Reliability of Electric Utility Distribution Systems: EPRI White Paper

Technical Report

Reliability of Electric Utility Distribution Systems: EPRI White Paper

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REPORT SUMMARY

This report discusses what is known about electric power distribution system reliability and investigates whether there are generally available methods for performing reliability analysis for distribution systems. The *theory* of the reliability of general systems is well understood. A fundamental issue is whether an appropriate *implementation* of the theory exists in a form readily usable by distribution system planners and designers.

Background
EPRI has been developing methods for distribution planning since 1992. At that time, research directed at the concept of distributed resources begun by EPRI, PG&E, and NREL led to further consideration of distribution planning in general. The distribution planning problem is to determine the least-cost expansion plan under load growth uncertainty. Electric utility restructuring and emphasis on competitive performance has increased the importance of the relationship between cost and reliability. Distribution planning must now include reliability/cost tradeoffs explicitly. One of the main questions in the present research is how should reliability considerations be incorporated into distribution systems planning? This is really a multi-part question, comprising such considerations as (a) how is reliability defined for distribution systems; (b) how is reliability valued for distribution systems; (c) how is reliability controlled and maintained in distribution systems; and, (d) what methods exist that measure reliability, predict reliability, or analyze reliability in distribution systems? The present research is aimed at answering these and related questions.

Objectives
To document what is known about reliability in distribution systems and to determine whether tools exist to perform the required reliability analysis for planning distribution systems.

Approach
A detailed literature survey, described in the report, created a Reliability Library, a tool intended to support further development of models and methodology. The utility and customer perspectives of reliability were defined and analyzed. The difference is between an equipment focus and a service focus. Approaches to measuring reliability, including indices in common use, were reviewed. There is no single accepted method of measurement. We studied what is known about utility practices, which vary considerably. The relationship among regulatory practices, measurement techniques, data gathering, and operating and investment decisions was investigated. The relationship, although acknowledged, is not supported by a generally accepted framework to guide thinking, much less a methodology to implement reliability-based planning and decision making. Approaches taken by utilities to address power quality issues were studied. Methods used in reliability analysis were identified and described. Methods are either historical,

designed to assess the past state of the distribution system, or predictive, designed to assess future performance. Most practical analyses have been historical. Although powerful analytical techniques exist for predictive analysis, their application has been limited.

Results

There is no generally available implementation or methodology that will permit distribution system planners to predict distribution system reliability. Not only is a usable methodology absent, but there is no general framework available for reliability-based decision making in the distribution system. It is not possible to answer such questions as (a) how will an additional investment in the distribution system affect customer service reliability, (b) how will a change in maintenance policy affect customer service reliability, (c) what is the optimal level of maintenance for the distribution system, or (d) what level of redundancy is appropriate for the distribution system? New methodology is needed because the state of the art in practice does not address the problems distribution systems planners currently face.

EPRI Perspective

Electric power restructuring is changing the nature of electric distribution planning, engineering, and operations. Corporate management and regulators are increasing their scrutiny and control of distribution investment and maintenance decisions, while requiring the distribution system managers and engineers to plan, design, construct, and maintain electric distribution infrastructure that satisfies customer needs for reliability and power quality. The need both to reduce costs and to satisfy specific customer needs is creating an important distribution-planning problem. Investment and O&M decisions must be supported by explicit analysis of this tradeoff.

One perspective on distribution planning is that there are two problems—planning for capacity and planning for reliability. EPRI has worked on the capacity problem since 1992. EPRI's *Load Dynamics Model* and *Area Investment Strategy Model* are state-of-the-art tools for forecasting load and developing least-cost investment strategies under uncertainty. However, the treatment of reliability by these tools is unsophisticated. Moreover, the capacity problem and the reliability problem have become more closely linked as restructuring proceeds.

In 1999, EPRI initiated two projects to help quantify the reliability/cost tradeoff: "Assessing Customer Needs" and "Measuring and Valuing Reliability." This report is the first result from the Reliability project. The research summarized here addresses two questions: (1) how, in principle, should reliability considerations be incorporated into distribution systems planning and (2) what methodologies currently exist to support reliability-based systems planning? The conclusion is that sound fundamental methodology can be created that will allow customer values for reliability and power quality to be added into distribution infrastructure decisions. Implementation of the methodology is in its infancy. Much work remains.

Keywords

Reliability Reliability of distribution systems Value based reliability planning

ABSTRACT

This report describes what is known with respect to the reliability of electric power distribution systems. We describe the state of knowledge, tools and practices for distribution system reliability. The report is based on an extensive literature survey, which investigated papers, reports, books and electronic media. The report discusses definitions of reliability; perspectives on reliability; measurment methods, including reliability indices; sources of data; utility planning practices; the role of regulators; utility power quality approaches; and existing methods for reliability analysis. The main conclusion of the report is that, although the theory of reliability of systems is well-developed, the application of analytical techniques to distribution systems planning is limited. There is no single, generally available, methodology that distribution planners can use to answer the questions associated with reliability-based planning.

CONTENTS

LIST OF FIGURES

1
INTRODUCTION

The purpose of this report is to describe what is known with respect to reliabilityin electric power distribution systems. Reliability is a broad concept, and the application of the term to electric power distribution systems is expansive. Consequently, a wide-ranging approach was taken in this report to map out the state of knowledge, tools, and practices for distribution system reliability.

A particular objective of this report is to determine whether there are generally available methods for performing reliability analysis for distribution systems. The theory of the reliability of general systems is well understood. The issue for us is whether an appropriate implementation of the theory exists in a form readily usable by distribution system planners and designers.

This is such an important issue that it seems appropriate to give the answer immediately. There is no generally available implementation or methodology that will permit distribution system planners to predict the reliability of the distribution system. Not only is a usable methodology absent, but there is no general framework available for reliability-based decision making in the distribution system. It is not possible, using any available approach, to answer such questions as (a) how will an additional investment in the distribution system affect customer service reliability? Or (b) how will a change in maintenance policy affect customer service reliability? Or (c) what is the optimal level of maintenance for the distribution system? Or (d) what level of redundancy is appropriate for the distribution system?

One of the main results of our research is that further methodology must be created in order to solve the reliability-based distribution planning problem. We hasten to add that such methodology will be based on the existing theory and state of the art in methodology; but the point we make is that the state of the art is far from sufficient to solve the problems distribution systems planners currently face.

The report begins with a literature survey. An important objective of the literature survey is to provide a library from which specific information on distribution system reliability could be easily located. This report describes the findings and resources developed, in the form of the Reliability Library, in the course of this literature survey. Most of the information in this report is from Reliability Library sources, as indicated by the citations. The Reliability Library is a tool that we intend to use as we develop models and methodology. The Reliability Library contains both reports and electronic files containing definitions, citations, and discussions of the citations. All these items are described in the report.

The next section of the report discusses various definitions and perspectives on reliability. What is remarkable is the multiplicity of ways of describing essentially the same thing: how to provide service to customers. The critical notion of perspective is described in this section. Perspective determines the view taken of reliability. The main distinction is between the customer perspective, that focuses on service, and the utility perspective, that may often focus on equipment performance and the availability of supply. This is a far simpler issue than one might suspect, based on the literature. The current practice is moving towards focusing on customers, which is clearly appropriate. Indeed, a working definition of reliability is the ability of the system to provide an acceptable level of continuity and quality of service to customers. The section presents many other approaches to defining reliability and all its relevant aspects.

Approaches to measuring reliability are described next. There are many indices in common use that characterize the behavior of the system with respect to frequency, duration, and extent of service outages. There is no single accepted method of measurement and the data that support the different measurement approaches are neither generally available nor consistent across utilities. Each utility is left to choose for itself how best to measure reliability and to gather for itself the data that will support such a measurement. Although there have been some efforts at standardization and some benchmarking studies have been done, there is no uniformly accepted measuring approach. One reason for this may be that reliability information is used for various purposes, so that no single measurement is sufficient. Another reason may be that there is no uniformly applicable analysis methodology, so that no single measurement can be used to support the various methodologies.

We investigated what is known about utility practices with respect to reliability. We learned that reliability is a basic design criterion in distribution planning and that the contingency-coverage perspective is taken in reliability-based planning. An important aspect of this practice is that customer values are rarely explicitly applied in determining the standards with respect to contingency planning: the reliability levels used as planning criteria have traditionally been set somewhat arbitrarily. The fact is that planning has been cost-based, selecting the least cost way of achieving the criteria, rather than value-based, selecting the way that maximizes customer value or some combination of cost and value. There is no generally accepted method to set the contingency criterion, nor is there a generally accepted method to support the decisions and policies that will achieve the criterion.

The role of regulators in reliability planning is addressed in the report. We found that formal regulation of the reliability of electric power distribution systems in North America is uncommon. A significant exception is the reliability requirement set by the New York Public Service Commission for Consolidated Edison to design to a second-contingency criterion in certain areas of the distribution system. Recent developments in various other locations include Performance Based Regulation (PBR). Naturally, there is a relationship among regulatory practices, measurement techniques, data gathering, and operating and investment decisions. The relationship, although acknowledged, is not supported by a generally accepted framework to guide thinking, much less a methodology to implement reliability based planning and decision making.

Power Quality is a fundamental aspect of reliability. Power quality is based on voltage level and waveform. We have identified ten different descriptors of power quality problems. Standards have been set by IEEE and ANSI, among other organizations. The section also discusses approaches taken by utilities to address power quality issues. These include gathering information about the quality of power provided and selecting equipment, such as filters, to help provide the required quality.

We investigated the methods used in reliability analysis. Methods are either historical, designed to assess the past state of the distribution system, or predictive, designed to assess the future performance. Most practical analysis is historical. Although powerful analytical techniques exist for predictive analysis, their application has been limited. We suggest that there are three main reasons for this. First, the analytic techniques are mathematically sophisticated and require equivalent user sophistication in order to apply the methods to any particular situation. Second, modeling expertise is generally required in order to represent the particular distribution system in a form such that the analytic techniques can be applied. That is, not only must users be sophisticated in the application of mathematical tools, but also users must be able to transform the systems they deal with into appropriate mathematical representations. These two kinds of expertise, complementary and different, are not always available. Third, data must be available to drive the analytical techniques. As the literature indicates, such data is not generally available. In addition, what is missing is an overall analytic decision framework for reliability that would guide the development of methodology and specify the data that must be gathered.

The final section of the report is the summary. The summary reiterates many of the points made in this introduction and throughout the report: reliability is an essential descriptor of system performance and ought to be considered when making distribution investment and maintenance decisions. Based on this study, we conclude that lack of a decision framework, supported by appropriate reliability analysis methodology and data, prevents utilities from performing reliability-based planning.

2 LITERATURE SURVEY INTRODUCTION

The objective of the literature survey is to map out the state of knowledge, tools, and practices for distribution system reliability. As noted in the introduction to the report, reliability is a broad concept and the applciation of the term for electric power distribution systems is expansive. Hence, we took a wide-ranging approach in the literature survey. An important objective of the literature survey is to provide a library from which specific information on distribution system reliability could be easily located. This report describes the findings and resources developed, in the form of the Reliability Library, in the course of this literature survey. Most of the information in this report is from Reliability Library sources, as indicated by the citations.

A large collection of journal articles, reports, and books were consulted. Other resources, such as websites, were also reviewed. The results are a part of the Reliability Library. The Reliability Library consists of hard-copy documents as well as electronic files. The electronic files contain results of the survey in the form of notes and summaries, as well as electronic versions of documents. The following table presents the current status of the library.

	Reviewed	**In Library**	**Summarized**
Reports	45	38	41
Journal Articles	58	58	33
Books	14	5	8

Figure 2-1
Reliability Library Contents

Some past efforts have had similar objectives to that of the present literature survey. As a result, less emphasis was placed on locating and reviewing documents covered by these works. The three-volume set *Development of Distribution System Reliability and Risk Analysis Models* (EPRI EL-2018; Research Project 1356-1: J. E. D. Northcote-Green, T. D. Vismor, C. L. Brooks; 8/81) and the accompanying *Distribution System Reliability Handbook* (EPRI EL-2651; Research Project 1356-1: S. J. Kostyal, T. D. Vismor, R. Billinton; 12/82) are the main pieces in the library for the period before January 1983. The subsequent period, from 1983 through the early 1990s, is covered similarly by the *Guide to Value Based Reliability Planning* (Godfrey, Billinton, CEA R&D Division; CEA 273 D 887; 1/96). This guide has an annotated bibliography on distribution system reliability that includes materials up to 1992. Selected documents discussed in these reports are included in the Reliability Library.

3
RELIABILITY LIBRARY

3.1 Hard copies

Books

The following books were reviewed as part of the literature survey, and hard copies of a number of them are part of the Reliability Library.

In Reliability Library

Reliability Evaluation of Power Systems, 2nd Edition,
Billinton and Allan; Plenum, New York, 1994

Power Distribution Planning Reference Book, Willis; Marcel Dekker, Inc., New York, 1997

IEEE Gold Book (IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems),
IEEE Std 493-1997 The Institute of Electrical and Electronics Engineers, Inc., New York, 1998

Electrical Distribution Engineering, Pansini; Fairmont Press, Inc., Lilburn, GA, 1991

Reliability Evaluation of Engineering Systems, Concepts and Techniques,
Billinton and Allan; New York, Plenum, 1983

Reviewed but not in Reliability Library

Reliability Assessment of Large Electric Power Systems,
Billinton and Allan; Kluwer Academic Publishers, 1988

Electric Utility Restructuring: A Guide to the Competitive Era,
Fox-Penner; Public Utilities Reports, Inc., Vienna Virginia

Power System Reliability Evaluation,
Billinton, Gordon, and Breach; Science Publishers, New York, 1970

Power-System Reliability Calculations,
Billinton, Ringlee, and Wood; MIT Press, Cambridge, 1973

Reliability Modeling in Electric Power Systems, Endrenyi; Wiley-Interscience, New York, 1978

Electric Utility Competition: A Survey of Regulators,
R. J. Rudden Associates and Fitch Investors Service, Inc., 1993

Electricity in the American Economy: Agent of Technological Progress,
Schurr, Burwell, Devine, and Sonenblum, 1990

Regulating Utilities: The Way Forward, Ed. Beesley, 1994

Electric Utility Planning and Regulation, Kahn, 1998

Reports

The following reports were reviewed as part of the literature survey, and hard copies of most of them are part of the Reliability Library.

NERC Operating Manual

Distribution System Reliability Issues.doc *(12/99)*, EPRISolutions Draft Report

The Strategic Role of Distributed Resources in Distribution Systems *(10/99)*,
EPRI TR-114095; Final Report; Prepared by Charles D. Feinstein

Reliability Benchmarking Application Guide with Customer/Utility Common Power Quality Indices (9/99), EPRI TP-113781; Final Report

Reliability Centered Maintenance for Distribution (6/9/99), EPRI Workshop

Reliability Centered Maintenance (RCM) for Distribution Systems and Equipment: Four Application Case Studies (5/99),
EPRI TR-112924; Final Report; Prepared by Scientech; D. Reid, C. Schwan

1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version (5/99), CEA (Item # 116.98)

'Bang Per Buck' Templates: Examples of How to Estimate the Cost-Effectiveness of Electric Reliability Programs, Navigant Consulting, Inc.

Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission (1999)

Reliability Assessment 1998 – 2007: The Reliability of Bulk Electric Systems in North America (9/98), North American Electric Reliability Council

Forced Outage Performance of Transmission Equipment for the period 1/1/92 to 12/31/96;
(7/98) CEA (Item #107.92)

Framework for Stochastic Reliability of Bulk Power System (3/98);
EPRI TR-110048; Final Report; Prepared by Center for Energy Systems and Control, J.A. Momoh

Software User Manual: Reliability Centered Maintenance (RCM) Workstation for Power Delivery (12/97*)*; EPRI CM-108076-R1; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann

Software User Manual: Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery (12/97*)*; EPRI TR-108076; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann

Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery (10/97);
EPRI TR-108068; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann

Reliability of Benchmarking Methodology (5/97)*;* TR-107938; Final Report

An Assessment of Distribution System Power Quality: Volumes 1-3 (5/96);
TR-106294-V1; Final Report

Outage cost estimation guidebook (12/95);
EPRI-TR-106082; Project 2878-04 Final Report; Prepared by Freeman, Sullivan and Co.; Sullivan, M.J., Keane, D.M. (192 p)

Power Quality Workbook for Utility and Industrial Applications (10/95);
EPRI TR-105500; Project 2935-30; Final Report; Prepared by Electrotek Concepts, Inc.; M. McGranagham, R. Dugan, A. Khan, D. Mueller, R.J. Ferraro

Active Power Line Conditioning Methods: A Literature Survey (7/95);
EPRI TR-105168; Project 2951-07; Final Report; Prepared by the University of Texas at Austin; W.M. Grady, A.H. Noyola

Quality of Service in an Era of Increasing Competition: A Review of the Literature with Policy Implications and Annotated Bibliography (2/95); Prepared for the Bureau of Consumer Services Pennsylvania Public Service Commission by John Shingler

Value-Based Transmission Resource Analysis, Volume 1: Technical Report (4/94);
EPRI TR-103587-V1; Project 2878-02; Final Report; Prepared by RCG/Hagler Bailly; D.M. Logan, E.G. Neudorf, B. Porretta, D.L. Kiguel, G.A. Hamoud, M.P. Bhavaraju, R. Billinton

Value-Based Transmission Resource Analysis, Volume 2: Applications Guide (4/94);
EPRI TR-103587-V2; Project 2878-02; Final Report; Prepared by RCG/Hagler Bailly; D.M. Logan, E.G. Neudorf, B. Porretta, D.L. Kiguel, G.A. Hamoud, M.P. Bhavaraju, R. Billinton

Types of Incentive Regulation: A Primer for the Electric Utility Industry (1993):
Edison Electric Institute Finance, Regulation and Power Supply Policy Group, EEI, Washington, D.C.; HD9685/U5/T96

TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems, Volume 1: A Summary (5/92): EPRI TR-100566; Project 3159-1; Final Report; Prepared by Public Service Electric and Gas Company

Cost-benefit analysis of power system reliability: Determination of interruption costs (5/90);
EPRI EL-6791; Project 2878-1 Final Report; Prepared by RCG/Hagler, Bailly Inc.; Sanghvi, A.P.

Customer Demand for Service Reliability: A Synthesis of the Outage Costs Literature (9/89);
EPRI P-6510; Project 2801-1 Final Report; Prepared by Laurits R. Christensen Associates, Inc. under contract to ADA; Caves, D.W., Herriges, J.A., Windle, R.J.

The Value of Service Reliability to Consumers (5/86);
EPRI EA-4494; Project 1104-6 Proceedings; Prepared by Criterion Inc.

Study of Effect of Load Management on Generating-System Reliability (7/84);
EPRI EA-3575; Project 1955-3; Final Report; Prepared by Associated Power Analysis, Inc.; A. D. Patton, C. Singh

Distribution System Reliability Handbook (12/82);
EPRI EL-2651; Research Project 1356-1 Final Report; Prepared by Westinghouse Electric Corporation; Principal Investigators: S. J. Kostyal, T. D. Vismor, R. Billinton

Development of Distribution System Reliability and Risk Analysis Models (8/81);
EPRI EL-2018; Research Project 1356-1 Final Report; Prepared by Westinghouse Electric Corporation; Principal Investigators: J. E. D. Northcote-Green, T. D. Vismor, C. L. Brooks

Distribution System Reliability Engineering Guide (3/76);
CEA (Item #105); Produced by the CEA Distribution System Reliability Engineering Committee

Investing Resources to Create Value (3/96);
EPRI TR-104917; Research Project 3678; Final Report; Prepared by Strategic Decisions Group

Costing and Pricing Electric Power Reserve Services (12/97);
EPRI TR-108916; Final Report; Prepared by Christensen Associates; L. D. Kirsch, R. Rajaraman

A Primer on Electric Power Flow for Economists and Utility Planners (2/95);
EPRI TR-104604; Project 2123-19; Final Report; Prepared by Incentives Research, Inc.; F.C Graves

Electric Generation Expansion Analysis System, Volume 1: Solution Techniques, Computing Methods, and Results (8/82); EPRI EL-2651; Project 1529-1; Final Report; Prepared by Massachusetts Institute of Technology; M.C. Caramanis, F.C. Schweppe, R.D. Tabors

Electric Generation Expansion Analysis System, Volume 2: Details of Solution Techniques, Data of Test Systems, and Glossary of Terms (8/82);
EPRI EL-2651; Project 1529-1; Final Report; Prepared by Massachusetts Institute of Technology; M.C. Caramanis, F.C. Schweppe, R.D. Tabors

Journal Articles

The following journal articles were reviewed as part of the literature survey (listed by year of publication). They are in the Reliability Library.

The IEEE Reliability Test System-1996
A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee, *IEEE Transactions on Power Systems*, Vol. 14, No. 3, 8/99, p. 1010

Application of Monte Carlo Simulation to Generating System Well-being Analysis
Roy Billinton, Rajesh Karki; *IEEE Transactions on Power Systems*, Vol. 14, No. 3, 8/99, p. 1172

Optimal Maintenance Scheduling in a Parallel Redundant System Consisting of Series Components in Each Branch
Roy Billinton and Jun Pan; *IEEE Transactions on Power Delivery*, Vol. 14, No. 3, 7/99, p. 928

Time Sequential Distribution System Reliability Worth Analysis Considering Time Varying Load and Cost Models
Peng Wang, Roy Billinton; *IEEE Transactions on Power Delivery*, Vol. 14, No. 3, 7/99, p. 1046

Teaching Distribution System Reliability Evaluation Using Monte Carlo Simulation
Roy Billinton, Peng Wang; *IEEE Transactions on Power Systems*, Vol. 14, No. 2, 5/99, p. 397

“Canadian Utility Perspective on Power Quality;” K.K. Cheng; CEA Electricity Conference; March, 1999; Vancouver, Canada.

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K. Jennifer Moroz; CEA Electricity Conference; March, 1999; Vancouver, Canada.

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Probabilistic Evaluation of Voltage Stability
Saleh Aboreshaid and Roy Billinton; *IEEE Transactions on Power Systems*, Vol. 14, No. 1, February, 1999, p.342

Application of DC Equivalents to the Reliability Evaluation of Composite Power Systems
H.A.M. Maghraby and R.N. Allan; *IEEE Transactions on Power Systems*, Vol. 14, No. 1, February, 1999, p.355

Modeling the Impact of Substations on Distribution Reliability
R.E. Brown and T.M. Taylor; *IEEE Transactions on Power Systems*, Vol. 14, No. 1, 2/99, p.349

"Innovative System Solutions for Power Quality Enhancement;"
Arora, Arun; Chan, Kevin; Jauch, Thomas; Kara, Alexander; Wirth,Ernst; ABB High Voltage Technologies Ltd. ABB Review n 3 1998. p 4-12.

"Attributing Harmonics in Private Power Production;"
Srinivasan K. IEEE Transactions on Industry Applications, 1998, 34 (5) 887-892.

"Analysis and Mitigation of Voltage Disturbances at an Industrial Customer's Corporate Campus;"
Khera P. P.; Dickey K. C.; IEEE Transactions on Industry Applications, 1998, 34 (5)893-896.

"New Approach To Monitoring Electric Power Quality;"
Dash, P.K.; Panda, S.K.; Liew, A.C.; Mishra, B.; Jena, R.K.; Electric Power Systems Research v 46 n 1 Jul 1998. p 11-20.

Distribution System Reliability Cost/Worth Analysis Using Analytical and Sequential Simulation Techniques
Roy Billinton, Peng Wang; *IEEE Transactions on Power Systems*, Vol. 13, No. 4, 11/98, p.1245

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Koval, Don O.; Bocancea, Romela A.; Yao, Kai; Hughes, M. Brent; IEEE Transactions on Industry Applications v 34 n 5 Sep-Oct 1998. p 904-910.

"Electric-Power-Quality Improvement Using Parallel Active-Power Conditioners."
Huang, S. J.; Wu, J. C.; Jou, H. L. IEE proceedings. Generation, transmission and distribution, 1998, 145 (5) 597-603.

"Voltage Sags: Their Impact on the Utility and Industrial Customers."
Melhorn, C. J.; Davis, T. D.; Beam, G. E.; IEEE Transactions on Industry Applications, 1998, 34 (3) 549-558.

Distribution System Reliability: Default Data and Model Validation
R.E. Brown, J.R. Ochoa; *IEEE Transactions on Power Systems*, Vol. 13, No. 2, 5/98, p.704

Generalized n+2 State System Markov Model for Station-Oriented Reliability Evaluation
R. Billinton. Hua Chen, Jiaqi Zhou; *IEEE Transactions on Power Systems*, Vol. 12, No. 4, November, 1997, p.1511

Features That Influence Composite Power System Reliability Worth Assessment
A. Jonnavithula, R. Billinton; *IEEE Transactions on Power Systems,* Vol. 12, No. 4, 11/97, p.1536

Reliability Issues in Today's Electric Power Utility Environment
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Key Documents

Some documents are particularly valuable in developing an understanding of distribution system reliability, utility reliability practices, and an historical perspective on reliability. Two are *Guide to Value Based Reliability Planning*, *Power Distribution Planning Reference Book*, *Cost-benefit analysis of power system reliability: Determination of interruption costs*, and *Development of Distribution System Reliability and Risk Analysis Models.* The best place to begin depends on the individual’s state of knowledge in distribution system reliability. For guidance, these documents are discussed briefly.

Godfrey and Billinton’s *Guide to Value Based Reliability Planning* (Godfrey, Billinton, CEA R&D Division; CEA 273 D 887; 1/96) provides valuable information about predictive reliability modelling. Textbooks by Billinton on reliability evaluation are also a part of the Reliability Library. This book is described by one of the electronic files in the Reliability Library (see page 11, below).

Background information on distribution system reliability planning and standard practices in distribution engineering is given in the *Power Distribution Planning Reference Book* (H. Lee Willis, Marcel Dekker, Inc., New York, 1997). The reader can be guided to relevant sections of this book through the reliability-focussed summaries of the book in the electronic file for textbooks, which is described in the next section of this report.

The three-volume report *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90) is ostensibly about obtaining interruption costs but Volume 1 contains much valuable information concerning reliability. The report describes reliability indices used for generation, transmission, and distribution. There are results from utility surveys on reliability practices, and a document on reliability practices at a sample utility is included as an appendix.

EPRI project work on reliability data collection and reliability system modeling (HISRAM, PRAM) from the early 1980s, as well as a handbook, *Distribution System Reliability Handbook* (EPRI EL-2651; Research Project 1356-1: S. J. Kostyal, T. D. Vismor, R. Billinton; 12/82) is described in a three-volume set. Volume 1, *Development of Distribution System Reliability and Risk Analysis Models* (EPRI EL-2018; Research Project 1356-1: J. E. D. Northcote-Green, T. D. Vismor, C. L. Brooks; 8/81), is the executive summary of the project. This short document presents the historical foundation of the material in the later reliability publications.

3.2 Electronic files

As part of the review process, many electronic files were created to guide others to specific information contained in the Reliability Library. All the reviewed documents are organized into different categories. There are detailed notes and a précis for each document. The précis gives an indication of whether material within the document addresses such issues as the definition of reliability, how reliability is measured, the modeling of reliability, or how reliability is used in planning. With the area of interest determined through a perusal of the subject catalog, one can quickly find the précis of the indicated documents in the summary files. The précis will help determine which article or document is the most relevant. The detailed notes may be of further help, but are most useful for electronic searching on terms and subjects. There are, in addition, a number of reliability-related documents available in electronic form in the Reliability Library. The outlines of the electronic files follow immediately below. There are eleven electronic files.

1. Reliability Document Categorization.doc

   Reviewed documents (journal articles, reports, books) are listed under each of the topics that they address. This file allows a quick concentration on relevant documents. It can be used with the summary files and with electronic searching through the notes files to zero in on information of interest.

   Subject Catalog

   I. Measuring and Defining Reliability:

      A. Definition and perception (Customers', utilities', regulators' perception of reliability)

      B. Indices

      C. Loss-of-Load Probability (LOLE/LOLP)

   II. Faults:

      A. Failure rates by equipment type (circuits, transformers, capacitors, cables, poles)

      B. Durations

      C. Causes (rural vs. urban, weather, peak loading, accident, sabotage)

      D. Classes (transmission vs. distribution; brownouts/blackouts; multiple contingency events, self-clearing events, system trips, switching events)

   III. Maintenance & Changing Reliability (in distribution)

      A. Equipment types

B. Policies

C. Engineering to change reliability

IV. Regulatory Issues

V. Power Quality

VI. Reliability Modeling

VII. Picing

A. Interruptible Rates

B. Differentiated Pricing (reliability, service, quality)

2. Reliability Definitions.doc

This file is a glossary on reliability. It contains

- a compilation of definitions of reliability from different sources and viewpoints,
- a compilation of definitions of reliability-related terms,
- a compilation of reliability index definitions, and
- a compilation of reliability-related acronyms and acronyms of organizations and utilities.

3. Reliability in Textbooks - SUMMARY.doc
4. Reliability in Textbooks - NOTES.doc
5. Reliability Journal Articles - SUMMARY.doc
6. Reliability Journal Articles - NOTES.doc
7. Reliability Reports and miscellaneous - SUMMARY.doc
8. Reliability Reports and miscellaneous - NOTES.doc
9. Reliability on websites - SUMMARY.doc
10. Reliability on websites - NOTES.doc

There are a number of electronic files containing précis and notes of reviewed documents. Each of the summary files listed above contains a compilation of précis for the reviewed documents, concentrating on reliability-related concerns. Each entry in the summary file has a hyperlink to the corresponding entry in the notes file. The notes file is a compilation of detailed notes on a number of documents. For example, *Reliability Journal Articles - SUMMARY.doc* contains summaries of all the journal articles in the Reliability Library. A hyperlink for each article takes the reader to the notes for the same article. For some journal articles, abstracts are included in the notes file. The *Reliability Reports and miscellaneous - SUMMARY.doc* file includes information on published reports and electronic documents that were reviewed, and which are available. Here are two sample summaries from these files.

<u>Reliability: NERC/FERC Convergence</u>
K. Jennifer Moroz; CEA Electricity Conference; March, 1999; Vancouver, Canada.

> The author summarizes the legislation proposed in the US by NERC and by the US Department of Energy that would make reliability standards legally enforceable. Deregulation has made voluntary compliance with reliability standards unlikely. The formation of a new North American Electric Reliability Organization (NAERO) overseen by the FERC would ensue. The impact on the Canadian electricity industry of these developments is examined and possible responses to the evolving regulatory situation in the US are discussed. The "Principles for Regulatory Support of Electricity System Reliability" developed by the CEA in 1997 (included in an Appendix) must be reviewed in light of the proposed US bills on reliability.

<u>Distribution System Reliability Handbook (12/82)</u>
EPRI EL-2651; Research Project 1356-1 Final Report; Prepared by Westinghouse Electric Corporation; Principal Investigators: S. J. Kostyal, T. D. Vismor, R. Billinton

> The objectives of this research project are in striking alignment with those of the present project, beginning with a compilation and an organization of reliability assessment techniques in use in 1981. A 3-volume final report (see below, EL-2018) documents the research. This practical distribution handbook for EPRI client utilities arose from the project. It describes the assessment models in detail, models for historical reliability assessment (HISRAM) and predictive reliability assessment (PRAM), which were successfully tested and executed at two utilities. It also includes practical guidelines for reliability assessment. It contains an extensive bibliography on distribution system reliability evaluation grouped into (a) analysis and applications, (b) outage data, and (c) reliability economics and indices; including abstracts for the most significant articles.

11. Guide to Reliability Planning notes.doc

    This file has chapter summaries and detailed notes of the report *Guide to Value Based Reliability Planning* (Godfrey, Billinton, CEA R&D Division; CEA 273 D 887; 1/96). This report addresses many issues relevant to the present literature survey and contains an annotated bibliography that covers up to 1992.

4
RELIABILITY DEFINITIONS AND PERSPECTIVES

4.1 Reliability Definitions

Reliability may be defined in many ways for any system. This is true for electric power systems, generally, and electric power distribution systems, in particular. Several definitions given in the literature are recorded in the file *Reliability Definitions.doc*. This file also contains the definitions of many other reliability-related terms and concepts taken from the literature.

The definitions of reliability in the literature address some common aspects of electric power systems. These include continuity of service, meeting customer demands, and the vulnerability of the power system. Reliability concerns are often split into three categories: *adequacy*, or the capacity and energy to meet demand; *security*, or the ability to withstand disturbances; and *quality*, or acceptable frequency, voltage, and harmonic characteristics.

Reliability cannot be discussed apart from the objectives of the system. The goals of the distribution system may be identified as (1) covering the territory (an aspect of adequacy), (2) having sufficient capacity for peak demand (another aspect of adequacy), (3) being able to operate under adverse conditions (security), and (4) providing a stable voltage (quality). Thus, the goals of the distribution system are congruent with reliability concerns (*Power Distribution Planning Reference Book*).

The North American Reliability Council provides a Glossary of Terms. Reliability and the concepts of adequacy and security are defined there as follows (*NERC Glossary of Terms*):

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system: adequacy and security.

Adequacy: the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Similarly, one may define reliability as the system's ability to provide an acceptable level of continuity and quality, or a reasonable assurance of continuity and quality (*Guide to Value-Based*

Reliability Planning A-4). A more analytic definition, one possibly more often applied to generation, sets reliability to one minus the probability of system failure, or the inability to meet load (*Costing and Pricing Electric Power Reserve Services 2-13*). This probabilistic view uses the availability as an indicator of reliability, where availability is the steady-state probability that a component is in service (*IEEE Gold Book, 19*). Another approach taken is to define reliability through indices. For example, the reliability of a distribution system is said to be described by a complete set of indices such as the individual load point indices (load point failure rate, load point outage duration, annual unavailability) combined with aggregate system indices (SAIFI, SAIDI, CAIDI, ASAI (ASUI), ENS, ASCI, ACCI) ("Computer Programs for Reliability Evaluation of Distribution Systems," *International Power Engineering Conference, 3/93, 37*).

4.2 Perspectives on Reliability

The appropriate definitions of reliability may vary with respect to the perspective taken of the system. *Cost-benefit analysis of power system reliability: Determination of interruption costs, Volume 1* (5/90) has the most comprehensive summary of the different perspectives on reliability. The figure below summarizes the varying concerns of different constituents, including the perspectives of the separate parts of the electric power system that are individually responsible for generation, transmission, and distribution.

The Customer Perspective

The customer perspective is fundamental. The customer, or user, experiences outages. The occurrence of an outage indicates that *service reliability* is not perfect. That is, service reliability measures the degree to which customers experience service outages. One should note that the words "outage" and "interruption" are frequently used interchangeably in the literature, but often they mean separate things. The important distinction is between equipment outages, as observed and recorded by operators, and interruptions of service to the customer. Clearly, an equipment outage need not cause a service interruption; planned maintenance is an example of such an equipment outage. We will try to clarify the difference in this report by using qualifiers such as "service outage" or "equipment outage" or "service interruption."

In addition to its obvious consequences to customers, poor service reliability raises public concerns with respect to noneconomic attributes such as health (*Bulk Power System Reliability Criteria and Indices: Trends and Future Needs*). Reliability concerns of customers depend on their end-use patterns. Some survey data indicate that customers associate service reliability with restoration time and how accessible and responsive the utility is during interruptions (*Cost-benefit analysis of power system reliability: Determination of interruption costs, Volume 1* (5/90)). Nevertheless, although customers value service reliability, they may fail to understand the direct relationship between quality of service and cost of service ("Bulk Power System Reliability Criteria and Indices: Trends and Future Needs").

The Utility Perspective

The utility perspective may differ from the customer or user perspective. The definition of reliability for the utility should be related to that of the end user, the customer. (That is, the utility's definition of reliability should be related to service reliability.) The precise relationship is neither clear nor uniform. Indeed, most utilities define reliability as service reliability, which is the reliability on the service side of customer load points, rather than supply reliability, which is reliability on the supply side. (*Cost-benefit analysis of power system reliability: Determination of interruption costs, Volume 1* (5/90), 5-15, “Bulk Power System Reliability Criteria and Indices: Trends and Future Needs”). The supply side of customer load points includes not only distribution equipment but also generation and transmission system assets and performance. Reliability on the supply side of customer load points is determined by the availability of utility equipment. Clearly, the availability of equipment in the distribution, transmission, and generation subsystems is related to service reliability, but equipment outages do not correspond directly to loss of continuity of service, since customers can be served by alternate supply assets.

It is also important to note that the maintenance policies adopted by utilities may reflect different perspectives on reliability. A utility that is focused on customer interruptions--service reliability--will adopt such policies as Reliability Centered Maintenance (RCM), which are driven by concerns about the effects of customer interruptions. A utility that is focused on supply reliability, with particular attention to distribution system equipment, will adopt maintenance policies that are driven by equipment availability criteria that may be set without regard to customer values or needs.

Other Perspectives

Others involved with the utility may have still different attitudes towards reliability. A *utility planner* will be concerned with the perception of the public; the public apparently, and naturally, given past performance, claims a right to service reliability. The planner will try to have the utility perform above average with respect to reliability, but will recognize that being the best may not be cost effective. A standard such as 4 outages a year and no more than 4 to 8 hours duration may be used to indicate when worries about public perception should begin. *Utility investors*, on the other hand, are concerned only with how reliability affects return. *Utility management* might take the approach that service interruptions are inevitable, and, if they happen, a rate increase can be requested. *Utility engineers* will most likely also see both service interruptions and component outages as inevitable and are concerned with the connection between the funding of different projects and the resulting reliability performance (“Reliability at What Cost? Analyzing the economics of (improving) distribution reliability”). Utility engineers will make clear the distinction between a service interruption, or the cessation of electric service or lack of availability, and an equipment outage, or a failure of one or more components of the electric system. This is a distinction that is unimportant to a customer, who knows only interruptions. Furthermore, potential service interruptions that occur when power is not being used—for example, when a store is closed and no clocks are plugged in—would be unimportant to a customer (“Bulk Power System Reliability Criteria and Indices: Trends and Future Needs”). *To utility design engineers*, reliability may be reflected in the tests they set for equipment and the safety margins they set for the establishment of suitable designs. The design of such tests and the setting of such margins are based on assessments of future uncertainty in the pursuit of reliability (“Bulk Power System Reliability Criteria and Indices: Trends and Future Needs”).

As noted at the beginning of this section, these considerations from the various perspectives are summarized in the following figure, which is taken, unedited, from the referenced report. The figure combines (a) indices nd other indicators of reliability (CAIFI, SAIFI, etc.), (b) concerns typically expressed with respect to the separate parts of the electric power system (such as stability and frequency of equipment outages) and (c) objectives (such as adequacy of energy supply). This combination of value that can be used to compare and select the best reliability policy among competing policy alternatives. We shall return to this notion later in the report.

