	0.001296	0.001549	490.99	588.23
9	Jan.90	0.006425	0.007735	2876.30	3478.70
10	Apr.90	0.001677	0.002039	629.79	761.78
11	Jul.90	0.025852	0.030636	14222.23	16932.29
12	Oct.90	0.003399	0.003915	1511.50	1738.45
Valley Filling : Base load-110%, Peal load-unchanged Energy-105%					

Table 6.4. Energy Increase

No	MONTH	LOLP		ENS	
		Base case	Energy Increase	Base case	Energy Increase
1	Jan.88	0.011915	0.015162	5692.25	6153.95
2	Apr.88	0.000527	0.000702	176.84	198.08
3	Jul.88	0.016088	0.020927	8704.77	9212.52
4	Oct.88	0.001881	0.002742	787.13	1035.29
5	Jan.89	0.005546	0.007403	2463.07	2810.67
6	Apr.89	0.001107	0.001491	400.84	456.18
7	Jul.89	0.020106	0.025460	10864.30	11920.88
8	Oct.89	0.001296	0.001771	490.99	575.00
9	Jan.90	0.006425	0.008393	2876.30	3192.22
10	Apr.90	0.001677	0.002252	629.79	711.52
11	Jul.90	0.025852	0.032966	14222.23	15606.00
12	Oct.90	0.003399	0.004802	1511.50	1902.17

Energy Increase : Base load-unchanged, Peak load-unchanged, Energy-105%

Table 6.5. Load Shifting

No	MONTH	LOLP		ENS	
		Base case	Load shifting	Base case	Load shifting
1	Jan.88	0.011915	0.007142	5692.25	3048.05
2	Apr.88	0.000527	0.000320	176.84	99.86
3	Jul.88	0.016088	0.009788	8704.77	4461.62
4	Oct.88	0.001881	0.000980	787.13	368.66
5	Jan.89	0.005546	0.003299	2463.07	1313.97
6	Apr.89	0.001107	0.000649	400.84	216.46
7	Jul.89	0.020106	0.011837	10864.30	5635.32
8	Oct.89	0.001296	0.000765	490.99	263.93
9	Jan.90	0.006425	0.003850	2876.30	1545.82
10	Apr.90	0.001677	0.001013	629.79	343.88
11	Jul.90	0.025852	0.015751	14222.23	7594.73
12	Oct.90	0.003399	0.001855	1511.50	732.08
Load Shifting : Base load-110%, Peak load-90%, Energy-unchanged					

Table 6.6. Peak Reduction

No	MONTH	LOLP		ENS	
		Base Case	Peak Decrease	Base Case	Peak Decrease
1	Jan.88	0.011915	0.007489	5692.25	3207.87
2	Apr.88	0.000527	0.000344	176.84	107.94
3	Jul.88	0.016088	0.010136	8704.77	4631.21
4	Oct.88	0.001881	0.001274	787.13	490.16
5	Jan.89	0.005546	0.003638	2463.07	1460.96
6	Apr.89	0.001107	0.000713	400.84	239.59
7	Jul.89	0.020106	0.012688	10864.30	6074.08
8	Oct.89	0.001296	0.000867	490.99	301.45
9	Jan.90	0.006425	0.004129	2876.30	1667.03
10	Apr.90	0.001677	0.001105	629.79	377.18
11	Jul.90	0.025852	0.016828	14222.23	8159.28
12	Oct.90	0.003399	0.002296	1511.50	921.82

Peak Decrease : Base load-unchanged, Peak load-90%, Energy-unchanged off-peak period, there are two possible cases that could be happen. First, the energy payback is at base load period; so, the base load is increased. The second case is the energy payback is not in the base load period; so the load shifting does not change the base load. For analyzing the first case, the base load is added by 10% and the peak load is reduced by 10%, and the energy is remains constant as the base case value. The result is shown in Table 6.5. From this table we can see that the reliability is increased. It is obvious that since we reduce the peak, we will have more of a reserve margin. Because of a bigger reserve margin, the reliability will be better. For the second case, the energy and the base load remain constant as the base case value, where the peak load is reduced by 10%. From the result, as shown in Table 6.6, the reliability is lower than what was seen in Table 6.5. We proved once more that maintaining the base load while keeping energy constant has a positive effect on the reliability of the system. With the base load constant, the reliability is smaller than if we increase the base load, where the energy and the peak load are the same between two cases. Because if the base load is increased, it means that part of the energy will go to the base load. So, the energy at the peak load period will be reduced. Since the curve at the peak load will influence the LOLP value, the reliability will be higher.

6.3.4. Strategic Load Growth

The strategic load growth is used for planning purposes. It deals with the managing of future loads. Load growth is the load shape change that refers to a general increase in sales beyond the peak clipping, valley filling and load shifting mentioned above. Load shape changes are reflected in terms of base load, peak load, and energy. The load growth may involve increased market share of loads that are, or can be, served by competing fuels, electrification such as the new emerging electric technologies

Table 6.7. Strategic Load Growth

No	MONTH	LOLP		ENS	
		Base Case	Strategic Load Growth	Base Case	Strategic Load Growth
1	Jan.88	0.011915	0.026802	5692.25	14474.95
2	Apr.88	0.000527	0.001258	176.84	454.67
3	Jul.88	0.016088	0.038530	8704.77	22629.52
4	Oct.88	0.001881	0.004381	787.13	2028.83
5	Jan.89	0.005546	0.012982	2463.07	6351.29
6	Apr.89	0.001107	0.002666	400.84	1034.87
7	Jul.89	0.020106	0.042840	10864.30	26621.76
8	Oct.89	0.001296	0.003096	490.99	1273.58
9	Jan.90	0.006425	0.015028	2876.30	7414.65
10	Apr.90	0.001677	0.004053	629.79	1638.01
11	Jul.90	0.025852	0.054250	14222.23	34583.89
12	Oct.90	0.003399	0.007875	1511.50	3884.85
Strat. Load Growth : Base load-110%, Peak load-110%, Energy-110%					

Table 6.8. Energy and Peak load Increase (1)

No	MONTH	LOLP		ENS	
		Base Case	Energy and Peak Increase	Base Case	Energy and Peak Increase
1	Jan.88	0.011915	0.022895	5692.25	7315.26
2	Apr.88	0.000527	0.001073	176.84	235.71
3	Jul.88	0.016088	0.033369	8704.77	10780.13
4	Oct.88	0.001881	0.003937	787.13	1169.10
5	Jan.89	0.005546	0.011116	2463.07	3336.57
6	Apr.89	0.001107	0.002283	400.84	540.87
7	Jul.89	0.020106	0.037200	10864.30	13909.39
8	Oct.89	0.001296	0.002662	490.99	679.93
9	Jan.90	0.006425	0.012809	2876.30	3805.14
10	Apr.90	0.001677	0.003455	629.79	848.19
11	Jul.90	0.025852	0.046827	14222.23	18353.87
12	Oct.90	0.003399	0.006987	1511.50	2174.10
Energy and Peak load Increase : Base load-unchanged, Peak load-110%, Energy-105%					

Table 6.9. Energy and Peak load Increase (2)

No	MONTH	LOLP		ENS	
		Base case	Energy and Peak Increase	Base case	Energy and Peak Increase
1	Jan.88	0.011915	0.023402	5692.25	12014.50
2	Apr.88	0.000527	0.001126	176.84	390.35
3	Jul.88	0.016088	0.031633	8704.77	17426.87
4	Oct.88	0.001881	0.004578	787.13	2071.01
5	Jan.89	0.005546	0.011872	2463.07	5592.58
6	Apr.89	0.001107	0.002348	400.84	904.58
7	Jul.89	0.020106	0.038716	10864.30	22603.56
8	Oct.89	0.001296	0.002864	490.99	1151.80
9	Jan.90	0.006425	0.013338	2876.30	6317.11
10	Apr.90	0.001677	0.003606	629.79	1419.56
11	Jul.90	0.025852	0.049547	14222.23	29687.66
12	Oct.90	0.003399	0.007955	1511.50	3788.55

Energy and Peak load Increase : Base load-unchanged, Peak load-105%, Energy-110%

surrounding electric vehicles, industrial process heating, and automation. The load growth will affect the peak load, base load and total energy demand. However, utilities have to manage the growth. Customers have to be encouraged to use the new energy, not in the peak period but in the off-peak period. As a result, it will reduce the peak increase and improve the load factor.

