

MULTIPERIOD OPTIMAL POWER PLANT MIX UNDER DEMAND UNCERTAINTY

Byong-Hun Ahn Bo-Woo Nam
Korea Advanced Institute of Science and Technology

(Received June 5, 1987; Revised March 3, 1988)

Abstract This paper is concerned with the thermal-based electric utility capacity expansion planning under demand uncertainty. The demand uncertainty is typically represented as a set of likely load duration curves (LDCs) with respective probabilities. Conventional scenario approaches prepare respective capacity expansion plans – one for each load curve – and synthesize these somehow into a single plan. This paper presents a simple yet justifiable method which combines multiple plans into a single implementable plan guaranteeing the minimum expected total cost. A “horizontal” expected load curve is the key concept in this method. We illustrate this using Korea’s data in a realistic multi-period optimal mix problem. It turns out that the recommended baseload capacity expansion (e.g., through construction of nuclear plants) follows closely that of the low-demand case, suggesting the need for conservative commitment to costly baseload plants in the presence of demand uncertainty.

1. Introduction

Since the oil crises of the 1970s, electric utilities in many oil importing countries have shifted from oil-based facilities to nuclear and coal plants as a safeguard against potential future oil shocks. Since it is costly and time-consuming to bring on line such baseload plants as nuclear and coal, the issues of uncertainty, particularly demand uncertainty, in expansion planning have received increasing attention. This trend is especially pronounced in oil-importing industrializing countries whose economies are fast-growing but sensitive to international energy market changes.

Korea, for example, in 1977 developed a power sector expansion program projecting up to the year 2001. With rapid annual demand growth of more than 25 percent and with the decision to move away from dependence on oil, more than forty nuclear reactors were planned up to the year 2001. Today, we

expect fifteen or fewer to be operating by that year, only 34% of those contained in the original plan. Furthermore, the current surplus capacity situation (an over 70 percent reserve margin, which is well beyond the conventional safety margin of 20~25%) has become a painful penalty to the nation's economy. This situation has resulted primarily from the hasty implementation of an "optimistic" expansion program, the considerable deviation of resolved actuals from forecasts, and the long construction lead times of baseload plants.

To avoid repeating this bitter experience and to better manage capacity expansion problems, Korea has taken two approaches: one is to adopt the rolling planning concept of updating a long-term expansion program annually, and the other is to utilize the scenario approach by preparing a set of expansion programs – one for each demand scenario. More specifically, three demand scenarios (high-, reference, and low-cases) are prepared, and the WASP (Wien Automatic System Planning Package) model [10] is employed to produce three distinct expansion plans. Since the long-term plan is updated annually, only current-year investment decisions are of prime concern, as future-year decisions are needed only to support the current-year decisions.

This paper presents a simple yet realistic expansion planning method that is well justified under these approaches: an expected-cost minimizing method that synthesizes the set of scenario-based expansion programs into a single plan. It does so by incorporating the future-year decisions in an "expectation" mode, lessening the computational burden, and, more importantly, allowing the use of the existing deterministic expansion planning models.

Before moving on to discussion of previous works in this area, we introduce the concept of "horizontal" expected load duration curve (HELDC), which plays the central role in this paper. One way to represent electrical load (kilowatts) is by its instantaneous power requirement at each point in time; that is, by deriving the chronological load curve (CLC). An alternative representation widely used in generation capacity planning is the load duration curve (LDC), which is an accumulation of CLC obtained by sorting loads in decreasing order of magnitude as shown in Figure 1. Now in the presence of load uncertainty, a set of likely LDCs is estimated with associated probabilities. Suppose that, as shown in Figure 2, there are two LDCs, high and low. The expected LDC of these two realizations can take two forms: one is the "vertical" expectation, which is the weighted average (by probability) of load levels for each point in time, and the other is the "horizontal" expectation which averages the durations for each load level. These two expected LDCs are shown in Figure 2. Although the vertical expected LDC is itself useful in many planning applications, we utilize the "horizontal" expected LDC in our approach.

