Transmission Planning for a Restructuring U.S. Electricity Industry

Eric Hirst and Brendan Kirby

June 2001

Prepared for

Edison Electric Institute
Washington, D.C.

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Transmission Planning for a Restructuring U.S. Electricity Industry

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CONTENTS

LIST OF ACRONYMS

ECAR	East Central Area Reliability Coordination Agreement
EEI	Edison Electric Institute
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible alternating-current transmission systems
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
HTS	High-temperature superconducting
HVDC	High-voltage direct current
ISO	Independent system operator
ITC	Independent transmission company
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
PJM	Pennsylvania-New Jersey-Maryland Interconnection
OPF	Optimal power flow
RTO	Regional transmission organization
SERC	Southeastern Electric Reliability Council
SMES	Superconducting magnetic energy storage
SPP	Southwest Power Pool
TLR	Transmission loading relief
WSCC	Western Systems Coordinating Council

SUMMARY

The U.S. electricity industry is in the midst of a transition from a structure dominated by vertically integrated utilities regulated primarily at the state level to one dominated by competitive markets. In part because of the complexities of this transition, planning and construction of new transmission facilities are lagging behind the need for such grid expansion.

Between 1979 and 1989, transmission capacity increased slightly faster than did summer peak demand (Fig. S-1). However, during the subsequent decade, utilities added transmission capacity at a much lower rate than loads grew. The trends established during this second decade are expected to persist through the next decade. Maintaining transmission adequacy at its current level would require an investment of about $56 billion during the present decade. This transmission investment is roughly half that needed for new generation during the same period.

The ultimate structure of the electricity industry, as envisioned by the Federal Energy Regulatory Commission, includes large regional transmission organizations (RTOs) that will be responsible for planning and expanding transmission systems on a broad regional scale. This shift from planning conducted by individual utilities for their system to meet the needs of their customers to planning conducted by RTOs to meet the needs of regional electricity markets raises important issues (Table S-1). These issues include the objectives of planning (reliability vs commerce), the role of congestion costs in deciding which projects to build, the consideration of generation and load alternatives to new transmission projects, the economic and land-use benefits of building larger facilities, the role of new solid-state technologies that permit operation of transmission systems closer to their thermal limits, and the growing difficulty in obtaining data on new generation and load growth caused by the separation of generation and retail service from transmission.

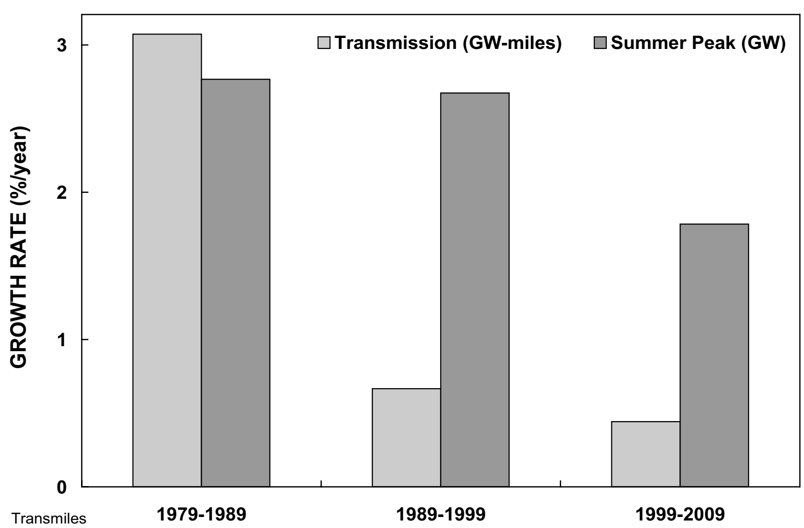

Figure S-1. Average annual growth rates in U.S. transmission capacity and summer peak demand for 1979-1989, 1989-1999, and projections for 1999-2009.

Table S-1. Key transmission-planning issues

Topic	Issues
Reliability vs commerce	To what extent should RTOs plan solely to meet reliability requirements, leaving decisions on grid expansion for commercial purposes (e.g., to reduce congestion costs) in the hands of market participants?
Congestion costs	Are historical congestion costs (in particular those reflected in short-term nodal or zonal congestion prices, as well as long-term firm transmission rights) a suitable basis for deciding on transmission investments?
Alternatives to transmission	What role should RTOs play in assessing and motivating suitably located generation and load alternatives to new transmission? Should RTOs provide information only or should they also help pay for such alternatives? How can these alternatives be assessed fairly given their very different characteristics from transmission [e.g., in availability, lifetimes, capital and operating costs, and regulatory framework (transmission is regulated, while generation is not)]?
Economies of scale	Should RTOs overbuild transmission facilities in anticipation of future need in order to reduce the dollar and land costs per GW-mile of new transmission facilities? How should these economies be balanced against the possibly greater financial risks of larger transmission facilities?
Advanced technologies	What are the prospects for widespread use of new technologies (e.g., superconductivity and solid-state electronics) to improve system control, thereby permitting operation of existing grids closer to their thermal limits? Are the costs of these new systems declining fast enough to make them attractive as commercial systems (because some of them permit system operators to control flows)?
Planning data	Who will provide the data needed for transmission planning, particularly on the locations, timing, and types of new and retiring generating units and the loads and load shapes of retail customers?
Centralized vs decentralized transmission planning and expansion	To what extent can private investors, rather than RTO planners, decide on and pay for new transmission facilities? Can they, in spite of network-externality effects, capture enough of the benefits of such transmission projects to justify their investment? How can new technologies advance private transmission investment (e.g., in DC lines)?

Chapter 1: INTRODUCTION

When the popular press [e.g., *Los Angeles Times*, *Washington Post*, and *Fortune* (Stipp 2001)] all write articles on a topic as dry and abstract as the nation's high-voltage transmission grids, something important must be happening. Indeed, as these articles make clear, California's lack of sufficient generation capacity is not the only critical infrastructure issue facing the U.S. electricity industry and its consumers. An equally important, and much more intractable, problem is the lack of sufficient transmission capacity.

Expanding transmission capacity requires good planning. The Federal Energy Regulatory Commission (FERC 1999) emphasized the importance of transmission planning in the creation of competitive wholesale markets. FERC wrote that each regional transmission organization (RTO) "must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and non-discriminatory transmission service and coordinate such efforts with appropriate state authorities." FERC included transmission planning as one of the eight minimum functions of an RTO:

> [T]he RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service … . The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability.

Under FERC's model, transmission planning will move from individual utilities to the regional level. This change should help limit the exercise of vertical market power by utilities that own transmission and generation. This change should also limit the exercise of horizontal market power by broadening the geographic scope of such planning.

The transmission grid is more than a "highway" linking generators to loads. As explained by the North American Electric Reliability Council (NERC 1997), transmission networks are the "principal media for achieving reliable electric supply." They deliver electricity from generators to loads; provide flexibility so that the highway functions can be maintained over a wide range of generation, load, and transmission conditions; reduce the amount of installed generating capacity needed for reliability by connecting different electrical systems; permit economic exchange of energy among systems; and connect new generators to the grid.

Because of the many changes under way in the structure and operation of the U.S. electricity industry, transmission planning faces many challenges (Exhibit 1). The changes affecting transmission planning include the deintegration (separation) of generation from transmission, the separation of both generation and transmission from system control, and the creation of competitive markets for generation. These changes require corresponding adjustments in how transmission planning is conducted. Transmission planning is becoming more complicated because the distinction between reliability and commerce is changing, congestion costs need to be considered, and timely and reliable data on the locations and sizes of new and retiring generating units are often unavailable.

Exhibit 1. Key Transmission Planning Issues

Industry Structure

- What are/should be the objectives of the transmission system and transmission planning?
- How might transmission planning be different within an independent system operator (ISO) vs a transmission-owning RTO? For an ISO, what roles should the ISO, transmission owners, and other stakeholders play in transmission planning?
- What are appropriate roles for state regulators and FERC in transmission planning?
- To what extent can transmission investment be driven by market forces alone? That is, can RTO planners provide information on use of the transmission system and leave expansion decisions to investors driven by the profit motive?

Relationship of Transmission to Generation and Load

- What are the fundamental differences between transmission and the generation and load alternatives (e.g., lifetime, availability, ownership)? How can these nontransmission alternatives be fairly compared to transmission, given these differences?
- Given the corporate separation of generation from transmission in many regions, how does transmission planning account for possible future locations, types, and sizes of new generating facilities?
- How does transmission planning account for possible future changes in patterns of electricity flows based on changes in wholesale energy commerce? How should planning reflect the possible investment risks associated with new transmission that might become uneconomical?
- Must transmission planning always react to the markets for generation and load, or can (should) transmission planning influence and anticipate those markets? If yes, how can this be done?

Planning Process and Models

- Can reliability and commerce be usefully distinguished in transmission planning?
- How does the planning process assure that input is obtained from all relevant parties? How can such inputs be obtained in a timely and efficient manner?
- How does transmission planning consider possible opposition to the specific locations of facilities (e.g., existing and possible future land uses, and environmental concerns)?
- How do the differences between the time it takes to plan, site, and construct transmission and the speed with which generation and load markets operate affect transmission planning?
- How are nontransmission alternatives considered in transmission planning?
- How do (should) congestion costs (both in real time and in the prices for firm transmission rights) affect decisions on the selection of transmission projects?
- How do planning models incorporate congestion costs in their analysis? How are data on available-transfer-capability limits, denied transactions, and transmission-loading-relief calls used in modeling?
- How does planning deal with economies of scale in transmission construction?
- How does transmission planning deal with economies of scope, the fact that an addition in one part of the grid may affect flows elsewhere on the grid?
- How does planning deal with transmission flows and constraints that change rapidly, making it difficult to analyze the benefits of proposed transmission projects?
- How does planning account for the effects a new transmission facility might have on subsequent decisions on generation construction and location?
- How do planning models incorporate the possible effects of new transmission facilities on the competitiveness of wholesale power markets (including the exercise of market power by generators)?
- Are deterministic models satisfactory, or are risk-based probabilistic methods needed?

Transmission planning is one element of a broader process that leads, ultimately, to the construction of needed bulk-power facilities (Fig. 1). To assess various transmission and nontransmission (generation and load) alternatives, transmission models require large amounts of data and projections related to loads, generation, and transmission. Transmission planners use detailed electrical-engineering computer models to assess these alternatives. Model results, combined with information on costs, environmental effects, siting, and regulatory requirements, lead to financial and regulatory assessments of different projects. Ideally, these plans lead to the construction of needed projects, cost recovery (including a return on investment) for transmission owners, and transmission rates that charge users for the services they receive.

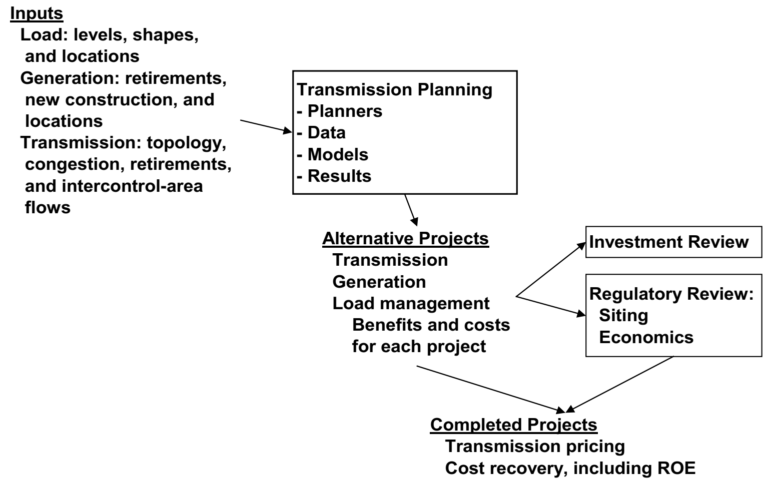

Fig. 1. The relationship between transmission planning and its inputs (data and projections) and results.

This report, in focusing on planning, does not discuss issues related to siting (environmental and land-use reviews), economic regulation (e.g., cost-of-service vs incentive regulation), or transmission pricing. It also does not address the pros and cons of different RTO structures, in particular differences between transmission-owning RTOs vs nonprofit RTOs that operate but do not own transmission. Our earlier report on transmission adequacy discussed some of these issues (Hirst 2000).