For the load growth analysis, we are going to examine three cases. First, the base load, the peak load, and the total energy served are increased by 10%. Second, the energy is increased by 5% only, where the peak load is increased by 10% and the base load remains constant. Finally, the peak load is increased by 5%, where the total energy is increased by 10% and the base load remains constant as the base case value. The purpose for the second and the third cases are to analyze the influence of the peak load on the reliability of the system compared to the influence of the total energy demand on the reliability of the system. As we have seen in the peak clipping case, the reliability is increased because of the total energy demand and the peak load reduction. Now, we want to know which one is influenced more--the total energy demand or the peak load. From the results of the first case in Table 6.7, it obvious that the reliability of the system is decreased, because the peak and the total energy are increased. From Table 6.8 for the second case and Table 6.9 for the third case, we can see that the influence of the energy on reliability is greater than the influence of the peak load on the reliability of the system, because the value of LOLP and ENS in Table 6.9 are bigger than the ones in Table 6.8. Since the energy of the third case is bigger, we can say that the total energy demand has a greater influence on the reliability than on the peak load.

6.3.5. The Strategic Conservation

The load shape change is not always caused by load management, it could be caused by weatherization and appliance efficiency improvement. The change reflects a modification of the load shape involving a reduction in sales as well as a change in the patterns of use. When employing energy conservation, the utility planner must consider what conservation actions would occur naturally, and then evaluate the cost-effectiveness of possible intended utility programs to accelerate or simulate those actions. Conservation is not only for reducing the load demand for reliability purposes, but also for reducing the emissions produced by power systems where the environment is a concern.

We ran the conservation case by reducing the base load, the peak load, and the total energy demand by 10%. Since the total energy demand and the peak load are reduced, the reliability of the system will be better as shown in Table 6.10. In reality, the reduction could be one or two of the variables. Since one of the total energy demand or the peak load is decreased, the reliability of the system will be increased, where the strategic conservation is an opposite of the Strategic Load Growth.

6.3.6. The Flexible Load Shape

In the flexible load shape, we ran the cases that are not included in the previous sections: energy reduction and base load reduction. The energy reduction case was without changing the peak load and the base load. It could happen when the improvement of the appliance's efficiency causes the reduction of the total energy demand; however, the reduction does not occur in the peak load and the base load periods. Since the energy is reduced and the peak load and the base load remain constant, the reliability of the system will be better. It can be shown as the result of this

Table 6.10. Strategic Conservation

No	MONTH	LOLP		ENS	
		Base case	Stat.Conservation	Base case	Stat.Conservation
1	Jan.88	0.011915	0.004711	5692.25	1990.66
2	Apr.88	0.000527	0.000210	176.84	64.84
3	Jul.88	0.016088	0.006782	8704.77	3062.11
4	Oct.88	0.001881	0.000726	787.13	274.54
5	Jan.89	0.005546	0.002165	2463.07	855.25
6	Apr.89	0.001107	0.000428	400.84	141.75
7	Jul.89	0.020106	0.008201	10864.30	3871.06
8	Oct.89	0.001296	0.000505	490.99	173.39
9	Jan.90	0.006425	0.002509	2876.30	998.02
10	Apr.90	0.001677	0.000658	629.79	221.71
11	Jul.90	0.025852	0.010630	14222.23	5077.48
12	Oct.90	0.003399	0.001335	1511.50	527.35

Strategic Conservation : Base load-90%, Peak load-90%, Energy-90%

Table 6.11. Energy Reduction

No	MONTH	LOLP		ENS	
		Base case	Reduced Energy	Base case	Reduced Energy
1	Jan.88	0.011915	0.008949	5692.25	12313.52
2	Apr.88	0.000527	0.000378	176.84	386.89
3	Jul.88	0.016088	0.013430	8704.77	19515.02
4	Oct.88	0.001881	0.001170	787.13	1829.03
5	Jan.89	0.005546	0.003891	2463.07	5426.65
6	Apr.89	0.001107	0.000785	400.84	884.68
7	Jul.89	0.020106	0.015233	10864.30	23026.39
8	Oct.89	0.001296	0.000880	490.99	1093.93
9	Jan.90	0.006425	0.004649	2876.30	6300.44
10	Apr.90	0.001677	0.001191	629.79	1393.16
11	Jul.90	0.025852	0.019376	14222.23	29722.42
12	Oct.90	0.003399	0.002211	1511.50	3451.95
Energy Reduction : Base load-unchanged, Peak load-unchanged, energy-95%					

case in Table 6.11, that the reliability of the system after energy reduction is increased. The second case is base load reduction. The base load was reduced by 10% and the peak load and total energy demand remained constant as the base case value. From Table 6.12, we can see that the system reliability is decreased . We proved one more time that the base load has a positive effect on the reliability, because when we reduce the base load, the system reliability decreases or LOLP value increases. The base load reduction almost never happens, in reality because no demand side activity encourages the customers to shift their load from base load period to another period. It could be happened if customers are shifting their load for reason unique to their applications.

6.3.7. Summary

Based on the results that have been discussed one by one above, we are going to compare and analyze them in terms of LOLP, ENS and the total energy demand. The total energy demand is important to know because it will influence the income of the utility. From the result of the analysis, the utility can choose which DSM activities will match with their situation and their goals.

As mentioned before, the purpose of implementing DSM is not only for the peak load reduction to meet the capacity need, but also for reducing emissions of pollutant gases resulting from the generation of electric energy. It is one of the reasons why utilities are encouraged to implement DSM in their planning and operation, because the pollutant gases from electricity production activities cause the global warming and acid rain.

Table 6.12. Base Load Reduction

No	MONTH	LOLP		ENS	
		Base Case	Base Reduction	Base Case	Base Reduction
1	Jan.88	0.011915	0.012810	5692.25	6153.95
2	Apr.88	0.000527	0.000591	176.84	198.08
3	Jul.88	0.016088	0.017958	8704.77	9212.52
4	Oct.88	0.001881	0.002426	787.13	1035.29
5	Jan.89	0.005546	0.006259	2463.07	2810.67
6	Apr.89	0.001107	0.001261	400.84	456.18
7	Jul.89	0.020106	0.021906	10864.30	11920.88
8	Oct.89	0.001296	0.001501	490.99	575.00
9	Jan.90	0.006425	0.007072	2876.30	3192.22
10	Apr.90	0.001677	0.001895	629.79	711.52
11	Jul.90	0.025852	0.028152	14222.23	15606.44
12	Oct.90	0.003399	0.004202	1511.50	1902.17

Base Reduction : Base load-90%, Peak load-unchanged, Energy-unchanged

Table 6.13. Summary of DSM Activities

	DSM ACTIVITIES	LOLP	ENS	RELIABILITY	ENERGY
1	PEAK CLIPPING	DECREASE	DECREASE	INCREASE	DECREASE
2	VALLEY FILLING	INCREASE	INCREASE	DECREASE	INCREASE
3	ENERGY INCREASE	INCREASE	INCREASE	DECREASE	INCREASE
4	LOAD SHIFTING	DECREASE	DECREASE	INCREASE	CONSTANT
5	PEAK DECREASE	DECREASE	DECREASE	INCREASE	CONSTANT
6	STRAT. LOAD GROWTH	INCREASE	INCREASE	DECREASE	INCREASE
7	ENERGY PEAK INCREASE	INCREASE	INCREASE	DECREASE	INCREASE
8	STRAT. CONSERVATION	DECREASE	DECREASE	INCREASE	DECREASE
9	ENERGY DECREASE	DECREASE	DECREASE	INCREASE	DECREASE
10	BASE LOAD DECREASE	INCREASE	INCREASE	DECREASE	CONSTANT