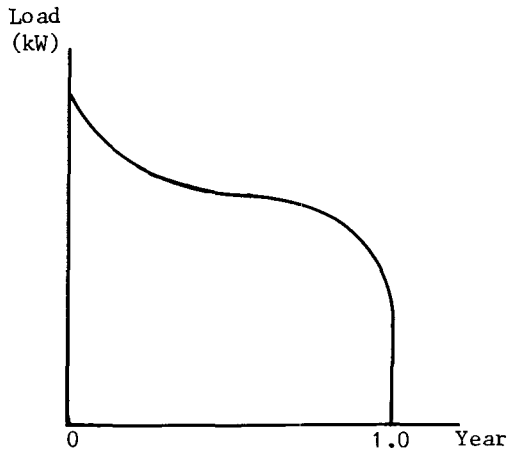


Figure 1. Example of a Load Duration Curve

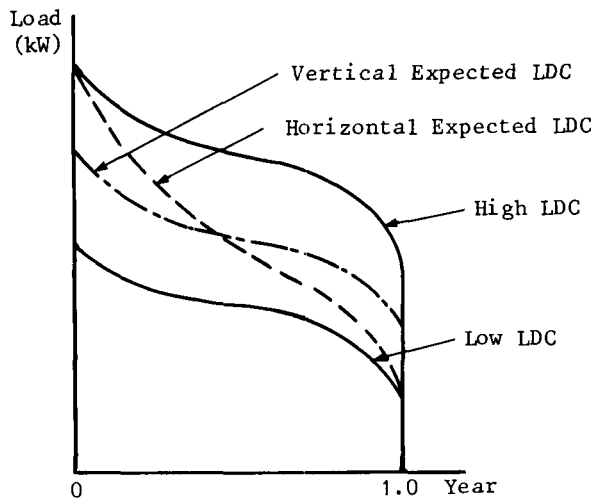


Figure 2. Concepts of Horizontal and Vertical Expected LDC

Basically, our approach suggests to use this "horizontal" expected LDC instead of a set of scenarios to incorporate the demand uncertainty in expansion planning, and shows that this will result in an expected cost minimizing expansion program. The only additional work needed, once a set of likely LDCs with associated probabilities is given, is to derive the "horizontal" expected LDC for each year within the planning horizon, to be fed into the existing expansion planning model.

In fact, a good deal of research has addressed uncertainty issues in power sector expansion planning – some studies, like ours, focusing on demand uncertainty, and others covering operating (fuel) costs and investment costs as well. Most works develop a set of "contingency" plans which explicitly specify the future-year decision along each uncertainty tree path. This contingency-plan method contrasts with our approach, in that the latter buries future-year decisions in an expectation mode. Henault et al. [9], Booth [3], Louveaux and Smeers [14], Borison [6], Dapkus and Bowe [8], Stremel [17] and the Over/Under model of the Electric Power Research Institute [7] are examples of the contingency approaches. These approaches do not assume the rolling planning concept of periodically updating expansion plans, and they typically require solving a large number of subproblems associated with uncertainty tree paths.

It is sometimes more practical to update or reevaluate expansion plans periodically to reflect changed planning environments than to stick to previously developed contingency plans. It is unlikely, for example, that an electric utility would set up a ten-year contingency plan and stick to it for ten years without capitalizing on changed planning environments (other than resolved uncertainties). For this reason, we assume here that the expansion plan is periodically updated, so that the contingency plans for future years are not mandatory.

The concept of using "expected" LDCs for demand uncertainty handling in power sector planning is not new. Murphy et al. [16] addressed this issue for a static optimal power plant mix problem under the simplifying assumptions on LDC and plant outage representations. They approximated the LDCs with step-functions and the plant outages with capacity derating, so that the expansion planning problem with demand uncertainty could be formulated as a two-stage stochastic linear program. This stochastic linear program formulation revealed that under mild conditions the deterministic model with the expected LDCs as inputs yields the same optimal solution of the stochastic linear program. In fact, this type of observation had been investigated much earlier in a general stochastic setting. Mangasarian [15] examined the relationship between the minimization of expected objective values and the minimum objective value with random variables replaced by respective expected values. Later, Ziemba [19] studied the conditions under which the stochastic dynamic programming problems can be converted into deterministic nonlinear programs.

This paper extends Murphy et al.'s work by relieving the step-function approximation of LDCs and the capacity derating for plant outage representation. Furthermore, we discuss the multi-period situations as well as the

static cases. A simple case study on Korea's power sector is used to illustrate our approach.

2. Optimal Mix Problem Under Uncertainty

In this section, using the typical optimal plant mix formulation, we develop the equivalency between a stochastic plan with uncertain loads and a deterministic one with "expected" load inputs. We start with a static optimal mix framework and later extend to a multi-period case.

The following conventional assumptions are adopted here:

1. There exists no economy of scale either in capacity costs with size or in operating costs with output level.
2. No generator start-up cost and transmission loss occur.

The first assumption had not been accepted in the past, but recent experience confirms that this assumption is the rule rather than exception, at least from a total-system cost (including reliability cost) point of view. The second assumption might be challenged in short term operation problems, but is commonly used in expansion planning studies (see Bloom [2]). Further, we assume the system consists of thermal plants only. Under this set of assumptions, the optimal operation plan is simply characterized by the variable cost (or merit) order (Anderson [1]).