This report discusses transmission planning in today's restructuring and transitional U.S. electricity industry. The primary purpose of this report is to highlight the key issues and changes associated with the electricity industry's transition to competition that affect and complicate transmission planning. In doing so, the report notes several areas requiring additional attention from transmission planners. Chapter 2 reviews historical data and projections for the current decade on transmission capacity. The chapter also discusses the amount of money the nation would need to spend during this decade to maintain transmission adequacy at the current level. Chapter 3 describes the primary types of planning models used to assess the need for and benefits of different transmission projects. Chapter 4 discusses several key planning issues and the complications that arise because of the increasing competitiveness and transitional state of the U.S. electricity industry. Chapter 5 reviews several recent transmission plans and the planning processes proposed by several RTOs in their filings with FERC. Chapter 6 summarizes the key findings and conclusions from this project.

Chapter 2: TRENDS IN TRANSMISSION ADEQUACY

DATA

Defining transmission adequacy is difficult because transmission capability varies with time as a function of transmission topology and the locations and magnitudes of generation and load. Nevertheless, data from the Edison Electric Institute (EEI 2001b) and the North American Electric Reliability Council (NERC 2000a and b) plus projections from NERC (2000a and b) show that transmission capacity relative to peak demand has been declining and is expected to continue to decline.[1] Our interpretation of these data assumes that the location of generation relative to load has not changed materially during the past two decades and is not likely to change much during the coming decade (Hirst 2000).

As shown in Fig. 2, normalized transmission capacity increased from 1978 through 1982 and then declined steadily through 1999. In particular, the MW-miles of transmission capacity per MW of summer peak demand *increased* by 3.3 percent per year between 1978 and 1982 and then *declined* by 1.4 percent per year between 1982 and 1999. Between 1994 and 1999, this indicator declined even more rapidly at a rate of 2.2 percent per year.

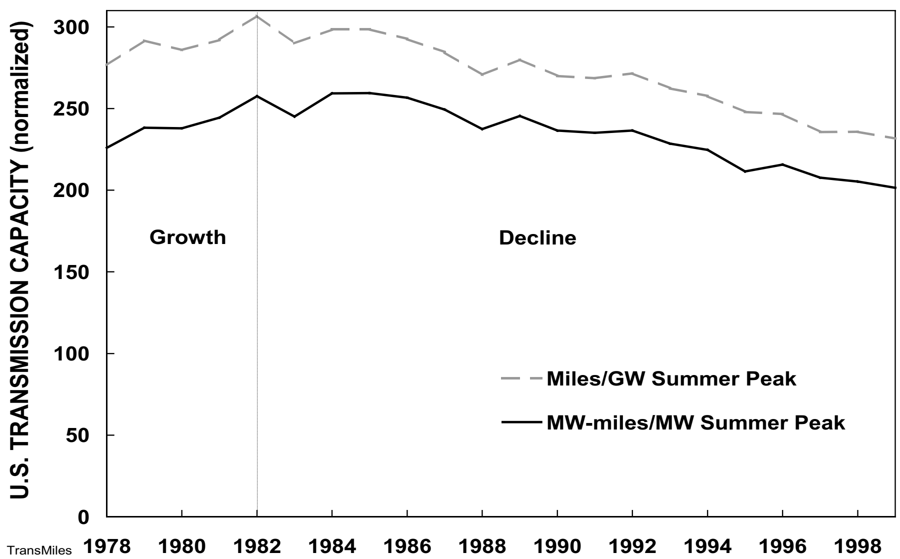

Fig. 2. U.S. transmission capacity normalized by summer peak demand from 1978 through 1999.

EEI (2001b) collects data on annual construction expenditures, including transmission, for investor-owned utilities. In addition, EEI (2001a) conducts a survey of utilities on planned construction expenditures for the next three years. These data show that transmission investments (in constant, inflation-adjusted 1999 dollars) have been declining for a quarter century at an average rate of almost $120 million a year (Fig. 3, page 6). Transmission investment in 1999 was less than half of what it had been 20 years earlier. Planned construction expenditures show a slight increase for 2000 followed by small declines in 2001 and 2002.[2]

[1] We adopt the NERC definition of transmission as facilities at 230-kV and above.

[2] The two EEI (2001a and b) data sources differ substantially on actual transmission investment in 1999. The construction-survey estimate is 60 percent higher than the *Statistical Yearbook* value. Based on conversations with EEI staff (Spencer 2001), we adjusted the construction forecast values down to reflect this difference in values for 1999.

PROJECTIONS

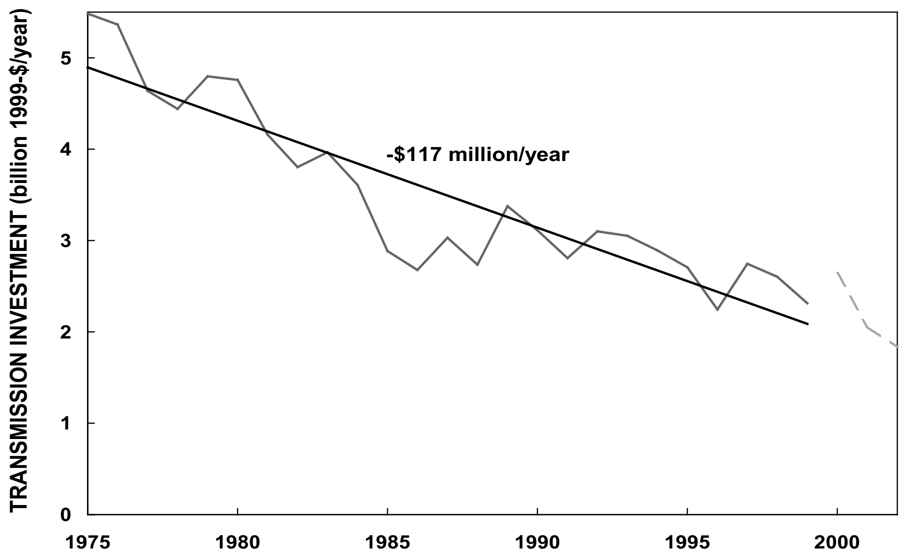

Fig. 3. Annual transmission investments from 1975 through 1999 and projections for 2000, 2001, and 2002.

Data reported to NERC show installed transmission capacity and planned additions five and ten years in the future (Fig. 4). Consistent with the EEI data discussed above, the NERC data show steady declines in U.S. transmission capacity relative to demand from 1989 through 1999. Utility plans as of 1990 showed a decline in normalized transmission capacity in 1994 and 1999. By 1995, both actual and projected capacity had declined. The situation in 2000 was even worse: normalized capacity was 17 percent lower relative to demand than it had been a decade earlier, and the projection for 2009 showed a further decline of 12 percent.[3] Interestingly, normalized transmission capacity at the end of 1999 was well below the values forecast for that year in 1990 and 1995.

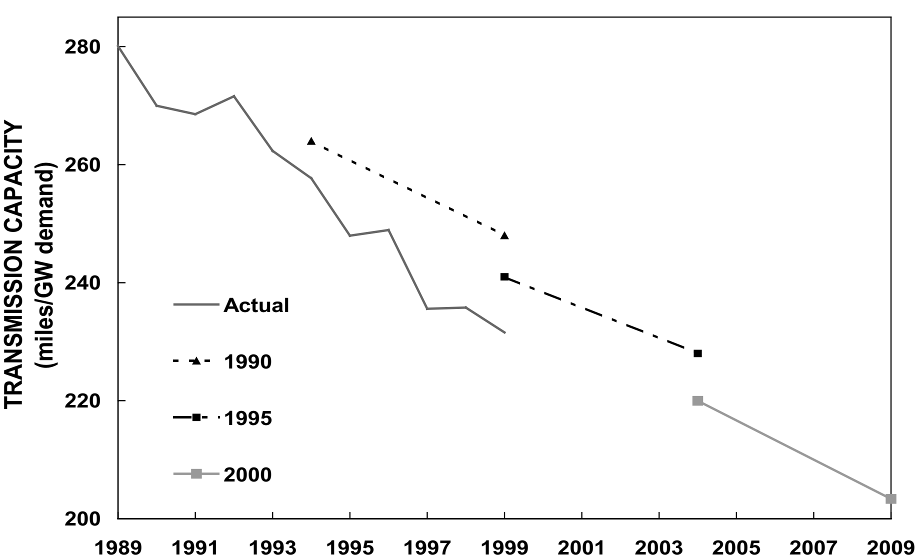

Fig. 4. U.S. transmission capacity normalized by summer peak demand from 1989 through 1999 plus 10-year projections from 1990, 1995, and 2000. Note that the *y* axis does not begin at zero.

The NERC data and projections show detail for each of the 10 regional reliability councils as well as the United States as a whole (Fig. 5). [We adjusted the data for the Southeastern Electric Reliability Council (SERC) and the Southwest Power Pool (SPP) for the years 1989 through 1996 to reflect the shift of Entergy from SPP to SERC in 1997.] Between 1989 and 1999, normalized transmission capacity declined in all 10 regions by amounts ranging from

[3] The NERC (2001) *2001 Summer Assessment* shows the addition of more than 1000 miles of new transmission between March and September 2001; this is a substantial increase relative to the 10-year projection of 7600 miles.

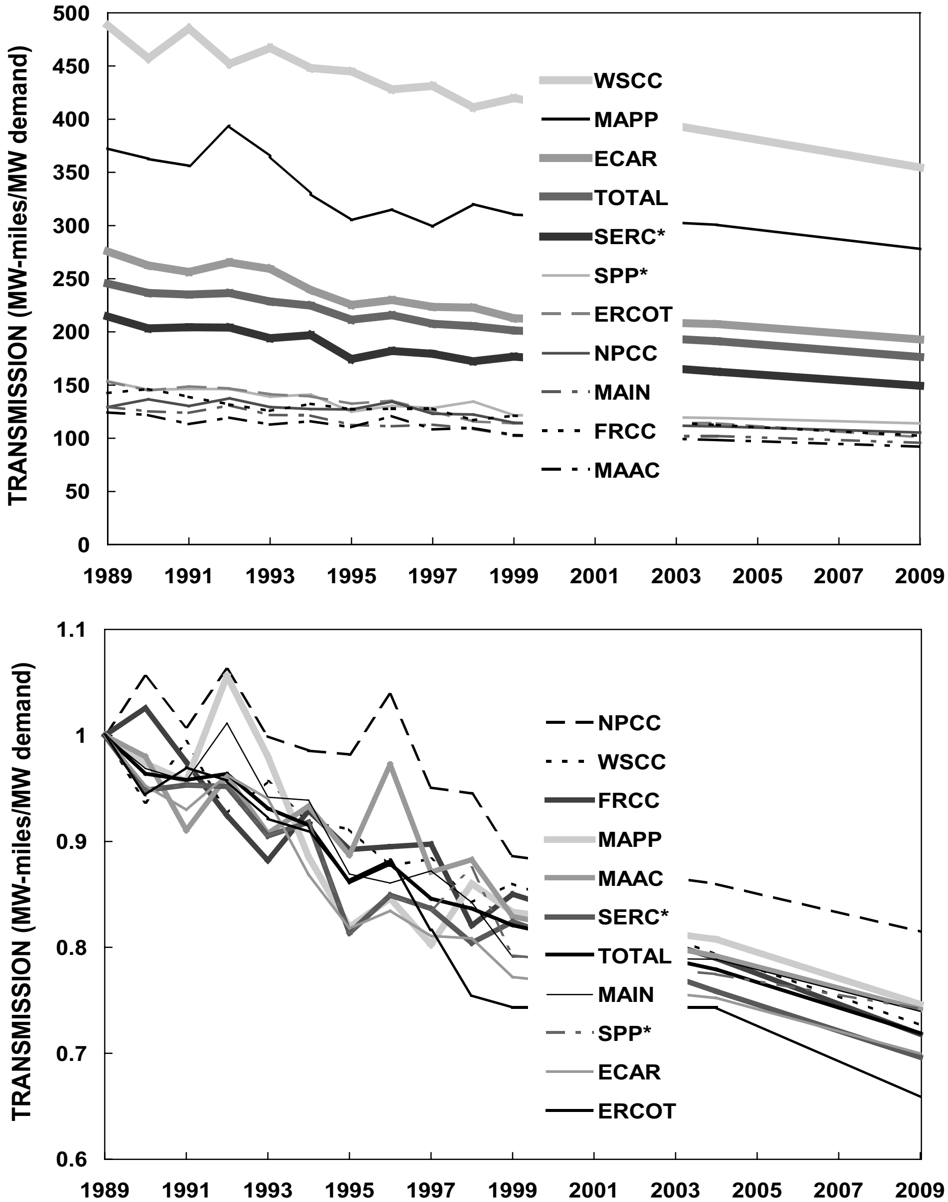

Fig. 5. U.S. transmission capacity for the 10 regional reliability councils normalized by summer peak demand from 1989 through 1999 with projections for 2004 and 2009 (top) and normalized by 1989 values (bottom).

