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ORIGINAL ARTICLE

Essential aspects of power system planning in developing countries

Abdullah M. Al-Shaalan

Electrical Engineering Department, College of Engineering, King Saud University, P.O. Box 800, Riyadh 11421, Saudi Arabia

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Abstract In developing countries, power system planning faces enormous challenges and problems as, for example, future load growth in the face of uncertainties, the constraints imposed on investment, the type and availability of fuel for the generating units, the need for consolidating the dispersed electric utilities in the isolated regions as a prerequisite for future interconnecting these regions via local national grids and with other neighboring countries. Also, how an optimal reliability level can be achieved that will guarantee a continuous power flow with a reasonable costs. All these obstacles made power systems planners and concerned agencies face tremendous difficulties in planning electric power facilities and making sound and appropriate decisions in constructing new power plants or adding new generating units or reinforcing the transmission and distribution networks. The proposed work attempts to display the most tedious and prominent problems and challenges that face the electric power systems in developing countries and influence the decision-making process which must be based on two major factors, namely, reliability and cost.

1. Introduction

Planning for power systems is essentially a projection of how the system should grow over a specific period of time, given certain assumptions and judgment about the future loads and the size of investment in generating capacity additions and transmission facilities expansion and reinforcements.

Any plan can become technically and economically obsolete. New inventions in electrical utilization equipment or unforeseen industrial, commercial or residential projects can change load forecast. Breakthroughs in new generation and transmission technologies, unexpected inflation in equipment or labor costs or change of national income can all mean that system plans may take another direction.

In developing countries, power system planning has become more difficult, but more important to provide the necessary information to enable decision to be made today about many years in the future. In almost all cases, planning must be done in the face of many uncertainties, for example: future load patterns, population increase and the economic growth which characterize the developing countries, as well as technical,

E-mail address: shaalan@ksu.edu.sa

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economical and environmental constraints (Schramm, 2006; Wilbanks, 2006).

The main issue regarding power system planning in developing countries is to establish basic principles and guidelines to serve as a framework within which the process of planning may proceed (Sullivan, 1977). This framework should be flexible, not rigid with broad objectives of finding a plan (or plans) which guarantees a desired degree of a continuous, reliable and least cost service. Good service or, in other words, acceptable reliability level of power system usually requires additions of more generating capacity to meet the expected increase in future electrical demands. However, in many developing countries with vast, separately populated areas reliability–cost tradeoffs exist between satisfying the fast load growth by investment in additional generating capacity for isolated systems or building transmission networks to interconnect these systems and transfer power between their load centers in case of emergencies and power shortages. Therefore, reliability and cost constraints are major considerations in power system planning process (Stoll, 2007; Sullivan, 1977).

2. Reliability evaluation techniques

Reliability is one of the most important criteria which must be taken into consideration during all phases of power system planning, design and operation. Reliability criterion is required to establish target reliability levels and to consistently analyze and compare the future reliability levels with feasible alternative expansion plans. This need has resulted in the development of comprehensive reliability evaluation and modeling techniques (Billinton and Allan, 1988; Munasinghe, 1979; Wang et al., 2002).

One capacity related reliability index, known as the loss of load expectation (LOLE) method, is presently considered as the most common adopted probabilistic index in system generation expansion planning. This method computes the expected number of days per year on which the available generating capacity is not sufficient to meet all the period load levels and can be evaluated as:

$$\mathrm{LOLE} = \sum_{k=1}^{n} t_k \cdot p(O_k)\ \frac{\text{days}}{\text{year}} \tag{1}$$

where $p(O_k)$ is the probability of loss of load due to the kth severe outage of size O_k; t_k is the time duration of that severe outage O_k will take; n is the total number of severe outages occurred during that period considered.

Any outage of generating capacity exceeding the reserve will result in a curtailment of system power. Therefore, another power related reliability index, known as the expected power not served ε(ENS), is also used to complement the LOLE index, and can be defined as:

$$\varepsilon(\mathrm{ENS}) = \sum_{k=1}^{n} (\mathrm{ENS})_k \cdot p(O_k)\ \frac{\text{MWh}}{\text{year}} \tag{2}$$

where $(\mathrm{ENS})_k$ is the energy not served due to severe kth outage of size O.

