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EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

PRA White Paper – A White Paper on the Incorporation of Risk Analysis into Planning Processes

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Executive Summary

Transmission planning is the core activity that ensures reliable and economic operation of a transmission system. At present, transmission planning analysis is primarily deterministic in nature. Decision making using the deterministic analysis has two attributes: 1) Reliability decisions are made in a "go, no-go" framework and 2) Economic decisions use "expected or average" case analyses. While the reliability of the North American electric system has been exceptional over the past half century and the cost of electricity has been reasonable, two key areas of challenges to the deterministic planning framework in the 21st Century should be considered. 1) System Changes: Changing generation resource mixes, changing regulatory framework, evolving electric consumption paradigms, and new technologies introduce new economic and reliability uncertainties and risks that cannot be solely addressed by the deterministic planning framework. 2) Analysis Inadequacies: The "worst case" scenarios used in deterministic planning may not lend themselves to optimal decisions. To the extent risk or uncertainty is asymmetric, the optimal decision may represent the selection of plans which are not more economic or more reliable than necessary under expected conditions. Further, subjectivity used in selecting deterministic cases used for making decisions may result in aggressive or conservative cases which can lead to suboptimal plans.

Transmission planners as well as regulators are looking for new approaches and methods to address the above challenges. Probabilistic Risk Assessment (PRA) methodologies, also referred as "risk-based planning" or "probabilistic planning" techniques, have the potential to provide a framework to address these concerns and consider various uncertainties and risks facing transmission planners in a more rigorous manner. The research efforts in developing this white paper focused on providing an in-depth understanding of 1) Various uncertainties and risks that impact the transmission planning decision process, and 2) State-of-the art on the PRA methodologies. The information presented in this white paper is intended to serve as a primer on the topic of risk-based transmission planning to states in Eastern Interconnection (EI). However, this white paper is equally useful to state regulators outside of EI, practicing transmission planners in North America, Independent State Operators (ISOs), Transmission Owners (TOs), federal regulators, academia, and other research organizations. The scope of this white paper covers the following areas with regards to PRA:

- A framework to categorize factors and uncertainties impacting transmission planning
- Risk-based transmission planning approaches for reliability and economic assessments
- Practical case studies using risk-based transmission planning concepts
- Current status of tools for performing risk-based transmission analyses
- Impediments to wide-scale integration of risk-based approaches
- Regulatory and jurisdictional considerations in incorporating risk-based planning concepts
- An augmented transmission planning framework and recommendations to states moving forward

1
Overview and Objectives

The main objective of a modern power system is to serve, within the regulatory framework, its customers by balancing the desired level of reliability with the cost of providing the service. Transmission planning is one of the most critical activities in achieving this objective. Transmission planning involves developing the system as economically as possible and maintaining an acceptable reliability level [1]. This requires assessing reliability performances of system plans, computing the costs and benefits of proposed investments, ranking various options on their technical, economical as well as other merits, and justifying development of new facilities in view of regulatory and other strategic considerations. Traditionally, the system assessment in transmission system planning has been performed using deterministic criteria and methods (e.g., N-1 contingency analysis, and worst case scenario assumptions for analysis). Such a rule based deterministic framework provides a simple and understandable way to plan and operate facilities.

Deterministic planning has served the industry well. It is under this planning philosophy that the US and many other developed nations' power systems have developed in the last several decades to the current relatively highly reliable power systems. The fact is that worst-case deterministic planning is reliability-centered planning done without consideration of the natural tradeoffs of reliability and economics. Significant changes in the industry over the last 5 to 10 years, however, have illuminated these reliability/economics tradeoffs and other related limitations of deterministic planning and have brought the discussions around probabilistic planning to the forefront. Some of these changes include:

1. Industry Restructuring: The introduction of open access and electricity markets has made it difficult to predict the location of new generation facilities and potential dispatch patterns for long term planning as the investment decisions are driven by market decisions. Therefore it is difficult to predict the location of new facilities and potential dispatch scenarios. This in turn has made it difficult to plan for transmission upgrades and reinforcements [2]. Increased access to the grid has also resulted in regulatory emphasis being placed on stakeholder participation and transparency in the transmission planning process.
2. Renewable Generation: Increasing levels of renewable generation (mainly wind and solar generation) are drastically increasing the levels of uncertainty and associated operational challenges of the system. The correlated output of numerous wind and solar plants across wide geographical areas along with load is difficult to predict. For future policy and economic scenarios with high levels of variable generation, the uncertainty in available energy to meet forecast loads and the uncertainty in the range of power flows that may occur can significantly complicate power system planning processes.
3. Distributed Energy Resources (DER): The levels of distributed resources such as residential/ commercial PV, electric vehicles, demand response, and community energy storage are expected to increase significantly over the next decade potentially changing the landscape of electric power systems. While DER presents a tremendous opportunity to tap and control renewable energy sources, significant penetration of these resources may result in a dynamic net load with characteristic totally dissimilar to traditional loads. Increased dependence upon

DER presents challenges for planners as the consumption patterns are altered and volatility is increased. The evolution of management systems for demand-side resources will drastically affect planning methods.

4. Environmental Regulations: The increased and continuous concern for the environment will likely lead to new and evolving regulations that will influence the generation fleet in the future. Already greenhouse gas (GHG) regulations and renewable portfolio standards (RPS) are significantly changing the electric power system landscape and considerably heightening the need for new approaches in transmission planning.

The above mentioned changes and sources of uncertainty, as well as other uncertainties such as fuel prices, long-term climate trends, population shifts, and macro-economic growth patterns are drastically affecting the traditional planning methods. Transmission planners are realizing the challenges posed by these issues, but generally do not possess a deep understanding of the challenges posed by uncertainty and lack the tools required for addressing these uncertainties. This may frequently result in failure to study a particular scenario that may have reliability implications, or more likely result in using planning studies that include increasing numbers of scenarios that consider the system at ever heightened levels of stress.

There is a growing understanding that probabilistic risk analysis methods provide an opportunity for evaluation of generation and transmission expansion plans considering the variability of the inputs to the analysis. It is worth mentioning that probabilistic approaches have been applied traditionally to resource adequacy planning. However, even in planning processes in which probabilistic risk analysis has been applied, innovation will be valuable. Generation adequacy for instance, has typically been analyzed without robust consideration of transmission network and distribution facilities because it was assumed that transmission network would be fully available to transport the energy to the load delivery points. However, in most cases and with increasing frequency, the availability of transmission should not be considered a certainty.

Probabilistic Risk Assessment (PRA) methodologies, also referred as “risk-based planning” or “probabilistic planning” techniques[1] have potential to provide a framework to consider various uncertainties and risks facing transmission planning in a more rigorous manner bring into focus the reliability/economic tradeoff considerations. PRA methods can address the complexities introduced by the uncertainties in data and forecasts. This cannot be captured in a deterministic framework because an impossibly large number of deterministic studies would be required to assess each possible combination of outcomes [2]. Another distinguishing feature of probabilistic planning is that the trade-off between reliability and cost can often be explicitly calculated. High reliability risk plans often carry low expected costs while plans with low reliability risk tend to be more expensive. The distributions of cost and risk output in PRA analyses allow planners to identify meaningful reliability targets that appropriately consider consumer costs. Furthermore, probabilistic planning can potentially address other regulatory requirements such cost allocation issues (FERC Order 1000) and Renewable Portfolio Standards (RPS) mandates.

[1] We will be using the terms “Probabilistic Risk Assessment (PRA)”, “risk-based planning” and “probabilistic planning” interchangeably in this document.

Although the focus of this white paper is on transmission planning, it must be emphasized that probabilistic planning concepts extend beyond transmission planning and are applicable to planning of generation resources (also referred to as “resource planning”) and planning of distribution systems. For such a “comprehensive system reliability” evaluation, it is imperative to consider uncertainties in non-transmission factors mentioned previously.

While the need for introducing risk-based planning criteria in the utility planning process is becoming obvious, it is not the recommendation of this paper to replace deterministic criteria with probabilistic planning altogether. The two approaches should not be considered mutually exclusive. Risk-based reliability analysis and risk-based economic analysis should be added as part of the whole planning process. As an example, traditional deterministic approaches such as N-1 contingency criteria can still be used as a first step for performing reliability evaluations while probabilistic approaches can be used as a second level of analysis to gain a more informed view of the system reliability and economic justification of a transmission investment. This view is supported by well-known industry researchers and practicing engineers in the area of power system reliability [1, 2]. Furthermore, current mandatory reliability standards in the United States developed by NERC and approved by FERC require deterministic analysis to exhibit compliance. Therefore, under the current rule-based deterministic reliability standard regime, there is a clear need to highlight how probabilistic planning can augment the deterministic planning from a planner’s perspective. There is a need to have a deeper understanding and synthesis of what the fundamental components of the planning processes are. This will allow planners to properly decide when deterministic methods are appropriate and when probabilistic methods can offer value to the planning process, as well as recognize that other approaches beyond probabilistic methods may be needed to address the issues at hand. Most importantly, there is a need for clarity in the various aspects of the planning process. It should be kept in mind that the broad-brush treatment of data, the across-the-board use of deterministic approaches, and loose definitions of terminologies, such as “uncertainty” and “risk” are not conducive to meeting the industry’s challenges of the future.

With the aforementioned discussion, this primer was developed to accomplish the following objectives:

1. Provide clear understanding of various uncertainties and risks impacting transmission planning
2. Provide an overview of existing risk-based methods, criteria, indices, and tools
3. Offer guidance on how to incorporate risk analysis into transmission and other resource planning

These research efforts were sponsored by NARUC/EISPC primarily to offer guidance to states in the Eastern Interconnection on how to incorporate risk analysis into planning of transmission and other resources. However, all the practicing transmission planners in North America, reliability organizations, research organizations, as well as academia will find the information presented in this paper to be informative.

Based on the experience of the project team working with utilities, some common opinions about risk-based planning can be summarized as follows:

1. Top five benefits of moving towards risk-based planning approaches are:
    a. Better representation of variable generation as penetration increases

   b. More realistic model of power system life processes
   c. Improved representation of load uncertainty. Load uncertainty is increasing even more due to increasing penetration of demand-side resources such as demand response and roof-top PVs.
   d. Screening contingencies by considering likelihood of occurrence and/or system impact in terms of frequency, duration and severity of system problems or load loss
   e. Comparing alternative expansion plans using reliability measures

2. While many transmission planners have heard of risk-based methods, very few have actually used them.
3. Top four hurdles for incorporating risk-based planning methods are:
   a. No requirements from regulatory bodies especially NERC
   b. Lack of knowledge, training, time, computer tools, and skillsets in applying probabilistic methods
   c. Additional data requirements beyond what is required for deterministic approaches
   d. Some respondents did not agree that probabilistic methods provide more information to make better decisions and believed that uncertainty and variability can be sufficiently accounted by planning for worst-case scenarios

From the responses received, it was apparent that while many transmission planners agree that the changing nature of power systems supports using risk-based approaches, there were others who were skeptical about the value of using these approaches. However, all the respondents thought that efforts such as this white paper and other such research work that EPRI performs will help the industry gain a better understanding and make an informed decision about when and how to use risk-based planning approaches. This whitepaper attempts to provide a clear and candid assessment of the current state and possible future of PRA in transmission planning while addressing both the concerns and suggestions of respondents.

This document is intended to serve as a primer to states in Eastern Interconnection (EI). However, this white paper is equally useful to state regulators outside of EI, practicing transmission planners in North America, Independent State Operators (ISOs), Transmission Owners (TOs), federal regulators, academia, and other research organizations. The key takeaways from this white paper are summarized as follows.

1. Transmission Planning Risk Assessment Framework

Transmission planning is a challenging endeavor for two reasons: 1) There are multiple factors that influence transmission planning decisions. Most of these factors cannot be known with certainty during the planning phase. 2) There are different time frames that influence transmission planning. These time frames typically necessitate consideration of varying planning tools and may result in competing multiple plans.

To facilitate good understanding of the factors that influence the transmission planning decisions, the project team proposed a transmission planning risk assessment framework that classifies these decision factors into three categories as shown in Figure 1-1 (and summarized in Table 3-1).

In transmission planning, we are always dealing with issues that span all of these three categories. However, no analysis framework exists today that tries to solve the problem systematically by recognizing these three distinct features to arrive at the proper solutions. The traditional approach is to treat all variables as certain and try to solve them with deterministic methods.

Non-quantifiable uncertainties are considered by defining a set of deterministic future scenarios by varying key inputs and analyzing the subsequent planning evaluation results. In most of the vertically integrated utilities and ISOs, these scenarios are generated by the resource adequacy planning group. Scenario based analysis is practical in the sense that once the scenarios have been defined, the computations are tractable and the results can be presented and well understood. The criticism of the scenario based approach is the question whether a small number of discrete scenarios can capture the uncertainty of the various parameters affecting the planning process. Because of this shortcoming the results have to be interpreted by the planner.

Quantifiable uncertainty variables can be represented using probabilistic models that can be built using historical data. For variable renewable generation, hydro availability, and system load (including demand response and demand-side resources) historical time series data is used to determine appropriate load-generation dispatch planning cases. At present there are no commercially available tools for this. However, this is an area of active research.

For generation and transmission components historical performance is used to come up with outage statistics which are used in assessing reliability using probabilistic approaches.

The factors impacting transmission planning and the framework are shown in Figure 1-1 and are described in considerable details in later Chapters.

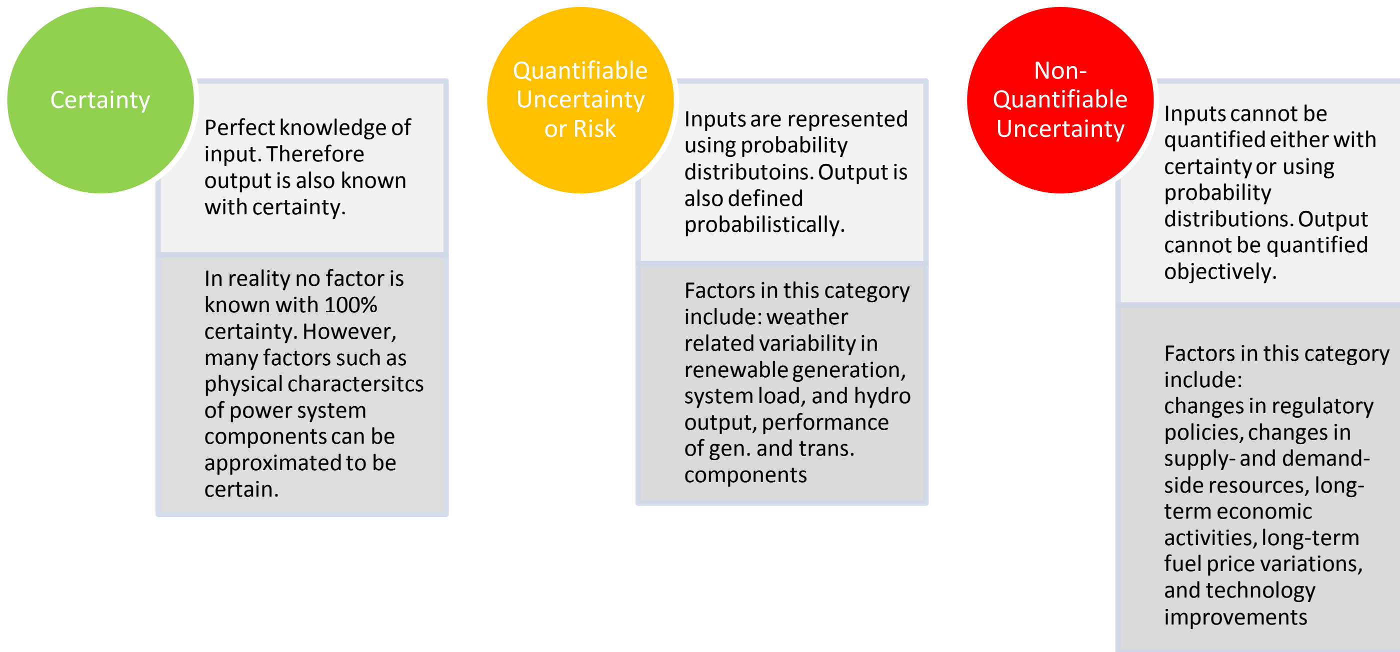

Figure 1-1 Categorization of Factors Impacting Transmission Planning

2. Risk-Based Transmission Planning Approaches for System Reliability and Economic Assessments

Risk-based system reliability assessments can be divided into two categories: 1) system adequacy and 2) system security. System adequacy is concerned with having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Adequacy is associated with static conditions and does not take system dynamics following a fault into consideration (for example loss of synchronism of generators or stalling of induction motors following a fault). Security assessment on the other hand is concerned with dynamic or transient conditions following a component failure. The majority of the existing PRA related research has been performed on system adequacy considerations (this includes resource adequacy as well as composite generation and transmission system assessments).

Two fundamental approaches used in system adequacy assessments include selective contingency enumeration and Monte Carlo simulations. Selective contingency enumeration is an analytical techniques whereas Monte Carlo simulation is based on random trials of system conditions. Both approaches have their pros and cons and are computationally intensive as compared to deterministic approaches.

Transmission reliability can be characterized in terms of probability, duration, frequency, and expected value of one or more indices. Typical indices used for system adequacy include thermal overloads, voltage violations, loss of load, and system islanding (separation). These indices can be evaluated for an area, for major bulk system load points or at component level.

Risk-based approaches readily facilitate economic decision making for transmission investments and provide a rational basis for selection of best alternatives. An approach known as Value-Based Transmission Reliability Planning (VBTRP) is commonly used in economic analysis. This approach aims to provide the system reliability required by customers at the lowest *Total Cost* from the customer's perspective.

Outage data is pivotal to risk-based approaches. In the US NERC's Transmission Availability Data System (TADS) and Generation Availability Data System (GADS) datasets can be used to provide component outage data. This data can be replaced by utility specific data if available.

3. Practical Case Studies using Risk-Based Transmission Planning Concepts

Availability of transmission planning case studies using risk-based approaches is limited, especially in the recent years. This underscores the fact that these approaches have not been widely adopted by the industry. The project team identified a few case studies based on literature review. In a companion research project, the team worked on four case studies using the concepts described in this white paper. These case studies are summarized in this white paper as well.

4. Current Status of Tools for Performing Risk-Based Transmission Analyses

At present there are only two programs in the US that are available for risk-based transmission planning: 1) Transmission Contingency Analysis and Reliability Evaluation (TransCARE), which is a research grade tool from EPRI, and 2) TPLAN module from Siemens PTI which is now integrated with PSS®E software. A number of research grade tools existed in the nineties. However, they have been discontinued over the years. The project team used TransCARE to perform the companion research.

There are no off-the shelf tools available for developing future planning scenarios or probabilistic load-generation dispatch cases. This is an area of active research and some prototype tools are available.

There are commercial tools available for resource adequacy and production costing analysis. Some of these tools are explicitly probabilistic while others are deterministic but may be used iteratively to mimic probabilistic runs.

5. Impediments to Wide Scale Integration of Risk-Based Approaches

In spite of significant research in the area of risk-based transmission planning, to date these approaches have not found broad acceptance. The main impediments include:

- Deterministic nature of NERC transmission planning standards.
- Lack of consensus on which indices to compute to assess reliability and how to compute. As the consequence, there is no consensus on thresholds to be used.
- Lack of standardization and availability of reliability data
- Lack of skilled personnel to apply the risk-based methods
- Limitations with the existing tools in terms of models, indices calculations, and usability
- No tools for risk-based system security assessments

- General acceptance and satisfaction with the deterministic approach among planners and their regulatory overseers

6. **Regulatory and Jurisdictional Considerations in Incorporating Risk-Based Planning Concepts**

Regulatory as well as federal and state jurisdictional issues are key considerations in transmission planning and in any future development and application of risk-based planning in the US. Key factors in the development of risk based planning that are the domain of regulators include risk-based planning criteria, and industry-wide collection of system reliability data. It is important for federal and state regulators to be aware of potential areas where risk-based transmission planning approaches can provide deeper insights into planning issues and may help to make better decisions.

7. **An Augmented Transmission Planning Framework and Recommendations to States Moving Forward**

Based on the research performed for this white paper, the main conclusions that can be drawn are:

Given the unprecedented changes in the electric power industry and the pressure to ensure system reliability at a minimum cost, transmission planning is becoming more complex than ever. Risk-based planning has significant potential to provide a better decision making framework for transmission planners.

Although the industry is not ready for a full-fledged adoption of risk-based transmission planning framework, these approaches can play an important role in augmenting the existing deterministic framework and help to identify system weaknesses, compare multiple alternatives for system upgrades, and justify transmission upgrades.

States can play a crucial role in evolutionary adoption of probabilistic planning concepts and bridge the existing gaps in the risk-based planning framework. In this regard, the recommendations for states are:

- Closer coordination with NERC and federal regulatory process
- Promote greater awareness about uncertainties and risks impacting transmission planning among various stakeholders
- Promote research efforts on risk-based planning
- Coordination among interconnections

1.1 White Paper Outline

The rest of the Chapters in this white paper are organized as follows:

Chapter 2 provides a summary of main activities performed in the transmission planning process as well as how transmission planning is linked with resource adequacy planning. The chapter also summarizes existing transmission reliability evaluation criteria which are based on the NERC TPL standards. The chapter sets the stage for the need for a more rigorous consideration of risks and uncertainties in the transmission planning process which is the main topic of this white paper.

Chapter 3 lays the framework of considering uncertainties and risks in the transmission planning processes. The terms “uncertainty” and “risk” are defined in the context of transmission planning. Various factors that impact transmission planning are identified and categorized in terms of uncertainties and risks. While transmission planners and regulators are familiar with some of these factors (for example long-term economic forecast and fuel price variation), other factors such as demand-side resources are new and became prominent only in last few years. This chapter is fundamental to the understanding of the concepts explained in later chapters in this white paper.

Chapter 4 is an extension of Chapter 3 but focuses solely on probabilistic methods to consider variability in renewable generation (mainly wind and solar) and system load. The chapter describes the latest research work from EPRI on this topic.

Chapter 5 is the crux of this white paper and provides an in-depth discussion of probabilistic approaches for evaluating transmission system reliability and economics. The chapter covers probabilistic analytical methods, indices, planning criteria, and data requirements. Salient differences between deterministic and probabilistic planning approaches are also highlighted in this chapter.

Chapter 6 discusses various case studies from utilities that have used risk-based planning concepts. There are not many examples of practical case studies, especially in the recent past. However, the case studies documented in this chapter do highlight additional insights provided by probabilistic approaches and compare them with deterministic approaches.

Chapter 7 provides an overview of the current state of the tools that can be used for risk-based planning based on the authors’ own experience as well as literature review. The chapter describes four probabilistic transmission planning tools. In addition it also gives an overview of resource adequacy and production costing tools which are further described in Appendix D.

In spite of considerable research in the area of risk-based transmission planning, there are significant barriers to the broad-scale integration of these approaches. Chapter 8 focuses on barriers to adaptation of probabilistic planning for vertically integrated utilities as well as for ISOs and RTOs.

Chapter 9 focuses on how risk-based approaches can help federal and state policy makers gain deeper understanding and make more informed decisions about transmission related policies. The chapter also summarizes efforts in WECC that were initiated in mid-nineties to develop risk-based reliability criteria. Although discontinued, this is an example of how risk-based criteria can be considered in the future by policy makers.

Finally, Chapter 10 provides a new framework that aims to augment the existing deterministic criteria with risk-based approaches. The Chapter concludes that although the industry is not ready to completely transition to risk-based approaches at this stage, these can play an important role in overall decision making process by providing deeper insights as compared to deterministic methods. The chapter also gives recommendations on how states and regions might effectively use risk-based planning in their transmission planning process.

2
Existing Transmission Planning Processes

This Chapter provides an overview of existing transmission planning processes in North America. Note that transmission planning is an involved topic and all the aspects associated with it cannot be covered in one chapter. However, the main objective of this chapter is to highlight the deterministic nature of the current process. This Chapter sets the background for subsequent chapters in this white paper.

2.1 An Overview of Transmission Planning

A detailed discussion of transmission systems and key policy issues associated with transmission planning can be found in the EISPC Transmission Planning White Paper [3]. A brief overview of the process is provided in this section. In addition, a summary of some of the existing planning processes is provided in Appendix A.

2.1.1 Objectives of Transmission Planning

The electric power system is customarily divided into the three main system functions of generation, transmission, and distribution. While transmission generally accounts for only a smaller fraction of total revenues in the electric system value chain, it remains a critical component. Since transmission is what links the generation and distribution system, without transmission neither generation nor distribution would be viable. Generally speaking, transmission systems exist because the generation and load are in different geographic locations and transmission moves power from areas with surplus generation to areas with generation deficits.

The above discussion suggests two general requirements for transmission:

1. Transmission planning must embody generation and loads that are interconnected by it.
2. Availability of transmission is critical for the proper functioning of the generation and distribution systems.

In addition to the general requirement as being a link between generation and load, transmission plays other fundamental roles in interconnected electric power systems. Specifically, it [4]:

- Interconnects generation and load areas using multiple interconnection pathways that form the grid
- Improves reliability by operating as a single, strong, grid
- Helps manage risk by providing access to multiple generation resources
- Reduces energy cost by providing access to diverse generation resources
- Reduces congestion by creating new flow paths and system capacity
- Increases efficiency by reducing line losses
- Facilitates wholesale markets and makes them more competitive and efficient

Thus, in addition to connecting generation to load, transmission lines play key reliability and market functions as depicted in Figure 2-1.

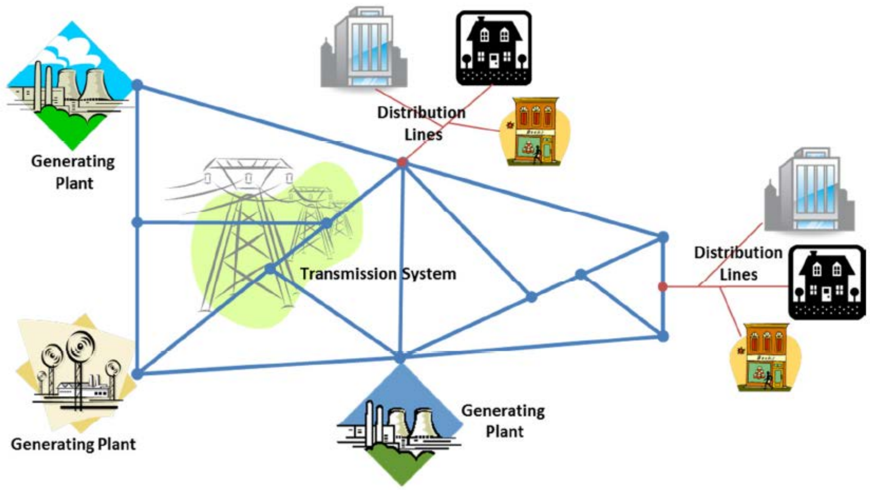

Figure 2-1 Transmission System Representation [3]

There are various overlapping regulatory, jurisdictional and technical issues that bulk power transmission planning needs to satisfy. Under the Federal Power Act, the interstate transmission and wholesale marketing of electric energy by public utilities is regulated by the Federal Electric Reliability Council (FERC). Key transmission related FERC Orders over the last two decades are summarized in Figure 2-2.

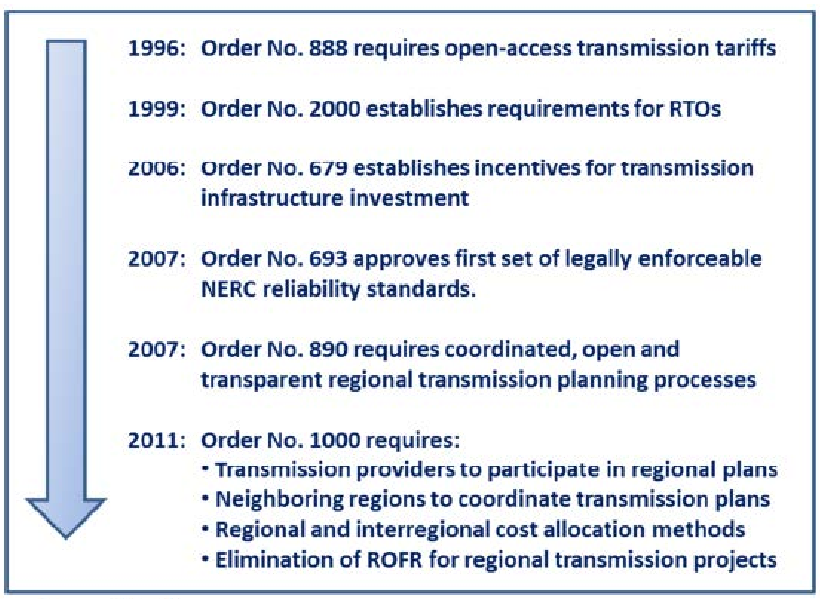

Figure 2-2 Transmission Related FERC Orders [3]

At the heart of these requirements are FERC Order No. 890 that sets nine principles for bulk power transmission planning processes in the U.S., and Order No. 693 that initiated mandatory reliability standards developed by the North American Electric Reliability Corporation (NERC).

Reliability standards are major jurisdictional issues that dictate transmission planning activities and outcomes. Reliability standards, principally those of NERC, and to a lesser extent, those of regional planning groups and local utilities are the dominant factors in transmission planning. In most cases, these are prescriptive and deterministically measured standards that each transmission system is required to meet through agreed upon system studies.

Many other transmission planning issues, such as transmission siting and permitting, wholesale energy marketing, transmission congestion mitigation, etc., are driven by various overlapping, and at times conflicting federal/state/local jurisdiction considerations. Transmission planning entails consideration of and allocation of appropriate time and effort to navigate through these jurisdictional issues.

Technical issues such as transmission parameters, equipment design, system modeling, and study methods, are some of the key considerations in transmission planning. These issues are handled through a combination of standards and accepted industry practices.

Transmission planning is a domain of many entities in the electric power business. The purpose and scope may vary, but these entities range from the traditional utilities, regional transmission planning groups, regional transmission organizations (RTO), independent system operators (ISO), regional reliability entities (RE), public utility commissions, transmission owners, transmission operators, independent transmission developers and many others.

2.1.2 Transmission Planning Time Horizons

For all practical purposes, transmission planning activities exist along a continuum. Starting from day-ahead system security planning and assessment associated with unit-commitment and scheduled or unscheduled transmission and generation outages, to very long-term (30+ years) resource planning and development activities. In this paper, we will classify this planning horizon continuum into three planning time periods: short-term (less than one-year), near-term (1 to 5 years), and long-term (greater than 5 years). For the most part, these classifications are consistent with those of NERC as defined in the NERC Glossary of Terms[2] [5].

One major issue that is a consideration of this whitepaper is the uncertainty associated with key drivers of transmission planning activities. The study period of the transmission planning activity has implications on the uncertainty associated with the parameters involved in that particular planning activity. Generally, the longer the planning horizon, the less certainty there is with the parameters involved in the associated planning considerations. Furthermore, the planning horizon is influenced greatly by the time period required for environmental assessment and permitting of a new transmission projects. Thus, a transmission line that is exposed to a very lengthy environmental process will have a much longer time horizon and much higher uncertainty factors associated with it versus the one with fewer environmental issues. The expected uncertainty as a function of the time horizon is shown in Figure 2-3.

[2] The time horizon definitions that are used in this whitepaper should not be confused with other definitions that may be used in the industry. For instance FERC OATT Pro Forma Tariff defines short-term as “a term of one year or less,” however; long-term is defined as “a term greater than one year.”

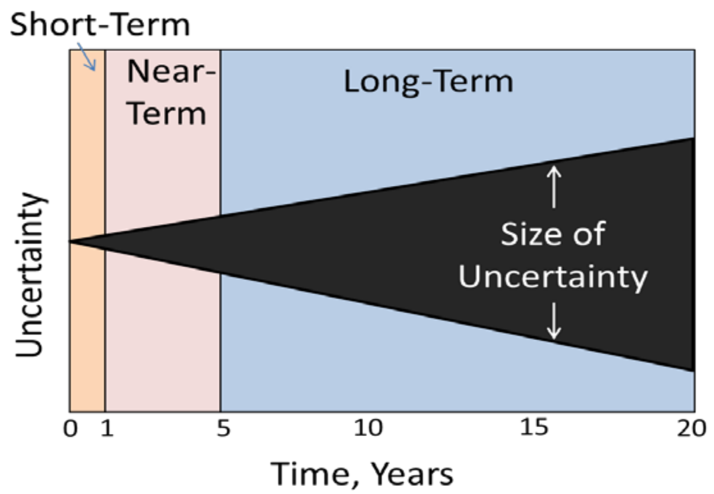

Figure 2-3 Transmission Planning Horizon Uncertainties as a function of time

Not all transmission planners perform the same types of planning activities or approach transmission planning studies the same way. Some typical system planning activities that occur in the three time periods discussed above are listed below:

1. Short-term (1 day to 1 year) Planning (Operational Planning)
    a. Unit Commitment
    b. Transmission/Generation Security Assessments
    c. Transmission Operations Studies
    d. Fuel Planning and Procurement Studies
2. Near-term (1-5 years) Planning
    a. Low-voltage Transmission System Plans
    b. Generator-interconnection Studies
3. Long-term (5-20 years) Planning
    a. Transmission Expansion Studies
    b. 10-year Transmission Assessments
    c. RTO Annual Transmission Plans
    d. Regional Transmission Plans
    e. Integrated Resource Planning

This is only a partial list, and does not include all of the planning activities considered in those time periods.

2.1.3 Overview of the Types of Transmission Plans

Not all of the transmission planning activities discussed in Section 2.1.2 have the same importance. Some of the key transmission planning activities that are performed by utility companies or RTOs are discussed in this section. These are planning activities that are mostly mandated by various governing bodies and include Integrated Resource Plan (IRP), Annual Transmission Assessment, Regional Coordination Transmission Studies, and Generation Interconnection Studies.

Development of an IRP is one of the most important resource planning activities performed in the power system today. Typically mandated by state regulatory agencies, these studies are performed by utility companies to ensure adequate and cost effective generation resources are available to meet future customer demands. Production simulation models with considerations for transmission constraints are the main study tools engaged in these studies. The goal of the IRP is to select a least-cost portfolio plan that incorporates generation, transmission, and Demand-Side Management (DSM) while serving the customer demand to a defined level of adequacy.

Generally, there is no explicitly and objectively defined probabilistic based risk assessment in the IRP assessment process. The key approaches in the IRP include, first the development of various resource portfolios, and then selection of various system scenarios to be assessed as sensitivities within each of the portfolios. As we develop more and better probabilistic methods, there exists an opportunity to work towards risk-based IRP processes. This would be a desired outcome as we bring more supply and demand resources that are highly variable and widely distributed.

NERC planning standards require that transmission planning authorities and planning coordinators conduct an annual transmission planning assessment covering the long-term planning horizon (ten years). Utility companies, RTOs, and regional councils, all conduct 10-year transmission assessment as required by the NERC planning standard TPL-001-4[3].

As required by FERC Orders 890 and 2000, most utility companies and RTOs have to engage in transmission planning activities through some form of coordinated transmission planning processes. Furthermore, during the multi-year development of a major transmission system project, there are specified transmission planning actions that need to be undertaken by the project sponsor to ensure the project is properly planned and designed to provide the maximum benefits to overall interconnected system and minimize impacts to the interconnected system.

Presently, by far, the largest amount of transmission planning effort by utilities is spent in generation interconnection studies. The need for these specialized studies are driven by the very high number of renewable resources that are going through various development and procurement processes in the various regions.

Though the core requirements of the generation interconnection studies are common throughout the electric power industry, there are some subtle differences depending whether the generation is large or small, or the interconnecting utility is investor or publicly owned. The jurisdictional issues are discussed in Chapter 9.

[3] The standard is available on-line at: http://www.nerc.com/files/TPL-001-4.pdf

2.1.4 Steps in Transmission Planning Analyses

Transmission planning involves several but interrelated tasks, including for example regulatory approvals, environmental assessments, and technical system studies. The key transmission planning activity that is the focal subject of this whitepaper is transmission planning analyses or transmission studies. A flow chart depicting this transmission analyses is shown in Figure 2-4.

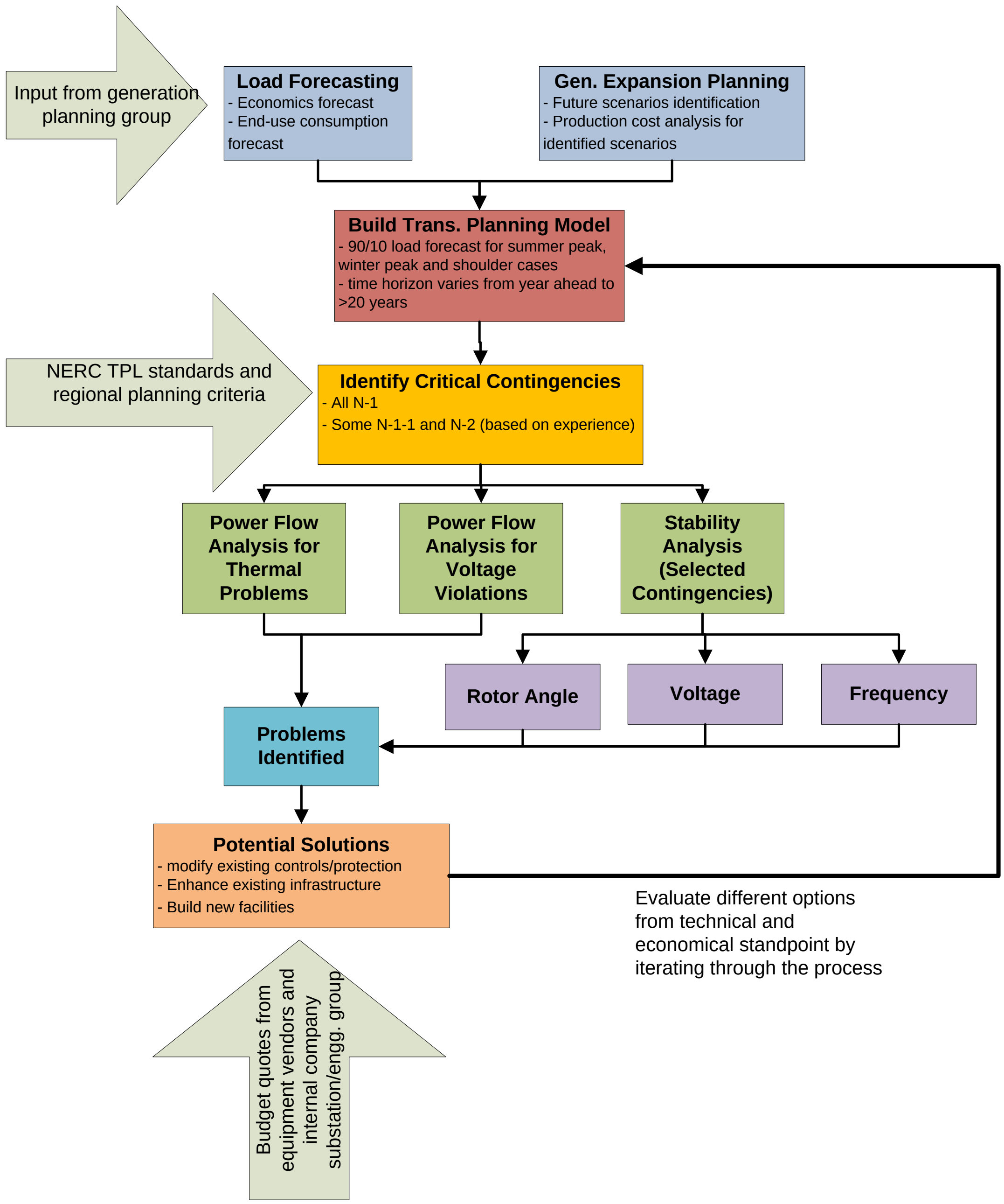

Figure 2-4 Existing Transmission Planning Approach

Two key inputs to the system studies are load forecasting and generation resource data. Combined with the electric network system data these make up the power system base cases. In addition, other data specific to the objectives of the study are used to prepare the study cases. Power flow and transient stability analyses, the most common types of transmission studies, are conducted to assess N-1, N-2 and other outage and disturbance conditions. An overview of various transmission planning analyses is provided in the next sections.