11 percent (NPCC) to 40 percent (SPP). The 10-year declines were most rapid in ERCOT, ECAR, MAIN, and SPP. The declines were least rapid in NPCC, WSCC, and FRCC. Planned transmission additions are lower than expected load growth in all 10 regions, with the declines likely to be most rapid in FRCC, SERC, and WSCC.

Between 1979 and 1989, transmission capacity increased slightly faster than did summer peak demand. However, during the subsequent decade, utilities added transmission capacity at a much lower rate than loads grew. The trends established during this second decade are expected to persist through the next decade.

Not surprisingly, these trends in transmission investment and expansion have operational consequences. As shown in Fig. 6, the number of times system operators in the Eastern Interconnection called for transmission loading relief (TLR) increased by less than 10 percent between 1998 and 1999 and then jumped by more than 200 percent between 1999 and 2000.The rate of TLR calls during the first quarter of 2001 was triple that of the comparable period in 2000. Although such curtailments in new transactions and interruptions in actual and planned transactions can occur for various reasons, the dramatic increase in their number suggests that additional transmission capacity is, indeed, needed.

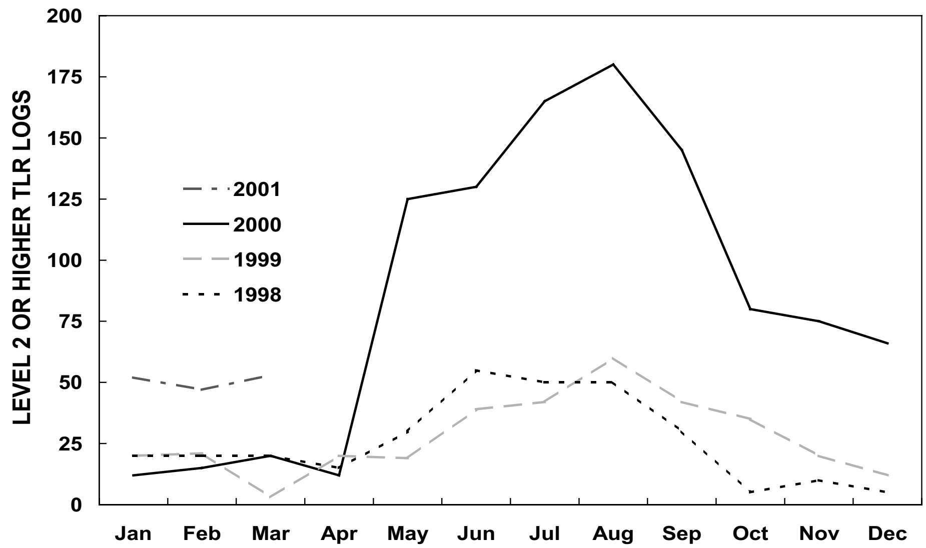

Fig. 6. Number of Level 2 or higher TLR calls in the Eastern Interconnection.

Gale, Graves, and Clapp (2001) estimate year-2000 congestion costs at $800 million for the transmission customers in New England, New York, PJM, and California. Congestion costs on California's Path 15 alone were as much as $169 million for the last four months of 2000 (California ISO 2001b).

HOW MUCH NEW CAPACITY IS NEEDED

The NERC data and projections show a very small increase in planned transmission capacity between 1999 and 2009, from 137,300 to 143,500 GW-miles. Because summer-peak demand is expected to grow more rapidly (from 681 to 813 GW), normalized transmission capacity is expected to decline from 201 to 176 MW-miles/MW demand.

Assume that the 1999 level of normalized transmission capacity is sufficient to meet the needs of an increasingly competitive electricity industry. How much more capacity must the industry build during the current decade? Maintaining a normalized capacity of 201 MW-miles/MW demand throughout the decade requires construction of 26,600 GW-miles, compared with the planned construction of only 6,200 GW-miles. Thus, transmission additions, net of retirements, must more than quadruple just to maintain the current level of transmission adequacy. Increasing adequacy to, say, its 1990 or 1995 level would require even more transmission investment during the current decade.

How much would it cost to build this much transmission? Seppa (1999) estimated the cost per mile of building 230-, 345-, 500-, and 765-kV transmission lines (Table 1). The cost of new lines, including the land and necessary substations, increases with increasing voltage. However, the cost per GW-mile of new capacity declines with increasing voltage, demonstrating substantial economies of scale. For example, it costs less than half as much per GW-mile to build a 500-kV line than it does to build a 230-kV line.

Combining the cost estimates in Table 1 with the NERC data on existing transmission capacity yields an overall cost of transmission of $0.90 million/GW-mile.[4] Applying this value to the 137,000 GW-miles of existing transmission yields a replacement value of current U.S. transmission capacity of $121 billion. This amount far exceeds the current book value of transmission, which is about $56 billion.[5]

The EEI data on annual transmission investments (the dollar amounts shown in Fig. 3), when coupled with the NERC data on installed transmission (the MW capacity shown in Fig. 4), provide another estimate of the cost of new transmission. To use the NERC data, however, one must estimate the amount of transmission capacity added each year to replace retired (i.e. worn out or obsolete) capacity. (Transmission rights-of-way are rarely abandoned. Rather, existing conductors are replaced, often with wires capable of handling larger power flows, or towers and conductors are replaced.) That is, the NERC data reflect the *net* effect of new transmission and transmission retirements. Assuming that 2 percent of the transmission capacity is retired each year yields an estimate of $0.9 million/GW-mile of new transmission. Using only data from the most recent decade yields a higher estimate of $1.0 million/GW-mile.

Table 1. Typical costs and thermal capacities of transmission lines

Voltage (kV)	Capital cost[a] (thousand $/mile)	Capacity[b] (MW)	Cost (million $/GW-mile)
230	480	350	1.37
345	900	900	1.00
500	1200	2000	0.60
765	1800	4000	0.45

[a] These estimates are from Seppa (1999) and include the costs of land, towers, poles, and conductors. We increased these estimates by 20 percent to account for the costs of substations and related equipment.

[b] These values reflect the thermal capacities at typical line lengths. Figure 7 in Chapter 3 shows how line limits depend on line length, with thermal limits restricting short lines, voltage limits restricting mid-length lines, and stability limits restricting long lines.

If the 2 percent annual retirement assumption is roughly correct, U.S. utilities plan to build 33,700 GW-miles of transmission between 2000 and 2010 (27,500 GW-miles to replace retired assets plus 6,200 GW-miles of new capacity). At a cost of $1.0 million/GW-mile, the nation's planned investment in transmission capacity during the current decade is $35 billion. To maintain transmission capacity at its current value relative to summer peak demand would require utilities to construct 54,000 GW-miles (27,500 GW-miles to replace retired assets plus 26,600 GW-miles of new capacity) during this decade. The cost of this investment would be $56 billion, about 60 percent higher than that for the base case and equal to the book value of existing

[4] Fuldner (no date) estimated the costs of different configurations for 230-kV lines, yielding estimates that ranged from $0.5 to $0.9 million/GW-mile. (Fuldner is unclear on whether these costs include land, substations, and other equipment.) The PJM transmission expansion plan (presented at a Transmission Expansion Advisory Committee meeting on 12/12/2000) provides estimates for some of these other costs: a 230-kV/115-kV transformer = $5.5 million, a 500-kV/230-kV transformer = $15.6 million, a 230-kV circuit breaker = $0.35 million, a 345-kV circuit breaker = $1.75 million, and a 350-MVAR static var compensator = $14.5 million. SPP recently identified the need for six new transmission lines in that region. The five 345-kV lines range in expected cost from $290,000 to $820,000 per mile, with an average cost of $600,000/mile (O'Grady 2001). The one 230-kV project is expected to cost $750,000/mile. The 345-kV costs are lower than the Seppa value and the 230-kV cost is higher.

[5] Roseman (2000) estimated the existing rate base for investor-owned utilities at $42 billion, based on FERC Form 1 data. We increased this estimate to account for the 25 percent of U.S. transmission owned by other kinds of utilities.

U.S. transmission facilities.[6] The deficit in past transmission investment poses large challenges to transmission planners. Not only must they plan for incremental needs, they must also plan to make up for transmission investments that did not occur during the 1990s.

It is interesting to compare this "needed" transmission investment of $56 billion for the current decade with likely costs in new generation for the same period. Projections from the Energy Information Administration (EIA 2000) suggest a need for 210 GW of new generating capacity from 2000 through 2009. At an installed cost of $500/kW, the total 10-year cost for new generation would be about $105 billion.

If these numbers are roughly correct, the needed investment in new transmission is about half of the amount needed in new generation during this decade.

[6] If only 1 percent of existing transmission assets are retired each year, the estimated cost of building enough new transmission this decade to maintain adequacy at its current level increases from $56 to $67 billion. Although the amount of new construction is lower, the cost per GW-mile is higher.

Chapter 3: TRANSMISSION-PLANNING MODELS

The purpose of transmission planning is to identify a flexible, robust, and implementable transmission system that reliably facilitates commerce and serves all loads in a cost-effective manner. Meeting this planning goal requires both technical (electrical engineering) analysis of different transmission-system configurations and economic analysis of different transmission projects. The computer models used by system planners serve a more modest goal. The modeling tools show how a particular bulk-power system will behave under a specific set of conditions. They calculate voltages at each bus (node) in the power system and power flows between adjacent buses.

While several types of models are used for planning, they share important characteristics. The most important feature is that the models analyze a particular time (e.g., the expected summer peak hour in 2007); they do not analyze the system over a month, a season, or a year. The system planner must run many scenarios with the models to simulate how the system will likely behave under a range of conditions and over an extended time frame.

The models do not, by themselves, suggest or determine system enhancements. Instead, they allow the system planner to simulate the operation of the power system under a range of stressful conditions (e.g., removing a line from service) to see how the system performs. The planner models various enhancements to see if they improve system performance. The planner uses this information to determine if a proposed enhancement is adequate. The planner must determine which enhancements to model and under what conditions to model the enhancements.

Modeling power systems is difficult, and requires complex tools, because of the scope of the system being modeled rather than the complexity of the individual elements. The problem is that each snapshot must cover a broad geographic area, including tens of thousands of pieces of equipment. AC power systems have few devices that directly control the power flow on individual transmission lines, so it is not possible to segregate a piece of the power system for study. Conditions on one part of the system affect the way the entire system behaves.

Because these analyses must be conducted over large geographic areas, the models have voracious appetites for data (some of which is commercially sensitive), the satisfaction of which is a major task. Ensuring cooperation across several control areas and many corporate entities may become increasingly difficult in a competitive environment.

Analyzing a condition of practical interest requires numerous model runs. The planner cannot know which individual power lines will be out of service because of maintenance or failure at some future time. So the system must be modeled repeatedly, removing individual pieces of equipment from the model one at a time. In addition, the planner must model the system under a range of generation conditions, including different output levels and forced outages.

Different models are used for steady-state, dynamic, and short-circuit analysis, but they all express their results in terms of voltages at each bus and flows through each line and transformer. The models do not select the conditions to be modeled. Neither do they decide what constitutes acceptable performance. They can make both jobs easier by facilitating the data-manipulation, analysis, and interpretation tasks and by providing effective displays for visualizing the results.

RELIABILITY OBJECTIVES

The objective of the modeling activity is to determine if the power system can accommodate a set of predefined contingencies. The objectives differ slightly from control area to control area and across the ten regional reliability councils, but they are similar in general terms: the system must be able to survive any single contingency (sudden loss of a transmission line, transformer, or generator) and any credible multiple contingency. The NERC (1997) *Planning Standards* specify performance requirements for transmission systems under normal and contingency conditions. PJM (2001) sets out the MAAC (2000) reliability requirements that its baseline transmission plan addressed, a slightly stricter version of the NERC standards. Standard II is Transmission Adequacy and Security Requirements, Standard III is General Requirements and relates to voltage support, Standard IV is Stability Requirements, Standard V is Abnormal Disturbances Testing, Standard VI is Relaying and Protective Devices, and Standard VII is Network Transfer Capability (Exhibit 2).

The single-contingency standard ensures that (1) all elements of the transmission system remain within their *emergency* ratings after one element suddenly trips offline and (2) the system can be subsequently adjusted to operate within normal limits. The second-contingency[7] standard ensures that the system can withstand an additional outage; specifically, all elements must operate within their *short-time emergency limits* after the second element suddenly fails, and the system can be subsequently adjusted so that all elements operate within their *emergency ratings* for the probable duration of the outage. The multiple-contingency standard ensures that the system can withstand the simultaneous failure of specific combinations of facilities (e.g., both circuits of a double-circuit line). Standard III ensures that sufficient reactive-power capability (both transmission and generation) is available throughout the system to maintain voltages within the required ranges both under normal conditions and after a contingency occurs. Standard IV ensures that the system will not become unstable upon the loss of a generating unit because of a fault at or near the unit. Standard VII tests the ability of the bulk transmission system to deliver minimum amounts of power to each of the areas within PJM.