3. Costs evaluation techniques

There are several different costs associated with power systems. These include:

3.1. Fixed cost

The fixed cost, FC, represents the cash flow at any stage of the planning horizon resulting from the costs of installing new generating units during the planning period. It depends on the current financial status of the utility, the type and size of generating units and the cost of time on money invested during the planning period. The total fixed costs for unit(s) can be computed as:

$$\mathrm{FC}_T = \sum_t \sum_k (\mathrm{CPKW})_k \cdot N_k \cdot \left(\frac{1+f}{1+i}\right)^t \tag{3}$$

where $(\mathrm{CPKW})_k$ is the cost per kilowatt capacity of unit of type k; N_k is the number of units of type k to be added to the system during interval of time t; f and i are inflation and interest rates, respectively.

3.2. Fixed operation and maintenance cost

The fixed operation and maintenance cost, FOMC, accounts for the cost of system operation, maintenance, repair, staffing and miscellaneous expenses associated with the type and size of the generating unit. These costs can be computed as:

$$\mathrm{FOMC}_T = \sum_t \sum_k (\mathrm{FOMC})_k \cdot N_k \cdot \left(\frac{1+f}{1+i}\right)^t \tag{4}$$

where $(\mathrm{FOMC})_k$ is the operation and maintenance cost of unit of type k.

3.3. Variable cost

The variable cost, VC, represents the cost of power served by the system. It is affected by the load variation, the type and size of generating units and the number of hours of operation. The total cost associated with power produced by all the units residing in the system is given by:

$$\mathrm{VC}_T = \sum_t \sum_k \varepsilon(\mathrm{ES})_k \cdot \varepsilon(\mathrm{ESC})_k \cdot N_k \cdot \left(\frac{1+f}{1+i}\right)^t \tag{5}$$

where $\varepsilon(\mathrm{ES})_k$ is the expected energy served by unit of type k; $\varepsilon(\mathrm{ESC})_k$ is the expected energy served cost of unit of type k.

The total system costs can be estimated by summing all the above individual costs at every stage of the planning period as expressed in the following equation:

$$\mathrm{SC}_T = \mathrm{FC}_T + \mathrm{FOMC}_T + \mathrm{VC}_T \tag{6}$$

3.4. Outages cost

In power system cost-benefit analysis, the outages cost (OC) forms a major part in the total system cost. These costs are associated with the power demanded but cannot be served by the system due to severe outages and is known as the expected power not served, ε(ENS) has been mentioned in Section 2). Outages cost will be borne by the utility and its customers. The utility outages cost includes loss of revenue, loss of goodwill, loss of future sales and increased maintenance and repair expenditure. However, the utility losses are small compared to the losses incurred by the customers when power interruptions occur. The customers perceive the power interruptions differently. A residential consumer may suffer a great deal of anxiety and inconvenience if an outage occurs during a hot summer day or deprives him from domestic activities and causes food spoilage. For a commercial user, he will also suffer a great hardship and loss of being forced to close until power is restored. Also, an outage may cause a great damage to an industrial customer if it occurs and disrupts the production process (Billinton and Wacker, 2007; Choi and Watada, 2007; Hamachi and Eto, 2006; Helseth and Holen, 2008; Wang, 2008; Ketkaew et al., 2008).

One method of evaluating the ε(ENS) is described in (Munasinghe, 1979). Therefore, for estimating the outages cost, OC, is to multiply the value of ε(ENS) by an appropriate outage cost rate (OCR), as follows:

$$\mathrm{OC}_T = \sum_t \varepsilon(\mathrm{ENS}) \cdot \mathrm{OCR}\left(\frac{1+f}{1+i}\right)^t \tag{7}$$

The total cost of supplying the electric power to the consumers is the sum of system cost that will generally increase as consumers are provided with higher reliability and customer outages cost that will, however, decrease as the reliability increases. This total system cost (TSC) can be expressed in the following equation:

$$\mathrm{TSC}_T = \mathrm{SC}_T + \mathrm{OC}_T \tag{8}$$

The prominent aspect of outage cost estimation, as noticed in the above equation, is to assess the worth of power system reliability and to compare it with the cost of system reinforcement in order to establish the appropriate system reliability level that ensures both power continuity and the least cost of its production (Lassila and Partanen, 2005; Lawton et al., 2006; Lineweber and McNulty, 2007).

