



March 1999

Reliability Considerations in Electric Industry Restructuring

Final Report

Prepared for

Legislative Study Commission on the
Future of Electric Service in North Carolina
300 N. Salisbury Street
Suite 545
Raleigh, NC 27603-5925

Prepared by

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Center for Economics Research
Research Triangle Park, NC 27709

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Contents

Executive Summary	ES-1
1. Introduction	1-1
2. Resource Adequacy Planning Processes	2-1
2.1 The IRP Process at the State Level.....	2-2
2.2 The Free-Market Approach.....	2-4
2.2.1 Generation	2-5
2.2.2 Transmission	2-9
3. Potential Impact of Competition on Generation and Transmission System Reliability	3-1
3.1 Potential Reliability Benefits and Risks of Competition.....	3-3
3.1.1 Introduction.....	3-3
3.1.2 Traditional Planning Process Proponents.....	3-4
3.1.3 Free-Market Proponents.....	3-6
3.1.4 Conclusion	3-8
3.2 State Roles in Generation and Transmission System Reliability	3-9
3.3 Generation and Transmission System Reliability in North Carolina: Performance and Concerns.....	3-14
3.3.1 Past Reliability Performance	3-15
3.3.2 NERC and SERC Assessment of Reliability.....	3-19
3.3.3 Utility Concerns about Future Reliability.....	3-20
3.4 Conclusions and Recommendations	3-26

4.	Potential Impact of Competition on Distribution System Reliability	4-1
4.1	Reliability of Distribution Service	4-1
4.1.1	Service Interruptions.....	4-2
4.1.2	Service Quality.....	4-3
4.2	Factors Affecting Reliability.....	4-4
4.3	Results of System Surveys and Interviews.....	4-9
4.3.1	Results of Utility Surveys	4-9
4.3.2	Characteristics of Systems Interviewed.....	4-11
4.3.3	Comparison of Results of Interviews.....	4-11
4.4	Recommendations for the Study Commission	4-14
4.4.1	Provide Adequate and Timely Compensation to Distribution Companies.....	4-14
4.4.2	Provide Timely and Complete Access to Customer Data for Planning and Operation.....	4-15
4.4.3	Establish Clear Customer Communication Procedures for Service Restoration.....	4-16
4.4.4	Preserve Communication with Customers and Advisory Services	4-16
4.4.5	Permit Options in the Level of Reliability of Service	4-17
4.4.6	Clarify Customer Curtailment Practices During Supply Shortages	4-18
4.4.7	Allow Distribution Companies to Regulate Customer Apparatus that Has Service Quality Impacts on Other Customers.....	4-18
4.4.8	Establish Policies for Handling Customer Revenue	4-20
	References	R-1

Appendixes

A	Generation/Transmission System Security Considerations and Institutions.....	A-1
B	Institutional Alternatives to Maintain Generation/Transmission System Security in the Future	B-1
C	National Association of Regulated Utility Commissioners (NARUC) Resolution on Electric System Reliability.....	C-1
D	Distribution Reliability Questionnaire for In-Person Interviews	D-1
E	Carolina Power & Light Distribution Reliability Interview Summary	E-1
F	Fayetteville Public Works Commission Distribution Reliability Interview Summary.....	F-1
G	Blue Ridge Co-op Distribution Reliability Interview Summary	G-1
H	Duke Power Company Distribution Reliability Interview Summary	H-1
I	Wilson Public Works Department Distribution Reliability Interview Summary.....	I-1
J	Piedmont Co-op Distribution Reliability Interview Summary	J-1

Figures

Figure 2-1	Illustrative Hourly Spot Prices in the Mid-Atlantic Region.....	2-7
Figure 3-1	The Number of Wholesale Transactions Handled by Duke Power in North and South Carolina.....	3-5
Figure 3-2	Reliability Conflicts before FERC.....	3-6
Figure 3-3	Map of North and South Carolina Showing Approximate Locations of Electric Utility Control Areas for North Carolina IOUs.....	3-16
Figure 3-4	Performance of the Utilities in the Virginia-Carolinas Subregion in Meeting the NERC Disturbance Standard for 1995, 1996, and 1997.....	3-17
Figure 3-5	Annual Expenditures for Transmission Operations and Maintenance and Total Transmission Investment for CP&L, Duke, and Virginia Power.....	3-18
Figure 4-1	Consumer Reaction to Electricity Outages.....	4-3
Figure 4-2	Distribution System Initial Stage.....	4-5
Figure 4-3	Distribution System Expansion Stage.....	4-5
Figure 4-4	Distribution System New Feeder Stage (with tie points).....	4-6
Figure 4-5	Distribution System New Substation Stage (with tie points).....	4-7

Tables

Table 3-1	Possible Federal and State Government Oversight of Generation and Transmission in a Restructured Electricity Industry	3-10
Table 4-1	Summary of the Impact on Customers for Some General Types of Power System Problems	4-4
Table 4-2	Summary of Survey Results	4-10
Table 4-3	Principal Characteristics of Systems Interviewed.....	4-12

Executive Summary

Reliability is a major concern in the electric utility industry. Reliability is generally considered to have two components: *adequacy* and *security*. Adequacy refers to the need to ensure that customer demand can be met. Adequacy is a long-run concept. Security refers to the system's ability to react to and withstand disturbances. Security is a short-run concept.

Unlike most products, electricity cannot be stored in large quantities in an economical manner. As a result, electricity has to be produced and delivered on demand. The operating capability of the generation, transmission, and distribution systems must be sufficient to meet constantly changing customer demands (loads) at all times.

Another distinguishing characteristic of electricity supply systems is the high degree of interdependence between generation and transmission. As a result of this interdependence, disturbances in generation may lead to transmission problems. For example, a major generation unit outage can quickly lead to an overload condition on the transmission system, which may result in transmission outages and loss of delivered power. Similarly, disturbances in transmission may lead to generation problems. For example, a transmission outage from adverse weather or an overload condition may quickly lead to generation outages and loss of delivered power. Currently system protection features are built in to limit the extent of disturbances and the possibility of equipment damage.

Also, electric power systems are designed with a very high degree of interconnection between neighboring areas to provide reliable and efficient electrical service. In the U.S., electric systems are alternating current (AC) systems, which require synchronous (in phase) operation of all generators within a synchronous area. There are four such areas within the U.S. (North Carolina is in an area that includes the eastern U.S.). A major disturbance, such as the loss of a generating unit, will affect all other units within the synchronous area to varying degrees, depending on the size of the unit and distance from the disturbance. Transmission systems are the superhighways that deliver electrical energy to substations and direct-serve customers, and that deliver emergency generating capacity from other locations within a synchronous area.

These facets of electrical systems,

- the lack of large-scale, economically efficient storage;
- the interdependence between generation and transmission; and
- the physics of power flows within and among interconnected systems, in which amounts and paths of power flows change instantaneously in response to changed supply and demand conditions,

place a premium on careful planning and rapid response operation to maintain system reliability. Careful planning, whether under regulatory oversight or not, is required several years in advance—at least 2 to 3 years to plan and install peaking units (smaller units that serve peak demands of customers), 8 to 12 years to plan and install baseload units (larger units that run continuously as long as they are available), and 4 to 10 years to plan and install transmission facilities. Rapid response operation must occur within seconds or minutes of changes in system conditions.

These considerations lead to questions of whether electric service reliability will be maintained in North Carolina. Reliability may potentially be affected by changes at the bulk power (wholesale) level and by changes at the retail level. Wholesale power moves along transmission lines to customers who resell that power, whereas retail power moves along transmission and distribution lines to ultimate customers (end users). Changes in the regulation of wholesale power by the Federal Energy Regulatory Commission (FERC) are underway, and their effects on reliability have yet to be

fully revealed. Recent events—particularly the failure of a supplier to deliver wholesale power (although no firm power retail customers were curtailed) and the concurrent price spike in Midwestern wholesale markets in late June 1998, and the blackouts on the West Coast in 1997—have increased concerns about reliability.

If the retail electric industry is not restructured (i.e., if franchised monopolies continue to operate), wholesale power reliability problems are an issue for the monopoly provider. They are only a problem for the retail customer if the monopoly provider cannot absorb and manage these reliability problems. However, if the retail electric industry is restructured, retail customers may be more exposed to wholesale power reliability problems.

This report discusses reliability issues associated with emerging wholesale market competition and reliability issues that may arise if retail market competition occurs. It discusses the roles of FERC, the North American Electric Reliability Council (NERC), and NERC's constituent regional electric reliability councils (such as the Southeastern Electric Reliability Council, or SERC) as they relate to electric system reliability. This report discusses potential mechanisms to help ensure continued generation, transmission, and distribution system reliability under wholesale and retail competition. It also discusses the traditional role of the North Carolina Utility Commission (NCUC) in maintaining reliability, particularly through its integrated resource planning process.

Reliability issues arise at both the planning (long run) and operational (short run) levels. Reliability issues at the planning level include both "resource adequacy" and "system security" issues. Resource adequacy is concerned with whether sufficient generation, transmission, and distribution capacity is planned and built in time to meet load growth. System security is concerned with hourly and "real time" (instantaneous) coordination, communication, and control of generation, transmission, and distribution systems among system participants (e.g., owners, operators, and users). System security issues apply at the operational as well as the planning level.

Resource adequacy and system security can affect reliability for the electric retail customer, whose concerns are with how frequently

outages occur, how difficult it is to report outages, and how quickly service can be restored. Resource adequacy and system security can also affect long-term economic growth in North Carolina.

Over the past quarter century, in the integrated resource plans (IRPs) they file with the NCUC, investor-owned utilities (IOUs) have addressed generation and transmission resource adequacy.

Traditionally, these plans include the following:

- ▶ forecasts of kW load and kWh energy for the next 10 years;
- ▶ reductions to these forecasts as a result of electricity conservation and load management programs;
- ▶ the amount, type, and timing of additional generating capacity needed to economically serve these “managed” load and energy requirements and to provide a reserve margin to cover uncertainties in load and resource availability; and
- ▶ transmission plans for the next 5 years.

The NCUC issues Certificates of Public Convenience and Necessity for generation resources it approves. Transmission resources above 161 kV are subject to a certification process. Distribution resources are neither included in the IRP process nor subject to a certification process.

The generation and transmission resource planning environment is changing. FERC, which regulates IOUs in wholesale power markets, has issued Orders 888 and 889 to implement portions of the 1992 Energy Policy Act (EPAAct). These Orders mandate open-access, nondiscriminatory transmission service (888) and open, real-time information systems (889) in wholesale power markets.

Generation and transmission providers are considering proposed new structures for generation and transmission resource planning and operation as a result of these FERC actions to foster wholesale market competition. For example, these providers are considering an independent system operator (ISO) structure to operate (but not own) transmission systems of ISO participants. It is difficult to predict exactly what structures will be put into place, where and when they will be put into place, how they will interact, and what their effect on the reliability of electric service will be. Key concerns include the following:

- Whether remuneration will be adequate to encourage transmission expansion in a timely manner.
- Whether generation reserve margins and generation fuel mix (diversity in fuels used) will be maintained in a restructured environment.
- Whether increased power flows over broader areas can be coordinated adequately among participants.
- Whether electricity suppliers, system operators, and customer loads will communicate and respond during regional or local system emergencies.
- Whether new players can deliver as promised under current contracts.
- Whether cost and risk responsibility can be assigned to minimize dispute possibilities.
- Whether restructuring, and the associated unbundling (separation) of generation as a competitive function from the regulated functions of transmission and distribution, will result in a loss of economies of scope across functions and higher transactions costs.¹

The addition of retail competition to wholesale competition may add the following concerns to the above list:

- There is likely to be an even greater concern with the adequacy of remuneration and its impact on generation and transmission expansion, generation and transmission reserve margins, and generation fuel mix.
- There will be a competitive disincentive for sharing critical planning information among suppliers and between suppliers and transmission operators, especially regarding plans for new generation (e.g., type, timing, and location).
- There will be many more combinations of electricity suppliers, transmission service providers, and customer loads, increasing the complexity of system operation, accounting and billing services, customer services (e.g., to explain bill components), and supplier services (e.g., to explain payments made to them).
- There are likely to be even greater increases in power flows over broader areas, which will present an additional challenge to system coordination and associated costs.

¹Economies of scope occur when the total costs of performing several functions is lower if they are performed by a single entity than if they are performed by separate entities. Economies of scope are not to be confused with economies of scale, which refers to costs per unit of output that fall as output (i.e., scale of operation) increases.

- There is likely to be increased concern with “delivery as promised” contracts and dispute resolution.
- There could be difficulties in outage reporting and service restoration.

Some of these concerns (e.g., the last three) are concerns that may apply only to the transition period to retail competition, rather than the end state of retail competition.

The movement to wholesale market competition, the possibility of retail competition, and uncertainties about how the key concerns will be resolved are all affecting resource adequacy now and will continue to do so in the future. For example, for North Carolina IOUs,

- planned generation reserve margins are being reduced (from 20 percent in the 1970s to approximately 13 percent today);
- generation capacity planning is more flexible and less certain—future capacity requirements are cited in IRPs, but utilities are uncertain whether they will build plants or buy power to meet these requirements; and
- generation capacity construction programs are increasingly relying on gas-fired units (e.g., gas-fired combustion turbine and combined-cycle units) that are smaller than coal and nuclear units in service now, in response to uncertainties about the future, financial pressures, and environmental concerns.

These changes may not necessarily result in a future reliability problem. Indeed, some of them (e.g., more size diversity in the existing generation system) can enhance reliability. To some extent, all of these changes simply reflect a response to changed supply and demand conditions. Reliance on competitive markets for reliability services and a wide array of customer rates might enhance reliability in the future.

The definition of retail competition and the decision of whether to adopt retail competition are matters of policy. For purposes of this study and other studies RTI is conducting for the Commission on the Future of Electric Service in North Carolina (the Study Commission), retail competition is defined as competition in generation and customer services. We make the assumption that transmission and distribution will continue to be regulated.

In weighing the potential benefits and risks of restructuring, the Study Commission must recognize the potential risks to reliability of electric service, identify those that can be managed at the state level, and consider ways to manage them. To help with this process, we offer the following recommendations for the Study Commission's consideration and potential delegation to other entities (e.g., the NCUC):

Generation and Transmission

1. Consider requiring that all entities supplying electricity to North Carolina retail customers be certified by the NCUC. Certification requirements might include financial viability, demonstrated performance in power supply (e.g., no firm power curtailments), and a minimum level of generation reserves. Noncompliance with the certification process or failure to maintain the minimum generation reserve requirements would be subject to financial penalties, decertification, and denial of rights to provide service.
2. Consider formation of a regional transmission organization (RTO), e.g., a transmission company (Transco) that owns and operates a regional transmission system or an ISO that only operates the system.
3. If an RTO is established, consider a multistate (regional) process to review applications for inter- and intrastate transmission enhancements, and an associated approval process that recognizes the economic and environmental interests of each state in the region.
4. Continually monitor generation and transmission investments and their implications for reserve margins and generation fuel mix. Consider methods to maintain minimum reserve margins and generation fuel mix if market failures occur.

Distribution

1. Provide adequate and timely compensation to distribution companies. Recognize that a result of separating generation and transmission from distribution is that the distribution systems will no longer have the financial resources available from the generation and transmission businesses to cover shortages of funds and short-term cost deficits for distribution operation.
2. Establish a system whereby distribution companies are provided with timely and complete access to customer data for planning and operation. Information concerning past

use and future customer requirements must continue to be available to the distribution system even when customers are supplied by others to help ensure reliable distribution service and to plan for future requirements.

3. Establish clear communication procedures for customers to contact their distribution companies for service restoration. Customer confusion about who is responsible when their service is interrupted should be avoided.
4. Preserve existing distribution company customer communications and advisory services. Past procedures under which distribution system representatives met with larger customers to stay abreast of their current and future service requirements should be continued.
5. Permit customer rate options in the level of reliability of service, at least for large commercial/industrial customers. Arrangements for backup and supplementary power that are currently available to customers who have their own generation should be continued.
6. Clarify customer curtailment practices during supply shortages. As customers begin to select different suppliers, only those customers should be curtailed whose supplier is unable to provide the needed power. In the past, customer curtailments during periods of power shortages were based on minimizing the impact on the community.
7. Allow distribution companies the authority to modify service to customers with equipment that has impacts on the quality of service provided by the companies to other distribution customers. Power quality problems (e.g., voltage surges or dips, harmonics) can affect customer equipment performance and lead to outages on the distribution side of the meter, which other customers may see as a reliability problem emanating from the distribution company. Past practices permitting distribution companies to control the use of certain types of equipment that affect the quality of service to other customers should be continued.
8. Establish policies for handling customer revenue, particularly if payments for distribution service are obtained by power suppliers. (Collection of payments for distribution service by power suppliers could delay payment to the distribution company and could result in nonpayment if the power supplier has financial problems.)

If these recommendations are implemented, major reliability concerns with industry restructuring may be reduced. Reliability levels may change over time in response to changed supply and

demand conditions, even in the absence of industry restructuring. Whether they change further with industry restructuring is still an open question, but any changes may be minimized by implementing the above recommendations.

1

Introduction

This topical report on reliability of electric service is one in a series of reports for the Study Commission on the Future of Electric Service in North Carolina. The Study Commission is investigating the subject of restructuring the electric industry in North Carolina. Key questions the Study Commission is considering in this investigation are whether to introduce retail competition into North Carolina electricity and, if so, when. Reliability is a key topic in this investigation.

The Study Commission is interested in the topic of reliability because of at least five factors:

- ▶ Electricity is a vital element of modern society in our homes, businesses, and communities.
- ▶ The Federal Energy Regulatory Commission (FERC) is well along in its efforts to create competitive wholesale power markets and to separate (unbundle) the provision of generation services from transmission services and to make transmission services available on an open-access, nondiscriminatory basis.
- ▶ Substantial increases in the number and complexity of transactions associated with greater wholesale and retail competition may affect reliability.
- ▶ Diverse market pressures facing many of the participants in power markets may discourage compliance with reliability requirements.
- ▶ Nationally, investor-owned utilities (IOUs) have reduced their annual expenditures on transmission maintenance and expansion by approximately 20 percent between 1990 and 1996. These reductions reflect slowdowns in generation investments, financial pressures, and productivity improvements, but they also reflect uncertainty about how

the transition from a vertically integrated, monopoly franchise industry to a new, more competitive structure will proceed, and whether investments in new capacity will be fully recoverable.

Reliability of electric service is a comprehensive and technical topic. It encompasses all aspects of providing reliable electric service to customers, which is made more challenging by the fact that electricity has to be produced and delivered on demand. Producing and delivering electricity on demand is challenging because, unlike most products, electricity cannot be stored in large quantities in an economical manner. Also, electrical systems are highly interconnected within control areas and across neighboring control areas.¹ As a result, disturbances at the generation level can lead instantaneously to problems at the transmission level, and vice versa, which poses additional challenges to system design and operations personnel.

To the electricity service provider, reliability encompasses planning and operational issues at the bulk power (generation and transmission) and distribution levels. The planning issues typically address resource adequacy and system security. Resource adequacy refers to having sufficient resources in place in a timely manner to produce and deliver power on demand and to provide a “buffer” (e.g., a reserve margin) to cover contingencies associated with unplanned electricity demand increases and unplanned electricity supply reductions. These contingencies can affect both production (generation) and delivery (transmission and distribution).

System security refers to having sufficient equipment and procedures in place to avoid harm to customers and to the electric system (generation, transmission, and distribution) in the case of disturbances. Disturbances can include adverse weather, equipment failures, and other events that could lead to an overload of the system or portions of the system. Because of the highly integrated nature of these systems and the inability to store electricity economically in large quantities, effective system

¹A control area is an electrical system within which generation is controlled to maintain frequency regulation and interchange schedules with other control areas. Telemetering and metering devices are deployed across the control area and at interconnection points with other systems to monitor system and interconnection conditions.

security requires a high degree of coordination, communication, and control on a real-time basis.

Reliability concerns were heightened in June 1998 with wholesale power delivery problems in the Midwest. This episode was triggered by the simultaneous occurrence of hot weather, key generating unit outages, and transmission constraints. One power marketer defaulted on a wholesale power delivery contract, and prices for some wholesale contracts rose approximately 100 times their normal level. This experience suggests that in wholesale markets

- price volatility may be the new norm,
- reliability of market players may be more of an issue now than in the recent past, and
- cooperation and coordination to ensure system security and to help regional electricity markets function effectively and quickly have become even more of a challenge.

Power markets are subdivided into bulk power (wholesale) markets and retail markets for regulatory purposes. Wholesale power sales are sales to resellers. Retail power sales are sales to ultimate customers (end users). Wholesale power sales involve generation and transmission services, whereas retail sales involve generation, transmission, and distribution services (including various customer services such as metering and billing).

Wholesale power markets are subject to regulation by FERC. Generation and transmission providers are in the process of complying with FERC Orders 888 and 889. These orders are designed to promote competition in wholesale electricity purchases and sales. They deal with issues of open access, nondiscriminatory transmission service (888), and open, real-time information systems (889) in wholesale power markets. Generation and transmission providers are also studying proposed new structures for reliability planning and transmission system operation. These efforts will require time to examine the issues raised about current changes at the wholesale power market level and to determine how providers can best respond to these changes.

Retail customers of resellers (e.g., munis, co-ops, and other large buyers who resell power to ultimate end users) have always been affected by changes in wholesale power markets. While retail customers of integrated (generation, transmission, and distribution)

providers have been affected to some degree by changes in wholesale power markets in the past, in the future they will be affected more by these changes as transmission systems and operating information become more open. These changes may be beneficial or detrimental, depending on what is being affected (e.g., prices, service reliability) and how adjustments are made.

Retail competition may bring additional changes and introduce additional issues that can affect retail customers. System planning and operation will become more complex, especially as the number of participants, the volume of transactions, and the diversity of transactions increase. The cost of maintaining current reliability levels may rise, even in the face of improvements in generation, transmission, distribution, and information technologies, unless efficiencies in competitive markets are large enough to affect this cost.

Proponents of the present system for ensuring reliability are concerned that power providers in a competitive environment may be more reluctant than they are now to

- make generation commitments in advance of demonstrated demand, resulting in demand not being met in a timely manner;
- share information that would assist resource planners; and
- invest in large-scale generating units or in generating units that rely on fuels other than natural gas.

However, the early experience with merchant plant construction indicates that the first concern has not yet been realized. The jury is still out on the second and third concerns. The question of whether a more competitive generation environment will degrade or improve the resource adequacy dimension of reliability is still open.

This report presents and discusses these and other reliability issues in detail. Although not discussed in this report, new technologies are needed to address the growing complexity of wholesale power market transactions and operations. New transmission, computing, and communications technologies are under development, which can help to maintain reliability in a more complicated competitive electricity industry. These technologies include new and faster data collection and communications systems, computer models that

estimate the current and likely future states of the transmission system, and systems that will enhance transmission capacity and controllability. In addition, distributed generation resources and energy-efficient, demand-side technologies could improve generation and transmission system reliability by expanding the amount of available capacity and distributing it widely throughout the transmission grid. The key question about distributed generation in this role is its cost-effectiveness.

In preparing this report, we have attempted to strike a balance between proponents and opponents of restructuring and their predictions of what will happen to the reliability of electric service if restructuring occurs. The question is hotly debated and is still an open question because, at this time, actual experience with industry restructuring is too limited to draw strong inferences about its effects on reliability.

2

Resource Adequacy Planning Processes

This section discusses and contrasts two competing resource planning processes and their implications for the resource adequacy dimension of reliability. The first is the integrated resource planning (IRP) process that has historically been used in state-level regulation of investor-owned utilities (IOUs). It involves public intervention in the planning process. The second is a free-market approach. It involves no public intervention except in siting decisions and perhaps in establishing certification procedures and codes of conduct for market participants.