Although these reliability standards are deterministic (i.e., the contingencies that are to be survived are specifically enumerated), there is a probabilistic element to the criteria. The system is designed to survive *credible* multiple contingencies, not all combinations of contingencies. There is simply not enough money to build a transmission system that can withstand any and all failures. The list of contingencies to consider is cut off at a point where the next event is judged to be too unlikely to warrant spending money to guard against. The determination of which contingencies to consider and how much risk to accept is, or should be, made in the public arena because the risk is shared by all users of the power system. Historically, the utility (or ISO) and NERC region publicized the planning criteria.

These requirements address power-system security, the ability to withstand sudden disturbances. System planning and modeling tools also address system adequacy: "the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times" (NERC 1997). Adequacy requirements are typically established in probabilistic terms, such as a loss of load no more often than one day in ten years.

[7] A *second* contingency occurs when a second element fails soon after the first element fails. A *double* contingency occurs when two elements fail at almost the same time.

Exhibit 2. PJM Compliance with MAAC Reliability Principles and Standards

- Single Contingency
  The system must be able to withstand the loss of any single transmission line, generating unit, transformer, bus, circuit breaker, or single pole of a bipolar DC line in addition to normal scheduled outages of bulk electric supply system facilities without exceeding the applicable emergency rating of any facility or applicable voltage criteria. After the outage, the system must be capable of readjustment so that all equipment (on the MAAC and neighboring systems) will be loaded within normal ratings.

- Second Contingency after Readjustment
  After occurrence of the outage and the readjustment of the system specified above, the system must be able to withstand the subsequent outage of any remaining generator or line without exceeding the short-time emergency rating of any facility. After this outage, the system must be capable of readjustment so that all remaining equipment will be loaded within applicable emergency ratings and voltage criteria for the probable duration of the outage.

- Multiple Facility Outages
  The system must be able to withstand the loss of any double circuit line, bipolar DC line, faulted circuit breaker or the combination of facilities resulting from a line fault coupled with a stuck breaker in addition to normal scheduled generator outages without exceeding the short-time emergency rating of any facility or applicable voltage criteria. After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

- General Requirements
  Sufficient megavar capacity with adequate controls shall be installed to supply the reactive load and loss requirements in order to maintain acceptable emergency transmission voltage profiles during all of the above contingencies.

  Installation of generation and transmission facilities shall be coordinated to ensure that the probability of load exceeding the available capacity resources shall not be greater, on average, than one day in ten years. Available capacity resources consist of the generating capability available internal to the system and the capacity that can be transmitted into the system.

- Stability Requirements
  The stability of the system shall be maintained without loss of load during and after the following types of contingencies occurring at the most critical locations at all load levels:
  – A three-phase fault with normal clearing.
  – Single phase-to-ground fault with a stuck breaker or other cause for delayed clearing.
  – The loss of any single facility with no fault.

- Network Transfer Capability—Capacity Emergency Transfers
  The amount of power to be transferred from one area to another for capacity shortages shall be limited as follows:
  1. With all transmission facilities in service and normal generator maintenance schedules, the loadings of all system components shall be within normal ratings, stability limits, and normal voltage limits.
  2. The interconnected systems shall then be able to absorb the initial power swing resulting from the sudden loss of any one transmission line or generating unit.
  3. After the initial swing period, the loadings of all system components shall be within short-time emergency ratings and voltage limits.

Historically, this requirement meant that the planner would model the worst-case condition of high load and generator outages that corresponded to that probability. If the system planner could devise a way (through any combination of generator redispatch, imports, export curtailment, interruptible-load deployment, etc.) to satisfy the security requirements listed above, then the system was considered adequate.

This concept of adequacy may differ in the future. It might be reasonable to require that the transmission system support some level of competitive market activity. PJM (2001) does not agree; its planning criteria state: “Transmission constraints on market dispatch are economic constraints. Economic constraints are not considered violations of reliability criteria as long as the system can be adjusted to remain within reliability limits on a pre-contingency basis.” PJM’s position may well be the correct one; it may be too expensive to provide sufficient transmission to support competition under all conditions. It certainly is correct that system security is not threatened.

This discussion of reliability requirements yields two key points. First, deciding what conditions to model and at what point there is adequate transmission capacity are very much in the public domain. Second, the modeling tools used to evaluate reliability and commerce are the same, only the evaluation criteria change.

DATA REQUIRED FOR MODELS

The system planner requires models that identify and characterize all the line and transformer impedances (resistance, inductance, and capacitance), all the transformer tap settings and ranges, all the generator outputs and reactive-power capabilities, all the real- and reactive-power loads and how they respond to voltage changes (constant power or constant impedance), all the capacitors and inductors, and so on, as well as how all these components are interconnected (Table 2). Collecting, organizing, and validating the data needed for transmission modeling is a major activity. Because flows on one part of the system influence flows throughout the system, data are required for a large geographic area. Load-flow models often include more than 50,000 buses and 100,000 lines and span several states. No single utility has direct access to all the required data. Utilities cooperate by developing data for specified conditions (e.g., summer peak, winter peak, shoulder peak, and offpeak for this year, next year, and five years in the future) and by sharing that data with each other. The regional reliability councils help coordinate and standardize these data-collection activities.

FERC (2000) recognizes the need to share transmission-system data. It requires all transmission-owning utilities to submit Form 715 every year, which includes base-case power-flow data, transmission-system maps and diagrams, a detailed description of the transmission-planning reliability criteria used to evaluate system performance, a detailed description of the transmission-planning assessment practices (including, but not limited to, how reliability criteria are applied and the steps taken in performing planning studies), and a detailed evaluation of the anticipated system performance. FERC permits the utilities to decide exactly what to submit, but FERC suggests that the Form 715 filings include one-, two-, five- and ten-year forecasts under summer and winter peak conditions as well as a one-year forecast under light-load/heavy-transfer conditions. This information can be submitted by each transmission-owning utility, but most choose to file on a regional or subregional basis. These data and projections can be downloaded from the FERC website at www.ferc.fed.us/electric/f715/form715.htm.

FERC also requires each utility to “provide the transmission planning reliability criteria used to assess and test the strength and limits of its transmission system to meet its load responsibility as well as to move bulk power

Table 2. Data requirements for load-flow modeling

Device	Required data
Transmission lines (and series capacitors and inductors)	Connectivity: electrical locations of the two ends Series impedance: line resistance and inductance Charging current: line capacitance Limits: maximum current-carrying capacity under normal and emergency conditions
Transformers	Connectivity: electrical locations of the two ends Series impedance: resistance and inductance Excitation current: no-load losses Limits: maximum current-carrying capacity under normal and emergency conditions Tap range: tap ratio or the tap-ratio range, if adjustable Control voltage: target voltage for the adjustable tap changer and which bus voltage to control
Shunt capacitors and inductors	Connectivity: electrical location of the device Capacity: reactive power the device produces or absorbs at normal voltage
Synchronous condensers and static var compensators	Connectivity: electrical location of the device Capacity range: maximum reactive power the device can produce and absorb Control voltage: target voltage and which bus voltage to control
Generators	Connectivity: electrical location of the generator Real power: amount of real power the generator injects into the network Reactive-power range: maximum reactive power the generator can produce and absorb Control voltage: target voltage and which bus voltage to control Fuel cost and heat rate as a function of output
Loads	Connectivity: electrical location of the load Real power: amount of real power the load consumes Reactive power: amount of reactive power the load consumes Load characteristic: is this load constant power (same MW and MVAR as voltage changes) or constant impedance (MW and MVAR vary with voltage)?
Swing bus	The generator whose real-power output will be adjusted to balance load plus losses with generation

between and among other electric systems.” The utility can reference NERC and regional requirements. Additional utility-specific requirements, such as voltage limits on its bulk and lower-voltage system, must be provided along with a description of procedures used when evaluating transmission adequacy. The utility must also provide its assessment of the transmission system’s future performance. This assessment must include “a clear understanding of existing and likely future transmission constraints, their sources, how it identified these constraints, and a description of any plans to mitigate the constraints,” including any stability limits that have been identified (FERC 2000).

LOAD-FLOW MODELS

Load-flow models, the most widely used tools in transmission planning, calculate (1) the steady-state flows through lines and transformers and (2) the bus voltages throughout the power system under specific conditions. The system planner starts with a model of the system for the time to be studied (e.g., the summer 2006 peak demand). The base case includes conditions as they are expected to exist at that time, including existing transmission lines and transformers, any new equipment, less any equipment that is being retired (Table 2). Generation and load are set at their expected levels at each bus. The model is run to determine the flows in each line and transformer and the voltages at each bus. These values are examined to assure that no bus voltage is outside its normal operating range (often 95 to 105 percent) and that no line flow is above its normal limit (often 95 percent of the nominal limit). The software permits easy manipulation of the input data to test different conditions and contingencies. Loads and/or generation can be adjusted up and down individually or in blocks.

An optimal power flow (OPF) model can adjust the generator levels automatically to find the least-cost or least-price generation dispatch, including losses, while respecting transmission limits, for the specific load and transmission conditions being modeled. OPF models can also calculate transformer-tap and capacitor-bank settings to minimize operating costs. OPF models require additional information on the operating costs or bid prices of each generator. Thus, while load-flow models *simulate* the performance of the transmission grid under specified conditions, the OPF models *optimize* system performance by minimizing power-production costs subject to transmission constraints.

The planner then uses the load-flow model to examine various contingency conditions. The model calculates flows and voltages when, one at a time, each line, transformer, generator, or other element is taken out of service. The planner then uses the model to analyze all credible double (or higher) contingencies; the line flows and bus voltages are examined to assure that all facilities are within their emergency ratings.[8]

At this point, the system planner has modeling results that show line flows and voltages under base-case and contingency conditions. The model helps the planner by identifying voltages and flows that are outside the acceptable range. Examining all of the results is a significant job in itself. Results are often presented graphically, as a map or one-line diagram, with flows and voltages presented for each line and bus.

The planner next determines what options are available to correct the problems that were identified with the model runs. These problems can occur in the base case itself or with specific contingencies. Some solutions involve new operating practices for specific loading conditions. Others involve capital expenditures for new transmission facilities.

Switching on or off existing equipment, such as capacitor banks or inductors, to raise or lower voltage under specific loading conditions involves little or no cost. Installing new capacitors or inductors to control voltage requires a capital investment but is usually routine. Restricting or requiring specific generator operations

[8] Emergency ratings are typically higher than normal ratings. Most transmission equipment is thermally limited. High temperatures damage transformer and cable insulation and make overhead lines sag. Higher flows, and higher temperatures, can be tolerated for a short time with acceptable degradation in equipment life in emergencies. Transmission equipment is rated for continuous (normal) operation and also for emergency operation (four hours, for example). Voltage tolerances are loosened for emergencies as well. Typically, postcontingency voltages are not allowed to drop more than 5 percent from their precontingency levels or below 95 percent of normal.

under specific operating conditions (e.g., “no more than two units at station A may operate when flows on line C are above 500 MVA” or “three units at station D must be operating whenever line G is out of service for maintenance”) restricts commerce and raises operating costs but does not require capital investments. Upgrading equipment (lines or transformers) to increase MVA flow limits is an option. Special protection schemes, which take unusual actions under specific contingency conditions (e.g., “whenever flows on transformer E are above 1000 MVA, arm a special protection scheme that will automatically trip generator A if there is a fault on line B”), are an option. Finally, adding new transmission lines or substations is an option, although the expense and difficulty in gaining public acceptance for new lines reduce their practicality.

Because transmission investments generally have long lives, it is necessary to look at numerous cases covering many years. Because the future is uncertain, a range of conditions must be modeled as well—high and low hydro, shifts in relative fuel prices, and shifts in the pattern and rate of load growth—to test the robustness of the plan. These variables compound, resulting in many cases to run.

DYNAMIC MODELS

While load-flow modeling examines the power system under steady-state conditions, dynamic modeling examines how the system responds to various disturbances that tend to destabilize it. These models analyze system behavior over time intervals ranging from cycles to seconds. They analyze both real-power and voltage stability. All the information required for load-flow modeling is required for stability modeling. Additional information concerning the dynamic response of the generators and other equipment is also required, including generator inertia, transient and subtransient impedances, governor-control characteristics, automatic-voltage-regulator characteristics, and protective-relaying response times.