Coupled with the merit order dispatch rule and the probabilistic simulation of plant outages, the optimal mix problem becomes that of minimizing the total of the construction costs, the operating costs, and the unserved energy cost as follows (see Borison and Morris [5]):

$$\begin{aligned} \min_x \quad & \sum_{i=1}^I (c_i x_i + f_i p_i \int_{u_{i-1}}^{u_i} G_i(Q) dQ) + v \int_{u_I}^{\infty} G_{I+1}(Q) dQ \\ \text{(P1)} \quad & \text{s.t.} \quad x \in S \end{aligned}$$

$$u_i = u_{i-1} + x_i, \quad i = 1, 2, \dots, I, \quad \text{with } u_0 = 0$$

given the "equivalent" load duration curves $G_{i+1}(Q)$, $i = 1, 2, \dots, I$, from

$$G_{i+1}(Q) = p_i G_i(Q) + (1-p_i) G_i(Q-x_i),$$

where i = index of merit-ordered plants,

I = number of plants,

c_i = fixed cost per unit capacity of plant i ,

x_i = capacity level of plant i ,

- f_i = operating cost per unit energy from plant i ,
 p_i = availability of plant i ,
 u_i = cumulative capacity up to and including plant i ,
 $G_1(\cdot)$ = original load duration curve,
 $G_i(\cdot)$ = equivalent load duration curve faced by plant i after
 accounting for the outages of prior plants in the merit order,
 v = unit cost of unserved energy,
 S = set of feasible capacities.

Note that, since the merit ordered operation is assumed, the power generation of each plant can be determined implicitly by integrating the relevant respective equivalent load duration curve (Borison [4], and Bloom [2]).

The static optimal mix problem (P1) is typically concerned with some future year for which uncertainty about demand, technical, economic and regulatory conditions could be significant. Expected cost minimization is a natural first choice to accommodate these uncertainties. Noting that the dispatch policy is invariant to load curve choice unless the merit order changes, we can transfer the uncertainty problem into the following stochastic problem:

$$(P2) \quad \min_x E \left[\sum_{i=1}^I (c_i x_i + f_i p_i \int_{u_{i-1}}^{u_i} G_i(Q) dQ) + v \int_{u_I}^{\infty} G_{I+1}(Q) dQ \right]$$

s. t. $x \in S$

$$u_i = u_{i-1} + x_i, \quad i = 1, 2, \dots, I, \quad \text{with } u_0 = 0,$$

where

$$G_{i+1}(Q) = p_i G_i(Q) + (1-p_i) G_i(Q-x_i), \quad i = 1, 2, \dots, I,$$

$E[\cdot]$ denotes the expectation function, and other notations are same as in the formulation (P1). Fixed costs c_i 's, variable costs f_i 's and original load duration curve $G_1(\cdot)$ all can be random variables. However, the random cost variables here yield only trivial results; we thus focus on demand uncertainty only.

Now we show that the expectation operators in the above optimal mix problem (P2) can be brought inside the integrals, so that this stochastic problem can be converted into an equivalent deterministic problem in which the random elements are replaced by their expected values. The following discussion elaborates on this.

First, note that u_i 's and $G_i(Q)$, $i = 2, \dots, I+1$, in the objective function can be removed using the recursive relations, and can be represented only by

x_i 's and the uncertain load duration curve $G_1(Q)$. The feasible capacity set constraint $x \in S$ is the only effective constraint for (P2) (also for (P1)). In other words, the random variables appear only in the objective function.

We first assume that the uncertain load duration curve $G_1(Q)$ for each load level Q is given as a set of K load duration curves $g_1^1(Q), \dots, g_1^K(Q)$ with respective probabilities π_1, \dots, π_K . Then the "horizontal" expected load duration curve is given as:

$$E[G_1(Q)] = \sum_{k=1}^K \pi_k g_1^k(Q).$$

Since $G_1(Q)$ is a random variable, the equivalent load duration curve $G_i(Q)$, $i = 2, \dots, I+1$, is also a random variable each with a set of realizations $g_i^1(Q), \dots, g_i^K(Q)$ given recursively as:

$$g_{i+1}^k(Q) = p_i g_i^k(Q) + (1-p_i) g_i^k(Q-x_i), \quad \text{for any } k.$$

Noting that the probability associated with $g_i^k(Q)$ is π_k , we have:

$$E[G_i(Q)] = \sum_{k=1}^K \pi_k g_i^k(Q)$$

From this result, we know the following trivial relations:

Lemma 1. Suppose the given load duration curve $G_1(Q)$ is a random variable for each load level Q . Then the following recursive equation holds for each plant i and each load level Q :

$$E[G_{i+1}(Q)] = p_i E[G_i(Q)] + (1-p_i) E[G_i(Q-x_i)].$$

Next we show that under a fixed dispatch order the expected power generation from plant i facing the uncertain equivalent load duration curve $G_i(\cdot)$ is equivalent to the "certain" power generation of plant i facing the expected equivalent load duration curve $E[G_i(\cdot)]$, that is,