System security planning is discussed in this section. While an important part of the planning process, responsibility for system security planning has historically resided, and will continue to reside, in national and regional organizations, and not at the state level. The responsibility resides at this level because transmission systems are highly interconnected and regional in scope, and because there is a strong interrelationship in system operation between transmission system reliability and generation system reliability. System security planning changes are underway at the national and regional levels that will affect North Carolina utilities, but they are outside the influence of North Carolina policymakers.

Appendix A discusses technical features of generation and transmission system operation that is important to an understanding of the planning challenges. This appendix includes a description of the current industry and regulatory institutions that seek to maintain the security of generation and transmission systems. Appendix B discusses the efforts of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the U.S. Department of Energy (USDOE) Task Force on reliability, and

others to update the reliability rules and practices to help ensure that today's reliability levels are maintained. The key driving force behind these updates is the implementation of FERC Orders 888 and 889.

2.1 THE IRP PROCESS AT THE STATE LEVEL

Historically, IOUs have included plans for generation and transmission reliability in the long-term IRPs they file with state regulatory commissions. These IRPs have traditionally included the following:

- ▶ forecasts of kW load and kWh energy growth;
- ▶ reductions to these forecasts as a result of electricity conservation and load management programs;
- ▶ reserve margin (generating capacity above peak load) criteria;
- ▶ generation capacity requirements needed to serve load and energy requirements and meet the reserve margin criteria;
- ▶ transmission expansion plans; and
- ▶ generation expansion plans.

In North Carolina, these IRPs have been filed every 3 years with the North Carolina Utilities Commission (NCUC), with annual updates for the intermediate years. The generation plant component of the IRP has traditionally included the following:

- ▶ megawatt (MW) size of requirements to meet load and reserve margin over a time horizon of at least 10 years;
- ▶ number, size, and timing of plants to meet these requirements;
- ▶ number and size of units per plant;
- ▶ technology and fuel type of units; and
- ▶ reasons for any delays in previously approved projects.

As of 1998, IOU generation plans have become less detailed.¹ For example, IOUs currently identify the amount and timing of new capacity requirements, but they specify their plans to meet these requirements generically—for example, they designate their generation plans as either peaking, intermediate, base-load, or

¹In 1998, the NCUC simplified the IRP requirements. Now, IOUs are required to file annual reports with 10-year forecasts of load and generation. New IRP plans do not have to address fuel and technology type of planned generation, nor do they have to address generation reserve margins.

undetermined. In previous years, IOUs specified the amount (in megawatts, MW) and timing by capacity type (e.g., nuclear). The less-specific plans filed currently are indicative of current major planning uncertainties—which are primarily related to uncertainties in future market structures and regulatory requirements—and of the large financial exposure that accompanies investments in large, base-load units. They also indicate a desire for planning flexibility, including the desire to have an option to build or “buy” (through purchased power contracts) future generating capacity.

In addition, generation planning reserve margins have declined. These margins are established to cover contingencies in power supply (e.g., unplanned outages of key generating units) and in power demand (e.g., unpredicted demand increases) and are determined by a combination of technical and financial criteria. They have declined from 20 percent in plans filed during the 1970s to approximately 13 percent in plans being made today. The key reasons for this decline are as follows:

- a more robust wholesale power market;
- improvements in operating performance (e.g., for nuclear units);
- gas turbine generators, which currently dominate new generation construction, require less lead time to construct than other types of generating facilities (e.g., coal, nuclear); and
- uncertain market and regulatory environments in the future.

The NCUC no longer specifies a reserve margin requirement or requires that one be cited in IRPs.

The transmission component in IRPs have traditionally included the following:

- kilovolt (kV) capacity requirements (transmission in North Carolina is defined as 161 kV or over) over a 5-year time horizon,
- location of proposed projects,
- schedules for completion and operation, and
- reasons for any delays in previously approved projects.

IOUs file applications for new generation and transmission projects consistent with the IRP, and the NCUC must certify these projects by issuing Certificates of Public Convenience and Necessity. FERC is involved in generation project approvals only if they are for

exempt wholesale generators (EWGs) pursuant to the U.S. Energy Policy Act (EPA) of 1992. FERC is involved in transmission project approvals only if the projects cross state lines. Neither the NCUC nor FERC approves IOU distribution system plans or projects, although the NCUC reviews the prudence of these investments in rate case proceedings.

The IRP process has helped ensure that generation and transmission capacity is built in time to serve customer load and energy requirements. By approving these projects, regulators have implicitly agreed that prudently incurred project costs can be recovered through rates. This has helped to reduce some of the financial risk from generation and transmission project development. Critics of the process have argued that it has resulted in too much capacity that is too expensive. Proponents counter that the IRP process has helped the U.S. build the most reliable electric system in the world, because generation adequacy has been mandated as a condition of continued operation.

2.2 THE FREE-MARKET APPROACH

Under restructuring, an alternative to the IRP process is a free-market approach. It relies on resource planning by individual companies with no public intervention. Although the plans are not integrated as in IRPs, cooperation and coordination can still occur through some form of regional transmission organization (RTO). An RTO, such as a transmission company (Transco) or independent system operator (ISO), can fill this role as it develops transmission plans in response to its participants' plans for new generation.

In theory, resource adequacy can be provided by the free-market approach. Free-market proponents contend that resource adequacy will be provided in a restructured environment if electricity prices and investment profitability are high enough to encourage the private sector to make these investments. Proponents of the present system for ensuring reliability are concerned that resource investment decisions may not be made in a timely manner, so that the resources are not available when needed. Proponents of the present system for ensuring reliability are also concerned that, even if the resources are available in a timely manner, these resources may not provide diversity in newly installed generation

technologies using diverse fuels. For example, the current trend toward building gas-fired generating units increases the size diversity of the overall generating mix, but it reduces fuel and technology diversity in new generating plants. They may have actually improved the reliability of the generation and transmission systems where they have been installed. Diversity in the overall generating mix—size, fuel, and technology—is desirable as a hedge against risks such as generation outages; adverse movements in gas availability and price; and future availability, performance, reliability, and price problems associated with a single technology.

It is clear that the resource adequacy outcomes under the free-market approach are uncertain, primarily because experience with this approach in electricity markets is just beginning. Whether a market approach to electricity investments will be as successful as market approaches to other industries and products is still an open question. There is no strong body of empirical evidence with electricity privatization and deregulation to demonstrate whether the resource adequacy concerns are real or not. Thus, the free-market approach remains a hotly debated public policy issue. A flavor of this debate is presented in the rest of this section.

2.2.1 Generation

How may the free market provide adequate generating capacity? To answer that question, one must first decide *who* will decide how much generating capacity is needed and *how* that entity will make such decisions. In most markets, *investors* make decisions regarding how much capacity to build, what technologies to deploy, and where to build generating facilities. Investors bear the risks of these decisions and enjoy the rewards if their decisions turn out well.

People who favor a strong central planning role in electricity point out that electricity is much more important to our health, safety, and economy than other products. Also, they are concerned that the difficulty in storing electricity (to equilibrate instantaneous demand and supply), and the several years it takes to license and build new generation facilities could lead to boom and bust cycles in the construction of these facilities.

Free-market proponents argue that market forces should determine the amounts, locations,² and types of generating resources to be retired, repowered, and built. Regulatory or institutional approaches, such as public utility commission (PUC) or ISO approaches, would undermine competitive electricity markets.

Here is how such a market system might operate. When ample generating capacity exists, hourly spot prices are low. (Hourly spot prices are based on fuel plus variable operation and maintenance [O&M] costs.) Potential investors see these low spot prices and decide not to build new generating facilities. As demand increases, or as old generating units are retired because they no longer generate enough revenues to cover their operating costs, the amount of excess capacity will decline. As excess capacity declines, spot prices will increase. When current (spot) and expected (future) prices are above the replacement cost of capacity, investors will build new power plants. They will do so on the basis of the following:

- their forecast of future demand and supply conditions and prices;
- their discount rate (reflecting both cost of capital and risk preferences) they use to compare investment returns in the future to current investment costs; and
- their assessment of the response to these same signals by their competitors.

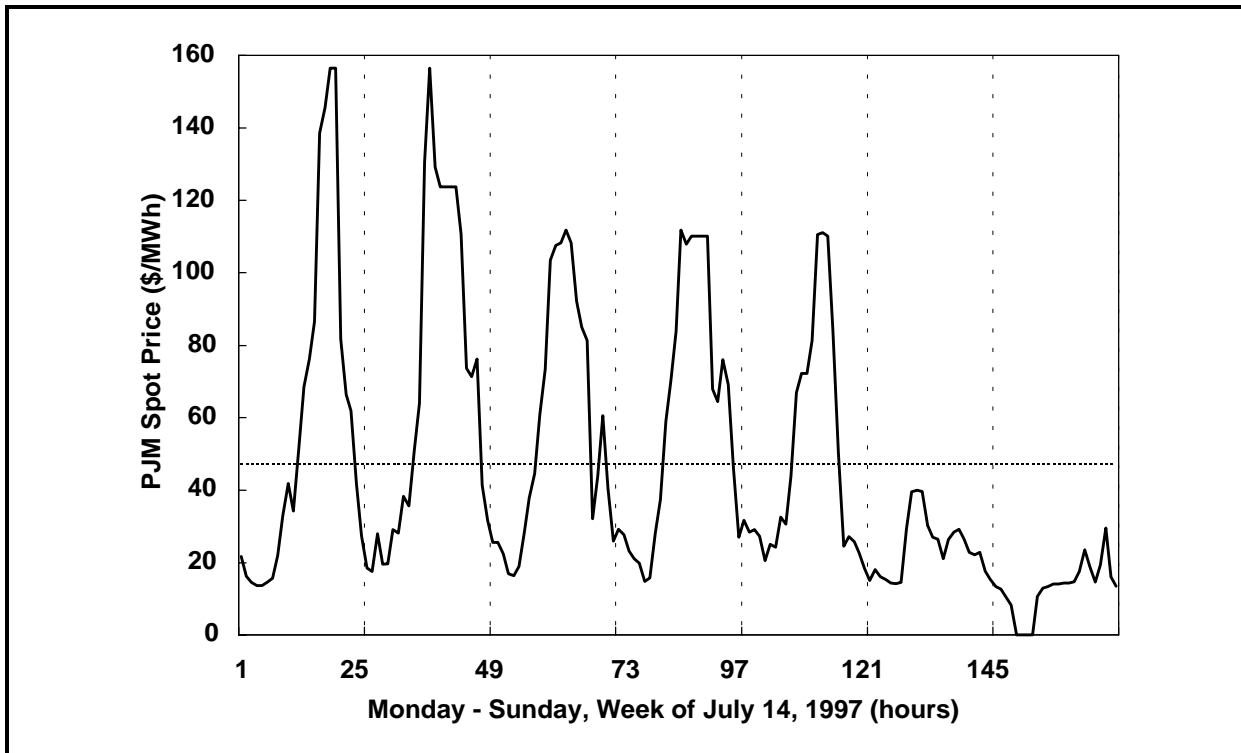
This approach assumes that generation capacity construction will follow market preferences on capacity amounts, types, and dates to enter service.

In the approach outlined above, the economic paradigm of supply and demand replaces planning reserves traditionally specified in IRPs. Proponents of this approach cite several features in favor of the economic paradigm. First, it is the only way to create and sustain truly competitive generation markets. They believe government determination of how much capacity to build represents an intrusion into the marketplace that could undermine the very competition being sought.

²They agree that state governments should retain siting and environmental authority over new generators. But, they argue, governments should have no say about the “need” for power.

Second, free-market proponents argue that hourly spot prices provide valuable and economically correct incentives to consumers and suppliers (Figure 2-1). The prices tell consumers when to consume more electricity (when prices are low) and when to consume less electricity (when prices are high); that is, time-varying prices encourage the installation and use of cost-effective load-management systems. Similarly, the prices tell suppliers when to bring on more capacity and when to retire old and inefficient units. Thus, volatility in electricity prices will be a key feature of a competitive market.

Figure 2-1. Illustrative Hourly Spot Prices in the Mid-Atlantic Region^a



^aPrices ranged from a low of \$0 to a high of \$156, with an average of \$47/MWh for the week. These prices are typically higher than prices in the Carolinas-Virginia region.

Third, free-market proponents argue that central determination of minimum planning reserves might undercut competitive spot-market prices for electricity. The more capacity that is available (whether centrally mandated or because of the cumulative effects of the decisions of individual investors), the lower spot prices will be. Thus, mandating minimum planning reserves may reduce profits in spot markets because it reduces information regarding when and

how much energy to purchase and supply and when to build new generating capacity.

Opponents of this free-market approach are concerned about price volatility and especially blackouts. What happens, they worry, on that anomalously hot spring or fall day when several large generators are out for planned maintenance, unconstrained demand is very high, and a major generating unit has just suffered a forced outage. (An example of this contingency occurred in the midwest in June 1998, which has spawned a FERC investigation, a congressional investigation, and lawsuits.) Either the system operator will have to disconnect loads or suppliers will “gouge” customers with prices that bear no relation to costs.

Not so, argue the free-market proponents. Under these circumstances, large customers on time-differentiated rates will see these high price “signals” and will voluntarily reduce their demands (either by shifting usage to other time periods, reducing demand, or, for some large industrial customers, increasing the output from their co- and self-generation facilities). Thus, the system may remain in supply/demand balance without load-switching or other emergency actions by the system operator.³ And, argue the free-market proponents, the high prices are not unfair. The high prices represent exactly the kind of supplier/customer interaction that characterizes competitive markets. Also, these high prices will likely occur for only a few hours a year.

How can we resolve these disagreements between the free-market proponents and those who prefer the traditional IRP process? First, the various experiments that are developing around the country as FERC approves diverse ISO systems should be followed closely. Below are two experiments that may provide interesting and informative comparisons over the next few years:

- the California ISO and Power Exchange (PX), in which the electricity market is an “energy-only” market (i.e., trading prices reflect only the “energy” costs of producing electricity and none of the generation and transmission capacity costs), and

³Limited experience in the U.S. (e.g., Georgia Power’s real-time pricing program) and in the UK shows that some customers do respond substantially to real-time price signals.

- the Northeast and mid-Atlantic ISOs, with their capacity markets, which have separate capacity and energy markets.

Second, a cautious middle ground might involve establishing some form of RTO that is permitted to specify minimum reserve requirements for all participants and to create a market for such reserves. The minimum reserve requirements could be reduced year by year if the situation warranted such reductions. The RTO could also establish minimum generation resource requirements for all suppliers to help ensure that adequate generation and transmission system reliability is maintained.

2.2.2 Transmission

Historically, vertically integrated utilities (IOUs) planned their generation and transmission systems on an integrated basis. That is, they optimized the location and capacity of generating units to match the configuration of the transmission grid. And they added transmission lines and substations to match the locations and usage of their generating units. This degree of integration will be more difficult to achieve in a restructured industry that has generation unbundled (separated) from transmission.

In our task reports, we assume retail restructuring may involve restructuring at the generation level. Restructuring of transmission is being spearheaded by FERC. As noted throughout this report, changes at the generation level can have effects at the transmission level, because the two are highly interrelated in a power supply system.

Potential Problems

Potential reliability problems associated with transmission arise for a number of reasons:

- Because transmission is a network, every action affects everything else throughout the interconnected grid. This interdependence makes it very difficult to establish clear physical or financial rights to individual pieces of transmission equipment embedded within a larger transmission grid.

For example, the owner of a generating unit can decide whether to generate power. He can also decide at what level to produce power or whether to reduce power output to permit selling ancillary services, such as spinning reserve. The owner of a transformer, substation, or individual

transmission line has very little ability to independently determine the use of that piece of equipment. Perhaps more important, it is virtually impossible to assign a value to a piece of transmission equipment without considering the entire grid within which that piece of equipment is embedded.

- Transmission capacity can be expanded in many ways. These methods include building new transmission lines, interconnecting systems through interties, upgrading existing lines to increase voltage and capacity, installing new technologies such as flexible alternating current transmission (FACT) devices, adding distributed generation at strategic locations, and redispatching existing generating units.

Decisions on whether and where to expand transmission capacity should be based on the location, extent, and costs of transmission congestion. Because there are many ways to relieve congestion, congestion pricing may be an important mechanism to signal investors on what to build, where, and when.

- Transmission pricing is a complicated and contentious topic. Pricing proposals range from the very simple (postage-stamp and license-plate pricing) to the very complicated (nodal pricing).⁴ Some forms of pricing require near-real-time computer calculations, which means that prices are often available only after the fact. In part, the disputes about transmission pricing arise because we would like these prices to accomplish several, perhaps competing, objectives. These objectives include embedded-cost recovery for transmission owners, economic incentives for short-term use of the grid, economic incentives for long-term expansion of the grid, economic incentives for long-term expansion and proper location of new generating units, support of competitive generation markets (which, to some, requires a priori specification of transmission prices), and simplicity and ease of administration.
- Even if transmission prices gave appropriate economic signals, acting on these prices would be difficult for two reasons. First, once the investment is made and the congestion is relieved, the money collected through congestion pricing would no longer be available. Second, because of the network characteristics of transmission systems, the benefits of any new transmission equipment are likely to be shared widely across the grid and therefore

⁴Postage-stamp pricing has all customers, regardless of location, paying the same \$/kW-month price. License-plate pricing has customers paying different prices depending on the location of the load (or generator) but, having paid that location-specific price, being allowed to wheel power across the grid without additional charges. Nodal pricing has different prices at each bus on the grid; the differences among nodal prices are a function of line losses and congestion.

difficult for the investor to capture (the “public goods” problem).

Potential Solutions

There are several possible organization solutions to the potential problems cited above. However, all of these solutions are either still under discussion or, in some cases (e.g., California), in the early implementation phase. One scenario of the future of the U.S. electricity industry involves a split among three separate types of generation/transmission entities: unregulated generating companies, FERC-regulated transmission companies, and FERC-regulated system operators. This scenario has ISOs performing the integrating function in the future. Many issues need to be resolved, including what authority ISOs will have, if any, to compel construction of needed transmission facilities. Another issue is what happens to transmission plans when generation construction plans change.

A second scenario involves the same split but replaces ISOs with regional Transcos. These companies would both own and operate transmission networks serving as both the system operator and the transmission owner/operator. Transcos are seen by some industry participants as a possible solution to potential resource adequacy problems with ISOs. For example, Transcos may help solve potential problems of transmission investment cost recovery with ISOs, generally removing a potential disincentive for transmission investments.

Conclusion

Regardless of the form of organization of the generation and transmission functions and their operation, public support for transmission expansion is very important because, although such expansions can have broad regional benefits, siting approval is a state function. Some have suggested that Congress grant FERC authority to approve the locations of new transmission lines, much as it now does for gas pipelines; the states are likely to strongly oppose such a transfer of authority to the federal government. Thus, transmission expansion and siting will continue to be debated at the federal, state, and local levels, regardless of whether the electric industry is restructured at the state level.

3

Potential Impact of Competition on Generation and Transmission System Reliability

Electricity industry restructuring may potentially affect the reliability of generation, transmission, and distribution systems. Because of the linkage between the two, this section addresses the reliability of generation and transmission systems together. Section 4 addresses distribution system reliability.

Because generation and transmission are so closely linked, they are often referred to as a single system (i.e., a generation and transmission system) that includes generating units, transmission lines, and system control equipment. The Federal Energy Regulatory Commission (FERC) regulates wholesale (also referred to as bulk power, or “sales for resale”) transactions. These transactions involve providing generation and transmission services but not distribution services. A key FERC regulatory activity is the regulation of investor-owned utility (IOU) wholesale tariffs and service practices. Other relevant FERC regulatory activities are as follows:

- certification of exempt wholesale generators (EWGs), which are generating units dedicated to supplying wholesale power (i.e., they supply no direct power to retail customers), and
- licensing and relicensing of hydropower facilities.

FERC is currently engaged in efforts to encourage the formation of regional transmission organizations (RTOs), such as independent system operators (ISOs) or transmission companies (Transcos). Also, FERC is soliciting views from state utility commissions on establishing regional electricity transmission districts to promote transmission interconnection and coordination. All of these FERC activities may potentially affect generation and transmission system reliability.

The North American Electric Reliability Council (NERC), an organization of industry professionals whose chief role is to review electric system reliability at the continent and national levels, has traditionally established reliability standards for generation and transmission systems. NERC comprises regional reliability councils that review electric system reliability within their regions and between their regions and neighboring regions. Currently, NERC is being recast as the North American Electric Reliability Organization (NAERO). Congressional legislation is being introduced to establish NAERO as a self-regulating reliability organization.

Appendix B discusses evolving institutional roles in wholesale power markets pursuant to FERC Orders 888 and 889. In particular, it discusses how changes currently underway may result in a stronger role for FERC and NERC (or NAERO) in maintaining generation and transmission reliability. For example, FERC may gain more influence over generation and transmission investments as a result of the move to “unbundle” (separately offer and price) generation and transmission services in wholesale power markets. Also, Congress may approve new authority for NERC (or NAERO) to enforce reliability standards.

States have a role in maintaining generation and transmission system reliability too. The North Carolina Utilities Commission (NCUC) issues Certificates of Public Convenience and Necessity to IOUs for approved generation facilities. Through its regulation of IOU retail rates and service practices, the NCUC can directly affect the profitability of generation and transmission investments and, thus, the extent of those investments. The NCUC also requires IOUs to submit integrated resource plans annually, although the process and the plans were simplified significantly in 1998. For example, plans are now shorter than they once were and the utilities commission no longer requires planning reserve margins to

be included in a plan. Other state agencies play a role as well (e.g., siting of generation and transmission facilities is subject to approval by state environmental authorities).

Currently, generation and transmission system reliability is a key issue because of the changes that are taking place at the FERC and NERC levels and the substantial increases in the number and complexity of wholesale power transactions. Although generation and transmission are responsible for only a small percentage of all power outages, the scope, as well as the economic and societal consequences of such outages, is much greater than that caused by distribution system failures.

3.1 POTENTIAL RELIABILITY BENEFITS AND RISKS OF COMPETITION

Restructuring the electric utility industry at the retail level (e.g., retail customers may select the electricity supplier (generating company, or Genco) or the retail energy service provider (ESCO) of their choice) can be accompanied by more or less retail regulation than has traditionally been the case. Generation and transmission system reliability may be directly affected by the model selected for resource planning. The two models of resource planning discussed in this section are the traditional integrated resource planning (IRP) model and a free-market model. The material in this subsection is partitioned into views forwarded by proponents of the traditional planning methods versus views forwarded by proponents of a free-market approach.

3.1.1 Introduction

Will increased competition at both the wholesale and retail levels worsen reliability? This question, like so many others related to restructuring the U.S. electricity industry, elicits strongly competing responses. These responses reflect the debate between proponents of the traditional planning processes (e.g., the IRP process) and proponents of a free-market approach that was presented in Section 2. Although data exist to quantify the success of traditional planning processes in maintaining reliability, we can only speculate as to the success of a free-market approach.