There are ten cases that we are going to compare. The summary of those results is shown in Table 6.13. In the reliability column, we can see that some of the reliability indices are increased and some are decreased. From such tables, the operator or the planner can choose which DSM activities will be best for their conditions. If the goal is peak reduction, the peak clipping and load shifting, and of course, the strategic conservation are implemented. The common reason for implementing DSM is to reduce the peak load, since the reduction of the peak load results in the reduction of capacity needs or an increase in the reserve margin. Where, total energy and the base load increase or decrease are the effect of the peak reduction. It was mentioned before that the base load has a positive effect on the reliability of the system. It means, the best period for increasing the energy or shifting the energy is in the base load period. It is not only because the price of energy production in the base load period is cheaper and the base load has a positive effect on the reliability, but also because the load factor of the system will be improved also.

6.4. Production Cost Analysis

In production cost analysis, fuel cost, O&M cost and heat rate are needed. So, we add this information in the generation unit data as shown in Table 6.1. The number of units in the production cost analysis is the same as the total number of units used in reliability analysis; that was 13 units. The load data is also the same as in the reliability analysis. As mentioned in the previous section, in production cost analysis, we used modified WASP, with the VPI model inserted into the MERSIM module.

Table 6.14. Base cases of Production Cost

No.	MONTH	Peak load (MW)	Base Load (MW)	Total Energy (MWh)	Prod. Cost ($)
1	Jan.88	7011.55	3060.85	3728901.23	240763.20
2	Apr.88	5033.60	2399.15	2571077.60	141770.50
3	Jul.88	7382.05	2596.10	3735832.75	250311.80
4	Oct.88	6524.70	2679.30	2842369.46	158120.40
5	Jan.89	6600.75	3114.80	3427458.45	206598.60
6	Apr.89	5525.00	2594.80	2767919.05	153690.50
7	Jul.89	7764.25	2873.00	3754270.65	252953.00
8	Oct.89	5686.20	2740.40	2917258.50	163242.00
9	Jan.90	6604.00	3077.10	3500956.55	214014.80
10	Apr.90	5731.05	2763.15	2927772.90	163966.70
11	Jul.90	7873.45	3209.70	3977202.45	275798.40
12	Oct.90	6802.25	2812.55	3055495.95	175808.20

Base case : Base load-100%, Peak load-100%, Energy-100%

Table 6.15. Valley Filling

No	MONTH	PRODUCTION COST ($)	
		Base case	Valley Filling
1	Jan.88	240763.20	258391.50
2	Apr.88	141770.50	147691.30
3	Jul.88	250311.80	267970.30
4	Oct.88	158120.40	165981.20
5	Jan.89	206598.60	220369.20
6	Apr.89	153690.50	160997.40
7	Jul.89	252953.00	271144.20
8	Oct.89	163242.00	171728.60
9	Jan.90	214014.80	228664.30
10	Apr.90	163966.70	172548.30
11	Jul.90	275798.40	297091.30
12	Oct.90	175808.20	185757.20
Valley Filling : Base load-110%, Peak load-unchanged Energy-105%			

Table 6.16 Load Shifting

No	MONTH	PRODUCTION COST ($)	
		Base case	Load Shifting
1	Jan.88	240763.20	231468.10
2	Apr.88	141770.50	139303.70
3	Jul.88	250311.80	238819.30
4	Oct.88	158120.40	154625.10
5	Jan.89	206598.60	199932.40
6	Apr.89	153690.50	150416.60
7	Jul.89	252953.00	242288.20
8	Oct.89	163242.00	159402.80
9	Jan.90	214014.80	206780.70
10	Apr.90	163966.70	160094.00
11	Jul.90	275798.40	264862.10
12	Oct.90	175808.20	171060.40
Load Shifting : Base load-110%, Peak load-90%, Energy-unchanged			

In the original WASP, Fourier series expansion model is used for performing the ILDC curve. From LDC curve's fifth degree polynomial, the total energy demand is calculated by integrating the curve. Since the VPI model is already in ILDC mode, we just integrate the VPI model which was already inserted into the MERSIM module for calculating total energy demand. We proved in the previous chapter that the VPI model is more accurate in the total energy calculation. Since the production cost is influenced by the total energy, we hoped that the result of production cost calculation with the VPI model would be more accurate.

As in the reliability analysis for this production cost study, the demand side management activities are also used as the case studies. There are five cases which will be analyzed and a case as a base case study. The cases are: Peak Clipping, Valley filling, Load Shifting, Strategic Conservation, and Strategic Load Growth. Before we run those cases, we run the base case first to calculate the production cost with 12 load data as in Table 5.3 in chapter 5, where the base case results are used as a reference. In the valley filling case, we increase the total energy demand by 5% and the base load by 10% from the base cases value, and the peak load remained constant. In the load shifting, we reduced the peak load by 10% and increased the base load by 10%, and kept the total energy demand as it was in the base case value. In the peak clipping, we reduced the peak load by 10%, energy by 5% and the base load remained constant as in the base case value. For strategic conservation, we reduced the peak load, base load and total energy demand by 10%. The last one was the strategic load growth. We increased the peak load, base load and total energy demand by 10%. We ran the modified WASP with those cases and the results for those cases are shown in Table 6.14, Table 6.15, Table 6.16, Table 6.17 , Table 6.18 and Table 6.19 for the base case, Valley filling, load shifting, peak clipping, strategic load growth, and strategic conservation, respectively. The summary for all six cases is shown in Table 6.20.

TABLE 6.17 Peak Clipping

No	MONTH	PRODUCTION COST ($)	
		Base case	Peak Clipping
1	Jan.88	240763.20	215520.00
2	Apr.88	141770.50	133860.50
3	Jul.88	250311.80	222915.00
4	Oct.88	158120.40	147400.00
5	Jan.89	206598.60	187417.40
6	Apr.89	153690.50	143736.80
7	Jul.89	252953.00	225750.80
8	Oct.89	163242.00	151663.30
9	Jan.90	214014.80	193489.10
10	Apr.90	163966.70	152267.10
11	Jul.90	275798.40	245347.70
12	Oct.90	175808.20	161988.30
Peak Clipping : Base load-unchanged, Peak load-90%, Energy-95%			

TABLE 6.18 Strategic Load Growth

No	MONTH	PRODUCTION COST ($)	
		Base case	Strategic Load Growth
1	Jan.88	240763.20	287897.90
2	Apr.88	141770.50	157375.60
3	Jul.88	250311.80	302016.90
4	Oct.88	158120.40	179019.70
5	Jan.89	206598.60	243408.50
6	Apr.89	153690.50	173226.00
7	Jul.89	252953.00	301635.10
8	Oct.89	163242.00	185935.10
9	Jan.90	214014.80	253236.00
10	Apr.90	163966.70	186893.50
11	Jul.90	275798.40	330736.10
12	Oct.90	175808.20	202415.50