Lemma 2. Under a fixed dispatch order, we have

$$E\left[\int_{u_{i-1}}^{u_i} G_i(Q) dQ\right] = \int_{u_{i-1}}^{u_i} E[G_i(Q)] dQ \quad \text{for each } i.$$

Proof: Since the cumulative capacity u_i is invariant to each realization of $G_i(Q)$ once the merit order is given, this can be trivially shown for each plant i as follows:

$$\begin{aligned}
E\left[\int_{u_{i-1}}^{u_i} G_i(Q) dQ\right] &= \sum_{k=1}^K \pi_k \int_{u_{i-1}}^{u_i} g_i^k(Q) dQ \\
&= \int_{u_{i-1}}^{u_i} \sum_{k=1}^K \pi_k g_i^k(Q) dQ \\
&= \int_{u_{i-1}}^{u_i} E[G_i(Q)] dQ. \quad ///
\end{aligned}$$

A similar result can be obtained for the unserved energy; i.e., the expected unserved energy facing uncertain loads is equal to the unserved energy facing the expected load:

$$E\left[\int_{u_I}^{\infty} G_{I+1}(Q) dQ\right] = \int_{u_I}^{\infty} E[G_{I+1}(Q)] dQ.$$

Now we are ready to present the following main result.

Theorem 1. The optimal mix problem under uncertainty (P2) is equivalent to the deterministic optimal mix problem (P1) with the load duration curve $E[G_i(Q)]$ as problem data; i.e., (P2) is equivalent to:

$$\min_x \sum_{i=1}^I (c_i x_i + f_i p_i \int_{u_{i-1}}^{u_i} E[G_i(Q)] dQ) + v \int_{u_I}^{\infty} E[G_{I+1}(Q)] dQ$$

$$\text{s.t. } x \in S$$

$$u_i = u_{i-1} + x_i, \quad i = 1, 2, \dots, I, \quad \text{with } u_0 = 0$$

where

$$E[G_{i+1}(Q)] = p_i E[G_i(Q)] + (1-p_i) E[G_i(Q-x_i)], \quad i = 1, 2, \dots, I.$$

Proof: Since the merit order does not change under demand uncertainty (the merit order is determined only by the variable cost ranking), u_i is uniquely determined for a given capacity profile x . From the linearity of the expectations operator and the result of Lemma 2, the objective function of (P2) can be rewritten as:

$$\sum_{i=1}^I (c_i x_i + f_i p_i \int_{u_{i-1}}^{u_i} E[G_i(Q)] dQ) + v \int_{u_I}^{\infty} E[G_{I+1}(Q)] dQ.$$

From Lemma 1, $E[G_i(Q)]$ satisfies the recursive relation:

$$E[G_{i+1}(Q)] = p_i E[G_i(Q)] + (1-p_i) E[G_i(Q-x_i)], \quad i = 1, 2, \dots, I.$$

This completes the proof. ///

It is noted, then, that we do not need to solve a set of optimal mix problems for each realization of demand uncertainty. We have only to solve one optimal mix problem (P3), which will nonetheless yield an optimal mix pattern for a system facing demand uncertainty.

It is helpful to make a brief comparison between the optimal mix under deterministic environments and the optimal mix derived using the "horizontal" expected LDC in the presence of demand uncertainty. As shown in Figure 3, the tip of this curve is equivalent to that of the highest load duration curve realized, while the base is similar to that of the lowest realized. As a result of these characteristics of this "horizontal" expected LDC, the total capacity is determined mostly by the peak demand of the highest realization (high-demand scenario), while the base load capacity will be governed largely by the lowest realization (low-demand scenario). This relationship would seem likely to pose a surplus capacity problem. In actual planning environments, however, such problems will generally not arise. Baseload plants need longer construction lead times, while peaking units require shorter lead times, so that the current investment decision is concerned with the baseload plants, not peaking units. Peaking units can be introduced, delayed, or cancelled later, once some uncertainties have been resolved.

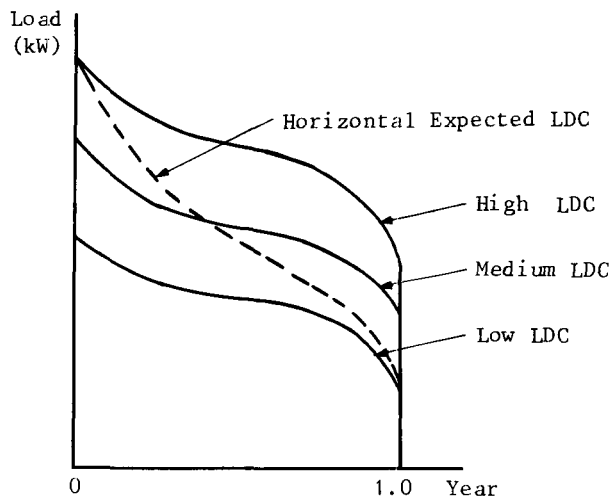


Figure 3. Example of a Horizontal Expected Load Duration Curve

3. Multi-Period Expansion Planning under Demand Uncertainty

Having established above the static (single period) equivalency between the stochastic expansion problem and the deterministic plan with the

"horizontal" expected LDCs, we now move on to the multi-period cases. Since most existing capacity expansion models such as the WASP model span multi-year periods, we need to establish the equivalency within a multi-period framework for our results to be appreciated in real-world planning environments.

