

CHAPTER 1

INTRODUCTION

1.1 RISK IN POWER SYSTEMS

There is considerable overlap in the words “risk” and “reliability.” In this book, it is assumed that the two words have the identical implication. They are the two facets of the same fact. Higher risk means lower reliability, and vice versa. Risk management has a wide-ranging content. The intent of the book is to discuss the models, methods, and applications of risk assessment in physical power systems. Risks associated with business, finance, and life safety are not included in the discussion.

The probabilistic behavior of power systems is the root origin of risk. Random failures of system equipment are generally outside the control of power system personnel. Loads always have uncertainties and it is impossible to obtain an exact load forecast. Energy exports and imports under the deregulation environment depend on the volatile power market. Consequences of power failures range from electricity interruptions in local areas to a possible widespread blackout. Economic impacts due to supply interruptions are not restricted to loss of revenue by the utility or loss of energy utilization by the customer but include indirect costs imposed on society and the environment. Risk assessment has become a challenge and an essential commitment in the power utility industry today.

Risk management includes at least the following three tasks:

1. Performing quantitative risk evaluation
2. Determining measures to reduce risk
3. Justifying an acceptable risk level

The purpose of quantitative evaluation is to create the indices representing system risk. A dictionary definition of risk is “the probability of loss or damage to hu-

man beings or assets.” This definition can be used in general cases. However, a comprehensive risk index should not contain only the probability but a combination of probability and consequence. In other words, the risk evaluation of power systems should recognize not only the likelihood of failure events but also the severity and degree of their consequences. Utilities have dealt with system risks for a long time. The criteria and methods first used in practical applications were all deterministically based, such as the percentage reserve in generation capacity planning and the single-contingency principle in transmission planning. The deterministic criteria have served the power industry for years. The basic weakness is that they do not respond to the probabilistic nature of power system behavior, load variation, and component failures.

A measure to reduce system risk is generally associated with enhancement of the system. In order to determine a rational measure, both the impact of the measure on risk reduction and the cost needed to implement it should be quantified. A probabilistic economic analysis is usually required. In risk management, an important concept to be appreciated is that zero risk can never be reached since random failure events are uncontrollable. In many cases, a decision has to be made to accept a risk as long as it can be technically and financially justified. Selecting a rational measure to reduce risks or accepting a risk level is a decision-making process. It should be recognized that on the one hand, quantitative risk evaluation is the basis of this process, and on the other hand, the process is more than risk evaluation and requires technical, economic, societal, and environmental assessments.

The risk assessment of power systems can be applied to all the areas in electric power utilities, including:

- Quantified reliability evaluation in generation, transmission, and distribution systems
- Probabilistic criteria in system planning and operation
- Compromise between the system risk and the economic benefit in a decision-making process
- Equipment aging failure management
- Spare equipment strategy
- Reliability-centered maintenance
- Load-side risk management
- Performance-based rate policy
- Operation-risk monitoring
- Interruption damage cost assessment

Risk management and quantified risk assessment have become ever-increasingly important since the power industry entered the deregulation era. The new competition environment forces utilities to plan and operate their systems closer to the limit. The stressed operation conditions have led to deterioration in system reliability. In fact, a lot of power-outage events have occurred across the world in the past