3.1.2 Traditional Planning Process Proponents

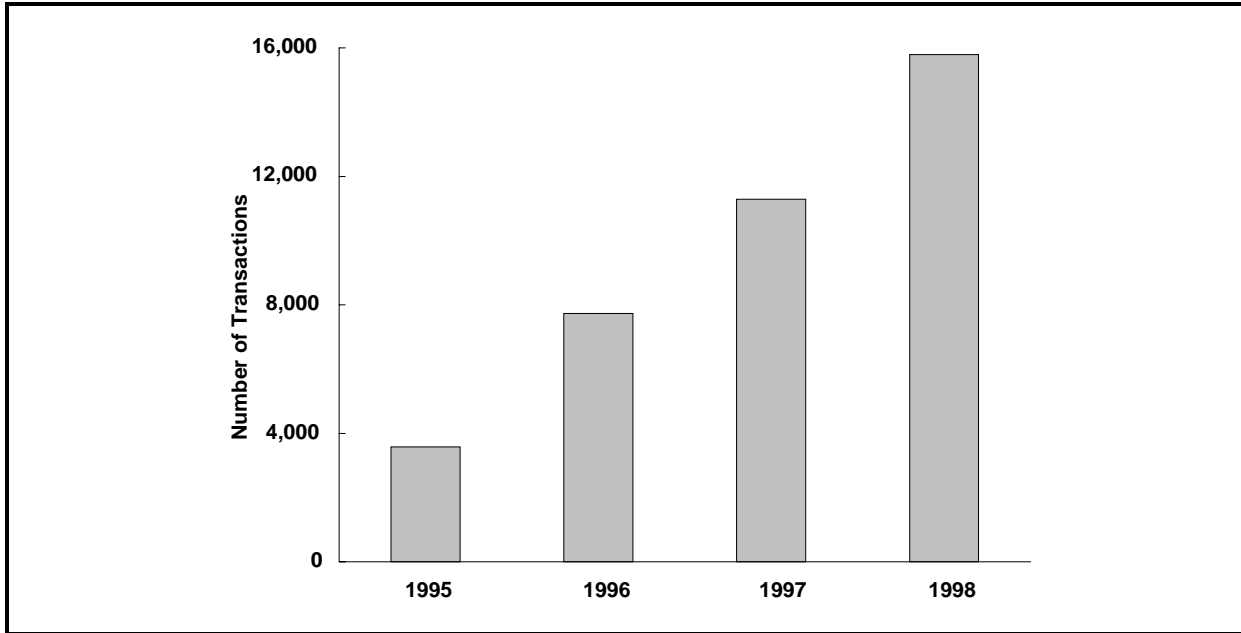
Those most concerned about the effects of competition on reliability are the people responsible for maintaining generation and transmission system reliability (Casazza, 1998). They argue that electricity is not just another commodity; rather, it has unique characteristics (as discussed in Appendix A) that require tight coordination and centralized control. They believe that markets might be able to provide for generation adequacy—for example, enough generating capacity to meet projected peak demands, operating reserve requirements, planned and forced outages of generating units, and load forecasting errors. However, they believe that markets cannot work well to ensure transmission system adequacy because of its network attributes.

They argue that design and operation against the worst single contingency means that the system cannot be made just a little bit less reliable than it is today. The contingency criteria can either be met or they cannot. According to another traditional planning process proponent (Loehr, 1998):

It's a quantum kind of thing. Some have suggested that transmission criteria should be based on probability rather than the present deterministic principles. Actually, industry experts have been working on developing a practical system for more than 30 years but so far have experienced limited success. The problem is that the probability of any single event approaches zero, while the number of possible events [contingencies] approaches infinity.

Finally, the people responsible for maintaining generation and transmission system reliability note the increasing number and complexity of transmission operations, with more and more diverse market participants engaging in more and more transactions. Utilities throughout the country report substantial increases in the number of schedules and schedule changes. Formerly, these transactions were primarily with adjacent utilities. Now they are with a variety of entities, including neighboring and distant utilities, independent power producers, and power marketers. For example, the number of transactions handled by Duke Power more than doubled between 1995 and 1996, increased another 50 percent between 1996 and 1997, and is increasing by about 40 percent in 1998 (Figure 3-1). In a similar fashion, the number of transactions

Figure 3-1. The Number of Wholesale Transactions Handled by Duke Power in North and South Carolina



handled by Southern Company Services¹ more than doubled between 1995 and 1998. In addition, utilities increasingly have difficulty tracing these flows from source to sink, which is why NERC implemented its tagging requirements (see Figure 3-2).

Current reliability planners also point to greater uncertainty concerning future requirements, and that it now takes longer to plan and build new transmission lines (4 to 10 years) than new generation (2 to 3 years for peaking units). They assert that these uncertainties, the increased complexity associated with many new players, and failure to consider the capacity benefits² of transmission lines can increase the cost of maintaining current levels of reliability.

¹Southern Company Services is the service arm of Southern Company, a holding company that includes Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric Power.

²Increased transmission capacity, or more interconnected transmission system over wide geographical area, can reduce the need for new generating capacity, thereby offering capacity benefits to a generation/transmission system.

Figure 3-2. Reliability Conflicts before FERC

FERC's recent actions on reliability (Appendix B) may have been stimulated by a complaint filed by a group of power marketers and large industrial customers in August 1997 (Coalition for a Competitive Electricity Market and Electricity Consumers Resource Council, 1997). The complaint concerned NERC's interim Transaction Information System and NERC's requirement for this "tagging" information on all transactions. NERC's requirements include the interchange schedule size (MW), start and stop times and ramp rates, generation reserves, and transmission service arrangements. The complaint alleged that absent prior approval from FERC, NERC lacks authority to require its members to impose such a condition on wholesale trade and that some utilities are using this NERC requirement to impede wholesale competition. The Coalition is concerned because NERC requires that the load-serving entity is the one responsible for providing the tagging information. But if that entity (almost always the local distribution company) does not do so, the power marketer or seller may be the one that loses.

In response, NERC (1997a) claimed that its current actions are a continuation of its 30-year efforts to maintain generation and transmission system reliability. NERC explained that this additional tagging information is "properly a part of NERC's Operating Policies and Procedures because it provides information required by Control Area Operators to physically match generation and load and thus maintain the integrity of the Interconnections." This NERC operating procedure is independent of FERC's open-access information system. NERC distinguishes between requesting and reserving transmission service (the financial deals), which is under FERC jurisdiction, and setting up and implementing interchange schedules between control areas (the physical energy transfers), which traditionally has been NERC's responsibility. These physical actions, matched between the sending and receiving control areas, are essential to maintaining frequency at its reference value and to prevent overloading of transmission lines.

In April 1998, FERC (1998a) concluded

that the establishment by NERC of a requirement to report certain information does not, in and of itself, require a change to the terms and conditions of the Open Access Tariffs on file with the Commission because the information which NERC requires is consistent with the information that the tariffs already require. As a result, we will dismiss the Coalition's filing. However, the question of whether information may be collected is different from the question of what actions can be taken under a utility's tariff in response to the information.

Thus, FERC seemed to steer a careful course between the opposing viewpoints, probably because of its uncertainty concerning its statutory authority to enforce reliability rules. As a result, reliability planning in wholesale power markets is in a state of flux. Some states are moving to fill some of this void, but there is much debate and uncertainty surrounding these efforts.

3.1.3 Free-Market Proponents

People who favor electric and wholesale competition, especially power marketers and large industrial customers, point to the potential benefits of increased reliance on markets to deliver reliability services. Rather than continue to use the traditional command-and-control approach to reliability, they suggest the use of economic incentives to encourage appropriate behavior on the part of electricity market participants (Hirst, 1997). They assert that

the use of economic incentives (i.e., competitive markets) to define reserve requirements and to buy and sell such reserves could improve reliability at no increase in cost, or maintain current reliability levels at a lower cost.

An example of how this approach might work is described as follows:

Operating reserves as defined by NERC have two components, spinning and supplemental reserves. Spinning reserve includes generating equipment that is online, synchronized to the grid that can begin to increase output immediately in response to changes in Interconnection frequency, and that can be fully available within 10 minutes to correct for generation/load imbalances caused by generation and transmission outages. Supplemental reserve differs from spinning reserve only in that supplemental reserve need not begin responding to an outage immediately.

Each of the regional reliability councils establishes minimum amounts of capacity that must be set aside for operating reserves, usually expressed as a percentage of the daily peak demand or of the largest single contingency. In principle, these levels are based on the planned availability of the generating units in the region, transmission conditions, speed of response, and many other factors.

In a competitive market, the responsibility of each unit to provide operating reserves should depend directly on its forced outage rate (Hirst and Kirby, 1998). Units with low outage rates would be required to provide or pay for less operating reserves than would the units that have high outage rates. This economic signal would provide the appropriate incentives to generation owners, encouraging them to undertake the amount of maintenance that would balance the higher cost of providing more reserves. In addition, in the event of an outage, the generator responsible for the outage should pay for the operating costs of the units that responded to the outage (i.e., the incremental fuel plus operation and maintenance (O&M) costs beyond those associated with the spot-market price for that hour). This pricing approach would provide further incentives

for maintaining high availability levels at all generating units.

This approach has yet to be tested on a broad scale; thus, its ability to be successfully implemented remains a point of debate between proponents and opponents of retail competition.

Also, proponents of reliance on markets claim that customer response to real-time pricing signals can help improve reliability. Rather than rely on technical standards to set minimum amounts of installed generating capacity, proponents favor more time- flexible, instantaneous cost-based pricing (such as real-time pricing). This type of pricing is currently cost-effective only for large customers, but it has the potential to help guide decisions on how much capacity is needed, where, and when. Sustained high prices will encourage the construction of new generating units and the prompt restoration to service of existing units that are offline. Similarly, high prices will encourage customers to reduce their usage at those times. Together, these supply and demand responses to price, if sustained, have the potential to reduce the need to maintain expensive generating capacity that is only rarely used. Thus, economics may substitute for regulation to maintain reliability.

3.1.4 Conclusion

Whether reliability at national and regional levels can best be maintained by relying solely on markets or on traditional planning processes involving technical standards is a key issue. Reliability is likely to be maintained in the future by a mix of the two. The challenge to the electricity industry is to find an appropriate mix of economic incentives and performance standards that maintain reliability at the lowest reasonable cost. As discussed in Appendix B, NERC, FERC, the Department of Energy (DOE) Task Force, and many others are working to update the reliability rules and practices to be sure that today's reliability levels are maintained.

3.2 STATE ROLES IN GENERATION AND TRANSMISSION SYSTEM RELIABILITY

Under emerging wholesale (bulk power) market competition and its regulation by FERC, the ability of states to affect generation and transmission reliability is eroding. FERC's mandated unbundling of generation and transmission services, and its assertion of authority over these services, effectively reduces state authority over generation and transmission system reliability.

State control over generation and transmission system reliability may also erode under retail competition if interconnections grow and more power is imported from out of state. In a more widely interconnected system, disturbances far away can now have a local impact. For example, a disturbance in the Pacific Northwest caused the August 1996 blackouts in California.

Nevertheless, state regulatory commissions are taking a keen interest in reliability. The Electricity Committee of the National Association of Regulatory Utility Commissioners (NARUC) established a reliability working group to study reliability issues. In addition, NARUC issued a resolution in November 1997 addressing reliability issues from the view of state regulators (see Appendix C). This resolution has generated a lively exchange of comments and opinions since its publication. Some participants in the deliberations, for example, have suggested the discussions include retaining the current method of transmission system management as well as studying alternatives such as various forms of RTOs.

Kincheloe and Burns (1997) take an optimistic view of the state role in maintaining reliability:

Transmission facilities and transmission services are shared goods that cannot efficiently be separated between retail and wholesale customers. In sum, state and federal regulators share sovereignty over transmission services and reliability. This implies that cooperation and coordination among state and federal regulatory authorities is necessary to bring about efficient outcomes that are consistent with assured reliability.

FERC is interested in working with states, but has not yet decided how best to do so, as indicated by this comment from Commissioner Massey (1998):

I believe states should have some ongoing role [with regard to multistate ISOs], but that role has not been clearly defined. Perhaps ISOs should have advisory committees that include state commission members. FERC has yet to explore the wisdom of so-called joint boards in the ISO context. We should explore all avenues for reasonable and appropriate state input.

Table 3-1 summarizes the possible roles of governments in overseeing generation and transmission system reliability in a restructured industry. These roles reflect the direction in which FERC is moving and FERC's adoption of a more free-market approach. The table is split into long- and short-term elements. The long-term elements involve generation and transmission adequacy, assuring that sufficient resources are available and properly located to meet growing customer electricity needs. The short-term elements involve operations, the use of existing generation, transmission, and system-control facilities and personnel to prevent outages from occurring, and, when such outages occur, the assurance of prompt and safe restoration of service.

Table 3-1. Possible Federal and State Government Oversight of Generation and Transmission in a Restructured Electricity Industry

	Long Term (Planning and Construction)	Short Term (Operations)
Generation	<p>Markets decide on unit construction, retirement, repowering, life extension</p> <p>State could set minimum reserve requirement and has siting and environmental authority</p>	<p>Markets decide on commercial use</p> <p>Control areas, subject to NERC rules, control some generation for reliability; FERC could approve NERC rules</p> <p>No clear state role</p>
Transmission	<p>Transmission owners and/or RTO decide on need, subject to FERC jurisdiction</p> <p>State has siting and environmental authority</p>	<p>Control area or RTO decides, subject to NERC reliability rules and FERC open access, nondiscrimination requirements</p> <p>No clear state role</p>

To the extent that the provision of generation services is deregulated, neither the federal government nor state governments will have much role over what plants are built, modified, or retired, or over how they are deployed. The owners of such facilities will make these decisions in competitive markets. However, states will continue to exercise their traditional authority over the siting and environmental impacts of these facilities.

The planning for and construction of new transmission facilities will continue to be regulated monopoly activities, overseen by both FERC and the state PUC. One major difference from tradition is that generation and transmission planning may no longer be integrated because these parts of the electricity industry are being unbundled (separated) and major components (bundles) of generation and transmission services will be separately offered and priced.

The RTO, in cooperation with transmission owners and other market participants, will develop alternative transmission-expansion plans and select one that meets reliability requirements, satisfies commercial interests, and is cost-effective. Whether the ISO form of RTO can *compel* the local transmission owners or others to build such facilities is unclear. FERC rules require its jurisdictional utilities (essentially the transmission-owning IOUs) to build facilities needed to effect requested transmission transactions. However, while FERC may certify the need for new transmission facilities, states retain their local siting authority. It is unclear whether states will approve the construction of new transmission lines that benefit the region as a whole if their construction is opposed locally. How will states balance the interests of their citizens against those of other states in the region? Another problem could arise if a state approves the construction of new transmission facilities that, because of retail competition, are FERC-jurisdictional and FERC subsequently denies recovery of these costs in transmission rates.

The operation of generating units (i.e., unit commitment and dispatch) may be left largely to competitive markets; that is, generator owners will choose to operate their units when they can do so profitably (i.e., when the spot price is above the variable cost of the unit) and will otherwise not run their units. Generators may be subject to a “must run” (minimum supply) requirement as a

condition for participation. This requirement may be imposed by a state regulatory commission or an RTO to help guarantee supply or to avoid large changes in supply conditions (e.g., with large generating units).

Reliability requirements for ancillary services (e.g., voltage regulation, spinning reserve, and supplemental reserve) in wholesale transactions will likely be separate from any must-run rule. A control area, in compliance with NERC and regional requirements, will likely acquire certain amounts of generating capacity for ancillary services, which may be supplied in competitive markets in the future. The provision of ancillary services should not lead to reliability problems for wholesale or retail customers if prices are adequate to call forth sufficient suppliers of these services.

Finally, the control-area operator will operate the transmission system to maintain system security. These operations will conform to the NERC requirements for system reliability and the FERC requirements for commerce (wholesale transactions). The NERC requirements concern voltage levels; frequency deviations; and thermal, voltage, and stability limits on various transmission-system elements. The FERC requirements cover electronic provision of information, nondiscriminatory operation of the system, and reservations of transmission capacity. Because many operational decisions affect both reliability and commerce (such as calculation and posting of available transfer capacity, real-time power-flow scheduling, and congestion management), they will be subject to both FERC and NERC rules. Traditionally, state regulators have not overseen these transmission system operating decisions.

The following is a brief description of the roles some states are playing in overseeing reliability.

Florida: Florida has not enacted retail competition but has unique reliability problems because it is a peninsula with two main interties to import power from the north. The Florida Legislature has granted considerable authority to the Florida Public Service Commission to oversee reliability in the state. The Commission has the power to “require installation or repair of necessary facilities including generating plants and transmission facilities....” The Legislature requires utilities to file 10-year site plans with the

Commission every 2 years. These plans show how the Commission's reliability authority will be implemented over the coming decade.

Because of this substantial power, the Commission staff and the Florida Reliability Coordinating Council work informally to study reliability issues. For example, the Council's *1997 Reliability Assessment* was conducted in response to Commission concerns about reserve margins. The Commission staff members were concerned because the aggregate winter reserve margin for Peninsular Florida's utilities is forecast to drop to 8 percent by 2006.

Illinois: Illinois has enacted a form of retail competition. The Electric Service Customer Choice and Rate Relief Act, passed in December 1997, requires the Illinois Commerce Commission to "adopt rules and regulations for assessing and assuring the reliability of the transmission and distribution systems and facilities that are under the Commission's jurisdiction." The Commission's (1998) new rules under Part 411 Electric Reliability define an interruption or an outage as one that lasts longer than one minute and requires human intervention. The rule lists three reliability indices:

- System average interruption frequency index is the average number of interruptions per customer during the year: total number of customer interruptions/total number of customers served (e.g., two interruptions on average per customer per year).
- Customer average interruption duration index is the average interruption duration for those customers who experience an interruption during the year (minutes): sum of all customer interruption durations/total number of customer interruptions (e.g., 6 hours on average per customer per year).
- Customer average interruption frequency index is the average number of interruptions a year for those customers that experience an interruption during the year: total number of customer interruptions/total number of customers affected (e.g., four interruptions on average per interrupted customer each year).

The Commission's rules call for IOUs to provide the Commission with certain statistics that they will use to assess service reliability. The rules do not require the utilities to take any remedial actions, merely to report on past performance and current plans. Also, the

legislation limits the Commission's authority to those "systems and facilities that are under the Commission's jurisdiction." Once retail competition begins, however, the transmission systems formerly under the jurisdiction of the Commission (intra-state system) will become FERC-jurisdictional. Thus, it is unclear whether the Commission will be able to exert much influence on generation and transmission system reliability in coming years.

California: California has also enacted a form of retail competition. Assembly Bill 1890, enacted in September 1996, directed the California ISO (1998) to report to the Legislature on a variety of reliability issues. The ISO's July 1998 report covers several issues related to NERC and Western System Coordinating Council reliability criteria, the economic costs of major transmission outages, the range of cost-effective options to prevent or mitigate such outages, communication protocols that may be needed to improve advance notice of outages, the need for additional generation reserves and other voltage support equipment, the need for transmission capacity additions, the adequacy of institutional provisions for maintenance of reliability, possible mechanisms to enforce transmission rights-of-way maintenance, and recommendations to improve electric reliability. The legislation gives the ISO the authority to "secure generation and transmission resources and efficiently use the transmission grid consistent with achieving planning and operating reserve criteria...." It is not clear what the word "secure" means, whether this means that the ISO can buy or order others to build and pay for new generation and transmission.

3.3 GENERATION AND TRANSMISSION SYSTEM RELIABILITY IN NORTH CAROLINA: PERFORMANCE AND CONCERNS

To address the issues discussed above in the context of North Carolina, we distributed a short mail questionnaire to the utilities serving retail load in North Carolina. This section is based primarily on the responses to that survey from Carolina Power & Light (CP&L), Duke Power, Electricities, North Carolina Electric Membership Cooperative (NCEMC), and Virginia Power.

North Carolina is served by three primary control areas (Figure 3-3). The western and central parts of the state are within the Duke control area, except for a small portion of western North Carolina that is in the CP&L West control area. Virginia Power covers the northeastern part of the state and CP&L covers the remainder. The Duke and CP&L control areas encompass much of South Carolina as well, and the Virginia Power control area includes much of Virginia.

3.3.1 Past Reliability Performance

Quantifiable measures are required to assess reliability performance. NERC developed these measures because it is the organization that sets industry standards and because it is the repository for reliability and operating data.

Until February 1998, NERC had a two-part voluntary standard for recovery from “disturbance conditions.” The standard specified the performance required of each control area in managing its area-control error (ACE) after the loss of a major generating unit:³

- ▶ B1 Standard: The ACE must return to zero within 10 minutes following the start of the disturbance.
- ▶ B2 Standard: The ACE must start to return to zero within 1 minute following the start of the disturbance.

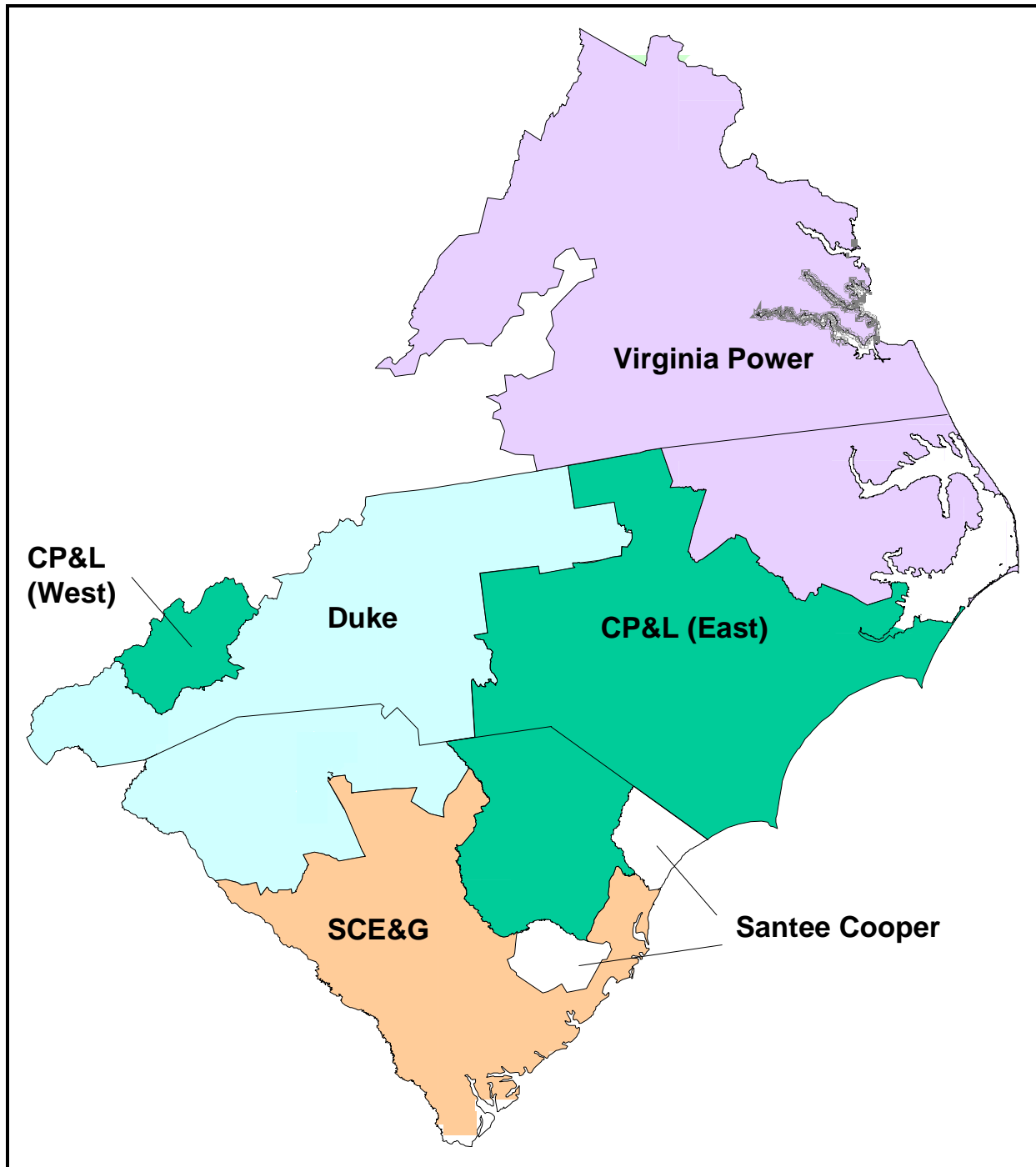
The B1/B2 criteria are only partial measures of generation and transmission system reliability. For example, they do not encompass transmission security.

To meet the B1 and B2 standards, utilities maintain and deploy reserve generation that is not needed to meet normal load but that can be called on quickly to supply the power lost because a generating unit trips offline.