2.1.4.1 Generation Plan and Load Forecasts

As was discussed in Section 2.1.1 transmission planning embodies consideration of both generation and distribution system functions. However, many of the planning activities for the generation and distribution system functions are often performed without full consideration of the transmission system that connects and integrates them. This approach is mainly an artifact of the evolutionary nature of the knowledge base, technical skills, and computer capabilities required to address all of these issues.

The goal of generation resource planning is to systematically determine the amount and type of power generation resources that addresses the utility customers' electricity needs for many years to come. This is based on the historical or legal (regulatory) responsibility of utility companies' "obligation to serve."

The traditional generation resource planning activity is simply ensuring sufficient generation resource capacity is available to meet the most adverse peak load condition in your system while at the same time considering some stringent system event. This in essence is what we call today as "resource adequacy" assessment. The most common industry planning practice is to plan the system to shed firm load obligations less than once every ten years. This is frequently known as the 1 day in 10 years Loss of Load Expectation (LOLE). Resource adequacy is also sometimes measured using the following metrics: Expected Unserved Energy (EUE) and Loss-of-load probability (LOLP).

IRP has been the preferred resource planning process that is advocated by regulatory bodies and utility commissions. In addition to fuel and customer load demand uncertainties, considerations of resource uncertainty associated with wind and solar generation resources or other variable generation resources (VGR) have been incorporated in IRPs.

There are three interrelated resource planning issues with ongoing aggressive VGR development. First, they are not dispatchable with high degree of certainty, unlike the conventional generation of coal, natural gas, nuclear and hydroelectric power, which make-up over 95% of the existing electric power generation in the world. Second, their output is not predictable and there is tremendous uncertainty associated with the generation output of these resources. Third, many of the fixed capacity resources are continuing to give way to renewable resource as they are replaced with renewable resources.

Thus, the ongoing massive VGRs development in the US is introducing an increasing level of uncertainty to the resource planning process.

Load forecasting is one of the oldest planning activities performed by a utility company. Load forecast data is one of the most important building blocks in all of the electric power utility's planning activities. The load forecasting time period exists over a continuum from the immediate to 30 or more years into the future.

There are two key components of load forecasting; energy demand (MWh), and load demand (MW) forecasting. Energy demand is the total daily, weekly, monthly or yearly MWh demand. On the other hand, load or power demand refers to the maximum or peak power (MW) demand and defines certain peak demand condition, such as system summer peak, system winter peak, and substation peak demand.

It is customary to represent the load forecast data as a probability distribution based on historical weather condition such as weather normalized load. Furthermore, load forecast data will be generated for various scenarios, such as normal (50% probability, or 1-in-2) or super peak (90% probability, or 1-in-10).

By far, the customer load data continue to be the source of the major uncertainties associated with utilities' demand side planning activities. Obviously, the shorter timeframe load forecast has much lower uncertainty and the load forecasts are much more accurate than those with longer timeframe as depicted in Figure 2.3.

Also, as we do more to control, manage and/or reduce customer load through incentive programs or by deploying energy efficiency or load shifting devices in the distribution system such as demand response and electric vehicles, the level and nature of uncertainties of the customer load are changing. Sophisticated load forecasting methodologies will be needed to deal with the emerging issues.

2.1.4.2 Transmission Base Case Development

The most common system studies for the transmission planning are power flow and transient stability studies, followed by fault analysis and economic dispatch simulations. Generally, the power system power flow and transient stability mathematical models and input data parameters follow industry standards and they share some common data sets. However, each software program used for the analysis has its own formatting requirements. One of the most onerous tasks of planning studies is the preparation of these system models and data.

The general structure and the standard data sets that describe the initial system condition are called base cases. NERC standards require that electric power industry follow strict guide lines on data collection, security, and accuracy. These standards provide for periodic testing and validation process. Furthermore, each regional council, through internal staffing and through committees and workgroups of its membership provide for a well-organized process of data collection, inter-utility coordination, system model development, and system performance assessment.

One of the initial activities of any system study is the development of a base case or a set of base cases that would be used for the analysis of particular system studies. Base case development is a very systematic and meticulous process mostly dictated by study guidelines agreed upon by industry groups and NERC standards.

Each of the base cases that define certain system conditions may represent a likelihood that the particular scenario will occur. However, in today's system planning activities no quantitative measure of such likelihood is attached to the base case development.

2.1.4.3 Power Flow and Stability Analysis

In most bulk system planning studies, power flow analysis of the steady-state system condition is conducted utilizing standard power flow analysis tool. In these studies, line thermal limits and system voltage levels are assessed for violations from ratings and specified system limits. From the perspective of system reliability, this is a test of system adequacy. Mitigations such as addition of new transmission lines, transformers, or substations, reduction of generation power schedules or addition of voltage support devices to the transmission system may be some of the solutions for violations found in the studies.

In the last decade, a system condition called post-transient voltage instability has been one of the limiting system conditions in bulk power transmission systems, and thus power flow analysis techniques have been developed to assess these voltage instability phenomena. This analysis, sometimes referred to as governor power flow, is now a standard power flow assessment consideration in many regional planning studies [6]. In Figure 2.4, this voltage stability assessment is combined in the voltage violation box.

Stability analysis, depicted in Figure 2.4, is the time-domain based analysis of transient or angular stability of the power system. Transient stability analysis tools, which typically are connected with power flow analysis software, are used to assess the power system stability. From the aspect of system reliability, this is a test of system security or operational reliability.

Depending on the type of issues that need to be addressed, specialized studies are also performed as part of transmission studies. Short-circuit analysis to assess fault currents and circuit breaker ratings are common if large generation and transmission additions or construction of a new substation are involved. In systems where a high-voltage series-compensated transmission line and large steam generating units are closely coupled, frequency or eigenvalue based sub-synchronous analysis is common to assess the electromechanical interactions and to safeguard the integrity of the nearby generating plants.

Today, the whole transmission planning analysis process, which includes base case selection, system event testing, and system analysis are all primarily deterministic in nature. There is very little information on the probability, or likelihood of any of the data associated in transmission planning studies except for some consideration in load forecasting. Furthermore, the standards these study results are compared against to determine their adequacy or security (operational reliability) are deterministic.

Theoretically, one of the most efficient cost allocation methods in the power system can be achieved with risk-based planning. Thus ideally, the goal of the planning process is to fully transform the power system planning process of Figure 2.4 to a risk-based planning. This approach requires the transformation of the each of the processes in Figure 2.4 from deterministic to probabilistic (stochastic) methods. Therefore, defining the contingencies and the analytical processes stochastically would achieve fully integrated risk-based assessment methods.

2.2 Linkage between Resource Planning and Transmission Planning

Even though the responsibility typically resides in two different organizations that are firewalled due to regulatory requirements, generation resource planning and transmission planning are interrelated and highly interdependent processes. For the most part, the goal of any planning process is to provide an optimum resource plan. These resource planning coordination and optimization issues are discussed in this section.

2.2.1 Integrated Planning of Generation and Transmission Resources

For entities that perform IRPs as a normal business practice, such as vertically integrated utilities, the IRP process is the key in providing an effective plan in meeting certain conditions. This planning process not only co-optimizes between generation and transmission resources, but also with other programs including DSM, distribution generation (DG), and other policy considerations. An IRP analysis, utilizing objective as well subjective measures, is expected to result in a least-cost best-fit plan.

2.2.2 Interdependence of Generation and Transmission

The coordination issue of resource supply and transmission planning is driven by the generation and transmission options that are available. Some of the factors that affect this coordination include:

- The overall timeline to plan and construct a high-voltage transmission line is typically much longer (twice or three times) than what is required for a conventional generation plant (with the exception of nuclear).
- Development of a large generation facility most often determines the need and dictates the form of the associated transmission plan.
- Small generation plant developments most often are planned to be in close proximity to existing transmission system in order to leverage the existing transmission system infrastructure.
- Transmission developments that are limited to reliability improvements or economically driven may not necessarily have a co-optimization consideration with any single generation resource.

2.2.3 Co-optimization Opportunities and Challenges

One should not assume that, in discussing co-optimization of generation and transmission resources, the normal transmission planning process is done in absence of generation resource consideration. Generation resources as well as loads are the building blocks of any transmission planning assessment. The base cases that planners develop are heavily influenced by the generation resources and load forecast. The planners evaluate generation contingencies as well as transmission contingencies. The performance tests are equally related to generation, transmission, and load.

One consideration that generally gets in the way of co-optimization is that the FERC Order 889 standard-of-conduct rules that mandate a clear separation of transmission and merchant functions of a power utilities business. These rules prohibit the direct coordination of the resource planning and procurement activities of a utility business with the day-to-day activities of the utilities transmission and bulk power operations. At times the firewall creates an information barrier that impedes legitimate need for co-optimization of generation and transmission resources.

As discussed in 2.2.1, the most common co-optimization based planning process today is the IRP. However, with the complexities of today's power system, having a more robust co-optimization study process would be very beneficial to the industry. To that end, EISPC has issued a white paper titled "Co-optimization of Transmission and Other Supply Resources" [7].

The EISPC co-optimization white paper defines co-optimization as: "*… the simultaneous identification of two or more classes of investment decisions within one optimization strategy.*" The paper proposes a stochastic based generation and transmission expansion plan co-optimization process (GENTEP). The key features of this process are depicted in Figure 2.5.

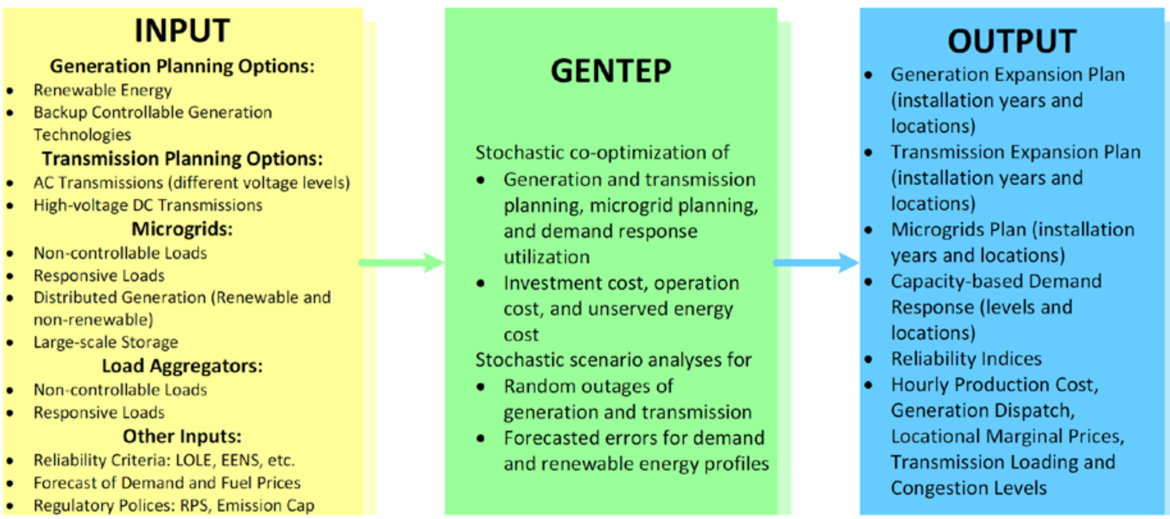

Figure 2-5 GENTEP input, engine and output [7]

2.3 *Transmission System Reliability Evaluation*

The goal of any transmission planning analysis is to evaluate and measure how reliable the power system is for the condition that is being studied. Having this measurement then provides data to compare against criteria or standards. The objective of this section is to describe how reliability impacts of transmission investments are being analyzed and measured at the present time.

2.3.1 System Studies and Reliability Performances

As discussed in Section 2.1.4 the key transmission planning studies are power flow (including governor power flow) and the transient stability studies. The objective of these studies is to evaluate reliability performance of the system being studied. The key task in these studies is to analyze the system reliability performance measures so that they can be compared with the applicable reliability criteria.

There are various system performance measures specified in reliability standards. The primary reliability performance measures are defined by the following three system conditions:

- Thermal Limit: the current that the line conductor can transmit without incurring any permanent damage resulting from the thermal heating of the conductor or failing to maintain minimum clearance to ground

- Voltage Limit: the maximum voltage drop allowed across a transmission line
- Stability Limit: the maximum power that can be delivered without loss of synchronism for gradual load increases or during credible system disturbances

In addition to these primary reliability measures, there are also other secondary measurements used in reliability assessment. These are typically based on specific facility or system condition such as project ratings and special protection systems (SPS).

2.3.2 Compliance with NERC Reliability Standards

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. As the designated Electric Reliability Organization under Section 215 of the Federal Power Act, NERC also assesses penalties when violations occur.

The set of NERC standards consist of over one hundred individual standards that are mandatory to all applicable users, owners, and operators of the electric power system in the United States (Canada and Northern Baja California, Mexico are also part of NERC). The current standards cover 14 areas or families of standards. The most relevant area for transmission planning is the Transmission Planning (TPL) standard. The Facilities Design, Connections, and Maintenance (FAC), and the Modeling, Data, and Analysis (MOD) areas also have some standards that apply to the transmission planning activities [8].

Until 2014, NERC transmission planning standard has been based upon the standards TPL-001, TPL-002, TPL-003 and TPL-004. Over the last several years, NERC has been working to update the TPL standards, and recently has issued a new standard. Among other things, the new updated standard consolidates the original four TPL standards into one TPL-001-4 standard. FERC has approved the changes; however the implementation is spread for two years as follows:

- Requirements R1 and R7 – January 1, 2015
- Requirements R2 through R6 – January 1, 2016

For all practical purposes, in 2015 the original four TPL standards are still in effect. As will be discussed later, the new TPL-001-4 is an expansion or a refinement to the framework of the original TPL standards. Thus, it is important to understand the general framework of the original four TPL standards.

Listed below are the original four transmission planning standards:

- **TPL-001-0.1:** System Performance Under Normal (No Contingency) Conditions (Category A)
- **TPL-002-0b:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- **TPL-003-0b:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

- **TPL-004-0a:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

The top four standards identified as Categories A through D define progressively less probable contingency events but more severe system impact that need to be evaluated in transmission planning studies. The detailed description of these standards is given in reference [8].

The arrangements of the events associated with the categories and the corresponding system impacts are based on a general framework with dimensions or considerations of event likelihood and degree of impact severity. For instance, under a more probable event of Category B (single-element contingency event), the allowed impact severity is minimal (no load curtailment). However, for a less probable event of Category C (two-element contingency event), the allowed impact severity is higher and may include load dropping. Similarly, for the least probable events of Category D (multi-element contingency event), the allowed severity may include cascading outages.

Regardless of the above categorizations, the evaluation is deterministic in nature. To implement probability methods for the Categories A through D, event probability and measurement of the degree of severity need to be provided so that expected values can be calculated.

For illustration purposes and to have a visual view of the NERC transmission planning standards framework, a graphical representation of the NERC TPL-001 through TPL-004 are shown in Figure 2-6. Some generic descriptions are used to identify the various contingency events and the performance impacts. For instance, “N-0” stands for “no element out” or “all facilities in-service”, “N-1” stands “loss of single element,” etc. The shaded area is considered standard violations area while the non-shaded area is where standard is met.

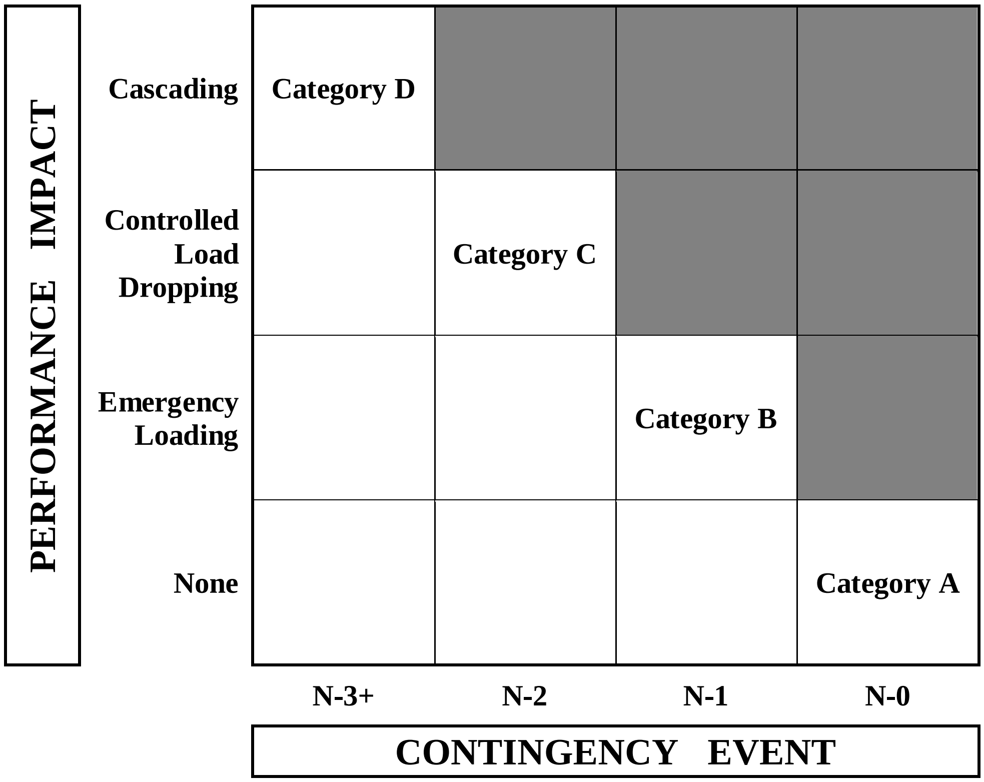

Figure 2-6 Mapping of the Original NERC TPL Standard in Reliability Framework

Close examination of the NERC performance table shows some key distinctions on how the allowed system impact performance is defined for Categories A through C verses that for Category D. For Categories A through C, the standard requires a clear test of pass/no pass for thermal, voltage and stability conditions as well as control customer load dropping. These are deterministic assessments within each of the categories.

For the Category D definition, the standard requires that the system planer to "[e]valuate for risks and consequences." The risks and consequences are associated with the very low probability events but with very severe impacts that may include system instability and cascading. This is one of the unique areas where the standard recognizes the need to conduct risk-based assessment. However, qualitative risk assessment rather than quantitative risk assessment is sufficient to meet the requirement for the standard.

2.3.2.1 Contingency Categories in TPL-001-4

Listed below are the new TPL-001-004 standard categories and applicable initial conditions:

- **P0:** No contingency- Normal system
- **P1:** Single contingency - Normal System
- **P2:** Single contingency (Internal breaker or bus section fault) - Normal System

- **P3:** Multiple contingency - Loss of generator unit followed by system adjustments
- **P4:** Multiple contingency (Fault plus stuck breaker) - Normal System
- **P5:** Multiple contingency (Fault plus relay failure to operate) - Normal System
- **P6:** Multiple contingency (Two overlapping singles) - Loss of a line or shut device followed by system adjustments
- **P7:** Multiple contingency (Common Structure) - Normal System
- **Extreme Events:** Multiple contingency with multiple elements outages, and local or wide area events affecting the Transmission System and others not covered by P0 to P7.

The detailed description of these standards is given in reference [8]. As it was mentioned earlier, these categories are an expansion or refinements to the original TPL standard framework.

Comparing the contingency categories of the original TPL standards to the new TPL standards, we find that:

- Category A is changed to Category P0
- Categories B and C are changed to Categories P1 through P7. (Roughly, P1-P3 can be mapped to Category B, and the rest to Category C, with the exception of events association with bus-section)
- Category D is changed to Extreme Events

In view of the reliability framework illustration of Figure 2-6, the new TPL standard is the expansion or refinement of the dimensions of the framework, from say 4X4 to, perhaps, 8X8 matrix. This is recognition of the fact that decomposing the likelihood of occurrence of the various types of events (event probabilities) and their associated impact severities into smaller categories is desirable and will give more accurate representation of the stochastic nature of the power system events.

2.3.3 Regional Planning Groups, RTOs and Local Utility Standards

It is common that the regional planning groups, RTO and local utilities publish reliability standards that they or their members will adhere to. These standards are most often simply a restatement of the NERC planning standards. However, some entities will publish standards unique to their system, or standards that are more stringent than the NERC standards.

2.4 Transmission System Economic Evaluation

Ultimately, transmission planning leads to a decision to construct or modify certain transmission systems and thus a major investment decision. All major utility investment decisions need to be supported through economic evaluations with clear justifications for the recommended plan.

2.4.1 Production Simulation Studies in Integrated Resource Planning

One of the key assessment tools in the IRP process is production simulation using unit commitment and economic dispatch models. Production simulation is a process whereby the least-cost energy and, in certain circumstances, ancillary system costs can be chronologically calculated for every increment of scheduling time (typically hourly) for periods up to many years in the future. This process establishes the commitment and dispatch status of each resource at each of those intervals. Using unit characteristics and fuel prices, the total production cost (which includes fuel and all other variable costs) can be calculated for each hour of the simulation period. Using the hourly production costs, annual and other present cost analyses are possible by discounting for time value of money.

Today's production simulation programs are designed to solve and incorporate complex system issues including: transmission congestion and losses, integration of variable generation, hydroelectric power storage constraints, ancillary service procurement and provision, emission and other environment costs, forced and scheduled outages of generation, and others. Some programs include capabilities to perform simplified power flow assessment, such as DC power flow, to incorporate effects of transmission limitations and provide locational marginal pricing (LMP) information.

Economic dispatch modeling is primarily deterministic in nature. Expected values for major uncertainties such as forced outage rates, fuel prices, and load are used to develop system production cost estimates. Investment decisions are typically made using only these deterministic estimates. Many available software programs provide risk assessment capabilities. However, the process for developing inputs, managing simulations, and applying the results of risk-based economic evaluations is often cumbersome and ill-defined. A list of common economic dispatch models is provided in Appendix D.

2.4.2 Economic Analysis in Long-Term Transmission Planning

The focus of regional transmission planning groups is strictly development of transmission lines and assessment of transmission alternatives. However, such evaluations would normally require making some assumptions on the generation resources that are required or expected to load the transmission lines so that proper assessment can be made. To that effect, regional transmission planning groups, spend significant effort in projections of potential generation development areas or zones. In large regional transmission planning studies, the production cost information is important in providing regional group members and policymakers information on the comparative importance of alternative transmission plans. At the same time, since the planning and construction time line for transmission lines is much longer than that required by the development of generation, it provides a proactive look at the transmission need of the region.

In addition to the production simulation cost analysis, the transmission project development and capital costs must be considered. Net Present Value (NPV) Costs of the alternative transmission projects are calculated using simple economic models.

2.5 Conclusions

Transmission planning entails identification and determination of the transmission solutions of a power system. Generally, the current transmission planning process is based on deterministic methods. An overview of the existing planning process is provided in this Chapter to establish a good understanding of the current process so that enhancements and advanced methods can be discussed and offered in subsequent Chapters. Some general conclusions of this Chapter include:

- Transmission planning should consider both generation and demand including demand-side resources.
- Transmission planning is governed by various overlapping regulatory, jurisdictional and technical issues.
- An extensive body of transmission planning studies and assessments are conducted to facilitate the proper functioning of the electric power business.
- It is essential that the expanding nature of uncertainties with the length of the planning time horizons, (short-, near- and long-term) should be recognized in planning studies.
- The existing planning process offers some optimization capabilities, however it is recognized that more robust optimization methods are desired.
- The existing planning process is limited to power flow and transient stability assessments using deterministic methods.
- Current NERC standards use rule-based deterministic criteria.

3
Uncertainties and Risk Impacting Transmission Planning

An overview of the transmission planning process and its deterministic nature was provided in Chapter 2. Transmission planning, like most engineering disciplines, is not an exact science and cannot be perceived as a binary or black and white process. The purpose of this Chapter is to provide a detailed discussion of various risks and uncertainties that can have a significant impact on transmission planning process.

3.1 Definitions of Key Terms

3.1.1 Uncertainty

In statistics, uncertainty is defined as a situation where neither the probability distribution nor the most frequently occurring value (also referred as mode) is known. As described later, one example related to power systems is various renewable portfolio standards (RPS) that might be enacted by federal, state, and local authorities. It is not conceivable to put a quantitative probability distribution for this problem. However, it is possible to use subjective judgment based on subject knowledge or expertise to come up with a set of possible outcomes. Thus a planner can assume different scenarios for how a RPS might be shaped in future.

3.1.2 Risk

A dictionary definition of risk is “the probability of loss or damage to human beings and assets.” Although this is a general definition, it is important to recognize that risk not only recognizes likelihood of an undesirable event but also the consequences of the event. Thus risk can be quantified as the product of probability of an undesirable event and consequences of that event. Therefore risk can fundamentally be determined only if we can assign some form of probability to an event. An example in power system can be dispatch of renewable generation. Although we cannot determine the exact renewable generation output for the next hour or 24 hours from now, we can use statistical models to come up with probabilistic outcomes. Another illustration is the risk associated with contingencies in power systems. Although one cannot say with certainty that a contingency will happen, one can come up with a probability of a contingency occurring based on historical performance of components involved. Consequences of that contingency occurring in terms of customer load loss (either in energy not served or a dollar figure) can also be determined. In the end, risk associated with that contingency can be quantified as the product of probability times the consequences.

Note that deterministic or certainty analysis is a special case of risk analysis where we assume probability to be 1 i.e. we are assume that the event will happen with certainty.

3.1.3 Reliability

Reliability is defined as the probability that a product or service will operate properly for a specified period of time (usually design life) under the designed operating conditions. Reliability is thus a measure of the system's success in providing its function properly [9].

Reliability can be expressed in terms of risk. Higher risk implies lower reliability and vice-versa.

Although the focus of these research efforts is on reliability considerations in transmission planning using probabilistic approaches, it is critical to understand that there are many factors outside of transmission planning arena that directly influence planning decisions (these were mentioned in the Introduction Chapter and are described in details in this Chapter). Considering these factors is imperative in developing credible planning scenarios for reliability analysis. Unfortunately, many of these external factors are very difficult to quantify and analyze in a simplistic model because of their uncertain and variable nature which makes transmission planning quite a challenging task. This is an area of active research for EPRI and other research organizations.

3.2 Decision Criteria

Decision theory deals with a process of selecting the best or optimum solutions taking into consideration the uncertainties and preferences associated with the input information. The transmission planning process has similar fundamental properties as to what a decision theory tries to address. Principally, transmission planning is a process of selecting the best or an optimum transmission plan taking into consideration the input parameters that contain substantial uncertainties.

Generally, decision making is divided into three categories based on the nature of factors influencing the decision. These categories are:

- Decision under Certainty
- Decision under Risk (or quantifiable uncertainty)
- Decision under Uncertainty (or non-quantifiable uncertainty)

These three decision criteria are shown in Figure 3-1 and discussed in the following sections.

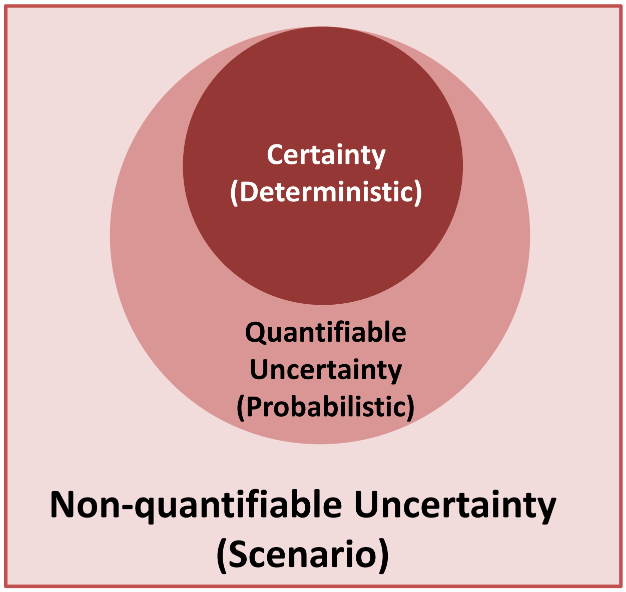

Figure 3-1 Decision Theory Application in Transmission Planning

3.2.1 Decision under Certainty

Decision under certainty, is when a decision is being made with perfect knowledge of the input parameters that are needed to make the decision. With perfect knowledge of the input parameters, including perfect knowledge of the relationship between the inputs and the output, we are guaranteed a definitively known outcome that is an optimum solution. This is a deterministic method and is a special case of decision under risk described next.

3.2.2 Decision under Risk

This category refers to the analysis when a decision is made with input parameters that are defined with probability distribution functions. These input variables may be termed as “quantifiable uncertainty” variables. With probabilistically defined input parameters, the outcome is also defined probabilistically, even with a perfect knowledge of the relationship between the inputs and output. Decision under quantifiable uncertainty variables is sometimes called “insurable risk” or “objective probability.” This is a probabilistic method. Note that for quantifiable variables, risk can be computed as:

Risk = Probability × Consequence

Where the probability of the outcome can be computed based on a probability distribution and the consequences can be estimated in terms of loss of dollars or some other form. Decision making for quantifiable variables is referred to as “decision under risk” or “decision under quantifiable uncertainty.”

3.2.3 Decision under Uncertainty

This category refers to the analysis when a decision is being made with input data such that we have no knowledge of their quantitative value or have no probability distribution functions defining them. These input variables may be termed as “non-quantifiable uncertainty” variables. With unknown values of the input parameters, the outcome is also unknown, even with a perfect knowledge of the relationship between the inputs and output. In decision theory, this is called Knightian uncertainty, attributing to Frank Knight, who originally proposed this concept in 1921 [10, 11, 12]. Decision under non-quantifiable uncertainty variables is sometimes called “uninsurable risk” or “subjective probability.” Decision making for non-quantifiable uncertainty variables is also referred as “decision under uncertainty.”

Appendix B gives three simple examples that clearly elucidate the three decision criteria.

The best analysis process to deal with uncertainty is often associated with “scenario analysis.” In scenario analysis, we select several data points to represent the uncertainty conditions and determine the outcome of those scenarios. Then, we make judgments, or using some preference selection criteria (subjective probability) we select the outcome or outcomes we prefer to be the solution to the problem.

In power systems, we are always dealing with issues that span all of these three categories. However, no analysis framework exists today that tries to solve the problem systematically by recognizing these three distinct features to arrive at the proper solutions. The traditional approach is to treat all uncertainties as Category 1 problems (i.e. decision under certainty) and try to solve them with deterministic methods. The objective of the whitepaper is to discuss these issues and proper solution techniques to address decision process under risk and decision process under uncertainty.

As discussed above, all studies that planners perform have inputs that cover the span of certainty to non-quantifiable uncertainty to one degree or another. The optimum approach to decision making would be to perform analysis which captures all known risk distributions, and to the extent possible assign probabilities to various uncertainty-based scenarios. Then the optimum plan would be the plan which provides the lowest weighted average system cost. The selected plan may further reflect some subjective risk adjustment where plans with higher risk or higher uncertainty are given lower weight. However, most studies do not use all available risk distributions or even attempt to cover the range of identified uncertainty. We have noted a number of reasons that Probabilistic Reliability Approaches (PRA) have not frequently been used, but the following sections will address a particular complaint about why it is not used: that the distribution of many risk and uncertainty variables cannot be known with much confidence. While this is a valid critique in many cases, the risk distributions of a number of variables can be known with reasonable confidence and could be used in meaningful PRA.

Questions that are frequently asked with respect to the validity of risk and uncertainty distributions include:

- Can planners reliably assess the likelihood of natural gas prices rising or falling?
- Is there enough information to predict the likelihood of load growing faster than expected or slower than expected?
- Will future generator and transmission component performance exhibit similar characteristics to its historical performance?
- Can the range of possible weather conditions be known with any certainty?
- Are the shapes of renewable production profiles known and can the magnitude of future renewable capacity be known with adequate confidence?
- What is the likelihood that regulatory changes or technology improvements will force a radical shift in resource mixes?

An overview of various factors impacting transmission planning is provided in Table 3-1. These factors are explained in more detail in the next few sections. It must be noted that it is possible that some input variables in the transmission planning process can be categorized under "risk (i.e. quantifiable uncertainties)" as well as "uncertainty (i.e. non-quantifiable uncertainties)" by assigning probabilities based on subjective judgment. For example, a planner can assign a certain probability to each scenario that is developed based on his perception rather than a mathematical model. Therefore there could be some fuzziness in the boundaries of the circles shown in the schematic in Figure 3-1.

Table 3-1 An Overview of Factors Influencing Transmission Planning

Factor Number	Variable Influencing Transmission Planning	How is it considered?	Where is it considered in planning process?
1	Changes in regulatory policies – federal, state, and local	Scenario modeling	Resource adequacy planning
2	Changing supply- and demand-side resources	Scenario modeling	Resource adequacy planning
	• Penetration of renewable generation		
	• Fossil plant retirements		
	• Nuclear policy		
	• Penetration of demand-side resources		
3	Long-term economic activities and growth	Scenario modeling	Resource adequacy planning
4	Population movements and growth	Scenario modeling	Resource adequacy planning
5	Long-term fuel price variation	Scenario modeling	Resource adequacy planning
6	Technology improvements	Scenario modeling	Resource adequacy planning
	• Demand-side technologies – electric vehicles, demand response		
	• Energy storage		
	• Carbon capture and potentially other technologies		
7	Weather related variability	Probabilistic modeling	Transmission planning
	• Temporal variation renewable generation		
	• Temporal variation in system loads		
	• Temporal variation in hydro output		
8	Performance of generation and transmission components	Probabilistic modeling	Transmission planning

3.3 Consideration of Subjective or Non-Quantifiable Factors Impacting Transmission Planning

The first six factors in Table 3-1 cannot be represented using probabilistic models and fall under “decision under uncertainty” category. As mentioned earlier, uncertainties cannot be quantitatively captured (at least not easily) in a mathematical model or probability distribution. For example, it is difficult to develop a probability distribution around possible federal regulations or the long term generation mix. Therefore the most common approach is to define a set of deterministic future scenarios by varying key inputs and analyzing the subsequent planning evaluation results relative to the sensitivity to the key future variables. In most of the vertically integrated utilities and ISOs, these scenarios are generated by the resource adequacy planning group. A more detailed description of the uncertainties is provided in the next few sections.

3.3.1 Changes in Federal, State, Local Regulatory Policies

The environmental and regulatory uncertainty component of system planning is typically considered to have both reliability and economic impacts. Environmental legislation can expedite generation retirements which can potentially affect reliability adversely. Legislation can also impose constraints on the operation of generating facilities which can affect reliability. Many environmental policies also impose economic penalties in the form of taxes on emissions or the requirement of emissions reductions through allowance markets.

Once regulatory policies are ratified, the reliability impact can typically be clearly identified and often can be at least partially mitigated. However, even if legislation has been finalized, the economic impact can still carry significant uncertainty. In environments where allowance markets have been utilized to reduce emissions, the supply and demand balance can vary widely, especially early in implementation, resulting in significant swings in the price of allowances.

The consideration of environmental legislation risk is most often performed using discrete scenarios without assigning probabilities. While the likelihood of more extreme scenarios is recognized as being less likely, this recognition is only qualitative. The integration of environmental risk into resource planning decisions is most often left to subjective judgment.

Given that legislation generally allows for adequate time to adjust plans after ratification, the question remains as to what extent alternate environmental scenarios should be considered in setting expansion plans.

3.3.2 Economic Growth

A significant component of load uncertainty is related to economic growth. Generation and transmission assets require very long lead-times for construction. The economic growth uncertainty is an important component of determining whether expansion plans were optimal. If load grows over a 5 year period by 1% slower than forecast each year, new generation or transmission assets constructed to accommodate the load growth that did not materialize may be economically inefficient. The likelihood of forecast error of such magnitude is important to consider. Using historical Congressional Budget Office forecast and actual data, the forecast accuracy of Gross Domestic Product growth can be assessed. After correlating the GDP forecast error with electric load forecast error, a distribution of load forecast uncertainty can be developed. An illustration of economic growth related uncertainty is shown in Figure 3-2.

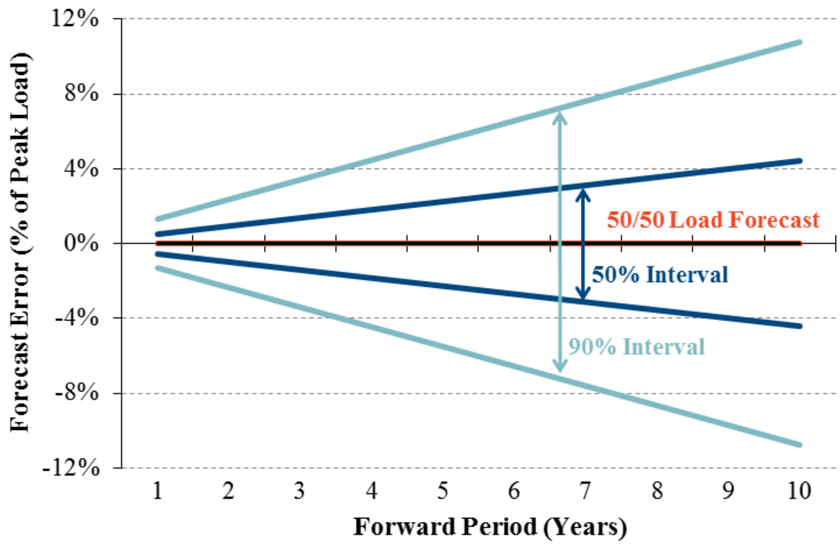

Figure 3-2 Economic Growth Related Uncertainty

As described above, probabilities can be defined for economic growth scenarios using historical growth forecast error. An important reason to consider economic growth uncertainty is that its impacts are asymmetrical; faster economic growth can have a larger impact on reliability and economics than slower economic growth would have in the opposite direction. While planners in the US have consistently over-forecast economic -related load growth for the past decade or more, that condition is not likely to be permanent.