years. According to an EPRI (Electric Power Research Institute) report based on the national survey in all business sectors, the U.S. economy alone is losing between \$104 and \$164 billion a year due to power system outages [83]. Severe power outage events have happened frequently in recent years. For instance, a major system disturbance separated the Western Electricity Coordinating Council (WECC) system in the west of North America into four islands on August 10, 1996, interrupting electricity service to 7.5 million customers for a period of up to nine hours. The 1998 blackout at the Auckland central business district in New Zealand impacted 30 square blocks of the downtown area for about two months, resulting in lawsuits totaling \$600 million against the utility. On August 14, 2003, the massive blackout in the east of North America covered eight states in the United States and two provinces in Canada, bringing about 50 million people into darkness for periods ranging from one to several days. These severe power outages let us realize that the single-contingency criterion (the N-1 principle) that has been used for many years in the power industry may not be sufficient to preserve a reasonable system reliability level. However, it is also commonly recognized that no utility can financially justify the N-2 or N-3 principle in power system planning. Obviously, one alternative is to bring risk management into the practice in planning, design, operation, and maintenance, keeping system risk within an acceptable range. On the other hand, the customers of the power industry have become more and more knowledgeable about electric power systems. They understand that it is impossible to expect 100% continuity in the power supply without any risk of outages. However, they have the right to know the risk level, including information on how often, for how long, and how severely a power interruption event can happen to them on the average. To answer this question is one of the objectives of power system risk assessment.

1.2 BASIC CONCEPTS OF POWER SYSTEM RISK ASSESSMENT

1.2.1 System Risk Evaluation

Power system risk evaluation is generally associated with the following four tasks:

1. Determining component outage models
2. Selecting system states and calculating their probabilities
3. Evaluating the consequences of selected system states
4. Calculating the risk indices

A power system consists of many components, including generators, transmission lines, cables, transformers, breakers, switches, and a variety of reactive power source equipment. Component outages are the root cause of a system failure state. The first task in system risk evaluation is to determine component outage models. Component failures are classed into two categories: independent and dependent outages. Each category can be further classified according to the outage modes. In most cases, only repairable forced outages are considered, whereas in some cases,

planned outages are also modeled. Aging failures have not been incorporated into the traditional risk evaluation. This book presents a modeling approach to aging failures and demonstrates examples of its application.

The second task is to select system failure states and calculate their probabilities. There are two basic methods for selecting a system state: state enumeration and Monte Carlo simulation. Both methods have merits and demerits. In general, if complex operating conditions are not considered and/or the failure probabilities of components are quite small, the state enumeration techniques are more efficient. When complex operating conditions are involved and/or the number of severe events is relatively large, Monte Carlo methods are often preferable.

The third task is to perform the analysis for system failure states and assess their consequences. Depending on the system under study, the analysis could be associated with the simple power balance, or the connectivity identification of a network configuration, or the complex calculation process, including the power flow, optimal power flow, or even transient and voltage-stability evaluation.

As mentioned earlier, risk is a combination of probability and consequence. With the information obtained in the second and third tasks, an index that truly represents system risk can be created. There are many possible risk indices for different purposes. Most of them are basically the expected value of a random variable, although a probability distribution can be calculated in some cases. It is important to appreciate that the expected value is not a deterministic parameter. It is the long-run average of the phenomenon under study. The expected indices serve as the risk indicators that reflect various factors, including component capacities and outages, load profiles and forecast uncertainties, system configurations and operational conditions, and so on.

According to system state analysis, power system risk assessment can be divided into two basic aspects: system adequacy and system security. Adequacy relates to the existence of sufficient facilities within the system to satisfy consumer load demand and system operational constraints. Adequacy is therefore associated with the static conditions that do not include system dynamic and transient processes. Security relates to the ability of the system to respond to dynamic and transient disturbances arising within the system. Security is therefore associated with the response of the system to whatever perturbations it is subject to. Normally, security evaluation requires the analysis of dynamic, transient, or voltage stability in the system. It should be pointed out that most of the risk evaluation techniques that have been used in the actual applications of utilities are in the domain of adequacy assessment. Some ideas for security assessment have been addressed recently. However, the practical application in this area is limited. Another fact is that most of the risk indices used in risk evaluation are inadequacy indices, not overall risk indices. The system indices that are based on historical outage statistics encompass the effect of both inadequacy and insecurity. It is important to recognize this fundamental difference in actual engineering applications.