Analyzing the power system’s dynamic stability is more complex than modeling steady-state performance. Different modeling tools are used to analyze various very fast phenomena, such as switching surges, lightning flashovers, and power-electronics switching. These models identify potential problems associated with voltage spikes, insulation failure, and equipment damage. Transient stability analysis examines the power system’s response to severe and sudden changes in system conditions, such as faults, generator tripping, or switching operations. Here, the models identify potential problems with real-power and voltage swings and with generators losing synchronism with the power system. Steady-state stability analysis is similar to transient stability analysis but deals with the system’s ability to withstand small disturbances without losing synchronism. Voltage stability analysis tests the system’s vulnerability to voltage collapse.

Although different tools are used to examine system dynamic performance, the results are typically converted into line-loading limits and generator-operating restrictions. By imposing these restrictions on the system before a contingency occurs, the system will remain stable during and after the contingency. Longer transmission lines weaken the coupling between generators and make it easier for generators to pull out of step (lose synchronism). Figure 7 on page 18 illustrates the importance of different limits at different line lengths.

Fast-acting devices, such as dynamic stabilizers on generators and FACTS (flexible AC transmission system) devices, including static var compensators and superconducting magnetic energy storage, can improve system stability and increase the transmission system’s capacity. Dynamic models are used to identify the need for such devices and to quantify how much improvement each device can offer, to determine where to locate the devices, and to specify what control action the devices should take.

SHORT-CIRCUIT MODELS

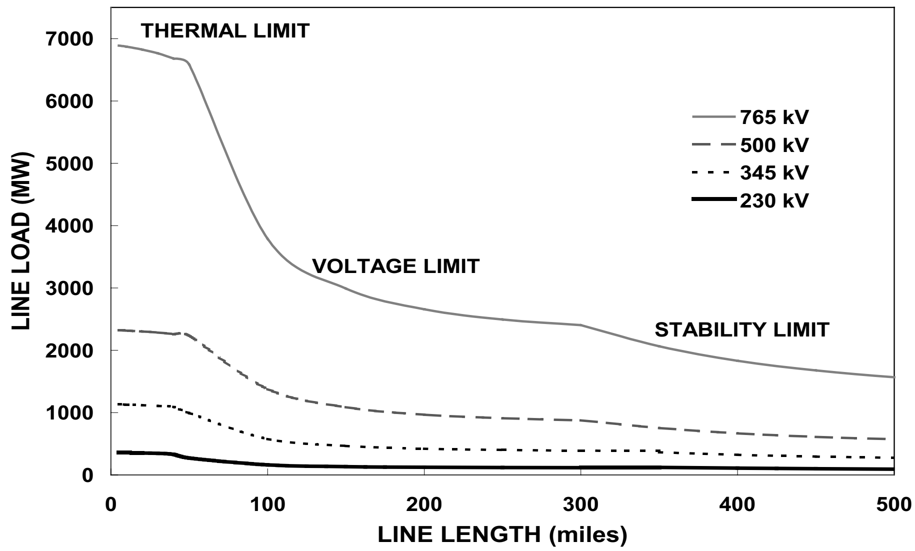

Fig. 7. Approximate limits for AC transmission lines as a function of line length.

Short-circuit modeling is used to help design the system-protection equipment and to assure that circuit breakers are capable of withstanding and interrupting the largest possible fault (short-circuit) current. Short-circuit analysis determines how much fault current might flow at each node in the grid if a short circuit occurs. This information is important because excessive fault current can damage equipment and pose a safety hazard to workers.

Short-circuit studies are done for three reasons: (1) to make sure any change to the system (e.g., adding a generator, reconfiguring lines, or changing a transformer) does not raise fault currents above the interrupting capability of the existing circuit breakers; (2) to tell the designers of new substation equipment what size breakers are needed at that location; and (3) to provide information for setting protective relays. These studies are critically important and regularly identify circuit breakers and other equipment that must be upgraded or replaced. Short-circuit concerns do not generally constrain transmission use, however, because the problems can usually be resolved at modest cost.

Much less data is needed for short-circuit modeling than for load flow or stability analysis because the geographic scope of short-circuit modeling is very limited. Most loads do not contribute to fault currents, so they need not be modeled. Also, only a few conditions (generally the worst conditions) must be modeled, further simplifying the task. Additional data, however, are required on the equipment being modeled, such as generator transient and subtransient impedances, as well as data for the transmission line and transformer.

Circuit breakers are located throughout the transmission system, on every line and bus. They are designed to rapidly (usually within a few cycles) interrupt the flow of power under certain conditions. They must be able to withstand and interrupt the available fault current. If the fault current exceeds a breaker's ratings, the breaker is said to be *overstressed*. If a breaker attempts to clear a fault with higher current than the breaker's rating, the current will continue flowing as the breaker contacts open, and an arc will form inside the breaker. In addition to failing to interrupt the fault current, the arc dissipates a great deal of energy within the circuit-breaker enclosure. If backup circuit breakers do not respond quickly enough, the breaker will likely explode.

Chapter 4: KEY PLANNING ISSUES AND COMPLEXITIES

Application of the planning models described in Chapter 3 sounds straightforward: collect lots of data and projections, run the models many times to test alternatives, and then recommend the most cost-effective projects that solve the problems analyzed. Unfortunately, many factors complicate such analyses and the interpretation of model results. This chapter discuses several such issues, including reliability vs commerce as planning goals, the role of congestion costs in assessing alternatives, generation and load-management alternatives to new transmission projects, economies of scale in transmission, criteria that might be used to assess transmission planning processes and the associated plans, the potential role of new transmission technologies, the importance of lack of control in transmission networks, and the lack of reliable data on new generation projects.

RELIABILITY VS COMMERCE

Traditionally, vertically integrated utilities planned their transmission systems with two goals in mind: (1) meet NERC and regional-reliability-council reliability requirements and (2) ensure that the outputs from the utility's generation could be transported to the utility's customers. (Utilities sometimes built transmission lines for economic reasons; for example, to provide access to cheaper power in a neighboring system.) Today, transmission systems are called on to do much more. They must serve dynamic and rapidly expanding markets in which the flows of power into, out of, and through a particular region vary substantially over time. As a consequence, it is not clear whether transmission planners should focus exclusively on the *NERC Planning Standards* in assessing alternative transmission projects or whether they should also consider enabling competition to occur over large geographic regions. In particular, this latter approach seeks to minimize the number of times transmission-service requests are denied and the number of times TLR is invoked. Where congestion (locational) pricing is used, this goal is met by reducing congestion costs (discussed later in this chapter). Some people believe that congestion pricing eliminates the distinction between reliability and commerce by explicitly pricing reliability.

Many of the industry experts we spoke with felt that the distinction between reliability and commerce in transmission planning is increasingly irrelevant. Reliability problems (e.g., a line that would become overloaded during a contingency) are also commercial problems that affect different market participants differently (e.g., flows are reduced on the line in question, which means that the output from cheap generators must be reduced and the output from expensive generators must be increased). Conversely, certain commercially desirable flows may be restricted because of reliability problems that would otherwise occur. Equally important, these people believe that transmission serves a vital enabling function, permitting the purchase and sale of energy and capacity across large regions and, in the process, reducing problems associated with generator market power.

A few people felt that the distinction between reliability and commerce is important. Not all reliability problems have commercial implications, they noted. Some local problems (e.g., low voltages close to load centers) are related more to reliability than to commerce. The solution to such reliability problems might be the addition of transformers to serve local loads regardless of whether the generation source is near or far. The distinction may be important in determining who pays for the project, with reliability projects paid for by all grid users but commercial projects paid for only by those transmission customers who benefit from the project. Of course, deciding who does and does not benefit from a project can be difficult and contentious.

CONGESTION COSTS

Traditional, vertically integrated utilities integrated their transmission and generation planning and operations. This coordination recognized any generation redispatch costs associated with the prevention of congestion during real-time operations.

In competitive electricity markets, with generation separated from transmission and system control, congestion pricing can offer valuable information on the potential benefits of new transmission investment. As Hogan (1998) said, "In the long-run, investment in the grid is undertaken when customers find it economic to reduce these congestion costs and the cost of losses. In this sense, evolution of the grid would be determined by the market. … [S]ecurity in the long-run is priced and provided through the market for long-run investments to increase generation and transmission adequacy."

FERC (1999), in its Order 2000, emphasized that the RTO transmission-planning process should "rely upon market signals and market solutions in assessing all feasible options (e.g., construction of new generation, redispatch of existing generation, as well as expansion of the transmission grid) to assure that the least costly option is pursued."

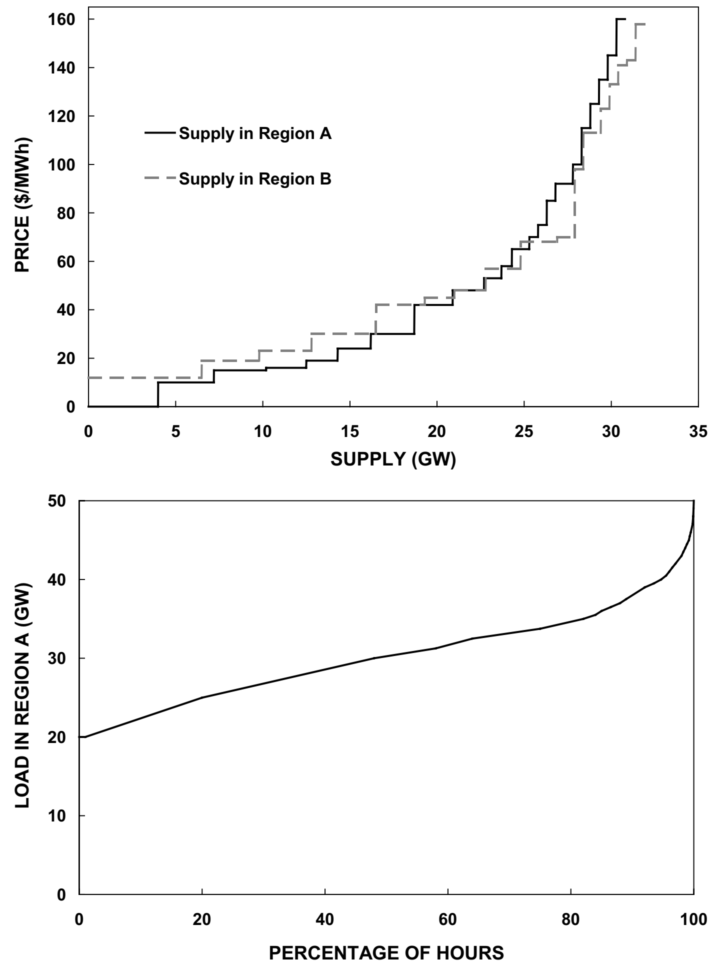

Fig. 8. Supply curves for regions A and B (top) and load-duration curve for Region B (bottom) in hypothetical example.

Decisions on whether to build new transmission are complicated by uncertainties over the future costs of congestion.[9] These uncertainties relate to load growth, the price responsiveness of load, fuel costs and therefore electricity prices, additions and retirements of generating capacity, and the locations of those generators.

We developed a simple hypothetical example to explore these issues and their complexities and interactions. This example involves two regions, A and B, separated by 200 miles. Region A contains 31 GW of generating capacity and no load. Region B contains 32 GW of generating capacity and 50 GW of load. Both regions contain a wide range of generating capacity, with running costs (or bids) that vary from zero to almost $160/

[9] Although transmission investment is about 10 percent of generation investment and transmission operating costs are far less than generation operating costs, it would be far too expensive to build a transmission system that was never congested.

MWh (top of Fig. 8, page 20). The load in Region B ranges from 20 to 50 GW, with a load factor of 63 percent (bottom of Fig. 8). Loads exceed 45 GW only 1 percent of the time.

We calculated the cost of congestion as the difference between (1) the cost of generation (including generators in both regions) to serve the load in Region B when transmission capacity between the two regions is limited and (2) the cost of generation when capacity between the two regions is infinite. The generation costs in both cases are calculated for every hour of the year using the load-duration curve shown in Fig. 8.

Figure 9 shows the cost of congestion as a function of the amount of transmission capacity connecting the two regions. With 21 GW of transmission capacity (the baseline in this example), electricity consumers in Region B pay $87 million a year because of congestion. As the amount of transmission capacity increases, the cost of congestion declines because the number of hours that congestion occurs and the price differences between A and B decline. However, as shown in Fig. 9, this decline is highly nonlinear, with each increment of transmission capacity providing less and less economic benefit. Expanding transmission capacity from 20 to 21 GW lowers the cost of congestion $99 million/year, expanding capacity from 21 to 22 GW saves $44 million, and expanding capacity from 22 to 23 GW cuts costs by only $29 million.

