Reliability Issues In Today's Electric Power Utility Environment


Reliability, Risk and Probability Applications Subcommittee

Abstract - Considerable change is occurring in the structure and operation of electric power systems throughout the world. This paper describes some of these changes, the forces creating them and the possible reliability issues associated with them.

Introduction

Electric power utilities throughout the world are undergoing considerable change in regard to structure, operation and regulation. This is particularly true in those countries with highly developed systems. The traditional vertically integrated utility structure consisting of generation, transmission and distribution functional zones has in many cases been decomposed into separate and distinct utilities in which each perform a single function in the overall electrical energy delivery system. The "unbundling" of vertically integrated utilities has created an environment in which the overall responsibility for serving the electrical energy needs of the individual consumer does not reside in a single utility and is difficult to assign.

Deregulation and competitive pricing will also make it possible for electricity consumers to select their supplier based on cost-effectiveness and reliability. Requests for use of the transmission network by third parties is extending the traditional analysis of transmission capability far beyond traditional institutional boundaries. Given these significant policy shifts, the electric utility industry is moving to new planning criteria where broader engineering considerations of transmission access and risks must be explicitly addressed. Specifically, the likelihood of the occurrence of worst possible scenarios must be recognized in the analysis and the acceptable risk levels incorporated in the decision making process. In general, the new planning criteria should address the following issues:

- maintaining service reliability with the planned load growth while being financially solvent
- uncertainties associated with deregulation, wheeling and transmission access, and disintegration of the distribution systems
- integrated generation and transmission system modeling.

The electric power utility environment will become increasingly competitive in the future. Traditional reliability criteria based on deterministic considerations will become increasingly difficult to apply as the traditional utility functions are unbundled. This is particularly true in the system operation domain where security constraints are deterministically based. In the planning domain, there is a long history of probabilistic techniques and applications. Many of these concepts and techniques can be utilized in the emerging utility environment. In order to appreciate the reliability issues arising in the present electric power utility environment, it is necessary to recognize the forces and actions which are shaping this environment. The following is a brief summary of some of the recent events in North America and Europe in this regard.

The Changing Electric Power Utility Environment

The question of competition through non-utility generation (NUG) and third party access is a key issue in North America where there are many public and private electric power utilities. Competition is also a key political issue in Europe.

In the USA, the Federal Energy Regulatory Commission (FERC) first announced its comparability standard in 1994 in its ruling on a Section 205 open access transmission tariff filed by American Electric Power Co. (AEP) under the Federal Power Act (FPA). In this case, FERC defined a new standard for the provision of "open access" transmission services to third parties as:

An open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable conditions, as the transmission provider's uses of the system.
In complying with this standard, the transmission provider must offer transmission service under the same terms, flexibility and conditions that the provider uses in its own system. However, the provider must take into account all operational and reliability constraints, when determining if service requests can be supported by the transmission system. After setting the AEP standard, the Commission set for hearing a number of cases and charged the parties with figuring out how to make the comparability standard work. It soon became obvious that the only way to make the widespread changes necessary in transmission access to facilitate a truly competitive generation market place was to act generically.

As a result, on March 29, 1995, the Commission issued a Notice of Proposed Rulemaking (NOPR) -- Docket #RM95-8-000 that would require utilities subject to FERC jurisdiction to provide open access transmission services and also would deal with the issue of stranded costs. Included with the NOPR are pro forma tariffs, which set out the minimum terms and conditions of open access. Other aspects of the NOPR are that utilities must functionally "unbundle" generation, transmission and ancillary services, how stranded costs are to be handled, and that parties taking service from a jurisdictional utility must also offer open access on a comparable basis.

Together with the NOPR, FERC also issued a data exchange associated with the open access (the RIN request for comments and later evolved to Transmission Services Information Network, TSIN). Since then, many issues have been widely discussed, which include questions of proprietary data, varying interpretations of the information, the requirement of auxiliary services, transmission congestion charges, the structure of the market place, the relationship between the transmission owners and operators, etc. Many new ideas and concepts have been developed along the discussions.