Figure 3-4 shows the overall month-to-month performance of the utilities in the VACAR region (Virginia, North Carolina, and South Carolina) in meeting the B1/B2 standard over the most recent 3-year period for which data are available. A score of 100 percent means that the utility met the B1 and B2 standards for each reportable outage. The average annual compliance was consistently at or above 90 percent during this period. The average compliance for 1995 was

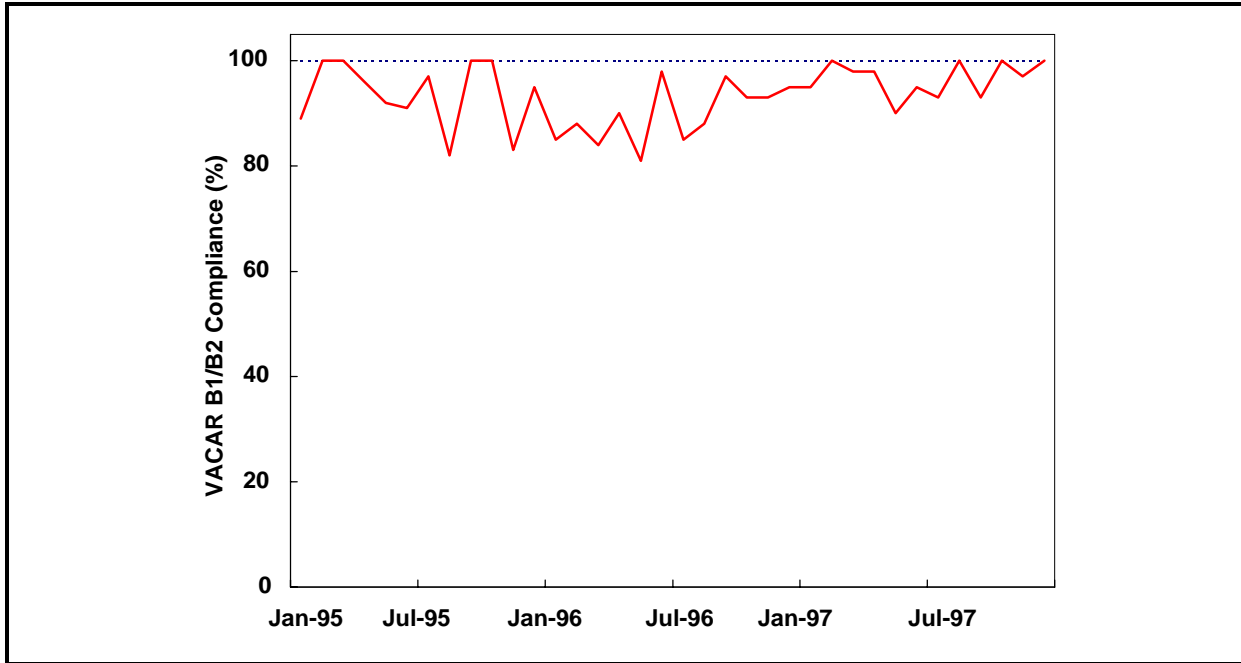
³In simplified terms, ACE measures the performance of a control area in matching its generation to its load in a way that does not impose burdens on other control areas or on the interconnection as a whole.

Figure 3-3. Map of North and South Carolina Showing Approximate Locations of Electric Utility Control Areas for North Carolina IOUs^a



^aThe Yadkin control area (not shown because of its small size) is on the boundary between Duke and CP&L East. North Carolina falls within the Virginia-Carolinas (VACAR) subregion of the Southeastern Electric Reliability Council (SERC).

Figure 3-4. Performance of the Utilities in the Virginia-Carolinas Subregion in Meeting the NERC Disturbance Standard for 1995, 1996, and 1997

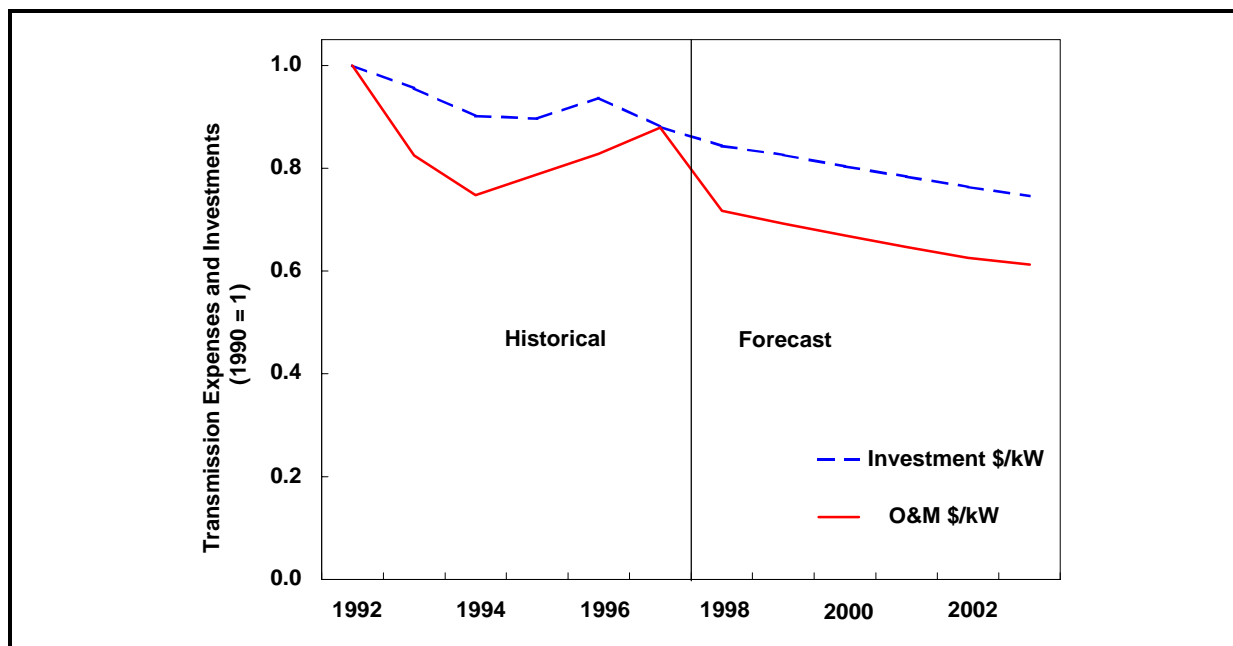


94 percent, 90 percent in 1996, and 97 percent in 1997. Although no comparable figures are available, this performance is believed to be at least as high as the performance of all utilities at the national level.

The three North Carolina IOUs also provided data on their transmission-addition investments and their annual expenditures on transmission operation and maintenance from 1992 through 1997. Two of the three IOUs provided projections for 1998 through 2003.⁴ Figure 3-5 shows these data and projections. The dollar amounts are all converted to 1996 dollars to correct for the effects of inflation. The dollar amounts are further adjusted by the annual peak demand for the three utilities; this comparison implicitly assumes that changes in transmission miles are correlated with changes in peak demand. Thus, the two curves in Figure 3-5 show annual expenditures to operate and maintain their transmission system per unit of demand and the annual capital investment in transmission per unit of demand. These trends mirror the trends in

⁴Virginia Power declined to provide projections, stating that such information is “confidential, proprietary, and competitively sensitive.” CP&L and Duke, however, provided these projections. We used the historical data for all three utilities to impute projections for Virginia Power.

Figure 3-5. Annual Expenditures for Transmission Operations and Maintenance and Total Transmission Investment for CP&L, Duke, and Virginia Power^a



^aThese costs are corrected for inflation and for growth in peak demand. The data are normalized to 1992 results.

those variables at the national level. They reflect a changed contingency planning philosophy and the increased difficulty of siting and installing additional transmission facilities.

The results show that both O&M and investment expenditures in transmission have declined from 1992 through 1997 and are expected to continue to decline over the next several years. These trends have sparked a debate as to whether they reflect efficiency improvements or a degradation in reliability.

CP&L believes that the declining costs are a consequence of its engineering improvements and adoption of reliability-centered maintenance practices (which focus attention on critical equipment and lines). Electricities, on the other hand, is concerned that these trends reflect a decline in transmission reserves and believes that the expenditure trends will probably soon reverse to expand transmission capacity. A plausible interpretation of these trends is that the recent trends in transmission O&M and investments have reflected efficiency improvements. However, because the potential for these improvements is not boundless, a continuation of these trends in transmission O&M and investments may signal a potential future reliability problem.

3.3.2 NERC and SERC Assessment of Reliability

NERC's (1997b) Reliability Assessment Subcommittee annually reviews "the overall reliability of the existing and planned electric generation and transmission systems of the [r]egional [c]ouncils." These annual assessments review the general issues affecting reliability and assess reliability for each of the ten regions.

SERC is one of the ten electric reliability councils in NERC. It compiles reliability on the Southeastern region, prepares a reliability assessment, and shares its assessment with NERC for integration into the North American assessment.

The SERC assessment noted that "planned capacity resources are judged to be adequate to supply the forecast annual summer peak demand growth of 2.3 percent....The ability to transfer power above contractually committed uses, both intra- and interregionally, has become [difficult] on some interfaces...."

Although the amount of generating capacity currently planned to be added in the Southeast is not enough to maintain adequate capacity margins through the year 2006, SERC believes that the current lead time of 2 years to build new units (combustion turbines, the units with the shortest lead time) is "marginally adequate." On the other hand, the transmission systems are likely to be stressed, according to SERC, because of the "increase in bulk power marketing activity resulting from transmission open access rulings" as well as the possibility of retail competition.

NERC's *1998 Summer Assessment* identified potentially serious problems in the upper Midwest and in New England, primarily because of ongoing nuclear-generation outages (NERC, 1998a). However, the review found no problems in SERC. It concluded that "resources [within the SERC region] will be adequate to meet the expected demand if load projections are not exceeded and if generator unit availability remains consistent with previous years." Generator unit availability could be adversely affected, however, if there are significant expansions in power transactions without concurrent expansion in generation resources. The expected reserve capacity margin ((capacity – peak demand) / capacity) for the Virginia-Carolinas subregion of SERC (VACAR) was 12.3 percent for July 1998, which is down from the 16 to

18 percent range in previous decades. Some speculate that, as these reserve margins decline, SERC may suffer reliability problems.

3.3.3 Utility Concerns about Future Reliability

Our questionnaire asked the utilities (CP&L, Duke, ElectricCities, NCEMC, and Virginia Power) for their views on how generation and transmission system reliability might change in the future with increased competition at both the wholesale and retail levels. The responses varied in detail and degree of concern. All expressed concern about the likely dramatic increases in the number and complexity of transactions. Some, however, were cautiously optimistic that generation and transmission system reliability will not be compromised by these changes; they believe that the application of people, money, and time will resolve these problems in ways that maintain generation and transmission system reliability at today's levels.

Problems

During the past few years, all the utilities noted substantial increases in the number of power transactions (Figure 3-1). This is true especially since FERC's issuance of its open access, nondiscriminatory transmission Order 888. A recent Electric Power Research Institute (EPRI) survey of transmission customers suggests that the number of transactions will double over the next 2 to 3 years.

In addition, the utilities noted the much greater diversity of market participants, with many having no history in the electricity industry.⁵ Many of these participants may not understand the complexities and real-time operating requirements of electrical systems. In addition, they are motivated primarily by profits and have no history of balancing reliability and commercial interests. Thus, balancing reliability with commercial interests may be increasingly difficult.

The utilities were especially concerned about situations that might arise when a customer has purchased energy and transmission service when neither is purchased on a "firm" basis (i.e., both can

⁵Many power marketers began their careers in natural gas. Because electricity flows at the speed of light and gas moves at 15 miles/hour, reliability issues are quite different for the two industries.

be curtailed). Will that customer have a backup supply? Or will the local utility be forced to serve the consumer as the provider of last resort? Because the utilities may remain responsible for reliability, they are concerned that they might have to provide resources during emergencies or to prevent emergencies, and that they will not be compensated adequately for these resources. In principle, distribution utilities should be obligated only to connect customers and power suppliers to the system and to *deliver* power. They should no longer be obligated to *serve* (i.e., supply and deliver power, which they have to do now).

The utilities noted that they built their transmission systems primarily to move power from *their* generating units to *their* retail customers. These transmission systems are being used today (and will be used even more extensively in the future) to support long-distance transactions for which the systems were not designed. This is a major potential problem for the future. These new transactions could create additional parallel path flows and cause congestion to occur more frequently.⁶ Will these changes hurt the retail customers for whom the systems were built?

Transmission planning will likely be more complicated in the future. Historically, utilities planned their transmission and generation as an integrated system. To the extent that generation and transmission are separate corporate entities, transmission planners may not have sufficient advance notice concerning the locations and sizes of new generating units. According to the Energy Modeling Forum (1998):

...decisions about generating and transmitting power are closely intertwined. The daily operation of the transmission system depends critically upon where and when to generate power. Longer-run decisions about investing in generation or loads are closely linked to those concerned with expanding the transmission system. The existence of these interrelationships, or complementarities, between functions presents opportunities to operate and

⁶Electricity flows according to the laws of physics, which generally bear little relation to the transmission paths specified in contracts. The difference between actual and contracted flows is called parallel path flows. In some cases, the utility whose transmission lines are being overloaded does not know the source and sink of the flow(s) causing the problem, and, therefore, does not know how best to reduce the overload.

expand both systems more efficiently or at a lower cost when done jointly rather than separately. A fundamental issue in restructuring concerns how to decentralize decisions about generation and loads and still acknowledge the complementarities between generation and transmission.

Utility respondents also noted that retail competition will eliminate a local utility's "obligation to serve." They were concerned that the traditional obligation to serve with a simple "obligation to connect" may result in reserve margins that are less than traditional planning reserve margins. Furthermore, retail competition is likely to exacerbate whatever reliability problems occur with wholesale competition because of the likely dramatic increase in transaction volumes and complexity.

Solutions

The problems discussed above are, at this point, primarily *potential* problems. Fortunately, several regional and national entities are working to prevent these problems from occurring.

At the national level, NERC (as discussed in Appendix B) is transforming itself from an entity dominated by large utilities into one that is broadly representative of all participants in wholesale power markets. As part of that transformation, NERC is changing its governance so that its board of directors is independent of all market participants. To emphasize these changes, the North American Electric Reliability Council (NERC) is changing its name to the North American Electric Reliability Organization (NAERO).

In addition, NERC is converting its system of voluntary compliance with its standards to one of mandatory compliance. NERC is developing a system of penalties to support these mandatory standards. For example, failure to meet the new Disturbance Control Standard (DCS), which replaced the B1 and B2 standards in February 1998, requires the control area to increase the amount of operating reserves it maintains until it complies fully with the new standard. To deal with congestion and parallel path flows, NERC instituted a system of transaction tagging so that control-area operators know the source and sink of every transaction. This information is required to effectively relieve transmission overloads.

Complementing these operating standards is a new set of planning (engineering) standards that NERC issued in September 1997.

During the past several years, various groups have proposed different kinds of regional organizations to operate today's transmission systems and to plan and build expansions to those systems. These entities include regional transmission groups, ISOs, independent system administrators, transmission-owning companies (Transcos), and regional transmission organizations (FERC's [1998b] latest term for such organizations).

As of spring 1999, five ISOs operate in the U.S. (California, Texas, PJM,⁷ New York, New England, and soon the Midwest). Several companies have proposed to create Transcos (including Northern States Power, Entergy, and a group of utilities called the Alliance Transmission Entity). The primary difference between an ISO and a Transco is that an ISO directs the operation of transmission assets that it does not own, whereas a Transco combines ownership and operation of the grid assets in one entity. An additional distinction that some Transco proponents make is that a Transco will be a for-profit enterprise, whereas the five operating ISOs are all nonprofit entities.

The Alliance Transmission Entity favors the Transco structure because, "The combination of ownership and operation may be very appealing to some investors and experts in managing transmission who view the future transmission business as an independent business that creates value for customers and shareholders alike. Aggregating management and technical expertise to this singular and clear focus offers the best opportunity for coupling performance to value; it is not clear that this opportunity will exist in other structures where ownership and operation are separated" (Alliance Transmission Entity, 1998). Transco advocates suggest that the owner-operator status of the Transco will lead to a more efficient, integrated approach to transmission planning and investment than one that must be coordinated across multiple organizations (e.g., the ISO and all the transmission owners).

⁷PJM = Pennsylvania, (New) Jersey, Maryland.

The Large Public Power Council (1998), on the other hand, argues that a not-for-profit Transco would better protect and balance the interests of all stakeholders, promote the public interest, have an open governance structure, lend itself to light-handed FERC regulation, and make it easier for municipal utilities to convey or transfer operations of their transmission to the Transco than would be the case with a for-profit Transco. The Council fears that a for-profit Transco could use its control over transmission to manipulate generation markets and increase transmission profits. (The Transco could have an incentive to either "gold plate" or "tin plate" the transmission system, depending on how FERC sets its rate structure.) Any efficiencies gained by the not-for-profit Transco, on the other hand, would go to ratepayers, so less regulation would be required. The Council also notes that current IRS private use restrictions, state and local charter authority limitations, and prohibitions from participating in stock-owning entities prevent public-power institutions from granting control of their facilities to for-profit organizations. The benefits of a large regional organization controlling the transmission system could be achieved, and include public-power facilities, by having a not-for-profit Transco.

FERC has been encouraging transmission owners to organize ISOs. These ISOs would not only help ensure open, nondiscriminatory access to transmission for all parties, but they would also be responsible for maintaining generation and transmission system reliability through a planning process coordinated by the ISO. This planning process could identify future transmission capacity requirements, but it would be up to the individual utilities to build it. In February 1999, FERC sponsored a series of consultations with the state on the subject of RTOs. These meetings showed a diversity of views, but there was general support for the concept of having transmission managed by large regional entities that are independent of generation.

Because RTOs are likely to be much larger than today's utility control areas (of which there are about 150), they would have a much broader regional perspective on transmission flows and potential problems. An RTO has the potential to manage transmission problems related to parallel path flows (when power flows along multiple paths, including transmission lines that are

distant from the power source and ultimate destination) and congestion more readily than can individual utilities. Major challenges to a large RTO include managing a larger volume of more diverse transactions, and resolving transmission tariff issues among its many members. Currently, there is much debate among IOUs on whether to move to an RTO, and if so, what form it should take. Among North Carolina IOUs, Virginia Power is currently participating in discussions about forming a new RTO called the Alliance RTO. Duke favors the Transco form of organization, and CP&L is continuing to study the merits and drawbacks of both relative to the traditional organization of control area operation. The transmission-dependent utilities in North Carolina (as elsewhere) are concerned that ISO and Transco formation is dominated by transmission owners, perhaps at the expense of transmission users.

The state of North Carolina could set minimum requirements on those entities that sell electricity to retail customers within the states. Such requirements could include financial performance measures and penalties for failure to provide sufficient generation resources to meet contracted loads. The state might also consider setting minimum levels of reserve requirements, which would be imposed on every entity selling firm power to North Carolina retail customers. These requirements would have to be accompanied by adequate and practical procedures to ensure compliance.

The state might consider encouraging the creation of one or more regional power exchanges (PX). These exchanges would create liquid, transparent markets for hourly energy (and perhaps other electricity products). Such markets could serve as a natural backup when an individual customer's supplier fails and has not obtained its own backup source. In such cases, the local utility would not be required to provide backup power for large customers; instead, these customers could either purchase power at the current spot price from the power exchange or be required to disconnect from the grid.⁸ Finally, the NCUC and the Public Staff could participate

⁸While it is feasible to identify and disconnect a large industrial customer whose backup supply has failed, it may be very difficult to do so for thousands of residential and small commercial customers scattered throughout a utility's service area.

actively in RTO discussions that involve the North Carolina utilities as well as comparable discussions with SERC.

The utility responses to our questionnaire show that many potential problems could compromise generation and transmission reliability in North Carolina. However, the utilities were hopeful that these potential problems would not become realities and that generation and transmission system reliability would remain at its current high level. The many activities underway at FERC, NERC, and the groups debating RTO formation lend support to the idea that the complexities associated with wholesale and retail competition will be managed in ways that do not degrade reliability.

3.4 CONCLUSIONS AND RECOMMENDATIONS

Restructuring the utility industry by “deintegrating” it, especially the unbundling (separation) of generation from transmission and of system control from both generation and transmission, will affect the institutional arrangements that oversee and implement reliability. The economic incentives among these three types of entities will also be affected. In particular, deregulating generation may make it difficult for the owners of these facilities to provide public services without adequate compensation. In the past, vertically integrated utilities could afford to devote resources, for example, to assist neighboring control areas without worrying that these costs would not be reimbursed. The traditional cost-of-service regulation allowed such costs to be recovered in rates paid by all customers. In competitive generation markets as in regulated markets, the providers of services that promote generation and transmission system reliability must be adequately compensated for their costs. New institutional arrangements in a restructured industry must consider economic realities and technical possibilities and constraints in reliability planning maintenance.

As discussed above, most of the responsibility for establishing and approving the rules to operate electrical systems in a reliable fashion will primarily reside in national organizations, such as FERC and NERC. State governments may have less influence over the operation of generation and transmission systems, in large part because of the multistate regional nature of electrical grids.

With respect to resource planning (e.g., the long-term planning for capacity expansion) states might choose to retain control over generation planning. With respect to transmission, states retain their siting authority although FERC will continue to have a role in the determination of need for additional interstate transmission facilities.

North Carolina (through the NCUC and/or the Public Staff) could consider taking the following actions to maintain generation and transmission system reliability if generation services are to be offered in a competitive market:

1. Consider requiring that all entities supplying electricity to North Carolina retail customers be certified by the NCUC. Certification requirements might include financial viability, demonstrated performance in power supply (e.g., no firm power curtailments), and a minimum level of generation reserves. Noncompliance with the certification process or failure to maintain the minimum operation reserve requirements would be subject to financial penalties, decertification, and denial of rights to provide service.
2. Consider formation of an RTO (e.g., a Transco or ISO).
3. If an RTO is established, consider a multistate (regional) process to review applications for inter- and intrastate transmission enhancements and an approval process that recognizes the economic and environmental interests of each state in the region.
4. Continually monitor generation and transmission investments and their implications for reserve margins and generation fuel mix. Consider methods to maintain minimum reserve margins and generation fuel mix if market failures occur.

4

Potential Impact of Competition on Distribution System Reliability

This section assesses distribution system reliability concerns associated with potential restructuring of the electric industry in North Carolina. The findings and recommendations were developed with the assistance of interviews conducted with investor-owned utilities (IOUs), co-ops, and muni utilities.

These concerns are separate from the generation and transmission system reliability concerns discussed in Section 3. Both sets of concerns are germane to the Study Commission's deliberation on whether, and if so when, to restructure North Carolina's electric utility industry.

4.1 RELIABILITY OF DISTRIBUTION SERVICE

Power system components are constantly susceptible to damage due to equipment failures, weather, and other causes. The public is generally unaware of the many times individual system components fail in operation. This is because of the way the system is both designed and operated. The sudden outage of one component, and sometimes several, will not affect the service continuity to customers, except for an occasional voltage dip or momentary outage.

An important distinction is made between outages of components and service interruptions. Component outages are almost always

imperceptible to the customer. Service interruptions, however, involve at least some customers losing power. Some customers, such as industrial customers, may also be sensitive to the quality of service they receive. These customers' business or equipment may be affected by voltage dips or momentary outages.

The two principal measures of reliability of service are service interruptions and service quality. The potential impact of retail competition on these measures is discussed below.

4.1.1 Service Interruptions

The most common cause for distribution line failure is falling trees and branches (usually in storms), which cause a short circuit on the lines. This short circuit is then interrupted by circuit breakers that separate the affected line from the network, de-energizing it. In some cases, this action may be sufficient to restore the line to its capability. A line is restored to its capacity when it is automatically reconnected to the network within a fraction of a second. However, restoration of service is more difficult for cables (underground service), because automatic reclosing cannot be used for them.