How much would it cost to build additional transmission lines between regions A and B to reduce the costs of congestion? As discussed above, the cost of new transmission lines, including the necessary substations, increases with increasing voltage (Table 1). However, the cost per GW-mile of new capacity declines, demonstrating substantial economies of scale.

Although it is cheaper to build larger lines, the lumpiness of transmission investments (e.g., one can build a 345-kV line or a 500-kV line but not a 410-kV line) complicates decisions on whether and by how much to expand capacity. As a consequence, the relationship between the benefits of adding transmission capacity (reduction in congestion costs) and the costs of doing so are highly nonlinear (Fig. 10, page 22). (We assume a fixed-charges rate of 15 percent to convert initial costs to annual costs.) For this example, if the goal is to increase capacity by 0.5 GW, it makes sense to build either two 230-kV lines or one 345-KV line, but not a 500-kV line. On the other hand, it is most cost effective to use 500-kV lines when expanding capacity by 1 GW or more. Indeed, the benefit/cost ratio for 230-kV lines increases in going from an addition of 0.5 to 1.0 GW, but then declines as more capacity is added. On the other hand, the benefit/cost ratio is more than two for the addition of a 500-kV line to expand capacity by 1.5 or 2.0 GW.

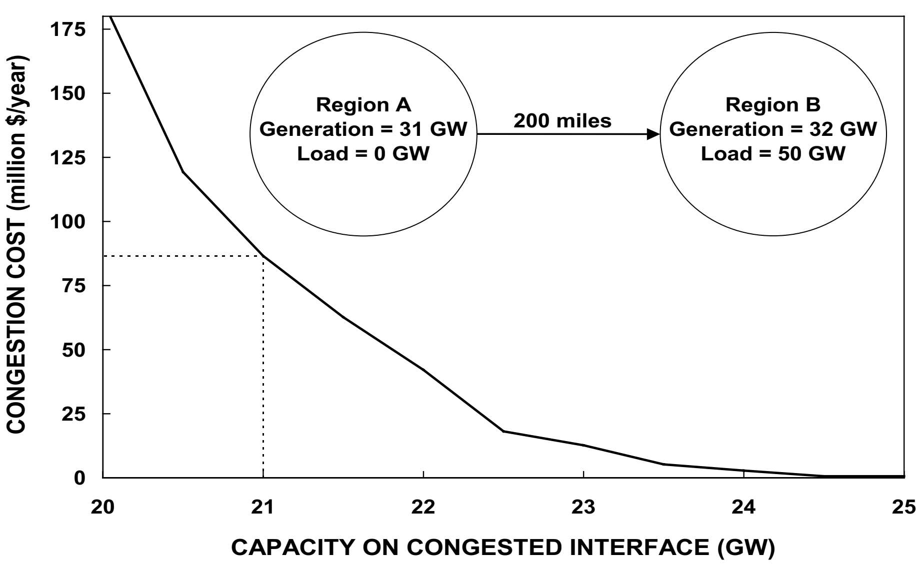

Fig. 9. The annual cost of congestion as a function of transmission capacity between hypothetical regions A and B.

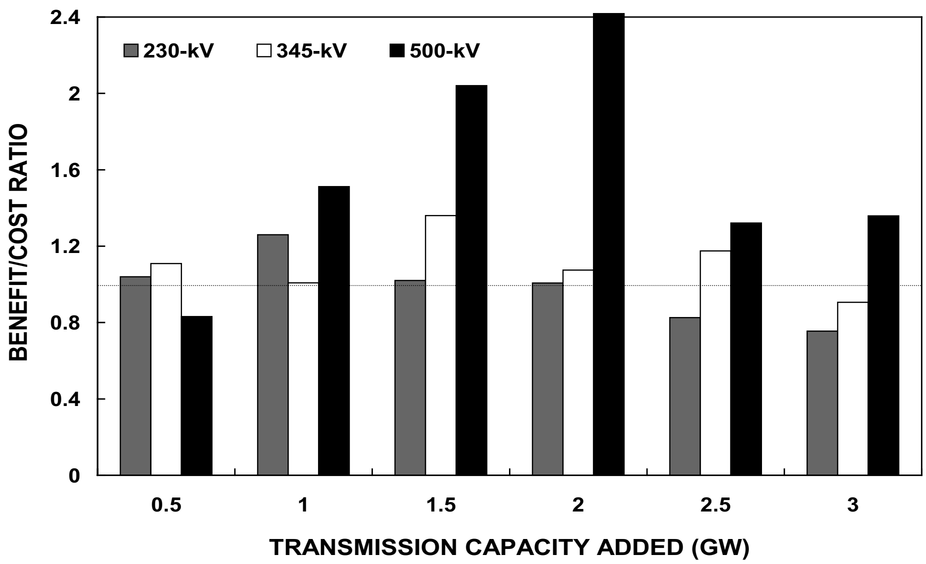

Fig. 10. Ratio of benefits (reduction in congestion costs) to costs to build new transmission lines for three sizes of lines.

What happens to these costs and benefits if additional generating capacity is built in Region B, close to the load center? Adding 0.5 GW of capacity with a running cost of $30/MWh reduces congestion costs by $19 million/year. Adding 2 GW of such capacity reduces congestion costs by $59 million/year. If the new generating capacity added to Region B had a running cost of $57/MWh, its congestion-reduction benefits would be only $14 and $35 million/year for 0.5- and 2-GW additions, respectively. These benefits are about two-thirds of those that would occur with new capacity at $30/MWh. Clearly, building new generation in Region B would undermine the economics of adding transmission capacity between regions A and B.

In addition, the congestion-reduction benefits of each additional MW of generating capacity are less than the benefits of earlier additions (Fig. 11). This effect is especially pronounced as the bid prices of the new units increase. For the more expensive of the two units shown in Fig. 11, there is no benefit from adding more than 1.5 GW of generating capacity in Region B because other generators are less expensive. Once again, the results are highly nonlinear.

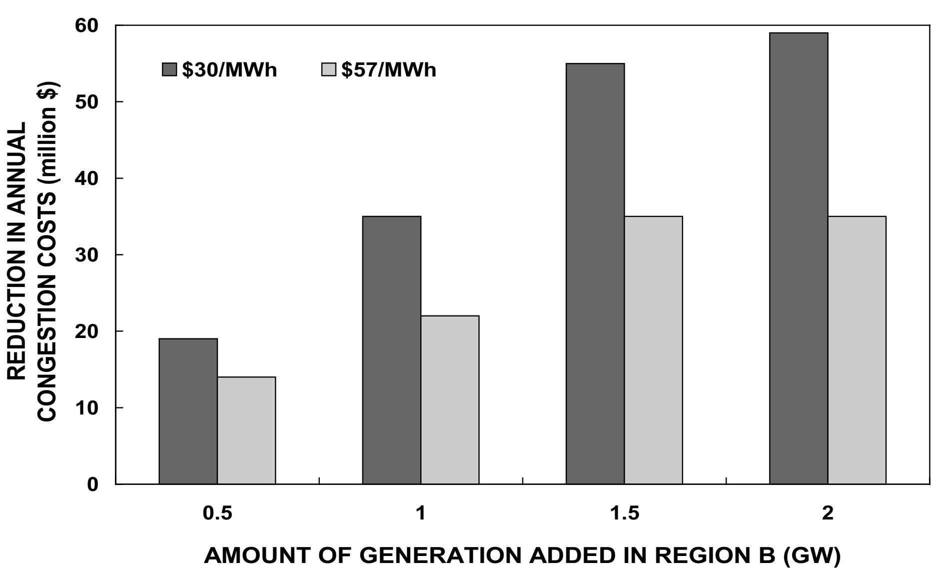

Fig. 11. The effects of additional generation in Region B on annual congestion costs as a function of the running cost (bid price) of the new generation.

What if loads grow in region B? If loads grow at 2 percent a year, the annual cost of congestion (assuming no additions to either generating or transmission capacity) increases from $87 million in the initial year to $125, $162, and $250 million in the second, third, and fourth years. Such increases in load make transmission investments substantially more cost-effective.

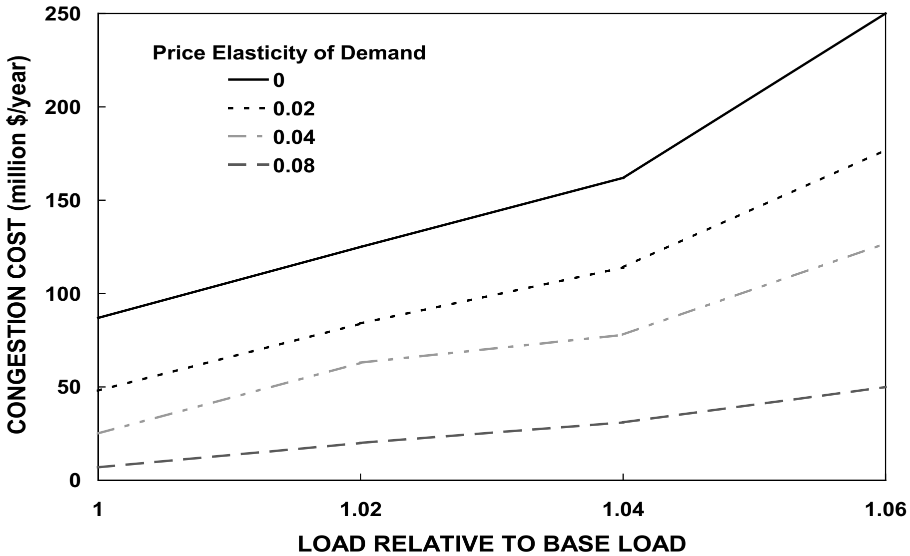

Fig. 12. Annual congestion costs as a function of amount of load and price elasticity of demand.

If loads respond to prices, such that loads are higher at low prices and lower at high prices, congestion costs would be reduced. In this example, as the price elasticity of demand increases from 0 to 0.02, 0.04, and 0.08, congestion costs are reduced from $87 million to $48, $25, and $7 million a year. Figure 12 summarizes the effects of changes in load and load shape (induced by customer responses to price changes) on annual congestion costs. For the ranges considered here, congestion costs vary from $7 to $250 million a year when the amount of transmission capacity between the two regions is 21 GW. Making decisions on how much money to invest in equipment with lifetimes of several decades is difficult in the face of such uncertainties about future load growth; customer response to dynamic pricing; and the amounts, locations, and running costs of new generating units.

Consider the situation in which 500 MW of $30/MWh generation has been added in Region B and consumers respond to price changes with an elasticity of 0.01. In this case, the annual cost of congestion when transmission capacity between A and B is 21 GW is $41 million, less than half the base-case value. The benefit/cost ratios shown in Fig. 10 are all cut by more than 50 percent. The only cost-effective project under these conditions is the construction of a single 500-kV line to provide an additional 2 GW of transmission capacity. Thus, changes in generation and load can affect the value of transmission, increasing risks to transmission owners.

The discussion so far has focused on the benefits of reducing congestion. But not all market participants benefit when additional transmission is built to relieve congestion. In particular, loads on the low-cost side of the constraint and generators on the high-cost side of the constraint lose money when congestion is reduced. For example, a generator in Region B with a bid price of $42/MWh would earn $6.9/kW-year when the transmission capacity between regions A and B is 20 GW. Expanding transmission capacity to 21 or 22 GW would reduce that generator's earnings to $4.6 and $3.7/kW-year, reductions of 33 percent and 46 percent, respectively. Such large prospective losses would likely engender substantial opposition to efforts to reduce congestion. (If Region A had loads that enjoyed the benefits of Region A's low-cost generation, those loads would also oppose efforts to reduce congestion.)

Finally, investors considering additional generation in Region B may worry that future construction of a new transmission line between A and B would undercut the value of their new generation.

GENERATION AND LOAD ALTERNATIVES

The U.S. Department of Energy Task Force on Electric System Reliability (1998) recommended that RTOs "ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns and that the marketplace and the [RTO's] standards and processes enable rational choices between these alternatives."

Transmission planners can encourage nontransmission alternatives in two ways. The simplest method is to provide transmission customers with information on current and likely future congestion costs. Such information on the costs and benefits of locating loads and generation in different places could motivate developers of new generation to pick locations where energy costs are high, thereby reducing congestion costs. Similarly, such information could motivate load-serving entities to offer load-reduction programs to their customers in those areas where energy prices are high because of congestion. For example, the National Grid USA (2000) transmission plan included a map of New England showing areas where new generation would worsen congestion (Maine, northern New Hampshire and Vermont, Rhode Island, and southeastern Massachusetts) and areas where new generation would reduce congestion (Boston and southwestern Connecticut); see Fig. 14 in Chapter 5.