4. Models developed for the reliability and cost evaluation used in this study

To perform the computation and analysis of this study, a computer program containing three basic models has been developed at the King Saud University and is available on request. These models, shown in Fig. 1, assess the requirements of developing power systems in order to satisfy specified reliability and economic criteria and they are briefly described as follows:

1. *CAPREL* model: Evaluates system reliability levels (LOLE) at every stage of the planning horizon and estimates the required capacity additions in case that reliability levels fall below the prescribed risk limit. The units in this model are characterized by their capacity and forced outage rates. The load models used are the daily load variation curve required for evaluating the LOLE index and the load duration curve required for power computation.
2. *INTERTIE* model: Evaluates system reliability levels (LOLE) for systems after being interconnected. This model is based on the two-array capacity outage probability method.
3. *SYSCOS* model: Evaluates system ε(ES) and ENS also estimates the fixed, variable, and outages costs.

5. Case study

The previous techniques have been applied to a particular problem in a developing country. This case study is based on two hypothetical systems (A and B) supposed to be serving a major populated community with potential future load growth. The study considers that uncertainty is a vital aspect of power systems planning in developing countries. Thus, the analysis procedure generally involves identifying the potential uncertain events and assigning a probability to the event. The impacts may then be probability-weighted, and a composite system impact value can be computed. This process may be repeated by examining alternative or contingency plans.

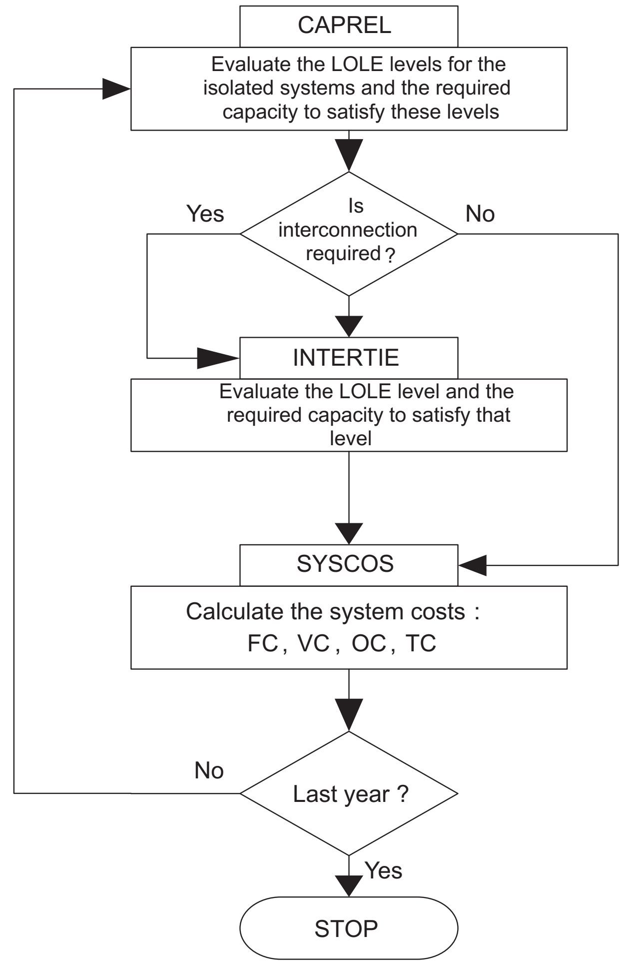

Figure 1 Flowchart for the proposed planning approach.

6. Isolated and interconnected power systems

Most power systems have interconnections with neighboring systems. The interconnection reduces the amount of generating capacity required to be installed as compared with that which would be required without the interconnection. The amount of such reduction depends on the amount of assistance that a system can get, the transfer capability of the tie-line and the availability of excess capacity reserve in the assisting systems.

One objective reported in this paper is to evaluate the reliability benefits associated with the interconnection of systems. Therefore, the study is focused on reliability evaluation of two systems both as isolated systems and as interconnected systems. Analysis of this type explores the benefits that may accrue from interconnecting systems rather being isolated as

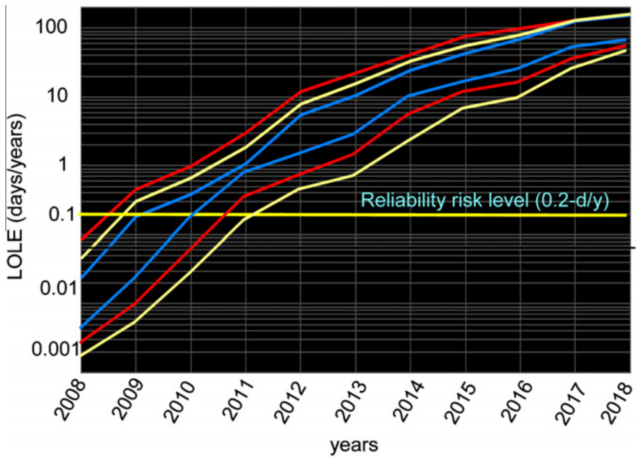

Figure 2 Variations of LOLE before and after interconnection.

well as deciding viable generation expansion plans (Munasinghe, 1979).