The deterministic multi-period optimal expansion models typically take the following form (see, for example, the WASP model [10] and Bloom [2]):

$$\begin{aligned} \min_x \quad & \sum_{t=0}^T \sum_{i=1}^I (c_{it} x_{i,t-L_i} + f_{it} p_i \int_{u_{i-1,t}}^{u_{it}} G_i^t(Q) dQ) + v_t \int_{u_{It}}^{\infty} G_{I+1}^t(Q) dQ \\ \text{(MP1)} \quad & \text{s.t. } x \in S \\ & z_{it} = z_{i,t-1} + x_{i,t-L_i}, \quad \text{for all } i, t, \\ & u_{it} = u_{i-1,t} + z_{it}, \quad \text{for all } i, t, \text{ and } u_{0t} = 0, \text{ for all } t, \end{aligned}$$

given the equivalent load duration curves $G_{i+1}^t(Q)$, for all i and t , from

$$G_{i+1}^t(Q) = p_i G_i^t(Q) + (1-p_i) G_i^t(Q - z_{it}),$$

where T = number of periods in the planning horizon,

t = index of period,

L_i = construction lead time for plant i ,

c_{it} = present value of the construction cost for plant i commissioned at t ,

x_{it} = capacity level of plant i commissioned (i.e., construction start) in period t and put into operation in $t+L_i$ (if $t < 0$, then it is the capacity of plant i already under construction),

z_{it} = available capacity level of plant i in period t , with z_{i0} representing the existing capacity level,

$G_1^t(Q)$ = original load duration curve in period t ,

$G_i^t(Q)$ = equivalent load duration curve in period t faced by plant i after accounting for the outages of prior plants in the merit order. Other notation is similar to that of (P1), except for index t .

As was done for the static case, suppose now that the LDCs are random variables. Then the expected-cost-minimizing expansion plan can be obtained from the following stochastic program:

$$\min_x E \left[\sum_{t=0}^T \sum_{i=1}^I (c_{it} x_{i,t-L_i} + f_{it} p_i \int_{u_{i-1,t}}^{u_{it}} G_i^t(Q) dQ) + v_t \int_{u_{It}}^{\infty} G_{I+1}^t(Q) dQ \right]$$

(MP2) s.t. $x \in S$ (1)

$$z_{it} = z_{i,t-1} + x_{i,t-L_i}, \text{ for all } i, t, \tag{2}$$

$$u_{it} = u_{i-1,t} + z_{it}, \text{ for all } i, t, \text{ and } u_{0t} = 0, \text{ for all } t, \tag{3}$$

where

$$G_{i+1}^t(Q) = p_i G_i^t(Q) + (1-p_i) G_i^t(Q - z_{it}), \text{ for all } i \text{ and } t, \tag{4}$$

$E[\cdot]$ denotes the expectation function, and other notation is the same as in the formulation (MP1). Original load duration curves $G_i^t(Q)$, $t = 1, \dots, T$, are random variables.

This formulation has been trivially obtained from (MP1) by imposing the expectations operator on the objective function. This simplicity was possible because our approach is concerned with the "expected" future decisions rather than with the contingency plans for future years along each uncertainty tree path. If the "contingency" approach is followed, x_{it} should be further indexed by the "contingency" node along the uncertainty tree path. The resulting model formulation then becomes quite complex and imposes a heavy computational burden (see, for example, Louveaux and Smeers [14]). Since our approach assumes periodic updating and thus is not concerned with contingency plans, (MP2) may well serve the purpose. Due to this simplicity, we can also extend without difficulty (in fact, almost trivially) the equivalency for the static case to that for the multi-period case.