A power system includes the three fundamental functions of generation, transmission (including substation), and distribution. Traditionally, the three functional zones are included in one utility. As reform in the power industry proceeds, the

three functional zones have been gradually separated to form organizationally independent generation, transmission, and distribution companies in many countries. In either case, risk assessment can be, and is, conducted in each of these functional zones. The risk evaluation for an overall system, including generation, transmission, and distribution, is impractical because such a system is too enormous to handle in terms of the existing computing capacity and accuracy requirements. On the one hand, the calculation modeling and algorithms are quite different for the risk evaluation of a generation, transmission, substation, distribution system. On the other hand, many techniques have been successfully developed to perform the risk evaluation for composite generation and transmission systems or composite transmission and substation systems. In the case of a large-scale transmission system, it is reasonable to limit the study to an area or subsystem. Doing so can provide more realistic results than evaluating the whole system. This is due to the fact that a change or reinforcement in the network may considerably affect a local area but have little impact on remote parts of the system. The contribution to the overall reliability of a large system due to a local line addition or reconfiguration may be so small that it is masked by computational errors and, consequently, cannot be reflected in the risk change of the whole system. This contribution, however, can be a relatively large portion of the risk change in the local area.

Generally, it is necessary to assess the relative benefits of different alternatives, including the option of doing nothing. The level of analysis need not be any more complex than that which enables the relative merits to be assessed. The ability to include a high degree of precision in calculations should never override the inherent uncertainty in the data. An absolute risk index, although an ideal objective, is virtually impossible to evaluate. This does not weaken the necessity to objectively assess the relative merits of alternative schemes. This is an important point to be appreciated in power system risk evaluation.

1.2.2 Data in Risk Evaluation

The reliability data required in power system risk evaluation are the parameters of component outage models. They are basically calculated from historical statistics, although an engineering judgment based on individual equipment assessments is also used in some special cases. Collecting suitable data is at least as essential as developing risk evaluation methods.

The data requirements should reflect the need for risk assessments. The data must be sufficiently comprehensive to ensure that an evaluation method can be applied, but restrictive enough to ensure that unnecessary data are not collected. For the simple models, the data relates to the two main processes of component behavior, namely, the failure process and the restoration process. For more complex models, the data are associated with the transition rates between various states.

The quality of data is an important factor to consider in data collection. The usual saying of “garbage in and garbage out” refers to the fact that if the quality of data cannot be guaranteed, the results of risk evaluation will not make any sense. Outage statistics constitute a huge data pool and some bad or invalid records cannot be ful-

ly avoided in any database. Data processing is necessary to filter out bad data. A parameter estimation procedure is needed to acquire the input data of risk evaluation from raw statistics. This requires the suitable design of statistical data modeling.

Another characteristic of reliability data is its dynamic feature. The volume of outage records will increase with the time and, therefore, the average failure frequency and repair time for a piece of equipment or an equipment group will change from year to year. The reliability database should have a means of continuous updating and should be also flexible enough to output reports in a variety of formats. Figure 1.1 is an example of reliability data collection system. The abbreviation SETR in the figure stands for system equipment trouble report.

1.2.3 Unit Interruption Cost [71]

The basic function of a modern electric power system is to provide electric energy to its customers at the lowest possible cost and at an acceptable risk level. There is a conflict between economy and risk. Risk-cost evaluation is an appropriate approach to putting risk and economic factors on a unified scale of monetary value.

The risk cost can be evaluated using a unit energy interruption cost times the expected energy not supplied. However, quantification of the interruption cost is complex and immature. The customer damage functions that are based on customer surveys have been presented for years. Although this method is applied in risk evaluation, there have been a lot of debates about its use. One typical viewpoint is that the customer damage functions do not represent utility damages and it is inappropriate to use them to balance the capital investment of a utility. The opposite argument is that customers eventually pay all costs through rates and, thus, the customer's interruption cost should be considered in utility system planning. This is a complicated issue that relies on many nontechnical aspects, including regulation or deregulation, ownership, and rate design.

The following three methods of evaluating the unit interruption cost are discussed here. Different utilities may select a different method in their practice and studies.