In addition to the Commission's actions to ensure open access to the transmission system, the United States Congress had previously passed the Public Utilities Regulatory Policies Act of 1978 (PURPA) and the Public Utility Holding Company Act of 1935 (PUHCA). Congress is reviewing the provisions of this and other legislation to determine what changes are necessary to allow for full and open competition in the generation marketplace. The Energy Policy Act of 1992 placed the issue of retail wheeling outside of FERC's jurisdiction. Therefore, issues associated with retail wheeling are being handled on a state by state basis. However, the FERC is trying to ensure that federal regulation does not interfere with the goal of all consumers reaping the benefits of competitively priced generation. State regulators are responsible for handling the issues associated with retail wheeling. State Commissions are at various stages of approval on a myriad of proposals that would allow the ultimate consumers to choose who they want as their generation supplier.

In Europe, the Commission of the European Union introduced the Internal Energy Market in January 1992 through a Directive which contains various issues. The various governments have different priorities and, after three years of debate between them and the Commission, agreement was obtained on several key points:

*All Member States agree on introducing competition in generation (new capacity addition) via either "licensing" or "competitive bidding" options;
*Unbundling of accounts separating G, T, D costs
*Existence of a system operator, with certain responsibilities, although it is not clear how much independence it should have.

Other issues, particularly the introduction of competition in the Distribution and Supply sectors remained in question until recently.

The options for the implementation of an internal Energy Market were:

i) A Commission proposal, modified in the course of years in order to take into account the various objections, for a Negotiated Third Party Access (TFA NEG). The main contents were:
- no more central planning; the fulfillment of the balance in supply vs demand was left to the market
- no more "obligation to serve"
- accounting unbundling of the Vertically Integrated Utilities (VIU)
- distributors can choose their supplier
- network (Transmission and Distribution) access, through the payment of a transparent tariff, subject only to refusal if it could compromise the fulfillment of the Network obligations
- in the VIU the Transmission System Operator (TSO) should be separated from the wholesale trade


The basic ideas were:
- to allow competition in generation
- to maintain exclusive supply rights
to maintain the forecast of demand
- to keep long term planning, with a particular attention to the issue of the "primary sources security of supply".

The SB promotes competitive bidding for the new capacity additions needed and stipulates long term contracts with the bidding winners. "Eligible consumers" (to be defined) can choose their supplier but, through a set of long term contracts, SB will be the sole intermediary between producers and eligible consumers, which remain clients of the SB.

In countries where the SB function will be entrusted to a VIU, particular cautions will be adopted to ensure transparency of behaviour and limitation of the information flow between SB and the production and distribution activities of the VIU. At the end of the day, the SB model tries to reconcile the liberalization of production with the safeguard of some obligations of "general interest" which in many countries are entrusted to the electric sector.

The key point which remained for a long time was that of Distributor access, namely if Distribution Companies would be allowed to shop around for their supplies. Some countries (France, Italy...) were against the idea to "equalize" the Distributors to the "eligible consumers", while others (UK, Germany, the Nordic Countries) supported Distributor access as vital for the development of competition.

Various compromises were debated, concerning the ideological possibility of co-existence of the two models and on the quantitative figures of market liberalization. Finally, on June 21, 1996, a solution was finally reached. It is based on the following points:

- opening of the Market up to a "significant share", calculated on the basis of the large consumers in the 15 countries of the Community having yearly consumption > 40 [GWh/yr/site]

- based on the above limit, the average value of the opening for the 15 countries will be around 22% of the supply
- the above limit should be effective with the approval by the European Parliament of the Directive, presumably from 1.1.97. The Member States will then have 2 years to accomplish the said "first step"

- a second step - to be completed in three years - will increase the opening, by computing the above share on the basis of those consumers having consumption > 20 [GWh/yr/site]. The corresponding average share should be around 27%, starting from 1.1.2000

- a third step - to be completed in the next three years - based on a consumption of 9 [GWh/yr/site] should increase the opening up to 33% by 1.1.2003.

Summarizing, the market opening should increase from 22% to 33% in six years.

Within these limits, the Government of each country should decide - according to the so called "subsidiarity"—which will be the "eligible consumers". In this way, the strong conflicts about the "eligibility" of the Distributors have been overcome. In any case, the "eligible consumers" should include those consumers having demand higher than 100 [GWh/yr/site] and the Distributors already defined as eligible in the various members states. The shares of 22%, 27% and 33% are compulsory and are to be reached in any case. A review of the practical results of the Directive is foreseen on 1.1.2006, that is nine years after its enactment.