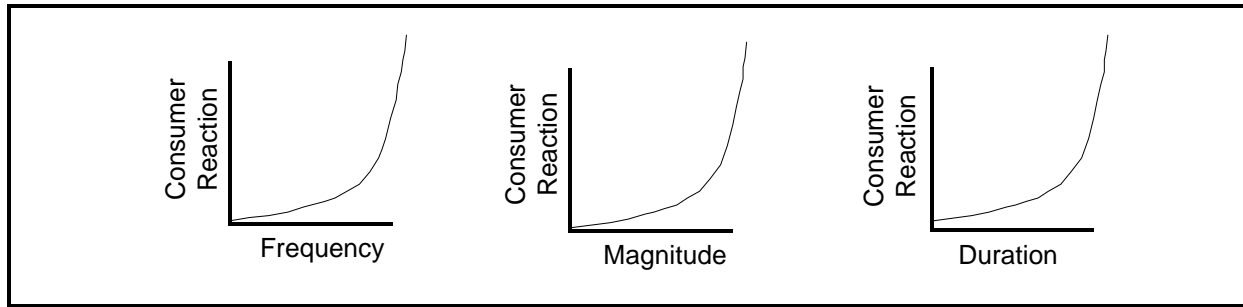
The frequency of line contacts with trees is a function of the amount of tree trimming that the utility performs. Other common causes of failures in the distribution system come from small animals and lightning.

Service interruptions are measured using the following variables:

- ▶ the frequency with which interruptions occur,
- ▶ the duration of interruption, and
- ▶ the amount of load interrupted at one time, as measured by the number of customers or the demand.

Consumer reaction depends on when the interruption occurs and whether advance warning has been given. Available evidence also indicates that the consequences and consumer reaction to interruptions is nonlinear, as shown in Figure 4-1. All these graphs illustrate that as interruption problems increase, customers' loss of patience increases at a faster rate. Acceptable tolerance levels in each graph vary by type of customer, and precise estimates of tolerance limits are not available.

Figure 4-1. Consumer Reaction to Electricity Outages



Experience has shown that there is an acceptable toleration level for each of these factors, beyond which consumer reaction increases dramatically. Experience and customer surveys have also shown that tolerance levels vary widely among customers; some are more able to cope with outages than others.

In reviewing distribution reliability, it is vital that the distribution design of the area be recognized. Most of the distribution system in North Carolina is of a radial design. With radial distribution systems, outages are generally limited to a single feeder or a portion of a feeder. Restoring radial feeders is relatively simple, but they do not provide multiple feeds to customers. Major metropolitan areas are treated differently because the impact of interruptions is much larger for consumers, the general public, and the functioning of government and other important institutions. To provide a higher level of reliability, metropolitan areas are generally served from multiple sources or through distribution networks. These networks involve a more complex distribution system design that delivers a higher level of reliability.

Table 4-1 provides a summary of the impact on customers for some general types of power system problems.

4.1.2 Service Quality

Electric service must not only be continuously available but also usable without problems. Low-voltage conditions can cause improper functioning, damage, and life reduction to a customer's equipment and appliances. It can also cause decreased efficiency and increased energy use. High-voltage conditions can also cause improper functioning and equipment or appliance damage.

Table 4-1. Summary of the Impact on Customers for Some General Types of Power System Problems

Type of Shortage or Contingency	Characteristics
Generating capacity shortages	<ul style="list-style-type: none">➤ Large number of customers usually affected➤ Advance notice can frequently be given➤ Customers interrupted can be rotated➤ Restoration time can be scheduled to not impose undue hardship
Loss of a substation, or portions of the subtransmission, or distribution networks	<ul style="list-style-type: none">➤ Large number of customers usually affected➤ Advance notice cannot be given➤ Restoration time can be extensive
Loss of an individual distribution feeder	<ul style="list-style-type: none">➤ Small number of customers affected➤ Advance notice cannot be given➤ Restoration time can be reduced by transferring most customers to other feeders

Voltage “dips” of various frequencies and magnitudes also cause interference in apparatus operation, computer and television reception problems, and dimming and flickering lighting. For some very sensitive electronic and manufacturing loads, high-frequency harmonics or electrical noise may also cause problems.

4.2 FACTORS AFFECTING RELIABILITY

The reliability of service to electric distribution customers depends on two major factors: the reliability of bulk supply to the distribution substations and the reliability of the distribution system. The initial stage in the development of a typical distribution system is shown in Figure 4-2. In this situation, growth in an area is supplied by a substation and two feeders. The design of this system depends on information about potential new customer building and growth in the area. If growth is expected to be rapid and extensive, the initial design of the substation and the size of the substation transformer will allow for additional feeders.

As new homes and businesses are built in the area, the local distribution system will be extended to new customers as shown in Figure 4-3. In this expansion stage, the distribution system grows by adding new branches to the existing two feeders. As long as the

Figure 4-2. Distribution System Initial Stage

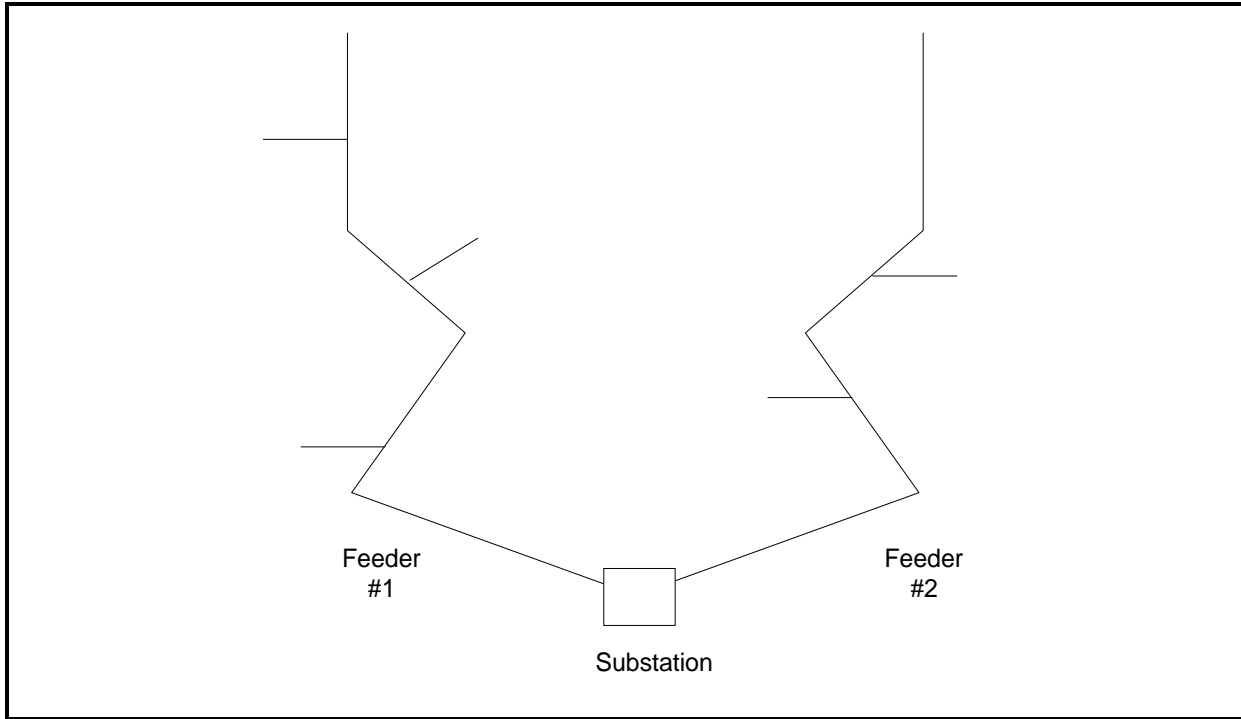
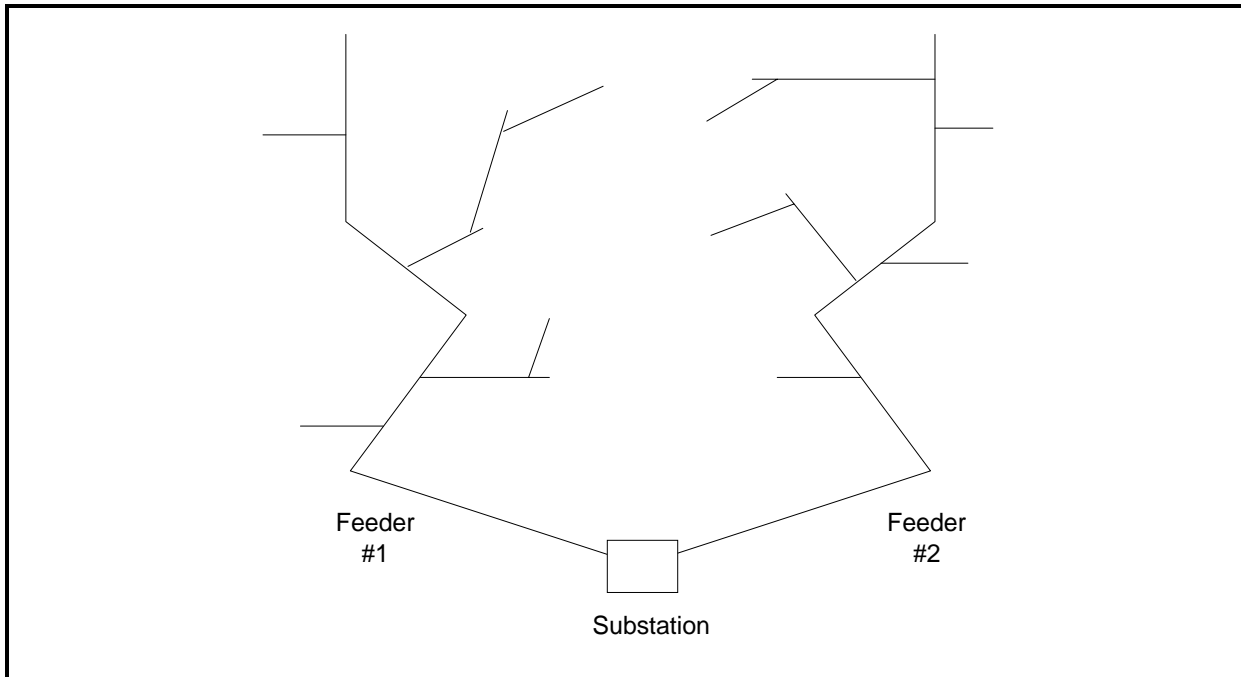


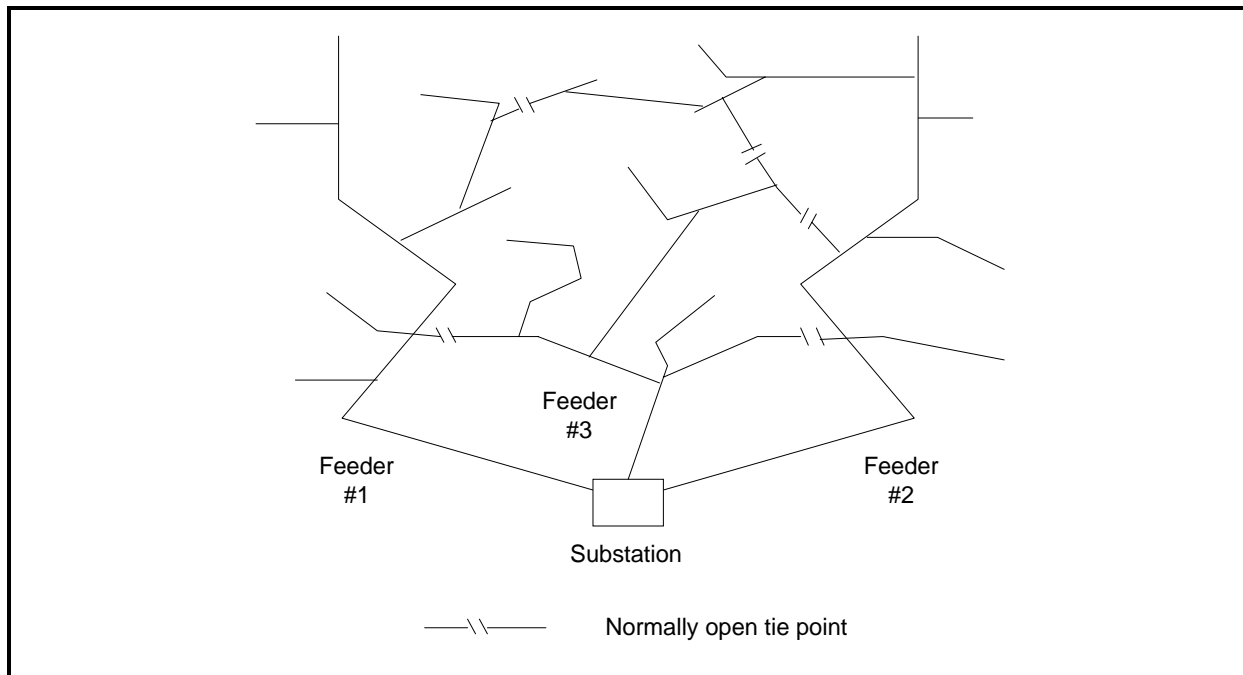
Figure 4-3. Distribution System Expansion Stage



loading on the feeders does not become too high, this approach may continue. This stage of distribution development also depends on information concerning customer building and growth in the area. To decide which feeder should serve new loads, specific information about the location and size of the new loads is necessary.

Over time, as the load of the existing customers grows and new customers are added, the loading on feeders 1 and 2 will become too high. Unless changes are made, these two feeders will become overloaded, and customer voltage will drop too much during high-load conditions. The most common solution is to add a new feeder as shown in Figure 4-4. In this case, the new feeder 3 serves both new load and some load that had been fed from feeders 1 and 2. Additional transformer capacity may also be needed at the substation.

Figure 4-4. Distribution System New Feeder Stage (with tie points)

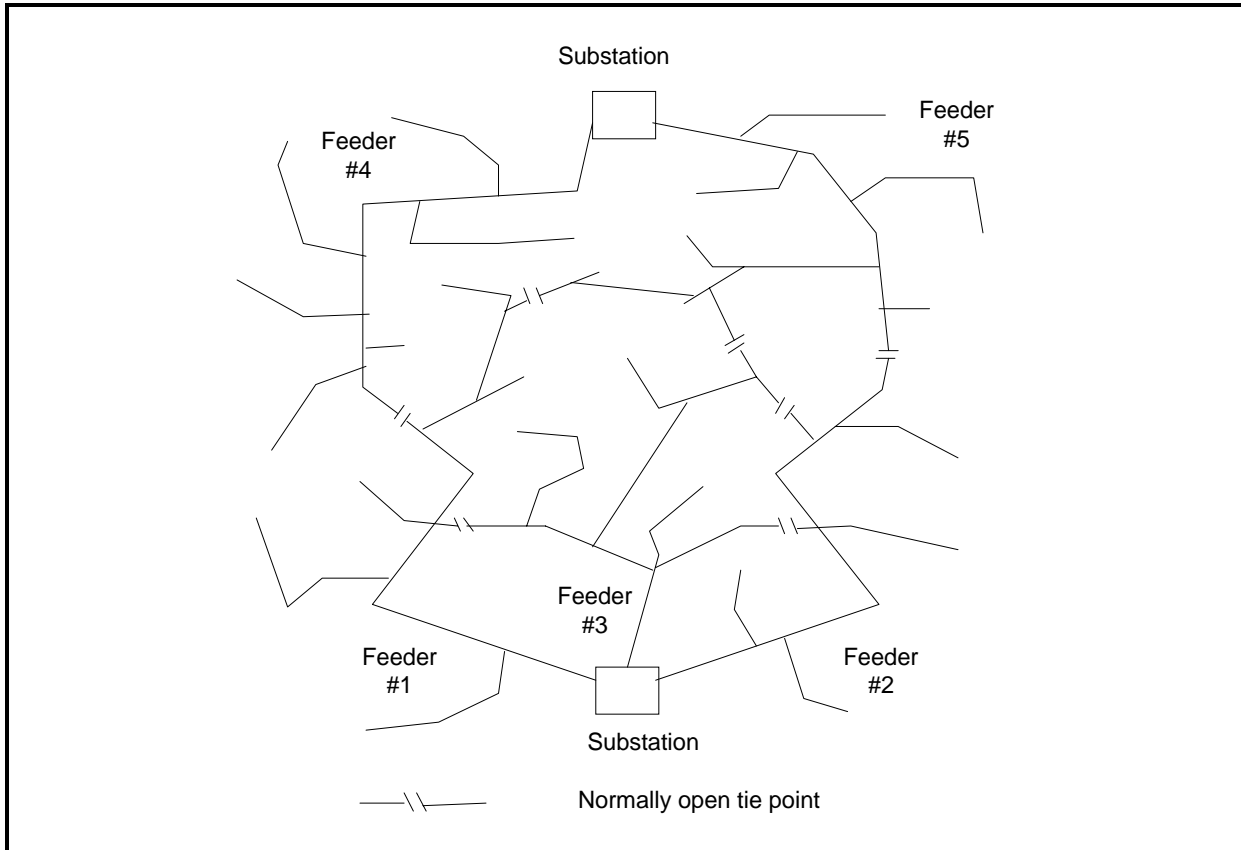


At this new-feeder stage, there is an opportunity to provide normally open tie points between the older and newer parts of this system. These tie points allow some added flexibility to rearrange the local system when there are extended local problems. Specific information required at this stage includes not only the load data

for the feeders, but also the loading on the various branches. These data are often obtained from individual customer billing data and allow the designers to properly set the loading on each of the three feeders.

As load continues to grow in the area, the total loading will eventually exceed the capability of the substation or feeders. When this happens, a new substation will be needed to serve the growing load as shown in Figure 4-5. The new substation will allow a new configuration of the existing feeders and branches as well as adding new feeders. There also will be new tie points that will allow additional flexibility in system operation and improved reliability. In this new configuration, the new substation is serving both new load and load that had been served by feeders 1, 2, and 3 of the older substation. With this process, individual customer usage data are required to properly decide how to reconfigure the existing feeders, new feeders, and branches.

Figure 4-5. Distribution System New Substation Stage (with tie points)



To illustrate the number of feeders and substations involved, assume a city or area of 25,000 people and a peak load of 50 MW. A city or area this size will typically have 4 substations and 10 to 15 feeders. The exact number of feeders and substations in this range will depend on the population density (customers per square mile).

This series of examples shows how individual customer data are essential to properly design and develop the local distribution system. Such proper planning, design, and operation of the distribution system requires the following:

- Load data and information are required, including historical load data, load characteristics, future loads, and potential new customers. Presently, such information has been obtained from
 - ✓ substation and feeder meter readings available to the utility,
 - ✓ individual customer monthly usage patterns and growth,
 - ✓ periodic contacts with customers through utility service and sales personnel, and
 - ✓ customer “postcard” surveys concerning plans for future appliance purchases and future electricity use. These surveys are often made as a part of sending customers periodic bills.
- Distribution planning and operation criteria and standards that determine current loading policies, equipment rating practices, and distribution system reserve (or spare) policies are required. These include policies for loop-feed arrangements,¹ provision of automatic throw-over arrangements,² and use of supervisory control and data acquisition (SCADA) controls for switching.³ If distribution criteria are lowered, reliability will decline.

The reliability provided in system plans and designs should continue to be in accordance with the policies of governmental authorities, and it should continue to recognize the willingness of customers to pay for the degree of reliability being provided. This willingness to pay should be assessed for different customer groups and for different types of reliability services.

¹Loop-feed arrangements provide feeders that can supply loads from a second direction if the first source is out of service.

²Automatic throw-over arrangements allow transfer of a portion of a feeder that is lost to another feeder that is in service.

³SCADA controls provide information on feeder conditions and the ability to switch portions of a feeder to other feeders from a remote location.

- Equipment maintenance policies both in substations and on distribution feeders are required. Maintenance on distribution circuits includes such items as tree trimming and improved lightning protection. Without adequate maintenance, distribution reliability will decline.
- Distribution system equipment purchase guidelines are required. Distribution system equipment can be purchased for a specific purpose and have different characteristics. For example, distribution transformers can be purchased that have differing losses and overload characteristics. The purchase of lower quality equipment to save money may decrease reliability and increase energy consumed by losses.

Distribution reliability may be adversely affected if the planners, designers, and operators of the distribution system cannot continue to obtain needed information from customers. It may also be adversely affected if distribution utilities have to reduce expenditures below present levels because of decreased revenue or high impact events such as hurricanes.

4.3 RESULTS OF SYSTEM SURVEYS AND INTERVIEWS

To gather information about distribution reliability concerns, surveys were mailed to the two major IOUs (Duke and CP&L), ten municipal utilities (munis), and five cooperatives (co-ops). All utilities responded except four of the munis. The muni and co-op selections were coordinated with ElectricCities and NCEMC, respectively. Based on the response to the surveys, in-person interviews were held with both IOUs, two munis, and two co-ops to reflect their concerns and diversity of viewpoints. Appendix D contains the questionnaire used in the interviews, and Appendices E through J contain summaries of the individual interviews.

4.3.1 Results of Utility Surveys

Thirteen utilities completed the mail survey that included seven “yes/no/not sure” questions. These mail surveys were a preliminary step to detailed (in-person) interviews with the six utilities, during which the questions were explored in depth to assure no misunderstandings. The results of the mail surveys are presented in Table 4-2 and summarized below:

Table 4-2. Summary of Survey Results

Question Answer	A			B			C			D			E			F			G		
	Y	N	NA	Y	N	NA	Y	N	NA	Y	N	NS	Y	N	NS	Y	N	NS	Y	N	NS
Co-ops																					
Blue Ridge	✓				✓		✓					✓	✓			✓			✓		
Crescent	✓			✓			✓					✓		✓				✓			✓
Halifax	✓			✓					✓			✓		✓			✓				✓
Piedmont	✓			✓			✓					✓		✓				✓			✓
Tideland	✓			✓			✓			✓				✓		✓			✓		
Munis																					
Fayetteville	✓			✓			✓			✓				✓		✓			✓		
Huntersville	✓			✓			✓					✓		✓				✓			✓
Lexington	✓			✓			✓					✓		✓		✓			✓		
Monroe		✓			✓		✓			✓				✓				✓	✓		
Washington	✓					✓	✓			✓			✓					✓			✓
Wilson	✓			✓			✓					✓		✓				✓			✓
IOUs																					
CP&L	✓			✓			✓					✓		✓				✓			✓
Duke Power	✓			✓			✓					✓		✓				✓			✓
Total	12	1	0	10	2	1	12	0	1	4	0	9	2	11	0	4	1	8	5	0	8

- A) Are you concerned about the potential effect of retail competition on the reliability of service to distribution customers served by your system?—12 utilities answered yes and one answered no.
- B) Are you concerned about the impact on distribution reliability that may be caused by the operation changes that can be required by bulk suppliers, security coordinators, control areas, ISOs, or other controlling organizations?—10 utilities answered yes, two answered no, and one did not answer.
- C) Are you concerned about the impact of retail competition on the information available to you that is needed for the operation, planning, design, and maintenance of your distribution system?—12 utilities answered yes and one did not answer.

- D) Will some information needed to manage and operate your distribution system no longer be available?—nine utilities were not sure and four answered yes—indicating this depends on the procedures adopted.
- E) Do you see any reliability benefits to your system from retail competition?—11 utilities answered no and two answered yes.
- F) Do you believe you have an obligation to serve new load to be supplied by another company even if this would result in a costly reinforcement?—eight utilities were not sure about their obligation to serve new load; four utilities believe they are responsible to serve new load, even at high cost; one utility answered no.
- G) Would you continue to serve an existing load supplied by another company even if its removal would avoid the need for costly reinforcements on your system?—eight utilities were not sure whether they would continue to serve such customers; five utilities answered yes.

4.3.2 Characteristics of Systems Interviewed

Table 4-3 shows the principal characteristics of the systems interviewed. This table includes two characteristics—total customers per mile and peak kW per mile—that are derived from previous entries in the table.