1. Method based on customer damage functions. A customer damage function is obtained from customer surveys and the relevant statistical analysis. Based on a wide investigation of utility companies across Canada, for instance, the average unit interruption cost is between \$4/KWh and \$10/KWh. This is the average social damage cost due to electricity supply interruptions. It is important to recognize that the unit interruption cost is region-, country-, and system-specific. A utility should use the unit interruption cost that is based on its own customer survey and system analysis. This method has general implications and is particularly well suited to the utility with a customer-focused strategy.
2. Method based on capital investments. For a utility, any capital investment to reinforce the power system brings about an incremental decrease in system

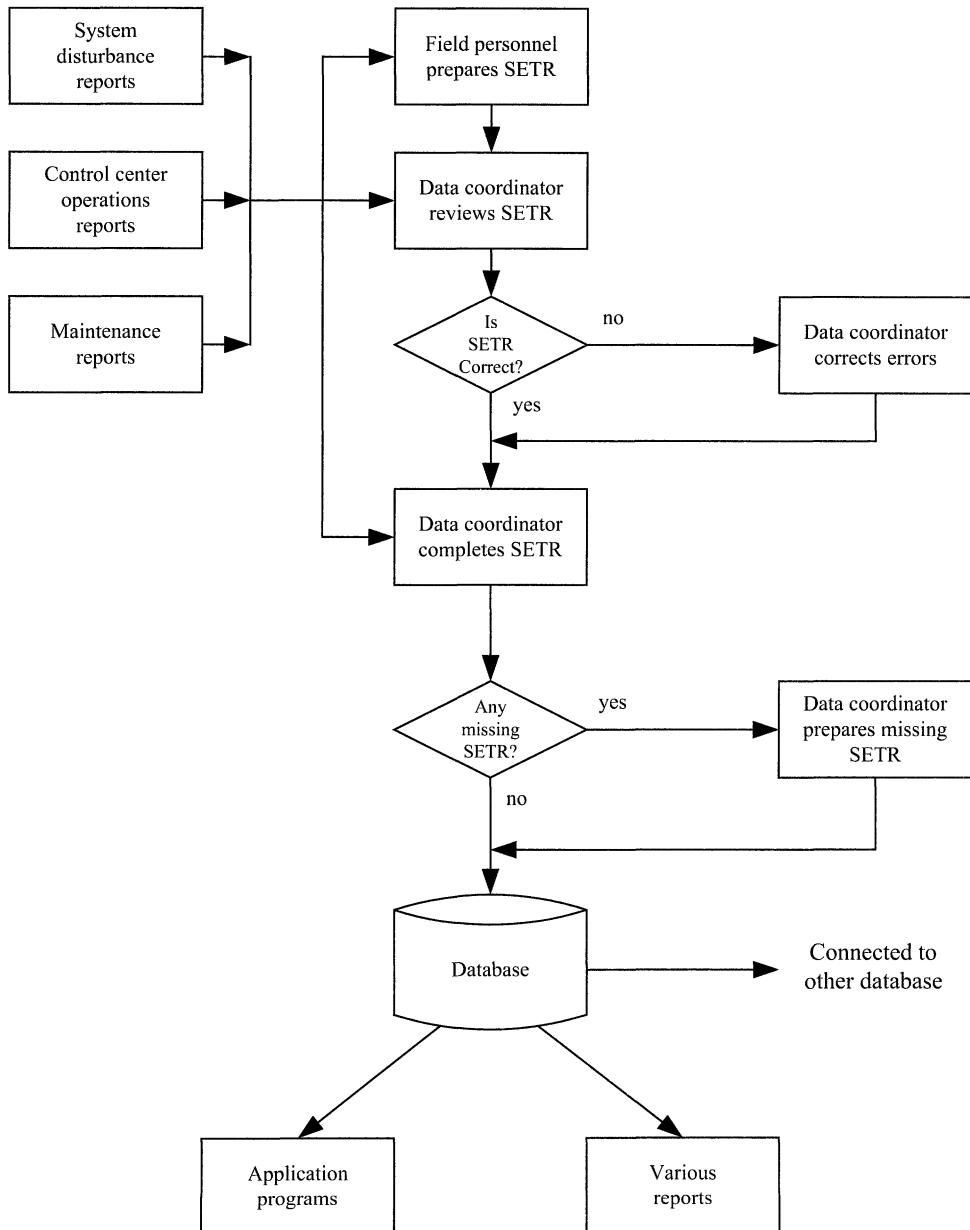


Figure 1.1 Reliability data collection system.