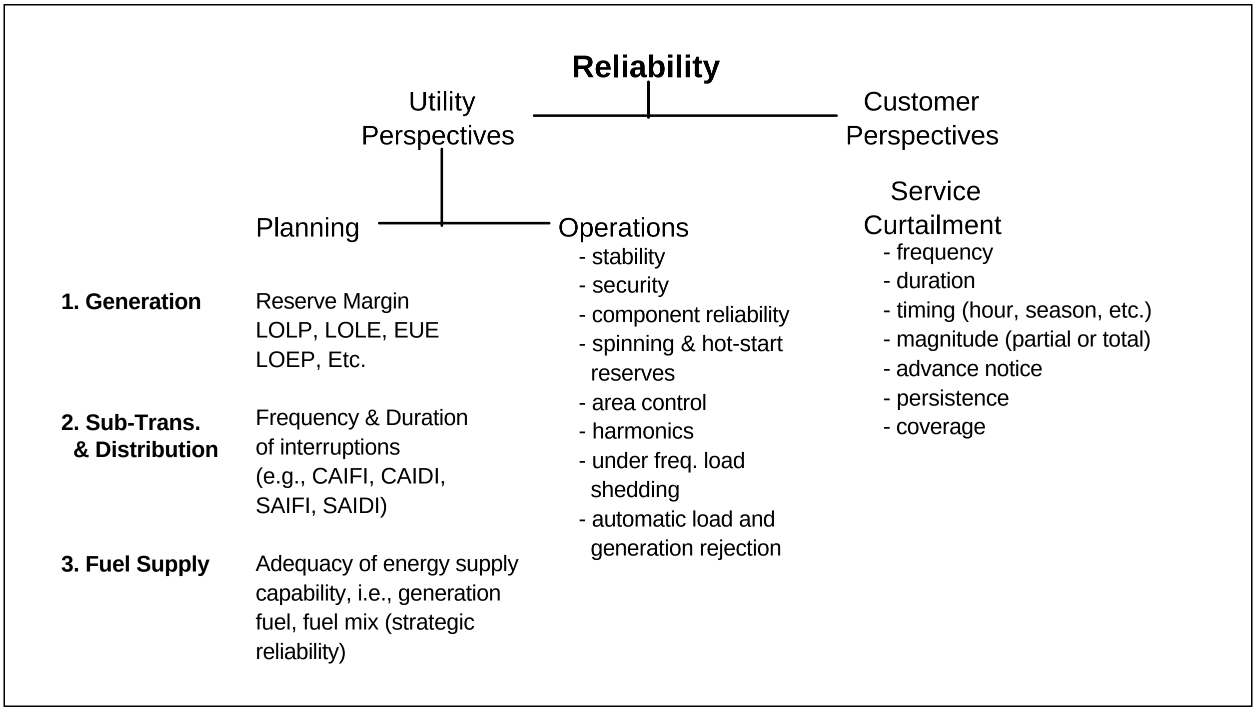

Figure 4-1
Perspectives on Reliability

5
MEASURING RELIABILITY

5.1 Reliability Indices

Overview

Along with the variety of definitions of reliability come a variety of ways to measure it. A metric for reliability is required for assessment of past performance, consideration of reliability in design, and setting of reliability goals. Many indices have been defined as measures of reliability. They measure different aspects of reliability or combinations of different aspects. Only a small number of these are common across several utilities, and the ones that are commonly used are not always defined in the exact same manner.

Reliability measures dealing with interruptions address three factors: frequency, duration, and extent or severity. The extent is the number of customers or load affected, which is determined by the layout of the distribution system (*Power Distribution Planning Reference Book*). Combining the two key factors of frequency and duration into a single appropriate measure may not be possible, so any one index may not be very valuable alone (*Power Distribution Planning Reference Book*). When assessing reliability, all three factors should be considered. Each reliability index may be important for a different purpose. Different utilities use different sets of indices.

There are more than forty reliability indices mentioned in the literature (see *Reliability Definitions.doc*). The most common indices are SAIFI, SAIDI, CAIDI, and ASAI. SAIFI and SAIDI are system-oriented measures of frequency and duration of interruptions. CAIDI and ASAI are customer-oriented measures of outage duration (per outage) and fraction of demand satisfied. CTAIDI and CAIFI are also important measures of outage duration and interruption frequency experienced by customers (*Power Distribution Planning Reference Book*). Other common indices that measure unavailability include ASUI, the complement of ASAI, and EENS, and AENS, measures of unserved load (*Reliability Assessment of Large Electric Power Systems*). Different utility personnel might employ different indices. For example, the planner may consider SAIFI, CAIFI, MAIFI, and MICIF to support decisions about layout and equipment (*Power Distribution Planning Reference Book*).

Standardization

Past efforts directed at standardization of the definitions and use of reliability indices have been reported in the literature. EPRI, through its Reliability Benchmarking Methodology efforts, has defined an extensive set of performance indices for use by all utilities (*Reliability of*

Benchmarking Methodology (5/97), TR-107938). Methods have also been provided for setting of target levels of quality (*Reliability Benchmarking Application Guide with Customer/Utility Common Power Quality Indices (9/99)*, TP-113781). The *IEEE Standard Trial Use Guide for Power Distribution Reliability Indices* (1366-1998; available at the IEEE website) has similar definitions and approaches. Distribution system reliability indices that are relevant to transmission are given in *IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States of Electrical Transmission Facilities* (#859-1987).

Reliability indices for distribution systems were defined as early as the 1970s. The Edison Electric Institute Transmission and Distribution Committee developed a *Guide for Reliability Measurement and Data Collection* (10/71) in 1971, which may have been unpublished. (See the citation in *Development of Distribution System Reliability and Risk Analysis Models* (8/81) Volume 1, 1-3.) The guide included the definitions of SAIDI, SAIFI, CAIDI, CAIFI, ASAI, and ALII. Prior to defining these frequency and duration indices, customer-hours of interruption and kVA-hours of interruption were proposed as measures of reliability and service (*Distribution System Reliability Engineering Guide* (3/76)). An early IEEE standard (346-1973) included SAIFI, CAIFI, SAIDI, CAIDI, ALII, ASCI, and ACCI (*Distribution System Reliability Engineering Guide* (3/76)). An early EPRI report indicated a preference for load point failure rate (or customer service outage rate) and average outage time as more physical, primary indicators that would give a better appreciation of system performance compared with the probabilities, availability and unavailability. Understanding that a certain customer will experience, for example, on average three service interruptions per year with four hours average duration was claimed to be more concrete or immediately descriptive than knowing that the customer's availability metric indicates a 99.95% probability of having service in any given hour. (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)).

Reliability Index Statistics

One use of reliability indices is the assessment of the past performance of the distribution system. Service continuity statistics for American utilities are generally not openly available. In Canada, however, the Distribution Section of the Canadian Electricity Association (CEA) compiled such statistics for over twenty years in annual continuity reports. (This practice may have increased record keeping as 45% of Canadian utilities did not determine service continuity statistics as of 1984 ("Distribution System Reliability Indices," R. Billinton, J.E. Billinton, *IEEE Transactions on Power Systems* 1/89).) The CEA now compiles this data through the Electric Power System Reliability Assessment (EPSRA). The 1998 report for example, *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99 CEA Item # 116.98), contains data from thirty-two Canadian and seven international utilities. Annual statistics as well as five-year average data of SAIFI, SAIFI (MI) [or MAIFI for momentary interruptions], SAIDI, CAIDI, and IOR [Index of Reliability; identical to ASAI] are given. The results are also broken out by cause: unknown/other; scheduled outage; loss of supply; tree contacts; lightning; defective equipment; adverse weather; adverse environment; human element; and foreign interference.

Sample statistics on the reliability performance for an American utility are tabulated in *Cost-benefit analysis of power system reliability: Determination of interruption costs Volume 1* (5/90). The leading cause of outages for the distribution system of this particular utility is storms, followed by equipment failures and third-party contracts (by third-party contracts, the authors may mean the curtailment of service to some customers because of contract requirements to supply power to third parties in certain situations). This report also contains a summary of outages by functional area:

- 85% of customer hours is lost from distribution system outages (poles and wires, cables, switchgear, etc.);
- 9% from substations;
- 4% from transmission;
- and less than 2% is caused by generation.

This is a clear indication of the primary importance of distribution system reliability to the reliability of the customers' electric power service: inability to provide service at individual load points arises mainly from distribution system equipment outages (*Reliability Assessment of Large Electric Power Systems*).

Groups of utilities in the United States participate in benchmarking programs on reliability performance of their distribution systems. One such program is the Annual Retail Utility Benchmarking Program of Hagler-Bailly for transmission and distribution (http://www.tbabenchmarking.com/htdocs/bench.html). The survey covers transmission and distribution costs and practices as well as service reliability. The report, which is only available to participating utilities, includes statistics on SAIDI, SAIFI, CAIFI, and MAIFI. Over one hundred utilities from the United States, Canada, and Europe were involved in the 1998 program. Another program is the Indianapolis Power and Light Large City Reliability Comparison. This survey concentrates on metropolitan area utilities.

Use of Reliability Indices

Comparisons across utilities such as the ones made in these programs must be done with caution. Differing definitions of interruptions can affect the reliability-index results. How different utilities treat momentary outages, scheduled outages, storms, and other non-failure related interruptions must be considered (*Power Distribution Planning Reference Book*). Given these concerns, utilities may be reluctant to allow comparisons of their performance. A survey of forty-nine utilities by the IEEE mentioned in a 1993 paper resulted in a Distribution Reliability Draft Guideline by the IEEE to promote the standardization of indices ("Measuring reliability of electric service is important," Beaty, W., *Electric Light and Power* v 71:5. May 1993, p. 35-38).

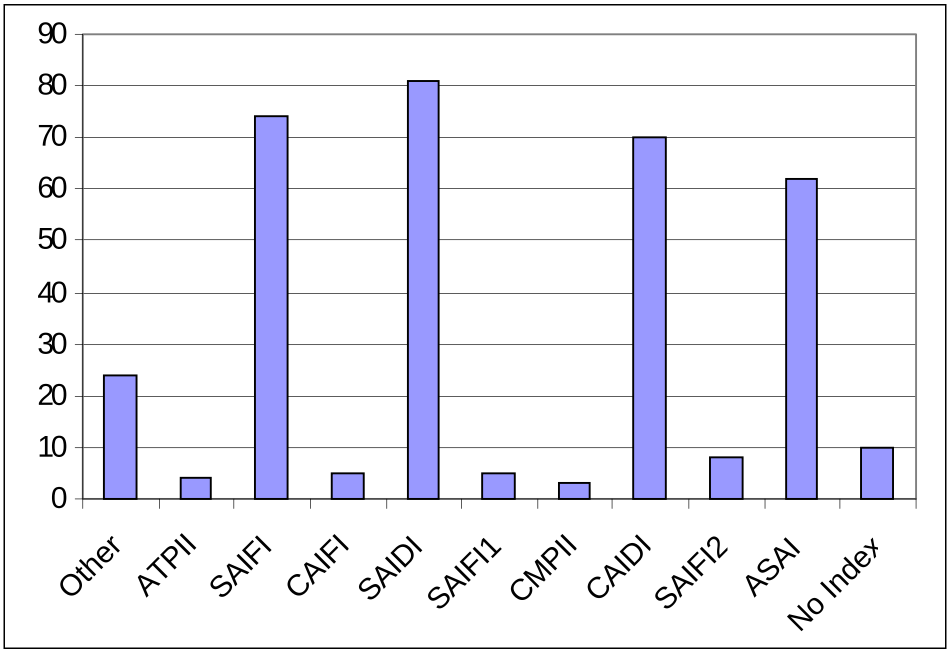

Figure 5-1
Use of Reliability Indices by Utilities
(Measuring reliability of electric service is important, Beaty, W. (5/93))

The figure above presents the use of reliability indices by utilities responding to the above-mentioned IEEE survey ("Measuring reliability of electric service is important," Beaty, W., *Electric Light and Power* v 71:5. May 1993, p. 35-38). Most utilities use more than one reliability index (*Power Distribution Planning Reference Book*). More than 80% of the surveyed utilities maintained SAIDI records. SAIFI, CAIDI, and ASAI were also widely used.

Although the use of indices may have increased over the years, the indices used most commonly have not changed. In 1981, it was reported that utilities used customer-related indices such as ASAI, SAIDI, and SAIFI (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)). At that time, about 20% of the utilities used their own indices. A comparison of results of surveys from Canadian and American utilities found, as well, that customer-related indices were more used than load-based ones. SAIDI, SAIFI, and CAIDI were popular in both countries. ASAI was found to be less popular in Canada ("Distribution System Reliability Indices," R. Billinton, J.E. Billinton, *IEEE Transactions on Power Systems* 1/89). Despite this, about 75% of North American utilities report availability (*Power Distribution Planning Reference Book*), a value that always suggests good utility performance but whose importance or accuracy as a characterization of reliability is questionable.

5.2 Equipment Data

Introduction

A lack of extensive and dependable equipment failure data has been a hindrance to quantitative distribution system reliability assessment in the past. Twenty years ago, few utilities recorded equipment failure data. A survey found that less than ten percent of responding utilities maintained component population records sufficient to provide failure rate data necessary for predictive reliability assessment (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)). This situation motivated the development of HISRAM by EPRI. HISRAM provided utilities with the tools and methodology to maintain equipment failure statistics. A decade later, equipment failure-rate databases for distribution systems still needed expansion. At that time, most utilities collected their own data for most transmission elements and logged distribution system failure and interruption data. For predictive reliability assessment, however, existing failure data were inadequate (*Cost-benefit analysis of power system reliability: Determination of interruption costs, Volume 1* (5/90)).

General Sources

There now exist several sources of equipment failure data. Present practices may promote even more extensive failure data collection (*Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery* (10/97)). Utility-specific data may be preferable for some purposes, but industry sources can be used in place of a utility's own data if that data is lacking. The IEEE Gold Book, *Design of Reliable Industrial and Commercial Power Systems* (IEEE Standard 493-1997), contains component failure data, including data for customer-side equipment. The Gold Book also contains other information on reliability modeling and customer outage costs.

More current data should be available from the Equipment Reliability Information System (ERIS) of the Canadian Electric Association (CEA). The CEA includes American utility participants. It presently publishes annual reports on transmission and generation equipment. For example, the reliability library includes the transmission report, *Forced Outage Performance of Transmission Equipment* (7/98). An analogous report for distribution system equipment is planned to be available in 2000.

Literature Sources

Journal articles are additional sources for distribution-system equipment failure information. There are articles specifically on failure rates for overhead equipment, underground equipment, and for circuit breakers. In addition, there are a variety of articles with sample data.

A five-year study ending in 1989 of eighty-five rural and ninety-five urban overhead distribution feeders produced a database for overhead distribution system components ("The Failure Rates of Overhead Distribution System Components"). Failure rates for transformers, switches, fuses, capacitors, reclosers, voltage regulators, and conductor were obtained from the study performed on the PG&E system. The study found that component failure accounted for 15% of sustained outages for the overhead feeders, while 75% was from external factors, such as automobiles, animals, trees, and lightning; 10% was from loss of supply. The authors contend that this result demonstrates that overhead distribution system reliability is insensitive to component failure at the existing component failure rates.

Data is available for underground systems as well. One sample result indicated that an urban underground system can have an average time to repair of seventy-three hours (*Power Distribution Planning Reference Book*). Data from 1968 to 1988 supplied by SDG&E and NELPA were used to calculate failure rates of underground components in "Determination of Failure Rates of Underground Distribution System Components from Historical Data." The article has results for HMPE 15-kV unjacketed cable, XLPE 15-kV unjacketed cable, single-phase distribution transformers, and load break elbows.

Circuit-breaker data can be found in "High Voltage Circuit Breaker Reliability Data for Use in System Reliability Studies." Data from two international studies from 1974-1977 and 1988-1989 are presented. The study involved tens of thousands of breakers. The combination of the results from the two studies covers both older technology circuit breakers and the newer SF6 circuit breakers.

Additional Sources

Sample data that is used for an assortment of purposes are located in some additional documents. Illustrative distribution-system component data for predictive reliability analysis is given in *Guide to Value Based Reliability Planning* (1/96). Further, articles such as "Value-based distribution reliability assessment and planning" (*IEEE Trans. Power Delivery* 1/95, 421) and "Application of customer-interruption costs for optimum distribution planning" (Mok, Chung; Energy (96)) contain tabulations of the failure data used in the their calculations.

The *Power Distribution Planning Reference Book* contains failure data as well as other sample outage and reliability information. Outage-rate data for substation transformers is said to be inadequate because (a) only a small amount of data is generally available, and (b) the use of different recording methods limits the general applicability of the available data. Outage results are examined for substations with different numbers of transformers, and for varying substation size. Varying sub-transmission voltages and configurations are also evaluated. Durability, the reliability of equipment as a function of remaining life and loading, is also discussed.

Finally, to overcome the hesitation of utilities to perform predictive distribution system reliability assessment because of inadequacy of historical component data, the authors of "Distribution System Reliability: Default Data and Model Validation" (*IEEE Trans. Power Systems* 5/98, 704) present a method by which default component reliability data can be developed and validated by matching historical values.

6
UTILITY RELIABILITY PRACTICES

6.1 Planning Philosophies

Overview

Reliability is a basic design criterion in distribution system planning for most American utilities. The criteria for reliability are usually set by the company and are rarely influenced by the customers or regulators (*Cost-benefit analysis of power system reliability: Determination of interruption costs Volume 1* (5/90)). Traditionally, the contingency-coverage perspective is taken in distribution system planning, where the system is designed to minimize interruption and to ensure efficient restoration of power under different scenarios of utility equipment failure (*Power Distribution Planning Reference Book*).

A more effective, but more difficult, approach is the reliability-index approach. With this newer approach to distribution system reliability planning, contingency support is provided to meet the set reliability-index targets. Software and data for the computation of reliability indices are required. Indices, such as SAIDI and SAIFI, are design constraints for the planner. Some contend that this approach may become more widely used for the following reasons: (a) it addresses reliability directly from a customer standpoint, rather than indirectly from a utility (equipment criteria) standpoint, leading to improved quality assurance; (b) it imposes no restrictions on design or equipment other than that the results meet customer performance needs; and (c) dependable, proven methods for reliability-based design are becoming widely available (*Power Distribution Planning Reference Book*). Statement (c), above, is clearly important. If methods do not exist, then the approach cannot be implemented. We are not as confident as the authors of this reference about the existence of such “dependable, proven methods.” Reliability-index-based design is not new and there are certainly examples of the application of different approaches, as we discuss below in the Analysis Methods section of this report. Two important reservations are the following: (1) there is no reason to believe that any of these techniques comprises the optimal approach to the problem and (2) what proven methods exist are not implemented in generally applicable software packages. It is important to clarify that the existence of a proven method does not imply the existence of a proven implementation of that method. The practical application of a method requires more than the mere existence of the method itself.

Examples of reliability standards used by some utilities are

1. ASAI≥0.9998, SAIFI<1, CAIDI<2 hours;

2. ASAI≥0.99975 for urban, ≥0.99935 for low-density rural, CAIDI≤270 min, SAIDI≤187 min, FAIFI 2.4/circuit/year;

3. SAIFI 0.75 for residential, 0.6 for commercial, SAIDI 65 min for residential, 45 min for commercial, at most one outage/year and 80 min for very large commercial (*Cost-benefit analysis of power system reliability: Determination of interruption costs Volume 1* (5/90)).

Common standards for generation reserve margin levels are LOLP of 1 in 10 years, and EUE of 24 hours in 10 years (Outage cost estimation guidebook (12/95)).

Clearly, it is not possible to plan to prevent all interruptions, yet planning can decrease the rate of occurrence of service interruptions. There are many causes for equipment outages and service interruptions. Outages can be caused by equipment failure due to weather conditions or other causes, and by equipment being switched off deliberately, by mistake, or by failure of control equipment. Service interruptions can be caused by a downed line, failed cables, a damaged transformer (e.g., by overloading), or failures in customers' equipment (e.g., open wiring, corroded switchgear). Momentary interruptions can be caused by natural events such as trees brushing conductors, thus causing a high-impedance fault; small animals contacting conductors and being vaporized; or lightning. Some interruption prevention solutions may be routinely included in planning because the cost of implementation is not high; e.g., placing two sub-transmission lines coming into a substation on different structures. Other issues are not so straightforward (Power Distribution Planning Reference Book 400). The distribution system needs to be planned, designed, and maintained with particular attention to interruption prevention.

In actual experience, North American customers see about 1 to 3 interruptions per year and 1 to 4 hours per year of outage, with rural customers experiencing typically 6.5 to 7 hours per year of outage. A typical customer may see three interruptions and three outage hours every two years (*Power Distribution Planning Reference Book*). Not surprisingly, the actual performance of utilities on the reliability indices varies. An IEEE survey found that SAIFI values ranged from 0.554 to 3.3 with an average of 1.5. SAIDI values ranged from 30 to 245 minutes per year, with an average of 97 minutes. ASAI averaged 0.99982 (*Measuring reliability of electric service is important*; Beaty, W.; Electric Light and Power (5/93)).

Value-Based Planning

The reliability levels used as planning criteria have traditionally been set somewhat arbitrarily. In addition, out of the set of alternatives that meet the specified criteria, the least cost alternative is chosen. This practice is required by the cost-based-pricing regulatory environment in which distribution utilities operate (*Power Distribution Planning Reference Book*). A *value-based planning* approach, on the other hand, selects reliability levels or alternative expansion/reinforcement plans based on both equipment costs and customer outage costs. Utilities in France, Great Britain, and Sweden began to collect outage costs more than three decades ago for use in generation planning. ("Report of the Group of Experts on Quality of Service from the Consumer's Point of View" Lennart Lundberg; *International Union of Producers and Distributors of Electrical Energy*, 1972. Report 60/D.1) The overall industry's experience with value-based planning is limited however, particularly for distribution systems (*Outage cost estimation guidebook* (12/95)). Perhaps as few as one percent of applications in transmission and distribution planning employ value-based reliability forecasts (*Power Distribution Planning Reference Book*). One interesting aspect of value-based planning is that it may change the levels of reliability provided to customers. Indeed, value-based methods suggest that the current high levels of reliability in the United States may not be justifiable with respect to reliability worth (*The Value of Service Reliability to* Consumers (5/86) Section 7: "Optimal Electricity Supply Reliability Using Customer Shortage Costs", Arun P. Sanghvi).

Value of service is considered implicitly in practice in some cases, resulting in differential reliability among customers ("Reliability at What Cost? Analyzing the economics of (improving) distribution reliability"). For example, reliability targets differ for urban and rural systems, as the cost per customer for improved reliability is much greater for rural systems. Reliability goals set by service area based on local conditions and local customer requirements would be best. In some situations, rate-reliability tier areas exist in categories such as downtown network, urban, high-use industrial, suburban, rural, and mountainous (*Power Distribution Planning Reference Book*). High reliability in situations of public safety is essential. For example, hospitals, military establishments, some larger theaters, department stores, apartment buildings, and hotels often are provided auxiliary sources (*Electrical Distribution Engineering, 2nd Edition*). Differing values for reliability across customers make it difficult to apply value-based planning, but the approach can help establish guidelines for different customer classes (*Power Distribution Planning Reference Book*).

Although value-based distribution system planning may not be widespread among utilities, another reliability-based program is being practiced. Utilities are using Reliability Centered Maintenance (RCM), under EPRI guidance, as a maintenance-planning tool. RCM is used to balance the cost of routine maintenance against service reliability. It is a step-by-step method to prioritize equipment maintenance needs. There are a variety of publications on RCM. Some have databases that are qualitative compilations of the causes of failure for specific equipment. One document, *Reliability Centered Maintenance (RCM) for Distribution Systems and Equipment: Four Application Case Studies* (5/99), discusses implementation and acceptance of RCM by utilities and management and may at some point be instructive for the promotion of reliability-based planning to utilities.

6.2 Typical Reliability-Related Practices

Introduction

The textbooks *Electrical Distribution Engineering, 2nd* Edition, and *Power Distribution Planning Reference Book* contain material on typical reliability practice for distribution systems at utilities. The following paragraphs summarize some of the information contained in these textbooks.

Feeder Design

Reliability is largely affected by and influences the choice of feeder layout. Most distribution systems, more than 80% worldwide, are radial, and less than 0.1% of power in the U.S. is delivered over secondary networks (*Power Distribution Planning Reference Book*). Generally, there is an increase in reliability in going from radial feeder layouts to loop systems to network systems. For radial systems, the failure of a segment interrupts, on average, the service of half its customers. A loop system can provide very high reliability. On average, for a loop system, two simultaneous failures interrupt only one quarter of the customers. Networks are the most reliable. The loss of a segment will not interrupt any customers, and multiple failures can occur with little or no interruption. Network systems, however, are more costly and require more expensive protective devices and coordination schemes. The ideal choice of feeder system varies with the situation and with design practice. For example, large commercial buildings require above average reliability, so loop feeders are used. Rural system reliability requirements are lower. Customers apparently accept that their remoteness justifies less reliable electrical service, so a radial system is often appropriate. Alternate sources, paths, and configurations of service must be planned so that both failures and maintenance do not affect customer service beyond a reasonable amount. The classical distribution system analysis did not assess the impact of feeder layout (i.e., the overall feeder system design) on service reliability, but that has changed (*Power Distribution Planning Reference Book*). Some methods have been presented that include feeder layout as an input to reliability analysis. See the references cited below that discuss some quantitative approaches to analyzing the effects of feeder layout on reliability parameters such as outage frequency, outage duration, and SAIDI.

Another choice in feeder design is between laying the feeders underground or using overhead feeders. Underground systems improve both reliability and aesthetics. Overhead design is much less costly but more vulnerable to natural hazards (wind, ice, lightning, flood, etc.) and people (vehicles hitting poles, kites, etc.) (*Electrical Distribution Engineering, 2nd Edition*). Adverse weather and trees cause most lengthy outages on overhead lines, and trees brushing against conductors in high winds cause most momentary outages. Underground systems circumvent these problems. Also, underground systems can reduce harmonics propagation between customers, since there is usually no shared power flow. Outages can occur with underground systems from ground lightning strikes that destroy cable. Construction dig-ins and rodents can also cause problems, and, if the cable survives the rodents, underground lines generally wear faster than overhead ones. In addition to reliability, the cost and time for routine maintenance and repair are also higher for underground systems. A concrete duct bank is difficult to repair and has a high initial expense, but increases reliability further (*Power Distribution Planning Reference Book*). Overhead feeders are easier to maintain as faults are easily located and fixed.

A quantitative comparison of the reliability of different feeder designs is presented in “Reliability and Quality Comparisons of Electric Power Distribution Systems” (Settembrini, Fisher, Hudak; *Proc. of T&D Conference*, IEEE (9/91)). Considering the layout along with the underground versus overhead option, there are a variety of different feeder designs from which to select. Seven common distribution system designs are simple radial (overhead), primary auto loop, underground residential distribution, primary selective, secondary selective, distributed grid network, and spot network. This article compares these designs with respect to outage frequency, outage duration, and other power quality characteristics.

Related to the above discussion is the concept of *extent*. Extent is the number of customers whose service is interrupted by the outage of particular utility equipment and is the key to the equipment outage-service interruption relationship. Extent is an important variable determined by the system layout. The distribution system planner trades off cost against extent. The result is that urban and suburban systems usually can have service restored in minutes by switching feeders. On the other hand, repair is often the solution selected in the system design for rural systems (*Power Distribution Planning Reference Book*).

As mentioned above, the contingency-coverage perspective guides most distribution system planning. Most urban and suburban feeder systems are laid out so every feeder has complete contingency backup through reswitching of its loads to other sources. Note that manual switching for contingency may have a practical limit of about six to eight switching operations. Automatic switching can increase the limit to a dozen or more (*Power Distribution Planning Reference Book*). A tabulation of the relative cost and relative SAIDI of various feeder-style contingency schemes is tabulated in the *Power Distribution Planning Reference Book.*

Additional Practices

Protection criteria in place for safety reasons also affect reliability. The planner goes by the general guideline that he must provide a distribution system that can be protected. Equipment, such as circuit breakers, sectionalizers, fused disconnects, control relays, and sensing equipment, detects interruption of normal service and isolates the faulted equipment. Design criteria set by the planners for engineers specify how equipment must be used. Usually, equipment is employed at levels below the manufacturers' ratings at levels dictated by local conditions and use. These loading standards are often exceeded in extreme emergencies, after considering the benefits of addressing the emergency. The usual view on criteria and standards is that they must be met, and that there is no additional benefit in exceeding them (*Power Distribution Planning Reference Book*).

Root causes for degradation of different equipment that could lead to interruptions, such as in the RCM report mentioned previously, are also described in *Electrical Distribution Engineering*. In addition, this book contains information on reliability-related design issues for equipment such as conductors, poles, cross arms, pins, racks, insulators, transformers, cutouts, surge arresters, regulators, capacitors, switches, reclosers, and automated distribution. For example, it is suggested that conductor failures, in particular, should be minimized, since they result in complete service interruptions. (The interruption is characterized as "complete" because a conductor failure causes all customers between the switches that isolate the downed line to have a service interruption and remain out until the line is fixed). (*Electrical Distribution Engineering, 2nd Edition*).

Reliability considerations also affect the planning for substations and their transformers. Distribution substation design, including costs for different capacities and reliability levels, is discussed in the *Power Distribution Planning Reference Book.* There are several important aspects of substation and transformer reliability considerations. Equipment reliability generally decreases as one moves down the system towards the customer. Reliability of equipment at the substation level has greater impact on customer service reliability than reliability of equipment nearer the customer, such as pole transformers, because more customers are affected by the former than the latter. Furthermore, the outage duration of substation transformers is measured in days, while that of pole transformers is measured in hours. Reliability improvements at the substation level are usually more costly. Voltage and contingency levels are decision variables in substation and transformer planning. Higher voltage lines are more reliable because they have better insulation and can better withstand lightning strikes. (Although this is what is reported in the cited reference, there are others who argue that 4kV systems are very reliable—an observable fact— because the lower voltage requires much less protection and insulation.) The towers for high voltage lines are stronger than lower voltage poles and they provide greater clearance, hence greater reliability. Multiple substation transformers provide additional reliability in the form of contingency support through redundancy. On the low-voltage side of the substation, equipment reliability, in itself, is not usually considered as critically in planning, outside of ensuring equipment compatibility with the transformer contingency support. (*Power Distribution Planning Reference Book*). The apparent justification for this reduced consideration is that service interruptions caused by outages of equipment on the low-voltage side of the substation can usually be addressed at the feeder level by switching. Furthermore, it is argued that the lower voltage of this equipment makes it more lasting and easier to maintain than the high-side and transformer equipment. These justifications can be argued, but cannot replace the need for a complete reliability analysis in order to value the consequences of various investment and maintenance policies on the low-voltage side of the substation.

7
REGULATORY ISSUES

7.1 Overview

Formal regulation of the reliability of electric power distribution systems in North America is uncommon. The utility usually sets the design criteria in distribution planning with little direct influence from customers or regulators (*Cost-benefit analysis of power system reliability: Determination of interruption costs Volume 1* (5/90)). The North American Electric Reliability Council (NERC) is not involved with the regulation of the reliability of the distribution system, nor are the ten regional reliability councils of which it is composed. The function of the NERC is to govern the reliability of the interconnected electric generation and transmission systems in North America through voluntary standards. State authorities regulate the distribution system. However, explicit regulations on the reliability of a distribution system are rare. One example of an explicit regulation is the requirement by the New York Public Service Commission for Consolidated Edison to design to a second-contingency criterion in certain areas of their distribution system (RFP from the New York City Economic Development Corporation on the Con Edison system; section II). This requirement was purportedly motivated by a major outage event in the early 1960s.

As mentioned, the three stages of electric utilities are regulated differently. For example, federal authorities regulate sales between utilities and transmission rates, while state regulators cover plant construction, retail rates, and distribution. Franchise and state utility statutes govern the enforcement of adequacy requirements for investor-owned utilities. Partly due to the self-governance of the reliability councils, there has been very little regulation of reliability at the state or federal level (*Electric Utility Restructuring: A Guide to the Competitive Era*). A description of the structure of the electric utility industry, including discussion of the regulatory structure, the history of regulation, and the connection between regulation and competition, can be found in *Electric Utility Restructuring: A Guide to the Competitive Era*. In addition, the book lists the recommendations of the Department of Energy (DOE) for the regulation of reliability under competition. State utility regulation is covered in this book, but there is no discussion of regulated reliability standards for the distribution system.

The state regulatory authorities for distribution systems concentrate on cost-based rate setting. The standard practice of state regulatory authorities is to review service quality at a rate case and possibly to adjust the rate of return if service quality was poor ("How to Construct a Service Quality Index in Performance-Based Ratemaking"). Recently however, regulators have begun introducing performance-based regulation (PBR) in isolated cases. Early PBR lacked provisions for maintenance of customer service (*Electric Utility Restructuring: A Guide to the Competitive Era*). That has changed in some cases. PBR can involve positive or negative regulatory incentives. For example, regulation for Consolidated Edison involves penalties for poor performance.

A PBR example incorporating reliability is provided by SDG&E. The PBR program has been in effect since 1994 and includes incentives for customer service and reliability. The reliability incentives are based on average customer minutes of interruption (ACMI) and frequency of customer interruption. With respect to the frequency metric, for example, if there are between 10350 and 11450 customer interruption events on the SDG&E system in a year, there is no reward or penalty under this PBR case. For each 183 additional customer interruptions above 11450, there is a $1 million penalty charged to SDG&E. Conversely, there is a $1 million reward per 183 interruptions that the customer interruption total falls below 10350, with an $18 million maximum. ("Reliability at What Cost? Analyzing the economics of (improving) distribution reliability").

Extensive regulations do not exist in Canada either. Distribution system reliability has no national standards or criteria, so utilities often develop corporate targets for common indices based on historical experience and benchmarking to other utilities (*Guide to Value Based Reliability Planning* (1/96)). A 1991 survey found that many utilities were unclear about what authority regulates them; i.e., the respondent could not say whether the reliability of the system would be regulated at the federal level, the provincial level, or the municipal level. Of those that responded informatively, 80% indicated regulation by a provincial authority and 20% by a municipal authority. 20% indicated that regulatory authorities formally considered reliability performance of the distribution system, while for the remainder it was considered informally or not at all. Half did indicate though that both utility and customer costs could be used to justify investments in distribution system reliability. The survey results can be found in *Guide to Value Based Reliability Planning.*

7.2 Reporting Requirements

Although there may not be strict regulation of reliability levels for distribution systems, there are reporting requirements. These requirements may include mandatory reporting of power quality incidents in addition to interruptions. Distribution systems are covered under the US DOE Disturbance Reporting Requirements for loss of firm system loads, voltage reductions or public appeals, vulnerabilities that could impact bulk electric power system adequacy or reliability, reports for other emergency conditions or abnormal events, or fuel supply emergencies (NERC operating manual).

Several states have also instituted annual reporting requirements of reliability performance (*Electric Utility Restructuring: A Guide to the Competitive Era*). These reporting requirements for utilities differ by state. A survey reported in the early 1980s found that nearly half of responding utilities collected outage data for legal or regulatory requirements (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)). The IEEE had produced standard definitions for reporting and analysis of reliability (IEEE 346-1973, *IEEE Standard Definitions in Power Operations Terminology Including Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Services*). *IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States of Electrical Transmission Facilities* (IEEE Standard #859-1987) is a more recent document from IEEE, but it is specifically for transmission. Regardless of the IEEE guidelines, the definitions for outages vary by state as well. From the survey, for example, some state authorities required reporting of sustained interruptions, but not all had specific definitions of a sustained interruption. Other requirements were for the recording of exceptional circumstances. California defined “exceptional” as 500 customers interrupted for 1 hour or a loss of 200MW capacity for 15 minutes. (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)). Some states required only that reliability information be available on demand. A tabulation of the results of the survey on reporting requirements is in *Development of Distribution System Reliability and Risk Analysis Models*. The results of a more recent survey found that at least one state requires classification of outages by cause and reporting of momentary outages is usually not required (“Measuring reliability of electric service is important”). Practices of utilities correspondingly vary with the reporting requirements, with utilities in states requiring reliability reports having more complete documentation (“Measuring reliability of electric service is important”).

The Edison Electric Institute (EEI) had suggested a set of outage data to be collected but the guidelines may have been unpublished (*Development of Distribution System Reliability and Risk Analysis Models* (8/81)). The 1971 Guide for Reliability Measurement and Data Collection (10/71) from the Transmission and Distribution Committee of EEI may contain these guidelines (“Distribution System Reliability Indices,” R. Billinton, J.E. Billinton; *IEEE Transactions on Power Systems* 1/89). The American Public Power Association (APPA), which represents municipal and other state and local government-owned electric utilities, may have their own guidelines. There is an indication that some organizations are involved in the evaluation of the reliability of distribution systems. The NERC relies on the expertise of the APPA, the EEI, and the National Rural Electric Cooperative Association to prepare quarterly assessments of American distribution systems for incorporation into an NERC report to the DOE (“Reliability Assessment 1998 – 2007: The Reliability of Bulk Electric Systems in North America” (9/98)). Again though, from past surveys, reporting requirements vary by state, and they are usually not extensive. No recent information was found that indicates the situation has been clarified.

An example of state requirements is from Illinois. Illinois utilities recently began reporting on the reliability of their transmission and distribution systems under the Reliability Rules of the Illinois Commerce Commission (Title 83 of the Illinois Administrative Code, Section 411.120(b)(3)). Under the rules, electric power utilities must report on

- the plan for investment and reliability improvements for transmission and distribution facilities
- implementation of the previous plan
- number and duration of interruptions and their impacts, controllable and uncontrollable, as well as ones caused by other entities
- comparison with alternative suppliers on interruption frequency and duration
- age, condition, reliability and performance of transmission and distribution facilities
- expenditures for transmission and distribution construction and maintenance
- results of an annual customer satisfaction survey on reliability, customer service, and customer understanding of service
- overview of customers’ reliability complaints
- CAIDI, CAIFI, SAIFI for each operating area

- list of worst-performing circuits for each operating area
- operating history, maintenance history, plans, and schedule for worst-performing circuits
- numbers of customers experiencing greater than set numbers of interruptions
- number of interruptions and duration, and the number of consecutive years the number of interruptions above service reliability targets for each customer
- discrete areas for which reliability data kept and reliability data-collection and record-keeping procedures
- and must maintain service records detailing any interruption that affects 10 or more customers or power fluctuations affecting 30,000 or more

7.3 Changes in North-American Regulatory Structure

The organization overseeing the reliability of the generation and transmission systems in North America is under transformation in response to deregulation, but distribution system regulation may not be affected. Short-term reliability for the design of generation and transmission systems is achieved by the voluntary agreements to use regional reliability council standards, which are all backed by state and federal regulatory authorities (*Electric Utility Restructuring: A Guide to the Competitive Era*). The history of the NERC and these regional reliability councils, which were created in part as a reaction to the 1965 blackout in the northeastern U.S., is discussed in *Electric Utility Restructuring: A Guide to the Competitive Era*. Recent legislation proposed in the U.S. by NERC and DOE would make the reliability standards legally enforceable. Deregulation has made voluntary compliance with reliability standards unlikely. The formation of a new North American Electric Reliability Organization (NAERO) overseen by the FERC is planned.("Reliability: NERC/FERC Convergence," "Reliability Assessment 1998 – 2007: The Reliability of Bulk Electric Systems in North America (9/98)"). Despite these changes, the distribution system will continue to be regulated by state authorities and prices for power delivery will still be cost based (*Power Distribution Planning Reference Book*).