3.3.3 Long-Term Fuel Price Variation

System production costs are highly dependent on fuel prices. While some fuel types exhibit stable pricing, natural gas and some coal prices can fluctuate significantly. While creating a range of realistic fuel price outcomes (and assigning probabilities to those outcomes) is certainly challenging, there are at least two generally accepted approaches for constructing multiple scenarios of forward price curves. First, option pricing theory allows for distributional forecasts using the historical volatility and current forward prices. Second, fundamental analysis performed by utilities, government entities, and consulting firms considers long-term trends in fuel production and fuel demand as well as factors such as regulatory environments and technology improvements. An example of natural gas price forecasts produced by the EIA incorporating a range of potential outcomes on multiple fundamental drivers is shown in Figure 3-3.

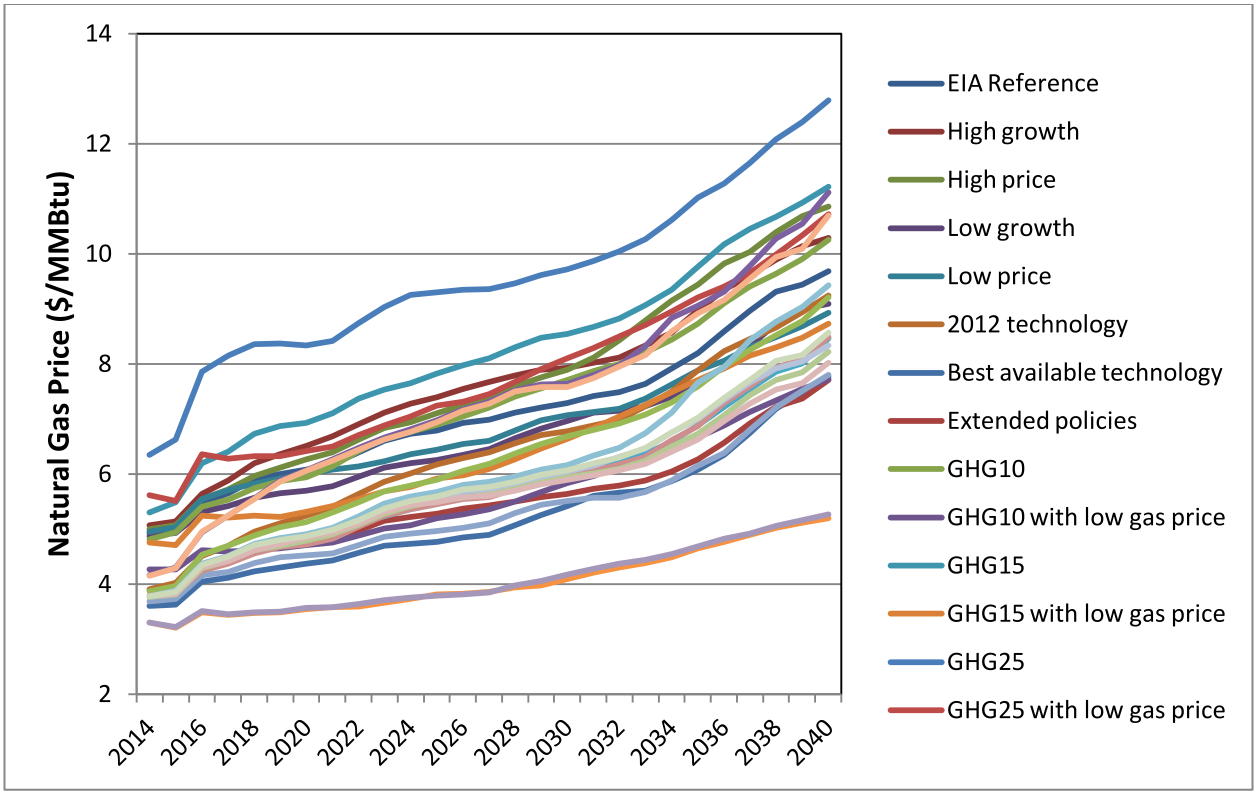

Figure 3-3 An Example of Natural Gas Price Forecast[4]

Typically, fundamental forecasts do not assess the likelihood or assign discrete probabilities to the various trajectories which can make incorporation of alternate fuel scenarios in risk based planning a challenge.

3.3.4 Technology Advancements

Technology advancements are beginning to fundamentally change the nature of power systems in some regions of the country. The technology advances that can significantly impact the future of the power system include distributed energy resources (DER) such as small natural gas-fueled generators, combined heat and power plants, electricity storage, demand response and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system [13]. These technological advances will require careful assessment of the costs and opportunities moving forward. For example, the past 20 years have seen a rapid decline in the price of photovoltaic installations. In some regions in the US, photovoltaic is approaching grid-parity even without government subsidies. If this trend continues, how will resource mixes change? How will generation dispatch change? What will be the impacts on the transmission grid?

The question for planners with respect to technology improvements - whether in photovoltaic technologies or others - is “is there incremental value to be gained by analyzing a range of possible scenarios versus simply analyzing a point forecast?” If a planner's point forecast assumes 5% annual

[4] U.S. Energy Information Administration’s *Annual Energy Outlook 2014* (AEO2014)

price declines in solar PV installations, what is the value in assessing the possibility of 10% or more annual price declines? Similar to the conclusion drawn with respect to economic growth uncertainty, the symmetry of the impact distribution is important. Will larger than expected price declines have a larger impact than smaller than expected price declines? Even if the probability of larger or smaller price declines cannot be known with confidence, if the distribution of impact is significantly asymmetric, analysis may be justified on alternative scenarios. With respect to photovoltaic technologies, extremely rapid price declines may result in stranded costs in other generation assets. If photovoltaic projects are installed because they are justified on an energy value basis alone, reserve margins may exceed targets, making other capacity resources less valuable. Further, significant penetration of non-dispatchable resources such as photovoltaics entails potential reliability risk. Solar output is non-dispatchable and has significant volatility and variability affecting the generation, transmission, and potentially distribution systems.

Technology improvement uncertainty can typically be handled well in the context of vertically integrated utilities because centralized planning allows for consideration of the side effects of higher penetrations of a particular class of resource. However, in structured markets the penetration of particular classes of resources can change substantially without much intervention from planners. While interconnection agreements are required for utility scale projects, behind-the-meter installations are exempt and can have a significant impact on generation dispatch patterns. Further, interconnection studies will not be able to assess the global impact of large scale changes to the generation mix.

3.3.5 Changing Generation Mix

As mentioned in [14], “North America’s resource mix is undergoing a significant transformation at an accelerated pace with ongoing retirements of fossil-fired and nuclear capacity and growth in natural gas, wind, and solar resources.” This shift is mainly driven by factors considered in sections 3.3.1 through 3.3.4.

For example, in Figure 3-4, the future generation mix was modeled out to 2040 to determine how different assumptions about gas prices can have an impact on the build-out of new generation and the subsequent mix of fuels used to meet energy demand. It can be seen that, in the other scenario (referred as “Hi TRR” scenario), lower gas prices result in a far greater build-out and utilization of natural gas, with less nuclear and wind generation being built and used. This is just one potential outcome, based on varying only fuel price; in reality, there are a large amount of potential factors that could changes this mix as discussed above.

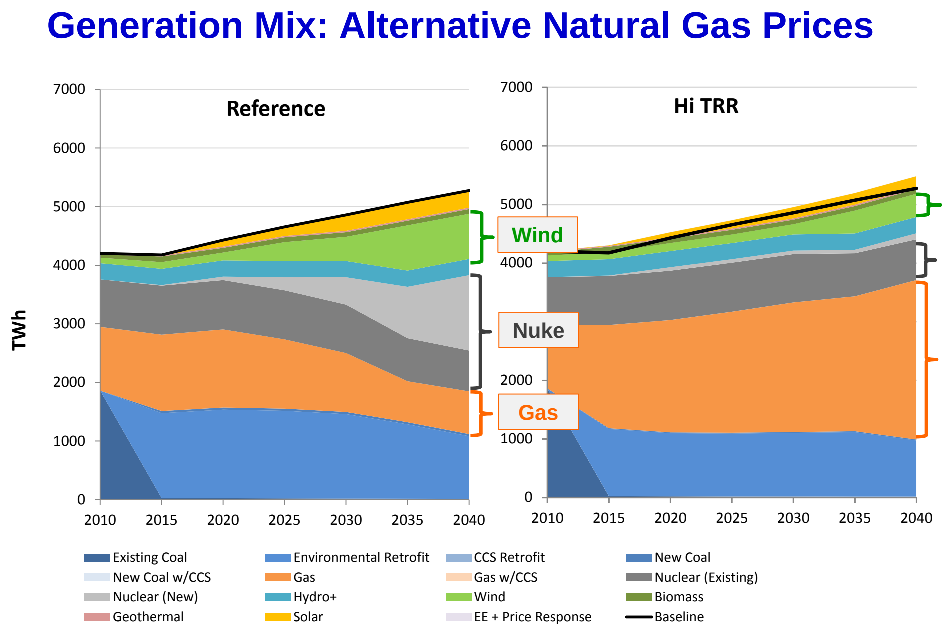

Figure 3-4 An Example of Two Future Generation Mix Scenarios

3.4 Industry Examples for Modeling Uncertainties

A summary of subjective or non-quantifiable factors impacting transmission planning was given in section 3.3. As mentioned before, these factors fall under the "decision under uncertainty" category for which we have no knowledge of the quantitative value of their consequences or have no probability distribution functions defining them. The most common approach to deal with uncertainties is what is referred as "scenario analysis" i.e. utilities or ISOs develop scenarios (also referred as "futures") based on inputs from various regulatory and stakeholder groups. Each one of the scenarios or futures represents a combination of assumptions about uncertainties. A subjective probability can be assigned to each scenario if desired. Subsequently the results are combined by using the probability of each scenario. This provides a probability distribution function of the outcomes of the analysis.

Scenario based analysis is practical in the sense that once the scenarios have been defined, the computations are tractable and the results can be presented and understood well. The criticism of the scenario based approach is the question whether a small number of discrete scenarios can capture the uncertainty of the various parameters affecting the planning process. Because of these shortcomings the results have to be interpreted by the planner.

One of the most well-known scenario development processes is the one that Midcontinent Independent System Operator (MISO) has developed as part of its Market Efficiency Planning Study (MEPS) for transmission planning process [15]. As part of MEPS 2013 study, four future scenarios were developed:

1. Business as Usual (BAU): Status quo environment that assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for renewable mandates and little or no change in environmental legislation.

2. Historical Growth (HG): Status quo environment, but assumes a quicker recovery from the economic downturn and a return to historic demand and energy growth rates. This scenario uses existing standards for renewable mandates and predicts little or no change in environmental legislation.
3. Limited Growth (LG): The Limited Growth future models a future with low demand and energy growth rates due to a very slow economic recovery. This can be considered a low side variation of the BAU future.
4. Combined Policy (COMBO): Combines impacts of multiple policy scenarios into one future with medium demand and high energy growth rates. This includes a Federal RPS, increased coal retirements, and increased smart grid and electric vehicle penetrations.

In defining these scenarios, the study team used the estimates shown in Table 3-2 of various uncertainties (each column except the last in the table).Also, a planning horizon of 20 years was assumed.

Table 3-2 Assumptions in Building MISO Scenarios - 2013

Scenario	Gas Price ($/MMBtu)	EPA Retirements (GW)	Effective Demand Growth Rate	Effective Energy Growth Rate	RPS Mandates	Weight
BAU	$4.25	12.6	0.67%	1.12%	State	37%
HG	$4.25	12.6	1.43%	2.00%	State	19%
LG	$4.25	12.6	-0.25%	0.11%	State	28%
COMBO	$8.00	23.0	0.5%	1.905	Federal (20% by 2025)	16%

It is interesting to note that MISO assigned a weighting factor (or probability) for each future. This was based on subjective judgment of the involved parties and not on any quantitative analysis.

Some other notable examples of scenario development are:

- Eastern Wind Integration and Transmission Study (EWITS) [16]
- Eastern Interconnection Planning Collaborative (EIPC) [17]

Research is being performed to develop enhanced approaches to come up with future scenarios [18]. However, these approaches have not been used on practical planning applications.

3.5 Consideration of Quantifiable Uncertainties or Objective Probability Factors Impacting Transmission Planning

As mentioned in section 3.2, there are some factors which impact the transmission planning process that can be quantified using mathematical concepts, specifically probability theory. These include:

1. Hourly/daily/seasonal variations in renewable generation output levels
2. Hourly/daily/seasonal variations in load level due to weather and changing nature of loads
3. Daily/seasonal variations in hydro generation (energy limited)
4. Generation and transmission equipment performance

As mentioned earlier, for these factors, risk can be calculated as Probability × Consequence

The most common approach to dealing with risk variables is to treat them as certain inputs and simplify analyses. Thus transmission planners come up with a number of load and generation dispatch cases. Typical cases considered by planners are peak and off-peak hour cases for summer, winter, fall and spring seasons. Reliability of each planning case is then analyzed using deterministic approaches. Determining these scenarios is increasingly more difficult with ever increasing penetration of renewable generation, spikes in extreme weather (for example unusually cold weather that gripped the US in early January of 2014), and changing load shapes due to demand response. Further complicating the representation of appropriate dispatch scenarios across these uncertainties is the inherent correlation between many of them (e.g., correlation between load levels due to weather patterns that also may impact wind/PV output and water availability).

Note that probabilistic models for risk variables are developed using historical data. Probabilistic models can be built using historical hourly (or some other time interval) data for load, renewable generation, demand response, and hydro availability. Historical performance is used to come up with failure rate per year and mean time to repair for generation and transmission components. These outage statistics are used in various risk-based techniques which are covered in Chapter 5.

A brief description of some of the quantifiable factors is provided in the next section.

3.5.1 Weather Related Load Variation

Impact on load and generation mix due to economic, regulatory and technology cost uncertainty was discussed in section 3.3.2. In this section we focus on weather related variations in system load. Most systems are planned to a peak load which assumes weather conditions from an average annual peak period. This load is considered “normal peak load”. This means that a system could experience higher load if weather conditions are more extreme than during a normal year, or the system could experience lower load if weather conditions are less extreme than during a normal year. Using the weather data from historical years, the magnitude and frequency of extreme loads can be predicted. Figure 3-5 illustrates what the peak load may be in a future year if the same weather conditions from a historical year occurred again, assuming the factors driving load profiles remain the same (e.g. consumers use electricity in the same way). This illustrates that in the mildest year, the peak load may be 12% below normal[5], and in the most extreme year the peak load may be >8% higher than normal.

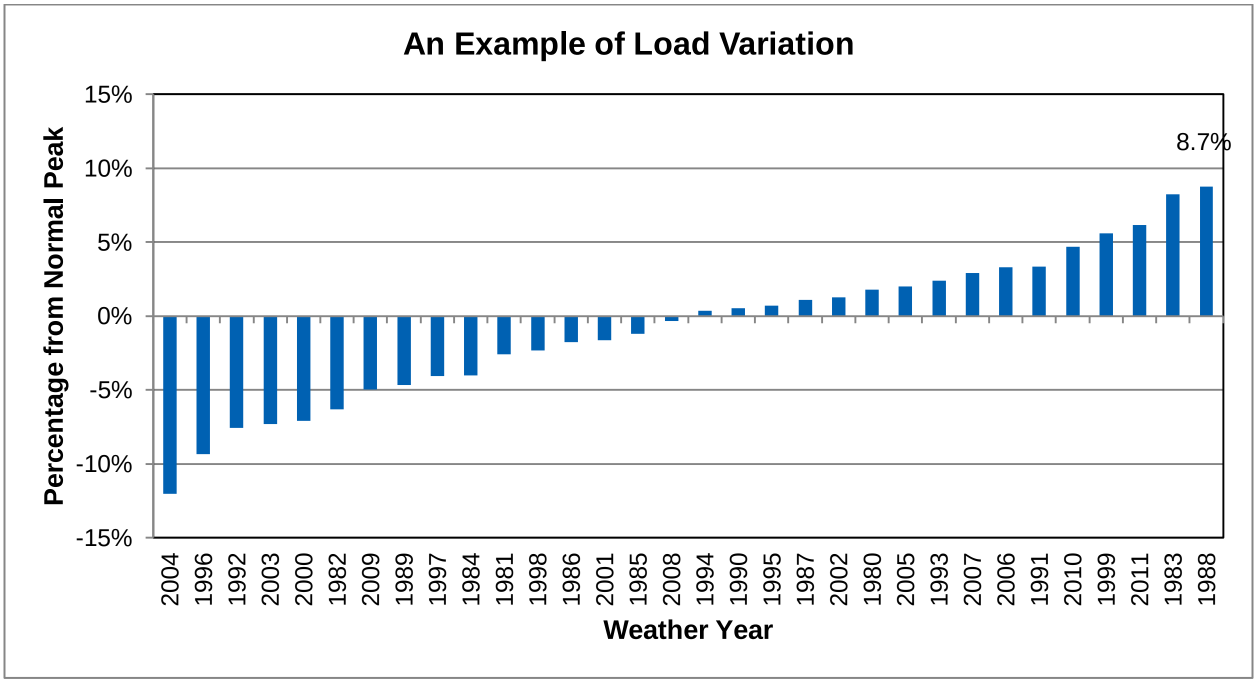

Figure 3-5 Weather Related Load Variability

Since most transmission planning processes only consider average peak load, the load conditions in half of all weather years could be unexamined as seen in Figure 3-5.While peak load conditions are generally considered under reliability planning, the range in peak load conditions can also have a substantial impact on system economics. Market prices respond asymmetrically to weather variation. Extremely hot weather can raise prices by much more than mild weather can depress prices. To the extent that extreme weather persists and consumers are subject to market price risk, annual consumer costs can vary widely from year to year. The persistent nature of weather conditions can be seen in Figure 3-6. Some years, peak loads occur with much higher frequency (red curve) than in other years (blue curve).

[5] Normal peak is defined in this context as the average annual peak load across all synthetic shapes. This should reflect the peak load in a year in which peak temperatures are equal to the long-term average peak temperatures.

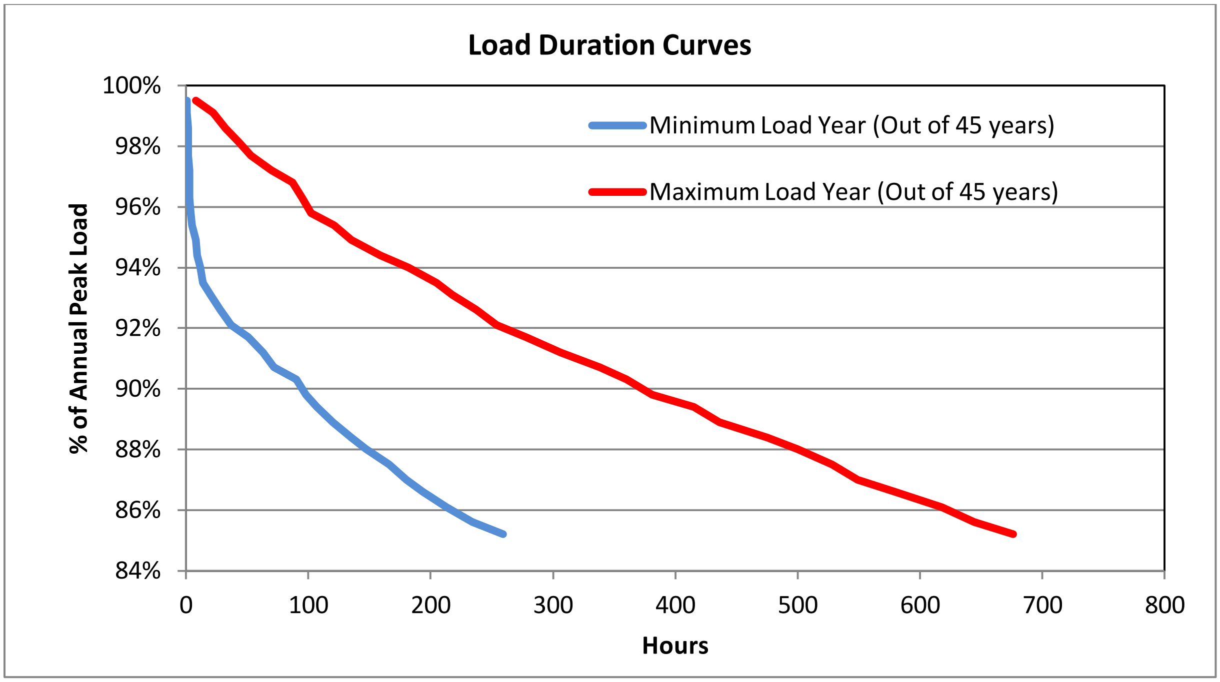

Figure 3-6 Impact of Weather on Load Duration Curve

Variation in load due to weather is well understood and highly predictable. Neural network models are frequently used to construct relationships between weather and load, and are statistically very robust.

3.5.2 Renewable Generation Output Variation

The NERC Integration of Variable Generation Task force (IVGTF) Task 1.6 report on probabilistic methods [19] has identified that renewable generation (mainly wind and PV presently) is characterized with variability that is at least one order of magnitude greater than variability that the power industry had to cope with in the past (for example uncertainty from load variations). Figure 3-7 is an example in the NERC IVGTF report [20] showing the total wind power distribution in Spain for the years of 2001 through 2005. It can be observed that the total wind generation across the region is never at the aggregated nameplate capacity. The median of the total wind generation is around 27% of the aggregated nameplate capacity. It implies that the total wind generation is below 27% of the capacity 50% of the time. The combined output will never reach their maximum output simultaneously due to the weather induced variability over time and geographical areas and thus building transmission to incorporate the entire capacity would be inefficient and expensive.

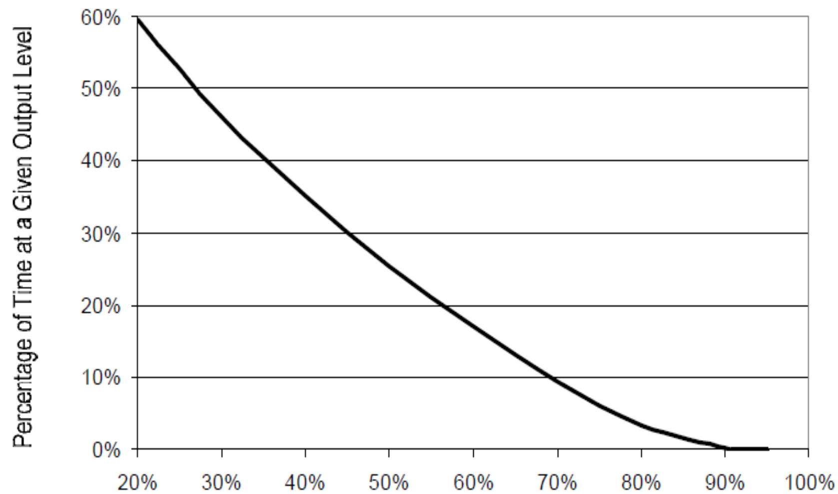

Figure 3-7 An Example of Variability in Wind Output [20]

Mathematical models can be developed to capture variability of wind and solar output and correlation among different wind and solar sites to develop dispatch scenarios. This is typically done by constructing artificial wind and solar profiles which use historical weather information. Given historical wind speed data and historical solar radiation data from various sites, hypothetical wind and solar shapes can be constructed based on projected wind and solar installations. The intent of this approach is to identify what the wind and solar output would be in a future year if the exact same weather patterns from a historical year were to occur again. Performing this analysis for a number of weather years allows planners to have confidence that the full range of possible conditions have been explored as well as assignment of probability to the various possible conditions being reasonable.

One of the common critiques of this method is that atmospheric models, although getting better, used for constructing historical wind profiles do not accurately capture site specific profiles. And even when aggregated to the system level, the atmospheric models may not be accurate. However, given significant wind installations and significant production data from those sites over the past 10 years or more, this approach can be calibrated better and more confidence can be placed in the resulting shapes.

The question still remains however of "how many alternate scenarios need to be examined?"' Current research activities by EPRI are attempting to address this question and are discussed in more detail in Chapter 4.

3.5.3 Equipment Performance

Reliability of the system is determined by performance of individual generator and transmission equipment.

The performance of generators is typically measured as a single point value – the average equivalent forced outage rate (EFOR). The system EFOR approximately captures the average MWs that are simultaneously out in an unplanned outage state (Figure 3-8). Most systems typically maintain an average EFOR of 3% - 7% over the course of the year. From a probabilistic risk assessment approach, not only is the average EFOR important, but also the range of possible instantaneous EFOR values. A system that operates with an average 3% EFOR could experience 10% of its generation capacity in simultaneous unplanned outages. Probabilistic approaches are used to calculate system EFOR.

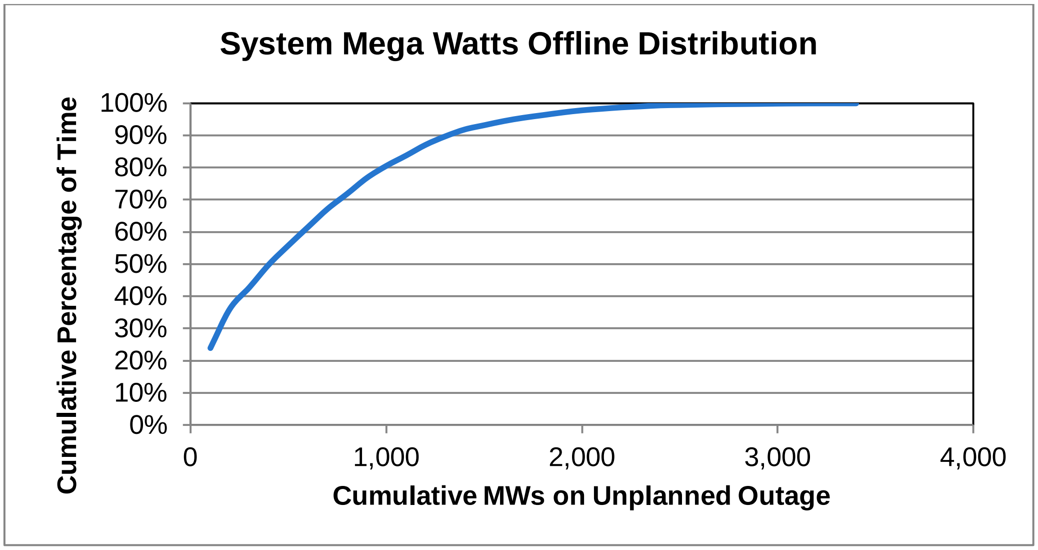

Figure 3-8 Distribution of System Capacity on Unplanned Outage

Reliability of the transmission system is evaluated by simulating the ability of the system to operate within specific thermal and voltage limits for the normal system state, all N-1 contingencies, and other credible contingencies with more than one component out. Again, transmission planners address the reliability evaluation using a deterministic framework. Formulating a fundamentally probabilistic problem into a “certain” or “deterministic” framework has the following potential weakness:

1. Likelihood of an event occurring is not explicitly considered. In real life, events have unequal chances of occurring due to various factors such as ambient conditions, exposure to environment etc. For example, an outage event even if extremely undesirable, is of little consequence if it is so unlikely that it can be ignored [1]. A planning solution based on such an event will lead to overinvestment. Risk-based decision making on the other hand recognizes not only consequences but also likelihood of occurrence of events.
2. Major system outages (referred as blackouts or cascading events) occur when multiple network components fail. However, it is not practical for transmission planners to examine all higher order combinations of component failures because there will be millions of potential combinations. Risk-based approaches can provide ways to examine multiple component failure and keep system risk within acceptable level.
3. A deterministic framework does not implicitly consider system economics while considering system reliability. Risk-based approaches on the other hand can prove to be quite important in justifying decisions about system upgrades.

Considerable research has been performed to develop probabilistic approaches to evaluate generator and transmission system reliability. **This is one of the main topics addressed in this white paper and is covered in Chapter 5.**

3.6 Time Frame of Various Factors Impacting Transmission Planning

In general, non-quantifiable or subjective probability factors impact the transmission planning process on a longer-term basis (> 5 years) whereas quantifiable or objective probability factors impact transmission planning on a shorter time frame (up to a year or so). It should be emphasized that although not considered in this white paper, certain variables such as load volatility affect the operation of the system in the very short term – from seconds to hours. Variation due to weather affects the commitment and dispatch of the system from hours to days. Hydro availability affects the planning of the system from days to months. Generator and transmission component failure affects the operation and planning of the system across a wide range of periods. A summary of time-frame over which various factors impact power system operation and planning is shown in Figure 3-9.

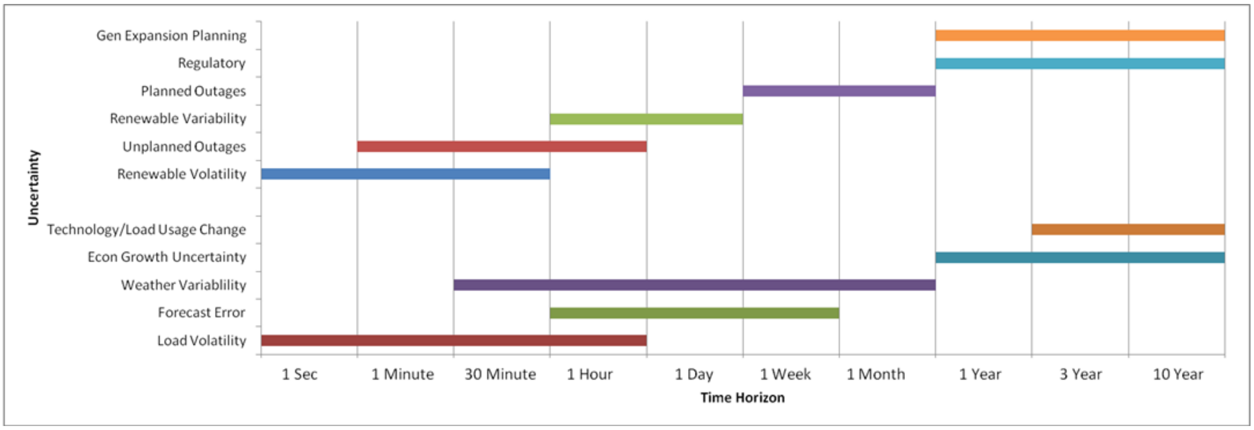

Figure 3-9 Time Frame of Various Uncertainties

This Chapter laid the groundwork for systematically categorizing factors that influence transmission planning process. Most of the inputs cannot be considered as point estimates in the transmission planning process as it could lead to erroneous estimates of system reliability and performance. The next Chapter delves into some of the approaches that can be used to capture weather related variation in renewable output and load.

4 Probabilistic Methods for Considering Weather Related Variability in Renewable Energy and Demand Resources

As mentioned in Chapter 3, temporal variations in renewable generation output, and system loads pose significant challenges in terms of developing credible load-dispatch scenarios. This Chapter is an extension of Chapter 3 and gives an overview of some of the probabilistic approaches that have been developed to quantitatively consider the risk posed by variable renewable generation.

The variable and uncertain nature of renewable generation (mainly wind and solar) introduces significant challenges for identifying the appropriate generation dispatch scenarios to study for planning efforts. The most common approach at present is to assume a certain output level and come up with discrete dispatch scenarios. This approach though simplistic, may not capture the gamut of renewable generation and load patterns.

The NERC IVGTF Task 1.6 report [19] has identified that as the percentage of variable generation increases in a system, both the operations and planning will be significantly altered. The report highlighted the need for risk assessment and probabilistic methods. In contrast to the real need for probabilistic methods, the report concludes that probabilistic methods are still in the research domain and they have not been adopted by the industry. This observation is consistent with the CIGRE[6] Study Working Group report [2]. The report also observes that while probabilistic methods are being developed their applicability has been demonstrated on small systems and they may not be pragmatic for real systems. The report does make it clear that there is a need to develop probabilistic methods that are practical for real systems and to improve the understanding of these methods within the industry. We agree with these findings and conclusions and we emphasize that the proliferation of variable generation makes this problem a high priority.

In this spirit, this Chapter presents probabilistic analysis of systems with variable generation. Presently, variable generation is mainly wind and solar. Solar includes rooftop distributed photovoltaics (PV) as well as larger arrays connected to transmission or distribution systems. As mentioned in Chapter 3, variability in renewable generation and load was categorized under “quantifiable uncertainty” or “objective probability” for which probabilistic models could be developed to quantify the risk.

As part of EPRI’s research efforts, two probabilistic methods have been developed for generating dispatches that consider variability in renewable generation and system load.

4.1 Composite Load Levels

The EPRI Composite Load/Wind/PV Level (CLL) methodology takes synchronized, chronological wind and PV generation output and coincidental bus load data as illustrated in Figure 4-1 and probabilistically represents the inherent correlations in renewable generation and load levels as composite snapshots of

[6] CIGRE stands for International Council on Large Electric Systems

wind and PV outputs for each plant and the corresponding load at specific busses as part of a power flow base case. The probability of each of these composite wind/PV/load levels is also calculated. The methodology is summarized in Figure 4-2. More details of the methodology can be found in [21].

Electric Load Observations				**Wind Plant output Observations**				**Solar Plant Output Observations**			
Pl1 MW	**Pl2 MW**	**…**	**Pln MW**	**Pw1 MW**	**Pw2 MW**	**…**	**Pwo MW**	**Ps1 MW**	**Ps1 MW**	**…**	**Psp MW**
$p_1(1)$	p_2 (1)	…	Pn(1)	w1(1), wg1(1)	w2(1), wg2(1)	…	wo(1), wgo(1)	s1(1), sg1(1)	s2(1), sg2(1)	…	sp(1), sgp(1)
$p_1(2)$	$p_{22}(2)$	…	$p_n(2)$	w1(2), wg1(2)	w2(2), wg2(2)	…	wo(2), wgo(2)	s1(2), sg1(2)	s2(2), sg2(2)	…	sp(2), sgp(2)
.	.	…	.	.	.	…	.	.	.	…	.
.	.	…	.	.	.	…	.	.	.	…	.
p_1**(m)**	$p_2(m)$	…	$p_n(m)$	w1(m), wg1(m)	w2(m), wg2(m)	…	wo(m), wgo(m)	s1(m), sg1(m)	s2(m), sg2(m)	…	sp(m), sgp(m)

Figure 4-1 Illustration of Synchronized, Chronological Load, Wind, and PV Data

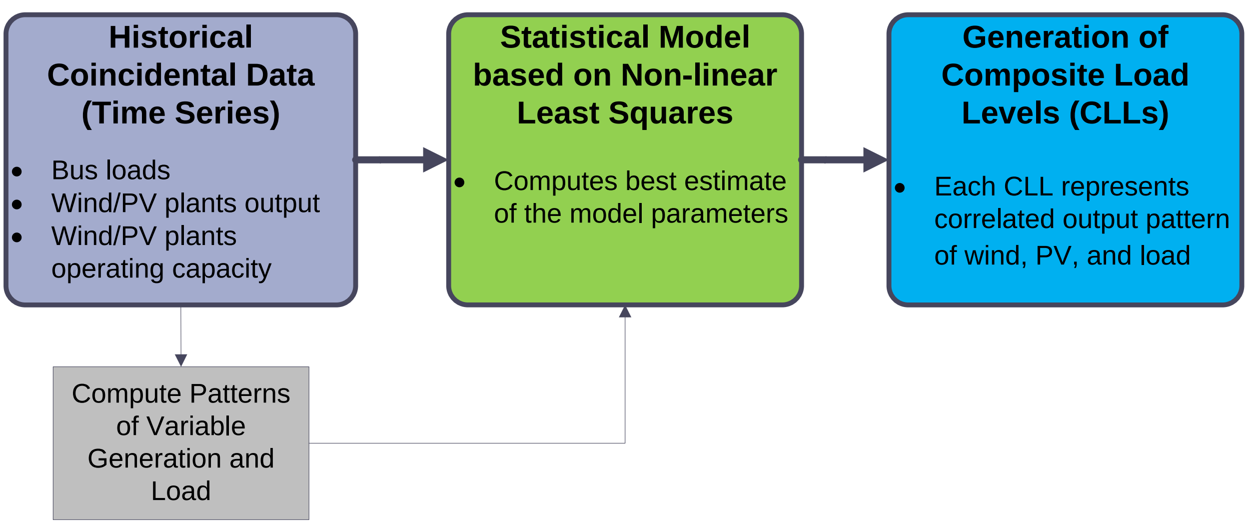

Figure 4-2 CLL Methodology

The mathematical model expresses variability and uncertainty associated with electric load and coincident wind and PV generation in terms of a small number of independent random variables in a closed form mathematical model. The aim of the mathematical model is to fit the historical data as closely as possible in terms of the random variables. The parameters of the model are found using the least-square estimation approach. Once the model parameters are found, the model can be used to provide a user specified number of wind/PV output as well as load level scenarios. These scenarios are referred as Composite Load Levels (CLLs). These CLLs are generated as power flow cases. Each CLL can be analyzed in a deterministic planning software like Siemens PTI PSS®E or EPRI's risk-based analysis software, TransCARE (refer to Chapter 7 for more details). The mathematical model calculates the probability of each CLL scenario occurring in a year as well as correlations among wind plants, PV plants, and system loads.

This approach is being tested in one of the case studies that we are performing as part of this project. A summary of the case study is provided in Chapter 6 while the details are provided in the report on the case studies.

Some of the limitations of this approach are as follows:

- Data requirements for this approach is onerous – in particular historical time series data for each wind plant, each PV plant, and each system load is required. In some cases there may be gaps in time series. These gaps need to be filled before using the data.
- The method is computationally intense as it involves inverting metrics of big dimensions. For the case study, sparsity techniques were used to fasten the computation process.
- By default there is a mis-match between generation and load in each CLL because existing generation in the power flow case is not adjusted as per renewable output levels and load levels calculated. Hence additional preparation of the CLL base cases is essential before utilizing these power flow base cases for planning studies. In particular, solving power flow for these CLLs requires running unit commitment, and security constrained economic dispatch (SCED) for the entire case, and adjusting area interchange to export the excess renewable generation. Again this is a time consuming task and requires economic cost data for fossil units.