An alternative approach to the provision of information only is to *pay* for nontransmission alternatives. With this approach, the transmission owner or RTO would first prepare a transmission plan. This plan would likely include one or more major transmission projects (new lines and/or substations). Next, the transmission owner or RTO would issue a request for proposals for alternatives and then review the proposals to see if they were less expensive than the original transmission project and provided the same or better reliability and commercial benefits that the transmission project would.

Appropriately comparing transmission to load or generation, however, is difficult because they differ in lifetimes, availability, capital and operating costs, market type, and technical applicability:

- Lifetimes: Transmission investments are long-lived (30 to 50 years). Generators typically have shorter lifetimes, and load-management projects may have much shorter lifetimes (e.g., if a building is extensively remodeled, the load-management systems may be removed and replaced with alternative systems for lighting, heating, cooling, and ventilation). The longer lifetimes of transmission projects enhance confidence in their ability to provide the needed service for many years; however they may reduce flexibility to respond to changed circumstances in the future.

- Availability: Transmission equipment typically has very high availability factors, much higher than those for either generation or load.

- Capital and operating costs: Although the capital costs of transmission can be high, transmission operating costs are very low. The operating costs for generators are high and depend strongly on uncertain future fuel prices. The tradeoff here is between high sunk costs (once the transmission project is completed) against uncertain operating costs for generation and load management.

- Type of market: The returns on transmission investments are regulated, today primarily at the state level and in the future primarily by FERC. The profitability of generation investments, on the other hand, is determined largely by competitive markets. Comparing costs (e.g., economic lifetimes and rates of return) between regulated and competitive markets is difficult.

- Technical applicability: Distributed resources cannot always solve the problems at which the transmission investment is aimed (e.g., high voltages, transient stability, or the need to replace aging or obsolete transmission equipment). Also, connection of the distributed resource to the grid may impose new costs on the system (e.g., if system-protection schemes must be upgraded).

These differences between transmission investments and distributed-resource investments might call for a risk factor to be applied to the distributed-resource alternatives (Niagara Mohawk 1999). This risk factor would reflect the generally higher value of transmission projects.

The difference in lifetimes between the transmission project and its alternatives raises the issue of whether the alternatives should be assessed against the cost of *deferring* the transmission project for several years or against the full cost of *displacing* (eliminating the need for) the transmission project. If the transmission project will likely be needed in any case, although at a later date, the deferral approach makes sense.

Having a centralized entity (the RTO, in this case) pay for generation or load reductions introduces a regulated monopoly entity into what is intended to be competitive markets. California has had considerable experience, and many problems, with its reliability-must-run contracts (Wolak 1999). These contracts give the ISO the right to call on certain generators to provide local reliability service, such as voltage support. These contracts initially created many problems for the competitive energy and ancillary-services markets in California.[10] On the other hand, when such nontransmission alternatives are cheaper than the transmission project, their selection lowers costs to electricity consumers. In particular, a multiyear contract may permit a generator or load to make capital investments that it could not afford to make if it was responding only to time-varying and uncertain real-time congestion costs.

Although the concept of encouraging competition between transmission investments and generation and load alternatives is appealing, implementation can be difficult. During the course of this project, we uncovered only one instance in which transmission planners explicitly considered distributed-resource alternatives to new transmission, the California ISO Tri-Valley Project.

The Tri-Valley project, proposed by Pacific Gas & Electric in northern California, involves the construction of new 230-kV transmission lines, construction of new 230/21-kV substations, and upgrading of several substations to 230-kV service. The California ISO issued a request for "cost effective and reliable alternatives … from generation and/or load alternatives to the proposed PG&E transmission project" (Winter and Fluckiger 2000). Alternatives were required to be available between the hours of 8 am and 1 am for up to 500 hours between April 1 and October 31 each year from 2001 through 2005. The ISO sought call options on about 175 MW. The request was issued in January 2000 with responses due in late March. The ISO received four proposals, all of which it subsequently rejected.

The ISO rejected all four bids because they failed one or more of the evaluation criteria (Exhibit 3, page 26), which involved commencement date, operating characteristics, ability to provide the proposed services, adequacy of the performance security offered by the proposer, safety, impacts on markets, and environmental implications. The key reason the bids were rejected is that they were substantially more expensive than the

[10] These contracts between the California ISO and the owners of specific generating units may provide a poor comparison with the kinds of nontransmission alternatives considered here. The reliability-must-run contracts were part of California's transition from a monopoly industry to a deintegrated, competitive industry. They were signed at a time when transmission alternatives to the continued use of these specific generators simply did not exist.

transmission project. Also, the transmission project was expected to provide more capacity to the system than the generation and load-management projects.

A year later, when faced with a similar situation, the ISO decided against issuing a competitive solicitation. In this case, the ISO approved construction of the San Diego Gas & Electric Valley-Rainbow transmission project (Detmers, Perez, and Greenleaf 2001). In part because of the electricity crisis California currently faces, the ISO decided that this project should be considered part of a "broad strategy by the state of California to put into place a robust transmission system to support reliable service to consumers." The benefits of this 500-kV transmission project would not be realized by generation or load-management alternatives. The proposed transmission line would permit generation from other parts of California, Arizona, and New Mexico to be moved to the San Diego area. The project would also permit new generators to be located near San Diego to reach distant markets. Finally, the project would provide local reliability benefits that otherwise would have to be purchased through reliability-must-run contracts. These reliability benefits would occur because the transmission project "integrates San Diego with the rest of the Western Interconnection, providing significant access to a wide variety of resources rather than being limited to the local area resources and the common concerns that they share, such as adequacy of gas supply."

Exhibit 3. California ISO Evaluation Criteria for Nontransmission Alternatives

Ability of the project to satisfy the grid planning criteria (technical characteristics and contractual terms)

Value of the project to the transmission system for
- Reliability benefits
- Cost-effectiveness relative to the transmission project
- Provision of access to regional energy markets
- Reduction in congestion costs
- Assurance of adequate system capability
- Effects on generator market power (ability to mitigate existing market power and to exercise market power)

Niagara Mohawk (1999) also assessed distributed generation as an alternative to transmission and distribution projects. Its review concluded that "distributed generation does not appear to be an economic alternative for most T&D applications."

The limited analysis conducted to date seems to argue against widespread use of suitably located generation and load management as alternatives to some new transmission projects. However, these analyses were conducted primarily by transmission engineers who are more comfortable with transmission and understand transmission better than they do its alternatives. Also, the continued opposition to construction of new transmission facilities requires the electricity industry to look long and hard at possibly viable alternatives.

ECONOMIES OF SCALE

It is generally cheaper per megawatt of capacity to build larger transmission lines. As discussed earlier (Table 1), the cost per MW-mile of a 500-kV transmission line is about half that of a 230-kV line. Higher-voltage lines also require less land per MW-mile than do lower-voltage lines (Fig. 13).

Both of these factors argue for overbuilding lines rather than trying to size lines to exactly match current and short-term forecast needs. Overbuilding a line now will reduce long-term costs by avoiding the much higher costs of building two smaller lines and will reduce the delays and opposition associated with transmission-line siting by eliminating these costs for the now unneeded second line.

On the other hand, the lumpiness of transmission investments can complicate decisions on what to build and the comparisons with nontransmission alternatives. Also, a large transmission line may impose more of a reliability burden on the system than do several smaller lines. Indeed, if a new, large line becomes the largest single contingency, contingency-reserve requirements might increase in the region.

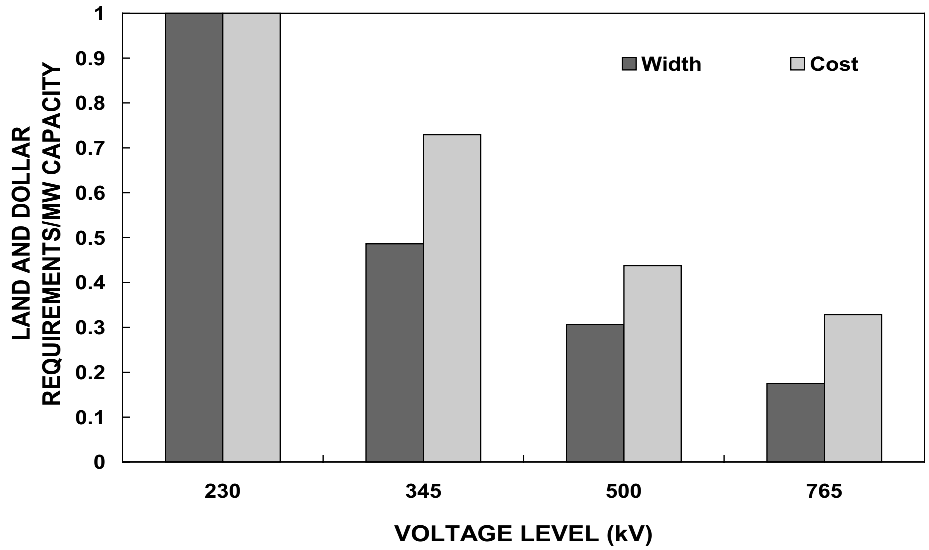

Fig. 13. The per-megawatt capital costs and land requirements for transmission lines relative to those for a 230-kV line.

ASSESSMENT CRITERIA

The electricity industry and its regulators would benefit from objective assessment criteria that can be applied to the transmission-planning process and to the resultant plans. Transmission plans should be low in cost, robust, and feasible to implement. To achieve these three objectives, the plan must consider a wide range of transmission and nontransmission alternatives relative to a variety of future load and generation scenarios. The assessment must consider compliance with reliability standards as well as commercial uses of the grid (including flows into, out of, and through the grid and their effects on congestion costs). Because of these many disparate factors, it is unlikely that the preferred plan will be *the* lowest-cost solution. Instead, planners (and, more important, society) should choose plans that are robust across a range of future scenarios, which means they may be least cost for none of the scenarios.

The transmission-planning process should be inclusive; be efficient in its use of time, money, and human resources; and recognize and appropriately balance the technical requirements of electric-power systems and public interests. Obviously, these three goals may conflict with each other. One way to reconcile these conflicts is to separate the development of plan-approval criteria from the specifics of any particular plan.

Generic criteria might include the following:

- Design a process that is both open *and* rapid.

- Expand the geographic scope of transmission planning and regulation; physical interactions are regional, and therefore so should the regulatory framework.

- Strive for robust, rather than optimal, transmission solutions.

- Recognize that regulated and competitive assets often perform the same function; select the lower-cost alternative.

- Encourage generators and/or loads to invest in transmission projects that improve their energy-market opportunities (i.e., to relieve congestion that blocks them from markets).

- Encourage use of technologies that provide flow control, such as DC lines and FACTS devices (discussed in the next section). Lines with flow control can, in principle, be competitive rather than regulated resources. Encourage regulatory structures that promote such private investments.

It may be possible to separate the multiple issues that must be dealt with when evaluating any transmission-enhancement proposal. Contentious issues that take a long time to resolve could be addressed in a generic way. Clear rules for transmission-line siting could be established with ample public input. RTOs and regulators should actively involve local communities to help them understand the general needs and what planners foresee as potential projects to provide a context for developing siting rules. This process would also establish the rules for what criteria make a specific project viable. The process would establish tradeoffs between electricity prices and transmission projects, along with preferences on aesthetics, line design, and other factors.

Although it may be difficult to find such an entity, the public process should be run by an organization with no commercial interests in the outcome of that process. ISOs may be perceived as having an interest in building more transmission to ease reliability problems. State regulators are an obvious choice, but the process sponsor needs considerable technical competence to present viable options and correctly articulate the alternatives.

Once established, the rules should be easy to apply in a way that avoids lengthy litigation. There will still be lots of contention when individual projects are selected, but the hope is that the process will focus on judging whether the proposed project meets the established guidelines, rather than judging each project against an open-ended set of possible objections. For example, the process could preapprove transmission routes that could be developed quickly at some future time if they are needed.

NEW TECHNOLOGIES

Superconductivity,[11] power electronics, and other new technologies could revolutionize transmission and make it easier to expand the system through merchant, rather than regulated, projects. “Recent advances in materials science offer the prospect of another industry paradigm: one based on robust facilities-based competition in network services, without the environmental and land-use impacts of traditional ‘big iron’ solutions” (Howe 2001). Some of these advances include:

- Superconducting Magnetic Energy Storage (SMES): high-speed magnetic-energy-storage devices that are strategically located in a transmission grid to damp out disturbances. These systems include a cryogenically cooled storage magnet, advanced line-monitoring equipment to detect voltage deviations, and inverters that can rapidly (within a second) inject the appropriate combination of real and reactive power to counteract voltage problems. By correcting for potential stability problems, these systems permit the operation of transmission lines at capacities much closer to their thermal limits than would otherwise be possible. Such systems are now operational in Wisconsin and Texas.