7.4 Additional Requirements

Despite the lack of extensive direct regulation of the reliability of the distribution system, utilities may need to conform to requirements and standards from an assortment of sources. For example, minimum design criteria for overhead conductors are suggested by the National Electric Safety Code (NESC). The widely accepted NESC is issued by the Institute of Electrical and Electronics Engineers (IEEE) (*Electrical Distribution Engineering, 2nd Edition*). These guidelines divide the country into high, medium, and light wind and ice load areas and suggest that local conditions should be taken into account. Another requirement is that no customer receive over 120 V and that the distribution feeder be at the lowest voltage possible permissible within voltage drop allowances (*Power Distribution Planning Reference Book*). Additionally, there are standards for power quality. These are discussed in the following power quality section.

8
POWER QUALITY

8.1 Introduction

Electricity must be delivered in a form that meets the requirements of the consumer. Changes in those requirements and in how electricity is delivered have brought a greater emphasis on power quality. Power quality refers to the attributes of the power delivered to customers, including voltage, wave form, and harmonics (*Power Distribution Planning Reference Book*). Today, loads are more sensitive, loads are interconnected in extensive networks having automated processes, and there is a growing percentage of loads using power electronics in conversion processes. Corresponding to these changes, there are three parties to the issue: the end user, the utility, and the equipment manufacturers (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). Some contend that the definition of power quality should relate most to the end users because they are the ones actually impacted. Thus, a power quality problem can be defined as voltage, current, or frequency deviations that result in failure or misoperation of equipment (*Power Quality Workbook for Utility and Industrial Applications* (10/95)).

With a sustained interruption being defined as a loss of voltage of greater than one minute, ninety-five percent of system faults are temporary (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). These interruptions can appear as voltage variations which, along with capacitor switching, can cause customer equipment failures or restarts. Equipment today requires "cleaner" power than did the electronic equipment of the past. Hence, common occurrences, including small changes in voltage, are no longer inconsequential (("Utilities today must provide 'clean' power"). As an example, the cost to utility customers in Canada has been estimated to be as high as $1.2 billion Canadian per year (*Canadian Utility Perspective on Power Quality*).

In addition to the greater service reliability and stricter voltage level requirements, the increased use of computers for control purposes and of other sensitive electronic loads has placed requirements on the waveform of the electricity supply. Distorted voltage waveforms are caused by customers or by the conditions of the electric system (*Electrical Distribution Engineering, 2nd Edition*). Customer loads are generating more harmonic currents. The distribution system can magnify these currents.

Harmonics may cause interference with communication circuits and affect the operation of computers *(Electrical Distribution Engineering, 2nd Edition*). Solutions are hindered by the complicated interaction between the harmonic currents and the electricity supply ((Utilities today must provide "clean" power)).

The practices of utilities have had to change with the increasing demands for power quality. For example, in the past, most utilities recorded only outages greater than five minutes, because shorter outages were rarely an inconvenience ("Reliability and Quality Comparisons of Electric Power Distribution Systems," Settembrini, Fisher, Hudak; *Proc. of T&D Conference*, IEEE (9/91)). Issues with which utilities now have to concern themselves (in addition to sufficient capacity, service continuity, and environmental considerations) are selection and maintenance of proper voltage, and the maintenance of frequency within strict limits. Voltage distortion and current fluctuations can affect the reliability of equipment and thus the reliability of the components of electrical distribution systems (*Electrical Distribution Engineering, 2nd Edition*). In the past, utilities responded to customer complaints on power quality and covered the cost of the solutions themselves. Now, the costs are being shifted to the customers causing the problem or to the customers requesting better than average power quality (*Canadian Utility Perspective on Power Quality*).

The concern of utilities with power quality is mirrored in the literature. There are many articles covering a variety of power quality issues (e.g., "Power quality. End user impacts." Smith, J.C, *Energy* 88:5). In addition, the *Power Distribution Planning Reference Book* has a great deal of information on the subject.

8.2 Categories For Power Quality Problems

Power quality problems can be categorized roughly as long duration voltage variations, sustained interruptions, voltage unbalance, impulsive transients, oscillatory transients, voltage sag, voltage swell, momentary interruption, and flicker (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). Flicker problems, or motor induced sags, are longer in duration than the momentary interruptions, but not as deep in voltage reduction (*Power Distribution Planning Reference Book*). Voltage sags are the most important power quality problem for many types of industrial customers, in part because they occur more frequently than interruptions (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). Harmonics, frequencies other than the standard 50 or 60 Hertz, can cause problems even if they don't cause malfunctions. They are thought to increase equipment costs by 10% due to reduction in useful life (*Power Distribution Planning Reference Book*). A clear review of the different types of power quality concerns along with definitions of power quality issues can be found in "Power quality monitoring of a distribution system" (4/94).

A categorization of power quality problems with more technical detail follows (*Active Power Line Conditioning Methods: A Literature Survey* (7/95)):

1. transients (<30 cycles),
2. short-duration RMS variations (0.5-30 cycles),
3. long-duration RMS variations (>30 cycles),
4. interruptions (at least ½ cycle),
5. distortion (harmonics between orders 2 to 100),

6. flicker (spectral content less than 30 Hz),
7. noise (0-200kHz),
8. electromagnetic interference (<200kHz),
9. electrostatic discharge, and
10. radio-frequency interference (>200kHz).

The variety of power quality problems arises from a variety of sources. A study of power quality showed that interruptions were the primary source of problems to utilities' residential customers. Besides interruptions, it was found that customers create most of their own power quality disturbances ("Power quality monitoring of a distribution system"). For example, flicker is usually caused by the starting of large, multi-phase motors. From this, flicker standards are often called motor start voltage standards or motor starting criteria. However, flicker can also be caused by other industrial equipment or switched utility equipment such as capacitors or phase shifters (*Power Distribution Planning Reference Book*). Induction motors, especially small ones for items such as blowers, air conditioning, compressors, and the powering of conveyor belts, can produce a lot of power quality problems as well. Harmonics are passively generated by electrical equipment with non-linear loads, such as transformers, motors, other overloaded 'wound' devices, AC-DC power supplies, clipping devices, diodes and semiconductor devices (*Power Distribution Planning Reference Book*). Some feel that lightning may be the leading cause of sags, with capacitor and other switching also contributing (*Power Distribution Planning Reference Book*). However, one study showed that lightning surges were not a primary cause of power quality problems in the area studied ("Power quality monitoring of a distribution system"). Lastly, one or two phases being down can lead to unusual voltages occurring in three-phase commercial buildings (*Power Distribution Planning Reference Book*).

8.3 Standards

Along with increasing concern with power quality on the part of utilities has come a desire for standardization of power quality and power quality measurement. Utilities may incorporate power quality standards into their design criteria for distribution planning. However, a study in the early 1990s contended that industry standards were deficient ("Power quality monitoring of a distribution system"). The variety of power quality problems complicates the standardization of measurement procedures and equipment (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). Some of the organizations involved in standards setting for power quality are

- The Institute of Electrical and Electronics Engineers, Inc. (IEEE http://www.ieee.org/)
- American National Standards Institute (ANSI http://www.ansi.org/)
- Canadian Electricity Association (CEA http://www.canelect.ca/)
- Comité Europeén de Normalisation Electrotechnique (CENELEC http://www.cenelec.be/)
- International Electrotechnical Commission (IEC http://www.iec.ch/)
- Computer and Business Equipment Manufacturers Association (CBEMA)

The standards for power quality in the United States are contained in IEEE 1159 (IEEE documents are available to members at the IEEE website). ANSI/IEEE Standards are referenced often. In Europe, utilities abide by the supply standards of CENELEC EN 50160. Internationally, there are the IEC standards. IEC 555-2 and IEC 555-3 are replacing or have replaced the IEC 1000 series standards and, in turn, will be replaced by the IEC 61000 series by 2001 (*Canadian Utility Perspective on Power Quality*).

Other relevant standards are ANSI C84.1 and ANSI/IEEE 519-92, "IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." This last document addresses harmonics. Increasing the tolerance of an appliance may be more costly than reducing its own harmonics output. However, no enforceable requirements for manufacturers exist, except for some medical and military equipment (*Power Distribution Planning Reference Book*).

Utilities may also have their own standards (see *Power Distribution Planning Reference Book* for sample, primary distribution-level voltage standards of ten utilities). For example, many utilities use a flicker magnitude versus frequency of occurrence guideline (*Power Distribution Planning Reference Book*).

Utility standards in the United States for voltage variation are usually based on ANSI standard Range A (±5% on 120V, 114 to 126, service voltage) and Range B (105.8% to 91.7% or 127 to 110) for temporary or infrequent conditions (*Power Distribution Planning Reference Book*). ANSI C84.1 specifies the steady state tolerances to be expected on a power system to be +6% to –13% of nominal (*Power Quality Workbook for Utility and Industrial Applications* (10/95)). A 10% range in voltage in a service area may be okay. However, any one customer must see only a ±3-6% variation, and any fluctuation must happen slowly. Voltage variations outside of ±10% may damage equipment. The 6% voltage spread at a single customer point may be reasonable if it occurs over a number of hours (*Power Distribution Planning Reference Book*). From tests, it has been shown that customers may not notice a 5% voltage reduction (*Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)). Rapid voltage fluctuation or flicker, on the other hand, is discernible in illumination at levels of 3% and 5% and very noticeable if it occurs within 1-2 seconds (*Power Distribution Planning Reference Book*).

The Computer and Business Equipment Manufacturers Association (CBEMA) has a set of recommended voltage variation versus duration levels. The chart is available in the *Power Distribution Planning Reference Book*. It is reported that 85% of the sags that are outside the CBEMA envelope are caused by faults.

Harmonics problems are often measured as the total harmonic distortion, or THD. THD is the square root of the sum of the squares of the amplitudes of the harmonics normalized by the amplitude of the standard frequency, and is measured as current or voltage. Other measurements are the telephone influence factor, which compares harmonic content in relation to the phone system, and the customer-message curve, a weighted index of frequencies of human hearing. There is also the K-factor index for estimating the impact of harmonics on losses. For the distribution level, it is recommended that there be no more than 5% THD in IEEE 519-92. There is also a recommendation that appliances function in the presence of 5% THD. Average THD values in a home however are 10% for voltage or over 200% for current (*Power Distribution Planning Reference Book*).

Before some standards can be set, different aspects of power quality have to be measurable in a standard manner. Power quality indices fill this role. As part of the Reliability Benchmarking Methodology (RBM) program, EPRI defined service quality indices that cover all areas of power quality (*Reliability of Benchmarking Methodology* (5/97) TR-107938; *Reliability Benchmarking Application Guide with Customer/Utility Common Power Quality Indices* (9/99) TP-113781). In addition, the methodology and software provide guidelines for the calculation of the indices. In Canada, the CEA formed a Power Quality Interest Group (PQIG) which defined 25 power quality indices in the "Power Quality Measurement Protocol" from 103 factors based on the IEC and IEEE standards (*Canadian Utility Perspective on Power Quality*).

8.4 Addressing Power Quality Issues

Power Quality Information

Up until the last decade, very little power quality information or data existed (*Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites*). Today, however, there are a number of resources on power quality, power quality measurement, and power quality data. EPRI offers a package for addressing the power quality of industrial customers (http://www.epri.com/corporate/products_services/collaborative_mem/ pf99/ trgt038.html, Power Quality for Improved Industrial Operations). Seminars in power quality are available through Electrotek (http://www.electrotek.com/seminars/pqwork.htm), in cooperation with EPRI and BPA, for utilities and customers. These programs use *The Power Quality Workbook for Utility and Industrial Applications* (EPRI, TR-105500).

EPRI has been involved recently in programs for the measurement of power quality problems and compilation of data. *An Assessment of Distribution System Power Quality: Volumes 1-3* (5/96) provides a comprehensive statistical database of power quality measurements collected during the Distribution Power Quality (DPQ) project, as well as guidelines for monitoring and modeling power quality phenomena on distribution systems. Another report, *A Guide to Monitoring Distribution Power Quality: Phase 1* (4/94; TR-103208), describes how to perform accurate power quality measurements using a new monitoring device and how to organize and analyze the data collected. The device, PQNode, characterizes the complete range of power quality variations on distribution systems. It measures transients, short and long duration RMS variations and interruptions, and waveform distortions. Some results of a project to monitor and simulate power quality on distribution feeders using PQNode can be found in "A Survey of distribution system power quality - preliminary results." Using the DPQ database, EPRI has developed benchmarks for the RBM indices (*Reliability of Benchmarking Methodology* (5/97) TR-107938). Some applications and guidelines for application of the RBM are in *Reliability Benchmarking Application Guide with Customer/Utility Common Power Quality Indices* (9/99, TP-113781).

The CEA has also been active in this area. A nationwide power quality survey to come up with acceptable baseline levels of eleven of the twenty-five power quality indices defined by their Power Quality Interest Group was proposed to start in 1999 ("CEA Power Quality Survey 2000"). An earlier national power quality survey ("CEA national power quality survey," CEA report 220 D711A; J.S. Chan and M.B. Hughes; 1995) already produced a set of power quality data. Data on voltage sags, surges, swells, and waveshape disturbances is available by time of day, day of week, and duration. Disturbances were measured both on the primary (utility) side as well as the secondary (industrial) side (*Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites*).

There have been other studies as well. For example, harmonic analysis techniques have been developed that can aid utility engineers in planning for the control of distortion ("Power quality and harmonic distortion on distribution systems"). A two-year study on two distribution feeders serving mainly residential customers is described in "Power quality monitoring of a distribution system." The results presented there arose from a comprehensive data acquisition and analysis.

Other articles analyze the general power quality problem. In "Reliability and Quality Comparisons of Electric Power Distribution Systems," (Settembrini, Fisher, Hudak; *Proc. of T&D Conference*, IEEE (9/91)), the authors rate the different types of distribution system designs on different dimensions of power quality, such as voltage regulation, voltage disturbance, and wave shape distortions. Another brief paper discusses what designers, manufacturers, and utilities should do to solve the power quality dilemma: new technologies may bring efficiency, but the new equipment may cause additional problems with respect to power quality issues. The paper suggests that all parties to the decision should be convinced to accept the higher initial cost of systems engineering and performance-based electrical designs of new products to avoid power quality problems ("Solving the power-quality dilemma").

Power Quality Equipment

As suggested by the articles noted above, there are a variety of power monitors and analyzers to help in the understanding of power quality problems. ("Utilities today must provide "clean" power"). In addition to equipment to detect power quality problems, including harmonics (*Electrical Distribution Engineering, 2nd Edition*), equipment exists to counteract power quality problems.

Some conventional solutions are passive filters, surge suppressors, motor-generator sets, static VAR compensators, uninterruptible power supplies (UPS), ferroresonant transformers, and line power conditioners. Then there are active power line conditioners (APLC's) (*Active Power Line Conditioning Methods: A Literature Survey* (7/95)). Problems can also be addressed in design. For example, underground distribution systems have reduced harmonics propagation over overhead feeder systems, as there is usually no shared power flow.

The different types of conventional solutions address different problems. Passive filters prevent customer site harmonics problems from getting to the distribution or transmission system. Active filters mitigate harmonics by producing harmonic currents equal to those in the load current, shunting them away. Passive filters are cheap, simple, and unpowered, but they need tuning. Active filters, on the other hand, are more robust, but they are expensive, consume much power, and create high electromagnetic interference. Lightning arresters (LA) and transient voltage surge suppressors (TVSS) are forms of protection equipment. Voltage regulation equipment, including line regulators, line drop compensators, and tap-changing transformers, can reduce voltage fluctuation. Capacitors are a type of voltage regulation equipment. They may be most effective if they are on the distribution system near the customer (*Power Distribution Planning Reference Book*).

Other Approaches

In addition to measurement and mitigation, another tactic is to perform calculations to predict power quality problems. Harmonic load flow simulators are sometimes used in planning, while motor start simulators are used in both planning and engineering. Motor start simulators or flicker studies produce profiles of voltage along feeder lines to identify where voltage fluctuation during starting may violate a utility's standards. It is difficult to calculate the expected frequency and severity of voltage dips since those calculations require a fault-current analysis of the system (*Power Distribution Planning Reference Book*).

Whereas there is a wealth of information on the categorization, measurement, standards, and data on power quality, no documentation of value-based approaches to power quality have been discovered. A value-based approach is one that would integrate customer value data into system planning. Value-based planning for power quality, as opposed to reliability, is mentioned briefly in the *Power Distribution Planning Reference Book.*

9
ANALYSIS METHODS

An analysis of the reliability of a distribution system can provide a utility with information that can enable it to make superior investment decisions. Ideally, a utility would understand the effect any investment would have on predicted equipment failure rates. In addition, the utility would determine the resulting additional costs or savings in maintenance and the cost impact to customers of any changes in reliability. This requires several capabilities. First, customer outage rates must be accurately predicted for any arrangement of the distribution system. Second, cost impacts on customers must be known for a variety of outage situations. Third, the costs to the customers must be incorporated appropriately with the costs to the utility. These requirements comprise a methodological challenge that is currently being addressed by EPRI.

9.1 Background

The emerging reliability problem is to determine how to associate capital investment costs and decisions and maintenance costs and policies with the occurrence and consequences of outages. The objective is to be able to predict costs and outage rates. We seek analysis techniques that will solve both the funds allocation problem and the prediction problem.

In the literature, the analysis of the reliability of a distribution system is split into two categories: historical and predictive. The historical perspective involves the documentation of past reliability incidents, the aggregation of the data, and use of the data for performance comparison. It is an assessment of the past state of the distribution system. The literature indicates that historical reliability analysis is much more commonly practiced than predictive reliability analysis. Some description of the historical reliability analysis practices of utilities is in the Measurement of Reliability and Reliability Practice sections of this report. Predictive reliability analysis is an assessment of the current and possible future states of the distribution system. The existing theoretical framework for predictive reliability analysis has been well established. However, the application of that theoretical framework by utilities for distribution systems is not yet common practice. The theory, the different categories, the software, and the use of predictive reliability analysis for distribution systems are described in this section.

Reliability in power distribution planning has generally been accounted for subjectively in the past. Nevertheless, powerful analytical techniques have existed. There are some descriptions of the application of predictive reliability methods to distribution systems in the literature. Value-based planning involving the consideration of customer costs has also been reported in recent literature.

Reliability assessment generally involves (a) an historical assessment of the reliability record, (b) a predictive assessment to evaluate reliability of alternative system designs, and (c) a calibration of the predictive model to the historical record (*Power Distribution Planning Reference Book*). Predictive reliability assessment of a distribution system, or of HL III (hierarchical level III includes the generation, transmission, and distribution systems), seeks to evaluate adequacy indices for customer load points, or the expected outage frequency and duration for every node. An accurate model of the distribution system and an extensive set of historical data are required. The sufficiency of available failure data has been covered in a previous section. The theory for modeling distribution systems has been at a high level of development for some time. Until recently, however, few software applications for distribution system modeling have existed, and the ones that did exist were non-commercial (*Guide to Value Based Reliability Planning* (1/96)).

The first serious attempt to implement the theory for analytically modeling a distribution system may have been performed by EPRI in the early 1980s using the PRAM software. The theory was well developed, including possibly for parallel or networked configurations using minimal cutsets or their dual, tiesets (see Allan & Billinton textbooks). A distribution system reliability engineering guide provided by the CEA in the mid-1970s relates that, even then, the fundamental series-parallel reduction modeling methods had been in place for over 25 years (see Barlow and Proschan, *Mathematical Theory of Reliability* (1965); ARINC Research, *Reliability Engineering* (1964)). The CEA guide states that, although component outage data lagged behind, at the time of writing a suitable methodology for predicting reliability indices was existent (*Distribution System Reliability Engineering Guide (3/76)*). Later work further described models for parallel or networked configurations, incorporated customer outage costs into the analysis, and implemented the parallel or networked configurations ("Application of customer-interruption costs for optimum distribution planning," Mok, Y.L.; Chung, T.S. *Energy*, 1996, v 21:3.). A history of the advances in value-based reliability planning in general can be found *in Value-Based Transmission Resource Analysis* (4/94), as well as in *Framework for Stochastic Reliability of Bulk Power System* (3/98). *Value-Based Transmission Resource Analysis* (4/94) also has a description of the development of value-based planning techniques and software for transmission systems specifically. This development for transmission systems, which includes comment on both analytical and simulation techniques, is more advanced but may be seen as somewhat analogous to the steps for development of techniques for distribution systems.

9.2 Categories For Reliability Analysis Methods

Overview

A quantitative analysis of a distribution system can be approached in a number of different ways, as shown by the hierarchy in . The split at the top of the figure gives the two approaches, analytic or simulation, used to describe outages on a system while the complex breakdown at the bottom of the figure displays the various methods for the measurement of customer costs once the outages have been described. The behavior of a distribution system can be modeled analytically or through simulation techniques as indicated in the top level of the figure. These two approaches are different ways of assessing the outage exposure of different nodes or customer load points, or in other words, of assessing the reliability of the distribution system. The lower level in the hierarchy shows the methods for cost accumulation for evaluation of proposed distribution system plans. For a value-based reliability assessment, the incorporation of customer outage costs can be handled in a number of different ways. The most accurate of these cost-accumulation techniques is contingency enumeration, in which each type of outage is represented (*Guide to Value Based Reliability Planning* (1/96)). The apparent complexity of the figure is a consequence of the fact that there are many different approaches to cost computation found in the literature. The different approaches are discussed below.

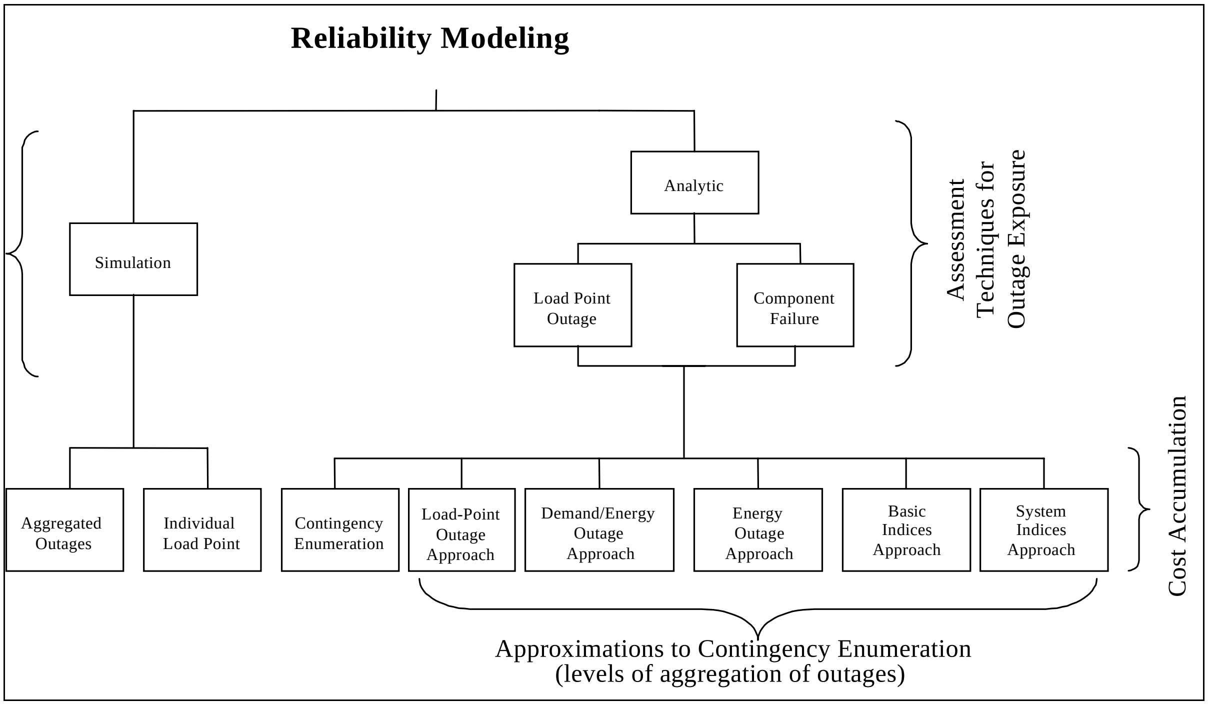

Figure 9-1
Approaches to the Modeling of Reliability in Distribution Systems

Traditional Analytic Approach

The original analytical techniques for assessing reliability indices of distribution systems combine the generic reliability evaluation techniques based on minimal-cut-set or failure-mode analysis with analytical equations which model failure and restoration processes (*Reliability Assessment of Large Electric Power Systems*). The techniques involve reducing sets of components, in series or in parallel, into grouped components. The basic analytical equations involved are for the reduction of two components in series or the reduction of two components in parallel into single equivalent components (see figure below). (*Development of Distribution System Reliability and Risk Analysis Models (8/81)*). Note that λ is the failure rate (failures/unit time) and r is the repair time (hrs/repair).

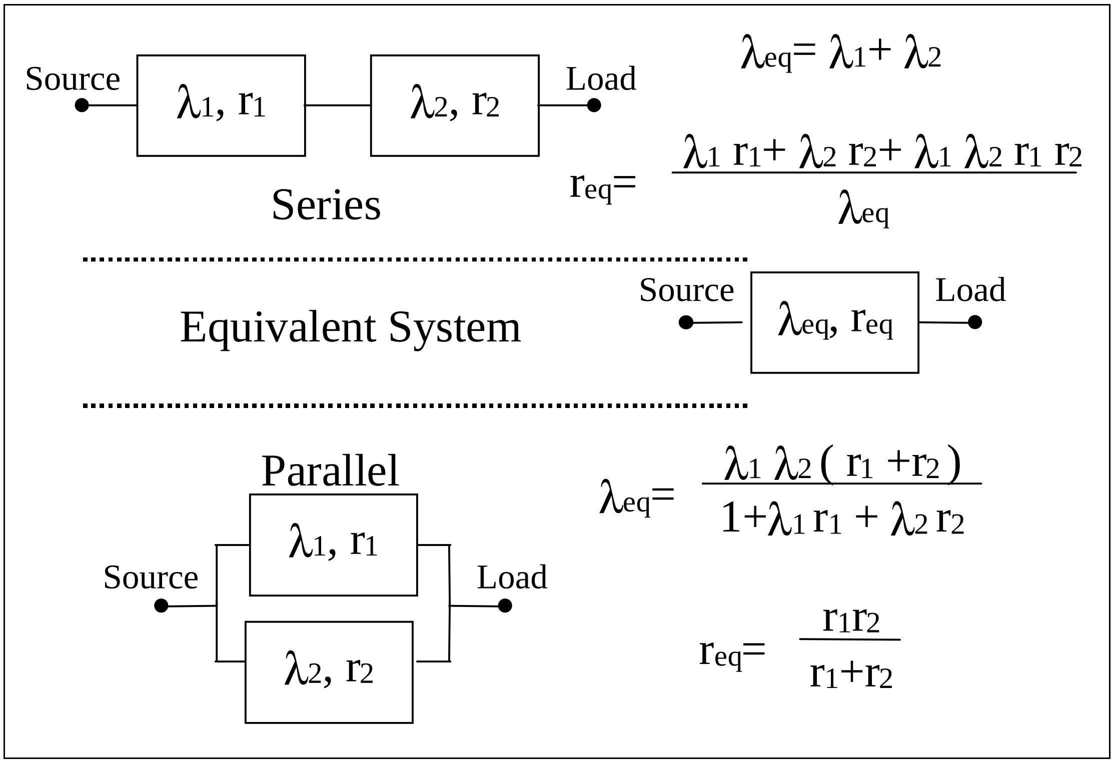

Figure 9-2
Series-Parallel Reduction Equations

Using these series-parallel reduction techniques, the outage exposure can be assessed by the load-point outage or component failure methods (*Guide to Value Based Reliability Planning* (1/96)). Using the load-point outage method for reliability assessment involves sequential consideration of customer load points. The events that would cause an outage on a selected load point are identified and the consequences of all these failure events for the specific load point are summed. Consequences are then summed across load points. The component failure approach, on the other hand, considers each component in the system sequentially. The load points isolated by a failure of the specific component are identified. The consequences on the load points are first summed. Then, the consequences across components are summed (*Guide to Value Based Reliability Planning* (1/96)). The algorithm for the load-point outage method is more efficient than that for the component failure approach. Using contingency enumeration for the accumulation of customer costs for the assessed outages, the two approaches, load-point outage and component failure, produce the same total customer interruption cost result.

Similar assumptions are typically made in both the load-point outage and component-failure approaches. These analytical assessments assume an average frequency and duration for each contingency. As such, they approximate the distribution system behavior. (*Guide to Value Based Reliability Planning* (1/96)). Furthermore, in using parallel-component reduction, the reliability calculations assume that alternate current paths are completely separate and independent, which produces optimistic reliability results ("Reliability and Quality Comparisons of Electric Power Distribution Systems," *Proceedings of the Transmission and Distribution Conference*, IEEE, 9/91, 704).

Customer Outage Costs in Traditional Analytic Techniques

Both these analytical techniques for outage assessment permit contingency enumeration in the accumulation of customer costs, because each failure mode and load point effect is treated individually. Enumerating or accounting for each separate contingency for the accumulation of outage costs is the most accurate incorporation of these customer costs among the traditional analytic techniques. The importance of contingency enumeration is that, to a some extent, it accounts for the nonlinearity of load-point customer damage functions; i.e., cost of outage is a nonlinear function of outage duration. The main assumption in contingency enumeration is that each contingency is described by its average frequency and average duration. The possibility that each contingency may cause outages at varying arrival intervals and of varying duration is not captured. Nevertheless, contingency enumeration is the most accurate of the traditional methods. The method gives inaccurate results for greatly nonlinear cost functions and for arrival distributions that vary greatly from the average interarrival time.

In order to simplify the cost computation, compared with a full contingency enumeration, different outages can be aggregated at a number of levels, prior to the incorporation of outage costs into the assessment. For example, the costing can be made at the level of load points with the *load-point-outage cost accumulation approach* (see). This technique is appropriate for subtransmission because it uses a customized outage cost function for each subtransmission load point, which serves a mix of customers. The *basic indices approach* uses the reliability indices of outage frequency, λ, average restoration time, r, and the unavailability, U. In that approach, the failure rate and duration are averaged for each customer load point before customer outage costs are incorporated. The *demand/energy outage approach* and the *energy outage approach* aggregate further and involve obtaining the demand and energy outage by customer sector before the costing of outages. Finally, the *system-indices approach* greatly simplifies the computation of the costs, using the compiled SAIFI and CAIDI for the system combined with a composite energy outage cost. By aggregating different outages, none of these increasingly rough approximations to contingency enumeration allow the nonlinearity of the customer damage function to be represented. The approximations simplify the calculations but come at a cost in accuracy. Some approximations to contingency enumeration have been shown to produce inaccurate results ("Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System," Goel, L.; Billinton, R. *IEE Proceedings Generation, Transmission, Distribution*; v 141 n 4 July 1994. p. 390-396). In an application to a test power system (the RBTS discussed below), the basic indices method and the system indices method were found to produce results significantly different from the results using the more accurate contingency enumeration method on the same system.

Other Techniques

Monte-Carlo simulation is an alternative to the analytic approaches to distribution system reliability modeling. The analytic approaches described above have been considered practical for a variety of system studies (*Reliability Assessment of Large Electric Power Systems*). They don't consider, however, the variability of reliability measures about their mean values. Monte-Carlo simulation can provide this probability distribution information, given input information on the statistical distribution of component failure events and restoration times. Monte-Carlo simulation involves the specification of the system configuration as well as this statistical component information. By randomly generating failures and restoration times using the statistical information, simulation produces the probability distributions of reliability indices. In so doing, simulation provides insights into the range of possible reliability outcomes as opposed to solely the average result, insights into worst-case and best-case results (*Power Distribution Planning Reference Book*). The drawbacks of high cost and scarce, unproven statistical-distribution failure data have limited the application of Monte Carlo simulation to academia and large utilities (*Guide to Value Based Reliability Planning* (1/96)).

Recent developments have involved the Markov modeling of distribution systems. Markov modeling is another analytical technique. The theory for this approach can be found in the literature, including in textbooks (*Reliability Evaluation of Power Systems, Reliability Evaluation of Engineering Systems*; Billinton and Allan). As noted above, it is typically assumed that different system components behave independently in order to apply some forms of analytical reliability assessment. Because system outage data can include multiple failures from dependent factors, the typical independence assumption can underestimate system failure by a few orders of magnitude (*Reliability Assessment of Large Electric Power Systems*). Markov modeling techniques can address this problem. Models for different types of dependencies can be found in an appendix of *Reliability Assessment of Large Electric Power Systems* for example. New software developed by the Snohomish Public Utility District in collaboration with the University of Washington has demonstrated the possibility of using Markov modeling for distribution system reliability. ("Distribution System Reliability Assessment Using Hierarchical Markov Modeling" *IEEE Transactions on Power Delivery*, Vol. 11, No. 4, October, 1996, p.1929). EPRI is currently reviewing this method.

9.3 Incorporation Of Outage Costs

Value-based planning analytically determines the best way to balance quality against cost by incorporating customer-value data for various levels of reliability and of quality of electric power. It involves finding the minimum of the total cost versus power quality where the total cost is the sum of customer and utility costs. Value-based reliability planning considers just reliability while value-based quality of service planning would consider overall power quality. Reliability considerations are more common as there is more information on reliability and it affects more customers (*Power Distribution Planning Reference Book*). In distribution system planning, a value-based approach can be used in establishing engineering design criteria, distribution circuit design, prioritizing investments among circuits, substation design, rating transformers, evaluating maintenance procedures and scheduling (e.g., tree trimming, equipment replacement), evaluating the cost-effectiveness of specific investments, and evaluating the cost-effectiveness of distributed generation and DSM (*Outage cost estimation guidebook* (12/95)).

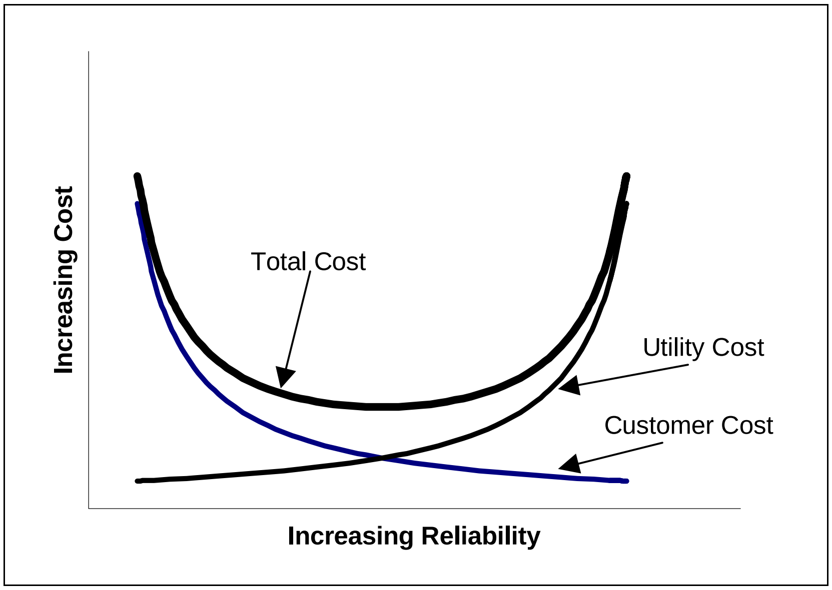

Figure 9-3
Total Cost in Value-Based Reliability Planning

A history of the development of value-based resource analysis can be found in *Value-Based Transmission Resource Analysis*, *Volume 1: Technical Report* (4/94). The history details the move from implicitly using a preselected reliability level towards explicitly incorporating outage costs into a cost minimization process. It is reported that quantitative adequacy assessment is used by most utilities for generation (HLI—hierarchical level I: generation) analysis but very few use it regularly for generation with transmission (HLII—hierarchical level II: generation with transmission). Outage costs were used in generation capacity planning in Europe, particularly in Norway, Sweden, Italy and France (*The Value of Service Reliability to Consumers* (5/86)). Although much information can be found in the literature on value-based planning in generation and transmission, one document reports that the adoption of the integration of outage cost information into a resource planning framework has not yet occurred (*Framework for Stochastic Reliability of Bulk Power System* (3/98)). The main hurdle is said to be the limitations of currently available models for calculating customer reliability indices. *Cost-benefit analysis of power system reliability* (Volume 1) summarizes the use of customer outage costs in each functional level (generation, transmission, distribution, composite). It relates that very few US utilities at the time of writing had individual customer outage data but most collected data for transmission elements.

Available customer outage cost data are adequate, however, as reported in the *Guide to Value Based Reliability Planning* (1/96). Guidelines for choosing amongst the available data sets and for making alterations if necessary are included in this guide. To produce a custom set of data, the authors here recommend survey-based methods, saying that they are more than adequate for utility planning purposes. In contrast, the *Value of Service Reliability to Consumers* (5/86) comments that a market-based approach to determining the value of reliability is better. (For more information on customer outage costs and the value of reliability see the Customer Needs Report.)

Examples of value-based planning applications are included in some of the reports in the reliability library. An example of the value-based planning approach for distribution reliability improvements can be found in *Value-Based Transmission Resource Analysis, Volume 2: Applications Guide* (4/94). In this example, a contingency enumeration cost accumulation with a load point outage analysis is used to evaluate alternatives for improving the reliability of service to customers served by a particular substation. The *Power Distribution Planning Reference Book* describes the tools and methods for value-based planning as including models to predict performance of system design, decision support tools for the choice among alternatives, and optimization methods. The book includes spatial, geographic reliability models used to produce a map of average reliability needs for a city based on a willingness-to-pay model of customer value, as an example of how linking reliability investment to customer values could be helpful in planning, if appropriate tools were available.

(Note: EPRI has reviewed and summarized the outage cost literature*: Customer Needs for Electric Power Relaibility and Quality: EPRI White Paper*, June 2000. This is a forthcoming EPRI report and is available from the project manager.)

9.4 Reliability Software

Historical Development

In the early 1980s, EPRI conducted a project that had as its objective the inclusion of reliability calculations in distribution planning (*Development of Distribution System Reliability and Risk Analysis Models (8/81))*. Along with a system and software for historical reliability assessment (HISRAM), EPRI developed predictive reliability assessment software (PRAM).

PRAM employed the series-parallel reduction techniques commonly found in the literature (Allan & Billinton textbooks) to treat radial systems, without consideration of redundancy. The load-point outage analytic approach was used. As such, PRAM began with the mean failure rate and average annual downtime to calculate statistics and reliability indices. It had three levels of protection-system modeling of increasing complexity and accuracy. For the distribution system, it calculated average restoration time, average annual uptime, steady-state availability, and, using the number of customers or connected load, it produced the indices SAIFI, SAIDI, CAIDI, ASAI, ALIFI, and ALIDI. No cost accumulation was included in PRAM, and, as the outages were not enumerated, cost accumulation by contingency enumeration does not seem like it would have been possible.