Strat. Load Growth : Base load-110%, Peak load-110%, Energy-110%

TABLE 6.19 Strategic Conservation

No	MONTH	PRODUCTION COST ($)	
		Base case	Strat. Conservation
1	Jan.88	240763.20	201169.60
2	Apr.88	141770.50	128857.20
3	Jul.88	250311.80	208353.30
4	Oct.88	158120.40	140859.80
5	Jan.89	206598.60	176225.20
6	Apr.89	153690.50	137650.00
7	Jul.89	252953.00	210761.20
8	Oct.89	163242.00	144666.40
9	Jan.90	214014.80	181592.50
10	Apr.90	163966.70	145196.60
11	Jul.90	275798.40	227533.00
12	Oct.90	175808.20	153809.50

Strat. Conservation : Base load-90%, Peak load-90%, Energy-90%

Production cost in the valley filling case is increased from the base case production cost. It is obvious that in the valley filling case the total energy sale, or total energy produced by the system, is increased. Since the total energy produced is increased, the total production cost will be increased. The total production cost is also influenced by the period of the increasing energy, because the energy at the base load period is cheaper than the energy at the peak period. In other words, for the unit which served the peak load period, the dollar per kw of energy produced, is more expensive than in the base load period. We can see in the load shifting case result, that even though the total energy demand is constant as the base case value, the total production cost is reduced. This is because, the energy at the peak period, which is the expensive energy price, is shifted to the base load period, which is a cheaper energy price than in the peak period. So, the total production cost is reduced. The reduction of total production cost in peak clipping is more than the reduction of total production cost in the load shifting. Because in peak clipping the total energy demand is reduced by 5%, where in the load shifting the total energy demand is not changed, just reduce the price of shifted energy ($/kw) from the expensive to the cheaper price. Since the total energy sale is not changed in load shifting, the income of the utility will not be reduced. Even, the benefit of the utility will be increased, because they sale the same amount of energy with less cost--in the case that the price of energy is the same everywhere.

For the strategic conservation, the energy is reduced by 10%, where in the peak clipping the energy was reduced just for 5%. That is why the total production cost in the strategic conservation is less than in peak clipping. In the strategic load growth, it is obvious that the total production cost is increased greatly, because the energy increase in the strategic load growth is 10% in the peak load period and base load period. So, the total production cost will also be greatly increased. After we finished studying the

Table 6.20. Production Cost Comparison ($)

No.	Base case	Valley Filling	Load Shifting	Peak Clipping	Strategic Conservation	Strategic Load Growth
1	240763.20	258391.50	231468.10	215520.00	201169.60	287897.90
2	141770.50	147691.30	139303.70	133860.50	128857.20	157375.60
3	250311.80	267970.30	238819.30	222915.00	208353.30	302016.90
4	158120.40	165981.20	154625.10	147400.00	140859.80	179019.70
5	206598.60	220369.20	199932.40	187417.40	176225.20	243408.50
6	153690.50	160997.40	150416.60	143736.80	137650.00	173226.00
7	252953.00	271144.20	242288.20	225750.80	210761.20	301635.10
8	163242.00	171728.60	159402.80	151663.30	144666.40	185935.10
9	214014.80	228664.30	206780.70	193489.10	181592.50	253236.00
10	163966.70	172548.30	160094.00	152267.10	145196.60	186893.50
11	275798.40	297091.30	264862.10	245347.70	227533.00	330736.10
12	175808.20	185757.20	171060.40	161988.30	153809.50	202415.50

production cost using the VPI model, in the next section, we are going to analyze the capacity credit of each unit in a system with different conditions.

6.5. Capacity Credit Analysis

The definition of capacity credit of a unit is the amount of peak load in MW that has to be reduced in order to maintain a certain reliability level, if that unit is not in operation. The capacity credit is important to know, especially when DSM activities are employed in utility operation and planning. The activities in DSM such as peak clipping and/or load shifting will be used as the case study for calculating the capacity credit of a unit. The purpose of using the peak clipping and the load shifting as the case-study is because both cases reduce the peak, where in the capacity credit calculation, the peak load need to be reduced. In peak clipping, there is no energy payback from customers when the operator disconnects their load. In other words, the energy will be decreased when the peak load is decreased. However, in load shifting, there is an energy payback from the customers. Because of the energy payback, the base load would be increased or would be constant in the case that the energy payback is not paid in the base load period. Since there is no energy shift or energy payback in peak clipping, the base load will be constant as the base case value. The energy payback in the load shifting could be 100% or less, and the period of pay back could be at any time except in the peak period.

The capacity credit calculation is needed in the operation and planning of a power system. In system operation, the operator has to know how much peak reduction is needed to keep the reliability level constant when a unit has failed to operate, is scheduled for maintenance, or if peak load increases, where the total capacity is not enough to keep the reliability at a certain level. And in planning, the planner has to know how much the peak reduction will be if a unit is not constructed or construction is delayed. For more understanding of the capacity credit calculation, the steps calculation are presented below. They are :

- Calculate the reliability indices of the complete system.
- Deletion of a unit that is going to calculate its capacity credit. After deletion of a unit, we call it the incomplete system. The reliability indices of incomplete system will be calculated after the new value of base load, peak load and total energy demand, are input. The new value of base load, and total energy demand depend upon the scenario we make.
- Compare the LOLP of the incomplete system to the LOLP of the complete system. If the reliability index, LOLP, of the incomplete system is not close to the LOLP of the complete unit, the program will increase or decrease the peak load automatically and calculate the LOLP again. The iteration will be stop if the LOLP of the incomplete system is close enough to the LOLP of the complete system. How close the LOLP values could get depends upon the control value given in the program, where that value could be changed.
- Calculate the capacity credit of the system as the difference between the peak load of complete system and the last peak load of the incomplete system. The time consumption of the capacity credit calculation is dependent upon the first guess of the peak load at the incomplete system after the first reliability of complete system is calculated. If the guessed

peak load is close to the actual peak load for the incomplete system, there will be less iteration and therefore less time consumed.

Before we discuss the capacity credit, we are going to analyze two things: how the number of units of a system will influence the reliability indices, such as LOLP and ENS; and how the unit order is related to reliability indices. The purpose of analyzing them, before studying the capacity credits, is to know the behavior of the reliability in both conditions, where the reliability will be used as a reference value in calculating the capacity credit of a unit. The result of analyzing them, will make a better understanding in the other cases. The generation unit data used in this study is as shown in Table 6.21, where the number of units in this study is bigger than the number of units in the reliability analysis or production cost analysis. However, the load data is the same as in the reliability analysis and production cost analysis as in Table 5.3. At first, we run two cases with the VPIDSM program, where the number of units is different. From the result, we conclude that the more units available, the greater the reliability. For the second, we run two cases with different unit order, and from the results we conclude that unit order does not influence to the reliability indices, such as LOLP and ENS values. There are two points that can be seen from these results:

- A unit's loading order does not influence its own or other's capacity credit.
- The reliability is changed if we reduce or increase the number of units in a system.