As before, for a given capacity profile x , the cumulative capacities u_{it} 's for all i and t are uniquely determined through the recursive equations (2) and (3). (Note that, although the merit order could vary across the time points due to the differences in fuel price escalations, it is invariant to the resolved demand uncertainty within each given period.) Then, along with the linearity of the expectations operator, the expectations operators of (MP2) can be brought inside the integrals as in the static case. Since the equivalent LDC $G_i^t(Q)$ for period t is represented by a linear combination of original random LDC $G_1^t(Q)$ of period t through (4), the expected equivalent LDCs $E[G_i^t(Q)]$ for all i and t satisfy the recursive relation:

$$E[G_{i+1}^t(Q)] = p_i E[G_i^t(Q)] + (1-p_i) E[G_i^t(Q - z_{it})], \text{ for all } i \text{ and } t.$$

Thus the multi-period expansion problem under demand uncertainty (MP2) is equivalent to the deterministic problem (MP1) with LDCs $E[G_1^t(Q)]$, $t = 1, 2$,

..., T , as input data; that is, (MP2) is equivalent to:

$$\begin{aligned} \min_x \quad & \sum_{t=0}^T \sum_{i=1}^I (c_{it} x_{i,t-L_i} + f_{it} p_i \int_{u_{i-1,t}}^{u_{it}} E[G_i^t(Q)] dQ) \\ & + v_t \int_{u_{It}}^{\infty} E[G_{I+1}^t(Q)] dQ \\ \text{(MP3)} \quad & \text{s.t. } x \in S \\ & z_{it} = z_{i,t-1} + x_{i,t-L_i} \quad \text{for all } i, t, \\ & u_{it} = u_{i-1,t} + z_{it}, \quad \text{for all } i, t, \text{ and } u_{0t} = 0, \text{ for all } t, \end{aligned}$$

where

$$E[G_{i+1}^t(Q)] = p_i E[G_i^t(Q)] + (1-p_i) E[G_i^t(Q - z_{it})], \quad \text{for all } i, t.$$

Some caveats should be noted in interpreting the equivalency. Although we have established the equivalency between (MP2) and (MP3) and it is possible to integrate the multiple expansion plans associated with multiple demand scenerios into one — that is, the optimal solution of (MP3) — this optimal solution itself is not the optimal investment pattern ready for implementation. Only the first-period solution, which is the current-year investment decision, is meaningful for actual implementation, since the future decisions in (MP3) are only in "expected" mode rather than being contingent upon the resolved uncertainties. Thus, the following year's investment decisions for actual implementation should be postponed for another year, to be updated by reflecting resolved demand uncertainty and other changes in the planning environment.

4. Case Analysis

In this section, we apply the "horizontal" expected LDC concept to Korea's power sector planning utilizing the WASP model, a deterministic dynamic programming model with full-fledged probabilistic simulation of plant outages.

Nuclear plants currently form the bulk of Korea's expansion program. The economics of fuel oil substitution in the late 1970s favored nuclear power over coal. The nuclear program was originally conceived as a way to substitute for costly fuel imports, to increase reliability of energy supply through diversification, and to acquire a higher level of technological know-how. It has been argued, however, that the nuclear power plants planned for 1995-96 are inferior to coal-fired plants both in terms of generation costs and from

a diversification standpoint (see World Bank [18] and Korean Ministry of Energy and Resources [13]). Further, KAIST [11] indicated that a two-year delay in commitment of new nuclear plants to 1997-98 is made desirable by economic cost considerations and operational efficiency (i.e., maintaining the quality of electricity) considerations, yet would not paralyze the nuclear industry, the associated infrastructure, or the expected technology transfer.

We would now like to add a new dimension to the generation technology choice discussion by explicitly introducing demand uncertainty into planning. This uncertainty has been a major cause of the Korea's current surplus capacity of 70~80% reserve margin and, consequently, has provided impetus for the adoption of rolling planning (the annual updating of long-term expansion plans) and of the demand scenario approach (high-, reference, and low-cases).

For our analysis, we adopt the demand scenarios prepared by Korea Electric Power Company (KEPCO). Each scenario is described by a set of load duration curves of five-degree polynomials – one for each period. Probabilities of each outcome are assumed as following: a 25 percent chance for the high-demand scenario, 50 percent for the reference scenario, and 25 percent for the low-demand scenario. Using the least squares error method, the HELDC for each year has been estimated. Table 1 summarizes electrical demand for the period of 1992-1996. The last column denotes the resulting HELDC parameters. Note that the peak load of the HELDC is equivalent to that of the high-case LDC, and that the minimum load is the same as that of the low-case LDC. Consequently, the load factor associated with the HELDC is lower than those of the three deterministic scenarios. This result, of course, is due to the added uncertainty embedded in the expected load duration curve. This raises an interesting planning concept – even if an active load management program is pursued to increase the load factor, its effect on future technology-mix decisions will not be pronounced, unless the degree of future uncertainty is well controlled.