The major problem connected with the above is the possibility that vertically integrated utilities will have to face "stranded investments" in generation and transmission. The effect on the traditional way of handling reliability, as a "component" of long term planning, will be affected by the solution that the Energy Council and the various member states adopt. In general, the strategic and financial problems appear presently more pressing than the technical ones.

Apart from the UK, where the industry was privatized in 1990 and all the supply sector will be deregulated by 1.1.98 with - at least in principle - no more franchise customers, it is worthwhile to mention that in the Nordic countries, after the opening of all transmission and distribution networks in Norway in 1992, a similar liberalization took place in Sweden and Finland by 1.1.1996. Moreover, one integrated Norwegian/Swedish power market was established and trade is now free across the border. Finland, and possibly Denmark, are expected to join with the final aim to have one integrated Nordic market.

In Italy, after the approval by Parliament in November 95 of the Bill for the Authority and the Concession of Operation to ENEL (28.12.96), the plan for the restructuring of ENEL and its administrative and managerial unbundling - to be completed within 1997 - is going on. In Italy, Generation will be liberalized and the new capacity additions will be assigned through competitive bidding, organized and ruled by an Independent Body (public or private). ENEL's Generation Division should be constituted as a separate company by May 1998. ENEL Transmission and Distribution will remain monopolistic, with increasing rights to Municipalities.
After the recent political elections in May 1996, in which a new government was established, the Chairman and the two Members of the Authority for the electric (and gas) sector were appointed on June 19, 1996. The Authority is a key milestone in the restructuring of the energy sector. It has proposing and overseeing powers, will control service quality and will establish a new tariff mechanism based on the "Price Cap".

At the moment of writing, the new Ministry of Industry has expressed its general agreement on the framework established by the previous Government for the restructuring of the electric sector. The Ministry of Treasury and Balance has indicated the beginning of 1997 as a possible date for the placement of ENEL, which since June 21 has a new Chairman and a new Chief Executive Officer appointed by the Government.

In the European Union, Italy is in favour of the SB system, which allows it to comply with the "public service obligations", namely the adoption of one tariff per consumer type across the country. The described enactment of the European Directive, to be adopted by the Italian Parliament, will probably help to solve the problem of the degree of liberalization of the supply, by avoiding further political & ideological debates.

From a reliability point of view, methods capable of assessing at least the adequacy of systems much larger than in the past are needed. The possibility offered in Europe by large interconnections requires a better recognition of the system losses, which on long distances rule the profitability of power exchanges, and the determination of algorithms which better represent system operation.

In Italy, Non Utility Generators (NUGs) are the new players in the generation sector. The production from renewables, syngas, process fuel and combined cycle plants with efficiencies higher than the fixed limit was liberalized in 1991 in an attempt to increase the efficiency of the electric sector. In fact, Italy is extremely dependent (80%) on energy import and the security of primary energy supply is the most important issue of the energy/electric Italian sectors. A very attractive mechanism for the production selling price to ENEL, based on "ENEL avoided cost + incentives", caused a proposal boom by independent power producers, gas producers, refiners using syngas and non-Italian electric utilities/joint ventures. ENEL keeps the responsibility of assessing the compatibility of the proposals with its system. The majority of the NUGs are not fully despatchable: Their "compatibility" is just evaluated on the basis of the diseconomies produced on the ENEL system, by obliging it to heavily load at night its base duty plant and/or, in some cases, even to waste water at its hydro plants. So far only 6.3 GW have been approved out of 12.3 GW proposed. A rethinking of the amount of the incentives and of the limits to the NUGs' proposals is a debated issue, with strong diverging interests.

As far as reliability it is concerned, on one side there is a tendency to overcapacity, and therefore to "understate" the problem, on the other the national system planning has to "trust" the availability figures anticipated by NUGs, which, especially for large Integrated Gasifier Combined Cycle plants using syngas, are not yet proven. In general the drivers appear to be more economic than technical.