Table 6.21. Generation Unit Data For Capacity Credit Analysis

No	Name	No. Of Unit	Size (MW)	Availability
1	NUCLEAR	1	1200	0.816788
2	NUCLEAR	1	1000	0.816788
3	NUCLEAR	1	800	0.816788
4	COAL	1	1000	0.778500
5	COAL	1	800	0.793592
6	COAL	1	600	0.816960
7	COAL	1	400	0.851733
8	COAL	1	200	0.903360
9	COAL	1	100	0.937950
10	COAL	1	100	0.920000
11	GAS	1	800	0.887283
12	GAS	1	600	0.900537
13	GAS	1	400	0.919632
14	GAS	1	200	0.947682
15	OIL	1	800	0.845390
16	OIL	1	600	0.862022
17	OIL	1	400	0.890120
18	OIL	1	200	0.927344
19	OIL	1	100	0.953540

6.5.1. The capacity credit and the weather

In this section we are going to see how the capacity credit of a unit is affected by seasons of the year. As we know, peak load, base load and total energy demand are different for each season. We already proved before that the reliability indices will be different if one of those three variable is different. Because the reference value is the reliability index (LOLP), the capacity credit could be changed if the reliability is changed. For the study of the influence of weather on the capacity credit, we use 12 different load data as shown in Table 5.3. We calculate the capacity credit of unit number 19, which is 100 MW. Using the VPIDSM program, we run the cases and plot the results in Figure 6.3. From the results we can see that the capacity credit of 100 MW unit is not the same in every season. As mentioned before, since the system reliability is not equal, the capacity credit will not be equal either. The January load data represents the winter, the April load data is for spring, the July load data is for summer, and October load data is for autumn. Because of the capacity credit in each season is not the same, the way we make a judgment in operation, is different from the judgment in the planning. In the operation, because we need more accurate results, we have to calculate the capacity credit of each kind of load curve. Where in the planning, we just use the biggest value of capacity credit in one year. That biggest capacity credit will be used as a reference data for DSM planning for the each year in the future. For example, in our case, for a 100 MW unit, we have to use 184 MW for 1988, 214 MW for 1989 and 202 MW for 1990 peak reduction or capacity credit as a reference data for the planning of demand side management. The base load and total energy demand could influence the capacity credit as happening in the reliability analysis in Chapter 5. The influence of the base load and the total energy to the capacity credit will be discussed in the next section 6.6.3 and 6.6.4.

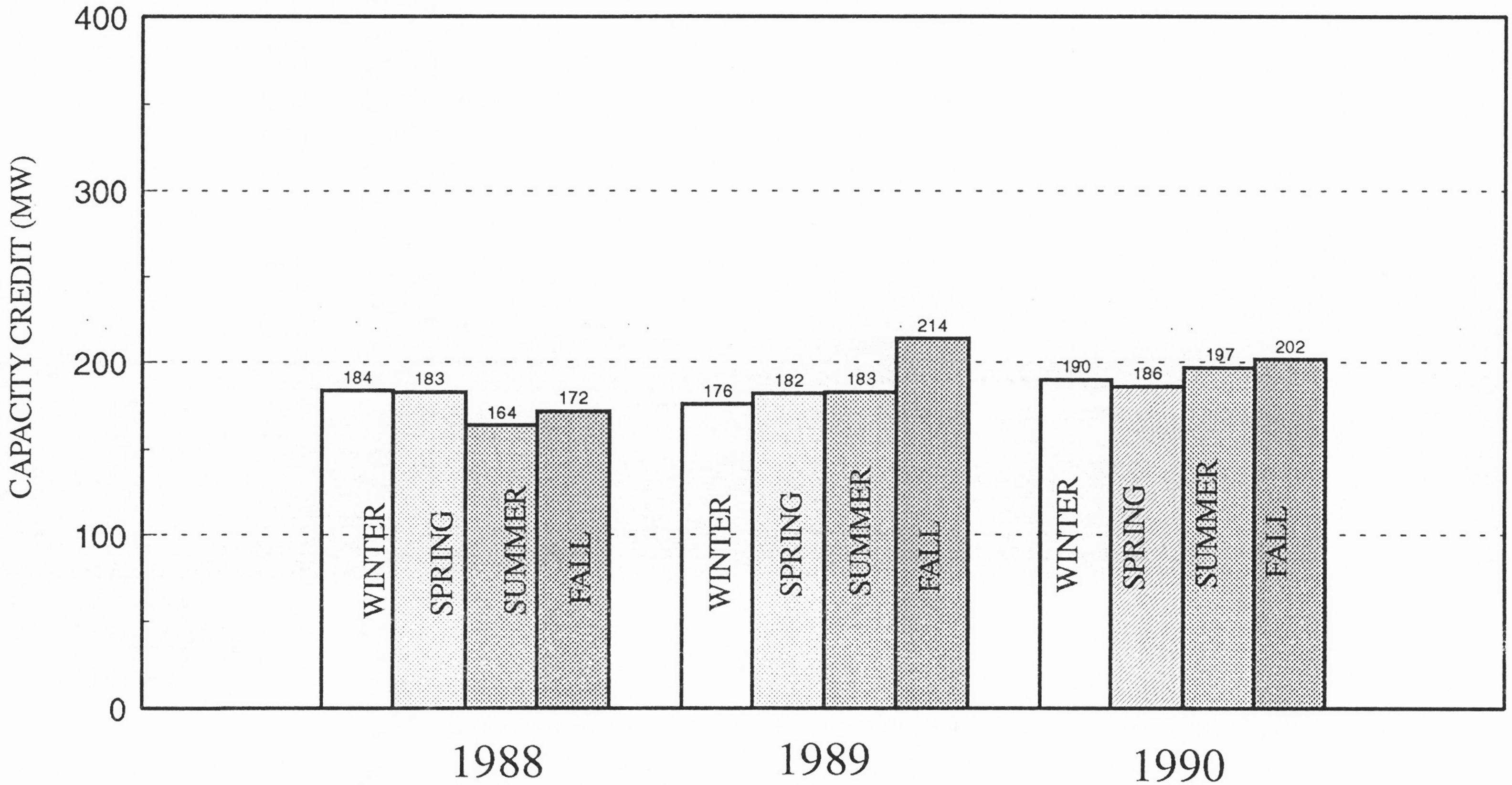

Figure 6.3. Capacity Credit of 100 MW Unit
In Different Seasons

6.5.2. Capacity credit and availability

In the capacity credit analysis, first, we are going to analyze how availability of a unit will influence the capacity credit of another unit and also how availability of a unit will influence its capacity credit. First, we run a case with the equal availability value for each unit. Second, we use the real availability data of each unit that we have in Table 6.21. Both results are compared. From this comparison, we can say that the availability of one unit influences the capacity credit of other units in the system. The third case is increasing the real availability of unit number 4 from 0.7785 to 0.8085. And we calculate the capacity credit of the unit number 19. The result shows us that the capacity credit of the unit number 19 is reduced from 184 to 180 MW. This means, the better reliability of the system, the smaller capacity credit of each unit in the system will be. The last case for this section is to analyze how the availability of "a unit" influences its the capacity credit. First, we calculated the capacity credit of the unit number 19, which is 100 MW and its availability is 0.9535, where its capacity credit is 184 MW. After that, instead of deleting unit number 19, the capacity credit of unit number 10 is calculated, which is also 100 MW unit and however, its availability is 0.9200. And the capacity credit of unit number 10 is 170 MW. So, with the same size but different availability, the capacity credit is different. It has already been proved that the loading order does not influence the capacity credit. Therefore, if we have to turn off a unit because of some reasons, it would be better if the unit which has a smaller availability is deleted. For more information for these cases, we ran 12 different load data with this case and plotted the results as shown in Figure 6.4. From this result we can see that all capacity credits of lower availability in different load data are less than the capacity credit of higher availability.