4.2 Stratified Sampling Concept using Monte Carlo Approach

EPRI began working on a second approach in 2014 to probabilistically develop dispatch scenarios to capture significant variability due to the following variables:

1. Variation in renewable output
2. Weather related load variation
3. Hydro availability limitations
4. Uncertainty in economic load growth
5. Uncertainty in demand response and demand-side resources
6. Generation and transmission component performance

The overall approach of the methodology is shown in Figure 4-3 and is described in details in [22]. The methodology uses time series data of system load, renewable output, and hydro output (if available). The data is divided into sub-populations. Each sub-population is homogeneous in the sense that data points in a sub-population have similar system conditions. Division of entire data into multiple strata ensures that even scenarios that have low probability of occurring will be captured in one of the strata and won't get lost in the entire population which is dominated by "average" scenarios occurring more frequently on the system. Monte Carlo sampling is used to come up with a user specified number of dispatch scenarios in each strata. The methodology will allow a planner to capture average scenarios as well as low probability high impact scenarios as shown in Figure 4-4.

Note that in addition to the uncertainties, the methodology also considers historical performance of generating units and transmission components to come up with deeper contingencies (beyond just N-1) for reliability evaluation using Monte Carlo approach.

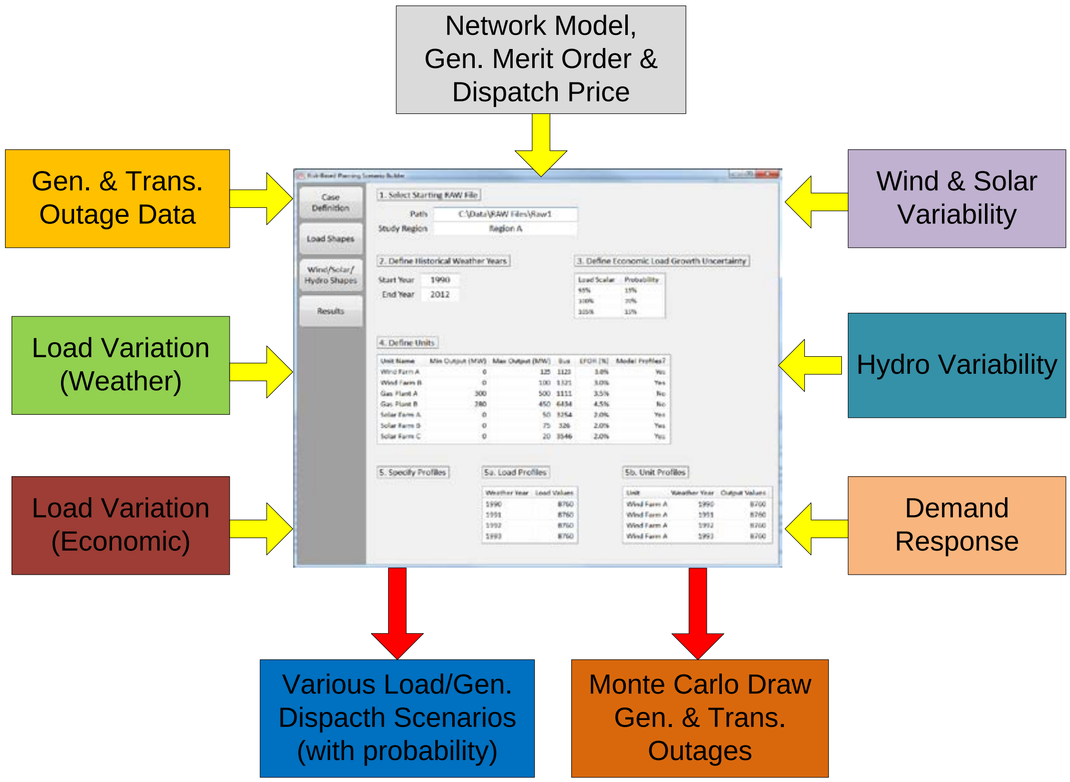

Figure 4-3 Schematic of Monte Carlo Based Sampling Approach

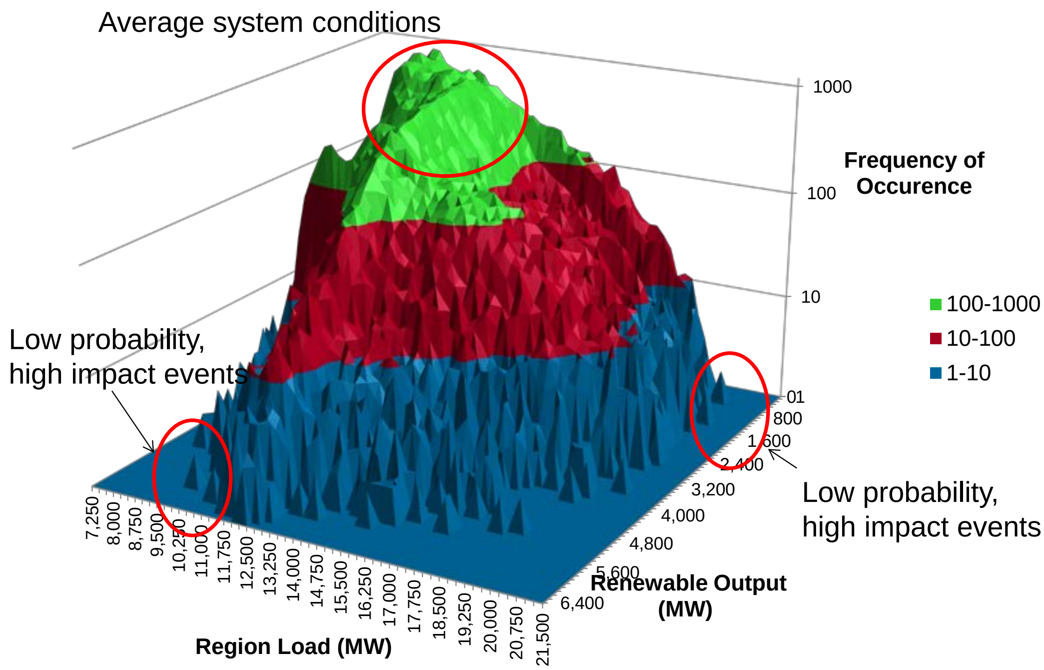

Figure 4-4 3-Dimensional View of the Frequency of Occurrence

It should be noted that this approach is still a work in progress and has not been tested on a realistic system. EPRI is planning to thoroughly test the methodology and make necessary improvements in 2015 and beyond.

It is worthwhile to mention that the uncertainty of variable generation effects not only the planning process but also the real time operation of the system as it has been identified in the NERC IVGTF report. Inversely, the way one copes with the real time operational problems as afflicted by variable generation effects the planning process. For example, wind and/or solar plants could be curtailed during periods of higher system stress when operating reserves may be lower – this is subject to the relative economics of this versus other options. Other operation changes may also help, such as more frequent scheduling decisions, increased coordination between balancing areas, or more optimal procurement of operating reserves. While this approach mitigates the problems, it is also uneconomical and wasteful since the 10% of available wind not used is lost forever. Others suggest that there is a need to develop mass storage to deal with variable generation, such as pumped hydro plants or other storage technologies. Storage may be a good solution that will allow full usage of available variable generation (subject to power lost in conversion when storing and generating power) and mitigating the operational problems; however it is also expensive at present. Then the probabilistic methods can address the issue of how much storage and what technology is needed for best performance (reliability, economic, technical and environmental).

Overall, the authors conclude that probabilistic methods for considering weather related variability and uncertainty for making planning decisions are still in the research phase. Although active research is being performed by EPRI and other research entities, many challenges remain before they can be widely accepted by the industry. This view is corroborated in the NERC IVGTF Task 1.6 report [19] and CIGRE Study Variable Generation report [23].

5
Probabilistic Planning Methods for System Reliability and Economics

Previous Chapters explained some of the basic concepts in existing transmission planning process and described the factors that have a strong impact on today's transmission planning. Considering only a point estimate of these factors is not sufficient and can give a grossly erroneous estimate of system reliability and costs. Chapter 3 laid the framework to consider these factors and categorized them into "quantifiable uncertainties or objective probability or risk" and "non-quantifiable uncertainty or subjective probability". These factors need to be carefully considered to develop credible planning cases for reliability and economic evaluation. As mentioned in Chapter 2, reliability assessment is performed in compliance with NERC TPL standards which are deterministic in nature. Also, there is no direct way of incorporating economic aspects into decision making. This Chapter delves into probabilistic methods that have been developed over the years for reliability and economic analyses. In particular, the Chapter provides an overview of:

1. Probabilistic methods for evaluating system reliability and economics
2. Probabilistic indices that can be used in planning process
3. Data requirements for using probabilistic methods
4. Qualitative discussion on probabilistic methods and their benefits as compared to deterministic approaches

As mentioned in Chapter 2, probabilistic planning methods encompass reliability as well as economic analysis. This Chapter considers both of these aspects. It should be noted that significant research has been performed over the years to develop probabilistic techniques. These techniques can be categorized under three hierarchical levels based on the three functional zones of a power system: generation, transmission and distribution as indicated in Figure 5-1.

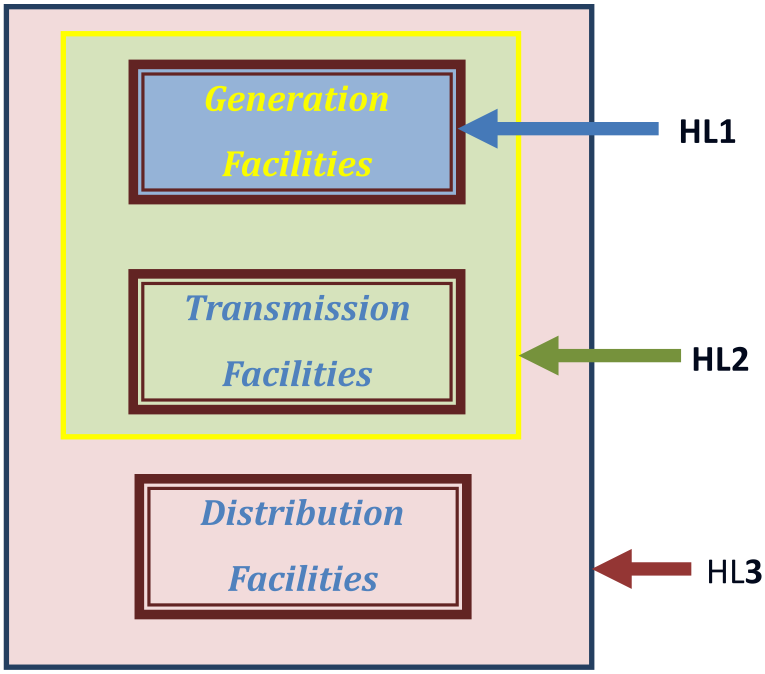

Figure 5-1 Three Hierarchical Levels for Reliability Analysis [2]

Hierarchical level one (HL1) considers generation system only. Hierarchical level two (HL2) encompasses both generation and transmission systems, often termed as "composite reliability." Hierarchical level three (HL3) considers the whole power system. HL1 analysis is commonly used for generation adequacy and production costing analysis. HL1 probabilistic approaches for resource adequacy are relatively well developed.

Increasing attention has been given to the incorporation of probabilistic techniques for composite reliability (HL2) evaluation. At present HL2 evaluation is performed using deterministic criteria set by NERC TPL standards. Using probabilistic techniques for HL2 evaluation, reliability and economic indices can be calculated for the overall system under study as well as for individual load locations (referred as "load buses" in a system network model). Although probabilistic methods for HL2 analysis have been available for some time, their application planning processes has been pretty much non-existent due to a number of reasons including deterministic nature of TPL standards, lack of tools, data, and skillset. These reasons are elaborated in Chapter 7 and Chapter 8. **Note that the HL2 level analysis is the main focus of this white paper.**

HL3 studies are typically excluded from transmission planning due to complexity and scale of the problem. Sometimes distribution companies can perform distribution only reliability analysis using probabilistic techniques to assess reliability at consumer load points.

In addition to these three levels of reliability studies, additional studies related to substation reliability, spare transformer assessments etc. are performed by utilities. These studies are also mostly performed using deterministic approaches due to lack of tools, data, wide-spread awareness about using these techniques, and skill set although probabilistic techniques are available.

Power system components are considered to be “repairable components” i.e. these components are subject to failure but once they fail, they are repaired and placed back in service. In general we describe these components with a Markov process. Markov modeling is a well-established modeling concept and is covered in textbooks on system component modeling [24, 25].

While the description of the component models is mathematically straightforward, the determination of the parameters of these models from observed performance of the components is quite complicated. The main reason is that typically there may not be enough information available in the historical data recorded for a component performance that will enable a reliable extraction of the model parameters. For example one item that is important is the cause of an outage and recording of events that result in system problems including load interruptions. This issue is fundamental to probabilistic methods because it provides the input to reliability analysis. There is a need for research into developing reliable methods for extracting the correct component reliability models from available historical data. Many times the historical data may be sparse or they may lack sufficient number of observed failures.

5.1 HL1 - Generation Systems Only Reliability

Although HL1 analysis is not the main focus of this white paper, a brief overview of HL1 analysis approaches is provided in this section for completeness. The basic issue addressed by the HL1 problem is the adequacy of the generation to serve the electric load. It is tacitly assumed that the transmission/distribution system is perfect. This problem is often referred to as Generation Reliability analysis.

The methods for generation reliability analysis can be categorized into three main approaches:

1. Chronological simulation
2. Probabilistic simulation
3. Monte Carlo simulation

These three approaches are briefly described in the following sections.

5.1.1 Chronological Simulation

This method simulates the operation of the system on a typically hourly interval over an extended period, for example one year. Inputs to the method are: (a) forecasted electric load, (b) forecasted fuel prices, (c) generating unit data including cost data, and other pertinent descriptions such as expected output models for wind, if wind generation is present, pumped hydro data, if such plants are present, etc. The method operates as follows: at each hour of the simulation horizon, the load, and other parameters are selected from the forecast model. Subsequently the system operation is simulated with a variety of analytical tools. The degree of sophistication of these analyses varies among different implementations of the method. The results are accumulated and are presented as histograms or their distribution is tabulated. This computational procedure is applied to each expansion plan (project) to determine the effect of the project on the performance of the system.

5.1.2 Probabilistic Simulation

This is probably the most successful analytical method for generation reliability analysis. It is often referred to as probabilistic production simulation (also referred as “Beleriaux method”, [26]). The methodology provides reliability indices as well as expected production quantities by taking into consideration operational practices of the electric power system, such as economic dispatch. As any other common generation reliability analysis method, it usually ignores transmission constraints, in other words it assumes that the transmission system is plentiful and 100% reliable. Given the forecasted electric load demand for the time period under consideration and a list of available generating units of the system with their reliability models, the operation of the system is simulated in order to compute reliability indices such as Loss of Load Probability (LOLP), Expected Unserved Energy (EUE), as well as energy utilization metrics such as energy generated by units, cost, and required fuel, taking into account the effects of scheduling functions within the time period considered and the random forced outages of the units.

5.1.3 Monte Carlo Simulation

Another approach for generation reliability analysis is by Monte Carlo simulation. Probabilistic models are developed for generators, electric load and other pertinent parameters of the system depending on the existing components of the system, for example, wind farms, PV plants, etc. A trial is executed by drawing a sample from each of the probabilistic models of the various components. The outcome is a specific power system with specific load, available units, and other components. This system is simulated and the results are tabulated. The simulation can be performed with varying degree of detail. The existing software products may differ in the number of options providing for the simulation. This approach requires a large number of trials. For a specific accuracy, one can compute the required number of trials which is in general a very large number. The results from all trials are utilized to compute various reliability indices. Specifically the frequency interpretation of probability is utilized to compute the usual reliability indices, such as loss of load probability, expected unserved energy, expected fuel consumption, etc.

5.2 HL2 – Composite System Reliability

As mentioned previously, HL2 involves evaluation of generation and transmission components and is the main focus of this white paper. HL2 evaluation using a probabilistic method involves the following steps in an iterative manner [27]:

1. Selecting a system state with failed and non- failed components
   Analyzing the system state to determine if it is a failure state (i.e. if it violated any system constraints)
   Calculating risk indices for the failure state
   Updating cumulative indices

As one should expect, the number of system states that can be identified in the first step of this procedure would be quite large for a practical system. Over the years, there are two main approaches developed for the manner by which the system states are selected.

1. Selective contingency enumeration approach
2. Monte Carlo approach

5.2.1 Selective Contingency Enumeration

The selective contingency enumeration is achieved with the use of contingency selection methods [28], [29] and the wind chime scheme [30]. Specifically, for any given system state the contingency selection method identifies the contingencies that may be problematic for the operation of the system. This is achieved by computing the impact of each possible contingency on a number of performance indices [30]. Then analysis is focused only on the top ranked contingencies. The results of the analysis dictate the selection of the next contingencies. The process is illustrated in Figure 5.2. It starts from a system state indicated as base case. This system state is with all components available. A contingency selection procedure is applied yielding an ordered list of first (N-1) contingencies – ordered in accordance to severity. Simulation starts with the highest ranked contingency and the process continues until the contingencies do not create failures to the system. That generates a list of evaluated and not evaluated contingencies. Subsequently, starting from a system state as dictated by an evaluated contingency, the contingency ranking method is applied creating a list of second order contingencies (N-2 and N-1-1) ordered by severity and the process is repeated. In this way the procedure identifies the occurrence of contingencies that have the capability to create a cascading event. In the process the analysis is limited to contingencies that are problematic to the system, i.e. contingencies that may contribute to the system unreliability. The results are utilized to compute a number of reliability indices. [30].

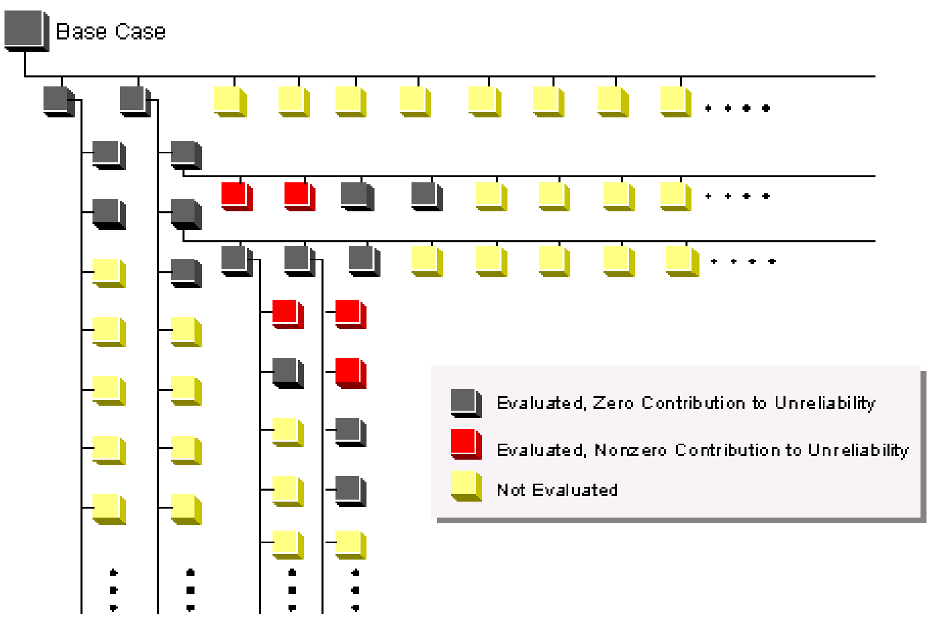

Figure 5-2 Wind Chime Enumeration Scheme

5.2.2 Monte Carlo Approach

Monte Carlo simulation is based on simulating a large number of random trials of system conditions, tabulating the results and interpreting the results as probabilities of the various events and outcomes involved. Each trial results in a specific system state by randomly extracting an outcome for the component reliability models of the system, i.e. it is assumed that each component is characterized by a probabilistic model. There are procedures for defining the required number of trials for a specified accuracy. In general for a reasonable accuracy the number of trials is huge. A flow chart of the overall approach is shown in Figure 5-3.

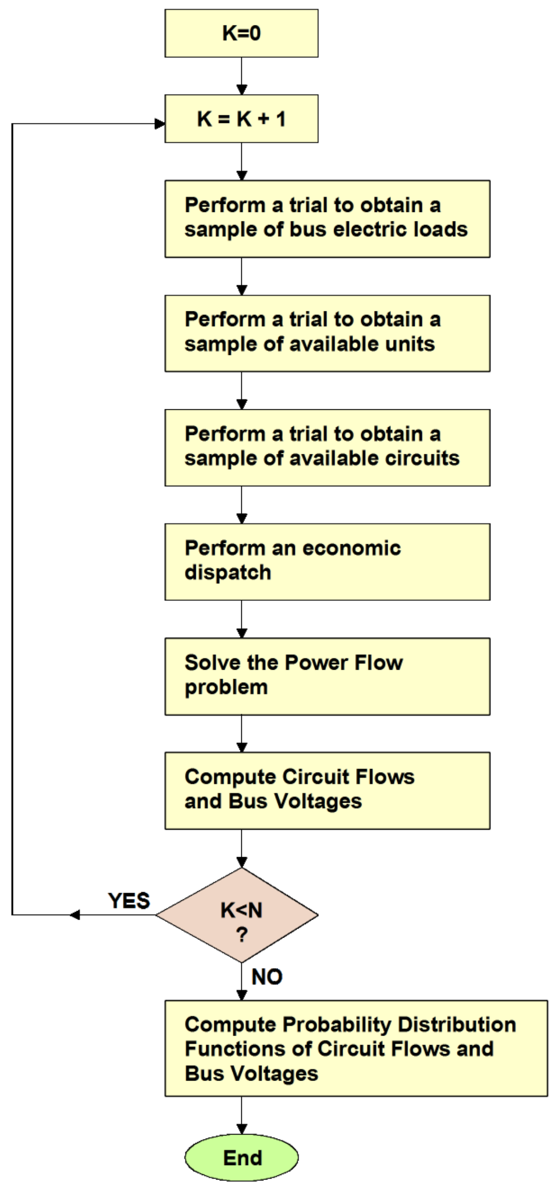

Figure 5-3 Flow Chart of Monte Carlo Simulation

Composite reliability evaluation using probabilistic approaches has been extremely challenging because of the following reasons [31]:

1. **Modeling of these approaches is quite challenging.** Specifically it is quite challenging to model:
    a. Failure/repair process associated with generators, transmission lines, transformers, and other transmission equipment
    b. System load variations over a period of time

c. Effects of weather on failure/repair processes and load
d. Remedial actions including those of the operator

Computational Issues: It is necessary to achieve an acceptable tradeoff between speed and accuracy. For a practical large-scale power system, the number of system states will be enormous. As an example, a system with n components and each component with two states (up or down as described in Markov modeling), there is a total of 2^n states. For example, if n is 2000, the number of states too large to consider. It is impossible to analyze each contingency one by one to identify the contingencies that contribute to the system unreliability. The problem is further complicated when remedial actions to alleviate system problems are evaluated.

Data: As explained later in this white paper, data is an issue for any probabilistic analysis. For HL2, data is required for characterizing failure rates of all equipment. Collecting and maintaining suitable database possess many difficulties.

These issues are explored in more details in Chapter 7 and Chapter 8.

5.3 Probabilistic Reliability Indices

The reliability of the power system is quantified in terms of reliability indices. The indices express a particular attribute of the system.

Reliability indices can be defined for all the three hierarchical levels (HL1, HL2, and HL3). Many reliability indices have been defined in the literature. The most commonly used indices are given later in this section. Recall that each of the reliability analysis methods is based on simulation of a number of system states defined in terms of the available components and the system loading. The simulation method depends on the specific reliability indices to be computed. The most usual simulation methods are the ones that allow the computation of adequacy or security indices. Adequacy and security are defined as follows [32]:

Adequacy: Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources refer to a combination of electricity generating and transmission facilities that produce and deliver electricity, and demand-response programs that reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.

Adequacy assessment is concerned with the evaluation of static or steady-state conditions when a combination of adverse system conditions are present, for example, extremely high loads, low renewable output, or significant unexpected generation and transmission component outages. The main failure problems are:

1. Capacity deficiency
2. Circuit overloads

3. Voltage violations

In generation adequacy assessment (HL1) only the first failure criterion is applicable, because the network is assumed to be perfect.

Security: For decades, NERC and the bulk power industry defined system security as the ability of the bulk power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber-attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Security assessment is concerned with dynamic or transient conditions following a component failure. The failure problems include:

1. Voltage instability and transient voltage dips
2. Loss of generation synchronism
3. Oscillations in system

It should be noted that most of the research on probabilistic methods has been performed for system adequacy assessments. Probabilistic security assessment is not a well-researched area at present. This is discussed further in Chapter 7.

5.3.1 Reliability Characterization

In both adequacy and security approaches, system reliability computation has three fundamental questions that need to be addressed (Figure 5-4):

1. What failure modes should be considered?
2. How to quantify these failure modes?
3. Where in the system should these failure modes be computed?

The failure modes that are considered for adequacy evaluation are:

- Component overloads
- Voltage violations
- Load drop
- System islanding

Each one of the failure modes can be quantified in terms of:

- Probability of a failure mode
- Duration of a failure mode
- Frequency of a failure mode
- Expected value (weighted mean) of a failure mode (for example, average value of transmission line overloads)

More details about computing probability, duration, frequency, and expected value are given in Appendix C.

The failure modes can be computed at:

- a system level or part of a system
- major bulk system load points
- at component level

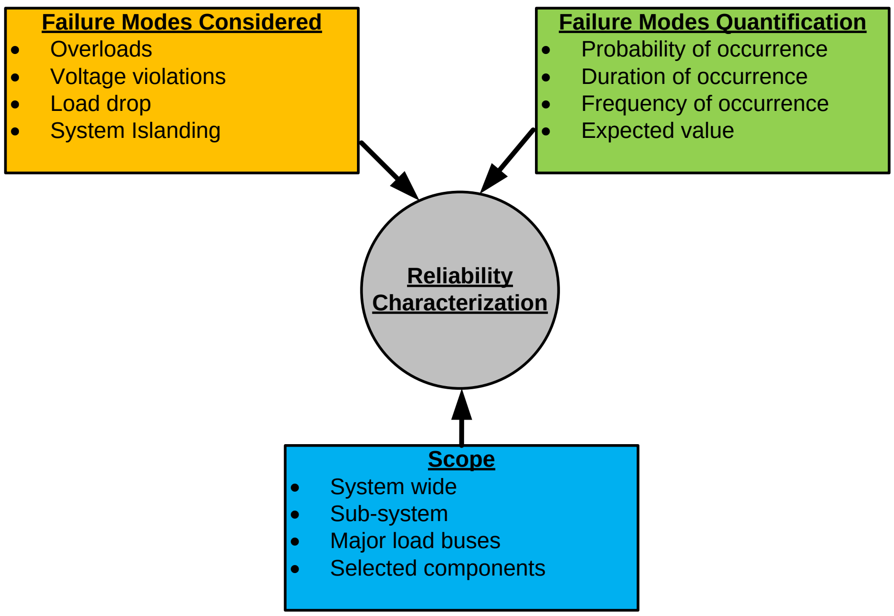

Figure 5-4 System Reliability Characterization

5.3.2 Commonly Used Reliability Indices

The end result of almost all reliability evaluations is to compute indices to characterize the system reliability level. There are a large number of indices that have been reported in literature. We summarize the most relevant and commonly used indices in this section. These indices are expressed in terms of probability, frequency and duration as explained in the last section. A summary of important reliability indices is provided in Figure 5-5.

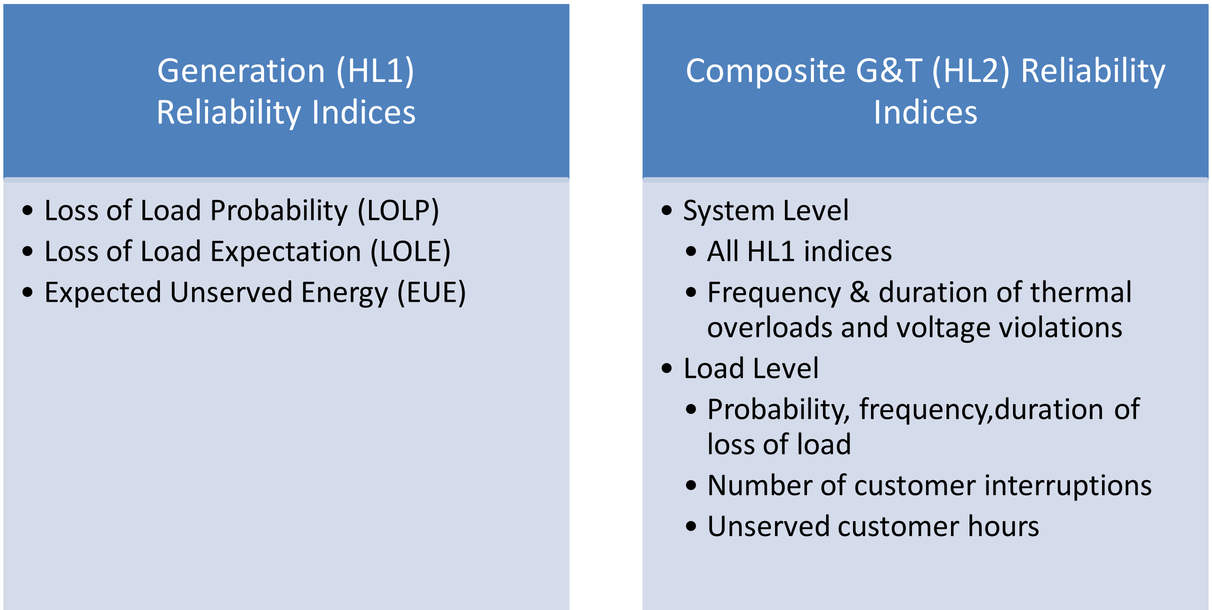

Figure 5-5 Commonly Used Reliability Indices

Note that indices can be calculated before and after applying remedial actions to alleviate undesired consequences. If indices are calculated before applying remedial actions, they will give a pessimistic view of transmission system reliability in that the probability of correcting problems by system operator actions is ignored. Also a particular outage combination is studied only once, assuming that there are no system readjustments after one outage in preparation for the next. This approach is referred as "system problem approach."

If the indices are computed assuming full utilization of readjustment capabilities without regard to response times, it is referred to as "capability approach or load curtailment approach." This approach gives an optimistic view of transmission system reliability in that it measures post-disturbance capability, ignoring the possibility of larger load curtailments during the transition from a specific pre-disturbance state to the post-disturbance state to the post-disturbance state.

For either the system problem or capability approach, indices can be calculated for a specified time interval- typically on annual basis. However, indices can also be calculated for different seasons. These seasonal indices are useful in identifying system behavior under different climatic conditions, varying load and generation profile. It is important to recognize the fact that maintenance outages and/or outages during extreme conditions can last for very long durations. Annualized indices by taking into account the load profile are helpful in tracking system performance over a period of time and comparing various alternatives.

5.4 Data Requirements for Probabilistic Reliability Analysis

The probabilistic methods are fundamentally data-driven. For transmission reliability analysis three types of data are required as shown in Figure 5-6.

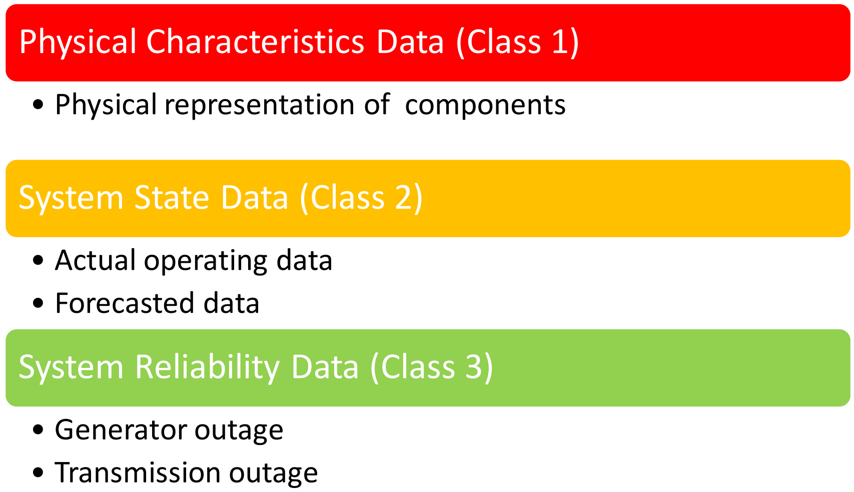

Figure 5-6 An Overview of Data Requirements

5.4.1 Physical Characteristics Data (Class 1)

These consist of parameters associated with the physical representation of generators, transmission lines, transformers, and loads. This included impedances, generator inertia constants, etc. Though there may be some small variability of these parameters with temperature or system frequency, for the most part they are considered to be fixed. These are the data typically associated with model development of power flow, transient stability, and production simulation assessments.

5.4.2 System State Data (Class 2)

These consist of variable system data that are associated with the actual operations of the power system. There are two types of the system operations data - Actual Operating Data (Class 2a) and Forecast Data (Class 2b).

<u>Actual Operating Data:</u> This is system data collected from actual system (historic) conditions or data for future system conditions. These data may be variable due to the variability of the system condition, but at all times, the data are known quantities. These data include generation power schedule, transformer tap settings, switchable device applications, and actual system power flows. Class 2a data is typically associated with deterministic assessment methods.

<u>Forecast Data:</u> Class 2b data are needed for the operation of the power system, however, the actual values of the data such as forecasted system loads and fuel prices, future generation and transmission additions are not precisely known. These categories of data have variability and uncertainty attributes.

5.4.3 System Reliability Data (Class 3)

These consist of statistically based probability (frequency, duration, unavailability) associated with random system events of equipment outages, weather conditions, price fluctuations, and human behavior. In addition to being random events, there are time, voltage class, and location attributes associated with some of the data. This Class 3 data can be divided into generation (Class 3a), transmission (including associated data, such as transformers, breakers, etc.) (Class 3b), and distribution

(Class 3c) data. These are the data required to conduct risk-based reliability assessment. Class 3 data is typically associated with risk-based or probabilistic-based assessment methods only whereas Class 1 and Class 2 data is required for deterministic as well as probabilistic assessments.

Outage data is pivotal to calculating reliability indices. The basic outage data information includes – outage duration, outage frequency, and unavailability. Outage data is generally reported by voltage class for transmission equipment and by maximum megawatt output and fuel type for generators. Sources of reliability data are given in the next section.

Outage data can be categorized in many different ways [22]:

1. Forced and planned outages. Forced outage data is always used in reliability calculations. Planned outage information may or may not be used. Both types of information are collected based on historical performance of components.
2. Sustained versus momentary outages. As per NERC's definition, a momentary outage is defined as an outage with duration less than one minute. Otherwise it is considered as a sustained outage. Momentary outages are associated with automatic reclosure or temporary switching events. Outage frequency is calculated separately for sustained and momentary outages. Outage duration is not an issue for momentary outages as all the outages will be restored within a minute.
3. Outages can be categorized based on whether they are related to one another. Specifically:
    a. Independent Outages – These are the outages that occur independent of one another. It is simpler to model independent outages and many reliability studies are done using this assumption. The simplest form of independent outages is N-1 assessment where it is assumed that only one element is out at a time.

    b. Dependent Outages – These are the outages where one outage is a result of another outage. For example a bus fault will cause outages of all the lines and transformers connected to it although there is only one real failure (bus failure) which is caused by a fault. These outages are difficult to model in reliability studies. Many times it is necessary to know breaker placement in the system topology to model these accurately.

    c. Common Cause Outages – These are the outages of multiple components caused by a common cause. However, note that one outage does not cause another as is the case with dependent outages. An example would be an outage of two circuits on the same tower caused by a tower failure or lightning strike. Additional data is required to model common cause outages and the analysis is challenging.

1. For transmission components, outages can be classified as equipment versus terminal-related outages. An equipment related outage is initiated on or within the element that is outaged. Terminal related outages are caused by failure of terminal devices which are auxiliary devices connected to the main element. An example, if failure of a current transformer causes a line outage, then it would be classified as terminal-related outage.

2. The impact of weather conditions on outages of outdoor components and the ability of the system operators/managers/owners to respond to outages during extreme weather conditions have a significant impact on system reliability. Therefore, outages can also be categorized based on whether they occurred during normal or extreme weather conditions. Examples of extreme

weather events include hurricanes, tornados, ice storms, or any other weather related event which can severely impact system performance over a wide geographical area for a significant amount of time.

Extensive standardized processes exist for developing, collecting and archiving Data Classes 1 and 2 throughout the industry. These include various IEEE standards on system and equipment modeling, NERC modeling standards such as MOD-10 through MOD-13, and EIA-411 data collection consisting of 6 schedules encompassing historical as well as focused loads and resources. When system forecast data is presented in Class 2b, there may be consideration for uncertainty and may be presented in view of expected probability.

All generator owners are required to submit their generator reliability related data (Class 3a) to NERC Generator Availability Data System (GADS). This is a mandatory requirement and applies to all types of generators larger than 20 MW. Also most utilities collect their distribution reliability data (Class 3c) as, in most cases, mandated by their state regulators. Collecting Class 3c data allows utilities to calculate their distribution reliability indices.

For data Class 3b, though there have been efforts and standards initiated at IEEE, CIGRE and other utilities over the last 60 years, it was only in 2010 that the transmission availability data (TAD) submittal by transmission owners in North America became mandatory by NERC. There are still various disparate data collection efforts by various other entities in the US and outside US. For instance the Canadian Electricity Association (CEA) has been collecting transmission outage data for over 30 years with great success. CIGRE also has a substantive record of transmission outage data.

5.5 Sources of Outage Data

Equipment and system performance data are usually collected for two basic reasons. The first, and possibly the most obvious reason, is to record, and retrieve operating information for improving the performance of electric generating equipment. The second reason is to provide the required information to estimate future performance.

In the US, NERC's Transmission Availability Data Systems (TADS) and Generation Availability Data Systems (GADS) are by far the most comprehensive databases for outage data [33]. Both datasets are compiled annually.

GADS data consists of three data types:

1. Design – equipment descriptions such as manufacturers, steam turbine MW rating, etc.
2. Performance – summaries of generation produced, fuels units, etc.
3. Event – description of equipment failures such as when the event started/ended, type of outage (forced, maintenance, planned), etc.

GADS data is available from the early 80s. In calculating LOLE, LOEE indices, one can use the Equivalent Forced Outage Rate (EFOR) which is the hours of unit failure given as a percentage of the total hours of the availability of that unit.

TADS database contains:

1. Overhead and underground ac circuits ≥ 200 kV;
2. Transformers with ≥ 200 kV low-side;
3. Back-to-back ac/dc converters with ≥ 200 kV ac on both sides; and
4. Dc circuits with ≥ ±200 kV dc voltage.

NERC uses the information available in TADS to develop transmission system metrics, analyzing outage frequency, duration, causes, and other factors related to transmission outages. NERC also provides a public report with TADS data aggregated for each one of the eight reliability regions. TADS data is available from 2008 to 2013. The data is updated annually.