4.3.3 Comparison of Results of Interviews

For certain issues, the responses are consistent; for a few they are different. The most important similarities and differences are summarized below.

Trade-Off of Reliability with Costs

All the utilities agreed that there is a direct relationship between reliability and costs. They feel that few distribution system reliability problems resulting from retail competition could not be solved by adding or upgrading equipment at an increase in cost. The increased uncertainty concerning future customer sources associated with competition could, for instance, require additional (and perhaps redundant) facilities to maintain reliability. Conversely, they all feel that, if it became necessary to cut capital improvements or tree-trimming budgets because of a delay in payments or increased costs, reliability would suffer.

Table 4-3. Principal Characteristics of Systems Interviewed

	CP&L	Duke	Fayetteville	Wilson	Blue Ridge	Piedmont
Ownership	IOU	IOU	Muni	Muni	Co-op	Co-op
Load						
Peak (MW)	10,200	14,600	410	200	200	90
Peak Season	Summer	Summer	Summer	Summer	Winter	Summer
Energy (MWh)	53,400,000	81,600,00	1,800,000	1,100,000	928,000	304,000
Customers						
Total	1,100,000	1,800,000	63,900	28,200	56,000	23,000
Residential	935,000	1,550,000	57,400	25,000	48,000	22,500
Commercial	166,000	250,000	6,500	4,000	8,000	500
Industrial	5,000	8,000	20	20	200	1
Distribution						
Voltage	15/25 kV	15/25 kV	15/25 kV	15/25 kV	15/25 kV	15/25 kV
Miles	50,500	73,500	2,000	1,000	6,000	900
Customers per mile	21.8	24.5	32.0	28.2	9.3	25.6
Peak kW per mile	202	199	205	200	33	100
Will serve load in unassigned territory	Yes	Yes	Yes	Yes	Yes	Yes

Recovering Distribution Costs

All the utilities are concerned that there would be problems or complications in collecting the distribution system costs from customers. In addition, the ability to obtain approval of increased costs that may be incurred, because of increased reserve requirements or new metering expenses, could cause revenue shortages.

Concern exists that revenue collection by the power supplier could delay payments to the distribution company. Concern also exists in cases where the power supplier has financial problems that result in nonpayment to the distribution company. If covering the distribution systems' costs becomes a problem because others are collecting customer revenue, budgets would be cut and reliability

would suffer. The larger utilities are concerned that the financial resources available to a distribution company would be smaller, a situation that is currently faced by distribution companies. These distribution companies would be less able to deal with large revenue or cost swings such as those caused by major storms.

Obtaining Customer Usage Data

All the utilities emphasize their need to have full access to customer usage data, which is a key source of information needed for distribution planning. Continued availability of this information is needed.

Data on variation in usage with time of day, seasonal trends in usage, and diversity in use between customer classes, for example, are needed for planning and reliable operation of distribution systems.

Confusion about Customer Contact Points

All the utilities are concerned that there would be delays in obtaining customer outage reports if customers are confused about who to contact. Often, the first indication of a distribution problem is a call from a customer. For larger outages, the geographic pattern of customer calls can be used to identify the most likely cause and location of the outage.⁴ This is useful for dispatching crews and speeding repairs. If the customer calls his power supplier, rather than the local distribution system, when his service is interrupted, information would be delayed in getting to the local distribution system. This will delay the local distribution company's process of identifying and correcting the problem and the customer will endure lengthier outages.

Need for and Difficulty of Unbundling

The utilities have differences of opinion concerning the difficulty of unbundling the distribution, supply, and transmission functions. The large IOUs feel that this could be accomplished through some form of business arrangement. Several of the smaller co-ops and

⁴One example is CP&L's system. CP&L uses "caller I.D." to identify equipment failures as customers call in. Its sophisticated system is based on direct trouble calls, customer phone numbers, and the physical connection (feeders) to each customer.

munis also feel this would not be a problem because they do not own any generation or any significant transmission facilities—they are, in effect, already distribution-only companies. The municipal systems that own and operate generating units wonder how they could unbundle these functions because they are a part of the city government. Those cities that provide water and gas service in addition to electricity wonder how they could unbundle their meter-reading operations.

4.4 RECOMMENDATIONS FOR THE STUDY COMMISSION

If a decision is made to pursue electric industry restructuring in North Carolina, we make several recommendations for the Study Commission's consideration of distribution reliability. Study Commission recommendations recognizing potential distribution system reliability problems are necessary to avoid potential degradation of distribution system reliability with restructuring. The Study Commission may choose to address these questions or to refer them to the NCUC for consideration. We have addressed these recommendations to the Study Commission, without regard for who ultimately considers them.

4.4.1 Provide Adequate and Timely Compensation to Distribution Companies

To avoid potential deterioration of reliability in the distribution system, the Study Commission should recommend that the distribution companies receive adequate and timely compensation in the short run and long run for their costs under retail competition.

- In the current environment, integrated utilities serve as a "self-insurance facility" to cover risks at the generation, transmission, and distribution levels. In a retail competition environment, the distribution-only companies will be smaller businesses with much smaller total revenue and asset bases than in the past. This will reduce the financial resources of these firms and reduce their ability to absorb losses due to storms. New customer connections may result

in a financial loss.⁵ The distribution companies, faced with smaller financial size and increasing costs, will need to either raise their rates or lower their costs to stay in business. If forced to lower their costs, less reliable supply arrangements, use of less reliable equipment, and other similar measures may become necessary to reduce their costs to match their economic resources.

4.4.2 Provide Timely and Complete Access to Customer Data for Planning and Operation

To prevent distribution reliability from deteriorating, the distribution companies should receive all meter data and information from all the customers it connects to, whether it provides the power or whether other utilities do. The most obvious approach to accomplish this is for the distribution company to provide the meters and do the meter reading. Another approach is for others to provide these services with the local distribution company receiving full information.

- The examples of Figures 4-1 through 4-5 demonstrate the dependence of distribution planning and operation on customer usage data. Without these data, the distribution system will be less reliable and distribution costs would rise. Suppliers require long lead times from utilities for major pieces of equipment, such as transmission/distribution transformers. Thus, the local distribution companies need accurate and early information on major load additions by customers (e.g., an industrial customer planning to add a production line that would use 5 MW and require a transformer upgrade).
- CP&L has a system for correlating meter readings with loading conditions for various portions of the distribution system. Without the meter reading data for customers supplied by others, this system will not be able to fully evaluate or anticipate future overload conditions.
- The real-time metering information will assist the local distribution utility in trouble-call analysis and possible remedial steps during outages.
- The future of customer metering is likely to include sophisticated electronic meters with built-in communication capabilities. These meters will be able to report individual

⁵This could happen if customer charges continue to be based on the average cost to serve each customer class and, as has been the case in the past, the incremental cost of connecting new customers is higher than the system average cost of connecting customers. The result will be that the cost of each new connection will be more than the revenue collected from the new customer. The difference between the cost and the revenue will be the net loss for each new customer.

customer usage on a nearly continuous basis. To effectively integrate these data, electronic communication standards and protocols must be set, as a minimum, for geographic regions, if not for the whole state. These standards will allow both the local distribution company and the control area operator to integrate the load data from all the customers' meters.

- One reason why metering should be considered to remain part of the regulated wires business is the ability of a single "wires" company to provide this sophisticated metering to more customers than otherwise might be possible. With allowance of cost recovery in the regulated rate structure, the wires company could make the new technologies available to all customers, not just the largest and wealthiest.

4.4.3 Establish Clear Customer Communication Procedures for Service Restoration

The Study Commission must recommend clear procedures for customer communication so customers can communicate quickly and directly with the local distribution company that has the responsibility for restoring service.

- The Study Commission needs to recognize that, with retail competition, not only will the distribution planning process become more complicated, but customer communication problems will be more complex and difficult. This can have an impact on overall reliability, particularly the amount of time it takes to restore service following interruptions. The local distribution company will have the responsibility for restoring service. If the customer contacts its power supplier, an intermediary will be placed in the communication process.
- In addition, customers may become frustrated at the inability to communicate directly with the local distribution company to find out about outage durations and other important information. A major communication problem could arise unless the lines of communication are clearly defined.

4.4.4 Preserve Communication with Customers and Advisory Services

The importance of direct contact between the local distribution company and industrial and large commercial customers must be recognized and such contacts preserved.

- These regular contacts allow the local distribution company to anticipate potential increases in load sufficiently in advance to plan and develop the distribution system to meet

the load growth. If the customers are supplied by others, the local distribution company must be able to obtain this information.

- Contacts with the local distribution company and power suppliers provide information on the efficient use of energy, demand-side management programs, and other valuable services. The local distribution companies should be able to continue these contacts under retail competition.

4.4.5 Permit Options in the Level of Reliability of Service

The Study Commission should recommend that utilities continue their present practice of offering higher reliability of service options to large commercial and industrial customers for an additional monthly charge with real-time notification of pending interruptions or curtailment requests.

- The utilities in North Carolina now routinely offer their large commercial and industrial customers options for distribution reliability. These include allowing large customers to have “dual feeds” or similar arrangements that provide higher reliability.
- Possible arrangements allowing customers to pay for different classes of reliability should be considered. These different reliability classes could provide facilities and system arrangements to a customer that would make outages less likely.
- The ability of a customer to select the level of reliability he will receive under retail competition should be considered.

The Study Commission might consider whether to establish a program for customers to pay for faster restoration of service after major system outages. The Study Commission should recognize that an arrangement under which some customers are restored sooner inherently means that other customers’ restoration might be delayed.

- When there have been wide-scale interruptions of service such as during major storms, floods, and blackouts, the question of priority of restoration of service is important. The basic rule of the North Carolina utilities is to restore essential customers first—such as police and fire stations, hospitals, etc. They then try to restore as many remaining customers as possible in the least possible time. Some of these remaining customers may wish to pay an extra amount for faster service restoration. However, such a restoration procedure could make the dispatching of crews quite challenging if the outages are widespread.

4.4.6 Clarify Customer Curtailment Practices During Supply Shortages

The Study Commission must decide if the load-curtailment practices should recognize the cause of the power supply shortages and require the local distribution company to reduce the load supplied by the suppliers that are short. Currently, these shortages occur infrequently.

- Current load reduction practices and equipment require load curtailments to be made first on customers who have signed up for curtailment programs and then on feeders or substations based on overall system conditions. This approach is indiscriminate at the feeder level, in that customers on a feeder are interrupted regardless of who supplied their power. (Current equipment allows for customer interruptions at the feeder level, and not at the customer level unless initiated by the customers themselves.) With retail competition, an overall supply shortage could be caused by one, or just a few, suppliers. The Study Commission could recommend that large customers of suppliers who are short will be the first to be curtailed.
- The alternative would be to continue the practice of reducing the load of all customers irrespective of the source of the shortage.

In cases of transmission shortages, existing procedures provide for load reductions that will have a maximum benefit for the transmission system. With retail competition, should the customers whose transmission supply is inadequate have their load curtailed? If there is a default provider, payment issues may arise. To the extent that new equipment is required to implement a more customer-specific curtailment policy, it must be recognized that the costs can range upward from \$100 to \$200 per customer. This cost per customer is typical for a residential customer, and includes the cost of circuit breakers and communication equipment. Clarification of curtailment policies, payment issues, and associated costs will be necessary.

4.4.7 Allow Distribution Companies to Regulate Customer Apparatus that Has Service Quality Impacts on Other Customers

The Study Commission should recommend methods as to how local distribution companies can proceed to correct situations in which a customer supplied by one power supplier is causing

problems for other customers on the distribution system supplied by other power suppliers.

- The equipment and manufacturing processes of individual customers can affect the ability of the local distribution company to provide safe, high-quality service. For example, a customer with a low power factor⁶ could cause low voltage problems that affect other nearby customers. Low power factors (e.g., below 85 percent) are addressed currently by stiff penalties in rate structures that encourage the customer to improve his power factor. Also, particular types of apparatus used by a customer could affect the quality of service received by others on the distribution system, such as equipment causing voltage dips. Currently, most utilities have power quality programs that diagnose the source of these problems and offer suggestions to customers on how to treat them at their source.
- Low voltage problems usually must be solved by adding new facilities. These new facilities would probably only be installed if the local distribution company receives adequate compensation. An important question the Study Commission should answer is whether the cost should be borne by the specific customer or power supplier causing the problem or shared by all customers.

The Study Commission should consider recommending that authority be granted to the local distribution company to continue to control or limit the use of specific apparatus operated by any customer that is causing problems on the distribution system affecting other customers.

- Service quality problems can be caused by welding or other similar equipment. The local distribution company will need to have the right to regulate the use of such specific apparatus operated by any customer that is causing problems on the distribution system and affecting other customers whose load is supplied by others.

The Study Commission must decide how local power sources, such as distributed generation or energy storage, are to be regulated and controlled by the local distribution company to protect its customers and the safety of its personnel.

- Among the technological changes that can occur in the future are continued improvements in the efficiency, reliability, and cost of self-generation, small-scale generation, and energy storage. This equipment, if installed on the customer side of the meter, could be operated

⁶Power factor is the fraction of total power delivered to the customer that is used by customer equipment to perform useful work.

parallel to the local distribution system. This could create safety problems from back-feeds or power supply quality problems. The local distribution company should be able to set standards for these devices and be able to regulate their use even when the customers are supplied by others.

4.4.8 Establish Policies for Handling Customer Revenue

The Study Commission should recommend policies for collecting and distributing customer revenue, regardless of who the supplier is, under a retail competition arrangement.

- A critical concern is who will bill the customers and handle payments. Customers are not likely to want to pay four (or more) separate bills for their electric service each month (e.g., distribution, transmission, supplier, ISO). Assuming there will be a single monthly bill, procedures must be established for handling customers who pay late or only make partial payments.
- These policies should ensure that the local distribution company is paid promptly. The Study Commission should also recommend that rules are established for discontinuing service to customers that are not paying their bills. The regulated local distribution company should receive priority over the energy supplier for partial payments if it will be compelled to provide energy delivery services under any circumstances.
- Customer disconnections for nonpayment will be more complex than under present arrangements. Each supplier will have to report any nonpayment to the distribution company, which would be responsible for the actual cutoff.
- The Study Commission needs to be aware of a problem that may occur if customers pay energy suppliers directly for all services: a supplier may fail to appropriately reimburse the local distribution company. Regulations may be necessary to ensure that the local distribution company will be paid even in the event of default by a customer or supplier.
- Appropriate agreements are needed with the power suppliers to satisfactorily compensate the “supplier of last resort” if the contract power supplier is unable to meet the needs of the customers. Procedures to ensure that these payments will be made to these back-up suppliers are essential.

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Appendix A: Generation/ Transmission System Security Considerations and Institutions

A reliable electric system is one that allows for few interruptions of service to customers. Outages can be described in terms of number, frequency, duration, and amount of load (or number of customers) affected. Equally important, but much more difficult to quantify, are the economic consequences of any loss of load. A 10-minute loss of power to a residence causes the annoyance of having to reset digital clocks, but little or no economic cost is imposed. A similar outage for a computer-chip manufacturer might entail the loss of millions of dollars of output.

Reliability can be further described in terms of adequacy and security (see Figure A-1). *Adequacy* refers to the amount of resources available to supply the aggregate customer electrical demand and energy requirements. Adequacy issues tend to be long term in nature (e.g., new power plants require at least 3 years to plan and build; larger ones may require 12 years) and amenable to market incentives to determine the amount of service required and the suppliers. *Security* refers to the ability of an electric system to withstand sudden disturbances. The security aspect typically addresses emergency operations that occur over short times (from seconds to hours), often requiring activation and operation of automatic protection devices and generally involving intervention by a system operator. This appendix focuses on the security aspect of generation/transmission system reliability.

Figure A-1. NERC’s Reliability Definition

The North American Electric Reliability Council (NERC) is the primary guardian of generation and transmission system reliability. It was established in 1968. NERC’s creation was a direct consequence of the 1965 blackout that left almost 30 million people in the northeastern United States and Ontario, Canada, without electricity.

NERC defines reliability as “the degree to which the performance of the elements of [the electrical] system results in power being delivered to consumers within accepted standards and in the amount desired.” NERC’s definition of reliability encompasses two concepts, adequacy and security. Adequacy is defined as “the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times.” It defines security as “the ability of the system to withstand sudden disturbances.”

In plain language, adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies. Security implies that the system will remain intact even after outages or other equipment failures occur.

A.1 KEY FEATURES OF ELECTRIC SYSTEMS

Bulk power systems include electrical generators, transmission networks, and control centers. These systems are fundamentally different from other large infrastructure systems, such as air traffic control centers, natural gas pipelines, and long-distance telephone networks. Electric systems have two unique characteristics:

- ▶ **Need for continuous and near instantaneous balancing of generation and load**, consistent with transmission-network constraints; this requirement stems from the absence of technologies to store electricity easily and involves metering; computing; telecommunications; and control equipment to monitor loads, generation, and the transmission system; and to adjust generation output to match load.
- ▶ **Passive nature of the transmission network**, with very few “control valves” or “booster pumps” to regulate electrical flows on individual lines; control actions are limited primarily to adjusting generation outputs and to opening and closing switches to reconfigure the network.

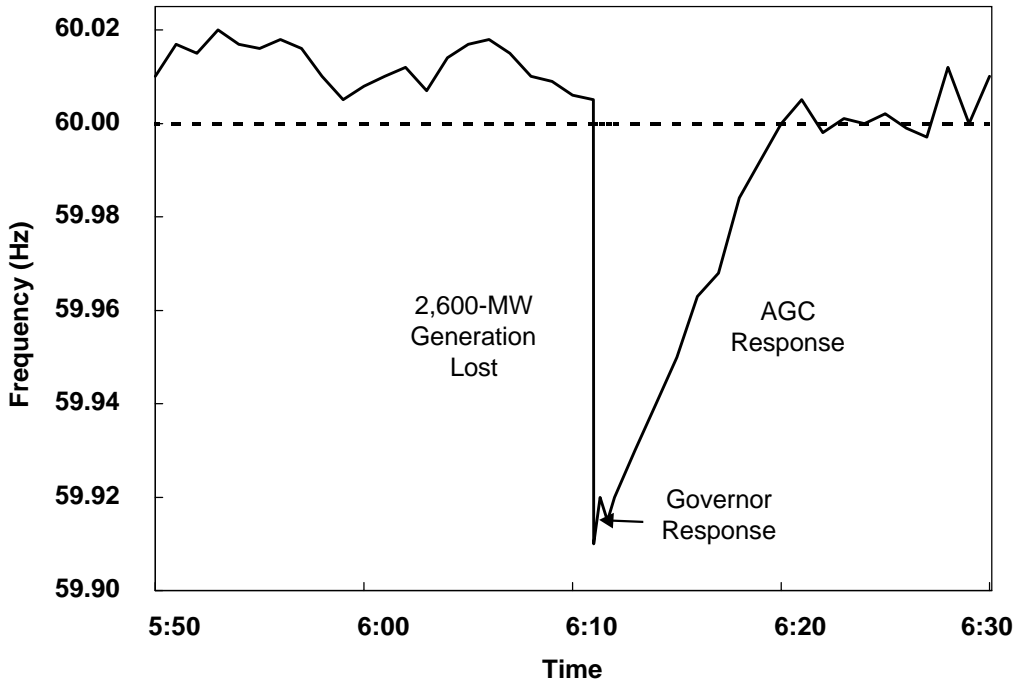
These two unique characteristics lead to three reliability consequences that dominate nearly all aspects of power system design and operations:

- ▶ **Every action can affect all other activities on the grid.** The activities of all players must be coordinated, often across large geographic regions.
- ▶ **Outages can increase in severity and cascade over large areas.** Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system.
- ▶ **The need to be ready for possible contingencies, more than current operating conditions, dominates the design and operation of bulk power systems.** It is usually not the present flow through a line or transformer that limits allowable transfers of power, but rather the flow that would occur if another element fails.

Figure A-2 shows an example of how the bulk power system responds to these unique features; the example explains how operating reserves (extra generating capacity that can be brought online quickly) are used to protect against major generation and transmission outages.

Figure A-2. Application of Operating Reserves

The figure illustrates how the electric system operates when a major generating unit suddenly trips offline. Prior to the outage, system frequency is very close to its 60 Hz reference value. Generally, within a second after the outage occurs, the system will have more power delivered than supplied so the frequency drops, in this case to just over 59.9 Hz. This drop is larger than drops that have typically occurred in the U.S., but is presented here for ease of illustration. If such a frequency decline occurs, it will occur throughout the synchronous area since the rotational inertia of all generating units in the area will provide additional power. The frequency decline is arrested primarily because many electrical loads (e.g., motors) are frequency responsive; that is, their demand varies with system frequency. Once the frequency decline exceeds the deadband of the generator governors, the governors at those generators so equipped sense the frequency decline and open valves on the steam turbines, which rapidly increases generator output. After a few more seconds, generator output declines slightly because the higher steam flow through the turbine is not matched by the steam flow from the boiler to the turbine. At this point, the operating reserves, in response to automatic-generation control signals from the control center, kick in. More fuel is added to the boiler, leading to a higher rate of steam production, which leads to higher power output. In this example, the system worked as it was intended to, and frequency was restored to its pre-contingency 60 Hz reference value within the required 10 minutes.



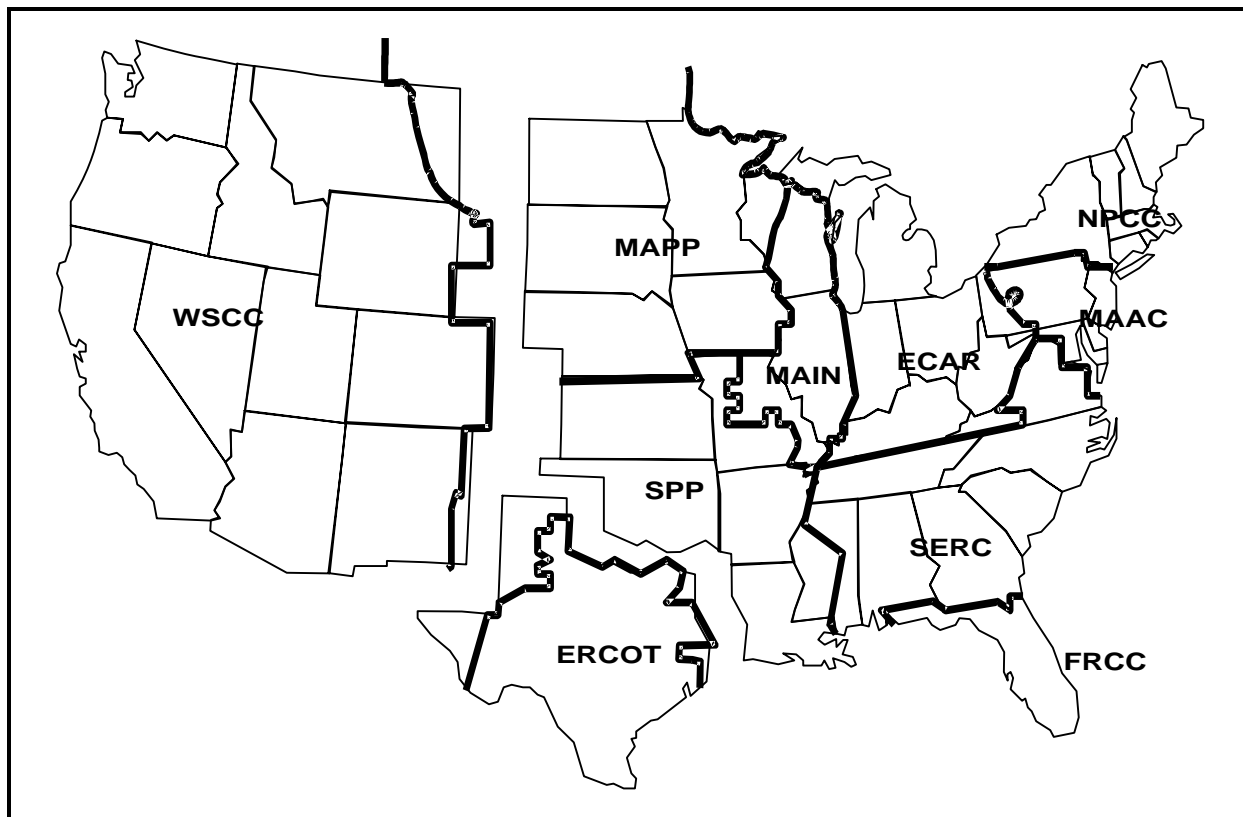
Interconnection frequency before and after the loss of 2,600 MW of generation.