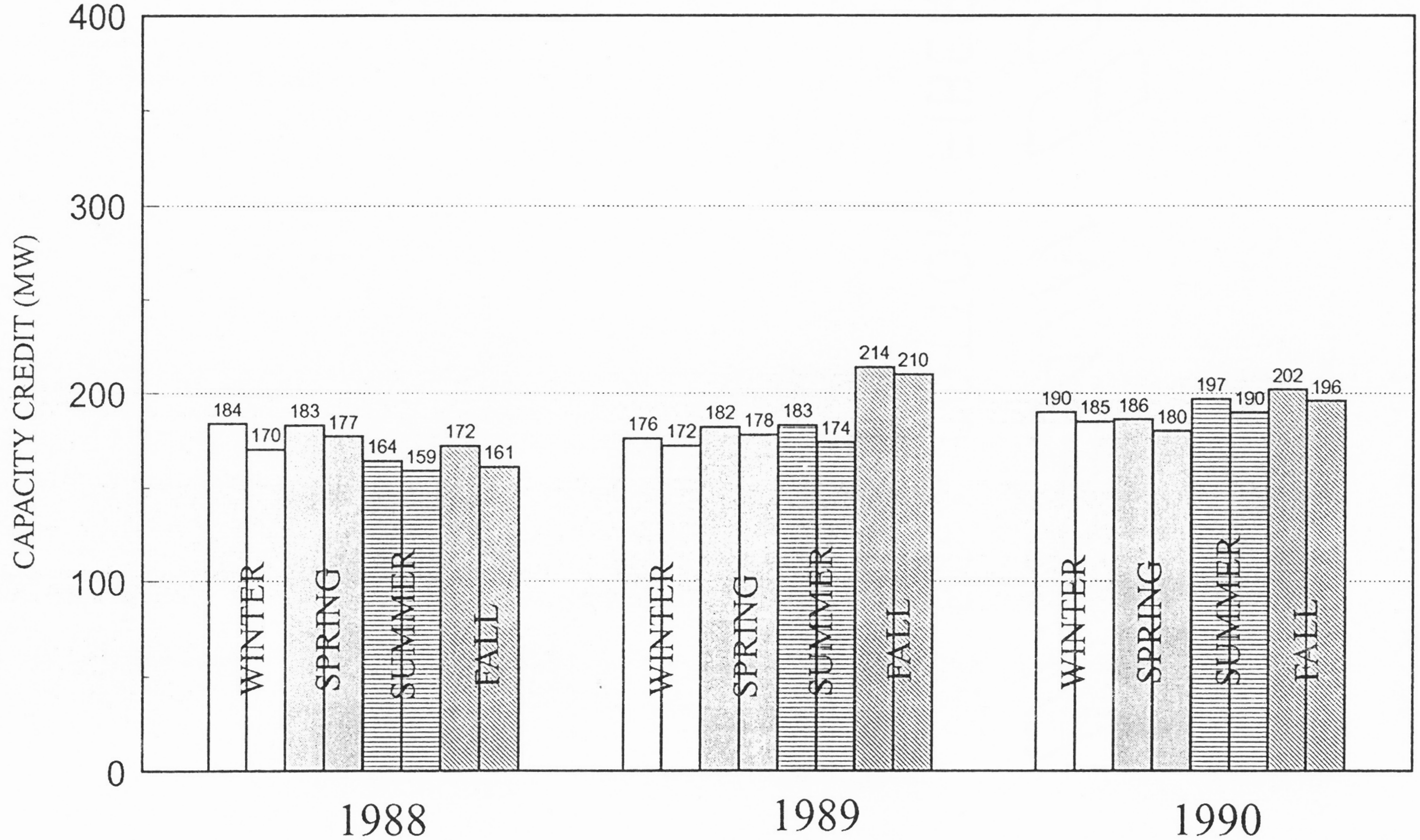

Figure 6.4.Capacity Credit of 100 MWUnit
with Different Availability

6.5.3. Capacity credit and base load

In this section we are going to discuss some cases to see how the base load influence the capacity credit of a unit. In the section 6.6.2, the base load and the energy remained constant after the peak load was reduced. If the energy remains constant, it means the energy pay back is 100%. When the base load remains constant the energy pay back period is not in the base load period. In this case, we ran the cases such that the base load was increased when the peak load was decreased and the total energy remained constant as the base case value; such cases can be called the load shifting. After we ran the case, we plot the capacity credit of this case and the capacity credit of the base case, the result is shown at Figure 6.5. One can see that the base load also influence the capacity credit, in this case the base load reduce capacity credit. As mentioned before that it is because the energy at the peak period is reduced. As the result the system reliability will be higher and the capacity credit will be smaller. The positive effect of the base load to reliability, as shown in the reliability analysis, also occurred in the capacity credit. If the base load is increased, the capacity credit is decreased.

6.5.4. Capacity credit and total energy demand

In this section we are going to see how the total energy demand influences the capacity credit of each unit in the system. We already know that the total energy influences the reliability of the system. For this purpose, we ran some cases where the total energy demands are reduced by 5% from the base case values. After we ran the cases, we had the results as shown in Figure 6.6. The capacity credit of reduced energy cases are smaller than the base case capacity credit. In other words, the total energy demand also influence the capacity credit of each unit. From these result we can see that the capacity credit could