Table 1 Demand Scenarios for 1982-1996

Year	Attributes	High	Reference	Low	HELDC
1992	Energy (GWH)	103,139	99,520	94,158	99,084
	Peak Load (MW)	16,820	16,230	15,355	16,820
	Minimum Load (MW)	6,812	6,573	6,467	6,467
1993	Energy (GWH)	111,169	106,300	99,559	105,832
	Peak Load (MW)	18,129	17,335	16,236	18,129
	Minimum Load (MW)	7,343	7,021	6,839	6,839
1994	Energy (GWH)	119,778	113,413	105,123	112,931
	Peak Load (MW)	19,533	18,495	17,143	18,495
	Minimum Load (MW)	7,911	7,490	7,220	7,220
1995	Energy (GWH)	129,036	120,918	110,893	120,441
	Peak Load (MW)	21,043	19,719	18,084	21,043
	Minimum Load (MW)	8,523	7,986	7,617	7,617
1996	Energy (GWH)	139,211	128,869	116,905	128,464
	Peak Load (MW)	22,702	21,016	19,065	22,702
	Minimum Load (MW)	9,194	8,511	8,030	8,030

Remarks: High-, reference, and low-demand forecasts are taken from KEPCO [12] estimates.

As candidate plants, we adopt three types – nuclear units of 900 MW size (pressurized water reactors), coal plants of 500 MW (with flue gas desulphurization) and oil-fired plants of 500 MW. Table 2 summarizes the technology data for each plant type.

Table 2 Candidate Technology Data

Specifications	Nuclear (900 MW)	Coal-fired (500 MW)	Oil-fired (500 MW)
Construction Cost (\$/kW)	1825	1093	742
Fixed O&M (\$/kW-year)	36.72	36.72	15.72
Availability (%)	70.70	80.70	83.20
Fuel Cost (mills/kWh)	7.42	19.59	43.23
Construction Time (years)	8	5	3
Plant Life (years)	25	25	25

Sources: Korea Electric Power Co. (KEPCO [12]) estimates, 1985.

Remarks: Construction costs include the interest during construction.

A simplistic way of utilizing these load forecasts is to find an expansion plan for each demand scenario and to synthesize these somehow to come up with a single plan. This is not a trivial task, however. To overcome this difficulty, as was suggested in this work, we have derived a synthesized plan

by applying the HELDC as load inputs into the WASP model.

In running the WASP model, we assume a real discount rate of 7 percent, and the hydro and pumped storage units are taken exogenously from the recent expansion plan of KEPCO. Table 3 summarizes the optimal expansion plans obtained from the WASP runs using three demand scenarios and the "horizontal" expected LDCs. It is noted that three expansion plans for high-, reference, and low-demand scenarios are markedly different from each other, except in that none of the three cases show any nuclear plants during 1992-94, due to the eight-year construction lead times (those under construction now are all scheduled to come on line by 1989). Considering construction lead times (8 years for nuclear units and 5 years for coal units), the current-year investment decision (as of 1987) implied by Table 3 involves 1 coal unit and 1 nuclear unit for the low-demand case (1,400 MW), 3 coal units and 2 nuclear units for the reference case (3,300 MW), and 5 coal units and 2 nuclear units for the high-demand case (4,300 MW). The HELDC approach, by contrast, suggests construction of 5 coal units and 1 nuclear unit (3,400 MW). Conventionally, the investment decision follows that of the reference case without due consideration of demand uncertainty -- that is, in this case, 3 coal and 2 nuclear plants totalling 3,300 MW. But by incorporating demand uncertainty as suggested in this paper, the expected-cost-minimizing investment decision becomes 5 coal and 1 nuclear units. Comparing these two options, we notice that the total capacities to be constructed are about the same (3,300 MW vs. 3,400 MW), but the technology mix is different. In other words, the demand uncertainty consideration favors two coal units in place of one nuclear unit. This confirms the common-sense belief that the plant with higher initial investment but lower operating costs is less favorable under uncertainty.

Table 3 Optimal Solution of WASP Run

Year	Unit: Number of New Units							
	Low		Reference		High		HELDC	
	C500	N900	C500	N900	C500	N900	C500	N900
1992	1	0	3	0	5	0	5	0
1993	2	0	3	0	4	0	4	0
1994	3	0	4	0	4	0	4	0
1995	1	1	0	2	0	2	2	1
1996	1	1	1	1	4	2	2	1

The introduction of new nuclear plants during 1995-1996 suggested by HELDC is, as expected, compatible with that of the low-demand case, but it

is lower by one unit than that of the reference case and two units lower than that of high-case. In other words, taking demand uncertainty into account reduces the new nuclear capacity by one or two units as a safeguard against uncertain demand outcomes. Thus, under demand uncertainty the baseload facility decision is largely governed by the low-demand case, while the peak capacity is mostly by the high-demand case (the peaking unit additions did not appear in Table 3, since Korea maintains sufficient oil plant capacity during the course of moving away from oil). This observation suggests a simple rule of thumb: under demand uncertainty decisions about the baseload units such as nuclear plants should be conservative, and, more specifically, should follow the low-demand case.