The fundamental entity responsible for maintaining generation and transmission system reliability is the control area. Control areas are linked to one another to form interconnections—electrical systems consisting of one or more control areas that operate at the same frequency and have connecting tie lines. Each control area seeks to

minimize any adverse effect it might have on other control areas within the interconnection by (1) matching its schedules with other control areas (i.e., matching its generation plus net incoming scheduled flows to its loads) and (2) helping the interconnection maintain frequency at its scheduled value (nominally 60 Hz).

Today's approximately 150 control areas are operated primarily by utilities, although a few are run by ISOs. Control areas are grouped into regional reliability councils, of which there are 10 in the 48 contiguous states, most of Canada, and a small but growing portion of Mexico (Figure A-3). These reliability councils, in turn, are parts of the three primary interconnections: Western, ERCOT, and Eastern. (A fourth interconnection, Quebec, is entirely in Canada.)

Figure A-3. Map of the United States Showing the Ten Regional Reliability Councils^a



Note: North Carolina, South Carolina, and Virginia operate as VACAR, which is part of the Southeastern Electric Reliability Council (SERC). This map portrays the situation in early 1998. Since its publication, some utilities may have changed regional reliability councils (e.g., Entergy moved from SPP to SERC), which would affect the boundary lines shown on the map.

^aThe Western Systems Coordinating Council and the Electric Reliability Council of Texas are each interconnections as well as reliability councils. The remaining eight councils are located within the Eastern interconnection.

Figure A-4 summarizes the roles of the three key institutions that affect generation and transmission system reliability: system operators, NERC, and the Federal Energy Regulatory Commission (FERC).

Figure A-4. Today's Reliability Institutions

System Operators and Security Coordinators rely on communications with each other, access to essential system information, and real-time monitoring and control of certain facilities to maintain reliability. When an emergency occurs, the control-area operator acts—both through communication and direct physical action—to ensure the integrity and security of the system. These people take and direct others to take the actions necessary to “keep the lights on” and to protect against damage to the entire system in the event of emergencies. In response to recent NERC requirements, 23 Regional Security Coordinators coordinate within the regions and across the regional boundaries.

NERC is a voluntary, industry-constituted governing body that develops standards, guidelines, and criteria for assuring system security and evaluating system adequacy. NERC has been funded by regional reliability councils, which adapt the NERC rules to meet the needs of their regions. Through the work of its ten regional councils, NERC has largely succeeded in maintaining a high degree of transmission-grid reliability throughout the country. Historically, the reliability councils have functioned without external enforcement powers, depending on voluntary compliance with standards and peer pressure.

FERC is the federal agency with jurisdiction over bulk power markets, including interstate transmission systems. As part of these responsibilities, FERC implements policies to assure that the owners and operators of bulk power transmission facilities under the agency's jurisdiction provide nondiscriminatory service to all participants in wholesale power markets. Historically, FERC has not had to involve itself with regulating reliability functions. Increasingly, some parties are calling on FERC to exercise its authorities by addressing reliability issues that intersect with the commercial needs of the industry.

A.2 SYSTEM DESIGN CRITERIA

Design criteria for electric systems differ for adequacy and security. In the past, the amount of generation capacity needed to maintain adequacy was usually based on probabilistic analyses typically intended to meet a loss-of-load-probability of 1 day in 10 years. In the future, generation adequacy decisions may be left more to markets and less to technical standards and regulatory requirements.

System security, on the other hand, is generally based on deterministic, rather than probabilistic, analysis. System security criteria specify that the system be able to withstand (i.e., continue to operate reliably after) the loss of any single element. Because

there is usually not sufficient time to respond to the sudden loss of a generator or transmission line through market interactions (response times are typically within seconds or minutes), technical standards are used to establish reserve and operating requirements.

A.3 RELIABILITY ACTIVITIES

Several activities are required to maintain system reliability beyond the installation of sufficient generation and transmission equipment. These activities include the following:

- ▶ **Observe the network**—Observe current (real-time) frequency, voltage, current, and power-flow conditions at each node and in each element to determine if failure of an element or voltage collapse is imminent.
- ▶ **Analyze and model the system**—Using computer models and data on current operating conditions such as current flows and voltages, anticipate conditions in individual pieces of equipment (such as lines and transformers) that are not directly observable; estimate what will happen if an element fails; determine whether a proposed transaction can be accommodated; and deal with normal uncertainties, such as load-forecast errors and the effects of temperature and wind speed on real-time thermal limits.
- ▶ **Communicate and coordinate**—Coordinate with other control-area operators to assure that activities do not threaten the integrity of the interconnected grid.
- ▶ **Take control actions**—Maintain system operation within acceptable limits (primarily changes in generation output, transmission switching to a lesser extent, and load shedding as a last resort).
- ▶ **Monitor and enforce compliance**—Ensure that all market participants (generators, aggregators, marketers, transmission operator, and loads) are consistently meeting reliability requirements.
- ▶ **Plan for future conditions**—Make improvements and additions (e.g., new generation, transmission lines, transformers, load control, and FACTS¹ devices) to improve reliability and relieve constraints. Improve communications and controls to enable more market participants to engage in reliability-enhancing activities. Improve capabilities to observe and model the system, thus allowing safe operation of the system closer to actual physical limits and better use of existing resources.

¹FACTS refers to flexible AC transmission systems, the use of high-speed solid-state technologies to control transmission equipment, thereby improving reliability and increasing capacity.

- **Get incentives right**—Ensure that price signals and contractual arrangements (for generators, transmission, and loads) evoke reliability-enhancing behavior in the most economically efficient manner. These signals must provide adequate incentive to invest without overcompensating investors.

These activities take place at various levels of geographic aggregation. Some activities (primarily monitoring and control of distribution systems) occur at the subcontrol area level, many at the control area, and some at higher levels of aggregation. The summer 1996 Western power outages revealed a need for greater regional coordination to improve reliability. In response to this need, NERC and the regional reliability councils created regional security centers. These 23 centers are now monitoring regional power flows, focusing on the “big picture” that individual control areas cannot easily see.

A.4 TIME SCALES

Table A-1 lists the actions to maintain reliability that occur over very different time frames, from cycles (fractions of a second) for the operation of automatic protection devices, to several years for planning additions to transmission and generation resources.

Although system operators must be able to respond quickly to disturbances, there are limits to their ability to intervene. Automatic protection devices are used where actions may be required before operator intervention is possible (e.g., response to a lightning strike occurs automatically within a few cycles).

As shown in Figure A-2, a generator tripping offline causes an immediate imbalance between generation and load, which causes a decline in interconnection frequency. In response to this frequency decline, the generators under governor control automatically increase output to begin to restore frequency to its 60-Hz reference value. Generators that are providing operating reserves increase output to restore generation/load balance within 10 minutes. System operators deal with these situations by redispatching generation, and perhaps transmission, resources.

The market can play a significant role in forward-looking activities such as transactions to ensure sufficient operating reserves for the following hour and day. System operators and planners also need

Table A-1. Services that the Traditional Vertically Integrated Utilities Perform that Can Affect Generation and Transmission System Reliability

Function	Time Scale	Description
Automatic protection	Instantaneous	Minimize damage to equipment and service interruptions caused by faults and equipment failures
Disturbance response	Instantaneous to minutes to hours	Adjust generation, breakers, and other transmission equipment to restore system to scheduled frequency and generation/load balance quickly and safely
Regulation and voltage control	Seconds to minutes	Adjust generation to match scheduled flows across transmission system inties plus actual system load. Adjust generation and transmission resources to maintain system voltages
Economic dispatch	Minutes to hours	Adjust committed units to maintain frequency and the generation/load area-interchange balance at minimum cost subject to transmission, voltage, and reserve-margin constraints
Transmission loading relief	Minutes to hours	Curtail transactions and redispatch generation to reduce power flows through critical transmission elements
Unit commitment	Hour ahead to week ahead	Decide when to start up and shut down generating units, respecting unit ramp-up and down rates, startup costs, and minimum runtimes and loadings
Transmission scheduling	Hour ahead to year ahead	Schedule individual transactions and reservations of transmission capacity
Maintenance scheduling	1 to 3 years	Schedule and coordinate planned generating-unit and transmission-equipment maintenance to maintain reliability and to minimize cost
Transmission planning	2 to 10 years	Design regional and local system additions to maintain reliability and to minimize cost
Generation planning	2 to 10 years	Develop a least-cost mix of new generating units, retirements, life extensions, and repowering based on long-term load forecasts

to forecast future demands on the system for day-ahead and week-ahead planning for reserves and longer term for maintenance and resource planning. Regional coordination for operating and planning activities is necessary to optimize efficient and reliable service. Finally, the planning for new generators and transmission system additions typically occurs several years ahead (e.g., 2 to 3 years for peaking units such as combustion turbines, and 8 to 12 years for base-load coal or nuclear units).

**Appendix B:
Institutional
Alternatives to
Maintain Generation/
Transmission
System Security in
the Future**

The 1992 Energy Policy Act might reasonably be considered the starting point for the current electric industry restructuring efforts underway at both the federal level (for wholesale power) and within some states (for retail power). As examples, FERC issued a notice of proposed rulemaking on open-access, nondiscriminatory transmission service in 1995 and issued its final rule (Order 888) in April 1996. And the California Public Utilities Commission (PUC) issued its “Blue Book” in March 1994, which set forth the state’s plan to reform electricity regulation in that state; 2 years later, the legislature passed a bill to accomplish those objectives. One study identified 16 states that in the spring of 1998 had begun to study or implement retail competition (Block, 1998).

Efforts underway at the North American Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and the U.S. Department of Energy (DOE) deal explicitly with the system’s security (operational) aspect of reliability, as explained in the following subsections.

B.1 NERC

During the past few years, NERC has begun to transform itself into an entity well suited to meet the generation and transmission system reliability needs of a competitive and deintegrated electricity industry. These changes include “universal participation, more detailed and uniform reliability standards that can be put in place quickly, independent monitoring of reliability performance, and the *obligation* to support, promote, and comply with NERC’s Policies.”

In the summer of 1997, NERC formed a blue-ribbon panel of experts, called the Electric Reliability Panel (1997), to help define the future course for ensuring generation and transmission system reliability. The panel’s report made several recommendations to the NERC Board that focused on the following issues:

- Independence: Rather than have the regional reliability councils be the owners of NERC, the proposed North American Electric Reliability Organization (NAERO) should have a board of directors, two-thirds of whom have no current ties to the electricity industry and represent the public interest and one-third of whom represent the various participants in the electricity supply industry.

- Membership: NAERO should be as inclusive as possible; all organizations with a physical or commercial interaction with the bulk power system should be eligible to join.
- Mission: The primary mission of NAERO should be grid security, with a secondary purpose of encouraging resource adequacy.
- Compliance and enforcement: NAERO should implement a mandatory compliance and enforcement program.
- Self-regulating organization: NAERO should have sufficient authority to enforce compliance with its reliability standards. Thus, the Canadian, U.S., and Mexican governments should provide NAERO with official recognition and authority. In the U.S., this change will likely require FERC and/or congressional action.

In response to the panel's report, the NERC Board appointed four task groups to offer proposals on the following: governance, standing committees, government interface, and funding for the new NAERO. The four groups issued reports and recommendations that were considered at the NERC Board's May 1998 meeting (NERC, 1998).

In July 1998, the NERC Board launched the new NAERO to transform NERC (a voluntary organization) into NAERO (a self-regulating reliability organization). The key recommendations are the following:

- election in January 1999 of nine new independent board members who will succeed the current NERC board after reliability legislation is adopted in the U.S. and Canada;
- binding agreements between NAERO and the affiliated regional reliability entities; and
- creation of three standing committees for security (operations), adequacy (planning), and market interface.

Thus, NERC is well on the way to creating an organization that is broadly representative of the entire electricity industry (consumers and power marketers as well as suppliers), requires compliance with its policies and rules, and is more of a top-down organization (and less beholden to the regional reliability councils).

B.2 FERC

In early 1998, FERC (1998c) opened an inquiry on reliability, perhaps stimulated in part by concerns over litigation between transmission customers and transmission owners over reliability

rules (Figure 3-2 in Section 3). Its announcement of a February 1998 technical conference on reliability suggested three alternative processes for addressing reliability:

- ▶ All transmission providers that are members of a reliability organization follow that organization's rule with no FERC approval. Transmission customers are free to challenge those rules under Section 206 of the Federal Power Act;
- ▶ All jurisdictional utilities that are members of a reliability organization would file the reliability rules with FERC as amendments to their transmission tariffs; or
- ▶ The reliability organization would file a request for a declaratory order with FERC that the rule is just and reasonable.¹

Participants in the technical conference expressed considerable disagreement over whether FERC should issue a new rule on reliability; NERC was strongly opposed to this idea because it is currently in the midst of so many changes. Others, including power marketers and large industrial customers, expressed concern about NERC's continued lack of a fully balanced membership on its board and many committees. These entities were also concerned about the possibility for the 23 security coordinators, most of which are utilities, to engage in discrimination. Overall, there seemed to be some consensus in favor of federal legislation giving FERC oversight over the forthcoming NAERO.

FERC (1998d) subsequently initiated another investigation, this one on ISOs. One of the six panels for an April 1998 technical conference addressed reliability. FERC's questions for the panel participants asked whether reliability rules should be national or regional, whether ISOs would enhance generation and transmission system reliability, what the relationship between an ISO and regional reliability council would be, and whether the ISO should be the Regional Security Coordinator. Participants in the technical conference expressed the same kinds of diverse views as those offered at the earlier conference on reliability. In general, participants favored formation of large regional ISOs both to ensure open access to transmission and to maintain reliability. There is a question of whether FERC currently has sufficient authority to order IOUs to form and join ISOs (FERC clearly lacks such authority with respect to municipal electric systems and rural electric cooperatives).

¹In June 1998, NERC filed such a request with FERC for a declaratory order on NERC's transmission loading relief procedures.

In November 1998, FERC (1998b) issued a *Notice to Consult* with the state regulators concerning FERC's role in encouraging or mandating the creation of regional transmission organizations (RTOs). In February 1999, FERC conducted three hearings at which many state PUCs offered their views. Not surprisingly, the PUC perspectives varied widely, depending on the status of RTOs in their state, the cost of electricity in their state, and other factors. Some commissioners encouraged FERC to take a strong position and require utilities to form large RTOs. Others, including those from the Southeast, urged FERC to recognize regional differences and to grant substantial deference to state decisions concerning grid regionalization.

B.3 DEPARTMENT OF ENERGY

In December 1996, the Secretary of Energy created a new Task Force on Electric System Reliability, which held its first meeting in January 1997. The 24 members of the Task Force represent all major elements of the electricity industry, including private and public suppliers, power marketers, customers, regulators, environmentalists, and academics. The Task Force met at two-month intervals through September 1998.

The Task Force (1998), in its final report, wrote:

The Task Force believes that restructuring the electric industry offers economic benefits to the Nation. Transmission-grid reliability and an open, competitive market can be compatible. Although the changes being brought about by restructuring are complex, the reliability of the bulk-power [generation/transmission] system need not be compromised—provided appropriate steps are taken.

These steps must be taken soon. Indeed, the Task Force believes that the primary challenges to bulk-power system reliability are presented by the transition itself, rather than by the end state of competition. Failure to act will leave substantial parts of North America at unacceptable risk.

To ensure continued reliability of the bulk-power system in this environment of change requires a concerted effort by existing reliability institutions and State and Federal governments. To help achieve this goal, the Task Force developed a series of recommendations. Table B-1 summarizes these recommendations and the entities with primary responsibility for their implementation. The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a

Table B-1. Primary Responsibility for Implementing the Recommendations of the DOE Task Force on Electric System Reliability^a

	U.S. Congress	FERC	DOE	NERC/SRRO	System Operators ^b	Market Participants
Authorize FERC to oversee bulk-power reliability	✓					
Approve governance, structure, and operations of SRRO		✓				
Review and approve national reliability standards		✓				
Oversee enforcement of national reliability standards		✓		✓		
Approve formation, governance, and rules of ISOs		✓				
Develop and implement reliability standards, including those for ancillary services				✓		
Identify preferred transmission-pricing methods that encourage appropriate transmission investments		✓				
Monitor transmission congestion				✓	✓	
Implement and enforce SRRO reliability standards					✓	
Comply fully with SRRO reliability standards					✓	✓
Monitor reliability R&D			✓			
Explore formation of regional regulatory agencies to oversee interstate transmission enhancements and to assure full consideration of alternatives, including demand-side management and distributed generation	✓	✓	✓			

^aDOE is the U.S. Department of Energy, and NERC/SRRO refers to a not-yet formed self-regulatory reliability organization that would be the successor to NERC.

^bTo the extent that the system operators are not *independent* of commercial interests, some of these responsibilities might be shifted to other entities.

restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability. This confidence, however, does not imply complacency. There is much to be done, especially during what is turning out to be a lengthy, complicated, and awkward transition period. During this period, as electric utilities open up their transmission systems to others and (in many cases) divest their generating assets, there is a critical need to be sure that reliability is not taken for granted as the industry restructures, and thus does not "fall through the cracks." The Task Force is especially interested in seeing the reliability institutions becoming truly independent of commercial interests so that their reliability plans and actions are—and are seen to be—unbiased and untainted by the economic interests of any set of bulk-power market participants. In addition, the Task Force believes that these reliability institutions should, wherever possible, rely on competitive markets to encourage producer and consumer behaviors that maintain and improve transmission-grid reliability. The Task Force believes that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC, including the authority to coordinate North American reliability with the appropriate regulatory agencies in Canada and Mexico. Finally, because commercial and reliability interests are inextricably linked in the electricity industry, the Task Force urges the FERC to use its existing authority to regulate on reliability matters that intersect with commercial markets to ensure nondiscriminatory access to reliable transmission services until Congress takes action.

B.4 FEDERAL LEGISLATION

Disputes between the new and traditional participants in bulk power markets (Figure 3-2) illustrate well the need for the U.S. Congress to expand and clarify FERC's role with respect to bulk power reliability. The Administration's proposed *Comprehensive Electricity Competition Act* offered four legislative changes to the Federal Power Act concerning FERC's authority over generation and transmission system reliability:

- ▶ Section 201 would extend FERC's jurisdiction over transmission services (but not the power business) to municipal, other publicly owned, cooperative, and federal utilities.
- ▶ Section 202 would permit FERC to approve interstate compacts that establish regional transmission planning agencies that facilitate coordination among states concerning the siting of new transmission facilities.

- Section 204 would give FERC the authority to establish ISOs and to require utilities to relinquish control of their transmission facilities to the ISO.
- Section 501 would give FERC the authority to register and oversee an electric reliability organization to prescribe and enforce mandatory reliability standards, which would apply to all users of the bulk power system (DOE, 1998).

**Appendix C:
National Association
of Regulated Utility
Commissioners
(NARUC) Resolution
on Electric System
Reliability**

NARUC Convention Floor Resolution No. 21
Resolution on Electric System Reliability

WHEREAS, The reliability of electric service, including the adequacy of supply and the security of system operations, is essential to the economic well-being and domestic security of the nation; and

WHEREAS, There is a national interest in a transmission network that is reliable and available to support competitive and efficient electricity markets; and

WHEREAS, Historically, the high level of electric reliability experienced in the United States has been achieved through the voluntary efforts of the electric utility industry, through the North American Electric Reliability Council (NERC) and the regional reliability councils, to police themselves with federal and state regulatory oversight; and

WHEREAS, More competition in the electricity industry means the commercial incentives affecting both the owners of the transmission system and the parties transacting business on the system will be complex and not always consistent with the voluntary spirit of cooperation on which the NERC system relies; and

WHEREAS, The existing NERC system is already facing pressures from the expansion of wholesale competition regardless of the pace at which retail competition may be broadly introduced; and

WHEREAS, Facility siting, environmental standards, and energy policy issues are currently in the purview of many of the states; and

WHEREAS, Some states have established and exercise the authority to impose sanctions against those who engage in actions which abuse, misuse, or manipulate the grid in a manner which threatens reliability to the detriment of the state's local retail markets; and

WHEREAS, Absolute reliability is not physically possible and reliability of transmission does not have infinite economic value; and

WHEREAS, The public interest in a reliable and cost-efficient transmission system requires that the level of reliability to be

achieved and the standards and criteria to be complied with be established with public input and oversight; now, therefore, be it

RESOLVED, By the National Association of Regulatory Utility Commissioners, convened at its 109th Annual Convention in Boston, Massachusetts, that actions by Congress and the States to ensure a reliable electricity transmission system should be consistent with, or include the following:

1. Reliability standards and criteria addressing both the planning and the operation for the bulk transmission system should be comprehensive and should consider: the economic value of reliability, the practical engineering of the network, and a full range of alternatives to additional transmission line investments.
2. The level of reliability to be achieved and the standards and criteria to be complied with must be established with public input and oversight. This is necessary to both preserve the public interest and prevent anti-competitive abuses with respect to the transmission system. Governance of the NERC and the regional councils should be fairly representative of all industry interests and should include mechanisms to allow input from federal and state regulatory authorities and other public interest groups while preserving independent regulatory oversight. Meetings to establish reliability criteria and standards should be open to public input.
3. Federal agencies and federal legislation should facilitate effective decision-making by the states and recognize the authority of the states to create regional mechanisms including but not limited to inter-state compacts, or regional reliability boards, for the purpose of addressing transmission reliability issues.
4. Where state authority exists to impose sanctions against those who engage in actions which abuse, misuse, or manipulate the grid in a manner which threatens reliability to the detriment of the state's local retail markets, it should be preserved.
5. Responsibility for compliance with both operational and planning reliability standards and criteria should be clearly established. Sanctions for violation of standards and criteria should be clearly established, and sufficient authority should exist to enforce compliance and impose sanctions if necessary. Enforcement of compliance with reliability standards and criteria should be non-discriminatory. Enforcement of operational standards and criteria should be supervised by the FERC in cooperation with the states through existing state authority, joint boards, or other mechanisms. Enforcement of compliance with planning

and system adequacy standards should rest first with the states and regional bodies.

6. The NERC and regional reliability council system should be strengthened to enable reliability standards and criteria to be mandatory for those who own, operate, or use the transmission network. Any reliability standards or operational criteria, the compliance with which is to be made mandatory, must be subject to government regulatory oversight; and be it further

RESOLVED, That, either separately or as part of any electric industry restructuring legislation, Congress should, consistent with the preceding six principles, explicitly affirm the public interest in transmission grid reliability, the need for mandatory compliance with reliability standards, and provision of an explicit grant of authority to the states and to FERC to act in cooperation to enforce the necessary standards; and be it further

RESOLVED, That the working group on reliability shall further study, refine, and define the principles set forth in this resolution and make recommendations to the appropriate NARUC standing committees.

Sponsored by Committee on Electricity

Adopted by the NARUC Executive Committee on November 11, 1997

**Appendix D:
Distribution
Reliability
Questionnaire for
In-Person Interviews**

- A) Are you concerned about the potential effect of retail competition on the reliability of service to distribution customers served by your system?
- Yes
- No
- Not sure
- B) Are you concerned about the impact on distribution reliability that may be caused by the operation changes that can be required by bulk suppliers, security coordinators, control areas, ISO's or other controlling organizations?
- Yes
- No
- Not sure
- C) Are you concerned about the impact of retail competition on the information available to you that is needed for the operation, planning, design, and maintenance of your distribution system?
- Yes
- No
- Not sure
- D) Will some information be needed to manage and operate your distribution system no longer be available?
- Yes
- No
- Not sure
- E) Do you see any reliability benefits to your system from retail competition?
- Yes
- No
- Not sure

F) Do you believe you have an obligation to serve new load to be supplied by another company even if this would result in a costly reinforcement?