Electric power supply developments in the United Kingdom illustrates some of the rapidly emerging issues in highly developed systems. This can be illustrated by considering a number of basic factors. In the UK, all generation is produced by private independent generators (except for the nuclear companies which are now being restructured and parts privatized). There is no central/global planning of this generation. The expansion of capacity and siting of plants is left to market forces not necessarily system requirements. The National Grid Company (NGC) vary system charges across the country in order to encourage appropriate siting of new generation. At present, reserve is excessive due to a rapid "dash for gas" from the North Sea. What will happen is both unknown and unpredictable. The theory is that in the long term as reserve decreases, prices of energy will increase and generators will be encouraged to build new generation and hence maintain security of supply. In the short term, it is said that the large reserves will prevent any immediate problems. However, two scares occurred in 1995 both due to inadequacy of available capacity. This reflects the fact that NGC can only dispatch generation declared available.

England and Wales are connected to France and Scotland via interconnections. Both of the latter can bid equally with other generators in England and Wales. In fact, France (EdF) get a nuclear subsidy because they bid their nuclear plant. France is continuously scheduled, so is Scotland generally because they also use cheap surplus nuclear energy. England and Wales therefore could become reliant on cheap energy sources from outside their own domain and therefore their own control could decrease or disappear. Impact again on reliability is again uncertain.

On a grand scale, system wheeling is not really an issue for an offshore island such as the UK. However it is of considerable interest within mainland Europe. In the UK, however, local wheeling is an issue. Any licensed supplier (those licensed by the Office of Electricity Regulation, OFFER) can use any
other company's network to supply their contracted customers. Contracting for customers is big business at present. Only customers with a maximum demand over 100 kW can enter this market, but in 1998 it is a free-for-all. Nobody knows the effect of this and the metering problem is a real issue. However the greatest profit is presently made by use of system charges, not for the sale of energy. This itself may change as the regulator delves more deeply into the operational aspects of the network and energy supply business. Reliability is an issue in this wheeling process because, although a licensed supplier may be contracted to supply energy to a customer, he has little or no control over the ability of the network to actually transport that energy.

The break-up of central control has removed the responsibility of anyone really having responsibility for security of supply. NGC only has the responsibility of efficiently and economically operating the system. If insufficient generation is offered by the generating companies then supplies will be cut, as nearly occurred in 1995. The price formula is intended to ensure that generators will maintain the availability of sufficient energy resources. Regional Electricity Companies (RECs) have little control although they are now allowed to generate some energy in their own right. The only real obligation on a REC is to provide a connection to customers (at a cost) but are not compelled to ensure a source of energy is available.

The UK now has a regulator (OFFER) who is responsible for acting on behalf of customers and ensuring the private monopolies are acting in an efficient, effective and economical manner. Whether the present level of regulation is sufficient is still uncertain but clearly in the new environment now existing in the UK, the need for regulation is absolutely essential to ensure some control, some customer perspectives, and some independent views over present and future requirements. To date since privatization and the restructuring of the industry, supplies have generally been secure and prices have been controlled. This is due mainly to the fact that the system currently has a very large reserve margin. How this reserve, security of supply, and prices behave in the future is considerably uncertain.

Customer Considerations

The focus of any discussion concerning electric system reliability should begin with the customer. The electric utility industry is moving towards an environment of competition and customer choice; reliability is one of the key factors influencing customer loyalty. To remain competitive in this new environment, utilities must understand and meet their customers' expectations.

Results of a survey of 3550 large energy users in the USA provided interesting insights into the expectations of customers. The key drivers of customer loyalty were identified as: price, reliability and power quality and complaint handling. Analysis of the survey results yielded two very interesting observations that will help shape the direction of reliability planning in the future. The first observation centers on likelihood of customers to switch electric suppliers for a reduction in price. The results provided in Table 1 illustrate how customer retention is sensitive to price. The national average shows that almost 70 percent of customers would switch electric suppliers for just a 2 percent reduction in price. Most utilities will have a very difficult time retaining customers unless they can get within 5 percent of the market price.

<table>
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<th>National Average</th>
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<tr>
<td>Likely to Switch for 2% Less</td>
<td>69%</td>
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<tr>
<td>Likely to Switch for 5% Less</td>
<td>81%</td>
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<tr>
<td>Likely to Switch for 10% Less</td>
<td>90%</td>
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<tr>
<td>Likely to Switch for 15% Less</td>
<td>92%</td>
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The second observation centers on the customer's perception of the importance of reliability. Customers state that reliability is very important; however, an increase in reliability performance does not guarantee improved loyalty whereas a decrease in reliability performance could be disastrous.