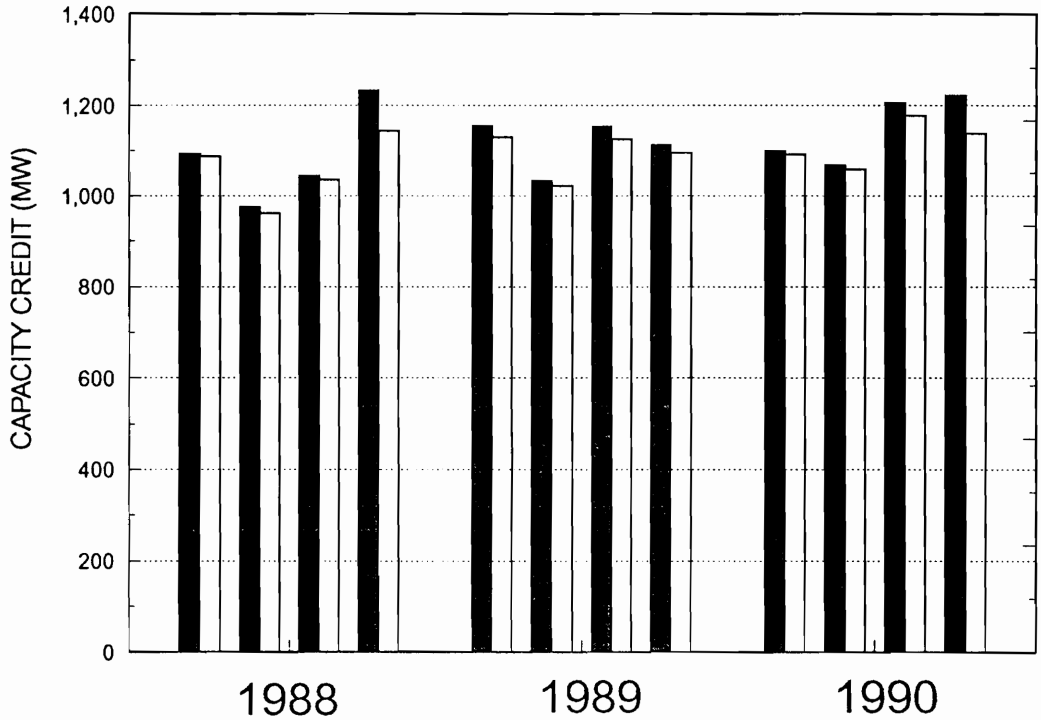

Figure 6.5. Capacity Credit of 800 MW Unit with Different Base Load

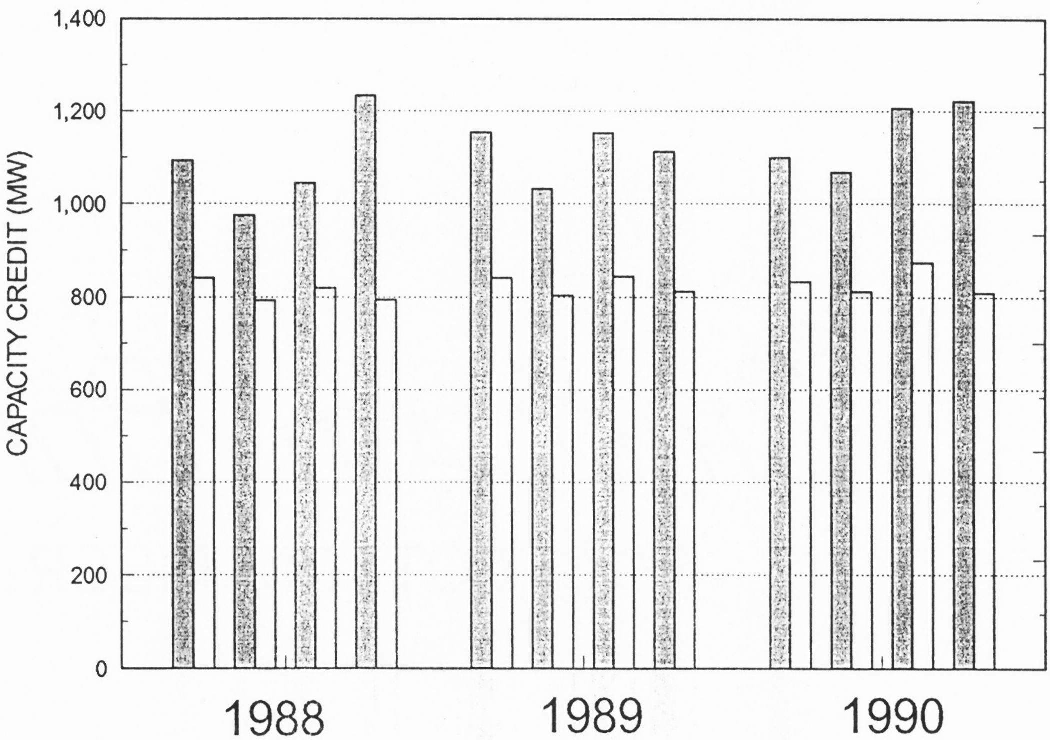

Figure 6.6. Capacity Credit of 800 MW Unit with Different Energy Demand

be less than the size of the unit, because some of the capacity credits in Figure 6.6, after energy reduction, are less than 800 MW, where the size of the unit is 800 MW.

6.5.5. Capacity credit and unit size

In this section, we are going to see how the capacity credit of a unit is related to its unit size. For that purpose, we ran the cases for calculating the capacity credit of each unit with the availability as in Table 6.21. To show how the capacity credit is related to the unit size, the capacity credit is divided by unit size and the result is plotted as shown in Figure 6.7. Two conclusions can be made from Figure 6.7 :

1. The smaller availability, with the same unit size, the bigger the ratio between capacity credit and unit size..
2. The smaller unit size, with the same availability, the bigger the ratio between capacity credit and unit size.

The first statement actually is an additional proof, which has been discussed in section 6.6.2. In this case, let's see the first three bars in Figure 6.7, which are for 100 MW units with different availabilities. The first bar has the smallest availability, and the third bar has the largest availability; Therefore we can see that statement number 1 is true.

To prove the second statement, more cases are needed. We ran some more cases setting the availability of units 6,7,8, and 9 at 0.816788; units number 1,2,3,6,7,8, and 9 had the same availability. As in the previous