HISRAM was perhaps the major contribution of the project to common utility practice, while PRAM being an experiment in state-of-the-art concepts in distribution system reliability. The systems used punch-card inputs and tape memory. PRAM may have pushed the contemporary limits on data availability and computational ability, which likely hindered its application. Reports of the use of PRAM subsequent to the pilot application have not been found, and it does not seem to have been updated.

Certain aspects of that EPRI project may be instructive to present developments in distribution-system reliability analysis software. The project integrated the reliability software into the Unified Distribution Planning Methodology with the goal of incorporating considerations of reliability and cost in distribution planning. This integration of the reliability analysis with different systems continues as a goal in present efforts. Also, the testing and pilot applications of the PRAM models identified shortcomings. Some of the lessons in this application could be instructive for new predictive reliability modeling tools.

Personnel at the University of Saskatchewan created SUBTREL for the sub-transmission section, looped or meshed sub transmission systems, and DISREL for radial distribution systems, the section from the distribution substation to the customer load points. The programs evaluated individual load point indices (load point failure rate, load point outage duration, annual unavailability) and system indices (SAIFI, SAIDI, CAIDI, ASAI (ASUI), ENS, ASCI, ACCI). The programs did not treat customer outage costs. The programs were not made commercial ("Application of customer-interruption costs for optimum distribution planning," *Energy* (1996, 3) 157; "Computer Programs for Reliability Evaluation of Distribution Systems," *International Power Engineering Conference, 3/93, 37*)

EPRI has continued to develop applications for reliability analysis for transmission systems. Software development for reliability analysis in transmission has generally been more active than for distribution. The Transmission Reliability Evaluation for Large-Scale Systems, or TRELSS, is EPRI's risk-based expansion planning tool for transmission systems (*Transmission Reliability Evaluation for Large-Scale Systems* (10/98; EPRI TO-111625)). It has become widely used in industry.

The extent of the use of predictive reliability at distribution utilities ranges from none to fairly sophisticated approaches. Some utilities assess the impact per dollar of alternative distribution system projects, incorporating customer outage costs, and offer a choice of combinations of cost and reliability to large customers. As seen in the following figure from a 1992 survey (found in *Guide to Value Based Reliability Planning* [1/96]), utilities have been found to use only analytical techniques and, until recently, used only proprietary software. Improved commercial software is now available, however, and some utilities are beginning to take more sophisticated approaches to predictive reliability of their distribution systems.

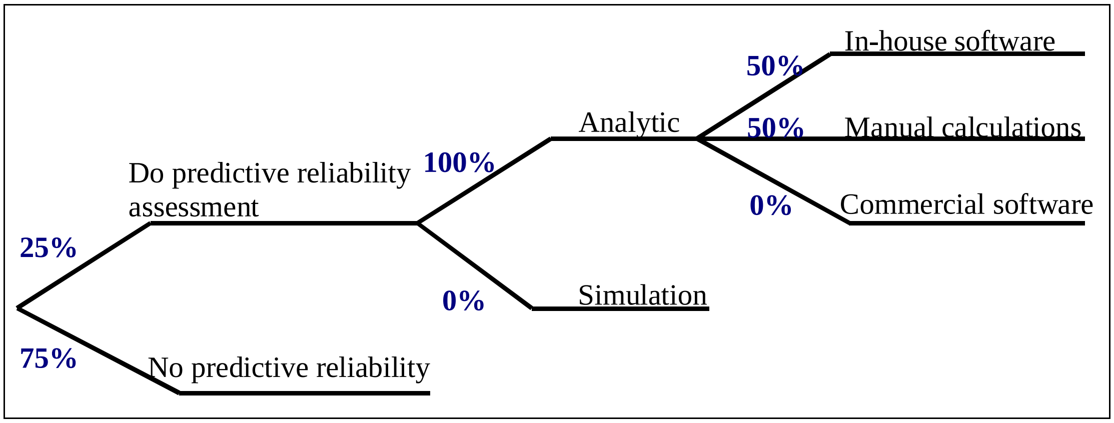

Figure 9-4
Utility Practice of Predictive Reliability

Commercial Products

Cooper Industries had their own software for reliability analysis. The version reviewed several years ago used inputs only at a circuit level, giving results only at an aggregate level. DISTRELY, as it was called, calculated aggregate SAIFI, SAIDI, CAIDI, LAIFI, and LAIDI (*Guide to Value Based Reliability Planning* (1/96; CEA 273 D 887)). It did not give results by sector or class of customer. Since that review, Cooper Industries may have expanded the capabilities of its software. Their website (http://www.cooperindustries.com/) discusses their Total Life Cycle (TLC) cost calculation software, which may be related to DISTRELY, with customer outage costs incorporated. This software does not appear to be sold as a product separate from Cooper Industries' consulting services.

Another commercial product reviewed in *Guide to Value Based Reliability Planning* (1/96; CEA 273 D 887) is from EDSA. EDSA had a reliability analysis module available for their distribution system programs that could handle small networks. It did reliability analyses and customer cost accumulations. EDSA's product represented breakers, line sections, normally open and normally closed switches, transformers, fused branches and transformers, and took also as input composite outage cost functions for each load point and failure/repair rates for each system component. It was assessed as being more suited to subtransmission (*Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887). EDSA seems to have expanded on the capabilities of this software subsequent to this review. Their website (www.edsa.com) shows modules to their distribution programs for substation configuration reliability analysis, distribution system reliability analysis, and block based reliability analysis.

A software program using Markov modeling has recently been developed ("Distribution System Reliability Assessment Using Hierarchical Markov Modeling", *IEEE Transactions on Power Delivery*, Vol. 11, No. 4, October, 1996, p.1929). Personnel at the Snohomish Public Utility District in collaboration with the University of Washington created this software for the prediction of the reliability of distribution primary systems. The Visual Basic, Windows-based software can use the power system topology data from Stoner's software or another source, or be used as part of Power Technologies, Incorporated (PTI) software. Early versions of the distribution system reliability software are licensed to PTI and Stoner. Thus, it is commercially available as a module to PTI's PSS/ADEPT software or Stoner's Distribution Primary Analysis/Graphics (DPA/G) software. A more recent, unreleased version can evaluate the transmission system as well.

9.5 Reliability Modeling Efforts In The Literature

Introduction

There are a number of articles in the literature that describe the application of reliability modeling methods to distribution systems. The documents that describe the methods commonly have example cases. The literature also contains articles with discussions of simple methods applied to distribution systems to assess relative reliability. The simplified methods may provide insights into considerations that may be important in any reliability modeling effort.

Applications of Series-Parallel Reduction

There are a few articles that describe the use of the software programs based on series-parallel reduction techniques. "Application of customer-interruption costs for optimum distribution planning" (*Energy* (1996, 3) 157) discusses an evaluation of the standardized reliability test system (RTS and RBTS) using SUBTREL and DISREL. The existence of a standardized system, including an appended distribution system, is mentioned in a number of documents (e.g., *The IEEE Reliability Test System-1996*). Any software development for power system reliability should involve test applications on the standardized test system. "Computer Programs for Reliability Evaluation of Distribution Systems," (*International Power Engineering Conference*, 3/93, 37) includes a similar evaluation of the RBTS, after a description of SUBTREL and DISREL. The paper is a demonstration of reliability modeling programs in general.

The most extensive application of the series-parallel reduction analytic techniques to distribution systems in a value-based approach was found in "Application of customer-interruption costs for optimum distribution planning" (Mok, Chung; *Energy* (96)). It describes the total cost minimization evaluation of eleven distribution-system capital improvement projects. In addition, the authors use minimal cut-set theory for mesh-distribution systems. Alternate plans are compared by average outage rate, average annual outage time, and average outage duration. Customer interruption costs differentiated by sector, duration, and season are used to calculate the customer cost part of total cost.

"Value-based distribution reliability assessment and planning" (Chen, Allan, Billinton*; IEEE Trans. Power Delivery* (1/95)) describes a spreadsheet implementation of an evaluation of alternate feeder capital-improvement projects at Scarborough Public Utilities Commission (SPUC). Outage exposure is assessed both by the load point and component failure techniques, with contingency enumeration cost accumulation. The analytic results from these two techniques for the total customer interruption costs are proven to be algebraically equivalent. However, the load point technique is found to be much faster computationally. SPUC's own historical fault data and that from North York Hydro and customer interruption costs from previous work are used. The resulting project prioritzation was used by SPUC in its capital budget planning, and a reliability assessment was repeated a couple of years later showing an improvement in overall customer interruption costs.

Another paper that includes distribution system value-based planning case studies is "Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System," (Goel, Billinton; *IEE Proc. Gen., Trans., Dist.* (7/94)). This paper presents the application of three different methods for the evaluation of reliability worth. The methods combine quantitative reliability evaluation with customer outage cost assessments in the form of customer damage functions (sector-SCDF's and composite-CCDF's). The load-point outage analytic approach is employed in an evaluation of the generation, transmission, and distribution test systems. The three different methods used for cost accumulation are contingency enumeration, the basic indices approach, and the system indices approach. The results demonstrate that these cost accumulation approximations are inaccurate, since their results differ greatly from those of contingency enumeration.

Another valuable article is "Reliability and Quality Comparisons of Electric Power Distribution Systems" (Settembrini, Fisher, Hudak; *Proc. of T&D Conference*, IEEE (9/91)). The authors perform rough calculations using the series-parallel reduction analytic approach and actual utility data to compare seven common distribution system designs on outage frequency and duration. Included with the results of the comparison are descriptions of the different types of distribution systems: simple radial (overhead), primary auto loop, underground residential distribution, primary selective, secondary selective, distributed grid network, and spot network. The parameters used for reliability are outages per year (greater than five minutes), average duration, and momentary interruptions (less than five minutes). To model the distribution systems, components are grouped into primary feeder and associated equipment, step down transformer and associated protective equipment, and secondary-conductor associated devices. The different distribution systems are rated on the basis of reliability, as well as the different dimensions of power quality.

One additional article, "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems" (Goel, Billinton, Gupta; *Electric Power Systems Research* (12/94)), describes an application of SUBTREL to a reliability test system. Here, the authors employ the load point outage analytical approach with load point cost accumulation at the sub transmission supply points. The impact of different contingencies on reliability indices is assessed.

Sample application case studies can also be found in textbooks on reliability analysis. For example, *Reliability Assessment of Large Electric Power Systems* includes a base-case analysis for a simple radial distribution system using common series-parallel reduction, then extends the analysis to a few other situations. This book attempts to document in one place the practical range of applications of value-based distribution system reliability planning. As a general comment, it is mentioned that the effect of failure of the main supply to the system is not normally included when evaluating the reliability indices of a distribution system.

Alternate Approaches

There are a few recent articles describing modeling efforts using Monte-Carlo simulation. The difference between analytical approaches and Monte-Carlo simulation in computation, using a set of mathematical equations versus observing a series of artificial histories, as well as the difference in the value of the insights provided by each method, are discussed in "Teaching Distribution System Reliability Evaluation Using Monte Carlo Simulation," *IEEE Trans. Power Systems*, (5/99). Reliability indices and their distributions are evaluated for the RBTS as a test distribution system. The results from the two approaches are found to be similar. The authors conclude that the probability distributions provide great additional insight into the distribution system reliability. The article "Distribution System Reliability Cost/Worth Analysis Using Analytical and Sequential Simulation Techniques" (*IEEE Trans. Power Systems*,11/98) presents a similar evaluation. "Time Sequential Distribution System Reliability Worth Analysis Considering Time Varying Load and Cost Models" (*IEEE Trans. Power Delivery*, 7/99) presents a sample application to a radial distribution system using time-varying load and cost models. Again, reliability indices and their distributions are evaluated for individual load points and found to be affected by the time variations.

There are also papers on value-based distribution reliability planning using simpler methods for the reliability analysis of the distribution system. For example, in "Using Customer Outage Costs in Electricity Reliability Planning" (Forte, Putnam, Pupp, Woo; *Energy* (2/95)), the authors present case studies on the evaluation of transmission and distribution projects comparing results for the best alternative without consideration of customer outage costs and with consideration of customer outage costs. The two situations examined are isolated possible projects impacting single failure events at Niagara Mohawk Power Corporation, so a full distribution system, or transmission system, model is not required. The relative reliability of the possible projects affecting the individual failure events is measured by the expected unserved energy, and a single average customer outage cost from a survey of the utility's customers is used. In addition, "A Method for Estimating the Reliability of Distribution Circuits" (Gilligan*; IEEE Trans. Power Delivery* (4/92)) presents a quick, simple calculation to compare relative outage exposure of existing circuits. The evaluation has an emphasis on environmentally caused outages (e.g., trees) and was used by San Diego Gas & Electric as their method to focus attention on problem distribution circuits. Considering these approaches, utilities may need to be convinced that the extra cost of more sophisticated methods for the analysis of distribution system reliability is justified by the greater understanding and control they may afford over that reliability.

The actual results of simplified evaluations of distribution system reliability must be viewed with a consideration of the major assumptions made, but the evaluations can provide insights into important elements. The paper just mentioned emphasizes the point that a large proportion of distribution outages is caused by external events (e.g., weather-related problems), so a field assessment of equipment environment is essential to a reliability analysis. The article presents a method to predict the relative reliability performance of distribution circuits and circuit segments. The method calculates with a spreadsheet the expected relative indices of annual interruption time and customer hours of interruption by multiplying factors for exposed length, exposure (to weather factors such as trees as well as inherent failure), conductor type, sectionalizing devices used, and customers connected. Customer outage values by sector are used to assess the cost effectiveness of reliability improvement projects suggested by the method. An application of the method to about 100 distribution circuits is discussed. Outages caused by defective equipment can cause less than 20% of distribution system outages (*1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99)), so the consideration of environmental factors in reliability analysis is important.

10
CONCLUSIONS: MOVING BEYOND TRADITIONAL RELIABILITY ANALYSIS

In this report, we attempted to learn the state of the art of the analysis of reliability in distribution systems. In a companion report, *Customer Needs for Electric Power Reliability on Power Quality*, we studied how customers value reliability. Together, the two studies give some clear directions for an improved approach for controlling and optimizing reliability with respect to customer needs and values.

The customer-focused approach described in the CUSTOMER NEEDS REPORT measures customer values directly rather than reducing them to a set of ad hoc reliability measures more oriented towards system performance than towards customer needs. This final section considers briefly the potential consequences of the new approach.

In this report, we found that there are a large number of indices for measuring reliability as well as a collection of methods for measuring these indices. Some of the common reliability measures are SAIFI, SAIDI, CAIDI, CAIFI, ASAI, CTAIDI, ASUI, ENS, AENS, MAIFI, MICIF, ALII, ASCI and ACCI, just to name a few. Even though each of these measures taken alone has some intrinsic logic to it, the sheer number of different indices brings confusion rather than clarity to reliability planning. In a seminar, Ronald A. Howard of Stanford University once compared a situation like this to Sir Isaac Newton trying to deduce the law of gravity by throwing up feathers from a pillow into the wind. Utility planners need a way to balance the issues that drive the different indices. The customer-focused approach provides a natural integrating framework.

In the Customer Needs study, we characterized the most fundamental customer needs in terms of key attributes of electric service, such as number of outages per year and duration per outage. We developed a customer value function with respect to these attributes. The customer valve function measures the importance of each attribute for customers and, most importantly, permits attributes to be compared directly. A fundamental implication of the valve function is that the attributes and indices measure different things. The service attributes that customers value are *not* the same as the system indices. In other words, the system indices are not what customers valve.

The two reports suggest that a better reliability planning method would begin with customer needs and use those needs to define the important aspects of system performance. With this view, we should create tools to measure system performance in terms of customer value attributes, determine how to control these measures of system performance and then build economic analysis tools that trade off the cost of control with customer values.

Utility planners need a way to balance the issues that drive the different indices and the customer-focused approach provides a natural integrating framework. Here in summary form are some of the implications of the customer-focused approach.

10.1 The new approach ties together traditional cost-benefit economic analysis with engineering system analysis

Traditional reliability analysis is engineering oriented. There is a clear and intentional equipment and electrical system focus to the reliability-index definitions.

Figure 10-1 shows the traditional reliability planning approach. Control strategies, such as repair/replace and installation of new equipment and circuits, are chosen that affect system performance and customer values, but the choice is made based on system indices that are only indirectly correlated with customer values. While there is no question that an improved system improves the way in which customer needs and values are satisfied, there is no direct link between system indices and customer values.

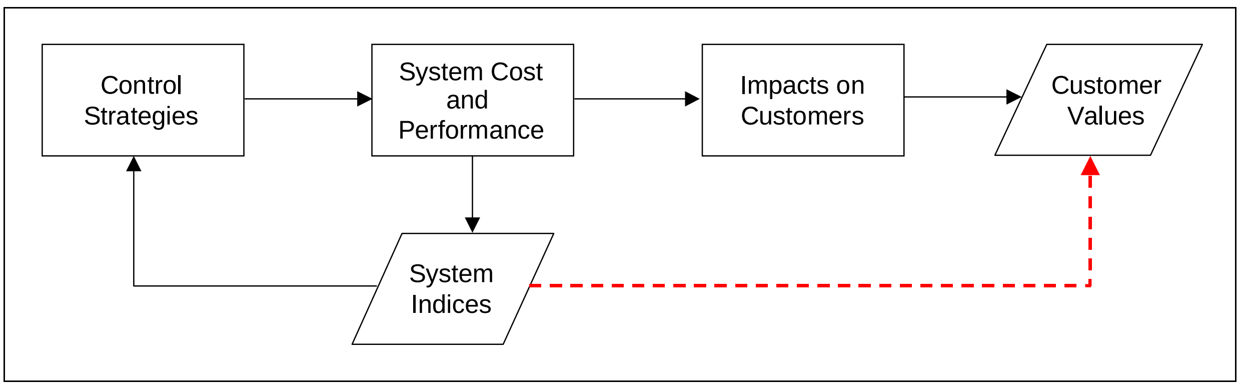

Figure 10-1
Traditional Approach to Reliability Planning

The issue is not whether the system is improved, but whether a utility can do even better with the same resources. The answer is "yes," because now we have an explicit objective function to maximize. Figure 10-2 shows a new approach, based on an explicit measurement of customer needs. In this approach, customer values, including the trade-off between cost and reliability, are used directly to drive the control strategy. System indices are still important for intuition and understanding, but only as intermediate measures that help us in our understanding of the complicated distribution system.

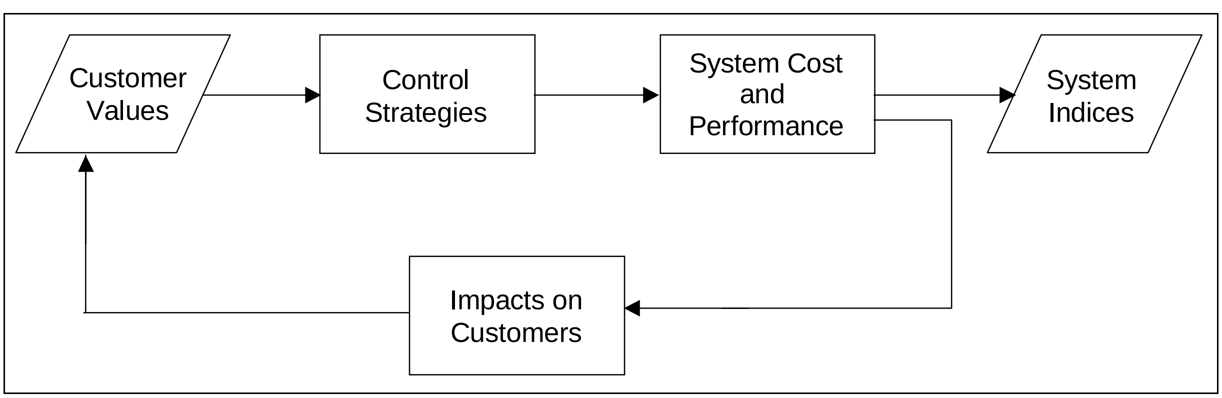

Figure 10-2
New Approach to Reliability Planning

10.2 The new approach allows comparison across customer segments

The Customer Needs study found that segmentation of the customer population is important. It is clear that different customer groups have very different values for electricity. Moreover, their needs are multi-dimensional.

System average indices do not reflect the diversity of the customer population and offer no way to balance the needs of the different customer segments. However, the customer-focused approach allows a direct comparison of the different dimensions of reliability and their differing impacts on different customer segments.

10.3 Reliability indices are ad hoc and do not directly address customer needs

As argued above, current reliability-planning practice uses indices that are measures of system performance, not customer valves or needs. While we would expect these indices to be correlated with customer value, they do not measure it. Consider, for example, the CAIDI index (Customer Average Interruption Duration Index). Two vastly different systems can have the same CAIDI, but the actual cost to customers can be arbitrarily distributed.

The distinction we are drawing is between means and ends. System performance, measured by the various indices, is a "means objective" in contradistinction to meeting customer needs, which is an "ends objective." In other words, system performance is only a means to a more fundamental end, which is to provide customers with reliable, high quality electricity. System indices are intermediate measures, not ultimate impacts.

10.4 Planning based on averages ignores risk and extreme events

Planning using only averages does not allow one to evaluate risk and the possibility of deviations from normal operations. In a very fundamental sense, reliability planning using averages makes no sense. Risk, or deviation from average, is the essence of reliability. If the electrical system always operated under “average” conditions, reliability planning would be easy. For example, there would be no need for reserve margins, no need for multiple-contingency planning and no need for backup generation or distribution.

Yet, while multiple-contingency policies and other risk averse strategies seem to make intuitive sense, current methods based on averages only cannot evaluate such policies. We need a way of predicting the range of outcomes and their probabilities based on all realistic contingencies.

Technically, approaches based on averages require a large number of limiting or possibly unrealistic assumptions (for example, exponential failure and restoration time distributions). One always needs to question whether there is there sufficient data to justify the assumptions empirically.

10.5 Planning based on averages ignores some key customer needs

Even if averages are calculated correctly, they are inadequate for representing stakeholder values. Our work in customer needs tells us that customers have non-linear value functions for both arrivals of outages and duration of outages. Non-linear value functions mean that excursions from average conditions can be very important.

This is not just a detailed technical point but a very practical issue. Customers and utility planners get upset when unusual events occur. Reserve margins and safety levels are based on unusual events and regulators often penalize companies in nonlinear fashion – for example, penalizing a company only after the number of outages exceeds some threshold level. It is often the unusual "non-average" event that drives utility planning at the highest level of the company. Consider the recent front-page newspaper headlines in California when parts of the state approached a Level 3 condition under which brownouts would occur. California utilities were subjected to conflicting pressures as voters questioned the lack of capacity while at the same time ratepayer groups were demanding lower rates.

To go beyond planning based on averages, we need new tools to evaluate the full consequences over the range of events that could occur (which in mathematical parlance is to say that we require the complete probability distribution over outcomes). It is fortunate that the theory necessary to guide the development of such tools appears to exist at present.

11
SUMMARY AND IMPLICATIONS

The research effort and literature survey on distribution system reliability has established a Reliability Library, has uncovered the state of the art, and has indicated the direction for future efforts in the area. Past efforts have been motivated by the importance of distribution system reliability. For example, seventy-five to eighty percent of customer unavailability arises from distribution system problems ("Application of customer-interruption costs for optimum distribution planning," Mok, Chung; *Energy*, (96); *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99), CEA (Item # 116.98)).

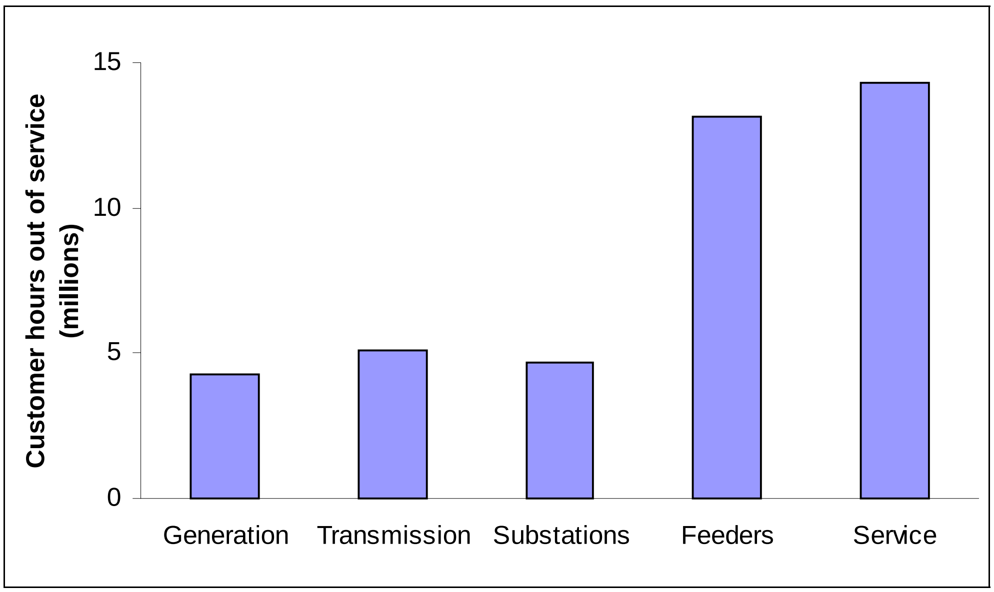

Figure 11-1
Source of Customer Outages (*Power Distribution Planning Reference Book*, Willis, p. 10; 10 years of customer interruptions for a large electric system)

The Reliability Library consists of hard copies and electronic files. Each reliability topic area is covered by an ample collection of reports, articles, books and websites. This extensive set of materials is organized and summarized in electronic files. These organized materials can be used as a general education in distribution system reliability or as a guide to specific information in the area.

Only a modest amount of material from the past five years was found. Additional citation searches on key documents are advisable to ensure that this situation reflects reality, as opposed to there being some efforts in distribution system reliability that are not well connected by references in the literature. Furthermore, continued, unrelated progress is doubtless being made. The library could remain current with only a low-level of ongoing effort.

The literature shows that theoretical, conceptual approaches exist for analyzing reliability. The concept of value-based distribution reliability modeling is well recognized. However, few practical applications are reported. A few examples of software for distribution system reliability modeling have been identified. However, only isolated instances of utilities regularly using reliability modeling and value-based planning concepts for distribution systems have been discovered. Furthermore, no general framework for decision making has been found in the literature.

A general framework for reliability decision making would guide development of techniques and define data that should be gathered. EPRI intends to proceed to develop such a framework for distribution systems. We will then continue our efforts in developing analytic modeling and analysis methods.

Indeed, the needs for further development in distribution system reliability modeling and analysis methods are defined by the current deficiencies. An essential improvement is a reliability modeling approach that can capture the full range of system behavior, especially rare events and their consequences, without relying on restrictive assumptions. The detail in this model should be dictated by the model's appropriateness for investment analysis and be balanced with the requirement that the model be supported by only a realistic, relatively undemanding data set. One important modeling contribution is replacement of exhaustive, burdensome data sets with model logic. The final improvement will be the incorporation of the analyses from such a model into an overall analytic decision framework that comprehensively considers a variety of the concerns of the utility.

A
REFERENCES AND RELIABILITY DOCUMENT CATEGORIZATION

This appendix contains a copy of the electronic file *Reliability Document Categorization.doc.* This file lists all documents that were reviewed as part of the literature search described in the report. Therefore, this appendix also serves as the reference section for the report. Reviewed documents are listed under each of the topics that each document addresses.

A.1 Reliability Document Categorization - Overview

The following is the categorization that is used to assign reviewed documents. Note that a single document may be assigned to more than one category.

1. Measuring and Defining Reliability:
   a) Definition and perception (Customers', utilities', regulators' perception of reliability)
   b) Indices
   c) Loss-of-Load Probability (LOLE/LOLP)

2. Faults:

3. Failure rates by equipment type (circuits, transformers, capacitors, cables, poles)

4. Durations

5. Causes (rural vs. urban, weather, peak loading, accident, sabotage)

6. Classes (transmission vs. distribution; brownouts/blackouts; multiple contingency events, self-clearing events, system trips, switching events)

7. Maintenance & Changing Reliability (in distribution)
   a) Equipment types
   b) Policies
   c) Engineering to change reliability

8. Regulatory Issues

9. Power Quality

10. Reliability Modeling

11. Pricing
    a) Interruptible Rates
    b) Differentiated Pricing (reliability, service, quality)

The following additional comments on categorization apply.

1. The categories **revealed preference data and analysis** and **willingness-to-pay data and analysis, especially cost-reliability tradeoff analysis** are not included in this categorization. Instead, those topics are treated in the companion report on Customer Needs.

2. The category **reliability; service reliability** falls under *Measuring and Defining Reliability*.

3. The category **results of customer reliability surveys** is not included in this categorization. That topic is treated in the companion report on Customer Needs.

4. The category **system security** falls under *Measuring and Defining Reliability* and under *Faults*.

5. The category **outage cost data** could be interpreted as the customers' perception of reliability but is excluded from this category. It is treated in the companion report on Customer Needs.

6. Papers concerned with power quality and not other aspects of reliability (e.g., adequacy, security) are included only in the *Power Quality* category. They are not further classified into planning and policies, maintenance, equipment types.

A.2 Reliability Document Categorization

1. Measuring and Defining Reliability:

   a) **Definition and perception**
   (Customers', utilities', regulators' perception of reliability)

   - *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
   - *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
   - *Electrical Distribution Engineering* (1991)
   - *Power Distribution Planning Reference Book* (1997)
   - "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
   - *Costing and Pricing Electric Power Reserve Services* (generation) (12/97) EPRI-TR-108916
   - *The Value of Service Reliability to Consumers* (5/86)
   - "Power quality monitoring of a distribution system," *IEEE Transactions on Power Delivery* 4/94, 1136

- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- *Development of Distribution System Reliability and Risk Analysis Models (8/81)*
- "Bulk Power System Reliability Criteria and Indices: Trends and Future Needs," *IEEE Trans. on Power Systems* 2/94, 181
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37
- CEA website
- "Quality of Service from the Consumer's Point of View," (70's)
- "Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System," (7/94)
- *Outage cost estimation guidebook* (12/95)
- *The Strategic Role of Distributed Resources in Distribution Systems* (10/99)
- *Value-Based Transmission Resource Analysis, Volume 1* (4/94)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98)
- *TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems, Vol. 1* (5/92)
- *Distribution System Reliability Engineering Guide* (3/76)
- *Distribution System Reliability Issues.doc* (12/99)
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)
- *Reliability Assessment of Large Electric Power Systems* ('98)
- *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)
- *Reliability at What Cost? Analyzing the economics of (improving) distribution reliability* (1/00)

b) Indices

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- *Electrical Distribution Engineering* (1991)
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195

- “Effect of protection systems on bulk power reliability evaluation,” *IEEE Trans. Power Systems* 2/94, 198
- “Power quality monitoring of a distribution system,” *IEEE Transactions on Power Delivery* 4/94, 1136
- “Value-based distribution reliability assessment and planning,” *IEEE Trans. Power Delivery* 1/95, 421
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- “Application of customer-interruption costs for optimum distribution planning,” *Energy* (1996, 3) 157
- *Development of Distribution System Reliability and Risk Analysis Models* (8/81)
- "Bulk Power System Reliability Criteria and Indices: Trends and Future Needs," *IEEE Trans. on Power Systems* 2/94, 181
- “Distribution System Reliability Indices,” *IEEE Trans. Power Systems*, 1/89, 561
- “Computer Programs for Reliability Evaluation of Distribution Systems,” International Power Engineering Conference, 3/93, 37
- CEA website
- “Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System,” (7/94)
- *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99)
- *Value-Based Transmission Resource Analysis, Volumes* 1&2 (4/94)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98)
- *TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems*, Vol. 1 (5/92)
- *Study of Effect of Load Management on Generating-System Reliability* (7/84) (*generation)
- *Distribution System Reliability Engineering Guide* (3/76)
- *Distribution System Reliability Issues.doc* (12/99)
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)
- *Reliability Assessment of Large Electric Power Systems* (’98)
- *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)
- *Reliability of Benchmarking Methodology* (5/97) (not currently (3/00) in library)

c) Loss-of-Load Probability (LOLE/LOLP)

- *The Value of Service Reliability to Consumers* (5/86)

- "Using Customer Outage Costs in Electricity Reliability Planning," *Energy* 2/95, 81
- "Reliability Pricing of Electric Power Service: A Probabilistic Production Cost Modeling Approach," *Energy* 2/96, 87
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "Bulk Power System Reliability Criteria and Indices: Trends and Future Needs," *IEEE Trans. on Power Systems 2/94*, 181
- *Outage cost estimation guidebook* (12/95)
- *Value-Based Transmission Resource Analysis, Volume 1* (4/94)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98)
- *TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems*, Vol. 1 (5/92)
- *Study of Effect of Load Management on Generating-System Reliability* (7/84) (*generation)
- *Reliability Assessment of Large Electric Power Systems* ('98)
- *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)

2. Faults:

a) Failure rates by equipment type (circuits, transformers, capacitors, cables, poles)

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- *Power Distribution Planning Reference Book* (1997)
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195
- "Value-based distribution reliability assessment and planning," *IEEE Trans. Power Delivery* 1/95, 421
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "Application of customer-interruption costs for optimum distribution planning," *Energy* (1996, 3) 157
- "The Failure Rates of Overhead Distribution System Components," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91 713
- "Determination of Failure Rates of Underground Distribution System Components from Historical Data," Proceedings of the Transmission and Distribution Conference, IEEE 9/91, 718
- "High Voltage Circuit Breaker Reliability Data for Use in System Reliability Studies--Interim Report CIGRE 13.06 Working Group," 9/91

- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704
- "A Method for Estimating the Reliability of Distribution Circuits," *IEEE Trans. Power Delivery* 4/92, 694
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37
- CEA website
- *Forced Outage Performance of Transmission Equipment*, 1/1/92 to 12/31/96, CEA (7/98) (*transmission)
- *Value-Based Transmission Resource Analysis; Volumes 1&2* (4/94) (*in generation & transmission)
- *Study of Effect of Load Management on Generating-System Reliability* (7/84) (*generation)
- *Distribution System Reliability Engineering Guide* (3/76)
- *Distribution System Reliability Issues.doc* (12/99)
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)

b) Durations

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195
- "Value-based distribution reliability assessment and planning," *IEEE Trans. Power Delivery* 1/95, 421
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "Application of customer-interruption costs for optimum distribution planning," *Energy* (1996, 3) 157
- "High Voltage Circuit Breaker Reliability Data for Use in System Reliability Studies--Interim Report CIGRE 13.06 Working Group," 9/91
- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37

- CEA website
- *Forced Outage Performance of Transmission Equipment*, 1/1/92 to 12/31/96, CEA (7/98) (*transmission)
- *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99)
- *Value-Based Transmission Resource Analysis, Volumes 1&2* (4/94) (*in generation & transmission)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98) (*in transmission)
- *Study of Effect of Load Management on Generating-System Reliability* (7/84) (*generation)
- *Distribution System Reliability Engineering Guide* (3/76)
- *Distribution System Reliability Issues.doc* (12/99)
- *'Bang Per Buck' Templates: Examples of how to estimate the cost-effectiveness of electric reliability programs*
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)

c) Causes (rural vs. urban, weather, peak loading, accident, sabotage)

- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "The Failure Rates of Overhead Distribution System Components," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91 713
- "Determination of Failure Rates of Underground Distribution System Components from Historical Data," Proceedings of the Transmission and Distribution Conference, IEEE 9/91, 718
- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704
- "A Method for Estimating the Reliability of Distribution Circuits," *IEEE Trans. Power Delivery* 4/92, 694
- "Distribution System Reliability Indices," *IEEE Trans. Power Systems*, 1/89, 561
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37

- *Forced Outage Performance of Transmission Equipment*, 1/1/92 to 12/31/96, CEA (7/98) (*transmission)
- *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99)
- *Distribution System Reliability Issues.doc* (12/99)
- *'Bang Per Buck' Templates: Examples of how to estimate the cost-effectiveness of electric reliability programs*
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)

d) Classes (transmission vs. distribution; brownouts/blackouts; multiple contingency events, self-clearing events, system trips)

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195
- "Effect of protection systems on bulk power reliability evaluation," *IEEE Trans. Power Systems* 2/94, 198
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "The Failure Rates of Overhead Distribution System Components," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91 713
- "Determination of Failure Rates of Underground Distribution System Components from Historical Data," Proceedings of the Transmission and Distribution Conference, IEEE 9/91, 718
- "Distribution System Reliability Indices," *IEEE Trans. Power Systems*, 1/89, 561
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37
- CEA website
- "Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System," (7/94)
- *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version* (5/99)
- *Distribution System Reliability Issues.doc* (12/99)
- *Reliability Assessment of Large Electric Power Systems* ('98)

3. Maintenance & Changing Reliability (in distribution)

a) Equipment types

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- *Electrical Distribution Engineering* (1991)
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Effect of protection systems on bulk power reliability evaluation," *IEEE Trans. Power Systems* 2/94, 198
- *Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery* (10/97)
- "High Voltage Circuit Breaker Reliability Data for Use in System Reliability Studies--Interim Report CIGRE 13.06 Working Group," 9/91
- CEA website
- *Outage cost estimation guidebook* (12/95)

b) Policies and planning

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- *Costing and Pricing Electric Power Reserve Services* (generation) (12/97) EPRI-TR-108916
- "Using Customer Outage Costs in Electricity Reliability Planning," *Energy* 2/95, 81
- "Most Value Planning: Estimating the Net Benefits of Electric Utility Resource Plans," *Energy Sources*, '94, 451
- "Power quality monitoring of a distribution system," *IEEE Transactions on Power Delivery* 4/94, 1136
- "Value-based distribution reliability assessment and planning," *IEEE Trans. Power Delivery* 1/95, 421
- Reliability Centered Maintenance presentation (RCM 61099.ppt)
- *Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery* (10/97)
- *Reliability Centered Maintenance (RCM) for Distribution Systems and Equipment: Four Application Case Studies* (5/99)

- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- *Development of Distribution System Reliability and Risk Analysis Models* (8/81)
- "A Method for Estimating the Reliability of Distribution Circuits," *IEEE Trans. Power Delivery* 4/92, 694
- "Distribution System Reliability Indices," *IEEE Trans. Power Systems*, 1/89, 561
- CEA website
- *Outage cost estimation guidebook* (12/95)
- *The Strategic Role of Distributed Resources in Distribution Systems* (10/99)
- *Value-Based Transmission Resource Analysis, Volumes 1&2* (4/94) (*in transmission)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98) (*in transmission)
- *Distribution System Reliability Engineering Guide* (3/76)
- *'Bang Per Buck' Templates: Examples of how to estimate the cost-effectiveness of electric reliability programs*
- *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)
- *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)
- *NERC Operating Manual* (*in generation & transmission)
- *Reliability at What Cost? Analyzing the economics of (improving) distribution reliability* (1/00)

c) Engineering to change reliability

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Electrical Distribution Engineering* (1991)
- *Power Distribution Planning Reference Book* (1997)
- "Measuring reliability of electric service is important," *Electric Light & Power* 5/93, 35
- "Using Customer Outage Costs in Electricity Reliability Planning," *Energy* 2/95, 81
- "Effect of protection systems on bulk power reliability evaluation," *IEEE Trans. Power Systems* 2/94, 198
- *Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery* (10/97)
- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704
- "A Method for Estimating the Reliability of Distribution Circuits," *IEEE Trans. Power Delivery* 4/92, 694