Customers are demanding lower rates and higher reliability. To remain competitive in this new environment, utilities must find ways to reduce costs and still provide the level of reliability required by their customers. The best way to accomplish this is through the use of probabilistic techniques in the system planning and operation areas.

Industry Utilization of Probabilistic Planning Techniques

Probabilistic planning is performed mainly by comparing reliability measures and benefits for different reinforcement and expansion projects. To effectively compute the reliability benefits associated with these alternatives, commonly computed reliability measures include:

- Probability of unacceptable events
- Frequency of unacceptable events
- Duration of unacceptable events
- Severity of unacceptable events in terms of loss of load

Additional reliability measures and indices can be computed. For example, if a measure is computed for an individual customer or for a service area it is
easy to think in terms of reliability indices such as energy not served and other loss of load indices presently used by the industry. Among several expansion and reinforcement projects proposed, which one is the most cost effective? In the past, alternative projects were often studied individually or in small sets. It was impractical, with the available tools and criteria, to determine adequately the merits of and contrasts between reinforcement alternatives. Now, with probabilistic criteria and appropriate software available, the planner can assess system-wide bulk power transmission reliability, impact of varying reinforcement expenditure levels and reliability outcomes for many alternatives. Once the reliability merits of each reinforcement have been analyzed, ranking or comparing the merits among all alternatives is most readily performed with a single, aggregated index such as EUE (Expected Unserved Energy). It is imperative that any single measure be a composite of the main reliability factors of concern.

The reliability analysis for a reinforcement project may include prediction of the expected load the system is capable of delivering without violating ratings. The severity of each system adequacy problem is accounted for by the expected load carrying capability. With incorporation of probability of demand levels, contingency scenarios, and possible operating practices, the predicted index becomes the measure of the degree that the demand will exceed the transmission system's capacity. Specifically, a reference or base case level of reliability is predicted for the existing network for the predicted load and generation but without reinforcements. The same procedure is applied to predict the reliability with the proposed reinforcement. The difference in reliability between the reinforcement alternative and the existing network measures the reliability benefit of the alternative. In order to make the best choice among reinforcement options, the reliability improvements afforded by each option are then compared and combined with the full set of attributes including losses, capital costs, institutional and regulatory requirements and constraints, etc.

The worth of reliability can be considered more explicitly using a reliability cost-benefit approach which uses the cost concept for ranking reinforcement alternatives, converts the reliability index (e.g., EUE) to a monetary cost. The reliability cost can be combined with installation cost and operating cost to allow monetary comparisons among disparate alternatives. Another advantage this approach offers is the possibility of modeling integrated generation and transmission system reliability. Conceptually, the reliability cost is the aggregated worth the customers are willing to pay to avoid load interruptions or voltage standard violations, and is the function of interruption frequency, duration, MW value, location, and other social effects. In some cases the costs are tangible, with inherent dollar values; in other instances the costs are intangible and subjective, depending upon the type and timing of interruptions and the kind of consumers.

Typically, there are two ways to convert predicted reliability to a cost value: (1) a customer damage function, and (2) a constant rate. The customer damage curve is derived from surveys which estimated what consumers would be willing to pay, either in increased rates or for backup service. The constant rate is used to construct the cost from EUE (or other indices alike) for specific location and time, and can be developed from aggregate or composite customer damage functions. Incorporation of reliability worth concepts into the basic probabilistic evaluation process provides the opportunity to include reliability effects into the total economic framework associated with the emerging electric power utility environment.

**Probabilistic Evaluation in System Operation**

Competitive electric energy systems provide strong motivation to reevaluate the traditional deterministic approach used in development of security limits for real-time operations, and consider in its place a risk-based security assessment approach, where risk is defined as the product of probability and consequence.