In Canada, the Canadian Electricity Association (CEA) maintains database for Canadian electric companies. The CEA is an organization for exchanging information on technical, marketing and management problems of mutual interest to its members. In 1975, CEA adopted a proposal to create a facility for centralized collection, processing and reporting of reliability and outage statistics for electrical generation, transmission and distribution equipment.

Consistent collection of data is essential as it forms the input to relevant reliability models, techniques and equations. Consistent data are required to continuously monitor the performance of an electric power system and to measure its ability to provide reliable service to its customers. Many utilities have established comprehensive procedures for assessing the performance of their systems. The data available from NERC, CEA or other bodies is useful in providing a good starting point. However the best source is the data collected, checked and processed by a utility company. It is important to keep track of causes, climatic conditions, design, manufacturer and the age of equipment to compute the Mean Time to Fail (MTTF) and Mean Time to Repair (MTTR) for each component.

As mentioned before, reliability and economic analyses are two essential aspects in transmission planning. The Chapter so far has focused on probabilistic approaches for reliability evaluation. The next few sections delve into probabilistic economic methods, indices, data requirements etc.

5.6 Cost Components in Transmission Planning

There are three cost components involved in the economic evaluation of transmission planning projects:

1. Capital costs
2. Operation cost
3. Unreliability cost

5.6.1 Capital Costs

This includes investment costs in a project and include:

1. Direct capital costs associated with buying, transportation, installation, and commissioning of equipment, land and right-of-way costs, removal costs of existing facilities, outsourced costs for

design and other services etc. If previous facilities have residual values that can be utilized in the new project, those can be added as negative costs.

2. Corporate overhead costs which represent additional corporate costs not included in the direct costs. These are usually represented as a percentage of direct capital costs.
3. Financial costs which consist of interest on borrowed capital and government's taxes on purchase of equipment and service which is a percentage of the purchase price.

5.6.2 Operation Cost

The operation cost is estimated on an annual basis and is related to operating expenditures related to the project and includes annual maintenance cost, and annual taxes. The operating expenditures are related to network losses, simulation of energy prices in a market, and simulation of system production costs. This is associated with considerable uncertainty factors such as load forecasts, power market behaviors, generation patterns, maintenance schedules etc.

5.6.3 Unreliability Costs

A major aspect of reliability based planning methodology is to assess the worth of power system reliability in order to be able to compare it with the costs of obtaining that reliability. Computation of reliability worth requires computation of customer costs associated with loss of power supply. It is generally accepted that the utility cost will increase as consumers are provided with higher reliability. On the other hand, the consumer costs associated with supply interruptions will decrease as the reliability increases. The cost of interruption at a single customer load point is dependent on customer load characteristics. This information is obtained by surveying customers. From a utility point of view, as a supplier, the customer outage cost associated with a particular outage at a specific point in the system involves an amalgamation of the costs associated with the customers affected by interruption at that point in the system. This amalgamation of costs is known as a customer damage function (CDF). CDF varies greatly based on the following factors:

1. Customer type (e.g. residential, industrial, commercial and agricultural)
2. Customer location (e.g. rural, metropolitan)
3. Duration of an outage (outage costs are not a linear function of outage duration)
4. Number of times an outage occurs (some industries such as glass, paper and pulp, are very sensitive to the frequency of a supply interruption)
5. Time that an outage occurs

5.7 Probabilistic Economic Analysis Methods

The main purpose of economic assessment is to compare different alternatives to justify or not justify an investment. There are two main approaches for economic assessment to compare different transmission alternatives as described in the following sections [1].

5.7.1 Total Cost Method

The basic idea is in this approach is to select the alternative that has minimum total cost:

Total cost = Capital Cost + Operating Cost + Unreliability Cost

The three cost components are described in section 5.7. Planners in general have a pretty good idea of capital and operating costs. Unreliability cost is the product of expected energy not served (EENS, in MWh/year) times unit interruption cost (UIC, in $/kWh). EENS can be calculated by using a probabilistic reliability approach described in section 5.2. UIC is calculated from customer damage function (CDF) as described in section 5.6.3. This approach is further elaborated in section 5.9.

5.7.2 Benefit/Cost Ratio Method

In this approach, alternatives can be ranked using benefit/cost ratios. Capital investment is the cost whereas the reduction in operation and unreliability costs is a benefit. Larger benefit to cost ratio indicates a better alternative. A greater ratio indicates a better planning alternative and vice-versa. A ratio of less than one cannot be economically justified. Utilities usually set a threshold value on the benefit/cost ratio for justification of an alternative. A benefit to cost ratio of less than 1 cannot be financially justified. A benefit to cost ratio greater than 1.5 or 2 is frequently used. Again, probabilistic reliability approaches are used to calculate EENS which is used in quantifying benefits.

5.8 Risk-Based Planning Criteria

There are no industry-wide accepted risk-based planning criteria for transmission planning. This is not surprising given that most of the planning activities are performed using deterministic approaches. However, many possible approaches have been suggested and often used by researchers. Reference [1] gives a description of these suggested criteria and are summarized in this section.

5.8.1 Probabilistic Cost Criteria

In this method system unreliability is expressed in terms of unreliability costs thus linking system reliability with economics. Total cost method and Benefit/Cost ratio methods described in section 5.7 fall under this category.

5.8.2 Specified Reliability Index Target

In this approach, a reliability index is used as a target and various alternatives are considered to meet the target index. For HL1 evaluation, Loss of Load Expectation (LOLE) index of one day per 10 years has been widely used as a target index. No one index has been proposed for HL2 analysis. However, a combination of indices related to system problems and load loss (both are described later in the Chapter) can be selected as reliability targets.

5.8.3 Relative Comparison

In this approach, various reliability indices can be used to compare multiple transmission upgrade options. Performing a relative comparison is better than using an absolute index because of the following:

1. Outage data may have some errors
2. There could be computational limitations in calculating absolute indices

Relative comparison rather than an absolute target can off-set these deficiencies.

5.8.4 Incremental Reliability Index

In this approach, incremental improvement in a reliability index or indices per million dollars of cost can be used as a planning criterion. The cost includes total cost of investment as well as O&M costs for a system enhancement option. In many cases Expected Energy Not Served (EENS) can be used to quantify incremental improvement in reliability.

5.9 Coordination between Cost and Reliability Analysis – A Value-Based Transmission Reliability Planning Process

A value-based transmission reliability planning process (VBTRP) that has been proposed is found to be satisfactory in justifying and ranking transmission projects described in this section [34].The principle objective of the process is to provide the system reliability required by customers at the lowest *Total Cost* from the customer's perspective. The VBTRP process attempts to quantify the impact of any proposed transmission project on system reliability in terms of customer outage costs and weigh these costs against the capital costs of the project. The goal is to properly balance the costs of improving service reliability for various types of customers with the benefits of value that the system improvements bring to these customers.

A value-based transmission reliability planning process (VBTRP) framework is shown in Figure 5-7.

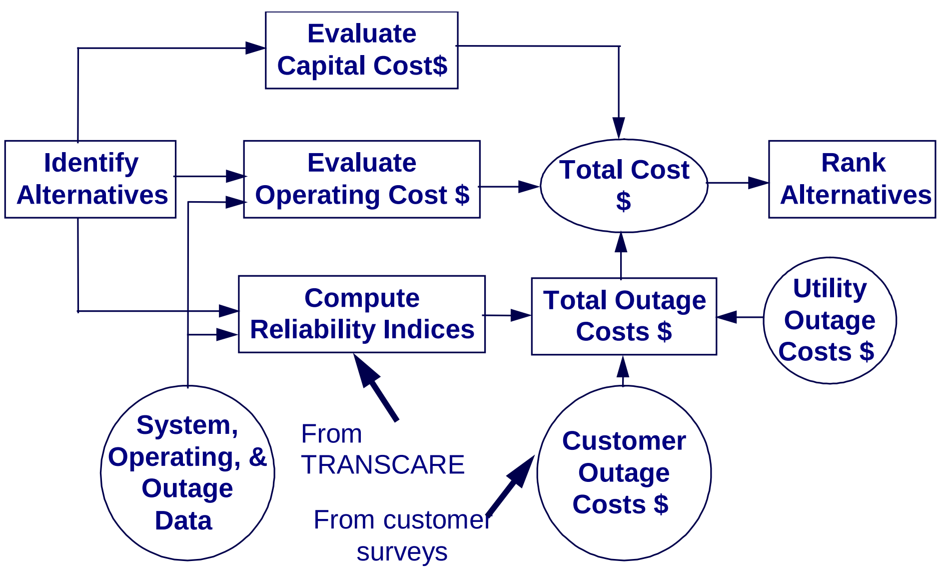

Figure A

Figure 5-7 Value-Based Transmission Reliability Planning Process (VBTRP) framework

The major steps outlined in the VBTRP framework are as follows:

- Identify alternatives
- Evaluate annualized capital costs & operating costs
- Compute reliability indices
- Compute outage costs from:
    - Customer outage costs

  - o Utility outage costs - lost business (revenue, customer, goodwill, etc.)
- Rank alternatives

This approach is conceptually shown in Figure 5-8 [34]. As can be seen, investment cost (denoted as "Cs") gradually increases with higher customer reliability, while the customer cost (denoted as "Co") associated with system failure decreases as reliability increases. The dotted curve is the total cost curve. The minimum of the dotted curve is the best alternative. The analysis is performed on annual basis using net present value (NPV) method.

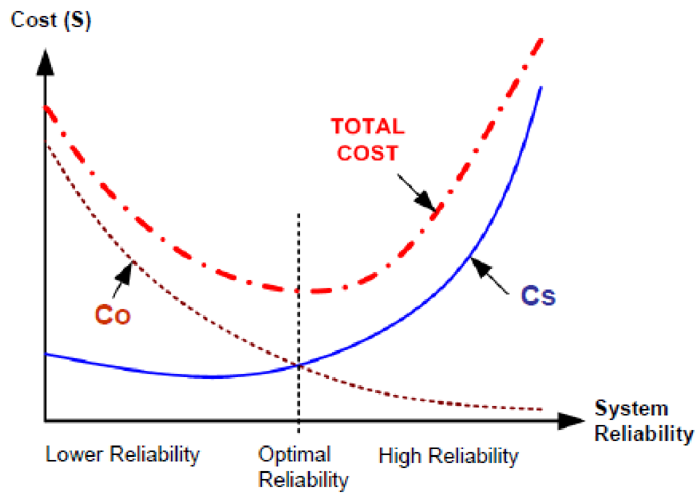

Figure 5-8 Balancing System Reliability Costs and Customer Costs

5.10 A High Level Comparison of Deterministic and Risk-Based Transmission Planning

This Chapter provided an in-depth discussion of various risk-based transmission planning approaches. We now compare the risk-based planning with the deterministic planning framework. Table 5-1 summarizes some of the salient characteristics of the two approaches [2].

Table 5-1 Comparison of Risk-Based and Deterministic Transmission Planning Approaches

	Risk-Based Planning	Deterministic Planning
Consideration of long-term uncertainties	Both approaches rely on scenario analysis. Research is being performed to quantify risks using probabilistic approaches	
Consideration of various risks	Many research grade methods exist to probabilistically determine load-generation dispatch scenarios	Considered on ad-hoc basis. Typically seasonal peak, off-peak cases are prepared.
Contingency level	Contingencies beyond N-1 and N-2 can be considered	Typically analysis is restricted to N-1 and a few select higher order contingencies
Selection of contingencies	Contingencies can be selected based on various criteria such that more severe contingencies are analyzed. Also, cut-off levels can be specified to limit the number of contingencies.	A limited number of contingencies are selected based on worst-case scenarios and engineering judgment
Ranking of contingencies	Contingencies can be ranked based on their risk (probability×consequences) Consequences can be system violations or cost of not serving energy to customers	There is no robust way of ranking contingencies as there is no information about probability of contingencies. Also, economic ranking is not implicit
Reliability indices	A number of reliability indices can be calculated implicitly as part of the analysis. These indices are related to frequency, duration and probability of thermal and voltage problems. In addition, load loss indices in terms of expected loss of load and expected energy not	Indices are not part of deterministic criteria. Frequency, duration related indices as well as load loss indices cannot be calculated.

	Risk-Based Planning	Deterministic Planning
	served can be calculated.	
Consideration of economics	Facilitates economic decision making for investments and provides a rational basis for selection of the best alternative.	No direct way of incorporating economic aspects into decision making. Planners have to use subjective judgment
Planning criteria	There are no industry-wide planning criteria established. Considerable research is needed.	Well established and well understood planning criteria
Availability of data	Risk-based approaches are data intense. Both quality and quantity of data required could be challenging.	Much less data intensive.
Software tool	No commercial tools are available	Well established planning tools
Technical expertise	Lack of skillset and subject expertise	Planners are well versed with the deterministic criteria

6
Examples of Existing Applications of Probabilistic Methods in Transmission Planning

As part of developing this white paper, the project team performed a literature review to identify studies that have been performed using risk-based transmission planning approaches in the past. A few of those case studies are summarized in this Chapter. Although literature is available on using these approaches on test cases, there is a lack of examples using real systems. This is an indication of reluctance on part of the industry to adopt these approaches on a broader scale. The reasons for this reluctance on the part of the industry are discussed in Chapter 8.

All but one of the case studies described in this Chapter are related to using risk-based approaches for transmission planning (HL2) analysis. The last case study describes using the probabilistic approach for resource adequacy (HL1) analysis.

In addition to this white paper, the project team is working on a companion research work involving four case studies using many of the probabilistic concepts described in Chapter 5. These four case studies are summarized in a separate report which will be available online (www.esipc.org) along with this white paper in 2015. A high level summary of these case studies is provided in this Chapter.

In general the case studies for transmission planning involved the following steps:

1. Define the problem and identify the causes that give rise to the problem.
2. Assemble data required for the study
3. Compute reliability indices using probabilistic methods
4. Select/rank projects using the indices, benefits and costs

The list of case studies described in this chapter is given in Table 6-1.

Table 6-1
Case Studies Summarized

Entity	Main Objective of the Study
San Diego Gas and Electric (SDG&E)	Development of a new transmission planning framework using a risk-based planning process and ranking of projects using probabilistic and deterministic methods
Atlantic Electric	Balancing the value of supply reliability to its customers with the costs associated with building, operating and maintaining electrical facilities
British Columbia Transmission	Demonstrate an application of probabilistic economic analysis in the North Metro 500/230/69 kV system of BCTC

Entity	Main Objective of the Study
Corporation (BCTC)	
CAISO System	Probabilistic approaches for system adequacy requirements
Tennessee Valley Authority (TVA)	Examine reliability benefits of the addition of new tie-lines with two different neighboring control areas
Tennessee Valley Authority (TVA)	Explore the benefits and drawbacks of deterministic analysis versus probabilistic analysis
Midcontinent Independent System Operator (MISO)	Provide additional probabilistic reliability and production cost analysis on two of the scenarios developed in the MISO Transmission Expansion Plan (MTEP) 2013 Process
Midcontinent Independent System Operator (MISO)	Compute probabilistic indices that can be used in the 7-step value-based planning process used in the Market Efficiency Planning Study
Southwest Power Pool (SPP)	A newly developed probabilistic methodology for transmission planning when a significant portion of generating capacity is comprised of highly-variable generation sources such as wind and solar power plants

6.1 San Diego Gas and Electric (SDG&E) Case Study

This study is documented in [35] and describes a risk-based planning process for planning transmission and substation facilities at SDG&E using reliability targets to ensure acceptable levels of reliability, meet capital spending objectives, and ensure that corporate goals are achieved. This new framework consisted of two steps:

1. Use the deterministic criteria to identify projects
2. Use the risk-based approach to prioritize and rank capital projects for funding.

The key features of the risk-based approach used were:

1. Expected Unserved Energy (EUE) was used as a reliability target for measuring system performance.
2. Projects were ranked using the differential Expected Unserved Energy (EUE) which is mitigated by proposed capital projects. Those projects which reduce the EUE the more will have the higher priority.

The objective of this study was not necessarily to spend less capital but to spend what was available more wisely, ensure reliability, and consider the value of service to the customer. This new planning approach accomplished this by providing a quantifiable level of risk and weighing it against the benefits/costs thus allowing management to make wise decisions with regard to future capital investments in the transmission system. This is referred as Value Based Transmission Reliability Process (VBTRP) as described in section 5.11.1. The probabilistic based planning process is more suitable for transmission owners, since it helps in maximizing the utilization of the existing system and ensuring reliability by quantifying the level of risk that transmission owners can comfortably take.

Table 6-2 summarizes the relative ranking of capital projects using both the deterministic methodology and the proposed risk-based approach for the 1995 Capital Budget.

Table 6-2 Capital Project Prioritization Comparison

Project Number	Project Description	Ranking Using Current Method	Ranking Using New Method
1	Reconductor 69 kV lines	1	4
2	New 69 kV line	2	6
3	Reconductor Lines A&B	3	3
4	New 138/69 kV transformer	4	2
5	Reconductor lines C&D	5	5
6	Install 69 kV Switches	6	1
7	New 138 kV tap	7	7

Results of using this new planning approach gave a different project ranking than using the ranking approach which was based on solely deterministic criteria. This change in ranking occurred because the new planning approach provided a more comprehensive assessment of the improvement of system reliability due to the addition of individual capital projects. The new planning approach provided a quantitative evaluation which considered how often (frequency of occurrence) the disturbance occurs, the number of customers affected, the duration of the outage, and the magnitude (MW) of load interruption.

6.2 Atlantic Electric Case Study

This case study is documented in [36].

Atlantic Electric (AE) was striving to balance the value of supply reliability to its customers with the costs associated with building, operating and maintaining electrical facilities. Competition in the electric utility industry had forced utilities to be more conscious of capital expenditures. It was important to ensure that proposed T&D projects satisfied system performance requirements and added measurable value to the customers and shareholders. AE was interested to evaluate potential of risk-based approaches in making planning decision to balance cost and service reliability. It was also important that engineers convey the results to the upper management in terms of costs ($) and reliability benefits (for example reduction in system problems or reduction in load loss) based on actual data. Non-specific quantifiers such as “good, better, best,” or “what we propose is the best solution” are not sufficient to operate in an unregulated environment.

The VBTRA methodology (described in section 5.9) was used to evaluate several feasible options to select the best T&D capital project. Both unreliability cost and project cost were computed for the four options and were used in selecting the best option:

OPTION 1 – Add a new 69 kV substation

OPTION 2 – Add a new 138/12 kV substation

OPTION 3 – Expansion of existing substations

OPTION 4 – Do nothing

Based on studies, it was estimated that total cost for option 2 is approximately $11.7 million, and for option 1 is approximately $10.9 million. Option 1 is therefore the most cost effective alternative. This is further confirmed by the fact that option 1 is closest to the minimal point on the total cost curve. The unreliability costs were computed by using the Expected Unserved Energy (EUE) of each option and using a $14 per kWh [12] as the cost of interruptions.

It should be pointed out that most of the reliability indices, however, favored selecting either option 2 or option 3 but the authors’ recommendation was to implement option 1. This resulted in a net savings of $0.8 million over the ‘most’ reliable option. The authors’ main objective was to know the added ‘risk’ that they were taking by choosing an option which may not be the most reliable option. Quantification of system unreliability gave them the comfort level that they were willing to accept as a measured business risk.

The project cost, unreliability cost and the total cost are shown in Figure 6-1. The optimal project cost is about $5.5 million. With the project cost of option 2 at about $7 million, and for option 1 at about $5.9 million, option 1 thus becomes the most cost effective alternative. This is further confirmed by the fact that option 1 is closest to the minimal point on the total cost curve. The total benefit, cost/benefit ratio, and the net benefit for each option were also computed. The net benefit was calculated as the difference of the total project benefit and the total project cost. It is noticed that options 1 and 2 are more economical than options 3 and 4. Option 1 has a better cost-benefit ratio than option 2. But option 2 has a higher net benefit than option 1. However, comparing the incremental benefit ($0.957 million) and the incremental cost ($1.075 million) between options 1 and 2, it can be seen that pursuing option 2 will be the equivalent of investing $1.075 million today to obtain a net benefit of $0.975 million over the 28 years economic life of the project. Hence, option 1 is considered the least cost and least risky alternative.

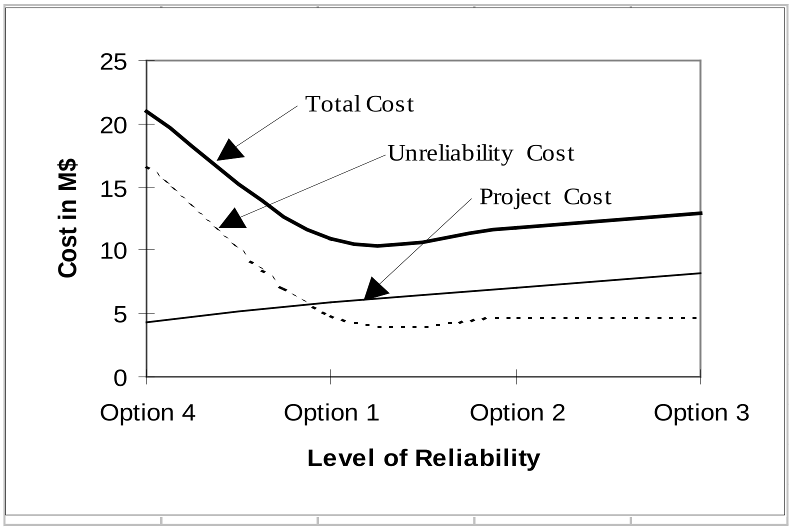

Figure 6-1 Cost Curves

6.3 British Columbia Transmission Corporation Case Study

This study is documented in [37] and demonstrates an application of probabilistic economic analysis in the North Metro (Figure 6-2) 500/230/69 kV system of British Columbia Transmission Corporation (BCTC). More reports on this topic can be found in the "Reliability Assessment" section of the BCTC Web site (http://www.bctc.com/the_transmission_system/reliability_assessment/). During the peak load period in some single-contingency cases overloading will occur on circuit 2L40 (BUT–NEL) as the load level in the North Metro region grows. The objective of probabilistic transmission planning is to solve this problem by selecting a reliable and economic reinforcement alternative. Based on the power flow and contingency analysis studies BCTC developed the following three alternatives to solve the overloading problem:

1. Uprating of circuit between 2L40 to be implemented in three stages. This is a natural option for solving overloading.
2. Cut circuits 2L22 (MDN-WYH) and 2L39 (NEL-COK) and tie into the line from NEL-MDN and COK-WYH.
3. Cut line from 2L39 and 2L51 (BND-MDN) and tie into the underground cable BND- COK and the line NEL-MDN.

Uprating 2L40, a high capital cost option, can eliminate the overloading problem in the long term and the other two low capital cost alternatives of cuts and ties only solve the overloading problem on 2L40 for four years only. A probabilistic analysis was performed to evaluate the reliability of the base system and the three alternatives and compare the total cost efficiency. The unreliability cost is computed by multiplying the Expected Energy Not Supplied (EENS) and the Utility Interruption Costs (UIC). The UIC is the electricity rate of the utility, which represents the lost revenue to the utility due to 1 kWh of loss of load.

Based on the results, the following two sequences that satisfy the single-contingency requirement were further compared using the minimum total cost criterion:

- **Sequence 1:** 2L40 uprating in three stages.
- **Sequence 2:** 2L39/2L51 cuts and ties in place first and 2L40 uprating deferred by 4 years. This deferral results in the 2L40 uprating requiring only the first two stages of the original uprating project to get to the end of the ten year planning horizon.

The results are summarized in Table 6-3.

Table 6-3 Comparison of Options

Cost	Sequence 1	Sequence 2	Difference
Investment	$ 3,025,000	$ 1,730,000	$ 1,295,000
Unreliability	$ 705,000	$ 729,000	$ (24,000)
Total	$ 3,730,000	$ 2,459,000	$ 1,271,000

Sequence 2 can save $1,271,000 of capital investment through deferring the 2L40 uprating by four years while both the sequences meet the single contingency requirement. Sequence 2 requires the lower total cost and provides basically the same reliability level. Probabilistic reliability studies confirmed that Sequence 2, a low cost option, provided the same reliability as Sequence 1, an obvious choice. This resulted in a saving of more than $1.2M.

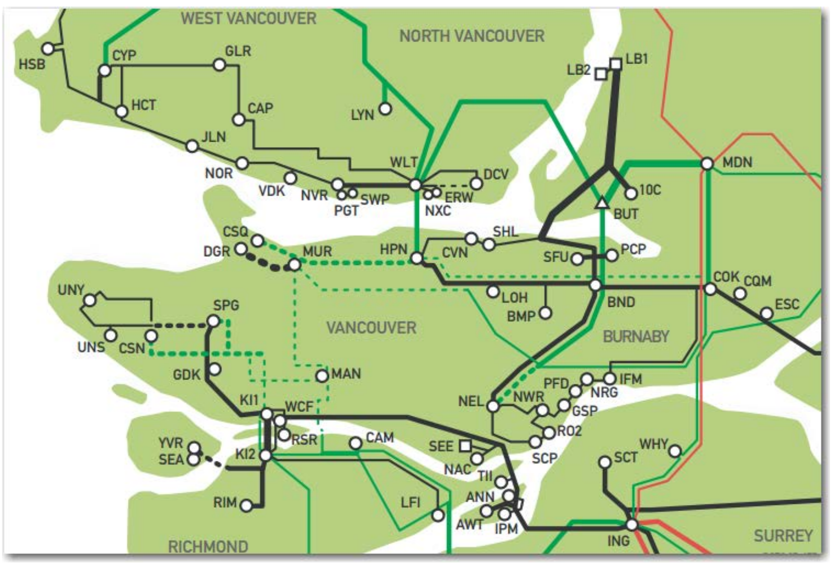

Figure 6-2 North Metro System of BCTC

Appendix A in [2] gives a few examples of risk-based planning approaches that have been used around the world for practical systems.

In addition to transmission planning, risk-based approaches can also be used for choosing optimum substation configuration and spare equipment analysis. [38] Describes a probabilistic process that was used for upgrading a major 220kV substation in Tasmania, Australia. This case study considered various bus and breaker arrangements and computed reliability indices for each option. The option that gave the lowest value of reliability indices was chosen.

6.4 CAISO System Flexibility Study

This case study illustrates using probabilistic approaches for system adequacy requirements. More details about the case study can be found at [39].

California's Renewable Portfolio Standard will require 33% of all electric energy to be produced by eligible renewable resources by 2020. Current projections estimate that by 2024 in CAISO, more than 14,000 MW of solar capacity and 10,000 MW of wind capacity will be online in order to meet this requirement[7]. The integration of such a significant portfolio of renewable resources is a daunting operational and resource adequacy challenge. The "duck chart" shown in Figure 6-3 illustrates the steep ramp up in net load in afternoon hours as solar output drops.

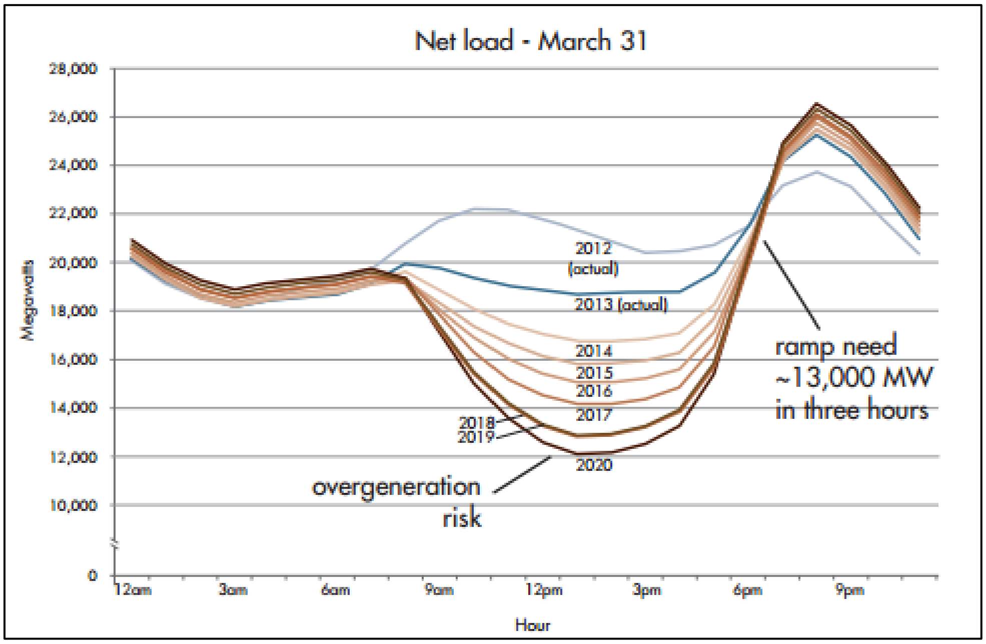

Figure 6-3 The Duck Curve

Even with the increase in penetration of renewable resources, typical days for all seasons can essentially be managed utilizing existing or planned conventional resources and conventional operating guidelines. However, probabilistic analysis demonstrates that the combination of unexpected weather conditions (reflected as unexpected load conditions and wind or solar output) and unit performance issues can result in an increase in renewable curtailment and flexible capacity shortages.

A study performed by Astrape Consulting in March 2014[8] assessed the ability of the CAISO system to avoid capacity deficiencies and flexibility deficiencies across a wide range of scenarios. This study compared reliability metrics from simulations using only a single shape to those from simulations using multiple shapes and found significant differences. The typical approach to performing either operational or long-term planning studies is to utilize load shapes from a single historical year. Planning studies

[7] http://www.cpuc.ca.gov/NR/rdonlyres/8E8B62D9-F664-4A35-ABDF-EDFB725A1B28/0/2014LTPPOpFlexModelingPresentation_060614.pdf, slide 64
[8] http://www.astrape.com/?ddownload=934

designed to assess reliability may scale those load shapes up or down to reflect extreme weather conditions, but the other effects of different load shapes, such as the duration or frequency of extreme events, are not captured. Figure 6-4 illustrates the potential differences in load duration curves from different years.

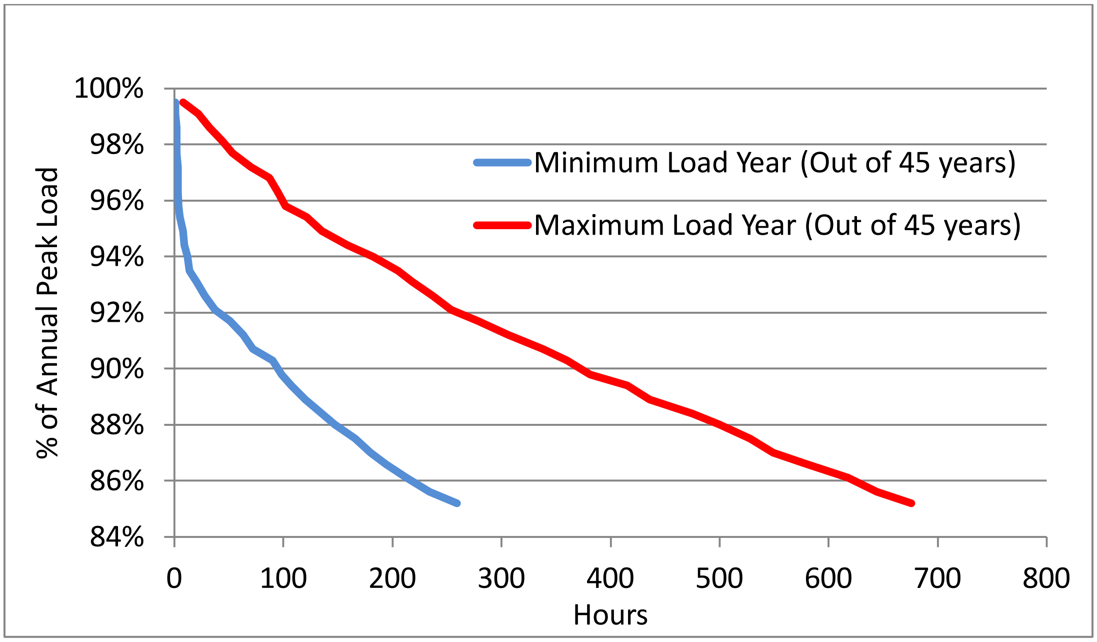

Figure 6-4 Load Duration Curve Comparison

In addition to load and weather related uncertainty, other variables were represented probabilistically in the simulations. Rather than giving the commitment algorithms perfect knowledge of the future load, wind, and solar output, Monte Carlo draws of forecast error for each component were used to construct artificial forecasts which reasonably represent the uncertainty that operators in CAISO have experienced historically. As the prompt hour approached during the simulations, the uncertainty in the forecasts would decrease, allowing the commitment and dispatch algorithms to adjust planned generation to reliably and economically meet load.

As the chart from the analysis in Figure 6-5 demonstrates[9], the metrics from all simulations performed across the wide range of scenarios demonstrated significant variation in the potential reliability of the system due to capacity deficiencies and flexibility deficiencies. Each point on this distribution represents the aggregate results from an entire year. The fact that a significant number of years have zero or very limited reliability issues emphasizes the importance of considering a spectrum of feasible scenarios for system planning studies where reliability is a concern.

[9] $LOLE_{RA}$ refers to Loss of Load Events caused by generation deficiencies. $LOLE_{RA+FLEX}$ refers to LOLE caused by either generation capacity deficiencies or flexible capacity deficiencies. EUE_{RA} and $EUE_{RA+FLEX}$ refer to Expected Unserved Energy.

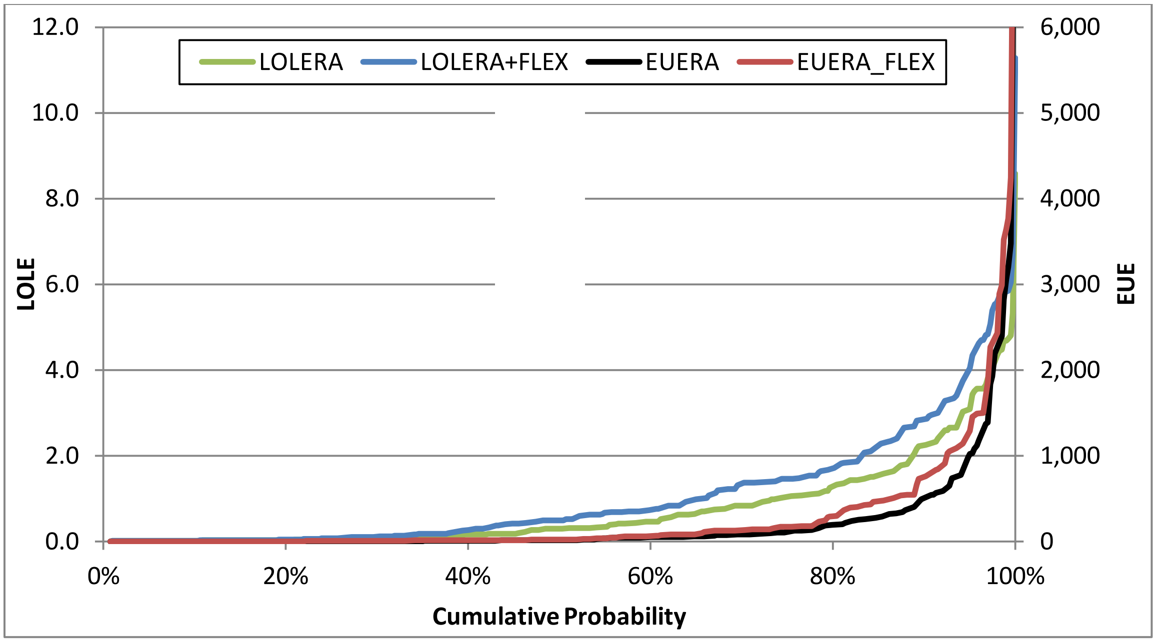

Figure 6-5 Distribution of CAISO Aggregate Reliability Metrics

6.5 EISPC Case Studies

In addition to this white paper, NARUC/EISPC sponsored research to perform case studies using the concepts described in this white paper. The aim of these case studies was to investigate the potential role and benefits of using probabilistic methods in bulk power system planning and demonstrate how explicit probabilistic methods could at the very least form an adjunct to existing deterministic methods. An overview of the case studies is provided in this section. Details of each case study are described in a separate report which will be released along with this white paper and available at www.eispc.org.

Three planning authorities participated in this endeavour by providing relevant network models, data and advice:

- Tennessee Valley Authority (TVA)
- Midcontinent Independent System Operator (MISO)
- Southwest Power Pool (SPP)

The studies fell into three broad categories:

1. Probabilistic evaluation of composite, that is, both generation and transmission system reliability using a full AC network model. These studies were performed using the EPRI Transmission Contingency Analysis Reliability Evaluation (TransCARE) program (described in Chapter 7 in this report as well as in the case studies report).
2. Generation adequacy evaluation and production cost computation for the TVA and the MISO systems using probabilistic approach. These studies used the proprietary Strategic Energy Risk Valuation Model (SERVM) software by Astrape Consulting (refer to Appendix D as well as the case studies report for a description of SERVM).

3. Demonstration of the probabilistic approach described in section 4.1 to capture variability and uncertainty in renewable generation and system load and generate load-generation dispatch scenarios that can be used for planning studies.

For all the case studies outage statistics were developed from the following sources:

1. For generator outage data, NERC's GADS database was used.
2. NERC's TADS database was used to develop outage statistics for transmission lines and transformers from 200kV and above. For the elements below 200kV, CEA's 2004 Equipment Reliability Information System (ERIS) database was used.

6.5.1 TVA Case Studies

The aim of the TVA case studies was to evaluate reliability and economic impacts of building two tie-lines to strengthen TVA network's connection with its neighboring utilities. Each tie-line was considered separately resulting in two different studies. The probabilistic reliability and economic studies are summarized in the following sections.

6.5.1.1 Probabilistic Transmission Reliability Evaluation

For the probabilistic transmission reliability analysis, the following network cases were provided by TVA:

1. A 2016 peak load case comprising of only the existing tie-lines in the TVA network.
2. A 2016 peak load case containing a new 765 KV tie-line connecting Rockport substation in the AEP control area and Paradise substation in the TVA transmission network.
3. A 2016 peak load case containing a new TVA to AECI 500kV tie-line termed the Lagoon Creek case.

For this analysis a combination of outage of up to 2 transmission components and up to 2 generators was used to enumerate contingencies. TransCARE's in-built contingency enumeration algorithm was used for this purpose. Analysis was restricted to 161kV and above transmission network. However, all the generating units within the study area were considered.

The probabilistic indices obtained using TransCARE are shown in Table 6-4 through Table 6-6. Note that these numbers are for the area under study which comprised of two zones[10] in the TVA's PSS®E planning cases. One zone was in the vicinity of one tie-line where as the other zone was in the vicinity of another tie-line. The zones were selected such that any reliability impact of the tie-lines would be notable in these zones.