A 10-year expansion plan for systems A and B (data for both systems are given in Appendix A) assuming a reliability criterion of 0.2 days/year (0.1–0.6 frequently quoted as appropriate values) was determined. The analysis represents the expansion plans for both systems as being isolated and interconnected. An outcome of these expansion plans is shown in Fig. 2.

If the two systems are reinforced whenever the reliability index falls below the prescribed level (i.e. LOLE = 0.2 days/year) at any year of the planning horizon, the results shown in Table 1 exhibit that the number of units and the PV cost are reduced if the two systems are interconnected rather than being isolated.

Therefore, it can be concluded from the above analysis that both systems will benefit from the interconnection. The reliability of both systems can be improved and consequently the cost of service is reduced through interconnection and reserve sharing. However, this is not the overall saving because the systems must be linked together in order to create an integrated system. The next stage must, therefore, assess the economic worth that may result from either interconnection or increasing generating capacity individually and independently.

7. Loads growth uncertainty

Future loads growth is one of the key forecast parameters that is subject to uncertainty. Load growth is influenced by many factors including the national economy, income per capita, power management, prices, policies and conservation. Therefore, changes in these factors may imply that the actual margins may turn out to be higher or lower than planned scenario and are likely to affect the system reliability criteria and consequently to influence the capacity planning decisions. The uncertainty in load forecasting can be included in the risk analysis by dividing the load forecast probability distribution into class intervals. The area of each class interval represents the probability of the load being the class interval mean. The risk is computed for each load represented by the class interval and weighted by the probability that this load exists. The sum of these products represents the risk for the forecast load. To investigate the impact of load forecast uncertainty on the planning outcome of system A, the forecasted peak load was assumed to be 350 MW, with uncertainty normally distributed using a seven step approximation (Billinton and Allan, 1988). The discredited peak load levels with a standard deviation of 6% load are shown in Table 2.

Table 2 Data for load forecast uncertainty.

Standard deviation from the mean	Load levels (MW)	Probability
0.006	−3	287
0.061	−2	308
0.242	−1	329
0.382	0	350
0.242	1	371
0.061	2	392
0.006	3	413

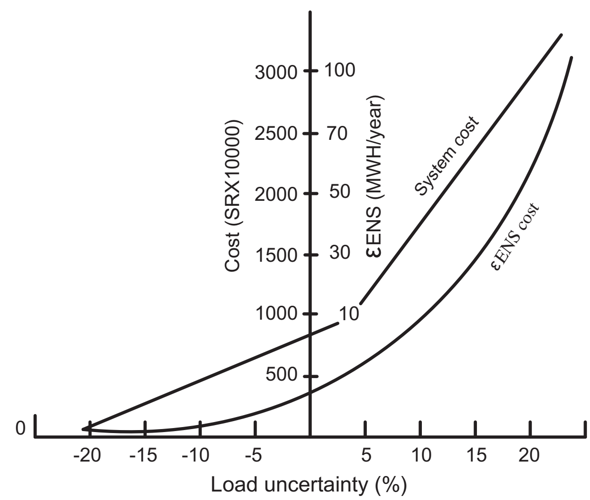

Figure 3 Effects of load uncertainty on system.

The results of this study as shown in Fig. 3 reveal that costs for system A (fixed and variable costs) increase with load. The reason is that costs increase with load owing to more additional units being operated and for longer periods.

8. Cost and expected energy not served ε(ENS)

The total cost of power supply to consumers is critically dependent on the cost assigned to the ENS. The effect of the ENS

Table 1 PV costs (MSR) for isolated and interconnected systems.

System	Isolated			Interconnected		
	No. of units	Cost (MSR)	ENS (MWH)	No. of units	Cost (MSR)	ENS (MWH)
A	4	45.62	5.652	2	35.44	1.054
B	2	63.42	4.852	1	31.75	2.045

Table 3 PV system costs (MSR) timely (deferred) installation time.