5. Conclusion and Summary

Many oil-importing industrializing countries like Korea are devoting increasing attention to uncertainty handling in power sector expansion planning. In Korea, the nation's capacity expansion plan is updated annually, and it has been suggested that planners adopt a simple method of using "expected" loads within the existing planning framework. This paper has justified this approach and also shown it to be an extension of some previous works of similar nature. It was shown that the optimal expansion planning under demand uncertainty can be well handled by the deterministic problem using the "horizontal" expected LDCs as inputs. In particular, the first-period solution guarantees compatibility with the expected-cost minimization. Thus, even to account for demand uncertainty, neither major changes in planning procedure (other than estimating the HELDCs) nor methodology changes (from existing ones) are required.

To illustrate our approach, Korea's expansion planning was analyzed using the WASP model, Korea Electric Power Company data, and the HELDC concept. It turns out that the presence of demand uncertainty makes it desirable to replace one nuclear unit of 900 MW with two coal units of 500 MW each as a safeguard against overinvestment. This method also suggests that baseload units such as nuclear reactors should be built conservatively, based on low-demand forecasts.

References

- [1] Anderson, D.: "Models for Determining Least-Cost Investments in Electricity Supply," *The Bell Journal of Economics and Management Science*, Vol.3 (1972), pp.267-299.
- [2] Bloom, J. A.: "Solving an Electricity Generating Capacity Expansion Planning Problem by Generalized Benders' Decomposition," *Operations Research*, Vol.31 (1983), pp.84-100.
- [3] Booth, R. R.: "Optimal Generation Planning Considering Uncertainty," *IEEE Transactions on Power Apparatus and Systems*, Vol.PAS-91 (1972), pp.71-77.
- [4] Borison, A. B.: Optimal Electric Utility Generation Expansion Under Uncertainty, Ph.D. dissertation, Department of Engineering-Economics Systems, Stanford University, 1982.
- [5] Borison, A. B. and Morris, P. A.: "An Efficient Approach to The Optimal Static Generation Mix Problem," *IEEE Transactions on Power Apparatus and Systems*, Vol.PAS-103 (1984), pp.576-580.
- [6] Borison, A. B., Morris, P. A. and Oren, S. S.: "A State-of-the World Decomposition and Uncertainty in Electric Utility Generation Expansion Planning," *Operations Research*, Vol.32 (1984), pp.1052-1068.
- [7] Cazalet, E. G., Clark, C. E. and Keelin, T. W.: Costs and Benefits of Over/Under Capacity in Electric Power System Planning, Decision Focus, Inc. (EPRI Report EA-927), 1978.
- [8] Dapkus, W. D. and Bowe, T. R.: "Planning for New Electric Generation Technologies: A Stochastic Dynamic Programming Approach," *IEEE Transactions on Power Apparatus and Systems*, Vol.PAS-103 (1984), pp.1447-1453.
- [9] Henault, P. H., Eastvedt, R. B., Peschon, J. and Hajdu, L. P.: "Power System Long-Term Planning in the Presence of Uncertainty," *IEEE Transactions on Power Apparatus and Systems*, Vol.PAS-80 (1970), pp.156-164.
- [10] Jenkins, R. T. and Joy, D. S.: Wien Automatic System Planning Package (WASP) - An Electric Utility Optimal Generation Expansion Planning Computer Code, Oak Ridge National Laboratory, Report ORNL-4945, 1974.
- [11] Korea Advanced Institute of Science and Technology, Comparative Evaluation of Nuclear and Coal-Fired Power Plants, Report No.KRC-84E-T10, 1986, (in Korean).
- [12] Korea Electric Power Company, Data for Generation Expansion Planning, 1986, (in Korean).
- [13] Korea Ministry of Energy and Resources, Long-Term Electric Generation Expansion Plan, 1986, (in Korean).

- [14] Louveaux, F. V. and Smeers, Y.: A Stochastic Model for Electricity Generation, Facultes Universitaires Notre-Dame de la Paix, 1979.
- [15] Mangasarian, O.L.: "Nonlinear Programming Problems with Stochastic Objective Functions," *Management Science*, Vol.10 (1964), pp.353-359.
- [16] Murphy, F. H., Sen, S. and Soyster, A. L.: "Electric Utility Capacity Expansion Planning with Uncertain Load Forecasts," *AIIE Transactions*, Vol.14 (1982), pp.52-59.
- [17] Stremel, J. P.: "Generation System Planning Under Load Forecast Uncertainty," *IEEE Transactions on Power Apparatus and Systems*, Vol.PAS-101 (1980), pp.284-393.
- [18] World Bank, Republic of Korea Energy Sector Issues, Report No.5307-KO, 1984.
- [19] Ziemba, W. T.: "Transforming Stochastic Dynamic Programming Problems into Nonlinear Programs," *Management Science*, Vol.17 (1971), pp.450-462.

Byong-Hun AHN: Department of Manage-
ment Science, Korea Advanced Institute
of Science and Technology
P.O. Box 150 Cheongryang, Seoul
Korea