Table 6-4 and Table 6-5 summarize thermal overload and voltage violation problems respectively for the three cases. Note that for these violations, no remedial actions were applied in the analysis to alleviate the problems. This approach is referred as "system problem" approach. Because the remedial actions were not considered to generate these numbers, they represent a pessimistic view of composite reliability and are an indicator of the worst case scenario. On the other hand, this approach is much

[10] A zone is a portion or sub-system of an entire control area for a utility or ISO in a planning case. A control area is typically divided into multiple zones in planning cases for ease of analysis.

faster in terms of computations as only network solutions and no system adjustment calculations are required.

Table 6-6 summarizes a set of load-loss indices as a measure of system unreliability. These indices were obtained after applying remedial actions following an outage. This approach is referred as "capability approach" and provides a more realistic view of system reliability.

Table 6-4 Thermal Violations for the TVA Cases (Without Remedial Actions)

Case	Frequency (Occurrence / yr.)	Duration (Hrs / Occurrence)	% Average Overload	% Max. Overload	# of Contingencies
Base Case	0.0185	6.7	111	164	276
765kV Tie Line Case	0.021	6.18	108	164	302
500kV Tie Line Case	0.0116	6.77	111	163	52

Table 6-5 Thermal Violations for the TVA Cases (Without Remedial Actions)

Case	Frequency (Occurrence / yr.)	Duration (Hrs / Occurrence)	% Average Overload	% Max. Overload	# of Contingencies	Problem
Base Case	0.00113	23.33	3.3	14.4	29	Low Voltage
765kV Tie Line Case	0.00149	18.81	3.7	14.4	40	Low Voltage
765kV Tie Line Case	0.163	137.78	0	0	3	High Voltage
500kV Tie Line Case	0.000963	26.44	3.3	14.5	13	Low Voltage

Table 6-6 Load Loss Indices after Applying Remedial Actions

Index	Base Case	500kV Tie Line	765kV Tie Line
Probability of Load Loss	0.010461	0.010463	0.010459
Frequency of Load Loss (Occurrence/Year)	9.34	9.34	9.33
Duration of Load Loss (Hrs./Year)	91.63	91.65	91.62

Expected Unserved Energy (MWh/Year)	2423.54	2423.75	2423.34
Expected Unserved Demand (MW/Year)	249.85	249.86	249.78

For the TransCARE analysis the following conclusion could be drawn:

1. Overall for the cases analyzed, the probabilistic analysis indicated no significant thermal or voltage violations. This can be seen from the small frequency numbers in the first column in Table 6-4 and Table 6-5. Note that these numbers were obtained using deeper contingencies (up to N-4) and not just restricted to N-1.
2. From the tables it can be concluded that adding these tie-lines do not have any reliability impact (good or bad) on the system reliability. This conclusion was in line with TVA's own analysis using the deterministic approach. However, this result by no means should be interpreted to mean that conclusions from a probabilistic analysis will always match with those from a deterministic analysis. As was shown in the SDG&E case study, the two frameworks can (and often will) give different results. Even for the TVA case studies, the benefits of the probabilistic approach should be tangible. Indices such as frequency, duration, and load loss indices including EUE provide a much more comprehensive view of the system which is not possible using the deterministic framework.

6.5.1.2 Probabilistic Economic Analysis

In addition to the probabilistic reliability analysis, probabilistic economic analysis was performed for the two tie-lines using Astrape Consulting's SERVM software. The economic analysis involved resource adequacy as well as production costing simulations. SERVM does not utilize a transmission network model, but it does perform economic commitment and dispatch for a wide range of unit performance, weather, economic, fuel and environmental scenarios. For the base case and two changed cases with tie-lines, four years were simulated: 2015, 2020, 2025, and 2030. Results were interpolated for years in between study years.Some of the salient aspects of the studies were:

1. To model the effects of weather uncertainty on load, thirty three historical weather years were created and load shapes were developed for each weather year
2. Economic impact on system load was modeled by considering three economic growth multipliers.
3. Three scenarios were developed to model uncertainties related to gas prices and environmental regulations.
4. Ten different scenarios were generated to capture generator unit performance (i.e. either complete or partial unit outages)
5. Thus, a total of 33 weather years x 3 economic load forecast scenarios x 3 fuel/CO_2 scenarios x 10 unit outage = 2970 scenarios were generated for each one of the study years
6. For each scenario hourly simulation for one complete year (i.e. 8760 hours) was performed

In summary, instead using average or median values, a range of scenarios were simulated to capture uncertainties due to various factors. The results obtained from these millions of runs are summarized as follows:

1. The two tie lines did not have any significant impact on Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE). This corroborated the results obtained from TransCARE that the two tie-lines cannot be justified based on reliability alone.
2. Net Present Value of the two tie-lines for a period of twenty years indicated that the TVA-AECI tie-line has potential for net savings whereas the TVA-PJM tie-line does not have economic benefit.
3. Figure 6-6 indicates the economic ramifications of a probabilistic view of weather, unit performance, and economic forecast error are asymmetric. The value offered by the tie-lines in extreme years is significantly higher than the median case, while the mild cases are only marginally below the median case. The weighted average annual production cost savings were $40 M for the TVA-AECI line. The median annual production cost savings were only $32 M. Since the weighted average value more closely represents the expected value, it should be used for making decisions. This means that making decisions from the median case is potentially not economically optimal for some projects, and thus performing probabilistic analysis may be essential for identifying optimal plans.

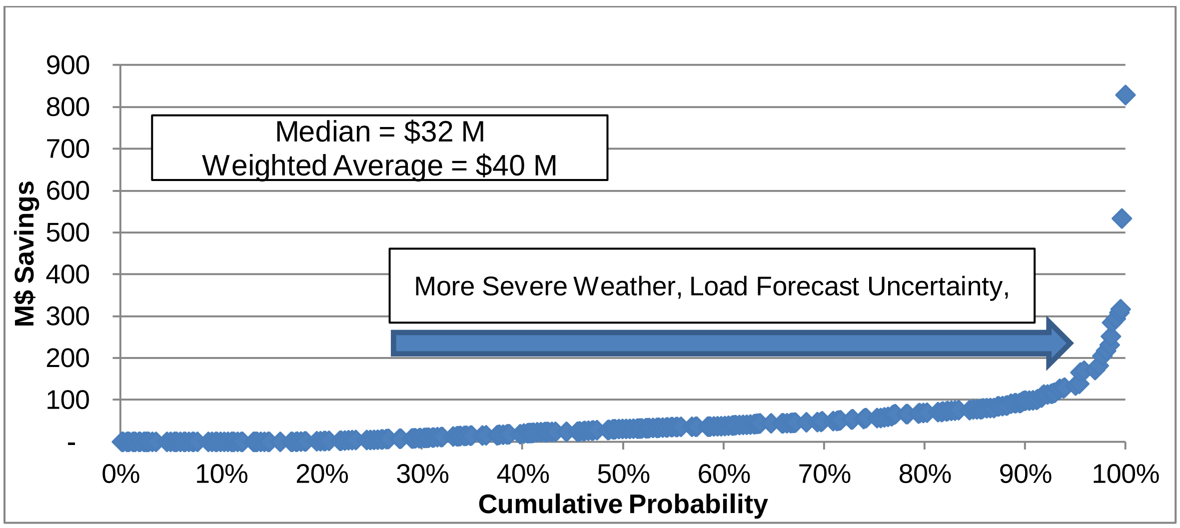

Figure 6-6 Distribution of System Production Cost Savings for 2025

6.5.2 MISO Case Study

The purpose of the MISO case study was to demonstrate potential use of probabilistic methods in the 7-step planning process developed by MISO to identify near- and long-term transmission planning needs. Specifically the case study focused on:

1. Feasibility of using probabilistic methods for transmission reliability assessments in the 7-step process.
2. Feasibility of using probabilistic approaches for resource adequacy and production costing analysis to consider uncertainties associated with weather, economic load growth uncertainty, unit performance, fuel price forecasts, and environmental legislation in the 7-step process.

6.5.2.1 Probabilistic Transmission Reliability Assessment

For probabilistic transmission reliability assessment, 2014 and2018 summer and winter cases were used. The 2018 cases had network improvements over the 2014 cases. The study area comprised of two zones in the Eastern region of the MISO transmission network. These zones were part of an interchange area containing a number of transmission network enhancement in the year 2018. Analysis was restricted to 138kV and above transmission network. However, all the generating units within the study area were considered. Also, because the study area was considerably large, analyzing deeper contingencies especially with remedial actions would have been impractical. Therefore the project team used TransCARE's in-built contingency enumeration logic to generate outage of maximum 1 generator and 1 transmission component simultaneously (i.e. up to N-2). In addition, MISO provided a list of additional N-2 and deeper contingencies that they use as part of the deterministic analysis. There were over 400 contingencies supplied by MISO for the area under study. Loss of load indices for summer 2014 and summer 2018 cases are shown in Table 6-7. It can be seen that there is substantial reduction in the load curtailment indices in 2018 indicating the positive impact of network improvements. The winter cases comparison also shows improvements in the indices in 2018 although they are not as significant.

Table 6-7 Comparison of MISO 2014 Summer and 2018 Summer Load Curtailment Indices

Index	2014 Summer	2018 Summer
Probability of Load Loss	0.01641	0.005
Frequency of Load Loss (Occurrence/Year)	16.9	5.34
Duration of Load Loss (Hrs./Year)	143.6	45.35
Expected Unserved Energy (MWh/Year)	31291	745.5
Expected Unserved Demand (MW/Year)	3794	89.4

Overall, this case study demonstrated the use of probabilistic approach to quantify the impacts of system improvements. This approach can be refined to see the impact of individual projects. Also, the approach can be used to compare more than one system improvement option and choose the most desirable based on a pre-determined criteria.

6.5.2.2 Probabilistic Economic Analysis

For the probabilistic economic analysis, two scenarios- Business As Usual (BAU) and Environmental (ENV) - provided by MISO were analyzed in SERVM. MISO's BAU case considers the future to be status quo with continued current economic trends. The power system is modeled as it exists today, with reference values and trends. Renewable portfolio standards vary by state and 12.2 GW of coal unit retirements are modeled. MISO's Environmental (ENV) case considers a future where policy decisions have a heavy impact on the future generation mix. Mid-level demand and energy growth rates are modeled. Potential new EPA regulations are accounted for using a carbon tax, state-level renewable portfolio standard mandates and goals are assumed to be met, and 23 GW of coal unit retirements are modeled. SERVM scenarios were created similar to the TVA studies as described in section 6.5.1.2. The two scenarios were simulated for 2015, 2020, and 2025 years. Overall results from the SERVM analysis for the two scenarios demonstrated the difficulty in making all decisions on a single base case and supported the inclusion of probabilistic analysis in the planning environment. For example, the economic distribution of production costs is shown in Figure 6-7.

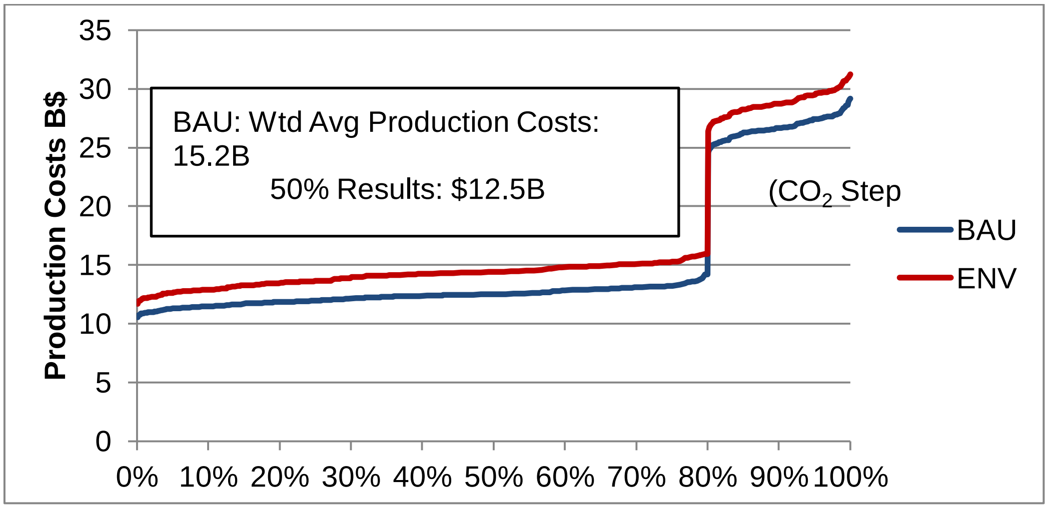

Figure 6-7 Production Cost Distribution

These simulations illustrate the impact as production costs increase from a $10 to $15 billion dollar range to a $25 to $30 billion dollar range when a $25/ton CO2 cost is applied. Also, the distribution of production costs are not symmetrical meaning the probabilistically weighted average may not always equal the single deterministic 50/50 case that many planners use to make decisions. The distributions can provide additional meaningful information such as how often the tail end events should occur and the impact of such events.

6.5.3 SPP Case Study

The SPP case study involved the demonstration of the Composite Load Level (CLL) tool to capture variability and uncertainty in renewable generation output along with system load. As mentioned in section 4.1, the CLL tool develops a reduced number of generation dispatch and load level scenarios (referred as CLLs) that try to capture significant variability and uncertainty in the renewable generation and system load. Each CLL has a certain probability of occurrence. The case study was setup as follows:

1. The power flow case used for this case study was one of the scenarios developed by EIPC. The scenario, referred as S2B1_Pass3 modeled a futuristic scenario (year 2030) for the Eastern Interconnection with the requirement that 30% of each region's load in 2030 be met with renewable resources within the region. For this case study, the focus was on the SPP footprint. A total of 23GW of wind and 5GW of solar capacity was modeled within the SPP footprint. The case was modified to include a new 765kV sub-network to provide new electrical pathways necessary to transport this massive amount of proposed generation.
2. SPP provided historical hourly time series data of the loads and some of the existing wind plants. For the proposed wind and solar plants, of course no historical data was available. For this, synthesized data from National Renewable Energy Laboratory (NREL) was used.
3. A total of 10 CLLs were generated for the study. Adding 28GW of new generation created a massive unbalance in generation and load. Therefore, unit commitment and economic dispatch

was performed on each CLL to adjust the conventional generation output and accommodate high levels of wind and solar generation. A summary of renewable output and system load for each SPP control area (NE, SPP-N, and SPP-S) for each CLL is provided in Table 6-8. Note that probability of occurrence of each CLL is also shown. In addition, variation at individual load, wind, and solar generation buses was also captured in this process. For example, wind generation variation at a wind power plant for the 10 CLLs is shown in Figure 6-8.

Table 6-8 CLL Summary Load / Fossil Generation / Wind / PV Levels for Each of the 3 Study Areas with Associated Probability

Area	Probability	Time of Day	Load (GW)	Fossil Generation (GW)	Wind (GW)	PV (GW)	Area GW Area Exchange
NE	0.16667	02:00	5.849	4.589	1.016	0.000	-0.245
SPP_N			12.115	6.062	4.612	0.000	-1.441
SPP_S			20.834	9.982	14.430	0.000	3.578
NE	0.16667	06:00	6.378	5.393	0.740	0.000	-0.245
SPP_N			13.249	7.668	4.140	0.000	-1.441
SPP_S			23.864	18.382	9.060	0.000	3.578
NE	0.02644	10:00	6.598	3.925	0.912	1.516	-0.245
SPP_N			13.834	6.371	5.968	0.054	-1.441
SPP_S			24.918	12.020	12.660	3.817	3.578
NE	0.11378		6.598	3.918	0.919	1.516	-0.245
SPP_N			13.834	6.301	6.038	0.054	-1.441
SPP_S			24.918	11.887	12.793	3.817	3.578
NE	0.02644		6.598	3.911	0.926	1.516	-0.245
SPP_N			13.834	6.232	6.107	0.054	-1.441
SPP_S			24.918	11.753	12.927	3.817	3.578
NE	0.02644	14:00	6.414	3.742	1.108	1.319	-0.245
SPP_N			13.426	5.029	6.918	0.038	-1.441
SPP_S			23.197	13.302	9.526	3.946	3.578
NE	0.11378		6.414	3.732	1.118	1.319	-0.245
SPP_N			13.426	4.949	6.998	0.038	-1.441
SPP_S			23.197	13.153	9.676	3.946	3.578
NE	0.02644		6.414	3.722	1.128	1.319	-0.245
SPP_N			13.426	4.869	7.078	0.038	-1.441
SPP_S			23.197	13.003	9.825	3.946	3.578
NE	0.16667	18:00	6.669	5.469	0.888	0.067	-0.245
SPP_N			13.937	7.391	5.105	0.000	-1.441
SPP_S			25.191	22.633	5.864	0.272	3.578
NE	0.16667	22:00	6.300	5.171	0.884	0.000	-0.245
SPP_N			13.113	7.955	3.717	0.000	-1.441
SPP_S			23.388	22.364	4.603	0.000	3.578

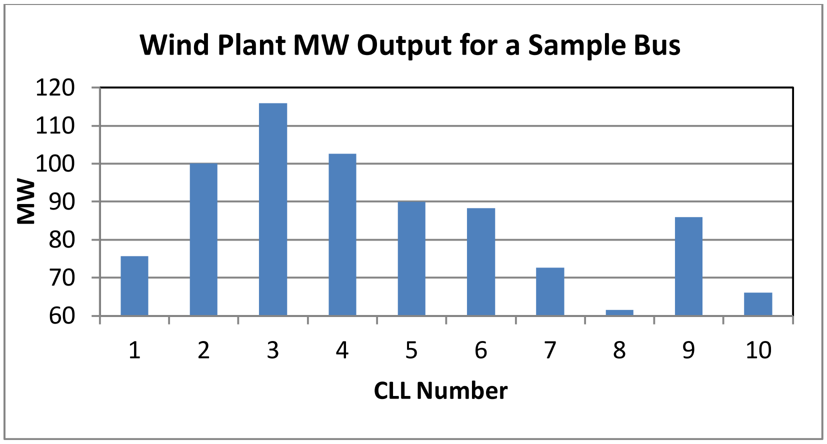

Figure 6-8 Variation in a Wind Plant Output for Ten CLLs

The generated CLLs could be used for performing either deterministic or probabilistic analysis. For this case study, the 10 CLLs were analyzed in TransCARE. These CLLs can be thought of as ten snapshots of the annual system variation. Four zones in the SPP-South control area were chosen as study areas. The analysis was confined to 138kV. However, all the generating units within the study area were considered. Also, because the study area was considerably large, analyzing deeper contingencies especially with remedial actions would have been impractical. Therefore the project team used TransCARE's in-built contingency enumeration logic to generate outage of maximum 1 generator and 1 transmission component simultaneously (i.e. up to N-2). As was done with the MISO case study, additional N-2 and deeper contingencies provided by SPP were used in addition to the automatically generated contingencies by TransCARE. The main highlights of the analysis are as follows:

Table 6-9 summarizes thermal overload and voltage violation problems respectively for the study area using the 10 CLLs. Note that for these violations, no remedial actions were applied in the analysis to alleviate the problems. It can be seen that thermal overloads are much more prominent than voltage violations.

Table 6-9 Thermal and Voltage Violation Summary for the Ten CLLs (Without Remedial Actions)

Type of System Problem	Frequency (Occurrence /yr.)	Duration (Hrs/ Occurrence)	% Average Overload	% Max. Overload	# of Contingencies
Thermal Overload	0.667	15.15	119	163	163
Low Voltage	0.0325	17.5	0	3.9	13
High Voltage	0.0823	133.8	0	0	11

As part of the TransCARE analysis, remedial actions were applied to alleviate problems following an outage. System loads were dropped as a last resort if other remedial actions failed to resolve the problems. The resultant load loss indices are shown in Table 6-10. In addition to study-area, the reliability numbers were available for individual load buses and contingencies analyzed. Such granular analysis can be used for identifying system weak spots. To reiterate, the indices provided in Table 6-9 and Table 6-10 cannot be obtained using a deterministic approach.

Table 6-10 Load Loss Indices

Index	Base Case
Probability of Load Loss	0.198
Frequency of Load Loss (Occurrence/Year)	9.313
Duration of Load Loss (Hrs./Year)	1739
Expected Unserved Energy (MWh/Year)	170751
Expected Unserved Demand (MW/Year)	1326

Overall, the SPP case study demonstrated that the CLL tool could be used to capture variability and uncertainty of renewable generation and system load. As mentioned in section 3.5, planners at present consider these deterministically mostly using engineering judgment. An approach such as the CLL tool can provide a significant improvement in this regard.

6.6 Track Record: Notable Successes and Failures of Probabilistic Approach, Particularly in Comparison with Deterministic Approaches

As mentioned earlier in the Chapter, the number of transmission planning case studies using risk-based approaches is limited. This underscores the fact that these approaches have not been widely adopted by the industry. The main obstacles in adopting these approaches are given in Chapter 8. However, the limited number of case studies available in public domain unequivocally highlight the benefits of using risk-based approaches as explained:

1. Risk-based approaches are more effective in identifying system weaknesses. System weakness can be quantified in terms of frequency and duration of system problems such as voltage and thermal violations, as well as in terms of load curtailment. Identification of system weak spots using risk-based approaches is possible because they consider likelihood of individual contingencies occurring in addition to their severity. Therefore it is possible to quantitatively rank the system weakness which is not possible in a deterministic framework. Note that none of the case studies used the worst case analysis in justifying the projects.
2. As can be seen from SDG&E, AE, and BCTC case studies, risk-based approaches implicitly consider economic assessment as part of planning criteria. This allows making objective decisions about system upgrades rather than use subjective judgment based on deterministic criteria. In summary, risk-based approaches can certainly augment the existing deterministic framework transmission planning framework.
3. In addition to transmission planning (HL2 analysis), probabilistic approaches can provide significant insights for resource adequacy analysis also. Traditionally conventional generator

outages have been represented using probabilistic models. However, using probabilistic models for considering weather related variability in system load, and renewable generation can capture impacts of extreme weather in terms of frequency and duration which are typically not captured otherwise. This is indicated in the CAISO case study as well as the TVA and MISO case studies.

7
Summary of Existing Probabilistic Planning Software Tools

An overview of various software tools related to probabilistic planning is presented in this Chapter. The information presented in this Chapter is based on literature review as well as the authors' personal experience in developing and using these tools. Tools for probabilistic modeling can be conceptually categorized into the four categories as shown in Table 7-1.

Table 7-1 Probabilistic Tool Categories

Category No.	Description	State-of-the-art
1	Tools to develop multiple scenarios to consider non-quantifiable uncertainties (refer to section 3.3)	No off-the-shelf commercial tools are available. This is an area of active research. Refer to Appendix D for details.
2	Tools to develop multiple load-generation dispatch planning cases to consider quantifiable uncertainties or risks (refer to section 3.4)	No off-the-shelf commercial tools are available. Some research grade tools are available (refer to Chapter 4). This is an area of active research.
3	Tools for resource adequacy and production costing analysis (HL1 analysis, refer to section 5.1)	Many commercial tools are available. Some are explicitly probabilistic, others are deterministic but may be used iteratively to mimic probabilistic runs. Refer to section 7.2 and Appendix D for details.
4	Tools for transmission reliability analysis(composite or HL2 analysis, refer to section 5.2)	Very few commercial tools are available. Many research grade tools are referred to in literature. However, most of them are discontinued and no longer available. Overall considerable gaps and usability issues remain for these type of tools.

Probabilistic transmission reliability analysis tools fall in category 4 and are the main focus of this chapter. It should be noted that there are well established software tools that are used for deterministic planning purposes including NERC TPL standard compliance, generation interconnection studies, and stability studies. A list of most commonly used tools in North America is given in Appendix D. Though powerful, these tools are deterministic in nature and do not typically include probabilistic analysis capabilities (one exception is TPLAN which is now integrated in Siemens PTI's PSS®E software as described in next section).

7.1 An Overview of Probabilistic Transmission Reliability Analysis Tools

An overview of five tools that are currently available for performing probabilistic transmission planning analysis is given in this section. All the tools are designed for steady state system reliability evaluation (i.e. adequacy evaluation as mentioned in section 5.3). The tools are summarized in Table 7-2. Note that there are a few other research grade probabilistic transmission reliability software that have been discontinued.

Table 7-2 A Summary of Probabilistic Transmission Reliability Analysis Tools

Name	Power Flow Approach	Contingency Selection Approach	Availability
TransCARE from EPRI	AC and DC	State enumeration	Commercially available
PSSE/TPLAN from SIEMENS PTI	AC and DC	State enumeration	Commercially available
NH2 from CEPEL (Brazil)	AC and DC	Monte Carlo	Not known
MECORE	DC	Hybrid analytical and Monte Carlo	No, used in-house at BC Hydro

7.1.1 Transmission Contingency Analysis and Reliability Evaluation (TransCARE) by EPRI

The Transmission-network Contingency Analysis and Reliability Evaluation (TransCARE) program supersedes the system of programs, known as Transmission Reliability Evaluation for Large-Scale Systems (TRELSS) developed as part of EPRI's research efforts. TransCARE utilizes the state-space (Markov) approach in computing bulk power system reliability. For each outage event TransCARE checks the system health by using the fast decoupled AC power flow and, if instructed, it takes post contingency corrective actions to alleviate system problems. If a problem such as a line overload or a bus voltage violation still persists, it will drop enough load to correct the problem. It computes a range of reliability indices to quantify the risk and/or vulnerability of the system under different outage conditions. The load variation and its impact on reliability is modelled by including up to 10 base case scenarios representing load, generation and network conditions at various times of the year.

TransCARE is capable of performing comprehensive contingency analysis by including:

- Independent contingencies enumeration of a combination of a maximum of 5 line-sections and 4 generators
- Common-mode contingencies
- User-supplied must-run contingencies
- Protection Control Group (PCG) outage due to temporary and permanent faults

The overall analysis approach in TransCARE is shown in Figure 7-1. More information about the tool can be obtained from [40].

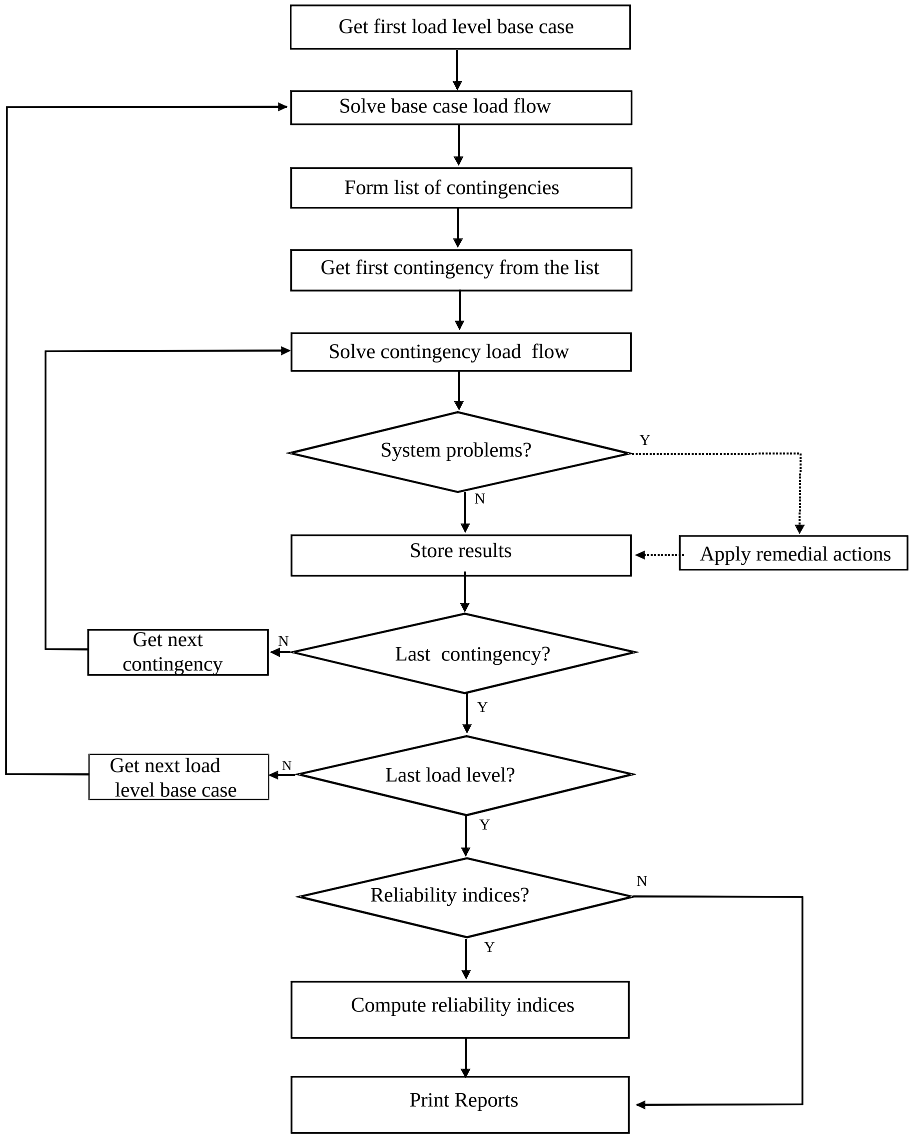

Figure 7-1 An Overview of TransCARE Framework

Note that the project team used TransCARE for performing the case studies for the other EISPC project. These case studies are described in details in a separate report ("A Study on Probabilistic Risk Assessment for Transmission and Other Resource Planning").

7.1.2 TPLAN™ by Siemens PTI

TPLAN™ used to be a standalone program from Siemens PTI. However, currently it has been integrated as part of Siemens PTI's PSS®E tool. The overall approach used in TPLAN™ is shown in Figure 7-2 [41].

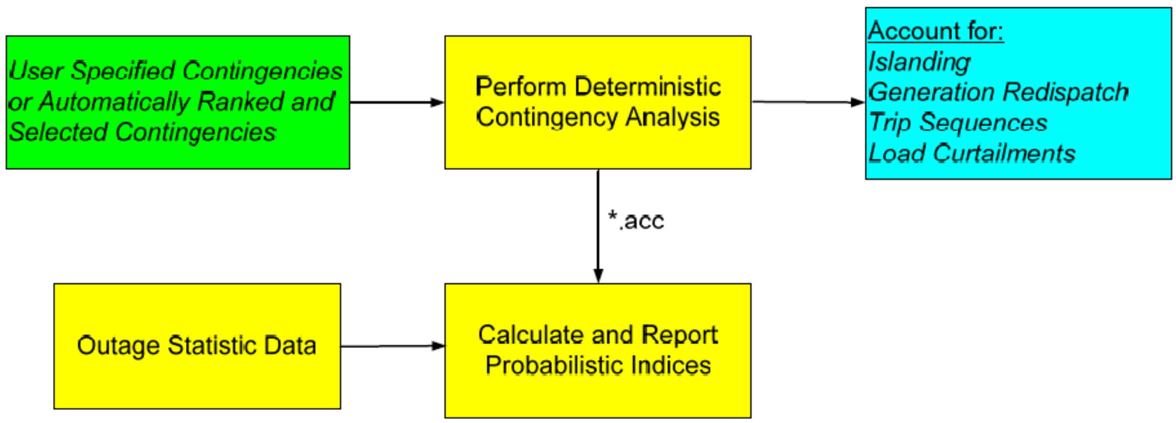

Figure 7-2 Overall Risk Assessment Approach in TPLAN™

The methodology used for risk assessment in TPLAN™ involves two major components: deterministic contingency analysis and probabilistic index computation (probabilistic reliability assessment). Deterministic analysis uses enumerative approach to evaluate each contingency and simulate sequences following a contingency. Based on deterministic contingency analysis results, outage statistics of contingencies are incorporated to calculate various probabilistic indices including probabilistic indices of overloads, voltage violation or voltage collapse, loss of load, expected unserved energy (EUE), etc. These indices can be used to measure weak points or risks in a system.

More details can be found in PSS®E user manuals (Program Operating Manual Vol 1 and Program Application Guide Vol. 1).

It is worth mentioning that there are some similarities between TransCARE and TPLAN. However, some noteworthy differences between the two are:

1. TPLAN can take out up to 3 components (N-3) in one contingency. TransCARE can take out up to 4 generators and 5 branches out (i.e. 9 components out in total) in one contingency.
2. TPLAN considers only one power flow case at a time to compute reliability indices. TransCARE can analyze up to 10 different power flow cases at a time as part of calculating annual reliability indices. In other words, up to 10 different snapshots of system can be used to calculate annual indices.

A thorough comparison of the two tools will be quite a useful exercise.

7.1.3 NH2 by CEPEL, Brazil

The NH2 software has been developed by CEPEL, the Brazilian research center for electric power, in close cooperation with Electrobras and other Brazilian utilities. NH2 is the official reliability tool used by the Brazilian independent system operator. It is also the official tool used by the Brazilian transmission expansion technical committee coordinated by the Brazilian Energy Ministry. Some of the main features reported in literature are:

- AC power flow

- Optimal power flow used for corrective measures
- Monte Carlo-based contingency enumeration
- Frequency and duration reliability indices which can be calculated at system and individual bus level
- Also perform probabilistic power flow and can generate probability density functions of selected variables such as power flows, voltages etc.

More details on NH2 can be found at http://www.nh2.cepel.br/

Based on the literature review, none of the utilities in the US have used NH2.

7.1.4 MECORE by University of Saskatchewan and BC Hydro

MECORE (Monte-Carlo Evaluation of COmposite system REliability) is a computing program for composite generation and transmission system reliability evaluation. The MECORE Program utilizes a DC-based power flow and optimization techniques. It can be used to assess composite generation and transmission reliability (HL2), generation reliability in a composite system, or transmission reliability in a composite system. It also provides unreliability cost indices which reflect reliability worth. The indices produced by the program can be utilized to compare different planning alternatives from a reliability point of view. Particularly, the unreliability cost index can be combined with the investment and other costs to conduct overall economic comparisons between alternatives. The program is based on the combination of Monte-Carlo simulation and enumeration techniques. The Monte-Carlo method is used to simulate system component states and calculate annualized indices at different system load levels and a hybrid method utilizing an enumeration approach for aggregated load states is used to calculate the annual indices considering the annual load curve. The program can handle many practical factors such as generating unit derated states, transmission line common cause outages, T-connection of transmission lines, monthly/ seasonal/ annual load curves, variable or flat bus load models, load curtailment philosophies and system separation and bus isolation.

MECOR is currently owned by British Columbia Transmission Corporation (BCTC). Based on the literature search, MECORE is used in-house by BC Hydro and is not commercially available.

7.2 Resource Adequacy and Production Costing Tools

There are a wide range of potential production cost tools which could be used for probabilistic risk analysis for HL1 analysis. Some of these are explicitly probabilistic (e.g. the results are probability distributions of costs, generator operation, etc.). Others are deterministic, but if run many times (using Monte Carlo analysis or similar), they can produce probabilistic-type results. There is a wide range of such tools, each with their own strengths. A summary of commercially available resource adequacy and production costing tools is provided in Appendix D. The list of software is non-exhaustive. However, this list covers some of the more relevant tools which are currently being applied in large studies, and many have advanced features that could be used for the type of analysis described here. For each tool, some of the more important features are described.

All production simulation tools aim to simulate how generators on a given system are likely to operate over a specified length of time, usually at least one year. They include various levels of detail on generator characteristics (minimum and maximum stable output, start times, up and down times, heat rate at different outputs, etc.), short term forecasting of load and variable generation, ancillary service requirements, transmission, fuel prices, energy limits such as hydro limits, outage rates and maintenance schedules, and interaction with neighboring regions, among other inputs. These are used to perform detailed simulations and produce results on an hourly or finer time resolution. "Zonal" models do not capture detailed transmission representation and assume all energy can flow freely within a given region, while "nodal" models capture the impact of transmission congestion and associated rescheduling of generation. As well as production costs, other results often tracked include energy and ancillary services prices, emissions, imports/exports from a given region, cycling behavior of generation, wind and solar curtailment, etc.

Please refer to Appendix D for a summary of resource adequacy and production costing tools. Note that the project team used SERVM software to perform part of the case studies for the EISPC project. These case studies are described in detail in a separate report ("A Study on Probabilistic Risk Assessment for Transmission and Other Resource Planning").

7.3 Tools to Develop Load-Generation Dispatch Planning Cases

This category of tools is referred as category 2 in Table 7-1.This topic was discussed in detail in Chapter 4. As mentioned, this is an area of active research as the current practice of coming up with deterministic load-generation dispatch scenarios may not be adequate to capture variability in renewable generation output, and changing load shape due to demand-side resources and technologies which will further increase load variability. There are no commercial software packages available to develop the load-dispatch scenarios. Current research has led to development of a few prototype tools which are described in Chapter 4. Also, it may be possible to use some of the existing deterministic tools with considerable efforts and engineering judgment to develop some of these load-generation dispatch cases.

7.4 Tools to Develop Planning Scenarios

As mentioned in Table 7-1 (category 1), there are no off-the-shelf tools available specifically to develop scenarios (mainly to model uncertainties or non-quantifiable or subjective probability factors). However, existing resource adequacy and production costing tools can certainly be used along with engineering judgment to develop planning scenarios. Researchers have developed methods and prototype tools for developing scenarios. A few of them are summarized in Appendix D.

7.5 Gaps in the Existing Probabilistic Transmission Planning Software

7.5.1 Limitations and Gaps with the Existing Tools

There is considerable published research in the area of reliability assessment of generation and transmission and a great deal of effort has been devoted to the application of probabilistic techniques in power system reliability assessment. This is quite evident from over 50 references cited in this white paper. Some of the general references about the past work are given in [42] through [50]. None-the-less, it is widely recognized that there are some limitations and gaps with the application of proposed risk-based methodologies and the tools used to conduct probabilistic reliability studies. These gaps may be grouped into several main areas of concern, namely: data requirements, present industry practices, modeling issues, issues associated with electricity deregulation, assessment of system dynamic performance, and lack of criteria. These topics are discussed in more detail in the next Chapter.

8
Barriers to Broad Integration of Risk-Based Planning

The electric power system is over a century-old well-established business. At the same time, it is an extremely complex industry. While many of the tools used for operating and planning electric systems are very advanced, the sophistication used to address its reliability and risk assessment issues, is still well below what is considered necessary to meet the need of the industry. Some of the barriers for this are systemic or institutional; others are lack of attention by researchers and policy makers. In this chapter, we will attempt to address some of these issues.

8.1 Deterministic Nature of Existing NERC Planning Practices

8.1.1 Deterministic and Rule-Based NERC Standards

The current transmission planning criteria are essentially rule-based and deterministic in nature. The term rule-based reliability planning is used here to identify the traditional transmission planning criteria and methods which are in practice today. Rules specify the performance criteria and test procedures for meeting the criteria. The test procedure is based on deterministic methods which are typically based on worst- case scenario contingency conditions. In this traditional method, probability or economics of system disturbances and power outages are not explicitly factored either in the criteria or in the test procedure. However, the current rule-base, criteria, and study methodologies have a century of experience that has led to refinements of existing rules and the development of new rules and criteria. Probabilistic or economic based reliability analyses are exceptions within the electric utilities today.