- CEA website
- *Distribution System Reliability Issues.doc* (12/99)

4. Regulatory Issues
   - *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
   - “Measuring reliability of electric service is important,” *Electric Light & Power* 5/93, 35
   - *The Value of Service Reliability to Consumers* (5/86)
   - “Power quality monitoring of a distribution system,” *IEEE Transactions on Power Delivery* 4/94, 1136
   - “Reliability Pricing of Electric Power Service: A Probabilistic Production Cost Modeling Approach,” *Energy* 2/96, 87
   - *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
   - *Development of Distribution System Reliability and Risk Analysis Models* (8/81)
   - "Bulk Power System Reliability Criteria and Indices: Trends and Future Needs," *IEEE Trans. on Power Systems* 2/94, 181
   - CEA website
   - “Canadian Utility Perspective on Power Quality,” CEA Electricity Conference 3/99
   - “Reliability: NERC/FERC Convergence,” CEA Electricity Conference 3/99
   - *Outage cost estimation guidebook* (12/95)
   - *Framework for Stochastic Reliability of Bulk Power System* (3/98) (*in transmission)
   - *Distribution System Reliability Issues.doc* (12/99)
   - *Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission* (1999)
   - *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)
   - *Reliability Assessment 1998 – 2007: The Reliability of Bulk Electric Systems in North America* (9/98)
   - *NERC Operating Manual*
   - *Quality of Service in an Era of Increasing Competition: A Review of the Literature with Policy Implications and Annotated Bibliography* (2/95)
   - *Types of Incentive Regulation: A Primer for the Electric Utility Industry* (1993)
   - *Electric Utility Restructuring: A Guide to the Competitive Era* (1997)
   - *How to Construct a Service Quality Index in Performance-Based Ratemaking* (4/96)
   - *Six Useful Observations for Designers of PBR Plans* (4/96)
   - *Seven Basic Rules for the PBR Regulator* (4/96)

- Reliability at What Cost? Analyzing the economics of (improving) distribution reliability (1/00)

5. Power Quality

- "Power Quality – A Growing Problem", *Electrical World* (09/96)
- "Power Quality – An Evolving Concern For Electric Utilities", *Transmission & Distribution* (05/92)
- "Conducting a Power Quality Site Analysis – Part 2", *Electrical Construction and Maintenance* (10/95)
- "Utilities Today Must Provide 'Clean' Power", *Electric Light and Power* (03/93)
- "A Major UK Distribution Power Quality Survey", (1994)
- "Application of Distribution System Capacitor Banks and Their Impact on Power Quality", *IEEE Trans. On Industry Applications* (05/96)
- "Power Quality: End User Impacts", *Energy Engineering Vol.88* (1991)
- "Power Quality: A Review", *IEEE Computer Applications in Power* (01/90)
- "The Electric Utility – Industrial User Partnership in Solving Power Quality Problems", *IEEE Trans. On Power Systems* (08/90)
- *Power Distribution Planning Reference Book* (1997)
- "Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites," *IEEE Trans. Ind. Appl.* 9/98 p 904
- "Electric-Power-Quality Improvement using Parallel Active-Power Conditioners", *IEEE Proc.-Gener. Transm. Distrib.* (9/1998)
- "Attributing Harmonics in Private Power Production", *IEEE Trans. On Industry Applications* (9/1998)
- "Innovative System Solutions for Power Quality Enhancement", *ABB Review* (3/1998)
- "A Survey of distribution system power quality - preliminary results" *IEEE Trans. Power Delivery* 1/95, 322
- "Power quality and harmonic distortion on distribution systems," *IEEE Trans. on Ind. Applications*, 3/94, 476
- "Power quality monitoring of a distribution system," *IEEE Transactions on Power Delivery* 4/94, 1136
- "Distribution customer power quality experience," *IEEE Trans. on Ind. Applications* 11/93, 1204
- "Practices for solving end-user power quality problems," *IEEE Trans. on Ind. Applications* 11/93, 1165
- "Voltage stability conditions considering load characteristics," *IEEE Trans. Power Systems* 12/92, 243
- "Solving the power-quality dilemma," *Electrical World* 11/92, 48

- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704
- CEA website
- "Canadian Utility Perspective on Power Quality," CEA Electricity Conference 3/99
- "CEA Power Quality Survey 2000," CEA Electricity Conference 3/99
- *Active Power Line Conditioning Methods: A Literature Survey* (7/95)
- *An Assessment of Distribution System Power Quality: Volumes 1-3* (5/96) (not currently (12/99) in library)
- *Distribution System Reliability Issues.doc* (12/99)
- *Power Quality Workbook for Utility and Industrial Applications* (10/95)
- "Power Quality – Two Different Perspectives", *IEEE Trans. On Power Delivery* (7/1990)
- *Reliability of Benchmarking Methodology* (5/97) (not currently (3/00) in library)
- *Reliability Benchmarking Application Guide with Customer/Utility Common Power* ***Quality Indices*** **(9/99) (not currently (3/00) in library)**

6. Reliability Modeling

- *Guide to Value Based Reliability Planning* (1/96) CEA 273 D 887
- *Distribution System Reliability Handbook* (12/82) EPRI EL-2651
- Power Distribution Planning Reference Book (1997)
- "Measuring reliability of electric service is important, "*Electric Light & Power* 5/93, 35
- "Effects of adverse weather conditions and higher order outages on customer interruption costs in electric subtransmission systems," *Electric Power Systems Research* 12/94, 195
- "Effect of protection systems on bulk power reliability evaluation," *IEEE Trans. Power Systems* 2/94, 198
- "Voltage stability conditions considering load characteristics," *IEEE Trans. Power Systems* 12/92, 243
- "Value-based distribution reliability assessment and planning," *IEEE Trans. Power Delivery* 1/95, 421
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- "Application of customer-interruption costs for optimum distribution planning," *Energy* (1996, 3) 157
- *Development of Distribution System Reliability and Risk Analysis Models* (8/81)
- "Reliability and Quality Comparisons of Electric Power Distribution Systems," Proceedings of the Transmission and Distribution Conference, IEEE, 9/91, 704

- "A Method for Estimating the Reliability of Distribution Circuits," *IEEE Trans. Power Delivery* 4/92, 694
- "Computer Programs for Reliability Evaluation of Distribution Systems," International Power Engineering Conference, 3/93, 37
- "Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System," (7/94)
- *Value-Based Transmission Resource Analysis, Volumes 1&2* (4/94) (*in generation & transmission)
- *Framework for Stochastic Reliability of Bulk Power System* (3/98) (*in transmission)
- *TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems, Vol. 1* (5/92) (*in transmission)
- *Distribution System Reliability Engineering Guide* (3/76)
- *Distribution System Reliability Issues.doc* (12/99)
- *'Bang Per Buck' Templates: Examples of how to estimate the cost-effectiveness of electric reliability programs*
- *Reliability Assessment of Large Electric Power Systems* ('98)

7. Pricing (see also Customer Needs library)

a) Interruptible Rates

- *Customer Demand for Service Reliability: A Synthesis of the Outage Costs Literature* (9/89)
- "Efficient Menu Structures for Pricing Interruptible Electric Power Service, "*Journal of Regulatory Economics* (1989)
- *The Value of Service Reliability to Consumers* (5/86)
- "Multilevel Demand Subscription Pricing for Electric Power," *Energy Economics* (10/1986)
- "Priority service and outage costs in the power sector The Taiwan experience," *Utilities Policy* 7/93, 255

b) Differentiated Pricing (reliability, service, quality)

- "Priority Pricing in electricity Supply: An Application for Israel", *Resource of Energy and Economics 19* (1997)
- *Customer Demand for Service Reliability: A Synthesis of the Outage Costs Literature* (9/89)
- "How Much Do Customers Want to Pay for Reliability? New Evidence on an Old Controversy," *Energy systems and Policy, Volume 15* (1991)
- "Priority service and outage costs in the power sector The Taiwan experience," *Utilities Policy* 7/93, 255

- "Priority Service: Pricing, Investment, and Market Organization," *The American Economic Review* (12/1987)
- "Reliability Pricing of Electric Power Service: A Probabilistic Production Cost Modeling Approach," *Energy 2/96*, 87
- *Cost-benefit analysis of power system reliability: Determination of interruption costs* (5/90)
- *Outage cost estimation guidebook* (12/95)
- *Distribution System Reliability Issues.doc* (12/99)
- *Reliability at What Cost? Analyzing the economics of (improving) distribution reliability* (1/00)

The following documents were reviewed in the Customer Needs report.

"Comprehensive Bibliography on Reliability Worth and Electrical Service Consumer Interruption Costs: 1980-1990", *IEEE Trans. On Power Systems* (11/91)

"Analysis and Mitigation of Voltage Disturbances at an Industrial Customers' Corporate Campus", *IEEE Trans. On Industry Applications* (9/1998)

"Costs of Service Disruptions to Electricity Consumers," *Energy Vol. 17 No. 2* (1992)

"Measurement and Applications of Customer Interruption Costs/Value of Service for Cost-benefit Reliability Evaluation: Some Commonly Raised Issues", *IEEE Trans. On Power Systems* (11/90)

"Voltage Sags: Their Impact on the Utility and Industrial Customers", *IEEE Trans. On Industry Applications* (04/98)

"Live-fire Fault Test of SVC: A Lesson in Power Quality," *Electrical World* (08/95)

B
DEFINITIONS USED IN THIS REPORT

Definitions are provided for terms used in this report, including words, reliability indices, abbreviations, and acronyms. For words, the format for each entry is <u>word</u>***:*** definition; *source*, when there is either a single source or virtually all sources agree on the definition—in the latter case, *source* may be omitted— or <u>word:</u> *source*=definition if various cited sources have somewhat different definitions that are important to recognize. Note that *source* includes a page location. The other entries are presented in obvious ways.

B.1 Definitions

It is natural to begin with the definition of reliability.

Reliability, Peak Reliability, Strategic Reliability

<u>Reliability:</u>

NERC Glossary= The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system Adequacy and Security.

Guide to Value-Based Reliability Planning A-4=*generally designates the ability of the system to provide an acceptable level of continuity and quality*

Power Distribution Planning Reference Book 2=provide uninterrupted flow of stable power; deliver all power demanded all the time

Power Distribution Planning Reference Book 155=as normally applied to power distribution means continuity of service to the utility's customers; a reliable power system provides power without interruption

Costing and Pricing Electric Power Reserve Services 2-13 (for generation)=one minus the probability of system failure (inability to meet load)

The Value of Service Reliability to Consumers=dependability or consistent performance

<u>peak reliability</u>: ability of a power system to meet peak load

strategic reliability: vulnerability of a power system to uncertain and long-term (weeks to months) disruptions that make system energy deficient

Other Definitions

Integrated Value-Based Planning:

Guide to Value-Based Reliability Planning iii=maximizing value to customers considering all of their needs

Guide to Value-Based Reliability Planning iii 2-3 (with further explanation)=uses customer value and cost as the basis of evaluating supply- and demand-side resources

Value-Based Distribution Reliability Planning =maximizing value to customers with a focus on the combination of electricity tariffs and reliability of service; *Guide to Value-Based Reliability Planning iii*

Value-Based Planning:

Guide to Value-Based Reliability Planning 1-2=incorporation of customer values and costs into overall utility planning

Power Distribution Planning Reference Book 111= analytical method to determine the best way to balance quality against cost that combines customer-value data with cost data for T&D system for various reliability and quality levels

Least-Cost Planning: attempted to find minimum cost over a wide range of supply options for a given level of service; *Guide to Value-Based Reliability Planning 2-3*

Adequacy: the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; *NERC Glossary of Terms*

Security: the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements; *NERC Glossary of Terms*

Reliability cost: investment cost of the utility in achieving a defined level of reliability (*from Abstract of Application of customer-interruption costs for optimum distribution Planning*)

Reliability worth: the benefit gained by the utility customer from an increase of reliability (*from Abstract of Application of customer-interruption costs for optimum distribution Planning*)

Tariff: schedule of rates or charges of a business or public utility

Outage: (most common definition) the time between either the first customer call or the first SCADA indication until circuit is reenergized; *Measuring reliability of electric service is important*

Permanent Outage: defined as 1, 2, 3, 5 minutes long by utilities; *Measuring reliability of electric service is important*

Primary side of Industrial Facility: the primary side of the transformer providing the customer's power: the utility side

Secondary side of Industrial Facility: the secondary side of the transformer providing the customer's power: the industrial/customer side; utilization voltage

Surge: *Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites*=overvoltage condition

Power Distribution Planning Reference Book 87=very transient swing in voltage – spike or other quick shift – which doesn't last over a number of cycles like a swell or sag

Sag: undervoltage condition; *Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites; Power Distribution Planning Reference Book 83*

stable voltage: any one customer must see same level (+-3-6%) always; any fluctuation must happen slowly; *Power Distribution Planning Reference Book 4*

Subtransmission lines: transmission lines whose sole or major function is to feed power to distribution substations; *Power Distribution Planning Reference Book 7*

Network: more than one electrical path between any two points in system

Radial: only one path through system; *Power Distribution Planning Reference Book 11-12*

Distribution: below 34.5kV; all utilization voltage equipment plus all lines that feed power to service transformers; all radial equipment (stated thus to distinguish between distribution and transmission); *Power Distribution Planning Reference Book 17*

Power Factor: measure of how well voltage and current in an alternating system are in step with one another; in perfect system their alternating cycles would be in conjunction; ratio of real (effective) power to maximum possible power; *Power Distribution Planning Reference Book 22*

Interruption: cessation of electric service; lack of availability; inverse of reliability

Outage: failure of one or more components of the electric system to do their job

Power quality: attributes of the power when some power is being delivered; *Power Distribution Planning Reference Book 76*

Interruption Durations: *Power Distribution Planning Reference Book 162 (alternates on 156)*

Instantaneous: an interruption restored immediately by completely automatic equipment, or a transient fault that causes no reaction by protective equipment. Typically less than 15 seconds

Momentary: An interruption restored by automatic, supervisory, or manual switching at a site where an operator is immediately available. Usually less than three minutes.

Temporary: An interruption restored by manual switching by an operator who is not immediately available. Typically, thirty minutes.

Sustained: Any interruption that is not instantaneous, momentary, or temporary. Normally more than an hour.

Permanent outage: defined as 1, 2, 3, or 5 minutes long by individual utilities; *Measuring reliability of electric service is important*

Momentary interruptions: often only a few seconds, and never more than a minute; *Power Distribution Planning Reference Book 79*

Extent: how many customers are interrupted by the outage of a particular line or unit of equipment; *Power Distribution Planning Reference Book 158*

Layout: the how and why of selection of equipment, connection to rest of system, arrangement and location of pieces in the assembly of a number of line segments and their ancillary equipment in a distribution feeder system; *Power Distribution Planning Reference Book 229*

Feeders: all primary voltage circuitry downstream of a low-side protective device at the substation; neighborhood size delivery circuits which route power from distribution substations (utility company sources) to vicinity of customers (service transformers); *Power Distribution Planning Reference Book 343, 285*

Contingency: limiting/containing duration: there should be a reasonable way to restore power in advance of repairs; *Power Distribution Planning Reference Book 348*

Substation: takes power at high voltage from transmission or sub-transmission level, reduces its voltage, and routes it onto a number of primary voltage feeders for distribution; *Power Distribution Planning Reference Book 391*

Durability: expected reliability as a function of remaining life and loading; *Power Distribution Planning Reference Book 766*

Brownout: voltage drop; *The Value of Service Reliability to Consumers 7-5*

Reserve Margin: percentage increment on expected peak demand; *The Value of Service Reliability to Consumers 6-1*

Expected Unserved Energy: The expected amount of energy curtailment per year due to demand exceeding available capacity. It is usually expressed in megawatthours (MWh); *NERC Glossary of Terms*

Abbreviations

AA=all aluminum conductor

ADIC=average demand interruption cost

AEIC=average energy interruption cost

ANSI=American National Standards Institute

AP=Alberta Power

ARC=adaptive response costs

ASCR=aluminum clad steel reinforced conductor

BC=British Columbia Hydro

BCP=budget constrained planning

CBEMA=Computer and Business Equipment Manufacturers Association

CCDF=composite customer damage functions

CEA=Canadian Electric Association

CIC=customer interruption costs

CPI=consumer price index

CPS=completely packaged substations

CSP=completely protected substations

CSP=completely self-protected

CVR=conservation voltage reduction

DE=Detroit Edison Co.

DG=distributed generation

DLC=direct load control service

DSM=Demand Side Management

DSR=demand subscription rates

EDF=Electricite de France

EEI=Edison Electric Institute

EENS=expected energy not served

EMI=electromagnetic interference

ENEL=Ente Nazionale per l'Energia Elettrica

EOC=expected outage costs

ESEERCO=Empire State Electric Energy Research Corporation

FO=forced oil transformer

FOFA=forced oil and forced air transformer

FPL=firm power level

HL&P=Houston Lighting and Power Company

I/C=interruptible/curtailable service

IEAR=Interrupted Energy Assessment Rates

IEEE=Institute of Electrical and Electronics Engineers

IRP=integrated resource plan

IRR=internal rate of return

LDC=less developed country

LDC=line drop compensator

LDC=local distribution company

LILCO=Long Island Lighting

LOEE=Loss of Energy Expectation

LOLE=Loss of Load Expectation

LOLP=Loss-of-Load Probability

LRMCC=long-run marginal customer costs

LRMRR=long-run marginal revenue requirement

LRMSC=long-run marginal societal costs

LTC=load transfer coupling

NC=normally closed

NEB=net economic benefit

NERC=North American Electric Reliability Council

NO=normally open

NPV=net present value

NSERC=Natural Science and Engineering Research Council of Canada

OGP=Optimum Generation Planning model

OH=Ontario Hydro

OH=overhead

PA=preparatory actions

PG&E=Pacific Gas and Electric

PM=Preventive Maintenance (used in the RCM presentation)

PURPA=Public Utilities Regulatory Policies Act

PVC=present value of costs

RCM=Reliability Centered Maintenance

RG&E=Rochester Gas and Electric Corporation

RIM=rate impact measure

RTP=real-time pricing

SAO=service-area optimization

SC=system cost

SCDF=sector customer damage functions

SCE=Southern California Edison

SP=Saskatchewan Power

T&D=Transmission and Distribution

TA=Trans Alta

TCC=total customer cost

THD=total harmonic distortion

TOU=time-of-use

TP&L=Texas Power and Light Company

TRC=total resource cost

TVA=Tennessee Valley Authority

UG=underground

VBP=value-based planning

VBRA=value based reliability assessment

VOS=value of service

WACC=weighted average cost of capital

WEPCO=Wisconsin Electric Power

WTA=willingness-to-accept

WTP=willingness-to-pay

WUMS=Wisconsin-Upper Michigan System

The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as Hourly Loss-of-Load-Expectation if hourly demands are used in the calculations instead of daily peak demands. LOLE also is commonly referred to as Loss-of-Load-Probability. See Expected Unserved Energy. *NERC Glossary of Terms*

A=availability=MTTF/MTBF=$\mu/(\lambda+\mu)$

EDC=expected demand curtailment [kW*outages/year] = [kW/year]

EENS=expected energy not supplied

IEAR=interrupted energy assessment rate

LOEP=Loss-of-Energy Probability

MTBF=mean time between failures; frequency of failure=1/MTBF=f=1/T

MTTF=mean time to failure; failure (or hazard) rate=1/MTTF=λ=1/m

MTTR=mean time to repair/restore; restoration hazard rate=1/MTTR=μ=1/r

U=unavailability=MTTR/MTBF=$\lambda/(\lambda+\mu)$

Reliability Indices

Source: Power Distribution Planning Reference Book 165-169

SAIFI: System Average Interruption Frequency Index

=(number of customer interruptions)/(total customers in system)

-one of 4 most important

-measures frequency

-average # interruptions per customer

CAIFI: Customer Average Interruption Frequency Index

=(number of customer interruptions)/(number of customers who had at least one interruption)

-one of 4 most important

-measures frequency

- average # interruptions over customers who had at least one interruption

-CAIFI≥SAIFI; CAIFI≥1

-large differences from SAIFI indicates concentration of outages from poor design, poor maintenance, differences in weather, bad luck

SAIDI: System Average Interruption Duration Index

=(sum of the durations of all customer interruptions)/(total customers in system)

-one of 4 most important

-measures duration

-average duration of all interruptions per customer

-simplest; most intuitively understandable

-perhaps, best single indicator of distribution system's health (equipment and design)

CTAIDI: Customer Total Average Interruption Duration Index

=(sum of the durations of all customer interruptions) /(number of customers who had at least one interruption)

-traditionally called CAIDI (see CAIDI)

-one of 4 most important

-measures duration

-average duration over customers who had at least one interruption

-large differences from SAIDI indicates concentration of outages from poor design, poor maintenance, differences in weather, bad luck

-CTAIDI≥SAIDI

-CTAIDI/SAIDI=CAIFI/SAIFI=fraction who experienced at least one outage

-only need one of CTAIDI or CAIFI but both usually used

CAIDI: Customer Average Interruption Duration Index

-measures duration

-duration divided by total customer interruptions=avg duration (average customer interruption duration)

-customer with 3 interruptions counted once in denominator of CTAIDI, 3 times in denominator of CAIDI

-CAIDI=CTAIDI/CAIFI=SAIDI/SAIFI

-statistic, not an index

-can show how types of outages vary (depending on reporting period) and management of restoration process

MAIFI: Momentary Average Interruption Frequency Index

-measures frequency

-average # momentary interruptions per customer

-if utility distinguishes, usually doesn't count momentary in SAIFI so total interruptions per overall customer = SAIFI+MAIFI

CALCI: Customer Average Load Curtailment Index

(sum of all customer load curtailments)/(number of customers who had at least one interruption)

-measures load curtailment

-average interruption kVA duration over customers who had at least one interruption

-load curtailment=duration of outage X kVA unserved

MICIF: Maximum Individual Customer Interruption Frequency

-measures frequency

-worst-case customer (often hard-to-reach)

-sometimes averaged over worst n customers (n=12-50)

MICID: Maximum Individual Customer Interruption Duration

-measures duration

-worst-case customer (not usually same as for MICIF)

-sometimes averaged over worst n customers (n=12-50)

Source: Distribution System Reliability Handbook 12/82, 2-2 and Measuring reliability of electric service is important; Electric Light & Power 5/93, 35

ALIFI=Average Load Interruption Frequency Index

=(total load interruptions)/(total connected load)

ALIDI=Average Load Interruption Duration Index

=(total load interruption durations)/(total connected load)

ASCI=Average System Curtailment Index

=(total load curtailment)/(total number of customers)

ACCI=Average Customer Curtailment Index

=(total load curtailment)/(total number of customers affected)

ASAI=Average Service Availability Index or Service Reliability Index

=(customer hours of available service)/(customer hours demanded)

ASUI=Average Service Unavailability Index: complementary to ASAI

SAIFI1 & SAIFI2: distinguish between permanent and momentary outages

MAIFI: (momentary or SAIFI short) average frequency of momentary (less than one minute) interruptions

LAIFI=Load Average Interruption Frequency Index (annual interruptions/kVA)

=(total number of load interruptions)/(total amount of customer load) [=] (kW-outages)/kW

LAIDI=Load Average Interruption Duration Index (annual hours lost/kVA)

LWMID=Load-Weighted Mean Interruption Duration

=(total customer energy interruptions)/(total customer load interruptions) [=] kWh/(kW-outages)

DLI=Demand Loss Index

=(total system load losses at peak)/(total system peak load) [=] kW/kW

ELI=Energy Loss Index

=(total system energy losses for year)/(total customer energy consumption for year) [=] kWh/kWh

Miscellaneous Abbreviations

c=customer

r=reliability

t=transmission

d=distribution

e=electric

v=voltage

ac=alternating current

u=utility

vbrp=value-based reliability planning

ivp=integrated value-based planning

w/=with

info=information

esp=especially

C
SUMMARY OF TEXTBOOKS

Books in the reliability library

Power Distribution Planning Reference Book

Electrical Distribution Engineering

IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book)

Reliability Evaluation of Power Systems, 2nd Edition

Reliability Evaluation of Engineering Systems, Concepts and Techniques

Books that have been reviewed and determined to be of relevance to distribution system reliability but hard copies of which are not in the reliability library

Reliability Assessment of Large Electric Power Systems

Electric Utility Restructuring: A Guide to the Competitive Era

Books that are not part of the reliability library as newer textbooks (above) cover the information contained in them

Power System Reliability Evaluation

Power-System Reliability Calculations

Reliability Modeling in Electric Power Systems

Books that are not part of the reliability library as they were reviewed and determined to not be of relevance to distribution system reliability

Electric Utility Competition: A Survey of Regulators

Electricity in the American Economy: Agent of Technological Progress

Regulating Utilities: The Way Forward

Electric Utility Planning and Regulation

Power Distribution Planning Reference Book

H. Lee Willis,
Marcel Dekker, Inc., New York, 1997
writing (1996) p.79

This book provides a solid background in distribution system reliability planning, including reliability-related concerns.

Chapter 1: Power Delivery Systems

This chapter covers general aspects of the transmission and distribution systems. The goals of these systems are to (1) cover the territory, (2) supply sufficient capacity for peak demand, (3) be highly reliable, and (4) provide a stable voltage, all at a low cost. Their reliability mission is to provide the uninterrupted flow of stable power and deliver all power demanded all the time. A chart on customer outages by level of a power system, from generation to service, is shown. There is a description of what the physical laws of electrical power distribution mean to planners and engineers. The layout of the different components of a power system is also described, and the observation is made that reliability decreases as you move further down the system towards the customer service point. The types of equipment in a distribution system are categorized into major ((a) transmission and distribution lines, (b) transformers), and other types including (a) safety, (b) fail-safe, and (c) voltage regulation equipment. Protective equipment, such as circuit breakers, sectionalizers, fused disconnects, control relays, and sensing equipment, detect interruption of normal function and isolate the damaged equipment. The power quality aspect of reliability is discussed somewhat. A 10% range in voltage in a service area is said to be okay. However, any one customer must see only a ±3-6% variation always, and any fluctuation must happen slowly. It is related that the worst offenders in terms of power quality are induction motors, especially small ones (for blowers, air conditioning, compressors, powering of conveyor belts). Voltage regulation equipment, including line regulators, line drop compensators, and tap-changing transformers, can reduce but not eliminate voltage fluctuation. Capacitors, a type of voltage regulation equipment, are said to do most good if they're on the distribution system near the customer. General costs for a distribution system are given. Different types of distribution systems are outlined, and there are comments on the increase in reliability from radial, to loop, to network types of systems.

Chapter 2: Electrical Load and Consumer Demand for Power

This chapter mainly discusses load curves, their measurement, modeling, and characteristics. It is mentioned that customer demand has 2 aspects: quantity and quality. Power quality here is composed of availability, stability, and the amount of harmonics and noise.

Chapter 3: Availability and Power Quality

There is a lot of valuable information concerning reliability and power quality in this chapter. It begins by stating that customers must understand that high quality of service and low price are mutually incompatible. It continues by distinguishing an interruption, the cessation of electric service or lack of availability, from an outage, failure of one or more components of the electric system. Interruptions accompany the outage of 1 or more parts. It is observed that interruptions that occur when power is not being used are unimportant. Power quality is defined as the attributes of the power when some power is being delivered. Some causes of outages are enumerated: equipment failure by weather or other, equipment switched off deliberately, by mistake, or by failure of control equipment. Also enumerated are some causes of interruptions: downed line, failed cable, damaged transformer (e.g., lightning), failures in customers' equipment (open wiring, corroded switchgear,…). Momentary interruptions, a few seconds to no more than a minute, are caused by things such as trees brushing conductors causing a usually high-impedance fault, small animals contacting conductors and being vaporized, or lightning. It is mentioned that some interruptions appear as voltage variations. Another cause of unusual voltages, which occurs in 3-phase commercial buildings, is 1 or 2 phases being down. Restoration times for interruptions are reported to differ between urban and suburban systems, where service can be restored in minutes by switching feeders, and rural systems where repair is often the only option. The chapter reports that customers usually see about 1-3 interruptions/year and 1-4 hours/year of outage, but these values are dependent on local conditions like weather.

Power quality is discussed in detail here. It is stated that voltage variations outside of ±10% may damage equipment. The Computer and Business Equipment Manufacturers Association (CBEMA) developed a set of recommended voltage variation versus duration levels, the chart of which is given. It is reported that 85% of the sags that are outside the CBEMA envelope are from faults. Motor-induced sags (flicker) are longer in duration but not as deep (~10%, not worse than 20%). The leading cause of sags worldwide is probably lightning, whereas capacitor and other switching are the most common non-weather causes. Protection comes in the form of lightning arresters (LA) and transient voltage surge suppressors (TVSS).

Another power quality problem is harmonics, frequencies other than 50 or 60 Hertz. Harmonics are generated passively by electrical equipment with a non-linear load, such as transformers, motors, other overloaded 'wound' devices, AC-DC power supplies, clipping devices, diodes and semiconductor devices. Tolerable levels of harmonics, ones that don't cause malfunctions or equipment damage, are thought to increase costs by 10% from loss of useful life. The most important index for this problem is THD, total harmonic distortion. THD is the root of squares of the harmonics normalized by standard frequency, and is measured as current or voltage. Other measurements are the telephone influence factor, which compares harmonic content in relation to the phone system, and the customer-message curve, a weight index of frequencies of human hearing. There is also the K-factor index for estimating the impact of harmonics on losses. Recommended guidelines from IEEE Standard 519-1992 for customer current injection and those permitted on a system are tabulated. For the distribution level, it is recommended that there be no more than 5% THD. It is stated that no enforceable requirements for manufacturers exist, except for some medical and military equipment. There is the recommendation that appliances function in the presence of 5% THD. It is observed, though, that increasing the tolerance of an appliance is more costly than reducing its own harmonics output. Average values in a home are reported as THD's of 10% voltage or over 200% for current. Mitigation of harmonics can be performed by passive filters, which prevent customer site problems from getting to the T&D system, or active filters, which produce harmonic currents equal to those in the load current, shunting them away. Passive filters are cheap, simple, unpowered, but need tuning. Active filters, on the other hand, are more robust, but they are expensive, consume much power, and create high EMI.

Value-based planning is also discussed here. The engineering characterization is said to be of matching availability and power quality against cost. Value-based planning is described as an analytical method to determine the best way to balance quality against cost that combines customer-value data for a T&D system for various reliability and quality levels. It involves finding the minimum of the sum of customer and utility costs versus power quality. This can be done for just reliability (value-based reliability planning), for just quality, or for overall power quality (value-based quality of service planning). The author states though that reliability affects the most customers and has more information on it. The final section of this chapter has a discussion on interruption costs and differentiated service issues. It is reported that reliability and power quality requirements differ among customers because (a) end-use patterns differ, and (b) appliance usage differs. An end-use analysis can provide a good basis for power quality needs. There is an example given of spatial, geographic reliability models used to produce a map of average reliability needs for a city based on a willingness-to-pay model of customer value.

Chapter 4: Planning Criteria

Utilities have standards and criteria for equipment and performance to ensure achievement of the utility's goals. Different types of criteria and practices related to them are discussed here. The authors mention that protection criteria, which are in place to address safety, also have a role in reliability. Design criteria by the planner for engineers specify how equipment must be used. Utilities derate from the manufacturers' ratings depending on local conditions and use. Also, loading standards may be exceeded in extreme emergencies after considering the benefits. Regulatory requirements are said to be that no customer have over 120 V and that the feeder be at the lowest voltage possible permissible within voltage drop allowances. The standard for voltage imbalance between phases is usually 4%. There is also the general guideline that the planner must provide a distribution system that can be protected. The view on criteria and standards is that they must be met, and there is no additional benefit in exceeding them.

It is stated that the fundamental objective of the distribution system is to deliver power in a usable form. Power quality criteria and standards are also a topic of this chapter. Utility standards in the US are usually based on ANSI standard Range A (: ±5% on 120V (114-126) service voltage) and Range B (105.8% to 91.7% or 127 to 110) for temporary or infrequent conditions. These standards translate to design criteria for distribution planning. Primary distribution level voltage standards for ten utilities are tabulated. A voltage spread at a single customer point of up to 6% is said to be reasonable if it happens on the time scale of hours. Rapid voltage fluctuations or flicker, on the other hand, is discernible in illumination at levels of 3% and 5% and very noticeable if it occurs within 1-2 seconds. Flicker is usually caused by the starting of large, multi-phase motors, so flicker standards are often called motor start voltage standards or motor starting criteria. Other industrial equipment, switched utility equipment such as capacitors or phase shifters, can also cause flicker. It is reported that many utilities use a flicker magnitude versus frequency of occurrence guideline.

Chapter 5: Reliability and Contingency Criteria

This chapter begins by saying that reliability as normally applied to power distribution means the continuity of service to the utility's customers. It has a reliability terms and definitions glossary and includes additional definitions throughout the chapter on such things as interruption durations and indices. The factors in reliability analysis are listed as frequency, duration, and extent, where extent is the number of customers interrupted by the outage of a particular line or unit of equipment. Extent is the key to the outage-interruption relationship and is determined by the layout of the distribution system. As such it is under the control of the distribution system planner, with it generally costing extra to minimize extent.

There is a large section of this chapter that covers reliability indices. For reliability to be used as a design criterion and to allow the setting of reliability goals, there needs to be a measure of it. The combination of frequency and duration into a single value, which is often tried, is said to be impossible. Most utilities use more than one index. No one index is really superior as they each can serve different purposes, and maybe no one index individually is useful. Care must be taken as apparently identical indices can vary because of differences in how interruptions are defined and interpreted. For example, many utilities do not include scheduled outages, storms, and other non-failure related interruptions in their reporting, while others don't include momentary outages.

A number of different indices are defined and described. Some indices are system oriented (starting with an S), others are customer oriented (with a C). SAIFI, CAIFI, SAIDI, and CTAIDI are said to be the four most important. CAIDI, MAIFI, CALCI, MICIF, and MICID are also defined. It is mentioned that about 75% of North American utilities report availability, but that doesn't tell much although the value looks good for the utility. The planner, having influence over layout and equipment, might concentrate on indices such as SAIFI, CAIFI, MAIFI, and MICIF. Indices can be used to evaluate historical data or used predictively to analyze proposed solutions. The author states that it is best to use reliability directly as a criterion in distribution system planning, but this is not widely done as of the writing of this book (1996).

The author relates that using reliability as a criterion in distribution system planning will become widely used. The reasoning is that (a) it addresses reliability directly from a customer standpoint, rather than indirectly from utility (equipment criteria) standpoint, leading to improved quality assurance; (b) it imposes no restrictions on design or equipment other than that the results must meet customer performance needs, thus possibly leading to lower costs; and (c) dependable, proven methods for reliability-based design are becoming widely available. Typically four criteria would be used, such as SAIDI, SAIFI, MICIF, and MICID, as design constraints for the planner. It is related that tiered reliability targets already exist for urban and rural systems, which recognize the characteristic that service reliability is less in sparsely populated areas as the cost to improve rural reliability is high because of the great distances and the cost is spreadable over fewer customers. Having rate-reliability tier areas is only sometimes done, though, for example for downtown network, urban, high-use industrial, suburban, rural, and mountainous categorizations. It would be best to set reliability goals based on local conditions and local customer requirements and feedback. Customer survey results may miss the understanding of the tradeoff of reliability and cost, however. Setting reliability goals based on past results is practical. The author states that value-based reliability planning is the most appealing method of setting reliability goals. This process optimizes the entire utility-customer value system by minimizing the total cost (utility cost plus customer costs of imperfect reliability). Providing more reliability than the minimum is giving customer’s more reliability than it is worth to them. The difficulty in value-based reliability planning is that different customers have different values for reliability, and the importance of frequency versus duration varies tremendously across customers but the reliability level set must serve all of them. Despite this, when applied to the planning of the entire utility or customer class, value-based reliability planning can establish guidelines.

Chapter 6: Economic Evaluation

The author discusses utility costs in this chapter. Most traditional utility planning involves selecting the lowest cost alternative from a set of alternatives, all of which satisfy requirements. Planning goals are defined by the cost-based pricing regulatory environment. With deregulation, the local distribution company will still be regulated and prices for delivery (if not power) will still be cost-based.

Chapter 7: Line Segment and Transformer Economics and Set Design

Different equipment options are discussed in this chapter. Underground feeders are reported to be better for esthetics and reliability. Most lengthy outages on overhead lines are caused by trees or adverse weather (e.g., ice). Most momentary outages are from trees brushing against conductor lines in high winds. These problems are avoided by underground feeders. A concrete duct bank is immune to outages, but is difficult to repair and is very expensive initially. Ground lightning strikes can destroy cable and dig-ins from construction and rodents can cause reliability problems for underground lines. Further underground lines wear out sooner than overhead ones, and repairs take longer. The differences between delta and wye configurations of wiring is also discussed. It is mentioned that reliability considerations are taken into account for planning for substation transformers, which have a much greater cost and impact on customer reliability than service transformers.

Chapter 8: Distribution Feeder Layout

The feeder system must distribute power while satisfying (a) economic, (b) electrical, and (c) service considerations. The reliability must be very high, and voltage and quality must be satisfactory. The different feeder system options are discussed here. It is reported that more than 80% of distribution systems worldwide are radial. For radial systems, the failure of a segment interrupts the service of half its customers on average. A loop system can provide very high reliability. On average for a loop system, two simultaneous failures interrupt only one quarter of the customers. Networks are the most reliable. The loss of a segment will not interrupt any customers, and multiple failures can occur with little or no interruption. Network systems are more costly and require more expensive protective devices and coordination schemes. Underground systems are also an improvement in reliability, but come at the cost of lengthier times for routine maintenance and repair. For example, a utility on the U.S. East Coast requires an average of 73 hours for time until repair for an urban underground system.

The ideal choices of feeder system for different situations and feeder design practices are also discussed. For large commercial buildings, the reliability requirements are above average, so loop feeders are used. Rural system reliability requirements are lower. Customers, homeowners and businesses accept that being in remote areas predicate less reliable electrical service, so a radial system is often appropriate. Reliability is often a major aspect influencing selection of feeder design. Alternate sources, paths, and configurations of service must be planned so that both failures and maintenance do not affect customer service beyond a reasonable amount. Many utilities use ANSI range-A voltages as design criteria for normal conditions and range-B ones for contingencies. Most urban and suburban feeder systems are laid out so every feeder has complete contingency backup through reswitching of its loads to other sources. The practical limit for contingency for manual switching is six to eight switching operations, while a dozen or more switching operations is feasible if they're automatic. Relative cost and relative SAIDI of various feeder-style contingency schemes is tabulated. This concerns reliability from the traditional 'contingency coverage' perspective, rather than an explicit reliability indices approach, which the author feels is more appropriate for modern utilities. The qualitative results and recommendations are the same regardless of whether a reliability-index or contingency coverage approach is taken.