Year	Unit added	SC (MSR)	OC (MSR)
1	0 (0)	00 (00)	2.2 (2.2)
2	0 (0)	00 (00)	4.4 (4.4)
3	1 (0)	44 (00)	3.2 (6.8)
4	0 (1)	00 (38)	5.3 (4.3)
5	1 (0)	31 (00)	4.9 (7.4)
Total		75 (38)	20.0 (25.1)

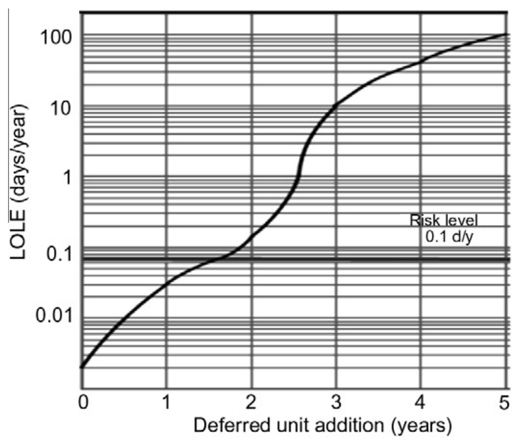

Figure 4 Effect of deferred unit addition upon system reliability level.

variation with load uncertainty is tested and the results are shown also in Fig. 3 which reveals that the ENS increases with increasing loads which implies reduction in the prescribed reliability level and hence requires more investment and operation costs.

9. Uncertainty in unit installation time

In developing countries, deferring (postponing) unit installation time, due to unexpected economic conditions, is probable and must be considered in the planning process. A summary of 5-year expansion plan results, which indicates the effect of 1 year postponement in installation time on system A expansion plans, is shown in Table 3.

It is seen from the above table that if the installation date of a unit which should be installed in a specific future year is deferred (between the brackets) until the next year, the PV system cost decreases because of payment postponement but the PV outage cost increases due to the deterioration of system reliability level. It is seen that capacity deferments have a considerable effect on reliability (see Fig. 4).

This increase in system risk explains the rise in outage costs resulting from postponing unit installation. If more uncertainties in installation time are assumed, results depicted by Fig. 5 show that, as unit deferring is increased, the outages cost increases rapidly but that the system cost steadily decreases. On the contrary, the timely installation has less effect on the outage costs than in the deferred case. Consequently, incentives should exist to justify decisions upon deferring or complying with the scheduled time of unit addition. One reason could be that it would be catastrophic if unit installation is postponed for longer periods as shown in Fig. 5.

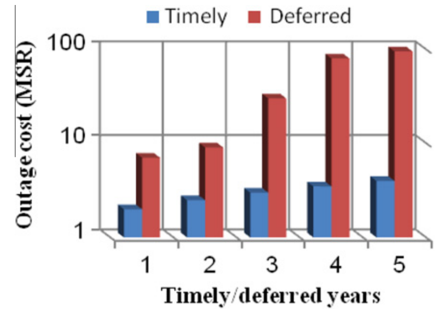

Figure 5 Impact of timely/deferred unit installation on outage cost.

10. Conclusions

In this paper, two major constraints associated with power planning process, namely, reliability and cost have been modeled and applied to particular systems expansion planning in a developing country. The results demonstrate the benefits and merits associated with both reliability and cost of interconnecting isolated systems into an integrated system. The uncertainly in future loads growth and unit installation time can be costly and undesirable. Therefore, their effects should be anticipated and studied in order to mitigate their effects so that possible deterioration in system reliability levels as well as unnecessary additional expenditure can be averted.

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Appendix A. Studied systems data

A.1. System A

Number of generating units = 9
Rated unit capacity = 50 MW
Availability = 0.90 (FOR = 0.10)
Maximum load = 350 MW
Minimum load = 160 MW
Load growth = 11.5% (over the next 10 years)
Cost per kW capacity (CPKW) = SR 2505/kW
O&M cost per kW (OMC) = SR 20/kW/year
Power production cost (EPC) = SR 70/MWh

A.2. System B

Number of generating units = 7
Rated unit capacity = 40 MW
Availability = 0.92 (FOR = 0.08)
Maximum load = 200 MW
Minimum load = 120 MW
Load growth = 9.5% (over the next 10 years)
Cost per kW capacity (CPKW) = SR 2310/kW
O&M cost per kW (OMC) = SR 18/kW/year

Power production cost (EPC) = SR 50/MWh
Outage charge rate (OCR) = 5 SR/kWh

A.3. Intertie capacity (double circuit) data

Voltage (kV)	Rating (MW)	Length (km)	Availability (%)
132	65	188	100

A.4. Outage charge rate (OCR)

OCR = SR 7.5/kWh

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