risk. In other words, there is a quantifiable relationship between the capital investment and the system risk index. With considerable studies in system reinforcement projects and relevant system risk assessments, the average unit interruption cost that is based on the capital investments can be obtained. The details of the method will be discussed in Chapter 12. This method may be particularly preferred by a private utility.

3. Method based on gross domestic product. A simple and useful method is to use the gross domestic product (GDP) concept. The gross domestic product for a province, state, or country divided by the total annual electric energy consumption of the province, state, or country results in a dollar value per kilowatt hour. This number reflects the average economic damage cost due to 1 KWh of electric energy loss in that province, state, or country. Obviously, this method is suitable for the utility owned by a government since the overall economic benefit in the province, state, or country must be considered as a whole.

1.3 OUTLINE OF THE BOOK

Considerable effort has been devoted to power system risk assessment in the past three decades. There are many technical papers and several books in this area [1, 3, 5–8, 19, 20]. The majority of the books have focused on analytical techniques [3, 5–7] and there has been one book on Monte Carlo simulation methods [1]. The emphasis in these books is placed on the theory and general methods for power system reliability evaluation, although some examples using small test systems have been used for demonstration purposes. This book has the following features:

- Most of this book is devoted to practical applications. The topics addressed are the actual issues in the utility industry. The special concepts, methods, and procedures for the different applications in planning, operation, maintenance, and asset management are developed. The examples provided are from real utility systems. Particularly, the results in the applications have been implemented in the utility's practice.
- The outage models of system components are systematically discussed in Chapter 2. Some concepts are new, such as the semiforced outage and individual model for common cause outages. Aging failure modeling is presented and applied to power system risk assessment for the first time.
- One whole chapter (Chapter 3) is committed to the parameter estimation of component outage models. This is an issue associated with how to perform statistical processing for historical outage records to handle the uncertainty of input data. It has not been sufficiently addressed so far in power system risk assessment.
- In evaluation methods, both the analytical and Monte Carlo approaches are discussed, with an emphasis on the applied techniques and actual considera-

tions in generation, transmission, substation, and distribution systems. The methods that are not popular in practical applications are not included.

The book can be divided into three parts. The first part is the modeling and methods that are discussed in Chapters 2 to 5. The second part, Chapters 6 to 13, focuses on the eight topics in practical applications. The third part consists of the five appendices, which provide the background knowledge needed in power system risk assessment.

Chapters 2 and 3 discuss modeling and data issues at the system component level. Chapter 2 presents the outage models of system components, including various independent and dependent outages. These are the basis of system risk evaluation. Chapter 3 discusses the estimation methods of the parameters used in component outage models. These include point and interval estimations of failure data, experimental distributions of failure statistics, and parameter estimation in aging failure models. The essence of parameter estimation is the determination of input data in risk evaluation. This is one of the key steps in actual applications.

Chapters 4 and 5 discuss the evaluation methods and analysis techniques for overall systems. Chapter 4 summarizes the general risk evaluation methods that have been extensively applied in power system risk assessment. The probability convolution, series and parallel networks, Markov equations, and frequency-duration approaches for simple systems are described first, then emphasis is placed on the state enumeration and Monte Carlo simulation methods for complex systems. The merits and limitations of the different methods are discussed from the viewpoint of practical engineering application.