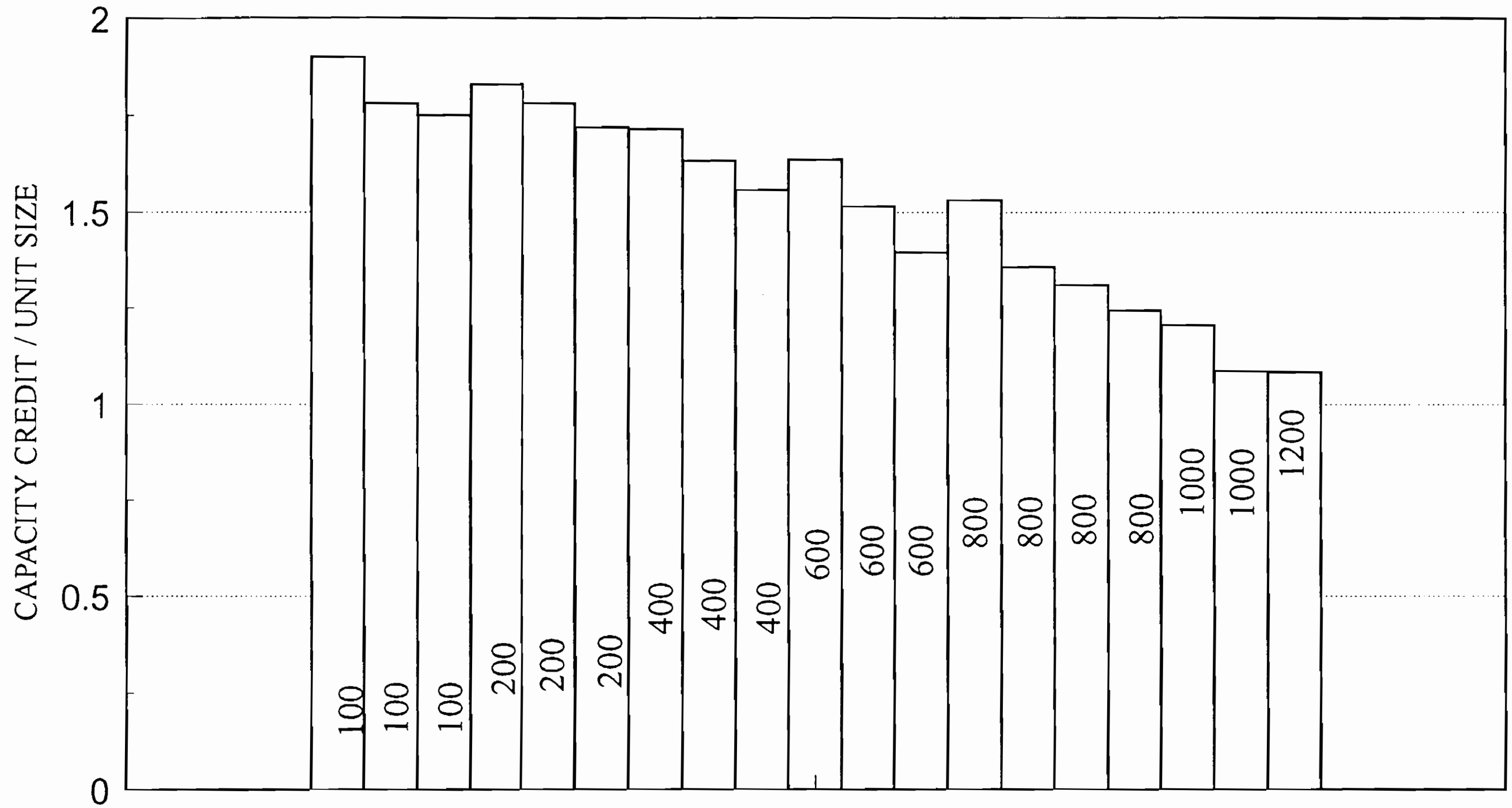

Figure 6.7. Normalized Capacity Credit of 19 Units for Winter 1990

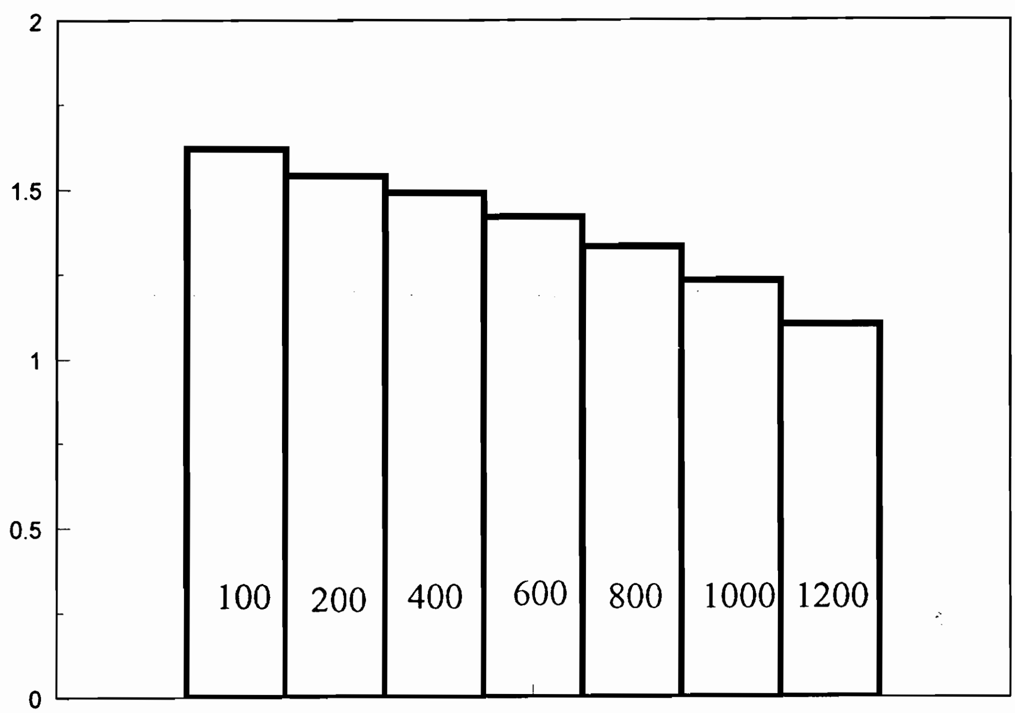

Figure 6.8. Normalized Capacity Credit With Equal Reliability

analysis, the capacity credit is divided by its unit size, and the result is plotted in Figure 6.8. From the result as shown in Figure 6.8., statement number 2 is show to be true.

6.5.6. Summary

After analyzing the capacity credit cases, we can see how important the capacity credit is in utility operation and planning, especially if demand side management activities are employed. It takes investment and effort to reduce the peak load. The more peak load reduction, the more effort needed to control the customer load, the more money needed for load management activities. So, the exact number of MW of peak load have to be reduced is needed to optimize cost efficiency.

CHAPTER VII

Conclusions and Recommendations

7.1. Conclusions

Demand Side Management (DSM) impacts need to be incorporated into power system planning and operation activities properly and accurately, because such impacts will affect the power system in many ways, such as the economic, technical and environmental aspects. These impacts are usually incorporated into the load duration curve (LDC). The inverted LDC is the most important part in power system capacity expansion planning. From inverted load duration curve, the system reliability indices and the production cost are calculated, and generation planning alternatives is analyzed.

A mathematical model of the Inverted Load Duration Curve (ILDC) has been presented in this study, it is called the VPI model. Existing models obtain the inverted load duration curve by mathematical manipulation of the load duration curve. With the VPI model, one does not have to use the LDC to have the expression of ILDC. One of the advantages of the VPI model is its the time saving feature. The variables of the VPI model are peak load, base load, and total energy demand. Because of those variables, the VPI model can incorporate the impacts of DSM properly, accurately and easily. Due to

DSM, those three variables are intended to change. The model, where peak load, base load and total energy demand are its variables, will be valuable for utility planning and operation.

The VPI model has been tested and compared to other models. The comparisons are based on the system reliability indices (LOLP and ENS), total energy demand, ILDC, ELDC, and the flexibility of the model to handle the problems. There are two methods that can be used to calculate the ELDC (LOLP and ENS are calculated from ELDC). The first is convolution method and the second is cumulant method. The cumulant method is unstable in many cases, because some of the cumulant's results have negative values for LOLP. However, the cumulant method is less time consuming. Since the cumulant method is not accurate in some cases, this study does not use cumulant method as a tool to calculate ELDC. Even though there are some studies that try to overcome the unstable results of cumulant method, it is achieved by sacrificing the accuracy of the results. One of them was studied by Hill and Jenkins [80].

The VPI model is a load curve model which uses the convolution method. The VPI load model has already been compared to other load models such as Snyder load model [9], fifth degree polynomial load model as WASP load model [83], and actual load data. The ILDC fit of VPI model is a good fit as compared to actual load data. Also the ELDC fit of VPI model is close to WASP's ELDC. For the LOLP and ENS comparison, the VPI model results are what are found from those of these models. From these facts, one can say that the VPI model can be used as a new load model for power system planning and operation purposes, specially after DSM is incorporated into power system activities.

To show the accuracy of the VPI model in the production cost calculation, the new model was inserted into the WASP computer program. With modified WASP, the production cost was calculated. The production cost comparisons are between the original WASP and modified WASP. It showed a good result ; the modified WASP production cost, with inserted VPI model, is close enough to the original WASP production cost. The difference of those two production costs was expected, because of the different between total energy demand calculated by VPI model and total energy demand calculated by original WASP. Since the total energy of the VPI model is closer to the actual data, the production cost of modified WASP, with the VPI model as a load model, was considered close to the actual production cost.

The simplicity and flexibility of VPI model have been demonstrated in this study. Using the VPI model, the impacts of DSM activities to system reliability were calculated. In each DSM activity, the peak load, base load, and/or total energy demand were changed. Using the program made for this study, the flexibility and the simplicity of the VPI model has been shown. Each case study takes only 18 seconds to run an 80486 PC.

The VPI model also demonstrated the capability to calculate the capacity credit of each unit in the system, with different conditions and different load characteristics. It is important in power system planning and operation to know capacity credit of each unit in the system. The knowledge the capacity credit of each unit in the system will help the operator to determine how many MW of peak loads has to be reduced if a unit fails to operate. In the planning arena, the planner will know how much load reduction will be necessary, if the construction of a unit is canceled or postponed, in order to keep reliability of the system at a certain level. With the VPI model, the operator or the planner can check the impacts of not only the peak load, but also to the total energy demand and the base load. Because more variables are involved, the results are expected to be more accurate using the VPI model.

7.2. Recommendations

The VPI model has been proven and tested such that it can be used as an alternative for power system activities in planning and operation. Because of the simplicity, flexibility, and accuracy of the VPI model, there are many possible applications that can be implemented in power system planning and operation. Those possible applications will be mentioned as a recommendation from this study that could become a research topic in power system area, especially in the power system planning. There are three recommendations presented below.

. The VPI model can be used to incorporate photovoltaic power into generation planning. Photovoltaics are considered more as an energy producer (in Mwh) than a power producer (in MW), because of its characteristics. The VPI model, where the energy is one of its variables, can be used to incorporate the total energy produced by photovoltaics into load duration curve, as a negative load or be treated as a load management DSM tool. So, with VPI model, the total energy produced would be incorporated accurately.

. The VPI model also can be used to analyze the impact of the electric vehicle (EV) load in power system operation and planning. As expected in the next decade, the electric car will be commercially produced, which means the demand for electricity will increase to proportions not seen at this time. At least for the beginning, the load forecast for EV will be separate from the usual load forecast as seen today, because it is hard to combine the forecast of the EV load with other loads, using the available methods. Since the electricity needed for an EV is used to recharge a battery, the time of use of the energy for recharging can be controlled and contained in the base load period. In other words, it is a valley filling activity. As mentioned before, in valley filling, the base load and energy will be changed. So, the VPI model is ideal for this situation.

. It has been demonstrated that the VPI model can calculate the capacity credit accurately. As mentioned, the calculation process was using iterations, where the value of LOLP had a reference value, and iteration will be stopped after having the same LOLP with reduced peak load, fixed base load and fixed total energy demand. To reduce time consumed in iterations, it would be better if one can make a formula for calculating capacity credit. The capacity credit formula will be a function of peak load, base load, total energy demand, and LOLP value, where the capacity credit calculated by the VPI model will be used as a reference.

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