The "traditional deterministic approach", used by most utilities today, imposes constraints on operating parameters (e.g., generation level, MW flow, voltage level) when-ever loss of a single circuit or generator will result in a violation of minimum operating reliability criteria. This is commonly referred to as an "N-1" criterion (under some conditions, such as when two circuits utilize the same corridor, an "N-2" criterion may also be used). The problem with this practice, is that all resulting limits are hard, i.e. there is no mechanism for adjusting the limit "hardness" as a function of the probability or consequence of the contingency requiring the limit. Therefore it is often the case that power systems are operated under constraints imposed by events low in probability of occurrence or severity of consequence even when the constraint imposes very significant opportunity costs, such as limiting economic interchange between power system participants. If risk is computed as the product of probability of an event resulting in a security violation and consequence of the violation, then one may summarize by saying that the traditional deterministic approach to security assessment often results in costly operating restrictions that are not justified by the corresponding low level of risk.
In addition, unlike the traditional environment of the regulated, fixed rate of return, vertically integrated utility, competitive electric energy systems create incentives for a multiplicity of players to take operating risks in order to maximize their profits. Unmanaged risk-taking may very well lead to degradation of security levels; this is particularly true for dynamic security since uncertainty in dynamic system response is large and the consequence of instability can be costly.

These reasons provide motivation to develop a risk-based approach to security assessment. Such an approach would offer:

- the potential to justify operating practices that more equitably balance the tradeoff between cost and security, resulting in substantial savings from use of less costly energy resources,
- a risk management system for security assessment that would prevent arbitrary or haphazard risk taking not conducive to good operating practices.

Risk management requires that probabilistic techniques be integrated into the security assessment process normally used in operational planning studies. This is not a well-researched area, because traditionally, probabilistic techniques have been used more by system planners than operators, since the decision horizon and consequently the uncertainty are quite different (the planning horizon is years whereas the operating horizon is months or less). However, operations will have introduced into it additional uncertainty because transmission flows, once driven only by normal load growth, which is relatively predictable, is now driven by the economics of long distance transactions, which may not be predictable at all.

Use of a risk-based approach to power system security assessment in operating a competitive electric energy system will require a method for computing security limits, based on both probability of insecurity and consequence of insecurity, in terms of operational parameters like generation levels, transmission line flows, and voltages. Operating points would then be judged acceptable depending on the level of risk and the economic benefits associated with the operating point, and not simply based on when system performance following the most limiting contingency first violates minimum operating reliability criteria.

Actions associated with maintaining a secure bulk transmission system should be economically induced in autonomous participants via appropriate security-related price signals. Such an approach should be seen as complementing the traditional, centralized "command and control" security framework that will likely be weakened in competitive electric energy systems.

Competition, by its very nature, requires a multiplicity of participants acting in an autonomous or at least semi-autonomous fashion. As buying and selling of electric energy at the bulk transmission level becomes more competitive (as surely it will with the recent entrance of so many non utility suppliers and power marketers and brokers), the coordination and control functions, including the security assessment function, traditionally provided by a centralized utility control center, will be more difficult to realize because of security-related problems introduced by competition.

One way to provide a coordinated approach is to require that the transmission grid, including the control center and related functions, be owned and operated by a "neutral" party, i.e., one that does not participate in the energy buy/sell competition, and this solution is under serious consideration today in much of North America. The question of balancing security and profit can be approached in a manner that conforms quite naturally to the new competitive structure by providing economic incentives for inducing participants (both suppliers and demands) to include in their decision-making the effects of those decisions on system security levels. One effective way to do this is to include a security-related component in the price of transmission service.

A basic set of criteria for this component is that it should penalize transactions which degrade security levels and reward transactions which improve security levels, that it be applied to all transactions and not simply the one triggering a need for curtailment, and that it be related to security effects on a per-MW basis so that large transactions are not penalized disproportionately. A final criterion, which has been emphasized by the U.S. Federal Energy Regulatory Commission (FERC), is that it allocate real and verifiable costs and benefits. To satisfy the last criterion, one might think of relating the impact of a transaction on security in terms of the risk of insecurity.

Conclusions

This paper briefly illustrates some of the changes occurring in the electric power environment in North America and Europe. It can clearly be seen that the thrust towards privatization and deregulation of the electric utility industry will introduce a wide range of reliability issues. These issues will require new system reliability criteria and analytical tools that recognize the residual uncertainties associated with power system planning and operation.