Chapter 5 illustrates the risk evaluation methods for generation, distribution, substation, and transmission systems using both the Monte Carlo simulation and state enumeration techniques. The focus is on the approaches of selecting system states and the techniques for performing system analyses. The practical considerations in the applications are discussed. The formulas of the risk indices for generation, distribution, substation, and transmission systems are derived. The formulas have different expressions for the Monte Carlo simulation and state enumeration techniques.

Eight application topics are presented in Chapters 6 to 13. In each chapter, not only are the concept, method, and procedure for a specific application described, but examples are also given to demonstrate the details of each application.

Chapter 6 illustrates the application of system risk assessment in transmission development planning, which is often called probabilistic planning in the utility environment. After the concept and approach are discussed, two examples are provided. The first one shows how to determine the lowest cost planning alternative and the second one shows how to apply different planning criteria.

Chapter 7 addresses the application of system risk assessment in transmission operation. The special aspects associated with operation modes are discussed and these include the impacts on system risk of load transfers, generation pattern changes, network reconfigurations, and switching actions. In addition to the example of determining the lowest risk operation mode in a large system, the simple case

of using hand calculations is also offered. This provides the particulars of the evaluation procedure, which can be performed on a spreadsheet.

Chapter 8 discusses the application of system risk assessment in generation source planning. The basic concept and method for generation reliability planning under the network constraint condition are explained and two examples are demonstrated. One is associated with selection of the location and size of a cogeneration plant and the other with decision making on the retirement of a local generation plant in a utility.

Chapter 9 presents the application of system risk assessment in subtransmission systems and substation configurations. The general method for risk evaluation in the combined system of transmission network and substations is developed. Two examples are given to illustrate how to use the presented method in selecting the best substation configuration under the transmission network constraint and in determining the optimal transmission line arrangement connected to multiple substation configurations, respectively.

In Chapter 10, reliability-centered maintenance is discussed. The application of risk assessment in this area has a wide range of implications. Following the discussion of the basic tasks in reliability-centered maintenance, three examples are provided. The first is determination of the lowest risk maintenance scheduling. The second addresses the issue of workforce planning in maintenance. The third shows that a reliability-centered maintenance problem in the real life does not always have to be complex and can be solved through simple calculations in some cases.

In Chapter 11, probabilistic spare equipment planning is addressed. This area has been a challenge in the electric power industry for years. The spare issue is tightly related to equipment aging and thus the aging failure mode has to be considered. The spare analysis methods based on the risk criteria and probabilistic cost models are presented. Two practical applications from the utility projects are discussed in detail. In the first one, the number and timing of spare transformers are determined, and in the second one, the rational on-line redundancy of 500 kV reactors is analyzed.

Chapter 12 discusses the special application of risk assessment in reliability-based transmission service pricing. In the deregulation environment of the power industry, system reliability becomes part of transmission services and must be reflected in the price design. The basic concept, calculation method, and rate design based on quantified system risk evaluation are illustrated. A utility example is used to explain the application.

Chapter 13 presents probabilistic transient stability assessment. This is a relatively immature area in power system risk evaluation. The failure models and simulation methods associated with transient stability are addressed. A utility system in which two applications are discussed is used as an example. One is associated with the calculation of probabilistic transfer limit and the other with the determination of probabilistic generation rejection.

There are five appendices in total. Appendices A and B contain the mathematical knowledge for risk assessment. Appendix A provides basic probability concepts and Appendix B presents the elements of Monte Carlo simulation. Appendices C

and D give the fundamentals of the power flow models and the optimization algorithms, respectively, that are used in power system risk assessment. Appendix E provides the three probability distribution tables that are often utilized in parameter estimation.

This book does not pretend to include all the known and available materials on the subject. It focuses instead on the aspects that have not been but should be sufficiently addressed in power system risk assessment. It will enable the reader who lacks experience in the power utility industry, such as a university student, to gain the practical ideas required in performing risk evaluation of real power systems. It will also help the reader, such as an engineer, who wants to learn more in modeling and methods and apply them to solve his or her actual problems, to acquire the requisite expertise in power system risk assessment.