Most existing bulk electric power reliability planning criteria and procedures were developed by the utilities, regional councils, and NERC originally as planning guidelines and rules to be voluntarily met by their members. The Energy Policy Act of 2005 in the U.S. provided for development of mandatory and enforceable reliability standards with the FERC as the oversight authority. Subsequently, NERC was designated by FERC as the Electric Reliability Organization (ERO) called for in the 2005 Act. In 2007, the initial set of reliability standards became mandatory and NERC was given responsibility to enforce those reliability standards and penalize infringements.

Due to the nature and application of rule-based and deterministic standards, the existing transmission network is generally planned and built with enough excess capacity to withstand unexpected outages. The criteria implicitly recognize the fact that the probability associated with certain events is more likely to occur than others. For example, as discussed in section 2.3.2, the differentiations among the NERC transmission standard TPL-001-4 (and the corresponding Categories A through D) are the implicit recognition of the probability differences of their occurrences [8]. However, they do not clearly and quantitatively define what a “more probable” (or “less probable”) contingency is. For the most part, the classification of contingencies (less probable or more probable) is based upon experience and what seems to be reasonable.

8.1.2 No Direct Economic Correlation with Reliability Standards

Similarly, economics is not explicitly factored in by the existing standards. However, the criteria implicitly recognize the fact that the economic severity associated with certain events is higher than with others. Again, the differentiations among the classical NERC transmission planning standards TPL-001 through TPL-004 (and the corresponding Categories A through D) are the implicit recognition of the severity differences of their occurrences. Nevertheless, they do not clearly and quantitatively define the economic risks of each of the categories.

The reliability standards as they are applied today, do not directly address the concerns of an individual customer because those concerns are driven more by distribution system attributes rather than those of the transmission system. For the most part, there is no direct correlation of an individual customer's electric service reliability and the rate they pay their service provider. This is a rate making choice by state or local regulatory agencies and has little or no connection to transmission system reliability. On the transmission system, there are differences in rates and terms of service for transmission service associated with wholesale energy sales, for example firm or non-firm transmission service, however these do not directly translate to individual customer retail bills.

Generally, transmission related reliability standards do not directly consider the varying costs associated with an outage to a customer. Customer outage costs greatly vary based on the following factors:

- Customer type (e.g. residential, industrial, commercial and agricultural),
- Duration of an outage (outage costs are not a linear function of outage duration),
- Number of times an outage occurs (some industries such as glass, paper and pulp, are very sensitive to the frequency of a supply interruptions)
- Time that an outage occurs.

It is rather impossible to predict when an outage will occur since most of the outages are due to random failures of a component. What can, however, be done is to plan to minimize the impact of outages to maintain a level of reliability that a customer expects and is also willing to pay. Customers are different and their reliability requirements can vary based on the businesses they are involved in.

8.1.3 Lack of Industry Accepted Methods, Indices, and Criteria

There are no established probabilistic indices and acceptable threshold values to be maintained for risk-based transmission planning. For resource adequacy evaluations, the generally accepted index is loss of load probability (LOLP) for which the value of 0.1 days per year (or one failure due to lack of generation every 10 years) was more or less universally recognized as a reasonable threshold and is used industry wide. There is no such index or a set of indices that has been accepted for transmission planning.

More specifically there are three gaps in this regard:

1. Specifying an industry wide acceptable method for data collection and processing needed to determine meaningful statistical modeling of various types of system failures and contingencies.

2. Establishing an industry wide accepted approach to computing of the probabilistic indices that quantify risk of system failure. This should include both a rate of occurrence of an undesirable system state and a minimum load curtailment per year to maintain system operation.
3. Then to establish acceptable thresholds based on these indices. This is the most difficult to determine. For example, is one loss of total load event every 10 years acceptable, or should it be one every 100 years? One way to proceed is to factor in the evaluation of the cost for system reinforcement to reduce system risk. But this in itself is not an easy task.

8.2 Analysis Approaches and Tools

Reliability assessment is the evaluation of the power systems integrity and survivability to system stresses and uncertainties of system events. As it was discussed in detail in Chapter 2, the dominant power system analysis tools are:

- Power Flow,
- Transient Stability,
- Post-Transient Voltage Stability, and
- Production Simulation

These tools inherently use deterministic methods in which only a portion of worst-case contingency events are tested. Which contingencies to test is based on engineering judgment and experience of the transmission planners.

Risk assessment using probabilistic methods inherently require that a large number of contingencies be tested to obtain credible and reasonably accurate results. Except for the power flow analysis, conducting a large number of system tests, using the existing iterative solution techniques of the other three analysis tools is a daunting task to consider. Even for the power flow analysis, using the full iterative solution is very challenging. The common solution method used is DC power flow, and thus it is limited to testing thermal limits.

Though the advances in computer speed and availability of large storage capability have improved the potential for full risk based probabilistic assessment, these remain one of the major structural issues with risk assessment. Thus, extensive research is needed to advance direct solution methods (as compared to iterative methods) as well as finding new more efficient solution algorithms and methodologies and parallel computing techniques to perform these analyses.

8.3 Modeling Issues

As mentioned above, the existing risk-based assessment software tools are limited to adequacy assessment. Thus, to date, there has not been security based risk-assessment software available in the market. Furthermore, there are some notable limitations and barriers associated with the adequacy-based risk assessment tools. These software and hardware limitations and issues are discussed below:

- Most existing composite generation and transmission system assessment tools are designed for probabilistic reliability assessment of large AC systems and none of them can fully handle HVDC systems.

- Most existing tools especially those designed for adequacy assessment of composite generation and transmission systems, cannot properly model the energy limited nature of hydro units. In most of these programs, hydro units are treated exactly the same as thermal units.
- Some programs use an economic generation dispatch and others use a dispatch similar to that in the base case power flow. The problem with these types of dispatches is that they remain unchanged while assessing the various system states (generation, transmission and load).
- Some of the existing tools recognize some system operating limits imposed on the transmission network due to thermal, voltage and stability considerations. The problem here is that those limits are assumed to be valid under all system operating conditions when assessing the system reliability.
- It is difficult and very time consuming to prepare reliability data files required by program.
- There is complexity of analysis and interpretation of results.
- The tools cannot properly model cascading or islanding, power flow divergent cases, load curves and multiple section circuits (tap connections).
- They cannot properly calculate bus reliability indices.
- There is an inability or difficulty to model multiple states or high order failure events for those programs using the enumeration technique.
- For large interconnected system reliability analyses it is preferable that the number of transmission contingencies to be assessed should be reduced to a manageable size without sacrificing the accuracy of the final results. It seems that none of the existing tools has the built-in algorithm to do this job.
- The tools cannot properly incorporate into the analysis substation related outages.
- The tools cannot properly include operating procedures, constraints and security dispatch.

8.3.1 Assessment of System Dynamic Performance

As mentioned previously, time-domain dynamic simulations which assess system security, are always performed in a deterministic way. That is, specific fixed parameters for all the various system dynamic components are used and specific events are simulated with an exact sequence of events. However, in reality all models are an approximation to the actual system and thus there are significant uncertainties in the various parameters that determine the state of the power system. Thus, the goal of system analysis is to take into account the nature of the phenomena under study with modeling techniques that acknowledge and minimize the impact of such uncertainties. Probabilistic methods are one approach to address such uncertainties. There are, however, no established commercial tools and techniques for considering such uncertainties in dynamic simulations and applying probabilistic or risk-based methods to time-domain dynamic simulations.

Research has been done related to the application of probabilistic techniques to dynamic simulations for system stability assessment [51], however, such work has never been brought into practical use. Again one of the major gaps is data. Most of the original research in this regard investigated two potential approaches: (1) a direct transformation of random variables such that the entire process of stability analysis is performed stochastically or (2) methods such as Monte Carlo simulation [51]. The advantage of direct transformation methods is that they are more mathematically rigorous. However, such methods are very complex and applying such a method to exceedingly large non-linear systems such as a power system is quite a challenging problem. Monte Carlo approach on the other hand may require significantly large number of simulations to get credible answers.

The application of probabilistic type methods to dynamic simulations, remains an area where much research and development is yet needed. The ultimate answer may be hybrid methods, since strict probabilistic methods may be too complicated for time-domain simulation applications.

The impact of uncertain parameters is generally not significant for unstressed conditions of the power system. As the stability margin reduces the system behavior becomes much more sensitive to parameter perturbations. It is particularly important to consider cases that are on the verge of protection operation [2].

8.4 Market Related issues

Many of the existing probabilistic tools have limited capability of recognizing and incorporating the increased uncertainties introduced by the deregulation of the electric utility industry. Today, as a result of restructuring and deregulation, reliability tools should be capable of dealing with a number of uncertainties associated with the electricity market. Under open-access electricity market conditions, transmission congestion issues have to be taken into consideration. For instance, in some cases generation cannot be delivered or load must be curtailed in specific areas due to transmission constraints. Price elasticity of demand and energy will introduce another form of uncertainty into the planning process. Demand side management technologies and conservation of energy already play a role in reducing or shifting energy use. The increasing utilization of renewable sources in electric power systems requires a better understanding of the impact of these variable energy sources on power system adequacy and security. Assessment methodology and tools are needed to examine and quantify the various issues associated with those highly variable energy sources. In a deregulated environment, being able to consider the following uncertainties is of paramount importance [2]:

- Uncertainty of power generation location, capacity, timing and availability of new conventional and un-conventional energy sources
- Uncertainty in future complexity of power transactions
- Uncertainty in future demand
- Uncertainty in future regulation/rules

8.5 Data Issues

Risk-based reliability calculations depend on data availability and requirements to support such studies. One of the major limitations for the application of probabilistic tools and methods is the lack of data collection and system monitoring, as well as inadequate system performance data (static and dynamic) and inadequate component performance data. There are, however, some existing examples of good data availability such as Canadian Electricity Association's (CEA) Equipment Reliability Information System (ERIS) [52] and North American Electricity Reliability Corporation's (NERC) Generation Availability Data System (GADS) for collecting outage information about generators and Transmission Availability Data System (TADS) for collecting outage information about transmission components [33]. CEA has been collecting bulk transmission outage data since 1980 and NERC TADS has started to collect data on all 200 kV lines and above across all NERC regions since 2008. None-the-less, the lack of statistical data on both system and component performance remains a significant gap.

With the increased complexities of power system regulation, the continuous introduction of advanced devices such as smart-grid, and the aging of the electric power grid, the nature of power system data is changing. Furthermore, the economic impact of system outages may be changing with the introduction of distributed generation, as well as availability of fault monitoring and control devices that are much faster than before. In addition to that, there are new reliability considerations with cyber security that are introducing further complexities to the overall data and risk-based reliability assessment issues. In total, all of these are expected to bring fundamental changes in how we view risk-based reliability assessment in the future.

For instance, the introduction of new communication devices and controls obviously brings with it more risk for equipment failures and risk of system outages. However, the new devices are there to provide quick reaction to system problems and capabilities to operate in islanded mode. All of these are new challenges to the traditional view of system reliability.

With the existing data collection process there are still some key limitations and issue that are important to recognize. These include:

- Lack of data on transmission configuration in view of transmission corridors and line crossings
- Lack of data on station configuration and outage causes
- Lack of data on protection and remedial action controls
- Rarity of extreme event data
- Adequacy and security indices are driven by a small number of high loading events. The nature of these rare events means that they are challenging to attribute a probability of occurrence
- New event types are possible due to the large scale change in power systems, which will not be considered when probabilistic input information is based on historical data

8.6 Workforce Skill Sets and Resource Availability

Risk-based assessment in electric power system requires a good understanding of the theories of statistics and probability, in addition to the advanced knowledge of the electric power network. Typical electrical power engineering curricula do not include such courses in their required class offering. Probability analysis continues to be a specialized discipline within electric power engineering. This has led to a general lack of understanding of probabilistic methods in the electric power industry.

It is a common theme now with all electric power utility business that their technical workforce is an aging workforce. This is happening on top of the growing need for advanced understanding of the electric power system fuelled by the continuing challenges of new technologies and regulations. This creates additional challenges in expanding system analysis capabilities to incorporate probabilistic methods.

Generally, the workforce and resource issues include:

- Time consumed with NERC compliance using existing deterministic methods is extensive, thus spending additional time to learn or work on additional methods, tools, analysis, etc. is quite difficult

- Hard to modify or replace the study tools that exist and support infrastructure in place for existing analysis methods, e.g., all of the IDEV or Python code around PSS®E, EPCL around PSLF™, base case management tools, etc.
- Shortage of planning engineers to cover the complex transmission planning needs of today

8.7 Gaps and Associated R&D Needs

As we have discussed in detail all of the issues and limitations with risk-based analysis, we would like to summarize the shortcomings and identify opportunities to address the gaps to facilitate more incorporation of risk-based approaches in transmission planning activities. Table 8-1 summarizes the main gaps identified in broader integration of risk-based approaches and recommendations.

Table 8-1
Summary of Barriers to Broad Integration of Risk-Based Approaches

<table>
<tr><th>Number</th><th>Barrier</th><th>Recommendations</th></tr>
<tr><td>1</td><td>Deterministic nature of NERC reliability standards</td><td rowspan="4">• Closer coordination and collaboration among federal policy makers (FERC and NERC), State policy makers, utilities, ISOs, and research organizations to develop long-term vision for adopting risk-based planning approaches in the existing planning framework
• Greater awareness among policy makers and practicing engineers about when and how risk-based transmission planning can provide significant value as compared to deterministic approaches
• Develop standard outage data collection process and centralize database of historical data. NERC’s efforts in collecting and maintaining TADS and GADS databases are commendable in this regard.</td></tr>
<tr><td>2</td><td>Lack of industry-wide accepted approach to decide which indices to compute and how to compute</td></tr>
<tr><td>3</td><td>Lack of industry-wide accepted threshold of the indices</td></tr>
<tr><td>4</td><td>Lack of standardization and availability of reliability data</td></tr>
<tr><td>5</td><td>Workforce skillset and lack of adequate resources</td><td>• Collaboration among utilities, ISOs, research organizations, and universities on incorporating relevant power systems reliability courses in curriculum
• Industry workshops such as the ones organized by NERC to create awareness among workforce</td></tr>
<tr><th>Number</th><th>Barrier</th><th>Recommendations</th></tr>
<tr><td>6</td><td>Consideration of changing regulatory environment</td><td>• Develop better approaches and possibly tools to design credible scenarios for future transmission expansions</td></tr>
<tr><td>7</td><td>Existing tools for system adequacy studies have limitations</td><td>• More research on developing new tools and improving some of the existing models, computation techniques, output data processing
• Implementation of the tools on High Performance Computing platforms</td></tr>
<tr><td>8</td><td>No tools are available for system security assessments</td><td>• Develop prototype tools based on the research performed so far</td></tr>
</table>

9
Regulatory and Jurisdictional Considerations

The regulatory landscape with regards to transmission planning is experiencing transformational changes since the mid-nineties. This includes landmark FERC Orders (starting from Order No. 888 in 1996 to Order No. 1000 in 2011) as well as laws enacted by states related to development of transmission projects. This chapter provides a discussion about if and how risk-based reliability and economic approaches can help policy makers at federal and state levels to gain a deeper understanding and make informed decisions about transmission projects.

In addition, this chapter provides an overview of WECC activities that were pursued in the mid-nineties to develop Risk-Based Planning Criteria. Those efforts did not come to fruition. However, the activity was the first of its kind in the US and provides a framework for developing probabilistic planning criteria for future efforts. An overview of NERC's activities in the area of risk-based planning is also provided.

9.1 Federal and State Jurisdictional Considerations

Starting with Public Utility Regulatory Act (PURPA) in 1978, and following with the National Energy Policy Act (EPAct) of 1992, and the Energy Policy Act of 2005 (EPAct05) the regulatory structure of the electric power system has been evolving with the goal of bringing about more efficiency, higher reliability, and less environmental impact. The hallmark of the evolving regulatory regimes is increasing competition. The key transmission related FERC orders are given in Figure 2-2 and the figure is re-produced in Figure 9-1 for easy reference.

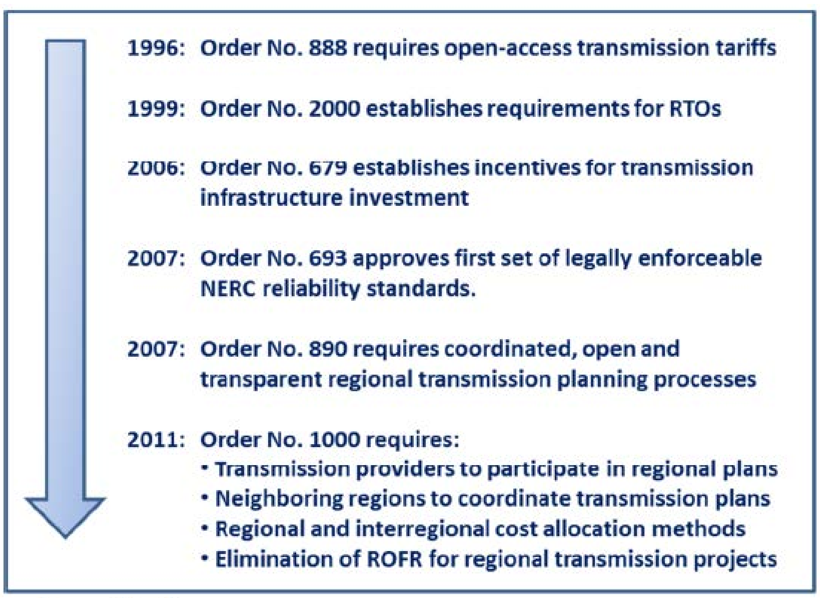

Figure 9-1 Key Transmission Related FERC Orders [3]

Some of these FERC Orders can be summarized as follows [53]:Order No. 888 issued in 1996 mandated non-discriminatory open access to transmission facilities owned, operated, and controlled by public utilities. This order established rudimentary requirements for the planning and development of transmission facilities necessary to serve network and long-term firm point-to-point transmission customers. Order 890 in 2007 further reformed the transmission planning process and mandated that public utility transmission providers adopt transmission planning processes designed to broaden the scope of transmission planning in terms of both geographic coverage and intended beneficiaries. Finally, Order 1000 further cemented regional planning and cost allocation, requiring utilities outside of the existing RTOs and ISOs to join regional planning entities and develop open and non-discriminatory regional transmission plans, including regional cost allocation for certain projects.

On the other hand, states have been enacting laws to restructure their states' electric power businesses. States still retain broad authority to grant or deny authorization to construct new facilities and oversee utility rates for retail service. A combination of federal and state legislation and the various regulatory orders from the federal and state commissions have become the key factors in transforming the electric power business. Both federal and state standards and regulatory approvals are needed to work symbiotically to build transmission infrastructure that is reliable, environmentally sustainable and affordable in the long-term. However, given the nature of the US federal and state systems, policy conflicts can often occur between federal and state regulators as well as among different states with conflicting interests. Some issues to consider in this regard are:

1. Federal regulations usually take a "top-down" approach where the focus is more on regional and inter-state planning process. As opposed to this, state regulations focus on more localized interests of the state. Thus, to avoid conflicts, it is necessary to develop a shared vision for the power grid in which states should actively participate in regional planning processes for better coordination while at the same time retaining the prerogatives for projects of local interests.
2. There may be conflicting interests among states. For example, states with substantial wind and solar generation potential may wish to develop those resources but find those resources undeliverable to the market because of a neighboring state's resistance to bolstering grid infrastructure. In this case, customers may be deprived of access to less expensive or more diverse power resources due to regulatory obstacles to transmission expansion in adjoining states [53].
3. FERC's top-down approach for regional transmission planning efforts has led to creation of transmission-only utilities (transcos) to construct, own, and operate transmission infrastructure. Transcos could be formed either in response to utility restructuring policies at the state level (for example American Transmission Co., LLC (ATC) in Wisconsin and International Transmission Company (ITC) Holdings in Michigan), or due to business decisions by utilities to divest transmission assets to an independent transmission company. Evaluating technical pros and cons of various proposed transmission alternatives is a major endeavor and developing robust approaches such as based on risk-based approaches will certainly prove beneficial to transcos.

In view of the preceding discussion, the question arises "Is there a place for risk-based approaches to help federal and state regulators as well as privately owned transcos to better understand project needs as well as to make better planning decisions?" This question is addressed in the next section.

9.2 Potential Role of Risk-Based Approaches in Regulatory Considerations

The project team believes that risk-based reliability and economic approaches can help in the transmission planning process by providing significantly deeper insights to regulators as well as planning engineers. This section focuses on reliability approaches for transmission planning.

For transmission planning, risk-based approaches can play a significant role for the following:

1. Identification of system weaknesses
2. Comparison of alternative transmission plans
3. Justification of new facilities

9.2.1 Identification of System Weakness

Identifying system weaknesses, inability to maintain reliability, and economic constraints is the first step before coming up with possible transmission solutions. These limitations can manifest themselves either locally in terms of thermal or voltage violations at a few buses or at a regional level in terms of insufficient transmission to carry power across states, i.e. transmission congestion. Either way, risk-based approaches to transmission system analysis can be helpful:

1. Probabilistic techniques provide the likelihood of individual contingencies in addition to the severity of impact when they occur. This allows a quantitative ranking of system constraints or weaknesses which is not possible in a deterministic framework. While deterministic testing is still required to meet NERC requirements, the ranking of constraints can provide useful information on the magnitude of impact from additional transmission investment.
2. System problem indices such as the frequency of low voltage at individual buses or the frequency of overload on individual circuits are useful measures for ranking system weaknesses. Analysis of the contingencies contributing most to the frequency of a specific system problem will often suggest where appropriate system modifications are required.
3. Load curtailment indices at load buses provide a powerful way of ranking system weak spots. Analysis of the contingencies contributing most to such bus indices would suggest where additional system reserve or remedial capabilities will improve reliability as an alternative or as an adjunct to system strengthening to avoid initial system problems such as overloads or low voltages.

9.2.2 Comparison of Alternate Transmission Plans

Risk-based approaches can provide a solid framework to help select the optimum alternative for transmission expansion and reinforcement. Even though a stand-alone risk-based approach is the ultimate goal for transmission planning when quantifiable uncertainties are involved, a more acceptable approach today may be to use risk-based approaches as complimentary refinements to the existing deterministic methods used by the utilities. Under such an approach, as a first step, all the alternatives that do not meet deterministic criteria can be discarded. After this step there may be two or more alternatives that may be functionally identical from a deterministic point of view. Now, risk-based methods can be used to stress the system with contingencies that are more severe than those used for the deterministic acceptance tests and produce indices reflecting the frequency or the probability of failure events. In addition, cost-benefit analysis can be performed on each alternative to identify cost benefits tradeoffs for various transmission solutions. In considering such analyses, among competing proposals, the cost of the solution would not necessarily be the primary driver for project selection as the analysis could also consider the project benefits of avoided unserved energy.

System expansion may impact a wide area or it may impact only a small group of buses. Reliability indices should be picked accordingly. A system-wide index is appropriate if the alternative is going to impact a wide area. On the other hand, bus indices are more suitable if the alternative is localized.

9.2.3 Justification of New Facilities

Transmission facilities are subject to various state and federal siting processes which involves non-technical personnel. Risk-based approaches provide a strong adjunct to the subjective judgment required in justifying new facilities. It is easier to communicate system issues in terms of frequency, duration, and impact of system problems and energy lost to non-technical personnel and communicate the need for the new facility.

Note that not all new facilities are for improving reliability. These could be strong economic reasons for building transmission projects which may or may not have any impact on system reliability. An example could be building tie lines to import cheaper power from neighboring regions rather than producing expensive power within the service territory. Such a scenario was considered in the TVA Case Study performed as part of the companion project (“A Study on Probabilistic Risk Assessment for Transmission and Other Resource Planning”). The factors impacting the economic worth of projects can have significant variability and uncertainty over the project lifetime. These factors were discussed in Chapter 3 and include:

- Weather related load uncertainty
- Economic growth
- Output of variable resources
- Fossil fleet retirements
- Long-term fuel prices
- Demand-side resources and demand response programs
- Availability of imports

As demonstrated in the case study, considering average or point estimates can be misleading and will not cover the entire gamut of scenarios over the project lifetime. Risk-based approaches such as the one demonstrated in the TVA case study can prove to be quite valuable in assessing economic worth of a transmission project.

9.3 Risk-Based Approaches for Resource Adequacy Assessments

Although not the main focus of this white paper, as mentioned in Chapter 5, risk-based approaches can be used in resource adequacy assessments as well. This has been emphasized by NERC in 2014 Long-Term Reliability Assessment report [14]. Traditionally the North American generation mix has primarily consisted of conventional generation. For conventional generation mix, a Reserve Margin metric has been found to be useful. Reserve Margin is the difference between installed capacity and expected peak demand in an area, expressed as a percentage of expected peak demand. Reserve Margin and Loss of

Load Expectation (LOLE) metrics are related as shown in Figure 9-2. The one-event-in-ten-year (0.1 events per year) LOLE is typically accepted standard.

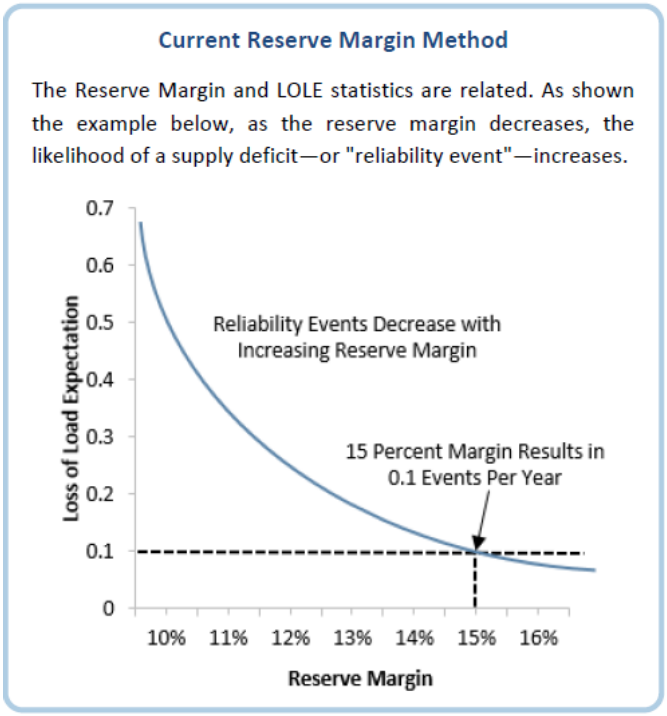

Figure 9-2 Reserve Margin as a Measure of Risk in Resource Adequacy [14]

However it is increasingly being realized that Reserve Margin alone is not a sufficient indicator of resource adequacy. This is because:

1. Reserve Margin metric assumes that generator fuel availability is not correlated with load levels or weather. However, extreme cold weather experienced in the Midwestern and Northeastern United States and Southern Canada in January 2014 clearly showed the limitations of this assumption. Extreme periods of cold temperatures directly impacted fuel availability, especially for natural gas fired generators as well as higher-than-forecast peak load. Therefore it is necessary to consider the impact of extreme weather on load spikes and increased generator outages. This can be achieved using risk-based methods.
2. Reserve Margin calculations do not consider reliability of renewable generators during off-peak hours or during extreme weather events. This can lead to optimistic risk assessment, or alternatively to derating variable renewables to a percentage of their capacity; however, the method to do this derating will, by its nature, be somewhat simplistic and will not represent the multi-year variability of the resources.

NERC has recommended using risk-based approaches such as the one used in the case studies for resource adequacy assessments.

9.4 WECC Probabilistic Methods Considerations

The discussion so far has focused on the potential uses of risk-based approaches for transmission planning and resource adequacy. This section discusses the efforts that were initiated in WECC to develop risk-based planning criteria in the mid-nineties. That was a ground breaking effort towards the development of probabilistic-based standards for transmission planning.

With the transition to mandatory reliability standards developed by NERC, some important differences in planning criteria, guidelines, and approaches that existed prior to 2006 were identified and initially approved as regional differences with the NERC standards. In addition, some regional differences were left as regional business practices for application by the respective regional councils. One such application was the WECC probabilistic-based reliability criteria (PBRC). WECC PBRC was one of the most significant probabilistic-based transmission criteria development activities that had been attempted within NERC to date.

In 1996, WECC initiated the Probabilistic Methods Task Force (PMTF) to develop PBRC for the then WSCC Reliability Criteria for Transmission System Planning. The goal was to expand the criteria to be more probabilistic based. PMTF developed a framework that included a four-phased approach for full transformation of the deterministic transmission criteria to probabilistic methods. Some of the considerations of the PBRC framework were:

- In Phase I, event probability data were to be developed and incorporated into the Performance Table. These data may be expressed in one or a combination of the following: outage rate, outage frequency, outage duration, forced outage rate (FOR), or availability. The main task of this phase was to define these probabilistic data.
- In Phase II, performance impact measures were to be developed and incorporated into the Performance Table. These measures may be expressed in MW, MWh, a combination of both, or some other related measure. The main task of this phase was to define these system impact data.
- In Phase III, performance risk measures were to be developed. These measures may be expressed in expected unserved energy (EUE), expected power not served (EPNS), outage minutes, MW (or MWh) in percent of peak, or other related measures. The main task of this phase was to define the necessary mathematical model and "map" the performance table to the model. Given P and I are event probability and impact, respectively, performance risk (PR) was defined as:

$$PR = \sum_{a}^{d} P_i I_i = \sum_{x} P_x I_x$$

Where:
a-d = contingency categories A through D
P_i = probability of contingency events in category i
I_i = level or amount impact of contingency events in category i
x = contingency state resulting in system impacts
P_x = probability of event in state x
I_x = level or amount of impact of the event in state x

- In Phase IV, economic risk measures were to be developed. These measures will be expressed in dollars. The main task of this phase was to define interruption cost factors. Economic risk (ER), where C is outage cost, is defined as:

$$ER = \sum_{a}^{d} P_i I_i C_i = \sum_{x} P_x I_x C_x$$

Where: C_i = outage cost of contingency event impact in category i
C_x = outage cost of event impact in state x

Due to the complexities of the work efforts, only Phase I of the WECC PBRC was completed. In 1998 WECC adapted the Phase 1 results as performance “Table W-1” shown here as Table 9-1 to be used as guide in transmission planning and for evaluation and testing of transmission outage performances [54]. Presently, the WECC PBRC has been adapted as WECC regional standard titled: System Performance TPL-001-WECC-CRT-2.1 Regional Criterion.

An illustration of the NERC transmission planning standard framework using the original NERC TPL standards was given in Figure 2-6. The figure is also shown in Figure 9-3. Also shown in the figure are some hypothetical values for the relative rankings of contingency events (frequency of outage) and their respective performance impacts (Expected Unserved Energy (EUE) or $ impact). For the hypothetical ranking the difference between each category is selected to be a multiple of 10. The risk matrix of the performance table is also shown (calculated by matrix multiplication of the corresponding events and impacts). The values shown are the risk rankings of the EUE per year or $ per year impact of the events and impacts associated with that particular block.

As can be seen in Figure 9-3, the unsecure (shaded) area has much larger risk value than the secure area. Conceptually, knowing the frequency of outage and the EUE or $ impact values for each categories will easily give us the true risk.

In Phase I of the WECC PBRC, the outage frequency ranges associated with each contingency event category were determined through extensive data collection and statistical analysis. These Phase I values were adopted by WECC as shown in Table 9-1. Phase II of the program was to identify the range of values associated with performance impact categories. In Phase IV the range of costs associated with each of the impacts were to be assessed.

As was discussed in Section 2.3.2, the new NERC TPL-001-4 is an expansion or a refinement to the original TPL standards. Thus, these new standards are to be viewed as an expansion of the dimensions of the reliability framework shown in Figure 9-3.

Table 9-1
The WECC PBRC Risk Assessment Table that was in used until mid-2014 using Hypothetical Data

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 3)
A	Not Applicable	Nothing in addition to NERC.		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC.		

		NERC TPL-001 through 004 Maping				Phase II: EUE (Relative Ranking)	Phase IV: $ Impact (Relative Ranking)	Resultant Risk Metrix			
PERFORMANCE IMPACT	Cascading	Category D				1000	1000	1,000	10,000	100,000	1,000,000
	Controlled Load Dropping		Category C			100	100	100	1,000	10,000	100,000
	Emergency Loading			Category B		10	10	10	100	1,000	10,000
	None				Category A	1	1	1	10	100	1,000
		N-3+	N-2	N-1	N-0			N-3+	N-2	N-1	N-0
		CONTINGENCY EVENT						CONTINGENCY EVENT			
	Phase I: Outage Frequency (Outagae/yr) Relative Ranking	1	10	100	1000						

Figure 9-3 Illustration of the WECC PBRC Risk Assessment Methodology using Hypothetical Data

9.5 NERC Considerations of Probabilistic Analysis

9.5.1 NERC's Reliability Assessment and Performance Analysis program

Using historical data and projections provided by utilities, NERC frequently conducts reliability evaluations of the bulk electric system and assesses risks that could impact system performance. Annually, NERC issues the "State of Reliability," "Long-Term Reliability Assessment" or LTRA, "NERC Probabilistic Assessment" and many other assessment reports as needed. NERC has developed reliability performance assessment models and various indices to assist it in communicating system performance measurements to the industry.

The NERC risk model used in the performance assessment is shown in Figure 9-4 [55]. One key metric calculated under the model is the Security Risk Index (SRI), which provides daily reliability risk severities for generation, transmission and load losses. Other important risk metrics reported in the State of Reliability report include: frequency response, protection system mis-operations, substation equipment failures and 16 adequacy level Indices (ALI). Combined, all of the indices provide a complete picture of the condition of the bulk power system.

NERC LTRA is a ten-year assessment of the adequacy of the NERC bulk electric system. Transmission system adequacy, electricity supply and demand, and key issues and trends that could affect reliability are also discussed in the report. The bulk electric system is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries [56].

NERC Probabilistic Assessments of resource adequacy are performed to compliment the adequacy metrics calculated through the LTRA. As discussed in Section 8.1, many regions use deterministically based resource adequacy targets such as planning reserves. This study is to assess the relationship of probabilistically based adequacy criteria versus the planning reserves [57]. Having appropriate measurements to assess the true nature of the required reserve is tremendously important to the efficient operation of the bulk power system. A detailed analysis of resource adequacy is provided in [58].

Reliability Risk Management (RRM) is the key NERC group that is responsible for providing most of the risk assessment described above. RRM's primary functions include: (1) Bulk-Power System awareness; (2) event analysis; (3) training; and (4) operator certification. All of these functions are essential in providing highly reliable systems [59].

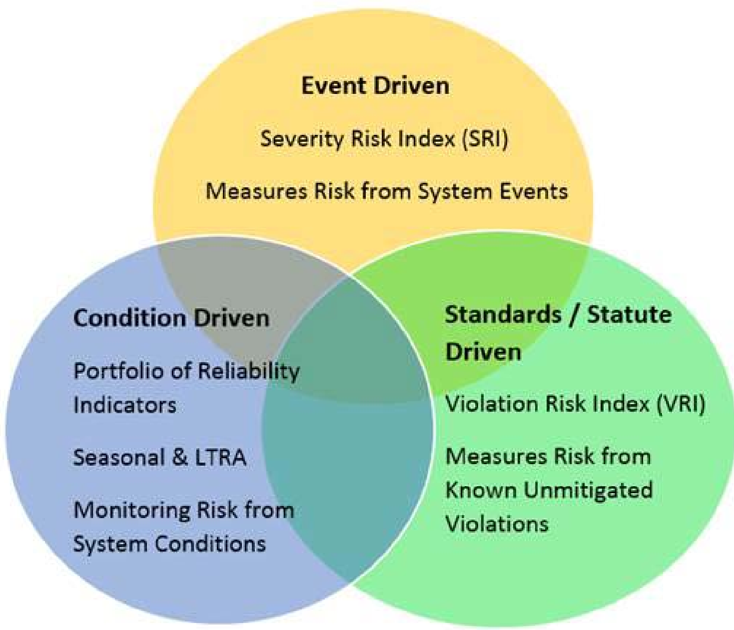

Figure 9-4 Conceptual Risk Model for Bulk Power System [55]

9.5.2 NERC's Data Collection Efforts

To properly conduct its reliability oversight responsibility, NERC collects system outage data for generators and transmission components. These unique databases are used to collect, record, and retrieve operating information and are used to conduct the system reliability performance assessments discussed in the section above.

Starting January 1, 2013, generator and transmission owners are mandated by NERC to provide their reliability related operations of their generators and transmission systems. Generator Availability Data System (GADS) is the reporting construct for conventional generating units with nameplate rating of 20 MWs or more. Presently, wind and solar power generation are not included in this requirement. Reporting by generators with nameplates lower than 20 MW is voluntary.

Starting in 2010, transmission owners are mandated to provide transmission related data to NERC. The Transmission Availability Data System (TADS) requirement is very extensive and is used to conduct transmission reliability assessments.

9.6 Conclusions

Regulatory and jurisdictional issues at the federal and state level are key considerations in transmission planning and the future development and application of risk-based planning in the United States. Various legislative and regulatory actions in the last 20 years have transformed the transmission planning process with the effect of bring more systematic regional planning approaches and implementing mandatory reliability standards. Key factors in the future development of risk based planning approaches that are the domain of regulators are probabilistic based planning criteria, and industry-wide collection of system reliability data. Previous probabilistic based reliability criteria development efforts by regional groups such as WECC have shown promise in promoting risk-based approaches. In addition, NERC is actively engaged in the collection of transmission outage data that is essential in the implementation of the risk based planning. As the fundamental input data becomes more available and risk-based approaches become more mature, they will likely play an increasing role in transmission planning and provide additional information to federal and state regulatory processes.

10
Recommendations

Transmission planning processes are faced with new and unique challenges that have not been encountered before. Most of these challenges are due to various uncertainties and risks that have become more prominent in the last few years. As was clearly mentioned in Chapter 3, these impact over a wide-range of timeframes and can have varying degrees of impact. Another factor that complicates transmission planning is scale of the problem - it is not a localized issue and in fact future planning may encompass broader regions or even entire interconnections.

While deterministic assumptions and approximations have served the industry reasonably well so far, it is very likely that these may not be adequate to ensure more optimal and effective transmission plans in future. As mentioned before, this by no means implies that risk-based planning should completely replace deterministic planning. Neither should it be concluded that risk-based methods and tools are ready for “prime time” so to speak. However, we are of the opinion that probabilistic methods can augment existing deterministic methods and can provide much deeper insights than just deterministic methods alone. This view has been reinforced throughout the white paper.