- Yes
- No
- Not sure

G) Would you continue to serve an existing load supplied by another company even if its removal would avoid the need for costly reinforcements on your system?

- Yes
- No
- Not sure

H) Please provide the following statistics for operations in the past three years:

Average frequency of customer interruptions: _____ /year

Average duration of each customer interruption: _____ /year

I) Please provide the basic system data for your system.

1. How is information obtained now?

a. Load data

- (i) existing loads
- (ii) new loads, load expansions
- (iii) forecasted rates of growth

b. Handling customer load transfers between feeders

2. How will information be obtained when some load is supplied by other companies?

a. Load data

- (i) existing loads
- (ii) new loads, load expansions (power application)
- (iii) forecasted rates of growth

b. Handling customers load transfer between feeders

3. Meter reading
 - a. How is it done now?
 - (i) What types of meters do you have now?
 - (ii) How many of each meter type?
 - (iii) If you plan to upgrade, is the justification labor savings? Something else?
 - b. What is planned for the future?
 - c. What data collection possibilities are being considered?
 - d. What are the reporting possibilities?
 - e. What would be the impact of having meters read by third parties?

- J) Please provide the following information concerning abnormal operations.
 1. What are your current system-restoration procedures?
 2. Do you have a written plan covering service restoration procedures with major outages?
 - a. Who is responsible for distribution restoration?
 - b. Who & how of call handling?
 - c. Who & how dispatches crew & equipment?
 - d. Who & how of crew placement?
 - e. Who & how equipment inventory & placement?
 - f. Who & how set restoration priority?
 3. What lessons were learned from recent years' storms, flooding, hurricanes & tornadoes?
 - a. Call handling?
 - b. Crew & equipment dispatching?
 - c. Crew placement?
 - d. Equipment inventory & placement?
 - e. Other?

4. Emergency operations
 - a. Under-frequency load shedding
 - (i) Who & how are customers selected?
 - (ii) Who & how coordinates with suppliers?
 - (iii) Who & how set under frequency relaying policy?
 - (iv) What will be done if under frequency relays are installed at a customer who selects another supplier?
5. Rotating blackouts
 - a. Who & how selects customers?
 - b. Who & how coordinates with suppliers?
6. With retail competition how would communications be handled with:
 - a. Transmission operator?
 - b. System control?
 - c. Suppliers?
 - d. Who would be in control?

K) Please provide the following information about your planning.

1. In regard to your current distribution design/planning:
 - a. What are feeder loading standards?
 - b. What are voltage drop standards?
 - c. What is voltage/power-factor correction policy
 - (i) reactive supply/voltage?
 - (ii) cost to supply?
 - d. What if low voltage or an overload is caused by as existing customer supplied by another company?
 - e. What is your obligation to serve new customers?
2. In regard to your current equipment improvements:
 - a. How do you decide what and where new facilities are needed?
 - b. What potential innovations do you foresee?

3. What innovation possibilities do you foresee that might affect distribution reliability such as:
 - a. Distributed generation?
 - b. Metering?
 - c. Other?
4. What service distinctions do you now make in regard to reliability or other quality-of-service issues for your customer groups:
 - a. Residential?
 - b. Commercial?
 - c. Industrial?
 - d. Government?
 - e. Public necessity—police, fire, hospitals, street lights, etc.?
 - f. Other?

**Appendix E:
Carolina Power &
Light Distribution
Reliability Interview
Summary**

E.1 Characteristics of CP&L System

Peak Load	10,536 MW
Total No. Customers	1,153,000
Load Characteristics	
Residential	23.6%
Commercial	19.0%
Industrial	28.6%
Other	28.8%
Forecast Rate of Load Growth	3%/yr (as high as 5% near some cities)
Power Supply	
Owned Generation	9,853 MW
Purchase from various	1,588 MW
Control Area:	have own area reserves

E.2 Procedures—CP&L System

- Carolina Power & Light (CP&L) expects to maintain a high quality of service reliability, although adding new parties to this system may complicate some reliability issues. For instance, who customers report outages to will affect how quickly CP&L can respond to such outages.
- CP&L communicates with an independent system operator (ISO) or reliability coordinator in the following manner:
 - ✓ CP&L has a separate dispatch center for bulk supply and distribution; and
 - ✓ the distribution center receives all trouble calls and dispatches crews as needed.
- If customer curtailments are needed, CP&L does not expect to be allowed to interrupt individual customers except, possibly, some of the larger customers. However, they are not sure what rules regarding this issue and others may be.
- A supplier's individual customers could be interrupted when supplies are low if the proper equipment is installed. Individual switching of customers may cost as much as \$200 per customer for such equipment—\$100 for a cell meter plus \$100 for a switch.
- If uniform minimum reliability standards for suppliers cannot be assumed, then two options exist when supplies are short:
 - ✓ individual switches to curtail only customers without suppliers; or
 - ✓ outages among customers regardless of supplier.
- Meter data are used to review feeder and transformer loadings for upgrades and replacement (overloads or under loads).

- During outages, CP&L uses Caller ID to predict equipment failures as customers call in. Their sophisticated system is based on direct trouble calls, customer phone numbers, and the physical connection (feeders) to each customer.
- Restoration procedure: customer calls
 - ✓ use customer database to identify feeder outages
 - ✓ dispatcher sends field repairman to suspected problem
 - ✓ CP&L sets restoration priorities to get the most customers back in service as quickly as possible
 - ✓ with major outages, they place higher priorities on restoring public facilities
- After retail competition:
 - ✓ if they become a wire company, they would keep the same approach
 - ✓ if they remain an integrated utility, they may do their own customers first
 - ✓ it may be possible for individual customers to pay for a higher restoration priority if the enabling legislation allows it

E.3 Impact of Retail Competition on Reliability to Distribution Customers

- Regarding metering, CP&L believes the regulated local distribution company needs to own the meters because they should be regulated for the public interest. CP&L can, in turn, make such data available to interested parties. If there are multiple owners of meters, there will likely be multiple designs and protocols resulting in communication protocol problems.
- Some large customers that require very high quality service now have meters that will automatically report voltage dips and brief interruptions.
- The use of load profiles instead of actual load data is a possible problem for reliability. (It also may be a commercial problem and technical problem for the bulk operator.)
- If CP&L is a regulated distribution company, they will have an “obligation to connect.” They may need to have more frequent rate cases to adjust for new facility costs. CP&L questions whether they will be able to cover the costs of major new loads. They may need some new tariff mechanism to have the customer pay for most of the additional costs. A reliability impact could occur if there were a delay in cost recovery, which would lead to less money available to spend on other projects to maintain reliability normally expected.

- Regarding new loads, CP&L sees little problem with forecasting area load growth with retail competition. However, there could be problems with large customers who are considering expansion or new facilities. They now have regular contact with these customers through account managers. This contact gives CP&L warning of potential expansion. Without this regular contact, they will lose some of their capability to make longer-term forecasts or know of potential new loads. Without enough warning, large pieces of equipment may not be available to supply the new load (e.g., 25 MVA transformers). Assuming customer load data is available, there should be little impact on distribution planning except for large customers as noted above.
- With multiple players in the marketplace, major outages would likely result in more calls that could place an extra burden on the telephone system.
- When CP&L has knowledge about health problems and other issues, it will give these customers priority. This special attention may not be available if CP&L does not receive direct calls.
- Even if customers are instructed to call the distribution company during outages, they may still call suppliers and anybody else who seems relevant, if a major outage occurs.
- CP&L depends on help from the outside repair crews during major outages. This may change under retail competition. Under retail competition, the “visiting crews” may do some marketing when they help to restore service. This potential problem would be eliminated if the distribution companies had defined service territories.
- Participation in standards regarding construction, tools, and practices may not continue. This could affect the interchangeability of tools and attachments used by different companies—they may not remain standardized.
- Separate distribution companies would be smaller and less able to share spare parts and crews. There may also be large differences in staffing levels. Technology has reduced staffing for normal operation, so there is less staff available for major outages. All of these factors may lead to longer restoration times in the future.
- CP&L current load-control scheme is on a feeder-by-feeder basis so they cannot easily curtail selected customers.
- There needs to be ways to address customer usage problems (such as voltage drop) regardless of who their supplier may be.

**Appendix F:
Fayetteville Public
Works Commission
Distribution
Reliability Interview
Summary**

F.1 Characteristics of Fayetteville System

Peak load	431 MW
Total No. Customers	66,000
Inside City	70%
Outside City	30%
Load Characteristics	
Residential	41.7%
Commercial	31.3%
Industrial	27.0%
Forecast rate of load growth	3%
Power Supply	
Owned Generation	230 MW
Purchase from various	156 MW
Supplemental (as needed) from CP&L	40 MW
Purchase from SEPA	5 MW
Control Area:	part of CP&L Control Area
Reserves:	distribution system and substations have ample reserves—loaded 50% of capacity

F.2 Procedures—Fayetteville System

- They plan to maintain their high level of reliability even if retail competition is implemented.
- They plan their distribution system using load data from substations and its supervisory control and data acquisition (SCADA) system.
- The entire system is operated from a single location
 - ✓ dispatch
 - ✓ control of circuit breakers
 - ✓ handling of outages
- Under-frequency relaying is only at the interconnections with Carolina Power & Light (CP&L). They trip large blocks of load if system frequency declines. They will keep as much load as possible in service using local generation.
- They are part of the CP&L curtailment plan and will curtail load on instructions from CP&L. They have a written curtailment plan with instructions. Key areas and loads not to be cut off have been identified.

F.3 Impact of Retail Competition on Reliability to Distribution Customers

1. RE: reliability of bulk suppliers
 - a) Concerned with decreasing reliability of bulk supply system.
 - ✓ They are entirely surrounded by the CP&L system.
 - ✓ With retail competition the complexity of bulk system operations will increase significantly.
 - ✓ Competitors will likely withhold important information.
 - b) Believe they need to put in additional generation of their own to protect their reliability of supply.
2. RE: potential reliability problems of distribution system
 - a) Would not continue to provide same degree of spare distribution capacity to provide operating flexibility to all customers under retail competition.
 - b) After power interruptions they would restore their own load first.
 - c) Would not provide facilities to meet potential growth needs as far into the future.
 - d) Would probably not provide as reliable a distribution supply if loads are supplied by others.
 - e) Following outages they would give priority in restoration to their own customers over those whose energy is supplied by others.
 - f) They see increasing difficulty in obtaining help from outside companies and systems in the event of major storm damage.
3. Potential causes and solutions of distribution system reliability problems.
 - a) They would reinforce the distribution system to serve loads supplied by others only as long they receive full financial compensation both long term and short term. For their existing customers, they are now compensated both by charges for facilities and through profits on the energy sold.
 - b) They would require extra payment to serve loads supplied by others for special reliability features they normally provide for their own customers—such as looped feeds. Without such an extra payment, a less reliable supply will be provided. An appropriate connection charge will be required from all new customers to be supplied by others.

- c) “Wires” charges to serve loads supplied to others must be sufficiently high, higher than to supply their own loads, to avoid a decline in reliability.
 - d) They must be provided meter data from all customers supplied by others to verify use of their system and adequately plan and operate their system.
4. Re: Obligation to serve
- a) RE: Emergency Energy Supply
 - ✓ They are willing to provide energy to any distribution customers normally supplied by another company if they have the energy available and are fully compensated for its cost.
 - b) RE: “Wires” service
 - ✓ They are willing to connect new customers supplied by others with minimum system reliability as justified by the payments they will receive.

F.4 Other Fayetteville Concerns

1. They do not believe they can “unbundle” their system since all facilities are owned by the City of Fayetteville.
2. They are concerned with outside suppliers “cherry picking” the most desirable distributions customers. This will leave them with increasing costs to supply the remaining higher-cost customers.

**Appendix G:
Blue Ridge Co-op
Distribution
Reliability Interview
Summary**

G.1 Characteristics of Blue Ridge System (estimated based on published materials)

Peak load	223 MW winter
Total No. Customers	55,800
Load Characteristics	
Residential	80%
Commercial	15%
Industrial	5%
Forecast rate of load growth	3%/yr
Power Supply	
Owned Generation	1 MW
Purchase from SEPA	2 MW
Purchase from NCEMC	(balance of requirements)
Control Area:	part of Duke control area

G.2 Procedures—Blue Ridge System

- Separating metering reading will be a big problem. By losing meter reading, they lose their membership relationship. This is an essential feature of a membership cooperative.
- They have supervisory control and data acquisition (SCADA) (they are upgrading); they get real-time data on feeder loading.
- Currently installing GPS mapping to get better response times.
- They have a lot of wind and ice in winter. They have planned restoration procedure for major outages.
- They will not discriminate between “their” customers and those supplied by others. They will remain true to their philosophy of universal service.
- Energy operations:
 - ✓ no under-frequency relaying
 - ✓ rotating blackouts—they would interrupt by feeder, avoiding hospitals, etc.
- Regarding equipment improvements, they expect distribution to be cost-based business, so costs would be regulated.

G.3 Impact of Retail Competition on Reliability to Distribution Customers

- Reliability can be maintained for a price. There does not need to be a reliability impact if the dollars are available.

If the co-ops starts to disappear because of higher costs, then rural areas will get poorer service as a cost-saving measure.

- Their area is isolated enough that they face little threat of others cherry picking their best customers because there are no nearby transmission facilities.
- They feel they need to be a thriving full-service utility to provide reliable service to their area.
- Not concerned about impact on distribution reliability that may be caused by operation changes that can be required by controlling organizations (independent system operator [ISOs], etc.) because they will continue to deal through North Carolina Electric Membership Cooperative (NCEMC).
- Concerned about transmission—if it is not really independent.
- Without their own metering, they would need to maintain a good relationship with meter owners so they have the data.
- Reliability benefits: Could be some innovation—mostly in customer service. They also may bundle other products with electricity.
- As a distribution co-op, they will serve new customers. They will have customers assigned costs only for the most extreme cases, such as building new distribution that costs over \$6,000 to serve a single customer. Otherwise, they will serve anybody.
- With unbundling, there will be different pricing and contracts, but not a change in reliability.

G.4 Key Objectives

- Do not break up co-ops as its essential that they remain economically viable.
- Cost vs. reliability is a trade off.

**Appendix H:
Duke Power
Company
Distribution
Reliability Interview
Summary**

H.1 Characteristics of Duke Power System

Peak load	14,600 MW
Total No. Customers	1,800,000
Inside City	950,000
Outside City	850,000
Load Characteristics	
Residential	27.3%
Commercial	34.2%
Industrial	38.5%
Forecast rate of load growth	2%/yr
Power Supply	
Owned Generation	17,300
Purchase from various	376
Control Area:	have own area reserves
Reserves:	17%
Distribution Characteristics	
24 kV	
12 kV	(Distribution)
4 kV	
Mostly radial	
Some loops, with automated throw over in city area	
Do not have supervisory control and data acquisition (SCADA) system	

The Duke distribution system supplies customers in their “franchised territory” and customers in “unassigned territory.” They are required to provide service to all customers in their franchised territory. They may compete for load in the “unassigned territory” if they believe this to be profitable.

In its “franchise territory” all customers are treated the same. In the “unassigned territory” the reliability provided will be that justified by the revenue.

H.2 Procedures—Duke System

- ▶ Plan distribution system using data from its distribution databases. These data are compiled from substation data and special software that determines subarea loads from customer billing records.
- ▶ Duke sales and service representatives periodically meet with larger customers to review their future power needs and any service problem. This information is used as a part of the Duke planning process and to correct possible distribution system problems.

- Planning is done by the individual regions with the general office providing overall management through control of expenditure.
- Distribution system is operated from a number of regional centers with the general office in Charlotte providing overall control and allocation of resources in emergencies.
- All customer outages are reported to a central computer system in Charlotte.
- Under-frequency relays are installed in specific feeders in substations and in the bulk supply system.
- Distribution feeders are divided into three categories:
 - ✓ Class 1—Outages involve risks to health and safety (e.g., hospitals, police, sewage)
 - ✓ Class 2—Outages have large economic impact (e.g., industry, shopping centers)
 - ✓ Class 3—Remainder of load

Duke has restoration procedures that call for distribution service to be restored in sequence with Class 1 first.

- Duke is able to prevent customer use of undesirable apparatus or low customer power factor that can cause problems for other customers on the distribution system.

H.3 Impact of Retail Competition on Reliability to Distribution Customers

The Duke views are based on a number of key assumptions:

1. They will continue to have full information on all meter readings no matter who supplies the energy. This information is needed for its planning and operating, specifically:
 - ✓ analyses of growth in various areas and for various types of load,
 - ✓ monitoring of distribution transformer loading, and
 - ✓ analyses of load involved when sections of feeders are cut-over to other feeders (they have software for this analyses).

With this information Duke will be able to plan and operate their distribution system as reliably with retail competition as without it.

If this information is not provided, Duke will have to install its own metering to obtain it. This could result in duplicate metering costs.

2. They will be able to maintain existing contacts with customers to obtain all information needed for planning.

3. They will continue to have control over customer load apparatus to prevent undesirable effects on other customers.
4. They will be fully compensated for all costs in supplying loads. Tariffs for distribution service will be completely independent of tariffs for energy.

With this condition Duke will not have to reduce quality of distribution equipment, back-ups, arrangements, and reserves presently provided, and reliability of service will not suffer.

5. They will be identified to the customer as the party to call in the event of service outages, not the company supplying energy to the customer (or at least at the same time).
6. The bulk supply system will continue to operate as reliably with retail competition as it would without it.

Based on these assumptions, Duke believes that retail competition will not adversely affect the reliability of distribution served in its franchised service territory. The reliability of service to its customers in the unassigned areas will depend on competitive pressures.

Duke would also like to be able to offer premium distribution service for a higher service fee. This premium service could provide better service quality (e.g., less voltage dips, a better service reliability through use of special equipment or special system arrangements). Duke is willing to consider higher restoration priority when it causes outages, provided it does not interfere with their overall restoration plans.

H.4 Key Duke Distribution Business Objectives

- Duke believes that the distribution business will continue to be regulated, will have an obligation to connect to customers, and will deliver distribution services (e.g., reliability, repairs, testing meters) to all connected customers.

**Appendix I:
Wilson Public Works
Department
Distribution
Reliability Interview
Summary**

I.1 Characteristics of Wilson System

Peak Load	229 MW
Total No. Customers	25,800
Inside City	16,900
Outside City	8,900
Load Characteristics	
Residential	27.9%
Commercial	23.1%
Industrial	42.8%
Wholesale	4.8%
City	1.3%
Forecast rate of load growth	3%
Power Supply	
Owned Generation	25 MW
Purchase from SEPA	18 MW
Eastern power agency (balance of requirements)	
Control Area:	part of CP&L control area

I.2 Procedures—Wilson System

- Plan distribution system using load data from substations and its supervisory control and data acquisition (SCADA) system.
- Entire system operated from a single location
 - ✓ dispatch
 - ✓ control of circuit breakers
 - ✓ handling of outages
- Under-frequency relaying is at major interconnections. They do not have any specific plans to deal with an under-frequency situation.
- Are part of Carolina Power & Light (CP&L) curtailment plan and will curtail load on instructions from CP&L. Have a written curtailment plan with instructions. Key areas and loads not to be cut off have been identified.

I.3 Impact of Retail Competition on Reliability to Distribution Customers

Since Wilson does not own or operate any significant amount of generation, they are very close to being a distribution-only utility now. Nearly all their energy (> 95 percent) is purchased from or through CP&L. They are participants in the North Carolina Eastern Municipal Power Agency and own about 25 MW of local peaking generation. They also provide water and gas service to their electric customers.

1. RE: reliability of bulk suppliers
 - a) Concerned with decreasing reliability of bulk supply system.
 - ✓ They are entirely surrounded by the CP&L system.
 - ✓ With retail competition the complexity of bulk system operations will increase significantly.
 - ✓ Concerned that the decreasing generation reserve margins in the region will lead to more outages.
2. RE: potential reliability problems of distribution system
 - a) Would not continue to provide same degree of spare distribution capacity to provide operating flexibility.
 - b) On power interruptions they would restore the loads with highest revenue first (after essential loads such as police, hospitals, for example).
 - c) They see increasing difficulty in obtaining help from outside companies and system in the event of a major storm.
3. Potential causes and solutions of distribution system reliability problems.
 - a) Would reinforce distribution system to serve loads supplied by others only as long they receive full financial compensation both long term and short term. For their existing customers they are compensated both by charges for facilities and through profits on the energy sold.
 - b) They must be provided meter data from all customers supplied by others to verify use of their system and adequately plan and operate their system.
4. Re: Obligation to serve
 - a) RE: Emergency Energy Supply
They generally do not produce energy for their customers, but purchase it from outside. They will deliver energy to any distribution customers normally supplied by another company.
 - b) RE: "Wires" service
They are willing to connect new customers supplied by others with a minimum system reliably as justified by the payments they will receive.

I.4 Other Wilson Comments

1. They do not believe they can "unbundle" their system since all facilities are owned by the City of Wilson.
2. They also do not expect to benefit from automatic meter reading until they can automate gas and water meters along with electric.

**Appendix J:
Piedmont Co-op
Distribution
Reliability Interview
Summary**

J.1 Characteristics of Piedmont System (estimated based on published materials)

Peak Load	89 MW
Total No. Customers	23,200
Load Characteristics	
Residential	93%
Commercial	5%
Industrial	2%
Forecast rate of load growth	2%/yr
Power Supply	
Owned Generation	0 MW
Purchase from NCEMC	(full requirements provider)
Control Area:	

J.2 Procedures—Piedmont System

- Separating meter reading is a potential problem. This is some of the most critical information they need to design and operate their system. If they lose meter reading, they also lose their membership relationship—an essential feature of a membership cooperative.
- They have been proactive in updating and replacing their distribution facilities.
- They will not discriminate between “their” customers and those supplied by others. They will remain true to their philosophy of universal service.
- Emergency operations:
 - ✓ no under-frequency relaying
 - ✓ rotating blackouts—they would interrupt by feeders as part of the state-wide plan, avoiding hospitals, etc.
- Regarding equipment improvements, they expect distribution to be cost-based business so costs would be regulated.

J.3 Impact of Retail Competition on Reliability to Distribution Customers

- Reliability can be maintained for a price. There does not need to be a reliability impact if the dollars are available.
- Without prompt cost-recovery, there could be problems keeping up with maintenance.
- Recovering the cost of new connections, which will usually be higher than the embedded costs, could become a problem.
- Without their own metering, they would need to maintain a good relationship with meter owners so they have the data.

- They serve a wide range of customers from rural areas to the Durham suburbs. Customers in these suburbs would be possible “targets” for other suppliers.
- With retail competition they would treat all the customers equally, regardless of the supplier if there were a general supply shortage. This is “no change” from current practice. There could be changes in load shedding procedures if one supplier was short. In this case they would try to curtail that supplier’s customers first.
- Not concerned about impact on distribution reliability that may be caused by operation changes that can be required by controlling organizations (independent system operator [ISOs], etc.) because they will continue to deal through North Carolina Electric Membership Cooperative (NCEMC). The control area operator will deal with the problem. They will respond to the instructions of their control area operator.
- Reliability benefits: there could be some innovations in regard to real-time metering. Other products may be bundled with electricity.
- As a distribution co-op, they will serve new customers. They now serve all single-phase without surcharge regardless of distance. As buried “drops” become the standard, this policy will probably be changed. Otherwise, they will serve anybody.

J.4 Key Objectives

- Do not break up co-ops because it is essential that they remain economically viable.
- Cost vs. reliability is a trade off.