Chapter 9: Multi-Feeder Layout and Volt-VAR Correction

The classical distribution system analysis did not assess the impact of feeder layout on service reliability. The material in this chapter includes those considerations. A goal is to have a reasonable way to restore power in advance of repairs. The level of contingency support strength and how to achieve it should be identified in planning. Planning can be contingency-scenario based or reliability-index based. Contingency-based planning is the traditional approach of designing a system to address certain failure scenarios. Reliability-index based planning is newer, more effective, and a more difficult way of applying contingency support planning selectively. It involves picking reliability targets and providing contingency support to meet them. It is difficult without access to software and data that can compute reliability indices on a node or segment basis. It is also mentioned that whole feeder lockouts contribute to only 10-15% of interruption problems and that customers see twice as many momentary and instantaneous interruptions with siamesed feeders.

Chapter 10: Distribution Substations

This chapter discusses the design of distribution substations and the accompanying equipment, such as transformers. There are tabulated data on the relative costs and reliability for different sub-transmission voltages and for a number of different configurations. The reliability of higher voltage lines is generally better because of the higher insulation and capability to withstand lightning strikes, and the fact that they're usually built on robust towers with considerable clearance from trees and other things. Multiple substation transformers can improve reliability and contingency support. Annual outage rates for different numbers of transformers is given. Outages from substation transformers are rare, but, when they occur, restoration is in days. The author reports that outage-rate data for substation transformers is sketchy as there is little available and recording practices differ. For the low-side substation equipment, reliability is seldom a planning concern. However, compatibility with transformer contingency support is a major reliability-related concern. Substation outages are important as they affect many customers. Sample substation costs for certain capacity and service interruption rates are given.

Chapter 11: Distribution System Layout

This chapter contains much tabulated failure data: for different levels of rural and other power systems, for different numbers of transformers at a substation, for substation size, and for different feeder causes as a function of substation size. The author works out the service reliability for an example system estimated using equipment reliabilities and switching times and compares the results to actual system results. Three interruptions and 3 hours every 2 years are typical for North American utility customers. A substation transformer is expected to fail unexpectedly once every 30 years and require 72 hours to repair, which gives an average annual expectation of 2.4 hours. A 2-transformer substation has an expectation that both are out of service due to simultaneous, unrelated failures of less than a minute per year. This implies about 1.2 hours a year of expected inability to serve load. The effect on reliability of substation spacing and size is discussed. Some duration data is also given. A rural system is said to have an annual outage duration of about 6.5 to 7 hours.

Chapter 12: Substation Siting and System Expansion Planning

This chapter includes an example calculation of the impact on reliability of siting a substation within a territory.

Chapter 13: Service Level Layout and Planning

It is mentioned in this chapter that less than 0.1% of power in the U.S. is delivered over secondary networks and that underground systems are thought to reduce harmonics propagation from one customer to another, as it commonly has no shared power flow.

Chapter 14: Planning and the T&D Planning Process

This chapter remarks that customer-level planning begins by adding more detailed end-use and customer value attributes to the load forecast, including reliability value functions, and optimizing by balancing the marginal cost of various customer-side options against the marginal cost of the supply-side.

Chapter 15: Forecasting T&D Load

The author points out here that customer ‘value-base’ (need for reliability) forecasts are used in 1% of applications in T&D planning.

Chapter 16: Distribution Feeder Analysis

Analysis methods are described. Simulators for predictive reliability are said to be used in planning, as are harmonic load flow simulators. Motor start simulators are used in both planning and engineering. Motor start simulators or flicker studies produce profiles of voltage along feeder lines to identify where voltage fluctuation during starting may violate a utility's standards. Reliability assessment involves (a) an historical reliability assessment to assess reliability 'health;' (b) a predictive reliability assessment to predict expected future reliability levels for design alternatives; and (c) a calibration of the predictive model to past events to ensure dependability. This requires a good base of historical information. The goal is to compute for every node the expected frequency and duration of outages. A desirable, but difficult, aspect is to compute the expected frequency and severity of voltage dips, which requires a fault-current analysis of the system. Some reliability analysis methods require details of a load flow solution.

Chapter 17: Automated Planning Tools and Methods

The tools and methods include simulators to predict performance of a particular system design, decision support tools to help select among alternatives, and optimization methods. This chapter also has information on durability, the expected reliability of equipment as a function of remaining life and loading. Some figures are given, for example for transformers' likelihood of failure for different loading levels. Higher loadings accelerate the loss of life and increase the likelihood of short-term failure. Considering the value of reliability to customers, a compromise can be found among loading levels, long-term use, and service reliability.

Chapter 18: Traditional versus Competitive Industry Paradigms

This chapter summarizes the contrast between the traditional least-cost planning and value-based planning. The results of an example situation of evaluating alternatives with a value-based reliability planning calculation are tabulated.

C.5: Electrical Distribution Engineering, 2nd Edition

Anthony J. Pansini
Fairmont Press, Inc., Lilburn, GA, 1991

The introduction to this book lays out the problem for the power distribution system engineer. Consumer requirements have not only created needs for greater service reliability and stricter voltage standards, but also new quality demands involving the wave form of alternating current supply. The extended application of computers, especially for control purposes, has brought about a need for tighter voltage regulation and a dip-free voltage supply. It is related that distorted voltage waves may be caused from conditions existing on the electric systems of other consumers connected to the utility system. The author mentions that current distribution usually affects the reliability of electrical distribution systems and voltage distortion affects the reliability of equipment. Harmonics may also cause interference with communication circuits and affect the operation of computers. Equipment is available, though, to detect harmonics and wave form distortion.

The book then covers system circuit design and equipment choice and design to address these issues, along with issues unrelated to reliability, from an engineering perspective. Design issues such as overhead versus underground feeder selection are covered. Overhead design is said to be much less costly but more vulnerable to natural hazards (wind, ice, lightning, flood, etc.) and people (vehicles hitting poles, kites, etc.). Overhead feeders are easier to maintain as faults are easily located and fixed. Design issues, including reliability-related concerns, are also covered for conductors, poles, cross arms, pins, racks, insulators, transformers, cutouts, surge arresters, regulators, capacitors, switches, reclosers, and automated distribution. For example, it is suggested that conductor failures should be minimized as they result in complete interruptions. Also, root causes of degradation of the different equipment that may lead to interruptions are described. The quality-of-service issues are said to include selection and maintenance of proper voltage, ample capacity, maintenance of frequency within very rigid limits; service continuity and environmental considerations. A high degree of reliability is reported to be essential where public safety is involved, for example auxiliary sources are often provided for hospitals, military establishments, and for some larger theaters, department stores, apartment buildings, and hotels. The book lists reliability indices. Minimum design criteria for overhead conductors are suggested by the National Electric Safety Code (NESC). The NESC is issued by the Institute of Electrical and Electronics Engineers (IEEE) and is reportedly widely accepted. These guidelines divide the country into high, medium, and light wind and ice load areas and suggest that local conditions should be taken into account.

IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book)

IEEE Std 493-1997 (Revision of IEEE Std 493-1990; Recognized as an American National Standard)
The Institute of Electrical and Electronics Engineers, Inc., New York, 1998
(TK/1005/I225/1990)

This book seems to concentrate on reliability of equipment that would be a part of an industrial plant's power system as opposed to that of the utility. It does have data, such as for transformers, that is likely pertinent to the considerations of utilities, and it has summaries of, for example, an EPRI survey on utility's motors, with a reference. The Appendices (e.g., I) do include some studies by utilities. Besides the equipment data, there is a lot of information on reliability analysis/modeling and interruption costs for industrial and commercial customers, including an extensive bibliography. This book is referenced on the calculation of failure rates from failure data (e.g., "The Failure Rates of Overhead Distribution System Components," W.F. Horton, S. Goldberg, C.A. Volkman, Proceedings of the Transmission and Distribution Conference, IEEE, Dallas, 9/91, 713-717)

Reliability Evaluation of Power Systems, 2nd Edition

R. Billinton, R.N. Allan, Plenum, New York 1994 (also see following text)
(TK/1010/B55/1996)

Reliability Evaluation of Engineering Systems, Concepts and Techniques

R. Billinton, R.N. Allan, New York, Plenum, 1983 (see above text) (TA/169/B598)

Reliability Assessment of Large Electric Power Systems

R. Billinton, R.N. Allan, Kluwer Academic Publishers, 1988 (TK/1005/B572/1988)

This book contains material that is a part of other Billinton textbooks, but, in contrast to the other textbooks, this one answers the question of why quantitative reliability evaluation should be performed and what it can achieve. It includes definitions of reliability-related concepts, the history of reliability assessment, exhaustive example applications to the RTS (as basis for comparison) and other systems, and it attempts to document in one place the practical range of applications. There are individual chapters on the techniques and status of reliability evaluation of the generation system, the composite system (HLII), and the distribution system, as well as a chapter on the assessment of reliability worth. It is stated that the inadequacy of individual load points is caused mainly by the distribution system, with localized effects, and HLII indices have a negligible effect, less than 1%. HLII failures affect large sections with possible catastrophic consequences, so they are also of importance. Material relating to the increased application of reliability evaluation to composite systems is included. Presently available probabilistic techniques are said to be mostly in the domain of adequacy. The comparison of cost to adequacy worth and the minimization of total cost are covered in the reliability worth chapter. The appendices have a description and data for the RTS for HLI and HLII.

The objective of the evaluation of HLIII is stated to be to obtain suitable adequacy indices at actual consumer load points. The primary indices are expected frequency (or rate) of failure, average duration, annual unavailability (or outage time) of load points. There are additional indices of expected load disconnected or energy not supplied. The analytical methods for evaluating these indices are highly developed. They combine the usual reliability evaluation techniques based on minimal-cut-set method or failure-mode analysis with sets of analytical equations to account for all realistic failure and restoration processes. The chapter on the distribution system lists SAIFI, SAIDI, and CAIDI, and additionally ASAI, ASUI, ENS, AENS as the most common indices. Example calculations of these for historical data are performed. Performed as well is an example base-case analysis for a simple radial distribution system using common series-parallel reduction, which is then extended to a few other situations. Through all the evaluations, it is understood that the effect of failure of the main supply to the system is not normally included when evaluating the reliability indices of a distribution system.

In addition to the analytical approach to distribution information, which is very practical and efficient for a wide range of system studies, a Monte-Carlo simulation approach is illustrated. The authors state that little consideration has been given to the variation of measures of reliability about its mean, in probability distributions. Monte-Carlo simulations of typical radial distribution systems can provide these. The book discusses a University of Saskatchewan program that simulates the performance of any radial distribution system with loads connected to laterals or directly to primary mains and the insights provided by an application to example systems. Determining probability distributions using an analytic or an approximate approach is also discussed.

An appendix describes the effects of dependence of components to failure. System data includes multiple relevant failures resulting from dependent factors. A common significant assumption in reliability evaluation is that the behaviour of any component is independent of any other component, directly or indirectly. This practice underestimates system failure by 1, 2, or more orders of magnitude. Dependency effects are categorized in terms of Markov modeling techniques. Models for each type of dependency are presented as extensions to the basic component model, the 2-state (up-down) representation. Evaluation techniques involving (1) the construction of a state-space diagram in stochastic transitional probability matrix form and solution using Markov techniques; and (2) the deduction of a set of approximate equations from a reliability model into which appropriate transition rates are inserted are discussed. The second technique is said to be very convenient in conjunction with minimal cut-set analysis.

Electric Utility Restructuring: A Guide to the Competitive Era

Peter Fox-Penner; Public Utilities Reports, Inc.; Vienna Virginia HD9685/U5/K34/1997 c.1

This book describes the structure of the electric utility industry, including much on the regulatory structure, and the interaction of regulation with competition. The three stages of electric utilities are regulated differently: federal government regulates sales between utilities and transmission rates; state regulators cover plant construction, retail rates, and distribution. The book's description includes coverage of the different types of electric utilities and how each type is regulated. For example, the enforcement of adequacy requirements for investor-owned utilities is governed by franchise and state utility statutes. There is a discussion on the role of the state utility regulation, which does not include a mention of reliability, but references are given. The history of regulation of electric utilities is covered. It is related that the NERC and regional reliability councils were created in part as a reaction to the 1965 blackout in the northeastern U.S. to promulgate voluntary system planning and operating criteria for generation and transmission. As stated in the book, 80% of customer outages are caused by a fallen distribution line or a nearby transformer. The widespread effects of transmission and generation outages through cascading failures are avoided by designing power systems to automatically disconnect the rest of the system from the problem area. Sample criteria of one regional reliability council are detailed. For example, the maximum permissible impact each utility system can have on its connected neighbors as a result of 1, 2, or 3 sudden plant or line outages is specified. Transmission grids are thus planned and operated to continue to function with the unplanned loss of one or two large lines, or to remain operable under an agreed-upon variety of contingencies that could occur anytime. Distribution systems, on the other hand, have some redundancy, but as a whole, they are one-way, one-path networks. The authors report that, partly due to the self-governance of the reliability councils, there has been very little regulation of reliability at the state or federal level. Short-term reliability is achieved by the voluntary agreements to use regional reliability council standards, all backed by state and federal regulatory authorities. There have been more recent regulatory approaches to measuring and incentivizing quality of service, of which reliability is a component, after early performance-based regulations (PBR) lacked special provisions for maintenance of customer service. It is related that price-cap PBR across the utility industries are always implemented with complex quality standards. The book reports that several states have also now instituted requirements requiring reporting of detailed reliability performance each year, but there is no discussion of regulated reliability standards, particularly for the distribution system. It is mentioned that in New York in 1991, the Public Service

Commission issued an order requiring each regulated utility to adhere to certain service standards (which may include reliability) and report its performance in an annual report. Finally, indices for generation adequacy, both for history and planning, are listed, as are DOE recommendations on the regulation of reliability under competition.

Power System Reliability Evaluation

R. Billinton, Gordon and Breach, Science Publishers, New York, 1970 (TK/1005/B598p)

Power-System Reliability Calculations

R. Billinton, R. J. Ringlee, A. J. Wood, MIT Press, Cambridge, 1973 (TK/1005/B598)

Reliability Modeling in Electric Power Systems

J. Endrenyi, Wiley-Interscience, New York, 1978 (TK/1005/E53)

Electric Utility Competition: A Survey of Regulators

R. J. Rudden Associates and Fitch Investors Service, Inc. HD9685/U5/E53/1993

This publication is focussed on the transition to competition in the electric utility industry and there is no mention of reliability or the regulation of reliability.

Electricity in the American Economy: Agent of Technological Progress

Sam H. Schurr, Calvin C. Burwell, Warren D. Devine, Jr., Sidney Sonenblum

HD9685/U5/E539 c.2 1990

This book does not address reliability or the regulation of the supply of electricity. It covers the economic effects that the supply of electricity has on various industries and the overall economy. It could be of some use in the understanding of the costs to society of changing regulatory standards, but does not address that topic itself.

Regulating Utilities: The Way Forward

Edited by Prof. M. E. Beesley *HD9685/R4/R37/1994*

This book covers a number of British utility industries. It has a chapter on regulating the transition to a competitive electricity market. There is no discussion of reliability, let alone distribution reliability or the regulation of reliability.

Electric Utility Planning and Regulation

Edward Kahn HD9685/U5/K34/1988

This book is not of relevance to distribution system reliability or the regulation of distribution system reliability. It is concerned more with planning the generation component of a utility.

D
SUMMARY OF JOURNAL ARTICLES

1999 Publications

The IEEE Reliability Test System-1996
A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee, IEEE Transactions on Power Systems, Vol. 14, No. 3, August, 1999, p. 1010

This article describes the newest version of the Reliability Test System for generation and transmission, RTS-96. The distribution system is not addressed by the RTS. The first version, RTS-79, was developed to satisfy the need for a standardized database to test and compare results from different reliability evaluation methodologies. The RTS is a reference containing core data and system parameters for composite system reliability evaluation. The other version before the present one, RTS-86, presented for comparison the system reliability indices derived through the use of rigorous solution techniques without using any approximations in the evaluation process. The RTS is not modeled after a specific system because of the desire to keep it universally applicable: A good test system should represent all the different methodologies and configurations that could be encountered on any system.

Application of Monte Carlo Simulation to Generating System Well-being Analysis
Roy Billinton, Rajesh Karki; IEEE Transactions on Power Systems, Vol. 14, No. 3, August, 1999, p. 1172

This article concerns generation reliability. It discusses well-being analysis, which the authors contend can act as a bridge between conventional deterministic analyses and more effective probabilistic analyses. Monte Carlo simulation is used to evaluate the well-being indices, the probability that the system is in a healthy state, marginal state, or an at risk state. These are the three states for the model for well-being analysis. The method is applied to the IEEE-RTS and the results are discussed. The authors contend that modern computers reduce the difficulty of excessive computation allowing the use of MCS for a wide range of studies.

Optimal Maintenance Scheduling in a Parallel Redundant System Consisting of Series Components in Each Branch
Roy Billinton and Jun Pan; IEEE Transactions on Power Delivery, Vol. 14, No. 3, July, 1999, p. 928

Time Sequential Distribution System Reliability Worth Analysis Considering Time Varying Load and Cost Models
Peng Wang, Roy Billinton; IEEE Transactions on Power Delivery, Vol. 14, No. 3, July, 1999, p. 1046

The article presents and implements a Monte Carlo simulation algorithm that incorporates time-varying load and cost models for the evaluation of distribution system reliability. Time-varying load models and time varying cost models for seven customer sectors are presented. A program performs the calculations on a sample, realistic radial distribution system. ECOST, EENS, and IEAR as well as the probability distributions for them are evaluated for individual load points. The results are compared to those from a similar evaluation using average load and cost values. It is found that the magnitude of the effect of using time varying models depends on the load point and, for the time-varying cost model, on the customer sector.

Teaching Distribution System Reliability Evaluation Using Monte Carlo Simulation
Roy Billinton, Peng Wang; IEEE Transactions on Power Systems, Vol. 14, No. 2, May, 1999, p. 397

The authors compare analytical and simulation approaches to distribution system reliability evaluation as well as the educational value of the two approaches. Analytical approaches use a set of mathematical equations along with a relatively simple procedure and relatively little computer time. They provide average values for load point and system indices. Monte Carlo simulation techniques, on the other hand, can also provide information on the probability distributions of these indices by running through a series of artificial histories. An algorithm for simulation is described here, and it is implemented in the application of a program to the Reliability Test System (RBTS). The results for this test system of the simulation and the analytical approach are similar with the system indices being no more than 3.2% different, and load point indices being no more than 8% different. The simulation, however, produces a pictorial representation of the distribution system reliability profile that should add considerably to a student's appreciation of distribution system reliability. Sample results are SAIFI=1.0 Int/Cu*year; SAIDI=3.8 hours/Cu*year; CAIDI=3.7 hours/Cu*Int. The system indices SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS, and AENS are all calculated. The formulas for these indices are given.

Canadian Utility Perspective on Power Quality
K.K. Cheng; CEA Electricity Conference; March, 1999; Vancouver, Canada.

This paper summarizes the status of power quality activities such as standard setting and regulation. It presents mainly the approach of Canadian utilities and the CEA but also discusses the situation in the U.S. and Europe. The approach to power quality problems has evolved from utilities responding to customer complaints and absorbing the costs to a stance where the party responsible for the power quality disruptions or those desiring better than average power quality must pay. The cost to Canadian utility customers of poor power quality is estimated at C$1.2b/year. In Europe, utilities must abide by the supply standards of CENELEC (EN 50160). The standards in the U.S. are in IEEE 1159. Internationally, the IEC 61000 series will replace, by 2001, the IEC 1000 series, which in turn is replacing IEC 555-2 and IEC 555-3. Addressing power quality problems involves the utility, the customer, and the equipment manufacturer. The

CEA has formed a Power Quality Interest Group (PQIG). Out of the CEA PQIG has recently come “Impact of the Introduction of the Electromagnetic Compatibility (EMC) Concept in the Canadian Electric Industry” and “Options and Devices Available for the Prevention, Correction, and Mitigation of Electric Power Quality Disturbances.” The PQIG has defined 25 power quality indices from 103 factors based on the IEC and IEEE standards in the “Power Quality Measurement Protocol”. A nationwide power quality survey to come up with acceptable baseline levels of 11 of these 25 indices is proposed (see “CEA Power Quality Survey 2000” and “Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites,” 1998). This baseline will allow a look into new business opportunities from offering different levels of “Grades of Electricity.”

<u>CEA Power Quality Survey 2000</u>
Ross Nelson; CEA Electricity Conference; March, 1999; Vancouver, Canada.

This presentation gives a quick overview of the status of a new power quality survey supported by the CEA Power Quality Interest Group (see “Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites,” 1998). The survey was to start in May, 1999 and is to measure 11 of the 25 CEA Protocol power quality indices. The objective of the study is to provide data for the determination of a baseline power quality performance and to allow for comparison to IEC (http://www.iec.ch/) EMC requirements.

<u>Reliability: NERC/FERC Convergence</u>
K. Jennifer Moroz; CEA Electricity Conference; March, 1999; Vancouver, Canada.

The author summarizes the legislation proposed in the US by NERC and by the US Department of Energy that would make reliability standards legally enforceable. Deregulation has made voluntary compliance with reliability standards unlikely. The formation of a new North American Electric Reliability Organization (NAERO) overseen by the FERC would ensue. The impact on the Canadian electricity industry of these developments is examined and possible responses to the evolving regulatory situation in the US are discussed. The “Principles for Regulatory Support of Electricity System Reliability” developed by the CEA in 1997 (included in an Appendix) must be reviewed in light of the proposed US bills on reliability.

<u>Bibliography on the Application of Probability Methods in Power System Reliability Evaluation: 1992-1996</u>
R.N. Allan, R. Billinton, A.M. Breipohl, C.H. Grigg; IEEE Transactions on Power Systems, Vol. 14, No. 1, February, 1999, p.51

This paper presents a bibliography of papers concerned with power system reliability evaluation. It includes sections on Transmission and Distribution System Reliability Evaluation, Equipment Outage Data, and Reliability Cost/Worth Analysis. These sections list articles relevant to distribution system reliability. The article is the fifth such bibliography, with previous ones published in 1972, 1978, 1984, 1988, and 1994.

<u>Probabilistic Evaluation of Voltage Stability</u>
Saleh Aboreshaid and Roy Billinton; IEEE Transactions on Power Systems, Vol. 14, No. 1, February, 1999, p.342 Not fully reviewed.

Application of DC Equivalents to the Reliability Evaluation of Composite Power Systems
H.A.M. Maghraby and R.N. Allan; IEEE Transactions on Power Systems, Vol. 14, No. 1, February, 1999, p.355 Not fully reviewed.

Modeling the Impact of Substations on Distribution Reliability
R.E. Brown and T.M. Taylor; IEEE Transactions on Power Systems, Vol. 14, No. 1, February, 1999, p.349 Not fully reviewed.

1998 Plublications

Innovative system solutions for power quality enhancement
Arora, Arun; Chan, Kevin; Jauch, Thomas; Kara, Alexander; Wirth,Ernst, ABB High Voltage Technologies Ltd. ABB Review n 3 1998. p 4-12. Not fully reviewed.

Attributing harmonics in private power production
SRINIVASAN K., IEEE Transactions on Industry Applications, 1998, 34 (5) 887-892.

Not fully reviewed.

Analysis and mitigation of voltage disturbances at an industrial customer's corporate campus
KHERA P. P.; DICKEY K. C., 3M Co, St. Paul MN, United States Journal: IEEE Transactions on Industry Applications, 1998, 34 (5)893-896. Not fully reviewed.

Distribution System Reliability Cost/Worth Analysis Using Analytical and Sequential Simulation Techniques
Roy Billinton, Peng Wang; IEEE Transactions on Power Systems, Vol. 13, No. 4, November, 1998, p.1245

This paper presents both a generalized analytical approach and a time sequential Monte Carlo simulation technique for evaluating the customer interruption cost in complex radial distribution systems. The authors state that relatively little work has been done in the area of reliability evaluation of distribution systems. Algorithms for the two evaluation techniques are described here and implemented in computer programs, DISRE1, and DISRE2. These programs are used in studies of two practical distribution systems of the RBTS. The basic distribution system reliability indices for load points, average failure rate, average outage duration, and annual outage duration are calculated. The system indices can be calculated from the load point indices: SAIFI, SAIDI, CAIDI, ASAI, and ASUI. Reliability cost/worth indices of EENS, ECOST, IEAR are also calculated from load point indices. The results of the analytic approach, and simulation with and without overlapping restoration times are used on the sample distribution systems. The approximate analytic technique is fast and provides comparable results to the Monte Carlo simulation. The simulation, however, provides the probability distributions of the failure parameters. In addition, it is found that consideration of overlapping times has little influence on results when the system is small and element restoration times are short.

Canadian National Power quality survey: Frequency and duration of voltage sags and surges at industrial sites
Koval, Don O.; Bocancea, Romela A.; Yao, Kai; Hughes, M. Brent, IEEE Transactions on Industry Applications v 34 n 5 Sep-Oct 1998. p 904-910.

This paper presents a summary of the data obtained in the CEA national power quality survey (CEA report 220 D711A). The authors state that prior to the 1991 survey, very little power quality information was available. Data on voltage sags, surges, swells and waveshape disturbances are presented by time of day, day of week, and duration. Disturbances were measured both on the primary (utility) side as well as the secondary (industrial) side.

New approach to monitoring electric power quality
Dash, P.K.; Panda, S.K.; Liew, A.C.; Mishra, B.; Jena, R.K., Electric Power Systems Research v 46 n 1 Jul 1998. p 11-20. Not fully reviewed.

Distribution System Reliability: Default Data and Model Validation
R.E. Brown, J.R. Ochoa; IEEE Transactions on Power Systems, Vol. 13, No. 2, May, 1998, p.704

To overcome the hesitation of utilities to perform predictive distribution system reliability assessment because of inadequacy of historical component data, the authors present a method by which default component reliability data can be developed and validated by the matching of historical values. Reliability is said to be associated with sustained customer interruptions as reflected by the predominant use of SAIFI and SAIDI. ASAI and CAIDI are reported to also be widely used, but they can be directly computed from SAIFI and SAIDI. The authors contend that MAIFI, SAIFI, and SAIDI reflect the overall reliability of a specified area, so they are used in the analysis. Power quality issues are described as becoming reliability issues, firstly momentary interruptions but also voltage sags. The different methods and the history of distribution system reliability assessment are discussed. Predictive reliability assessment has reached the point where commercially available software products exist. The steps to predictive reliability are enumerated as (a) defining meaningful measures of reliability; (b) developing a method to compute these measures; (c) judiciously choosing the best available data to be used. The different approaches are listed as network modeling, Markov modeling, Monte Carlo simulation, and state enumeration. An included state enumeration technique is implemented in software that is being developed by ABB. The paper claims that state enumeration is computationally efficienct and has the ability to model complex system behaviour. DISTREL (DISTribution RELiability), the implementation, will be an add on model for ABB's distribution analysis package CADPAD and the radial complement of ABB's network reliability assessment package NETREL (NETwork RELiability). In the validation, the paper first identifies which default component reliability parameters should be modified through a sensitivity analysis of results of application on a test system. The method to compute these parameter values so that predicted system index values match historical ones is described. The method is performed on a portion of the RBTS.

Electric-power-quality improvement using parallel active-power conditioners.
HUANG, S. J.; WU, J. C.; JOU, H. L.
Department of Electrical Engineering, National Cheng Kung University, Tainan, 70101, Taiwan; Department of Electrical Engineering, National Kaohsiung Institute of Technology, Kaohsiung

80782, Taiwan Journal: IEE proceedings. Generation, transmission and distribution, 1998, 145 (5) 597-603. Not fully reviewed.

Voltage sags: Their impact on the utility and industrial customers
MELHORN, C. J.; DAVIS, T. D.; BEAM, G. E.

Electrotek Concepts, Inc, Knoxville TN, United States Journal: IEEE Transactions on Industry Applications, 1998, 34 (3) 549-558. Not fully reviewed.

1997 Publications

Generalized n+2 State System Markov Model for Station-Oriented Reliability Evaluation
R. Billinton. Hua Chen, Jiaqi Zhou; IEEE Transactions on Power Systems, Vol. 12, No. 4, November, 1997, p.1511 Not fully reviewed.

Features That Influence Composite Power System Reliability Worth Assessment
A. Jonnavithula, R. Billinton; IEEE Transactions on Power Systems, Vol. 12, No. 4, November, 1997, p.1536

The authors perform reliability assessments of composite generation-transmission systems from the IEEE-RTS and the RBTS. A sequential Monte Carlo simulation approach with time varying loads is used. They explore the effects of temporal variations of the cost function for different customer sectors. Sample customer cost data is included. They also explore the effects of using a interruption cost probability distribution approach to the cost evaluation. Analyses are performed on the sample systems to compare this method to the conventional CDF approach. The authors state that the most useful reliability index for reliability worth evaluation is EENS, and that IEAR is usually used to link EENS to ECOST.

Reliability Issues in Today's Electric Power Utility Environment
R. Billinton, L. Salvaderi, J.D. McCalley, H. Chao, Th. Seitz, R.N. Allan, J. Odom, C. Fallon; IEEE Transactions on Power Systems, Vol. 12, No. 4, November, 1997, p.1708 Not fully reviewed.

Priority pricing in electricity supply: An application for Israel.
Beenstock, Michael; Goldin, Ephraim, Resource and Energy Economics v 19 n 3 Aug 1997. p 175-189. Not fully reviewed.

1996 Publications

A Test System For Teaching Overall Power System Reliability Assessment
Roy Billinton, Satish Jonnavithula; IEEE Transactions on Power Systems, Vol. 11, No. 4, November, 1996, p.1670 Not fully reviewed.

Distribution System Reliability Assessment Using Hierarchical Markov Modeling
R. E. Brown, S. Gupta, R. D. Christie, S. S. Venkata, R. Fletcher; IEEE Transactions on Power Delivery, Vol. 11, No. 4, October, 1996, p.1929

A new approach to predictive distribution system reliability assessment, hierarchical Markov modeling is presented in this paper. The University of Washington, in conjunction with Snohomish PUD, has developed a software tool that implements this approach. It involves 3 levels of Markov modeling accounting for (a) the system topology, (b) protection system behaviour, and (c) multiple failure modes. The tool, DS-RADS, sequentially solves the Markov models to permit the calculation of the interruption profile of each customer. Sample data are given and used in sample calculations. Results show that the inclusion of the most protection and switching effects in the model most closely matches historical results. Finally, the tool is used to evaluate alternative design options for a portion of the Snohomish PUD. A suggested improvement to the software is to include the measurement of reliability in terms of incurred costs.

Seven Basic Rules for the PBR Regulator.
Peter Navarro, The Electricity Journal, April 1996, p. 24

This article covers the process of designing PBR plans and some of the economic concepts that should be considered. It does not address issues specific to distribution system reliability. There is a section on the quality control mechanism. This mechanism is required to link any utility cost savings achieved to maintaining various measures of utility quality thus preventing false cost savings by sacrificing service quality. The regulators must devise a system that penalizes the utility for undesirable reductions in quality. The creation of a quality control mechanism involves determining measures, setting thresholds, and devising penalties. The author contends that the measures should include system reliability, customer service, and employee safety. Each is regularly measured by the utility and easy to monitor. An explanation is given as to why it may not be optimal to set quality at an existing level. The penalties must ensure that the marginal penalty from reducing quality below a set quality floor is always greater than the utility’s marginal benefit in undercutting the floor. This approach requires assigning dollar values to the various quality parameters. The author suggests, to avoid this difficulty, to assess a penalty as some fraction of the cost savings, with the penalty increasing as quality falls. Finally, it is claimed that it is counterproductive to include any rewards for quality improvements.

Six Useful Observations for Designers of PBR Plans.
G. Alan Comnes, Steve Stoft, Nathanael Greene, and Larry Hill, The Electricity Journal, April 1996, p. 16

This article discusses the most significant observations made from a review and detailed analysis of nine PBR plans proposed or implemented at U.S. electric utilities. There have been recent proposals for comprehensive incentive regulation of U.S. electric utilities, and the utilities examined here are “early adopters.” Reliability is not part of the subject matter, and it is only mentioned that service quality is a supplemental incentive mechanism for the PBR plans of seven of the nine utilities covered.

How to Construct a Service Quality Index in Performance-Based Ratemaking.
Barbara R. Alexander, The Electricity Journal, April 1996, p. 46

This article is on the recent use of performance-based ratemaking (PBR) by state regulatory bodies. It mostly takes a normative approach. It is based in large part on telecommunications experience, but has a brief description of the use of PBR in the electric power industry, as well as the example from telecommunications. The electric utility example is of the first service quality index approved for an electric utility, devised in New York for New York State Electric & Gas and Niagara Mohawk Power Corporation. Also, the Maine Commission set up a comprehensive price cap plan for the Central Maine Power Company, including two outage-related metrics. PBR replaces the common practice of using a rate case as a means to review service quality, and sometimes to adjust the rate of return to reflect poor service. A description of a process for setting the baseline and penalties in PBR is given. The authors state that it's easy to determine the baseline if the utility's service quality performance is above average or even adequate in the recent past, as can use historical data to establish a baseline that reflects the most recent performance. The recent cases in Maine have calculated the average performance over past two to three years, and longer for outage and reliability, and set the baseline as the average minus some factor that reflects statistical variation.

<u>Reliability Pricing of Electric-Power Service: A Probabilistic Production Cost Modeling Approach.</u>
Hegazy Y; Guldmann J.M., ENERGY, 1996, V21, N2 (FEB), P87-97.

The paper presents 3 models, customer choice, supply cost, welfare maximization/pricing, that comprise an approach to reliability pricing. Generation reliability is considered here, but the authors suggest further research to incorporate transmission outages into the model. LOLP is used as the measure of reliability, as it is claimed that the probability of interruption is the most important piece of information a consumer needs in advance and LOLP is the most developed index a power company can provide. Shortages are assumed to be from excessive demand. A summary of customer outage costs by industry class and by time of day is given, from which the data is taken for the models. The results indicate considerable advantage to unbundling power services in terms of reliability as reliability pricing yields highest economic welfare and energy savings over spot and Ramsey pricing.

<u>Application of Customer-Interruption Costs for Optimum Distribution Planning.</u>
Mok, Y.L.; Chung, T.S. (Hong Kong Polytechnic Univ., Kowloon (Hong Kong). Dept. of Electrical Engineering), Energy, 1996, v 21:3.

This paper presents a sample application of the value-based distribution reliability planning and modeling methods found in the Billinton material. Eleven alternate capital-improvement projects to a distribution system are compared by total cost, in a total cost minimization. The distribution system reliability modeling formulas using series-parallel reduction with component failure rates and restoration times are the same as those in Billinton's publications, with some simplifications. In addition, the authors use minimal cut-set theory for mesh-distribution systems. This method isn't discussed: the results are just shown. Tabulated values of failure and reliability data for distribution components are used in the reliability modeling. The authors state this type of component data from historical performance are usually available from a utility's database. The average outage rate (f/yr), average annual outage time (hr/yr), average outage duration (hr) are the reliability indices by which alternate plans are compared. Customer interruption costs differentiated by sector, duration, and season are used to calculate the customer cost part of total cost.

Application of distribution System Capacitor Banks and Their Impact On Power Quality.
Grebe, Thomas E., IEEE Transactions on Industry Applications v 32 n 3 May-June 1996. p 714-719. Not fully reviewed.

Power Quality - A Growing Problem.
Keenan, Campbell, Electrical World (Melbourne, Australia) v 61 n 9 Sep 1996. p 24-26. Not fully reviewed.

1995 Publications

A Survey of Distribution System Power Quality - Preliminary Results.
Gunther, Erich W.; Mehta, Harshad, IEEE Transactions on Power Delivery v 10 n 1 Jan 1995. p 322-329.

This article gives preliminary results of an EPRI project (RP3098-1) to monitor and simulate power quality on distribution feeders. It describes the monitoring effort on the utility side across statistically sampled group of utilities and feeders. Sample data are given for individual feeders, as well as general conclusions on the overall data set. The project uses a device that measures transients, short and long duration RMS variations and interruptions and waveform distortions.

Value-Based Distribution Reliability Assessment and Planning.
Chen R.L.; Allen K.; Billinton R., IEEE TRANSACTIONS ON POWER DELIVERY, 1995, V10, N1 (JAN), P421-429.

This paper discusses VBDRA (value-based distribution reliability assessment) and its 1992 application at Scarborough Public Utilities Commission (SPUC) to assess feeder projects. VBDRA combines distribution reliability indices with customer interruption costs at load points. The reliability assessment model follows that in the *Guide to Value Based Reliability Planning,* also written by Billinton. Outage exposure is assessed both by the load point and component failure techniques. The analytic results from these two techniques for the total customer interruption costs are proven to be algebraically equivalent. However, the load point technique is found to be much faster computationally. The data requirements for an assessment are outlined. Feeder level reliability indices are defined and calculated and combined with customer interruption costs to calculate relative benefits of a number of competing capital-investment feeder projects at SPUC. SPUC's own historical fault data, and that from North York Hydro, and customer interruption costs from previous work are used. The resulting project prioritzation was used by SPUC in its capital budget planning, and a reliability assessment was repeated a couple of years later showing an improvement in overall customer interruption costs.

Using Customer Outage Costs in Electricity Reliability Planning.
Forte, V.J. Jr. Putnam, R. Jr. Pupps, R.L.; Chikeung Woo , Energy v 20:2. 2/95 p 81-87.

Authors from a utility present 2 case studies where customer outage costs were incorporated into distribution planning, and they compare the optimal alternatives by total cost or cost minimization with and without consideration of customer outage costs. The simplified examples use a single average customer outage cost from a survey done by the utility itself. The expected unserved energy is the measure of reliability that is used. The two situations examined are isolated possible projects, impacting one failure event. Relative outage costs are compared for the one failure event, so system reliability modeling is not required.

Conducting a Power Quality Site Analysis - Part 2.
Waggoner, Ray, EC&M: Electrical Construction and Maintenance v 94 n 10 Oct 1995. 2pp. Not fully reviewed.

Live-fire Fault Test of SVC: A Lesson in Power Quality.
Reason, John;, Electrical World v. 209 (Aug. '95) p. 34-7. Not fully reviewed.

1994 Publications

Major UK Distribution Power Quality Survey.
Delaney, Eamon J.; Mueller, David R.; Foster, Nigel G., Proceedings of the 29th Universities Power Engineering Conference. Part 2 (of 2), Galway, Irel, 1994,
p 712-715. Not fully reviewed.

Bulk Power System Reliability Criteria and Indices: Trends and Future Needs
APM Bulk Power Indices Task Force, Sub-Task Force on Future Needs; R.J. Ringlee, Chmn; Paul Albrecht; R.N. Allan; M.P. Bhavaraju; R. Billinton; R. Ludorf; B.K. LeReverend; E. Neudorf; M.G. Lauby; P.R.S. Kuruganty; M.F. McCoy; T.C. Mielnik; N.S. Rau; B. Silverstein; C. Singh; J.A. Stratton; *IEEE Transactions on Power Systems* v 9 n 1 Feb 1994. p 181.