10.1 Proposed Comprehensive Transmission Planning Approach

In this section, we propose a comprehensive transmission planning approach which attempts to combine the strengths of risk-based approaches with the existing deterministic framework. The proposed approach is shown in Figure 10-1.

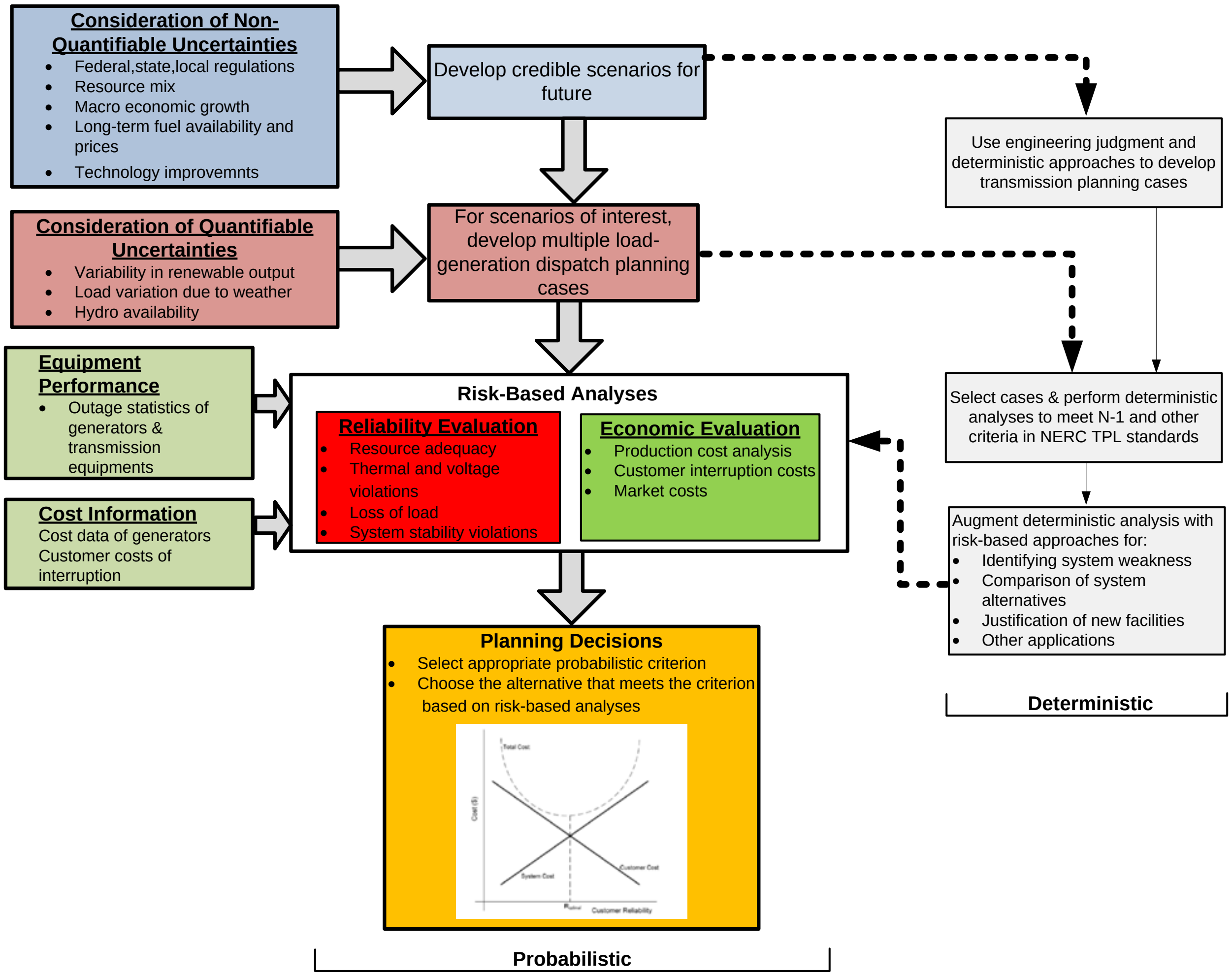

Figure 10-1 Proposed Framework of Risk-Based Transmission Planning and Link to Deterministic Planning

Note in Figure 10-1, the blocks on the left (with thicker boundaries) represent the risk-based planning process while the blocks on right (with thinner boundaries) represent tasks in the deterministic planning process. The dotted arrows are the links between the two processes and show how risk-based approaches can supplement the deterministic planning process. Referring to Figure 10-1, the steps for performing probabilistic planning are summarized first as follows:

1. Develop multiple scenarios (or futures) to consider long-term uncertainties (also referred as non-quantifiable uncertainties or subjective probability variables) that impact transmission planning process but cannot be quantitatively expressed using probability distributions (refer to section 3.2 for details). As mentioned in this white paper, the main uncertainties that can impact transmission planning processes are – federal, state, and local regulations related to environmental restrictions, changing resource mix both on supply and demand side, long-term fuel costs and availability, economic growth, and new technologies across generation, transmission and distribution systems. Multiple scenarios are developed to discretize these uncertainties. Although relatively simple, scenarios are still a deterministic representation and may not capture the entire gamut of possibilities that can occur in future. Research is being

performed to develop improved methods to capture uncertainties but at present, scenario development remains the most practical approach to consider uncertainties. Most of the utilities and ISOs develop scenarios based on inputs from stakeholders.

2. Once a certain number of scenarios are developed, various risks (also referred as quantifiable uncertainties or objective probabilities) impacting transmission planning should be considered for each scenario to develop transmission planning cases that represent credible load-generation dispatch scenarios (refer to section 3.4 for details). At present this is done on an ad hoc basis by considering only a few deterministic cases and without any thorough consideration of the probabilistic nature of these risks. This might result in coming up with scenarios that are not representative of the actual operating conditions. Many probabilistic approaches are being developed to quantitatively capture these risks (refer to Chapter 4 for more details).However, most of the work is still in research domain and no off-the-shelf commercial tools are available for planners to develop these planning cases.
3. The transmission planning cases developed in step 2 can be analyzed using risk-based reliability and risk-based economic methods and planning criteria. These are covered in details in Chapter 5. The analyses should be performed for the baseline case as well as for any proposed system enhancements. Risk-based reliability analysis involves finding frequency and duration of voltage and thermal problems, load curtailment due to remedial actions, as well as finding unreliability costs. The reliability analysis can be performed using either state enumeration or Monte Carlo technique. At present none of the standard planning tools available have these techniques. Research grade software, EPRI's TransCARE being the most prominent, are available and can be used for reliability analysis. Probabilistic economic analysis can be used to calculate cash flows and net present value of different system enhancements. Finally using either one of the approaches in section 5.8.2, various alternatives can be compared and the one that meets the c criterion can be selected.

The three steps mentioned here summarize the risk-based transmission planning process. Generation reliability (HL1) analysis for finding LOLE values is typically performed using probabilistic approaches and have been implemented in commercial software. Production costing runs which provide details of economics of generation are typically made under a deterministic set of assumptions. Using a probabilistic approach would allow the planners to calculate production costs for a number of system conditions. On the other hand, this requires significantly more data and associated computational burden.

Figure 10-1 schematically shows how risk-based planning can be used to augment deterministic transmission planning. Some of the areas where risk-based planning can strongly support the existing deterministic framework are as follows:

1. At present planners try to simulate the worst case scenario along with a few seasonal cases without any explicit treatment of uncertainties and risks. As mentioned in Chapter 3, this may no longer be sufficient to address variability due to renewable generation, changing load shapes as a result of demand-side technologies, and spikes in extreme weather. Probabilistic approaches can be used to come up with transmission planning cases as described before.
2. For the developed transmission planning cases, existing deterministic criteria including the N-1 principle can be applied to assess system reliability and ensure that all deterministic criteria are respected in accordance with NERC standards. However, risk-based planning can be used in

addition as a safety net to confirm need, timing, priority, and potentially, whether a more substantial investment is justified. In addition, using a probabilistic economic criteria can ensure that reliability and costs are appropriately weighted in to make a better decision. As mentioned in Chapter 9, risk-based approaches can provide a strong analytical framework to identify system weaknesses, compare multiple alternatives for system upgrades, and justify transmission upgrades.

In summary, risk-based planning approaches can not only co-exist with the deterministic framework but can play a very important role in making planning decisions.

10.2 Recommendations for States

Given the unprecedented changes in the electric power industry and the pressure to ensure system reliability at a minimum cost, transmission planning is becoming more complex than ever. Risk-based planning has significant potential to provide a better decision making framework for transmission planners. However this is still an area of active research and significant gaps remain in terms of developing a robust probabilistic framework that planners can routinely use.

It must be made clear that we are not advocating a "revolutionary" approach of full-fledged adoption of probabilistic methods and dropping of deterministic framework. The industry is not ready for this drastic transition. Instead, we are proposing an "evolutionary" approach in which we gradually start considering risk-based methods to augment the existing deterministic framework and make sure that planners get comfortable. Over a period of time more and more planning activities can be performed based on risk-based planning concepts which may eventually lead to full adoption of risk-based framework.

States can play a crucial role in evolutionary adoption of probabilistic planning concepts and bridge the existing gaps in the risk-based planning framework. Towards that goal, the project team has the following recommendations:

1. **Closer coordination with NERC.** All the existing NERC transmission planning standards are deterministic. However, recently NERC has shown interest in considering probabilistic approaches in transmission planning and organized multiple workshops in Eastern Interconnection as well as in WECC on risk-based planning. NERC and states in collaboration with other stakeholders can work closely and come up with a long term vision for developing risk-based planning framework. **In particular, there are no well-defined criteria and indices that can be broadly accepted and enforced. This is an area where significant work and coordination is needed.** In addition by working closely with NERC, states can ensure that state and local policies complement the federal policies and there are no inherent contradictions.
2. **Greater awareness about uncertainties and risks among various stakeholders.** Transmission planning is an arduous activity involving federal, state, local and private entities. All the stakeholders may not be equally aware of various risks and uncertainties that are going to impact transmission planning in the coming years. Also, they may have different views about the future.
   Different stakeholders may have completely different opinions about risk-based planning. Based on our own experience, some may consider it as a panacea for all the risks and uncertainties while others may consider it as an overbearing approach which may lead to underinvestment in

the long run. **With such divergent and wide gaps in views there is definitely a need to engage all the stakeholders in the process and provide a platform for disseminating fact-based information.**

It is also recommended that states get more actively involved in regional transmission planning processes initiated by FERC or regional planning organizations for better collaboration and broader perspective.

3. **Promote research efforts on risk-based planning.** As clearly stated in this white paper, risk-based planning needs active research and industry participation for its broader adoption. States can promote research efforts and also work closely with research organizations, universities, national labs, commercial software developers, and utility industry to ensure that research needs are addressed and practical solutions are developed. A research effort like this project is a significant step towards that goal.
4. **Coordination among interconnections.** Risks and uncertainties transcend geographical boundaries and impact all the interconnections. In fact, long term planning decisions can have wide spread impacts spanning multiple interconnections. Coordinated and collaborated efforts among Eastern Interconnection, WECC, and ERCOT will prove to be greatly mutually beneficial to all. Again, working closely with NERC, and research organizations will help to coordinate the activities across the interconnections.

11
Glossary of Terms

Adequacy	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adverse Reliability Impact	The impact of an event that results in Bulk Electric System instability or Cascading.
Availability	The probability that a system, or part of a system, is operational when demanded to perform. Availability is a unit less value from 0 to 1, where 0 is a certainty of failure. Availability equations account for both failures and repairs of the system.
Common Cause Failure	A single event that can cause other failures of a system. For example: a set of pumps bolted to a rack. If the rack falls apart, the pumps fail as well. The probability of the failure of the rack must be added to the probability of the pumps failing on their own. Common causes can be modeled explicitly via Repeat Events, or implicitly via Alpha and Beta failure models.
Common Mode Outage	An event where more than one component forced outage results from a single primary cause and where the outages are not consequences of each other.
Component Forced Outage	The automatic or emergency removal of a Major Component directly caused by defective equipment, adverse weather, adverse environment, system condition, human element or foreign interference. Recording is not done for the case of healthy Major Components which are removed from service as a result of cascading system events or as a result of the outage (or malfunction) of some other Major Component and recording is not done for manual removal of a component from service where that removal may be delayed more than thirty minutes to allow load transfer or other operations.
Derating	Derating is a guideline used to ensure that components are operated well below their rated voltage, power, or current levels. By default, failure rates calculated within reliability prediction standards assume a higher than typical-design stress on the components, leading to conservative results. Derating guidelines point out the components in the analysis which are Nominal, Above Nominal, or Overstressed. This enables the analyst to recommend which stress levels are appropriate for the component, ensuring increased reliability

	and lower failure rates. There are several military and commercial derating standards available, and it is possible to define your own.
Deterministic Risk Assessment	In a deterministic risk assessment, each input parameter is given by a point estimate. Variability and uncertainty can be taken into account when choosing the input; however, variability and uncertainty are not controlled or evaluated in the calculations. The traditional way of handling uncertainty and variability has been to incorporate safety factors or use conservative assumptions, which can lead to unrealistically high estimations which are neither transparent nor efficient when further testing or measures might be necessary. Conversely, it is also possible to underestimate the exposure for sensitive populations. Deterministic estimations are given with a precision that does not reflect the uncertainty and variability that is inevitable in such assessments.
Distribution Parameters	Each statistical distribution requires certain parameters such as mean, standard deviation, characteristic life, shape factor, bounds, etc. The parameters needed will depend on the type of distribution being used.
Environmental Impact	Any alteration to the environment caused by man and affecting human, animal, fish and/or plant life.
Equivalent Forced Outage Rate	Hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours)
Expected Unserved Energy	Measures the expected amount of Energy in MWh that will fail to be supplied per year due to available generation capacity being short of the load demand + required ancillary services
Exponential Distribution	The most widely used distribution in reliability engineering. Used for time-dependent data where the rate of event occurrence does not vary.
Exponential Distribution	The most widely used distribution in reliability engineering. Used for time-dependent data where the rate of event occurrence does not vary.
Failure Mode	A specific “way” a component or function fails. A description of the type of fault (or malfunction) which the system sustains as a result of a Component Forced Outage. The failure mode of a component or function is expected to have a direct effect on another part of the system.
Failure Rate	The number of failures experienced or expected divided by the total exposure time. The failure rate is the inverse of the mean time between failures (MTBF).
Forced Unavailable Time	The elapsed time required to restore the Major Component to service or to repair it in the case where it has been replaced. All events have a Forced Unavailable Time of minimum one minute with the exception of Automatic Reclosures on Transmission Lines which are reported as “zero” forced

	unavailable time.
Loss of Load Expectation	Measured most commonly in events per year and is the expected number of events that available generation capacity is short of the load demand + required ancillary services
Loss of Load Hours	Expected hour per year that available generation capacity is short of the load demand + required ancillary services
Major Component	A unit of Transmission Equipment, including all the associated auxiliaries that make it a functional entity within a power system.
Markov process	A simple stochastic process in which the distribution of future states depends only on the present state and not on how it arrived in the present state
Mean Time Between Failures (MTBF)	The mean time expected between failures. MTBF is the inverse of the failure rate. MTBF should be used for repairable items, while MTTF (Mean Time to Failure) should be used for non-repairable items. The assumption is that over an extended period of time the fail/repair cycle will occur many times.
Mean Time to Failure (MTTF)	The mean time expected to the first failure. MTTF is the inverse of the failure rate. MTTF should be used for non-repairable items.
Mean Time to Repair (MTTR)	The mean time spent performing all corrective and/or preventative maintenance repairs.
Model uncertainty	Models are never exact representations of reality, but rather simplifications. Sources of model uncertainty can be extrapolation, dependencies, assumptions and when a model is used out of its applicability domain.
Monte Carlo Simulation	A simulation approach which performs random tests on a system to determine an approximate overall reliability and availability of the system. Monte Carlo is not as accurate as Latin-Hypercube approach to approximation.
Normal Distribution	A commonly used distribution in the field of statistics and probability. The distribution is symmetric. The mean and standard deviation are its two parameters.
Operating Environment	One of the key reliability prediction standard parameters is the assumed environment the system or devices are operating in. The predicted failure rate of a device is greatly impacted by the operating environment
Parameter uncertainty	Uncertainty in different types of quantities. These can be both empirical quantities (measurable) and defined constants. Sources of this uncertainty can, for example, be measurement errors, the use of default data and sample uncertainty, that is to say the representativeness of the data set and uncertainty in the choice of statistical distributions.
Primary Cause	The reason to which one can attribute the outage or malfunction of a Major Component.
Probabilistic modeling	A technique that utilizes the entire range of input data to develop a probability distribution of exposure or risk rather

	than a single point value. The input data can be measured values and/or estimated distributions. Values for these input parameters are sampled thousands of times through a modeling or simulation process to develop a distribution of likely exposure or risk. Probabilistic models can be used to evaluate the impact of variability and uncertainty in the various input parameters, such as environmental exposure levels, fate and transport processes, etc.
Probabilistic Risk Assessment	An approach to assessing risk to or a result of a system, using established probabilistic and statistical methods. All upsetting events and their eventual outcomes are considered, along with their probability of occurrence. The end result is a view of each “end state”, the probability of it occurring, and any consequences to safety, finance, or other aspects of an organization or system. In order to make a probabilistic evaluation of risk, it is consequently necessary to account for uncertainty and variability. Thus, in probabilistic methods, variability and uncertainty are characterized to obtain a more transparent and better basis for decision making.
Qualitative	A modeling approach which considers only the elements which make up a system, and how they interact with each other logically. No effort is taken to associate probability of occurrence, or failure rate numbers to the elements of the system. However, the results of this type of analysis include possible paths to failure, and a clear picture of how the system can fail.
Quantitative	A modeling approach which is based upon a qualitative foundation, but includes probability and failure model distributions to determine numeric results for the overall system availability and other factors.
Redundancy	Having more than one piece of equipment available to perform a function within a system. In general, redundancy helps improve the reliability and availability of the system, but this may not always be the case, depending on the other elements of the system.
Reliability	The ability to perform a required function under stated conditions for a stated period of time. Reliability is expressed as a probability from 0 to 1. Assuming the system was operating at time zero, Reliability is the probability that it continues to operate until time t.
Replacement Time	The elapsed time required to replace the Major Components from stock or other location in the network.
Scenario uncertainty	uncertainty in assumptions about different scenarios made in risk assessments
Spatial variability	variation in space
Sustained Forced Outage	A transmission line related forced outage the duration of which is one minute or more. It does, therefore, not include automatic reclosure events

Temporal variability	variation over time
Transient Forced Outage	A transmission line forced outage the duration of which is less than one minute and is, therefore, recorded as zero. It covers only automatic reclosure events
Unavailability	The probability a system is failed at a specific point in its lifetime. 1- Availability
Unavailability	1.0 – Availability
Uncertainty	The degree of the lack of confidence in a result. Uncertainty refers to our inability to know for sure - it is often due to incomplete data and incomplete understanding of processes. When using distributions for reliability analysis, there is inherent uncertainty of the values used. These uncertainties add up at the system level, creating even greater uncertainty.
Unreliability	1.0 – Reliability
Variability	Natural variation

12
Acronyms

ARRA	American Recovery and Reinvestment Act
ASAI	Average Service Availability Index
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operators
CBM	Capacity Benefit Margin
CDF	Customer Damage Function
CEA	Canadian Electricity Association
CIGRE	International Council for Large Electric Systems (Conseil International des Grands Réseaux Électriques)
CLL	Composite Load Level
DOE	Department of Energy
DSM	Demand –Side Management
EENS	Expected Energy Not Served
EFOR	Equivalent Forced Outage Rate
EGEAS	Economic Generation Expansion Analysis System
EIA	*Energy Information Administration*
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EOP	Emergency Preparedness and Operations
EPA	Environmental Protection Agency
EUE	Expected Unserved Energy
EWITS	Eastern Wind Integration and Transmission Study
FAC	Facilities Design, Connections, and Maintenance
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
GADS	Generator Availability Data System
G&T	Generation & Transmission
HL	Hierarchical Level
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Planning
ISO	Independent System Operators
IVGTF	Integration of Variable Generation Task Force
LMP	Locational Marginal Prices
LOLE	Loss of Load Expectation

LOLP	Loss of Load Probability
LRZ	Local Resource Zones
MIP	Mixed Integer Programming
MISO	Midcontinent Independent System Operator
MOD	Modeling, Data, and Analysis
MTTF	Mean Time To Failure
MTTR	Mean Time To Repair
n-x	Simultaneous Outage of x (x=1,2,3…) Components
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NOAA	National Oceanic and Atmospheric Administration
OPF	Optimal Power Flow
PBRC	Probabilistic-Based Reliability Criteria
PCG	Protection Control Group
PDF	Probability Density Function
PJM	Pennsylvania New Jersey Maryland Interconnection
PNNL	Pacific Northwest National Laboratory
PRA	Probabilistic Risk Assessment
PSO	Power System Optimizer
PV	Photovoltaics
RE	Reliability Entity
RRM	Reliability Risk Management
RTO	Regional Transmission Organizations
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SFM	Service Failure Mode
SPP	Southwest Power Pool
SPS	Special Protection Systems
T&D	Transmission & Distribution
TADS	Transmission Availability Data System
TOP	Transmission Operations
TPL	Transmission Planning
UIC	Unit Interruption Cost
VaR	Value at Risk
VAR	Voltage and Reactive

VBRP	Value Based Reliability Planning
VBTRA	Value Based Transmission Resource Analysis
VBRP	Value Based Reliability Planning
VGR	Variable Generation Resources
WECC	Western Energy Coordinating Council

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A
Summary of Existing Transmission Planning Processes

A summary of existing planning practices based on the authors' experience is provided in this section. The key points are:

1. In addition to NERC TPL compliance standards, most utilities are required to meet regional or local reliability requirements. However, they did not indicate that these are overbearing requirements.
2. There is no consensus among transmission planners on the terms "long-term" and "short-term" planning horizons. However, majority considered a period of 5 years or less as short-term and more than 5 years as long term.
3. There is no consensus on how uncertainties and risks should be considered in the planning process. Few utilities do not even include these uncertainties as part of their transmission planning process. For example, some utilities do not consider demand response a resource for transmission planning and the transmission system is planned to be able to supply all demand. For load uncertainty they plan for single contingencies and certain double contingencies at few load levels (mentioned in bullet 4). Some utilities leave it up to their reliability councils to address these uncertainties when performing Long Term System Assessments. Some companies conduct sensitivity studies for different scenarios. The purpose of the sensitivities generally is to evaluate the robustness required in any solution or comparison of alternate solutions. The scenario based planning studies normally incorporate one uncertainty in one run. Utilities study potential generation retirements based on units that might be likely to retire due to environmental regulations.
4. Typical load-generation dispatch scenarios considered are:
    a) 50/50 load scenarios for summer and winter (i.e. there is 50% probability that the load will exceed the level that is being considered in the case)
    b) 90/10 load scenarios for summer and winter (i.e. there is 10% probability that the load will exceed the level that is being considered in the case)
    c) Additional shoulder cases (in spring and fall seasons)
    d) Other cases such as high wind scenario, light load etc.

B
Examples of Decision Criteria

In Chapter 2, we broadly categorized transmission planning decisions into three types:

- Decision under Certainty
- Decision under Risk
- Decision under Uncertainty

This appendix gives examples of each decision type.

Example 1: Decision under Certainty

Assume we have two input parameters *A* and *B* and the relationship is *C = A x B*. Now if *A* and *B* are known quantitates, say 2 and 10, respectively, the outcome *C* is definitely 20. In transmission planning, this is analogous to having the true knowledge of a line resistance and current flow on one end of a line and determining the voltages across the line using an ohms law of *V = R x I*. Thus, for the transmission analogy, if *R*= 2 ohms (Ω) and *I*=10 Amps, the voltage drop, *V*, across the line is 20 volts.

This is truly a deterministic method. Thus, assuming that the power system models and power system analysis methods are true representations of the electric power system, and that also we know the true value of the electrical parameters involved, in this example the whole power system analysis is based on a deterministic method.

Example 2: Decision under Risk

For the same example above, now consider that *A* and *B* are defined with their independent distribution functions *P(A)* and *P(B)*. Then *P(C) = P(A) x P(B)*. Thus, *C* is also defined with a distribution function resulting from the joint probability of *A* and *B*. In probabilistic analysis, the *P(C)* is defined as the probability of *C, E(C)* = sum of all of the combinations of *A* and *B* multiplied by their probabilities. Mathematically, this is expressed as:

$$E(C) = \sum_{i=1}^{m} \sum_{j=1}^{n} A_i \, P(A)_i B_j P(B)_j = \sum_{x} \sum_{y} A_x P(A)_x \, B_y P(B)_y$$

where: i=1, 2, 3,…m; and j=1, 2, 3,…n represent the elements of *A* and *B*, respectively

x= state containing event *A*, y = state containing event *B*

Let's assume that *P(A)* and *P(B)* are each defined as having two probability defined discrete values. Say *A* is 1 with probability of 30% and 3 with probability of 70%. Similarly, *B* is 8 with probability 40% and 12 with probability of 60%. (Remember that the un-weighed average values of *A* and *B* are still 2, and 10, respectively, the same as Example 1.)

Now considering the probability assessment given above, the expected value for *E(C):*

$E(C)$ = (1)(.3)(8)(.4)+(1)(.3)(12)(.6)+(3)(.7)(8)(.4)+(3)(.7)(12)(.6) = 27.04

This is a much higher than Example 1 outcome. However, the outcome is dependent on the probability distribution functions of *A* and *B*. With different distribution function, we will get different results. This is not a deterministic process, but probabilistic, because the outcome depends on the probability functions of the components.

In transmission planning, this is analogous to having, for example, the knowledge of a distribution functions of the line resistances associated with topology changes and current flow associated with flow changes. This could be an example where the system resistance is either 1 or 3 (average 2) with 30% of time been 1ohms and 70% time been 3 ohms. Similarly, the current flow is 8 Amps and 12 Amps, with 40% and 60% probability, respectively. The expected voltage drop across the transmission line is 27.04 volts.

This is truly a probabilistic method. However, presently, transmission planning is based on a worst-case deterministic study. Application of worst-case deterministic assessment will lead in considering the worst resistance topology and the highest current flow condition, which are 3 ohms and 12 Amps, respectively. This will have a result of 36 volts, which is much larger than the expected value of 27 volts, and the average value of 20 volts (of Example 1).

Example 3: Decision under Uncertainty

Using the same example as before, now, using decision under uncertainty theory, we have no knowledge of the values *A* and B, and thus no knowledge of C. This means, *A* and/or *B,* could have very large or very small values, thus it is unknown what the outcome is going to be.

In transmission planning, this is analogous to having the no knowledge of the line resistances associated to topology changes, and current flow associated with flow changes. This is a common condition in power system long-term planning were we know nothing of what would happen 30 years from now, say in fuel prices. For instance, we don’t know exactly, nor do we have the distribution function for what transmission lines or generators will be built or be modified to 30 years from now. These uncertainties of future actions create uncertainties in the resistance and current flow of the above example.

In such instances, the best analysis process is often used is what we call “scenario analysis.” In this case, we select several data points to represent the uncertainty conditions and determine the outcome of those scenarios. Then, we make judgments, or using some preference selection criteria (subjective probability) we select the outcome or outcomes we prefer to be the solution to the problem.

For instance, for example 3, we select three scenarios and uncertainty data associated with the scenarios as shown below:

Scenario 1: R=3, I=10, and then V= 30

Scenario 2: R=5, I=15, and then V=75

Scenario 3: R=1, I=50, and then V=50

Now, how we arrive at the final decision is not based on mathematical or statistical assessment, but on preferences or use of some “subjective probabilities.” Some experience in the subject area, may lead us to making a better informed preferential choices, however, unlike Category 1 and 2 methods, the decision under Category 3 is not based on a strictly mathematical or statistical basis. Typically, a scenario that is considered to be the worst-case scenario may be selected, without regard to the basis of the data that is used to come up with the outcome. Thus, the voltage output of 75 or 50 may be selected as solution for the problem.

C
An Overview of Reliability Indices Computation

Reliability indices that can be computed using risk-based approaches were described in section 5.3. In this appendix, we present an overview of how those indices can be computed.

Reliability analysis is the mathematical procedure by which these reliability indices are computed from known reliability models of the individual components that make up the system. As described earlier, the electric power system comprises repairable components that are subject to random failures. For this reason reliability methods are typically based on a component reliability model and using this model events are defined that represent system failure of a certain reliability criterion. The reliability indices are then computed from this model. As an example consider the illustration of Figure C-1 which shows an event S_r that consists of the union of several system conditions or states. Each state may represent a contingency at which the system has failed by a specific reliability criterion. Each state is characterized with a certain probability p_j and transition rates to and from other system states, such as λ_{jk} and λ_{ij}.

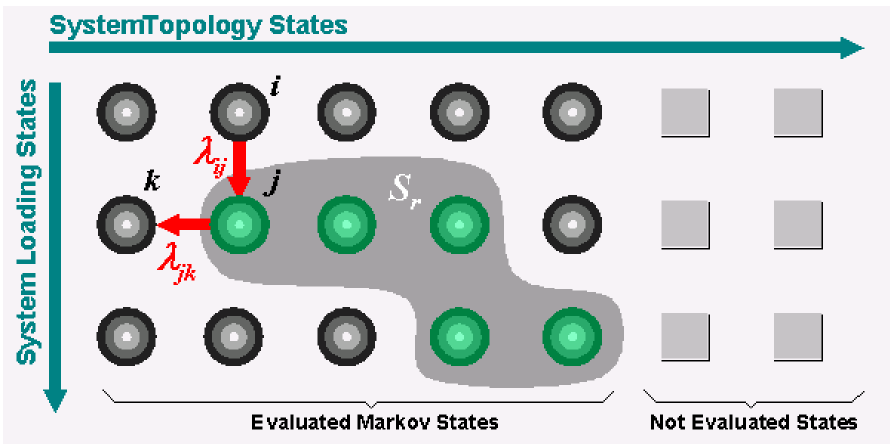

Figure C-1 State-Space Diagram

The three different classes of reliability indices are computed as follows:

1. Probability index: The probability of S_r is obtained by adding all the state probabilities in the set S_r:

   $$P_r[S_r] = \sum_{j \in S_r} p_j \tag{1}$$

2. Frequency index: The frequency of event S_r is the total of the transition frequency of a state j inside S_r to a state i outside of S_r, therefore

$$f_{S_r} = \sum_{i \notin S_r} \sum_{j \in S_r} f_{ji} = \sum_{i \notin S_r} \sum_{j \in S_r} p_j \lambda_{ji} = \sum_{j \in S_r} (p_j \sum_{i \notin S_r} \lambda_{ji}) \tag{2}$$

where

λ_{ji}: transition rate from state j to state i

f_{ji}: frequency of transfer from state j to state i, which is defined as the expected number of direct transfers from j to i per unit time. The relation between f_{ji} and λ_{ji} can be written as

$$f_{ji} = \lambda_{ji} p_j \tag{3}$$

3. Duration index: The duration index of event S_r is calculated using the probability index and frequency index:

$$T_{S_r} = \frac{P_r[S_r]}{f_{S_r}} \tag{4}$$

4. Expectation index: The expectation index of event S is calculated by summing the contributions from all states, i.e.

$E_{S_r} = \sum_{j \in S_r} p_j v_j$, where v is the numerical value of the attribute (5)

D
An Overview of Software Tools for Probabilistic Analysis of Power Systems

This appendix is an extension of Chapter 7 on software tools and provides an overview of software tools in various categories mentioned in Table 7-1.

Main Tools used for NERC Reliability Compliance and Other Deterministic Studies in Transmission Planning[11]

A list of tools used for deterministic planning studies including NERC reliability compliance studies, generation interconnection studies, and system stability studies is given:

1. Siemens PTI's PSS®E and related suite of tools (http://w3.siemens.com/smartgrid/global/en/products-systems-solutions/software-solutions/planning-data-management-software/planning-simulation/pages/pss-e.aspx)
2. GE PSLF™ (http://www.geenergyconsulting.com/practice-area/software-products/pslf)
3. Powertech Lab's DSA Tools (http://www.dsatools.com/)
4. PowerWorld Simulator (http://www.powerworld.com/products/simulator/overview)
5. V&R Energy's POM suite of tools (http://www.vrenergy.com/index.php/powersystemsoftware.html)
6. PowerGEM's TARA software (http://www.power-gem.com/TARA.htm)

A Summary of Resource Adequacy and Production Costing Tools

The following list describes some of the most relevant production cost tools; significantly more detail is available in other locations. As there are a wide variety of these types of tools, and they can be used for many different applications, direct comparison is difficult. Some of the most relevant features to this paper are discussed below:

- SERVM

SERVM is a hybrid resource adequacy and production cost model developed by Astrape Consulting. The model stochastically simulates unit performance, weather conditions, and other stochastic variables representing load growth uncertainty, and resource outages. It simulates thousands of iterations representing full years with a 5-minute granularity taking into account the short-term uncertainties introduced by load, wind, and solar generation. SERVM also evaluates the trade-off between reliability and costs as it estimates the frequency and duration of deficiencies, as well as the costs of unserved energy, operating reserve deficiencies, and generation curtailment.

- PROMOD IV

[11] Note that this list is not exhaustive by any means and there may be other products in use as well in North America.

PROMOD IV performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the nodal level. PROMOD IV forecasts hourly energy and congestion and loss prices, unit generation, revenues, and fuel consumption, external market transactions, transmission flows.

The core of PROMOD IV is an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand.

- PLEXOS

PLEXOS is a market simulation and optimization software package. PLEXOS' co-optimization architecture co-optimizes thermal, hydro, energy, reserves, fuel markets and contracts. PLEXOS is extremely detailed compared to other energy market modeling software and can model 5-minute or shorter time steps. Consequently, PLEXOS has relatively high run times compared to similar models.

- ProMaxLT

ProMaxLT deploys a Mixed-Integer Programming (MIP) based Security Constrained Unit Commitment and a Linear Programming (LP) based Security Constrained Economic Dispatch. The transmission model could be AC or DC, and contingencies are modeled through an advanced screening and processing approach. Thousands of post-contingency constraints are modeled in the engine, without approximations. All current ISO functions, including co-optimization of energy and ancillary services, hydro modeling, demand response, scarcity pricing and convergence bidding are modeled. Sequential modeling of all markets, e.g. day-ahead, hour-ahead, and real time are modeled, while uncertainties such as generator outages are modeled using Monte Carlo techniques.

- UPLAN

UPLAN Network Power Model (UPLAN-NPM) incorporates a rich, integrated representation of physical features of the electric generators, loads and transmission, financial characteristics and system operation. UPLAN-NPM performs coordinated marginal cost (or bid) based energy and ancillary service procurement, congestion management, N-x contingency analysis with Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) similar to those used by ISOs. A novel feature of UPLAN is simultaneous Unit Commitment, Optimal Power Flow (OPF), and dispatch to ensure that all transmission constraints, line contingencies, outages and physical constraints for power delivery are obeyed. UPLAN has no inherent restriction on size, speed, transmission contingencies, number of generators, and load buses. The program can dispatch at 5 minute intervals, unit commitment is done hourly.

- Power System Optimizer (PSO) from Polaris

This tool uses a number of advanced features, chief among them being a multi-cycle approach which allows users to accurately represent the various operational decision-making stages to simulate the impact of imperfect information in the decision-making process. This allows for examination of how decisions made at different cycles (e.g., day-ahead, hour-ahead, "real-time") impact each other.

- Aurora

AURORAxmp is an electricity market forecasting tool used primarily for power market price forecasting, analysis of contract and portfolio operations, optimized resource expansion, and power market risk analysis.

- GE MAPS

GE MAPS calculates hour-by-hour production costs while recognizing the constraints on generation dispatch imposed by the transmission system. GE MAPS performs a transmission-constrained production simulation, which uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of re-dispatching the generation to satisfy transmission line flow limits and security constraints. MAPS has the flexibility to perform either zonal or nodal analysis. The MAPS nodal software recognizes normal and security-related transmission constraints to model the actual electrical system in detail. This allows you to analyze opportunities for an individual company or examine the economic interchange of energy between several companies in a region. Issues commonly studied with MAPS include locational spot pricing, transmission bottlenecks, actual power flow estimates, and need for transmission upgrades.

- Flexible Energy Scheduling Tool for Integration of Variable Generation (FESTIV)

This tool, developed by NREL, was designed to understand the impacts of variability and uncertainty on operating reserve requirements. Using nested models of security-constrained unit commitment, security-constrained economic dispatch, and automatic generation control, the impact of load, wind, and solar variability and uncertainty on the Area Control Error can be examined in conjunction with the system operating costs.

Other advanced simulation tools are available or are under development at research labs, consultancies, and universities.

A Summary of Recent Research/Prototype Tools on Scenario Development

1. PRIMA Tool from Pacific Northwest National Laboratory (PNNL)

PNNL's Platform for Regional Integrated Modeling and Analysis (PRIMA) is a resource reliability analysis tool that integrates energy, water and environmental sector into an integrated model to assess the interrelationships among these sectors and there availability. It may be a useful tool to predict how electrical power systems will be affected by other concerns, and specifically water and the environment. This tool is not a traditional tool that a power system planner may want to use in evaluating expansion plans.

A brief description of the PRIMA framework taken directly from the PNNL website (http://prima.pnnl.gov/) is as follows:

- State-of-the-art models of human and natural systems that account for key regional-scale processes while remaining consistent with global boundary conditions and constraints
- A flexible software architecture capable of bringing these models together in different ways, depending on the questions being asked
- Sophisticated analysis and visualization tools and a robust, stakeholder-driven uncertainty characterization process.

2. Iowa State University Tool/Method

Iowa state university has been developing planning tools that consist of the integration of many modules of optimization (CPLEX), generation forecasts (NETPLAN), network analysis, automated transmission plan generation (modeled in MATLAB), etc. The objective of the overall analysis is to assess the value of each expansion plan. Details have been provided in many technical papers as well as in the EISPC report “Co-optimization of Transmission and Other Supply Resources” which was published in September 2013. Uncertainty is characterized through an uncertainty matrix and then specific uncertainty scenarios are selected to perform the analysis. This is a practical approach but does not provide a mathematically rigorous approach to assess the full extent of the uncertainty.

Within this approach risk analysis can be performed as an expectation index of various risk parameters, for example expected value of cost minus revenue or expected value of unserved energy.

3. Prof. Ben Hobbs’ Approach

Prof. Hobbs has proposed to formulate the transmission planning problem as a multi-stage stochastic optimization problem. The uncertainty comes from fuel prices, technology cost, policies and imports. The objective function is the cost of the expansion plans plus the expected value of operations cost over a selected set of scenarios. Constraints include Kirchhoff’s laws, generator and transmission capacity and operating restrictions, siting restrictions, emissions caps and renewable portfolio standards. Network constraints are linearized in the approach.