As the title states, this paper is concerned only with the bulk electricity system (BES: major generation and transmission facilities up to points of delivery to area transmission and distribution system). It discusses the indices that are used to measure reliability of the BES and ones that should be used in the future. Then it reviews least cost planning practices and the regulatory trend to relate allowable rates of return of utilities to performance. The authors state that quantitative reliability methods have not caught on for bulk systems, as engineers, managers, and regulators are hesitant to adopt methods which will result in large changes in reliability. The problems of normalization of interruption cost data (to annual peak demand, to annual energy consumed, or to energy not served) and of proper modeling of social costs for wide-spread interruptions, as well as the limitations of reliability models of adequate available interruption cost data and uncertainty with component reliability, are also concerns. Nevertheless, there is increased attention in North American and European regulatory circles on least cost economic indices to justify new generation and transmission facilities, with some Public Utility Commissions (e.g., California) directing that projects be justified not solely on the basis of deterministic reliability criteria. For example, certain Federal agencies, e.g., Bonneville Power Administration, are required to develop financial performance measures that include service performance. In the BES, interruption costs are applied uniformly across the system. Customer Damage Functions could be used to recognize differences across the system. Least cost applications in France and Great Britain are mentioned, with some outage cost data given. For EDF, the costs used were differentiated by levels of curtailed load percentages and by generation and transmission outages. For the model for area transmission and distribution outages, \$2.60/kWh for 1-hour to \$13/kWh for 4 hours were used. In Great Britain, £2/kWh was used for generation. The paper also mentions a trend towards composite system reliability procedures, as opposed to a concentration on just generation. Contemporary reliability assessment methods have been limited mainly to static (load flow) assessments with dynamic (stability) assessments of large-scale systems limited to defined contingency (disturbance) tests. The authors suggest, though, that bulk transmission models for long range planning should carry no greater precision than alternative evaluation strategies, concluding that the level of modeling and the indices used for composite reliability investigations are adequate for long range planning.

The paper discusses two alternate views of reliability, public perception and engineering design. For the public perception, the user understands and experiences the lack of service reliability rather than the effect of reliability itself, and he has concerns of noneconomic attributes such as health and reliability. Engineering design philosophy involves defining the envelope to cover future uncertainty by defining tests for equipment with a safety margin to establish suitability of designs. The tests and margins reflect reliability.

The article includes much discussion on the appropriate reliability indices for the BES in the future. One view is that predictive indices for planning and operations should address the same parameters: frequency, duration, severity. It is suggested that the need is not for new indices, but more for new methods including dynamic models for calculating delivery point interruption and curtailment indices. Bulk system failures are classified by severity in system minutes (SM). The authors propose that the measurement of BES reliability should be extended to include assessment of margins to operations emergency actions. The indices used for long range planning of resource and production are reserve deficit, LOLE, EENS, and System Minutes.

<u>Effect of Protection Systems on Bulk Power Reliability Evaluation.</u>
APM Task Force Report on Protection Systems Reliability, Shahidepour, Mohammad; Allan, Ronald; Anderson, Paul; Bhuiyan, Mukhles; Billinton, Roy; Deeb, Nedal; Endrenyi, John; Fong, Clement; Grigg,Cliff; Haddad, Suheil; Hormozi, John; Schneider, Alex; Singh, Chanan; Wang,Lu., IEEE Transactions on Power Systems v 9 n 1 Feb 1994. p 198-205.

The Task Force reviews the status of the knowledge on protection system reliability, its effects on bulk power systems reliability, and its incorporation into bulk systems reliability evaluation. Protection schemes fundamentals are reviewed including an overview of component protection scheme operation. The available methods and modeling techniques from the literature for evaluating effects of protection system malfunctions on the operation of power systems are reviewed. Reliability performance indices for protection system devices, effectiveness, dependability, and unnecessary operation, are given. Extensive references that support the current status are included.

<u>Power Quality and Harmonic Distortion on Distribution Systems.</u>
Phipps, James K.; Nelson, John P.; Sen, Pankaj K., IEEE Transactions on Industry Applications v 30 n 2 Mar-Apr 1994, p 476-484.

This paper reviews the mathematical fundamentals behind power systems harmonics analysis and shows some actual sample recorded waveforms. It describes the equipment that can cause harmonics and the effects of the harmonics. Some harmonics control standards that are set in IEEE-519 are included. Sample measurements recorded at different points on a transmission and distribution system are given.

Power Quality Monitoring of a Distribution System.
Barker, Philip P.; Burke, James J.; Mancao, Ramon T.; Short, Thomas A.; Warren, Cheryl A.; Burns, Clayton W.; Siewierski, Jerome J., IEEE Transactions on Power Delivery v 9 n 2 Apr 1994. p 1136-1142.

This paper presents the results of a two-year study of power quality, including interruptions, on two distribution feeders serving mainly residential customers that involved comprehensive data acquisition and a pointed analysis. A clear review of the different types of power quality concerns is included, with definitions of power quality issues. Power quality was monitored simultaneously in a number of locations. Interruptions were found to be the primary utility cause of problems to the residential customers, and, besides interruptions, it was found that customers cause most of their own power quality disturbances. CAIDI was the index used for interruptions, and the result was compared to the national average given as 120 minutes/year. The evidence showed that lightning surges were not a primary cause of power quality problems. Deficiencies in industry standards were identified from the study results.

Prediction of Customer Load Point Service Reliability Worth Estimates in an Electric Power System.
Goel, L.; Billinton, R., IEE Proceedings Generation, Transmission, Distribution; v 141 n 4 July 1994. p. 390-396.

This paper presents the application of 3 different methods for the evaluation of reliability worth, which the authors state is not a well developed process. The methods combine quantitative reliability evaluation, which is stated to be well accepted, with customer outage cost assessments in the form of customer damage functions (sector-SCDF's and composite-CCDF's). The load-point outage analytical approach to power system reliability modeling is employed. Reliability is discussed in terms of the customer load point indices λ, r, U, and system performance indices SAIFI, SAIDI, CAIDI, ENS, ASAI, ASUI. Interrupted energy assessment rates (IEAR in $/kWH of ENS) are calculated considering the overall electric power system, hierarchical level (HLIII). The contingency enumeration method used is equivalent to that explained in Billinton's *Guide to Value Based Reliability Planning*, but it is employed here to account for transmission and generation outages as well as distribution outages. Contingency enumeration doesn't recognize each distinct event but comprehensively counts up the effects from each failure mode and effect, with its main assumption being that of using the average frequency and duration of each contingency. It allows the nonlinear nature of the individual load point SCDF's to be incorporated (cost vs. duration). The other two methods, basic indices method and the system indices method are approximations of the contingency enumeration method, as they further aggregate events. The 3 methods are explained, and a computer program is used to apply the 3 methods to the standard RBTS test system. It is a case study for radial distribution system configuration (i.e., presence of disconnects, 100% reliable fuses in laterals, 100% available alternate supply and repair of low-voltage transformers). It is found that, for the test system, the basic indices and system indices methods are poor approximations of the contingency enumeration method producing IEAR results 40-50% lower. An IEAR ($/kWh) value for a bus evaluated using the contingency enumeration method, thus accounting for the variety of outage causes, can be combined with an adequacy index giving the kWh of outage for that bus to assess the impact of unsupplied energy. In the contingency enumeration method, a composite generation and transmission system contingency evaluation program (COMREL) is used for values for load curtailed, probability, frequency, and duration of each contingency that leads to load curtailment for each system bus. A 7-step load model incorporates the effects of varying load levels on this system. Contributions from sub transmission and distribution networks, for which other models are supposedly used, are combined with these results. Contingency enumeration and the system indices method, which is equivalent to the aggregated system performance approach, are detailed in *Guide to Value Based Reliability Planning, also written by Billinton*. The basic indices approach uses average customer load point indices (λ, r) to accumulate costs instead of accounting for each type of failure event as contingency enumeration does.

<u>Effects of Adverse Weather Conditions and Higher Order Outages on Customer Interruption Costs in Electric Subtransmission Systems.</u>
Goel, L.; Billinton, R.; Gupta, R., Electric Power Systems Research v 31 n 3 Dec 1994. p 195-202.

This paper examines the effect on reliability cost-benefit indices of higher-order outages and adverse-weather failures. It begins with a summary of the definitions of different types and orders of outages. It discusses the application of a reliability evaluation that incorporates interruption costs to a small test system, but it is a very comprehensive demonstration of reliability modeling for the sub transmission system. A load point outage analytical approach is used with load-point outage cost accumulation. The analysis is performed using a created software package (SUBTREL) that performs the calculations using the reliability indices λ, r, U (failure rate, average duration, annual outage time) and SCDFs to produce results of SPIEAR, SPEIC, and SPEENS (supply-point specific). Minimal cut-sets are involved in the analysis of the relative effects of different orders of contingencies on the reliability indices. It concludes that ignoring adverse-weather related outages can produce significant errors.

<u>Most Value Planning: Estimating the Net Benefits of Electric Utility Resource Plans.</u>
Hobbs BF; Wilson AF, ENERGY SOURCES, 1994, V16, N3 (JUL-SEP), P451-477.
Most-value planning accounts for the economic benefits or value of energy use in planning. It considers the change in customer value from changes in services, rates, and outages. The consumer surplus method (demand curves) is explained and used to derive willingness to pay components of customer value. Customer outage costs are mentioned briefly. Three case studies are included but none explicitly consider customer outage costs as the focus is on DSM programs.

1993 Publications

<u>Distribution Customer Power Quality Experience</u>
Hughes, Brent M.; Chan, John S.; Koval, Don O., IEEE Transactions on Industry Applications v 29 n 6 Nov-Dec 1993. p 1204-1211.

The paper discusses the method B.C. Hydro used in its power quality survey. It presents sample data from a residential, a commercial, and an industrial customer. One objective of the survey was to develop a database to facilitate the prediction of customer power quality given the characteristics of the customer’s utility supply.

Utilities Today Must Provide “Clean” Power.
Beaty, W., Electric Light and Power (Boston) (United States) v 71:3. 1993, p 19-20.

Not fully reviewed.

Practices for solving End-User Power Quality Problems.
Price, Kenneth, IEEE Transactions on Industry Applications v 29 n 6 Nov-Dec 1993. p 1165-1169.

The author describes troubleshooting techniques for isolating the causes of power quality problems. Some characteristics of measured disturbances that are indicators of problem circumstances are detailed. Two simplified step-by-step examples of power quality investigations are described.

Priority Service and Outage Costs in the Power Sector the Taiwan Experience.
Hsu, G.J.Y.; Tseryieth Chen , Utilities Policy (United Kingdom) v 3:3. 7/93, p 255-260.

The authors detail the experience of Taipower with its curtailable rate programme, which concentrates on industrial customers. They discuss how the relationship between priority service programmes and outage costs affects the planning of priority service programmes. In contrast to most of the literature which focuses on full outages, Taipower undertook surveys of customer costs of partial outages. The costs were differentiated by depth of outage, outage duration, and by nine customer industry groups. Customers participatory reaction to the utility’s curtailable rate programme contradicts their response to the survey questions. Possible reasons for this are discussed, as are comparisons to results of priority service programmes of U.S. utilities.

Measuring Reliability of Electric Service Is Important.
Beaty, W., Electric Light and Power v 71:5. May 1993, p. 35-38.

This article discusses the definitions of reliability and practices in the measurement of reliability. The author concludes that there is little agreement on the definitions or how to assess reliability, nor a standardized way to track it. Many differences exist across utilities, for example in the definition of a momentary versus a permanent outage or what constitutes a storm. Utilities fear unfair comparison and regulation in light of these difficulties. The paper reports some results from a survey of 49 utilities from 28 states performed by the IEEE. An outcome of the effort was a Distribution Reliability Draft Guideline to define terms and promote the use of standard reliability indices. It was found that utilities for which the state regulators require reliability reports had very complete reliability documents. SAIDI was tracked by more than 80% of the surveyed utilities. SAIFI, CAIDI, and ASAI were used by more than 60% of them. It is mentioned that regulators don’t require reporting on momentary outages. Some other results of the survey: SAIFI values from 0.554 to 3.3, average 1.5; SAIDI values from 30 to 245 minutes/year, average 97; ASAI of 0.99982. The indices used by the utilities were ATPII, SAIFI, CAIFI, SAIDI, SAIFI1, CMPII, CAIDI, SAIFI2, and ASAI. It is noted from the survey that one state requires classification of outages by cause. The reliability practices of a couple of utilities are recounted.

Computer Programs for Reliability Evaluation of Distribution Systems
Billinton, R.; Gupta, R.; Chowdhury, N.A.; Goel, L., International Power Engineering Conference, 1993, Singapore; March 18-19, 1993, 37

This paper describes the capabilities of 2 computer programs developed at the University of Saskatchewan (from Master's theses references) for reliability evaluation of distribution systems. SUBTREL for the sub-transmission section (for looped or meshed sub transmission systems) and DISTREL (for radial distribution systems) for the section from the distribution substation to the customer load points are applied to a standardized reliability test system (RBTS). The authors state that the basic techniques of quantitative reliability analysis and required equations have existed for some time but are not regularly used. Accounting for weather dependent failures, different repair and switching procedures, and 3rd order events requires equations too complicated for manual analysis. The programs evaluate individual load point indices (load point failure rate, load point outage duration, annual unavailability) and system indices (SAIFI, SAIDI, CAIDI, ASAI (ASUI), ENS, ASCI, ACCI), which the authors feel constitute a complete set describing the reliability of a distribution system. Component reliability data (transformers, breakers, busbars, transmission lines), required weather and maintenance data are given. Results of sensitivity studies are presented.

1992 Publications

Solving the Power-Quality Dilemma.
Harvey, Jeffrey P; Electrical World v. 206 (Nov. '92) p. 48.

A brief paper discussing what designers, manufacturers, and utilities should do to solve the power quality dilemma: New efficient technologies can create power quality problems. Customers should be convinced to accept the higher initial cost of systems engineering and performance-based electrical designs of new products to avoid power quality problems.

Costs of Service Disruptions to Electricity Consumers
Chi-Keung Woo, Roger L. Pupp, Energy Vol. 17 No. 2, pp. 109-126 Not fully reviewed.

A Method for Estimating the Reliability of Distribution Circuits
S.R. Gilligan, IEEE Transactions on Power Delivery v 7 n 2 April 1992. p 694-698.

The article presents a method to predict the relative reliability performance of distribution circuits and circuit segments. The method calculates with a spreadsheet the expected relative indices of annual interruption time and customer hours of interruption by multiplying factors for exposed length, exposure (to weather factors such as trees as well as inherent failure), conductor type, sectionalizing devices used, and customers connected. The results must be normalized somehow to be compared to actual performance. Customer outage values of $1.30/kWh residential, $7.42/kWh commercial, and $9.27/kWh industrial are used to assess the cost effectiveness of reliability improvement projects suggested by the method. The author states that no historical data is required. The factors, though, are empirical, based on general experience with circuit operation. The method examines only the post-substation, pre-secondary-transformer circuits of distribution systems. An application of the method to about 100 distribution circuits is discussed. Although less accurate than a method using historical data in a more sophisticated model, this seems like a valuable, quick and simple method. An answer to the question of whether a more sophisticated reliability modeling method is worth the effort and cost over the method presented here must be addressed. The paper exposes the key point that a field assessment of equipment environment is important to a reliability analysis, dependent on the fact that a large proportion of distribution outages are caused by external events (e.g., weather related problems). The method assumes the multiplicative factors are all independent and that the indexes are linear functions of each factor (e.g., annual interruption time is linearly dependent on conductor length and on fault rate for the exposure and that the fault rate per length is not dependent on length). This is reasonable if the analysis is only addressing interruptions caused by external events, but possibly not for inherent equipment failure. The paper doesn't address restoration time. This article is referenced in a paper by Billinton “Value-based distribution reliability assessment and planning,” 1/95, but the reliability prediction method isn't commented on there. It is just mentioned that failure rates are available in this paper.

<u>Voltage Stability Conditions Considering Load Characteristics.</u>
Pal, M. K., IEEE Transactions on Power Systems v 7 n 1 Feb 1992 p 243-249.

The mathematical theory underlying voltage stability is presented here. The stability limits for a simple, single-load, system are derived, with the equilibrium shown illustratively as the intersection of system power-voltage curves with the load characteristic line. Dynamic loads, composite dynamic-static loads, and motor loads are considered. The extension to larger systems is discussed.It is concluded that a detailed dynamic analysis is not always required as the existence of a stable equilibrium state in the final post-disturbance system, as determined by standard power flow model steady-state analysis, assures stability.

<u>Power Quality - An Evolving Concern for Electric Utilities.</u>
Garner, G., Transmission and Distribution, vol.44, no.5, p.32-4, 36-7.
Not fully reviewed.

1991 Publications

<u>Power Quality. End User Impacts.</u>
Smith, J.C. (Electrotek Concepts, Inc., Knoxville, TN (US)), Energy Engineering (United States) v 88:5. Not fully reviewed.

<u>How Much Do Electric Customers Want to Pay for Reliability? New Evidence on an Old Controversy</u>
Chi-Keung Woo, Roger L. Pupp, Theresa Flaim, Robert Mango, Energy Systems and Policy, Volume 15, pp. 145-159, 1991 Not fully reviewed.

<u>Reliability and Quality Comparisons of Electric Power Distribution Systems</u>
R.C. Settembrini, J.R. Fisher, N.E. Hudak, Proceedings of the Transmission and Distribution Conference, IEEE, Dallas, 9/91, 704-712.

This article compares the different types of distribution systems using model calculations of reliability as well as actual utility data. There are excellent descriptions of a number of different types of distribution systems: simple radial (overhead), primary auto loop, underground residential distribution, primary selective, secondary selective, distributed grid network, and spot network. The parameters used for reliability are outages per year (> 5 minutes), average duration, and momentary interruptions (<5min). The authors state that most utilities only maintain records of outages of greater than 5-minute duration, because, historically, shorter outages were inconsequential. Modern end uses have changed that. Power quality in terms of voltage regulation, voltage disturbance, and wave shape distortions is also treated. The results of a study that showed that most voltage disturbances are caused by weather is presented. To model the distribution systems, components are grouped into (A) primary feeder and associated equipment, (B) step down transformer and associated protective equipment, and (C) secondary conductors associated devices. The different distribution-system types are modeled using these three components and formulas for two-component series and parallel systems (same series-parallel reduction fundamentals as in other reliability documents, e.g., Billinton). The different distribution systems are rated on the basis of reliability, as well as the different dimensions of power quality.

<u>The Failure Rates of Overhead Distribution System Components</u>
W.F. Horton, S. Goldberg, C.A. Volkman, Proceedings of the Transmission and Distribution Conference, IEEE, Dallas, 9/91, 713-717.

A 5 year (1984-1989) study of 85 rural and 95 urban non-mountain overhead (OH) distribution feeders in the PG&E system is described. Generic service time failure rates for transformers, switches, fuses, capacitors, reclosers, voltage regulators, and conductor were obtained. The failure rates detailed represent contribution rates to feeder interruptions. The data excludes secondary interruptions so transformer failure rates are relatively lower than might be expected. The component failure rates were 15% of sustained outages for the OH feeders. 75% were from external factors (automobiles, animals, trees, lightning,…) and 10% from loss of supply. This result demonstrates that overhead distribution system reliability is insensitive to component failures at existing failure rates.

<u>Determination of Failure Rates of Underground Distribution System Components from Historical Data</u>
W.F. Horton, S. Goldberg, Proceedings of the Transmission and Distribution Conference, IEEE, Dallas, 9/91, 718-723.

This article presents results of calculations of failure rates of underground distribution system components using data from 1968 to 1988. The data was supplied by SDG&E and NELPA. An exponential form is used to fit to historical data. The number of components installed and removed during each year and the number of failures that occurred during the year are the data required. Results are given for HMPE 15 kV unjacketed cable, XLPE 15 kV unjacketed cable, single-phase distribution transformers, and load break elbows. If the required data isn't available service time failure rates can be calculated from thecumulative failures divided by cumulative years of service. This value is equal to the constant in the exponential (with zero exponent) if the underlying failure rate is constant.

<u>High Voltage Circuit Breaker Reliability Data for Use in System Reliability Studies</u>
Interim Report CIGRE 13.06 Working Group; A Bargigia, C.R. Heising et al., Paper 2-01 CIGRE Symposium on Electric Power System Reliability, Sept. 16-18, 1991, Montreal

This articles summarizes two international studies on high-voltage circuit breakers. First, there are data on 20000 miscellaneous breakers from 1974-1977, an effort that involved 102 utilities in 22 countries. Second is data on 16500 of the newer technology single-pressure SF6 breakers from 1988-1989, which is the first half of a 4-year study involving 100 utilities in 18 countries. It presents raw data failure rates (•) for a number of failure modes and calculated probability results that can be used in system reliability studies. The Working Group includes definitions of the different events. The possible failure modes include not responding to an operating command. The combination of the results from the two studies covers both older technology circuit breakers and the newer SF6 circuit breakers for system reliability studies.

Comprehensive bibliography on reliability worth and electrical service consumer interruption costs: 1980-1990.
Tollefson, G.; Billinton, R.; Wacker, G., IEEE Transactions on Power Systems v 6 n 4 Nov 1991 p 1508-1514. Not fully reviewed.

1990 Publications

<u>The Electric Utility - Industrial User Partnership In Solving Power Quality Problems (Panel session).</u>
Flory, John E.; Key, Thomas S.; Smith, William M.; Statford, R. P.; Smith, J. Charles; Clemmensen, Jane M.; Saunders, Lynn F.; Potts, Charles D.; Emmett, Gary L.; Moncrief, W. A.; Singletary, Bryan., IEEE Transactions on Power Systems v 5 n 3 Aug 1990 p 878-886. Not fully reviewed.

Measurement and application of customer interruption costs/value of service for cost-benefit reliability evaluation: Some commonly raised issues.
Sanghvi, Arun P., IEEE Transactions on Power Systems v 5 n 4 Nov 1990 p 1333-1344. Not fully reviewed.

<u>Power quality--Two Different Perspectives.</u>
IEEE Transactions on Power Delivery v. 5 (July '90) p. 1501-13. Not fully reviewed.

<u>Power Quality - A Review.</u>
Kazibwe, W.E.; Ringlee, R.J.; Woodzell, G.W.; Sendaula, H.M. (Temple Univ., Philadelphia, PA (USA)), IEEE Computer Applications and Power (USA) v 3:1., Jan 1990, p 39-42. Not fully reviewed.

1989 Publications

<u>Distribution System Reliability Indices</u>
R. Billinton, J.E. Billinton, IEEE Transactions on Power Systems v 4 n 1 1/89 p 561-568.

The Billintons here compare survey results from Canadian and American utilities on service continuity data collection and utilization, and they present a summary of service continuity statistics for Canadian utilities from CEA annual service continuity reports, including contributions of different causes. Service continuity statistics from American utilities are generally not openly available. The American survey results are from the 1981 EPRI distribution system reliability report that is in the reliability library (see *Reliability Reports and miscellaneous.doc*). The paper first compares the different indices used by utilities in the different countries. In general customer-based indices are more popular than kVA based values. SAIDI, SAIFI, CAIDI are popular in Canada and the US. ASAI is the most popular in the United States, but is less popular in Canada. 45% of Canadian utilities did not determine service continuity statistics as of 1984. The Distribution Section of the CEA had compiled service continuity statistics for twenty years. The Consultative Committee on Outage Statistics (CCOS) assembles the data. The CCOS is responsible for the CEA Equipment Reliability Information System (ERIS) which compiles information on generation and transmission equipment. From this data, loss of supply contributes 22% and 13% to SAIFI and SAIDI. This supports the general statement that ~80% of all customer interruptions are from failure in the distribution system. 13-20% of outages is from defective equipment. The appendix includes definitions and example calculations of all the indices.

<u>Efficient Menu Structures for Pricing Interruptible Electric Power Service</u>
Stephen A. Smith; Journal of regulatory Economics, 1989 Not fully reviewed.

1987 Publications

<u>Priority Service: Pricing, Investment, and Market Organization</u>
Hung-Po Chao, Robert Wilson; The American Economic Review, December 1987
Not fully reviewed.

1986 Pbulications

<u>Multilevel Demand Subscription Pricing for Electric Power</u>
Hung-Po Chao, Shmuel S. Oren, Stephen A. Smith and Robert B. Wilson, Energy Economics, October 1986

1972 Publications

<u>Report of the Group of Experts on Quality of Service from the Consumer's Point of View</u>
Lennart Lundberg; International Union of Producers and Distributors of Electrical Energy, 1972. Report 60/D.1 (From The British Library; Document Supply Centre; referenced in Value-Based Transmission Resource Analysis, Volume 1, EPRI TR-103587-V1; Ch.2)

A paper probably from the early 1970's that discusses collection of and usage of outage costs in France, Great Britain, and Sweden. These 3 are the only countries with data available that is amenable to calculations of optimum supply security. Outage cost values are given.

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SUMMARY OF REPORTS

Reliability at What Cost? Analyzing the economics of (improving) distribution reliability

Greg Ball; Energy and Environmental Economics, Inc.; January 25, 2000, (presentation Infocast6_GregBall.ppt)

This presentation touches on a number of issues related to reliability for wires companies, reliability in distribution systems. It discusses different perspectives on reliability, premium, differentiated service, performance-based ratemaking (PBR), and distributed generation. The planner's perspective on reliability is related to be that reliability is a right and that public perception is important. The planner's objective is to be above average but not first. The reliability level for public perception worries is less than four outages per year and not more than four to eight hours. Wall Street's perspective is stated as show the money and don't turn off the lights. Stuff happens but it isn't costly and the response is just to ask for a rate increase is said to be management's perspective on reliability. Finally, the perspective of engineers on reliability is that stuff happens, but only because their project wasn't funded. It is observed that differential reliability planning somewhat happens implicitly, with value of service (VOS) as the basic element. The process of contracting for premium service is laid out and the primary benefit of customer selection of service is related. PBR is commented on and the SDG&E PBR example that has incentives on customer service and reliability and has been in effect since 1994 is explained. Incentives are based on average customer minutes of interruption (ACMI), frequency of customer interruption, and customer satisfaction from surveys. An example PBR frequency standard is given: Example Frequency Standard: Baseline of 10,900 interruption events with a 1,100 event dead-band; Outside of dead-band, reward or penalty of $1 million per 183 interruptions, up to $18 million.

NERC Operating Manual (this copy last updated 1/00)

North American Electric Reliability Council

This document contains the operating policies, training documents and data of the NERC. It includes a history of the organization. As the NERC and this document are exclusively concerned with the generation and transmission system components of the power system, this document was not fully reviewed. There is only one mention of distribution systems: the DOE Disturbance Reporting Requirements pertain to distribution systems as well.

Distribution System Reliability Issues.doc (12/99)

EPRISolutions Draft Report

This section of an EPRI report has a wealth of relevant information and, itself, does a fair job of summarizing much of the findings of the present effort. Particularly, there is information in the areas of reliability indices, component failure rates, and reliability modeling. It includes a review of the different technical approaches to distribution system predictive reliability assessment, along with a list of requirements for a reliability assessment tool. The authors state that reliability in the context of what the customer perceives as acceptable represents the concept of supplying continuous satisfactory service and that the transmission and distribution of reliable and secure power has been seen as a social obligation. They point out that existing conditions are making utilities look at reliability as a commodity, and utilities are focussing on reducing the probability of service interruptions however reasonably possible. It is related that, in the past, the transmission network has been built with enough excess capacity to withstand an unexpected outage of any component during system peak conditions without thermal overloads or voltage variations. Criteria such as these do not explicitly consider likelihood, nor do they explicitly address the concerns of a customer as no priority is assigned to any customers given their outage costs. Common measures of reliability are said to be the probability, frequency, duration, and the severity in terms of the loss of load of unacceptable events. Any single measure that is used for the evaluation of alternative projects must be a composite of these main reliability factors. The report presents a categorization of interruptions into planned and unplanned with the unplanned ones categorized further into causes by (a) other retail electric supplier or utility, (b) utility or contract personnel, (c) customer, or (d) public. Utility and nationwide data on the breakdown of the causes is given as are typical data on the four most common reliability indices: SAIDI=95.9 min/year; SAIFI=1.18 int/year; CAIDI=76.93 min/year; ASAI=0.9994 int/year. It is said that ASAI is generally used only to compare to other parts of the same utility system and is rarely used as reliability metric. A caution is given on comparisons across utilities based on reliability indices, as different levels of parameters are used in the definition of the different indices. Typical distribution system component failure rates are also tabulated.

The Strategic Role of Distributed Resources in Distribution Systems (10/99)

EPRI TR-114095; Final Report; Prepared by Charles D. Feinstein, Santa Clara University

This report is a description of the assessment of the potential value of distributed resources (DR) in distribution systems. DR being a part of the least cost expansion plan determined by a model of a distribution planning area is taken as an attestation to its value. Relative customer outage costs are incorporated in the model (e.g., a total cost) through the cost of unserved energy of alternate plans. The cost of unserved energy is used as a proxy for the reliability. Outage times of 0.25hr/1000hr for system and distribution resources are stated and linear outage costs of $7/kWhr are used. The model does not assess the reliability but assumes that DR reduces unexpected energy by 50%, and this value is varied along with the per hour outage cost value to examine potential effects on total cost using DR.

Reliability Benchmarking Application Guide with Customer/Utility Common Power Quality Indices (9/99), EPRI TP-113781; Final Report

This report discusses the utilization of the existing EPRI RBM (TR-107938) indices for various voltage sag benchmarking applications. Additionally, this report defines new indices that can be used to characterize performance for customers in terms of different equipment ride-through characteristics. This report also provides methodologies for determining target levels of quality for various applications based on historical measurement data. These quality levels are selected based on the statistical distribution of quality indices values calculated from the measurement data acquired.

Reliability Centered Maintenance for Distribution (6/9/99)

EPRI Workshop Presentation

This presentation discusses a method (RCM) to reduce maintenance costs without affecting reliability by using a systematic approach to the problem. The RCM method is to be used as a guiding tool in maintenance planning. RCM is used to balance the cost of routine maintenance against service reliability. It is a step-by-step method to prioritize equipment maintenance needs (see RCM reports below, 1997)

Reliability Centered Maintenance (RCM) for Distribution Systems and Equipment: Four Application Case Studies (5/99)

EPRI TR-112924; Final Report; Prepared by Scientech; D. Reid, C. Schwan, (see other RCM documents, 1997 and 1999, and RCM presentation, 1999)

Applications of RCM at four utilities for planning of routine preventive maintenance is presented here. Reliability is discussed in terms of equipment availability. Some resultant data on outages prevented are displayed. The power quality program of one of the utilities, Duke, is also mentioned. A common difficulty identified in the application of RCM is the absence of accurate reliability data for the utilities to use. However, RCM studies may promote more extensive failure data collection. This report discusses implementation and acceptance of RCM by utilities and management and may be instructive for the promotion of reliability-based planning to utilities.

1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Composite Version (5/99)

CEA (Item # 116.98)

This report contains extensive data on system indices from CEA’s Electric Power System Reliability Assessment (EPSRA). The data is compiled from 32 Canadian and 7 international utilities for 1998. Annual data and 5-year average data, using previous versions of the report, are shown, including results broken out by cause. Definitions of the reliability indices used are given.

'Bang Per Buck' Templates: Examples of how to estimate the cost-effectiveness of electric reliability programs

Navigant Consulting, Inc. (presentation overheads with no date given)

This short presentation gives simple methods and sample cases for the calculation of the cost per avoided interruption or per avoided outage minute. This is the bang per buck, which is shown having diminishing returns. Example measures of the reliability are illustrated as SAIDI, SAIFI, and worst circuit complaints. Vegetation (the most frequent cause of interruptions), lightning, animals, URD cable, circuit breaker, pole inspection, and sectionalizing are analyzed.

Commonwealth Edison Company 1998 Report on Reliability to the Illinois Commerce Commission (1999)

The submission of this report is for the satisfaction of a regulatory requirement by Commonwealth Edison. This is Commonwealth Edison's first annual report under the Reliability Rules of the Illinois Commerce Commission (see listing below). It covers statistics, status, record-keeping and operating and maintenance procedures, and improvement plans concerning the reliability of their transmission and distribution systems. Interruption data is tabulated and is grouped by type of interruption within the classifications of planned and unplanned interruptions. The state of Illinois has recently also made the distinction between controllable and uncontrollable interruptions a consideration. The state defines a sustained interruption as greater than one minute, and CAIDI, CAIFI, and SAIFI are used as measures of the reliability. For ComEd in 1998, a year of bad storms, the system indices were CAIDI=274 minutes; CAIFI 2.63 interruptions; SAIFI=2.20 interruptions. No power fluctuations of a severity requiring reporting (affecting 30,000 customers) occurred. The report states that trees are the single largest cause of interruptions, especially in terms of their impact on duration. The utility warns that comparing statistics across utilities should be done with caution and should consider weather, type of load (urban, suburban, rural), type of reporting (load based or customer based), and the definitions used for the reliability indices. ComEd uses reliability-centered maintenance (RCM) procedures for routine preventative maintenance at appropriate intervals. They maintain a model of the system that is continuously tested to ensure compliance with NERC Planning Standards. These standards require that the system be planned, designed, and constructed such that it can withstand a variety of disturbances without experiencing overload of transmission elements, cascading (domino effect) outages, or uncontrolled loss of load. Compliance is reported to and monitored by the Mid-America Interconnected Network (MAIN), the regional reliability entity. Additionally, ComEd reports their own planning criteria annually to the FERC.

Summary of Illinois Commerce Commission's Reliability Rules, from Title 83 of the Illinois Administrative Code (Section 411.120(b)(3)). Utilities must report on

- the plan for investment and reliability improvements for transmission and distribution facilities
- implementation of the previous plan
- number and duration of interruptions and their impacts, controllable and uncontrollable, as well as ones caused by other entities
- comparison with alternative suppliers on interruption frequency and duration
- age, condition, reliability and performance of transmission and distribution facilities
- expenditures for transmission and distribution construction and maintenance
- results of an annual customer satisfaction survey on reliability, customer service, and customer understanding of service
- overview of customers' reliability complaints
- CAIDI, CAIFI, SAIFI for each operating area
- list of worstperforming circuits for each operating area
- operating history, maintenance history, plans, and schedule for worstperforming circuits
- numbers of customers experiencing greater than set numbers of interruptions
- number of interruptions and duration, and the number of consecutive years the number of interruptions above service reliability targets for each customer
- projected load and peak demand
- peak loading on each transmission and distribution substation operating above 90% normal capacity
- discrete areas for which reliability data kept and reliability datacollection and recordkeeping procedures
- and maintain service records detailing any interruption that affects 10 or more customers or power fluctuations affecting 30000 or more

Reliability Assessment 1998 – 2007: The Reliability of Bulk Electric Systems in North America (9/98)

North American Electric Reliability Council, actual document: NERC reliability assessment.pdf

As the NERC and this document are exclusively concerned with the generation and transmission system components of the power system, this document was not fully reviewed. Besides the reliability assessment, the document contains some information on the reliability regulatory structure in North America, some of which is included in the notes section for this document. Following is an excerpted summary of the report:

The North American Electric Reliability Council (NERC) Board of Trustees formed the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of existing and planned electric generation and transmission systems of the Regional Councils. This Reliability Assessment 1998-2007 report presents: an assessment of electric generation and transmission reliability through 2007, an assessment of the generation adequacy of each Interconnection in North America, a discussion of key issues affecting reliability of future electric supply, and Regional assessments of electric supply reliability, including issues of specific Regional concern.

Forced Outage Performance of Transmission Equipment (7/98) for the period 1/1/92 to 12/31/96

CEA (Item #107.92)

This report contains extensive data on transmission outages from the CEA's Equipment Reliability Information System (ERIS). Detailed data on lines, transformer banks, circuit breakers, cables, synchronous and static compensators, shunt reactors, shunt capacitor, and series capacitors, as well as their subcomponents is given. Failure rates and duration information is given by outage type, cause, and voltage level. The data is compiled from 11 participating Canadian utilities.

Framework for Stochastic Reliability of Bulk Power System (3/98)

EPRI TR-110048; Final Report; Prepared by Center for Energy Systems and Control, J.A. Momoh, (see also *Value-Based Transmission Resource Analysis* (4/94) below)

This report focuses on reliability analysis of transmission and composite generation and transmission systems. It presents a framework for value-based reliability assessment and develops an integration of reliability assessment software with cost-benefit analysis software. It discusses reliability indices and reliability assessment software for transmission. The author states that a reliability index is considered adequate if it (i) ranks projects resulting from the use of deterministic criteria to meet budget constraints, and (ii) assesses the changes in system reliability for alternate network configurations, load/generation changes, operations, etc. The stochastic nature of outages motivated the establishment of probabilistic indices such as LOLE, LOEE, EUE, SAIFI, CAIFI, and ASAI. It is claimed that no consensus has been reached on which reliability indices are best. Some commonly used ones are LOLP, LOLE, and EUE. Indices are split into 3 categories: system problem, load curtailment, and customer indices. The competing reliability criteria from WSSC, BPA and NERC are expounded. It is related that reliability criteria for system design are established by each of the 9 regional councils in NERC. The discussion on power system reliability assessment computational tools classifies them into enumeration approaches (TRELSS, COMREL from the University of Saskatchewan, PCAC by PTI, GATOR from Florida Power, others) and Monte Carlo simulation approaches (CREAM, MECORE of the University of Saskatchewan, SICRET by ENEL and MEXICO by EdF). The varying programs are summarized. TRELSS computes most of the indices proposed in the literature and recommended by IEEE. A checklist of the shortcomings of TRELSS that arose from extensive review and testing is included. This list would be instructive in a development of analogous distribution software. The author writes that the integration of customer outage cost information into resource planning framework is yet to be adopted. The report ends with a review of the literature on reliability, including an extensive listing of transmission reliability and general reliability software programs.

Software User Manual: Reliability Centered Maintenance (RCM) Workstation for Power Delivery (12/97)

EPRI CM-108076-R1; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann, (see accompanying Report below and other RCM documents, 1997, and RCM presentation, 1999)

The RCM Workstation (RCMWS) for Power Delivery is the companion software product to the RCM Technical Reference ‘handbook’ (the EPRI TR-108068 Reference is available in hardcopy or software versions). The workstation software is a data management tool which enables RCM studies using methods and generic data from the Technical Reference. It provides the structure for data collection and analysis. The database of qualitative reference data from the handbook is accessible in the workstation.

Software User Manual: Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery (12/97)

EPRI TR-108076; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann, (see accompanying Report below and other RCM documents, 1997, and RCM presentation, 1999)

Software containing the information in the EPRI RCM ‘handbook’ (EPRI TR-108068 below) is available. The software gives step-by-step guidance in applying RCM. The same qualitative reference data and glossary information from the handbook can be accessed with the software. This manual has installation and startup instructions for the software.

Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery (10/97)

EPRI TR-108068; Final Report; Prepared by Scientech; Earl S. Hill, William D. Midgett, Clair A. Schwann

This report is an RCM ‘handbook’ for the utility power delivery sector. It gives guidance for performing RCM studies and planning. Included are technical examples and qualitative technical data. These are all provided for the three technical areas of substations, transmission, and distribution equipment. The handbook also includes a glossary of terms for RCM. The authors refer to quantitative industry-shared failure information but do not provide references where this information can be found. In RCM, the mean time between failure (MTBF and failure rate=1/MTBF) is used as a measure of reliability. MTBF is used in determining maintenance task frequencies for equipment. The mean time to repair (MTTR) is used to assess the relative impact of equipment failures in terms of durations of power outages. In the total costs of maintenance, which is arrived at by adding all costs for preventive and corrective activities, indirect costs (replacement power, lost revenue, customer interruption penalties, adverse publicity, loss of customer base) are considered. (see other RCM documents, 1997 and 1999, and RCM presentation, 1999)

Reliability of Benchmarking Methodology (5/97)

TR-107938; Final Report

EPRI developed the Reliability Benchmarking Methodology (RBM) and associated software to enable utilities to quantify distribution system reliability in terms of the quality of service provided. In this report, EPRI defines an extensive set of service performance indices that assess all areas of power quality based on monitored data. EPRI's RBM indices are defined so that they can be applied to systems of varying size and provide a common basis and terminology for assessing and discussing service quality. The methodology and software guides the calculation of these reliability indices. Finally, with the help of EPRI's DPQ database (TR-106294), the indices are benchmarked.

An Assessment of Distribution System Power Quality: Volumes 1-3 (5/96)

TR-106294-V1; Final Report

This report provides a comprehensive statistical database of power quality measurements collected during the EPRI Distribution Power Quality (DPQ) project as well as guidelines for monitoring and modeling power quality phenomena on distribution systems. *A Guide to Monitoring Distribution Power Quality: Phase 1* (4/94; TR-103208), a precursor to this report, describes how to perform accurate power quality measurements using a new monitoring device and how to organize and analyze the data collected. The device, PQNode, characterizes the complete range of power quality variations on distribution systems. Hard copies of these reports are not presently (12/99) in the reliability library. Information on EPRI reports is available at www.epri.com.

Outage cost estimation guidebook (12/95)

EPRI-TR-106082; Project 2878-04 Final Report; Prepared by Freeman, Sullivan and Co.; Sullivan, M.J., Keane, D.M. (192 p)

Sections of this report discuss value based planning and the use of customer outage costs in general. The report states that reliable techniques for estimating interruption costs have only recently developed and utilities have only begun to apply value based reliability planning to transmission and distribution. Traditional engineering approaches ignore customer outage costs and select an arbitrary reliability level. For example, in generation, reserve margin levels, LOLP of 1 in 10 years, EUE of 24 hours in 10 years are sample reliability standards that have been used without a quantitative economic basis. The primary objective of value based planning is the identification of economically efficient investment strategies that match a level of reliable power with the economic value of service (VOS). An example where these are matched is from new developments that have placed a system operator in control of generation capacity and prices, with pool prices being designed to ensure an appropriate level of generation reliability by reflecting the economic value of avoided customer interruption costs. The industry's experience with value based planning is assessed as limited but promising. Possible applications in generation, transmission, and distribution are outlined. Included in this is a discussion on reliability differentiated service.

Power Quality Workbook for Utility and Industrial Applications (10/95)

EPRI TR-105500; Project 2935-30; Final Report; Prepared by Electrotek Concepts, Inc.; M. McGranagham, R. Dugan, A. Khan, D. Mueller, R.J. Ferraro

Power quality problems are described, and methods and processes to measure and mitigate them are detailed. Three important changes in loads and systems have made power quality no longer synonymous with reliability: (1) loads are more sensitive; (2) loads are interconnected in extensive networks which have automated processes; (3) there is a growing % of loads which utilize power electronics in some type of conversion process. There are 3 equal partners in these problems: the utility, the end user, and equipment manufacturers. The different categories of power quality problems are enumerated and described in this report, and their characteristics are illustrated with many sample, illustrative figures and tables. It is stated that the wide variety of conditions making up 'power quality' makes development of standard measurement procedures and equipment very difficult. The authors contend that the end users are the ones ultimately affected so the best definition of power quality should relate to their concerns: A power quality problem is any power problem manifested in voltage, current, or frequency deviations that results in failure or misoperation of utility or end user equipment. The given categories are long duration voltage variations, sustained interruptions, voltage unbalance, impulsive transients, oscillatory transients, voltage sag, voltage swell, momentary interruption, and flicker. Voltage sag is said to be the most important power quality variation affecting many types of industrial customers, as they are more numerous than interruptions. Statistics for some problems are given. For example, the expected voltage sags and the THD statistics for a typical US distribution system from a monitoring of 300 sites are included. Relevant standards and standards documents are cited, for example ANSI C84.1 and IEEE 519-92. ANSI C84.1 specifies the steady state tolerances to be expected on a power system to be +6% to –13% of nominal and the maximum voltage unbalance at the service entrance under no load conditions to be 3%. IEEE 519-92 recommends a limit of 5% harmonic voltage distortion on general systems. It is stated that 95% of faults on a system are temporary, with the definition of a sustained interruption being a complete loss of voltage for greater than 1 minute. Finally, measuring and monitoring equipment and power conditioning equipment are discussed.

Active Power Line Conditioning Methods: A Literature Survey (7/95)

EPRI TR-105168; Project 2951-07; Final Report; Prepared by the University of Texas at Austin; W.M. Grady, A.H. Noyola

This is a detailed review of the status of APLC technology up to 1992. An APLC compensates for power system disturbances by sensing voltage and waveforms and injecting current pulses that force distorted waveforms back within acceptable tolerances of 60-Hz sine waves. Eighty-four key publications from 1971 to July, 1992 are summarized and analyzed. A categorization of power quality disturbances from a referenced EPRI report is given: (1) transients (<30 cycles); (2) short-duration RMS variations (0.5-30 cycles); (3) long-duration RMS variations (>30 cycles); (4) interruptions (at least ½ cycle); (5) distortion (harmonics between orders 2 to 100); (6) flicker (spectral content less than 30 Hz); (7) noise (0-200kHz); (8) electromagnetic interference (<200kHz); (9) electrostatic discharge; and (10) radio-frequency interference (>200kHz). Conventional solutions are also listed: (1) passive filters; (2) surge suppressors; (3) motor-generator sets; (4) static VAR compensators; (5) uninterruptible power supplies (UPS); (6) ferroresonant transformers; and (7) line power conditioners (not APLC's).

There are other EPRI reports on APLC's. In *Assessment of Active Power Line Conditioning Technologies* (4/93; TR-102026), four APLC technologies are identified and assessed. *Active Power Line Conditioning Technologies Application Guide* (4/98; TR-106535) is a resource for power quality engineers. It explains APLC operation and applications. Hard copies of these reports are not presently (12/99) in the reliability library. Information on EPRI reports is available at www.epri.com.

Quality of Service in an Era of Increasing Competition: A Review of the Literature with Policy Implications and Annotated Bibliography (2/95)

Prepared for the Bureau of Consumer Services Pennsylvania Public Service Commission by John Shingler

This document discusses mostly what electric utilities should do in comparison to what has happened in telecommunications. There is nothing specifically on reliability. The document was found at the Consumer Services Information Systems Project (CSIS) website (http://www.aers.psu.edu/csis/index.htm), in the Research and Publications section. The html version of the paper is in the reliability library (..\reliability documents\Quality of Service ...0295.htm) as well as an MS Word version with highlights (Quality of Service…0295.doc). The author does note that very few quality of service articles discuss the electric or gas industries.

Value-Based Transmission Resource Analysis, Volume 1: Technical Report (4/94)

EPRI TR-103587-V1; Project 2878-02; Final Report; Prepared by RCG/Hagler Bailly; D.M. Logan, E.G. Neudorf, B. Porretta, D.L. Kiguel, G.A. Hamoud, M.P. Bhavaraju, R. Billinton

(see also Volume 2 below, the Application Guide & *Framework for Stochastic Reliability of Bulk Power System* (3/98) above))

This project presents a framework for the practical implementation of value-based transmission resource analysis (VBTRA). A history of the development of value-based resource analysis written by Billinton is included, detailing the move from implicitly using a preselected reliability level towards explicitly incorporating outage costs into a cost minimization process. VBRA is based on the explicit cost approach. The historical summary is comprised of research on the impacts of electric power interruptions, quantification of customer costs, and the study of reliability worth, with an extensive bibliography covering each of these. The bibliography is slim on value-based reliability assessment of distribution systems. The history of EPRI transmission reliability work is also given. It is stated that a reliability risk index should portray severity, frequency, and duration. EENS is widely used with IEAR in VBTR. LOLP and EPNS are also mentioned. Several transmission and composite generation reliability modeling programs for contingency ranking, contingency evaluation, remedial action simulation, and index calculation are discussed. SYREL first implemented the state enumeration method in a 150-bus prototype transmission reliability program. TRELSS, CREAM, and PROCOSE are summarized, and others are mentioned, GATOR from the Florida Power Corporation, RECS from Southern Company, and COMREL from the University of Saskatchewan. TRELSS (Transmission Reliability Evaluation for Large Scale Systems) is a production grade program done in 1992 using state enumeration. CREAM (Composite System Reliability Evaluation by Monte Carlo), done in 1987 to 1990, can be used to analyze composite generation and transmission using Monte Carlo simulation. PROCOSE (Probabilistic Composite System Evaluation), which was developed by Ontario Hydro and also uses state enumeration, is a third program for adequacy assessment. Probabilistic security evaluation, on the other hand, is very complex and not covered by the composite reliability models. In this report, CREAM, TRELSS, and PROCOSE are applied to the IEEE Reliability Test System, and case studies at PG&E and Duke. Each is said to be suitable for particular applications. The authors write that most utilities in North America use quantitative adequacy assessment at HLI (generation), but very few utilities around the world routinely use quantitative reliability assessment at HLII (generation with transmission). It is concluded that the primary complication in applying VBRA to power system planning is the limitations of currently available models that compute reliability indices, with regard to their ability to accurately represent customer reliability. For example, PROCOSE, CREAM, and TRELSS all assume equal interruption costs across load buses.

Value-Based Transmission Resource Analysis, Volume 2: Applications Guide (4/94)

EPRI TR-103587-V2; Project 2878-02; Final Report; Prepared by RCG/Hagler Bailly; D.M. Logan, E.G. Neudorf, B. Porretta, D.L. Kiguel, G.A. Hamoud, M.P. Bhavaraju, R. Billinton, (see also Volume 1 above, the Technical Report & *Framework for Stochastic Reliability of Bulk Power System* (3/98) above)

This volume condenses selected material from Volume 1 that focuses on how to implement VBTRA and describes a number of additional problems amenable to VBTRA. The guidance is applicable to more than transmission, and 2 example problems in VBRA that do not directly involve transmission are also discussed. One example is the application of the value-based approach to distribution reliability improvements, in which the feeder indices of SAIFI, SAIDI, CAIDI, and ASAI are used. A contingency enumeration cost accumulation with a load point outage analysis is used to evaluate alternatives for improving the reliability of service to customers served by a particular substation. The alternatives are ranked by total cost. Included in the guide are typical outage data for transmission and generation equipment.

Types of Incentive Regulation: A Primer for the Electric Utility Industry (1993)

Edison Electric Institute Finance, Regulation and Power Supply Policy Group, EEI, Washington, D.C.; HD9685/U5/T96

This monograph briefly describes a number of different types of incentive regulation in the investor-owned electric utility industry. There is a general explanation of the parameters and measurements involved with formulas for some, but the explanation does not include a detailed analysis. Examples of where the different types of incentives are in practice are given. Distribution is not addressed specifically. It is reported that some commissions regularly review utility performance in each rate case and, as a matter of policy or by statutory requirement, they take the results into account in setting the return on equity. The authors state that industry experience with broad corporate performance incentives, including customer service, is meager. The only example of a broad-based incentive being used in practice is the Mississippi Power Company's Performance Evaluation Plan. This uses a sliding scale mechanism for both rewards and penalties covering seven areas: (1) construction cost management; (2) load factor improvement; (3) customer satisfaction; (4) plant availability; (5) residential rate levels; (6) employee accident levels; (7) service reliability

TRELSS: A Computer Program for Transmission Reliability Evaluation of Large-Scale Systems, Volume 1: A Summary (5/92)

EPRI TR-100566; Project 3159-1; Final Report; Prepared by Public Service Electric and Gas Company, (see also *Framework for Stochastic Reliability of Bulk Power System* (3/98) above)

(TRELSS is now on version 4.0: TRELSS -- Transmission Reliability Evaluation for Large Scale Systems Version 4.0, Software AP-110886 (5/98))

TRELSS is the production-grade portion of an EPRI effort in Value-Based Transmission Resource Analysis (VBTRA). The effort began with a 150-bus prototype program (SYREL). It continued with a comparison of SYREL's methods to those employed in other programs, GATOR (Florida Power Corp.), RECS (Southern Company Services), and COMREL (University of Saskatchewan), before the design and coding of TRELSS, which began in 1987. The overall VBTRA effort includes (a) collection and analysis of transmission outage data, (b) TRELSS, (c) GENREL for generation reliability assessment, (d) CREAM for combined reliability evaluation using Monte Carlo, and (e) an interruption cost calculation procedure. The quantitative part of the effort for transmission, TRELSS, is a FORTRAN 77 program that uses contingency enumeration of generation and transmission contingencies to evaluate power network reliability. TRELSS provides a probabilistic measure for planning transmission systems of up to 2500 buses using several solution methods: simulating system conditions, tallying system problems, calculating load curtailment indexes. Indices of system problems are calculated by TRELSS as measures of system unreliability using the probability, frequency, and duration of contingencies evaluated. The program evaluates both area and bus indices of reliability, indices that address frequency, duration, and severity. The indices are split into (a) system problem indices (frequency and duration of failures: bus low and high violations, circuit overloads, system separation); (b) load curtailment indices (probability of loss of load; frequency of load loss; loss of load duration; expected unserved demand (MW/occurrence, MW/year); EUE (MWh/occurrence, MWh/year)); (c) customer indices (number of customers interrupted/occurrence, number of hours of interruption/customer; total number of unserved customer hours per year; service availability). Bounds on the reliability indices under normal and adverse weather conditions are calculated and are included in this volume. The program models (a) independent outages; (b) independent overlapping outages; (c) related outages (up to 6 simultaneous); (d) adverse weather; and (e) scheduled outages. Five host utilities extensively tested the software. This volume is the summary (only volume included in reliability library), while volume 2 is a User's Manual, 3 and 4 are Programmer's Manuals, and volume 5 is an Installation manual.

A more recent document, Transmission Reliability Evaluation for Large-Scale Systems (10/98; EPRI TO-111625), further describes EPRI's Risk-Based Transmission Expansion Planning Tool, TRELSS. The information on this document states that version 5.0 of TRELSS is scheduled for release by spring of 1999 and that this software has become an industry standard in transmission reliability evaluation. It is in use at several utilities nationwide as well as overseas. A case study with TRELSS performed at BPA is reported in another EPRI document (TR-108815). Another effort connected to VBTRA and TRELSS involves the production of contingency statistics for probabilistic adequacy assessment software such as TRELSS. *Monte Carlo Approach for Estimating Contingency Statistics: Volumes 1 and 2* (TR-103639-V1; 7/94) describes MACS, a research-grade program based on the Monte Carlo method that accounts for the dependency of components in providing statistics on contingencies, including common-mode and dependent failures, for a network. Hard copies of these reports are not presently (12/99) in the reliability library. Information on EPRI reports is available at www.epri.com.

Cost-benefit analysis of power system reliability: Determination of interruption costs (5/90)

EPRI EL-6791; Project 2878-1 Final Report; Prepared by RCG/Hagler, Bailly Inc.; Sanghvi, A.P.

This 3 volume report is ostensibly about obtaining interruption costs, but it contains a large amount of important information on other aspects of reliability. The report starts from the point that utilities do not have individual customer interruption costs. The prime objective is to 'formulate, develop, test, and demonstrate the most effective measurement approaches for estimates of customer interruption costs,' with a secondary objective of reviewing reliability planning practices of utilities. There is much discussion on indices used for each of generation, transmission, and distribution, including a summary figure. Volume 1 contains the most valuable information concerning reliability. Volumes 2 and 3 summarize results from surveys performed by two utilities of their customers, which include questions on experience with reliability problems and attitudes to reliability.

Volume 1

The differing definitions of reliability for different groups of people and their use in the different functional areas of a utility are outlined in a section of this report which includes a summary figure of common indices by functional area. From survey data, it is shown that consumers associate service reliability with restoration time and how accessible and responsive the utility is during interruptions. This volume also reviews the use of outage costs in generation planning in different countries since the 1950's (table) and the novel use of them in transmission by a couple of utilities. The different programs used to model composite system reliability are tabulated. Suggestions on applications where interruption costs could be used for the 3 levels in a utility are also included (table).

For generation an LOLP of 1/2400 or 1 in 10 years is standard, but for reliability planning, EUE is a better index as it combines the effects of duration, magnitude, and frequency. It is stated that most utilities are collecting their own data for most transmission elements and log failure and interruption data on the distribution system, but, for value-based distribution and transmission reliability planning, existing outage databases and reliability models need to be enhanced. The observation that there is an increased interest in delivery point reliability performance monitoring (frequency, duration, expected unserved energy of load curtailment) is made. Most American utilities use reliability as basic design criteria in distribution planning with the criteria set by the company. Only rarely do customer or regulatory concerns affect the planning. SAIFI, SAIDI, CAIDI, CAIFI, ASAI are the reliability indices most commonly used. Some examples of standards used by some utilities are given: ASAI≥0.9998, SAIFI<1, CAIDI<2 hours; ASAI≥0.99975 for urban, ≥0.99935 for low-density rural, CAIDI≤270 min, SAIDI≤187 min, FAIFI 2.4/circuit/year; SAIFI 0.75 residential, .6 commercial, SAIDI 65 min residential, 45 min commercial, at most one outage/year and 80 min for very large commercial. A summary of outages by functional area is given: 85% customer hours lost from distribution system outages; 9% to substations, 4% to transmission, <2% generation. Sample outage statistics by cause from a U.S. utility are tabulated, with the leading causes for distribution system failure being storms, equipment failures, and 3rd party contracts.

An appendix contains a 1988 Ontario Hydro document on reliability planning, including sections addressing the 3 functional levels, and the composite system. The appendix details Ontario Hydro's use of a reliability evaluation program to compare alternative transmission plans, the results of which are often used with customer interruption costs for decision making. The program produces the outputs SAIFI, CAIDI, SAIDI indices for feeders, areas, regions, and province-wide. Individual delivery point performance is assessed with indices. However, this utility does not use customer interruption cost data in overall distribution system planning. For use of interruption costs in generation planning, the utility concludes that LOLP is not satisfactory as it does not give the best indication of variations in the absolute level of reliability with variations in reserve. Unsupplied energy is used as the measure of reliability as it is the single factor most closely related to customer losses. It is calculated assuming that all normal and emergency operating actions are taken by a Frequency and Duration program. Regulatory monitoring and requirements obligate the utility to an LOLP < 1 day in 10 years, however. Emergency assistance (of 700MW) is accounted for in the calculation of the optimum reserve in generation planning which results in a total energy and customer outage costs optimum at 20-50 system minutes. The adopted annual-EUE 25-system-minute criterion translates to 27% effective generation reserve, which is 3% less than the standard LOLP<1/2400. It is also stated that tests show that customers do not notice a 5% voltage reduction. An additional appendix includes some examples of some simple uses of outage costs to compare improvement alternatives from PG&E.

Volumes 2 and 3

These contain summaries of results of customer surveys by BPA and a southeast utility. Included in the results are summaries of customers' experience with service reliability and power quality, purchases they have made to mitigate reliability problems, and their attitudes towards reliability. It is found that most commercial and industrial, as well as residential customers, are satisfied with the level of service reliability that they receive. (see Customer Needs library documentation for further notes and summary)

Customer Demand for Service Reliability: A Synthesis of the Outage Costs Literature (9/89)

EPRI P-6510; Project 2801-1 Final Report; Prepared by Laurits R. Christensen Associates, Inc. under contract to ADA; Caves, D.W., Herriges, J.A., Windle, R.J.

This document investigates the status of the outage cost literature with a focus on the use of outage cost data for priority service program design. It reviews different types of priority service programs and studies of them. The annotated bibliography groups papers on the different types of priority service programs. The thrust of the work, though, is on the procurement of outage cost data by different methods, including by analysis of data from actual priority service programs. It contains many tables and figures with data from previous work on outage costs.

The Value of Service Reliability to Consumers (5/86)

EPRI EA-4494; Project 1104-6 Proceedings; Prepared by Criterion Inc.

This is a collection of articles on the methods of estimating the value of reliability, recent findings from these methods, and their use in utility planning in 4 European countries and Canada. There is an emphasis on generation-capacity decisions. It is a product of 3 workshops sponsored by EPRI on the subject. Articles 1, 6, 7, and 9 are the most pertinent to reliability issues, as opposed to customer outage costs.

Section 1: "The Layman's Guide to the Value of Electric Power Reliability", Frank J. Alesso, Peter Lewin, and Steve G. Parsons

This introduction to the proceedings begins with a discussion of how the value of reliability is exhibited for other commodities and then discusses different elements of customers' perceptions of electric power reliability. It has an emphasis of the effects of the value of reliability on generation decisions. It surveys the different methods for analyzing the value of reliability and indicates which are appropriate for each customer sector. The article also outlines the steps to be followed in each of eight uses for value of reliability estimates.

Section 2: "How to Assess the Value of Electricity Reliability" William B. Shew

This article discusses the different techniques of varied complexity that can be used to calculate a value of reliability estimate.

Section 3 "Shortage Costs: Results of Empirical Studies", Ernest Mosbaek

Summarizes outage cost figures for residential, commercial, and industrial consumers from various studies, actual results stated. Costs are aggregated by size of user for industrial and commercial. Impact cost is broken down into components for all three.

Section 4 "Environmental and Socioeconomic Consequences of a Shortage in Installed Generating Capacity", R. Ciliano

Methodology for measuring impacts of outages. Includes a table (4-8) of outage costs per KWH by time of day.

Section 5 "Pricing Electricity in an Uncertain Environment" Raymond P. H. Fishe and G. S. Maddala

This article discusses the use of marginal cost pricing in the electric utility industry and the effect of uncertainty in demand and supply on pricing decisions, which are made by regulators. Reliability-related pricing concerns are not a topic.

Section 6: "Costs and Benefits of Over/Under Capacity in Electric Power System Planning" Edward G. Cazalet

This article's topic is a new methodology based on decision analysis for planning and regulating capacity additions. The process employs total consumer costs and consideration of probabilistic weighted future demand (with learning and downstream decisions!). It produces curves of total customer costs vs. planning reserve margin which show the optimal planning reserve margin at the minimum of total costs.

Section 7: "Optimal Electricity Supply Reliability Using Customer Shortage Costs", Arun P. Sanghvi

A review of the current use of customer outage costs amongst a number of countries and current reliability levels begins the article. It shows that the literature indicates that the current high levels of reliability in the US may not be justified. An illustration of how the disregard of adaptive responses in customer outage costs is shown to lead to inaccurate results. A theoretical basis for finding the mutually optimum level of capacity investment, reliability, and prices, using supply-demand curves and an engineering-economics approach, is outlined.

Section 8 "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience", Arun P. Sanghvi

Overview and comparison of methods of measuring customer outage costs. Contains a table of outage cost estimates from various studies for residential(8-30), industrial(8-34), and commercial(8-37) customers.

Section 9: "Customer Outage Costs in Investment Planning Models for Optimizing Generation System Expansion and Reliability", Arun P. Sanghvi

This paper reviews the expansion planning models that consider customer outage costs. The focus is on generation capacity, but there is also a discussion on the interaction with transmission and distribution reliability. It reviews the use of customer outage costs in planning by European countries and Canada and the growing interest elsewhere, including in the United States.

Section 10 "Ontario Hydro Surveys on Power System Reliability: Summary of Customer Viewpoints"

Very useful document on outage costs. Summary of results from 7 surveys (by Ontario Hydro) of residential, commercial, and industrial consumers on outage costs. Lots of data, aggregated by sector, trade, and size of organization. Classification of interruptions by frequency, duration, and amount of advance notice.

Section 13 "The Cost of Electrical Supply Interruptions", Michael D. Fisher

Assessment of outage costs from a survey, respondents aggregated by industry (Machinery, Wholesale Trade, Retail Trade, Services, …), generating capacity. Contains data on outage costs by duration, season, advance notice. Also assesses ability to withstand voltage reductions.

Section 14 "New Tool Gauges Customer View of Reliability"

Describes a study by Empire State Electric Energy Research Corporation (ESEERCO) on customer values associated with outages. Uses a form of Mulitple Tradeoff Analysis. Only briefly summarizes results, but the direct results of the survey may be useful. Main conclusion is that customers have a high value for advance information on planned outages.

Other articles read from this report but not deemed useful include: Section 11: "The Cost of Electric Power Interruptions in the Tennessee Valley", Warren D. Devine, Jr., Len Scott; Section 12: "The Cost of Residential Electric Power Outages", Richard S. Mack, Robert W. Gilmer

Study of Effect of Load Management on Generating-System Reliability (7/84)

EPRI EA-3575; Project 1955-3; Final Report; Prepared by Associated Power Analysis, Inc.; A. D. Patton, C. Singh

This study involves a comparison of a new model (OPCON) for calculating generation reliability, which accounts for load changes, with conventional methods. There is much discussion on reliability indices for generation. OPCON calculates the measures of unreliability LOLE, EUE, frequency, f, and duration, D of capacity deficiency events. It is stated that the most widely known index is LOLP. The reliability parameters for generating units, probability of being totally (FOR) or partially (DFOR) unavailable, are used in the conventional methods and are calculated from historical data.

Distribution System Reliability Handbook (12/82)

EPRI EL-2651; Research Project 1356-1 Final Report; Prepared by Westinghouse Electric Corporation; Principal Investigators: S. J. Kostyal, T. D. Vismor, R. Billinton

The objectives of this research project are in striking alignment with those of the present project, beginning with a compilation and an organization of reliability assessment techniques in use in 1981. A 3-volume final report (see below, EL-2018) documents the research. This practical distribution handbook for EPRI client utilities arose from the project. It describes the assessment models in detail, models for historical reliability assessment (HISRAM) and predictive reliability assessment (PRAM), which were successfully tested and executed at two utilities. It also includes practical guidelines for reliability assessment. It contains an extensive bibliography on distribution system reliability evaluation grouped into (a) analysis and applications, (b) outage data, and (c) reliability economics and indices; including abstracts for the most significant articles.

Development of Distribution System Reliability and Risk Analysis Models (8/81)

EPRI EL-2018; Research Project 1356-1 Final Report; Prepared by Westinghouse Electric Corporation; Principal Investigators: J. E. D. Northcote-Green, T. D. Vismor, C. L. Brooks

The objectives of this research project are in striking alignment with those of the present project, beginning with a compilation and organization of reliability assessment techniques in use in 1981. A practical distribution reliability handbook followed from this research (see above, EL-2651). The 3-volume set includes an executive summary of the project (Volume 1), a compilation of surveyed present utility practices in reliability evaluation (Volume 2), and a detailed discussion of the historical (HISRAM) and predictive (PRAM) reliability assessment models (Volume 3). However, there is no discussion of explicit consideration of customer outage costs.

Volume 1

This volume gives the summary of the project. It summarizes the view of reliability taken in this study: Reliability evaluation involves observing historical outages, noting causes and effects, summarizing, and using this information to improve performance and predict future performance. Key results from the utility survey are given: Utilities mostly use customer related indices, such as ASAI, SAIDI, SAIFI, while a fifth of utilities used their own indices, and interchanges of reliability data are scarce. It briefly describes the historical (HISRAM) and predictive (PRAM) reliability assessment models and the combination of historical and predictive approaches into an integrated approach. HISRAM is for collection, analysis, and summarizing of data, and can accommodate a variety of levels of detail and information requirements. The basis of PRAM, which is for analysis of radial systems, is the reduction of the system between source and load into a single equivalent component. PRAM also has varying levels of complexity, in how the protection system is modeled and allows analysis of 1800 nodes among 100 substations. The results of tests of the models at a couple of utilities are discussed as are the integration of HISRAM and PRAM with existing planning models.

Volume 2

This volume reports the research undertaken to determine present industry practices in reliability evaluation and organizational functions within a utility supported by or requiring reliability information. It begins with an analysis of the requirements of an information system for distribution system reliability. Predictive reliability assessment methods presently reported in the literature are reviewed in detail, with predictive-reliability modeling material similar to that found in Billinton documents. Availability and unavailability are probabilities, and the authors state that as measures of reliability, probabilities are not very physical indicators. A better appreciation of system performance may be possible from failure rate and average outage time as primary indices. It is also noted that, in predictive modeling, the recognition and awareness of series element dominance can save considerable computational effort. The data requirements for reliability analysis are also detailed. Component definitions for data requirements are done by individual utilities. The selection of component levels for modeling and calculation of failure parameters required in the model is done using historical data. An appendix of this volume contains a survey, with results, of utilities on reliability practices. A tabulation of regulatory reporting requirements for different states is included here. One result of note is that fewer than 5 of 56 responding utilities maintained component population data necessary to compute outage rates for predictive models. An additional appendix contains a bibliography with précis of important articles.

Volume 3

HISRAM and PRAM are discussed in more detail in this volume. It seems that HISRAM was to be the major contribution of this project to common utility practice and that PRAM was an experiment using state-of-the-art concepts in distribution system reliability that pushed the contemporary limits on data availability and computing power. The applications used punchcard inputs and tape memory. A project objective was to include reliability calculations in long-range distribution planning and selection. The integration of the reliability models into the Unified

Distribution Planning Methodology (UDPM) for this purpose may be analogous to the incorporation of reliability into the present-day Area Investment Strategy Model and the Capital Budgeting Model. The goal of the integration was to be able to consider both reliability and cost in distribution planning, but separately: There is no mechanism, e.g., customer outage costs, to consider explicit tradeoffs. The testing of the models identified shortcomings. These shortcomings might prove instructive in a development of new predictive reliability modeling tools. The utility testing section and summary sections of this volume should be read during model development to ensure the problems encountered during PRAM implementation are recognized and avoided.

HISRAM satisfied existing reliability information requirements and provided utilities a framework for expansion of their reliability information collection and use. The utilities testing it already collected outage data similar to that proposed by Edison Electric Institute. The tool provided component reliability parameters that the utility's normal systems did not and proved more flexible. A 60-minute, 4-year average threshold for highlighting problem circuits was a practice of note used by one of the utilities.

PRAM uses the concept of continuity as the foundation of its reliability calculations of radial systems. It had 3 models of the protection system of increasing complexity and accuracy. These models combine component reliabilities into load-point reliabilities based on system configuration using network reduction. PRAM starts from the two fundamental indicators for load-point reliability are mean failure rate, λ_{eq}, and average annual downtime, U'_{eq}, to calculate other statistics and indices, such as average restoration time, average annual uptime, and steady-state availability. Using the number of customers or connected load, SAIFI, SAIDI, CAIDI, ASAI, ALIFI, ALIDI, can be calculated. The use of these indices in long-range planning were only for comparison of alternatives and as indicators of trends. PRAM was compatible with Levels 3 and 4 of HISRAM. The utility testing of PRAM showed the feasibility of predictive reliability modeling. However, interpretation of the PRAM results was difficult because of the lack of experience with predictive techniques. One of the tests was to study the effects of altering the protection strategy on one circuit. The tests required substantial approximations for PRAM parameter estimation, illustrating the basic data availability problems at the time. The key future improvements were identified as consideration of quality of service (voltage degradation, line overloads), the evaluation of parallel/networked configurations using minimal cutsets or their dual minimal tie sets, and the propagation of parameter uncertainty. This last improvement was said to require the most research as error propagation techniques in reliability calculations had not been widely investigated, indicating that even predictive reliability calculations for parallel/networked configurations were not something entirely novel.

Distribution System Reliability Engineering Guide (3/76)

CEA (Item #105); Produced by the CEA Distribution System Reliability Engineering Committee

The reliability engineering guide provided by the CEA has the fundamental series-parallel reduction modeling information that has been in place for over 25 years. It states that there existed at the time of writing a suitable methodology for predicting reliability indices, but component outage data has lagged behind. The initial reliability indices defined were customer-hours of interruption and kVA-hours of interruption, before frequency and duration. The indices defined here are SAIFI, CAIFI, SAIDI, CAIDI, ALII, ASCI, and ACCI, as contained in an early IEEE standard (# 346-1973). The guide discusses reliability criteria based on outage frequency, average duration, and expected annual outage time can be used to assess continuity. The appendices illustrate a number of calculation examples for predictive reliability assessment of small portions of systems, including one example comparing 2 alternatives considering reliability worth.

Reports of Little Relevance Investing Resources to Create Value (3/96)

EPRI TR-104917; Research Project 3678; Final Report; Prepared by Strategic Decisions Group

This report describes a portfolio approach to capital and O&M budgeting. It does not directly address reliability concerns. However, a couple of case studies in the final section discuss how to assess the shareholder value of investments for reliability improvement. An influence diagram depicting the translation to shareholder value of investments in equipment reduction and replacement, information technology, and customer programs is included.

Costing and Pricing Electric Power Reserve Services (12/97)

EPRI TR-108916; Final Report; Prepared by Christensen Associates; L. D. Kirsch, R. Rajaraman

A methodology for costing and pricing reserve services for use by generation and merchant firms is presented. Generation reliability with reserves is discussed. It determines the reserve requirements (R) as a sum of a power system's expected need (m) and an uncertain need ($k\sigma$): $R=m+k\sigma$ (p.2-12). The power system's reliability index k is expressed in standard deviations. Setting the reserve requirements $k\sigma$ above implies a certain probability of system failure (normalized area under the reserve requirement probability distribution curve to the right of $m+k\sigma$). If the reserves requirements are normally distributed (it discusses why it isn't exactly), then a k=3.719 implies a 99.99% reliability (one minus the probability of system failure—inability to meet load). Sample calculations are shown, with m and σ the mean and standard deviation of the combined load and generator uncertainty in the reserve service time frame (5-14).

A Primer on Electric Power Flow for Economists and Utility Planners (2/95)

EPRI TR-104604; Project 2123-19; Final Report; Prepared by Incentives Research, Inc.; F.C Graves

This report gives the fundamental technical aspects whose understanding can provide insights to transmission planners of how power flow can affect the economics of providing utility service. Reliability is not directly addressed.

Electric Generation Expansion Analysis System, Volume 1: Solution Techniques, Computing Methods, and Results (8/82)

EPRI EL-2651; Project 1529-1; Final Report; Prepared by Massachusetts Institute of Technology; M.C. Caramanis, F.C. Schweppe, R.D. Tabors

This is a report on the development of a generation planning model (EGEAS) that incorporates the considerations of generation optimization, production costing, reliability, and an assessment of effects of new generation technologies and processes. The report includes a review of selected capacity expansion models. Reliability being incorporated as a reserve margin constraint is discussed. Also, reliability is represented by the probabilistic criterion of EUE.

Electric Generation Expansion Analysis System, Volume 2: Details of Solution Techniques, Data of Test Systems, and Glossary of Terms (8/82)

EPRI EL-2651; Project 1529-1; Final Report; Prepared by Massachusetts Institute of Technology; M.C. Caramanis, F.C. Schweppe, R.D. Tabors, (see Volume 1 above)

This is the second volume of the 6-volume set. It contains appendices with the mathematical, technical details of the models, a detailed description of the test systems, and a glossary of terms.

F
SUMMARY OF WEB SITES

EPRI website

http://www.epri.com

The site has information on EPRI and its ongoing research programs. Information on all recent EPRI reports can be found (do a search on the report number), which includes the abstract, background, results, and the EPRI perspective.

Canadian Electricity Association (CEA) website

http://www.canelect.ca

The CEA website has paths to much information on reports on reliability and customer attitudes. The CEA's Equipment Reliability Information System (ERIS) and the Electric Power System Reliability Assessment (EPSRA) have collected information concerning reliability. Some reports are available only to participating utilities, but the more general information is publicly available. Annual reports of reliability are available on generation and transmission equipment (*Forced Outage Performance of Transmission Equipment Report*), and a report for distribution equipment is under development. The annual *Service Continuity Report on Distribution System Performance* contains SAIDI, SAIFI, CAIDI, and IOR statistics for Canadian electrical utilities. There are many links for USA and international organizations, as well as Canada. (relevant web pages are in the electronic library as html files)

Glossary of Terms

Prepared by the Glossary of Terms Task Force, North American Electric Reliability Council; August 1996

The NERC developed a glossary to serve the needs of the electrical industry and to promote consistency in terminology. It provides a list of terms and their definitions describing various aspects of interconnected electric systems planning and operation from a reliability perspective. The focus is on the generation and transmission systems. This (..\reliability documents\Reliability Glossary.htm) is an HTML-format document downloaded from the NERC site: ftp://ftp.nerc.com/pub. There's an Acrobat and a Word 6.1 version available as well.

North American Electric Reliability Council website
http://www.nerc.com/

This website has much information relevant to the function of the NERC, which is to govern the reliability of the interconnected electric generation and transmission systems in North America through voluntary standards. This information includes a database of electric system disturbances. There are documents that can be downloaded which address specific issues. For example, there is the NERC Operating Manual (..\reliability documents\NERC operating manual.pdf) and the report on the reliability status of the bulk North American electric system (..\reliability documents\NERC reliability assessment.pdf). (for notes and a summary of these 2 documents, refer to their entries in Reliability Reports and miscellaneous.doc) The NERC is not involved with the reliability of distribution systems, nor are the ten regional reliability councils of which it is composed. Links to the websites of the 10 regional councils are given.

American Public Power Association (APPA) website

http://www.appanet.org/

CENELEC website

http://www.cenelec.be/

Comité Europeén de Normalisation Electrotechnique

IEC website

http://www.iec.ch/

International Electrotechnical Commission

is the international standards and conformity assessment body for all fields of electrotechnology

ABB Power Systems

http://www.abb.se/pow/hvdc.htm

The website for this Swedish company has an explanation of HVDC technology. It includes an online tutorial on HVDC.

System Reliability Modelling and Evaluation

http://ee.tamu.edu/people/csbook/csbook.html

Chanan Singh and Roy Billinton. Copyright © Chanan Singh and Roy Billinton, 1977. This textbook is online in Adobe Acrobat form.

IEEE 1366 (1998)

IEEE Standard Trial Use Guide for Power Distribution Reliability Indices, 1366-1998

IEEE 519 (1992)

"IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems," *ANSI/IEEE Std 519-1992*

This standards document can be found at http://grouper.ieee.org/groups/harmonic/p519a/index.html (password protected). It addresses the power quality issue of harmonics. Tabulated values of some standards can be found in the paper "Power quality and harmonic distortion on distribution systems," *IEEE Trans. on Ind. Applications*, 3/94, 476. The scope of these standards and the abstract and table of contents (http://standards.ieee.org/reading/ieee/std_public/description/staticp/519-1992_desc.html) are given below.

Target:
Distribution Systems

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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