[11] Superconductivity, the lack of resistance to the flow of electricity, essentially eliminates power losses and permits more compact designs.

- High-Temperature Superconducting (HTS) cable: can carry five times as much power as copper wires with the same dimensions. Although initially applicable to underground distribution systems in dense urban areas, eventually this technology may be used for medium- and high-voltage underground transmission lines. The use of these cables would greatly reduce the land required for transmission lines and lessen aesthetic impacts and public opposition.

- Flexible AC Transmission System (FACTS) devices: a variety of power-electronic devices used to improve control and stability of the transmission grid. These systems respond quickly and precisely. They can control the flow of real and reactive power directly or they can inject or absorb real and reactive power into the grid. These characteristics provide both steady-state and dynamic benefits. Direct power-flow control makes the devices useful for eliminating loop flows. The very fast response makes the devices useful for improving system stability. Both characteristics permit the system to be operated closer to its thermal limits. FACTS devices include static var compensators, which provide a dynamic source of reactive power; thyristor-controlled series capacitors, which provide variable transmission-line compensation (effectively "shortening" the line length and reducing stability problems); synchronous static compensators, which provide a dynamic source of reactive power; and universal power-flow controllers, which control both real- and reactive-power flows.

- High-Voltage DC (HVDC) systems: HVDC lines have several advantages over AC transmission lines, including no limits on line length (see Fig. 7), which is useful for moving large amounts of power over long distances; reduced right-of-way because of their more compact design; precise control of power flows, eliminating loop flows; and fast control of real- and reactive-power to enhance system stability. The primary drawback of HVDC is the high cost of the converter stations (which convert power from AC to DC or vice versa) at each end of the line.

- HVDC Light: This new approach to HVDC uses integrated-gate bipolar transistor-based valves (instead of thyristor-based valves) in the converter stations. These new valves permit economical construction of lower-voltage lines, which greatly increases the range of applicability for DC lines; involves much more factory construction instead of onsite construction, which lowers capital costs; and provides better control of voltages and power flows. HVDC-light lines have recently been built in Australia and Denmark, and others have been proposed for the United States.

- Real-time ratings of transmission lines: represent another use of advanced information technologies to expand the capability of existing systems (Seppa 1999). Such systems measure the tension in transmission lines, ambient temperature and wind speed, or cable sag in real time; the results of these measurements are telemetered to the control center, which then adjusts the line rating according to actual temperatures and wind speeds.

In spite of their wonderful attributes and recent declines in their costs, these technologies are generally too expensive to warrant their widespread use today. (To date, they have been deployed in a few locations, primarily by utilities to improve the performance of their systems.) However, as the technologies are improved and demonstrated, their costs will likely continue to drop enough that they become cost effective. When that day arrives, transmission planning will be simpler, primarily because market participants (rather than regulators or system operators) will be able to decide whether to invest in these systems and will be able to retain their benefits (because some of these technologies use devices that permit direct control of power flows).

LACK OF CONTROL

The fundamental characteristic that makes transmission planning and investment so difficult is *lack of control of the grid*, the inability to control the flow through individual transmission elements (e.g., lines and transformers). Because flows cannot be controlled, transmission lines cannot compete with each other for business. An investor cannot risk capital, build a transmission line, and compete on price to attract customers. Each element (line, transformer, or breaker) is part of a network that is a common resource available to all and therefore must be regulated. Under today's regulatory frameworks, this situation means some form of open, inclusive, project-selection process is required. As the kinds of advanced technologies discussed in the preceding section mature, the ability to deploy fast-acting, intelligent controls will ameliorate this fundamental problem.

The entity deciding which lines to add cannot have a commercial interest in the generators, or it might use its control over the transmission system to limit the operation of competitors' generators. As a consequence, FERC (1996 and 1999) insists that system operators be independent of merchant functions and regulated, and that the entire transmission system be available to all users on a nondiscriminatory basis.

Several secondary characteristics result from the lack of control:

- Large Geographic Scope: Conditions on one part of an AC network affect flows throughout the network. Consequently, transfers between any two points on the network can be restricted by constraints elsewhere in the network. Similarly, upgrades to any part of the network affect transfer capabilities throughout the network.

- Diversity of Interests: Each transmission enhancement affects many market participants. Generators are affected because the enhancement will either expand their market opportunities (if they are low cost) or reduce their market opportunities (if they are high cost and have captive customers). Loads have similar, but opposite, interests.

- Transmission vs Generation: The split and differences between competitive generation and regulated transmission compound transmission-planning difficulties. The competitive business environment of generation pushes investors to faster planning, shorter deployment times, and less sharing of commercially sensitive information. The regulated business environment of transmission pushes it to slower planning and longer deployment times (to accommodate an inclusive public process) and the wide sharing of information. These differences are compounded by the shift in generation technologies. Gas-fired generating units can be built within a few years, whereas nuclear units required 10 to 20 years to build. Of course, one reason the new gas-fired technologies are selected is that they can be deployed quickly.

- Interchangeability of Generation and Transmission: Transmission congestion changes character if a local generator has market power. In the example discussed earlier in this chapter, generators in Region B could charge any amount for loads above the transfer limit between regions A and B. This situation could be relieved by expanding the transmission system. Alternatively, a new generator or a curtailable load located in Region B could relieve the problem. This substitution of suitably located generation or load for transmission can be especially applicable if the congestion lasts only a few hours per year.

Other factors complicate transmission planning:

- Long Life: Transmission is a long-lived (30 to 50 years), immobile investment with very low operating costs. The need for new transmission shows up in real-time congestion prices. It is difficult to accurately forecast the long-term need for a specific transmission investment for several decades. The generation alternatives are often shorter lived and always have higher operating costs that can be eliminated if the investment is not needed.

- Regulatory Decision Process: As with most regulated assets, the decision makers are deciding with other peoples' money. Because the regulator (and the regulated entity) are spending ratepayer dollars, public processes are used to try to arrive at the best decision. All opinions and options are welcome and considered, which can lead to a time-consuming process.

- Regulatory Uncertainty: Investors are unlikely to spend their money until it is clear that they will recoup their investment and earn a reasonable return on that investment.

- Environmental Impacts: Some people oppose new transmission lines (and, to a lesser extent, substations) on aesthetic grounds or because they might lower property values. Others are concerned about the health effects of electromagnetic fields.[12]

PROJECTIONS OF NEW GENERATION AND LOAD GROWTH

The deintegration of the traditional utility, which encompassed generation, transmission, distribution, and customer service in one entity, raises two important informational issues for transmission planning. First, from what sources will transmission planners obtain reliable information on the locations, types, capacities, and in-service dates of new generation? Second, what entity will be responsible for developing projections of future load growth?

Historically, utilities reported their plans for new generation to EIA and NERC. Increasingly, however, new generation is being constructed by independent power producers. Although EIA collects data from such entities, long lags can occur between the time a company announces a new power plant and the time it shows up in the EIA system (Terry 2001). The Electric Power Supply Association also collects data on power-plant construction plans. Because the Association does not provide details on the status of the project, it is hard to determine the probability that a project will get built and produce power. The probability of unit completion increases as the project moves from initial announcement to applications for siting and on to environmental permits, construction, and completion.[13]

Analogous issues concern projections of future load growth (Terry 2001). System operators (ISOs and, in the future, RTOs) monitor and record data on power flows down to the level of distribution substations. But,

[12] Although little scientific evidence supports this concern about transmission lines (National Institute of Environmental Health Sciences 1999), public perceptions and fears may lead to opposition to construction of new transmission lines.

[13] The status of any system impact study and facilities study (FERC 1996) associated with a proposed generator also provides information on the likelihood the generator will be constructed. A system impact study is an assessment by the transmission provider of the possible need for and costs of additional transmission facilities required to connect the new generator to the grid. A facilities study is a more detailed engineering analysis conducted by the transmission provider to determine any needed modification or additions to the transmission system to connect the new generator.

because of their focus on bulk-power flows and wholesale electricity markets, system operators are unlikely to have data on end-use demand by customer class. The competitive load-serving entities may have such information but are unlikely to want to make such information publicly available. The electricity industry needs to develop a system to collect relevant data on customer electricity-using equipment, load shapes, and load levels and to provide this information to transmission planners (as well as to other entities responsible for maintaining a healthy bulk-power system).

Chapter 5: PLANS AND PLANNING PROCESSES

TRANSMISSION PLANS

We reviewed recent transmission plans prepared by the California ISO (2001a), the ERCOT ISO (2000), ISO New England (2000), MAPP (2000), National Grid USA (2000), the New York ISO (2000), the Northwest Regional Transmission Association et al. (2000), and PJM (2001). These plans varied greatly in their objectives, topics covered, and value.

The ERCOT ISO (1999) planning responsibilities include reliability, integration of new generation "which, in the opinion of the ISO, are reasonably sited," "support [of] renewable energy projects," and provision of "adequate competitive generation to load areas." Thus, ERCOT's planning encompasses a broad range of reliability, commercial, and environmental goals.

The ERCOT ISO (2000) plan is comprehensive and thoughtful. The report discusses historical and projected generation and load by region within ERCOT, including a range of projections. These projections form the basis for an identification of existing and likely future transmission constraints within the Interconnection and of an assessment of the need for additional transmission. The ERCOT report includes a discussion of existing transmission capacity and expansion possibilities for each of the five ERCOT subregions.

Overall, the ERCOT plan identifies six major transmission constraints (generally thermal limits, but sometimes stability limits). The plan also identifies several projects intended to mitigate these constraints. These projects include several 345-kV lines (both new lines and additional circuits on existing towers), a STATCOM (to provide dynamic reactive-power support), and capacitors (to provide static reactive-power support). In addition, the transmission owners proposed several projects, which, upon review, the ERCOT ISO recommended for construction.

One indication of the success of the ERCOT transmission-planning process is the number of transmission projects recently completed or under construction. ERCOT has several transmission advantages over other regions, including regulation by a single entity, the Texas PUC, and a state government that supports additional transmission. Of the seven projects considered critical during the past few years, one was completed in 2000, five are on schedule to be completed by the end of 2002, and one is undergoing further evaluation (Texas Public Utility Commission 2001).

The National Grid USA (2000) report is less a detailed plan for New England and more an overview of likely transmission needs in the future. The report examined the period 2001 through 2005 in terms of demand projections, generation, the relationship of generation to demand, transmission-system topology (major zones and interfaces), transmission performance (system power flows), capability[14] (transfer limits and congestion costs), and transmission-system opportunities.

[14] *Transmission capacity*, according to NERC (1996), differs from *transfer capability*. Capacity refers to a specific limit (e.g., thermal or voltage) that characterizes a single component of the system (e.g., a transformer or line). Capability refers to the ability of a system to transfer power and depends strongly on the current configuration of generation, demand, and the transmission system. Thus capability is a dynamic term, while capacity is a static term.

The chapter on opportunities is especially interesting because it shows where within New England new generator interconnections "would alleviate or exacerbate congestion on the transmission system." As Fig. 14 shows, locating generators in Boston or southwest Connecticut would relieve congestion, whereas locating generators in Maine, northern Vermont or New Hampshire, Rhode Island, or southeastern Massachusetts would worsen congestion. Information like that shown in Fig. 14 should help guide market decisions on new generation and load-management programs, as well as possible merchant-transmission projects.[15]

Fig. 14. National Grid USA's assessment of the best and worst locations within New England to locate new generating units.

The goals of the MAPP (2000) plan are to ensure that the transmission system can "reliably serve the load indigenous to the MAPP region, … provide sufficient transfer capability to reliably accommodate firm transfers of power among areas within MAPP and between MAPP and adjacent reliability regions, and provide an indication of transmission costs for enhancing transfer capability and relative costs for alternative locations of new generation." The MAPP process is bottom up, with plans developed by individual transmission owners, then integrated for each of the five subregions, and then integrated again at the MAPP level. In addition, considerable analysis is done for the MAPP region as a whole, primarily to analyze projects that span more than one subregion. Also, the MAPP review ensures that projects proposed in one subregion will not adversely affect the electrical system in other subregions.

The MAPP plan uses information on transmission service requests that were refused along with data on transmission curtailments to help in the analysis of "desired market use of the regional and inter-regional transmission system." These data "provided strong evidence to indicate that transmission constraints to the east of MAPP significantly hampered electrical sales" (Mazur 1999).

The Western Interconnection report, less a single plan and more of a compilation of several utility plans, also examined data on the commercial uses of the transmission system (Northwest Regional Transmission Association et al. 2000). The report analyzed actual power flows relative to transfer capability "to identify those paths in the Western Interconnection which are heavily used or potentially congested … ." Although these data, like those reported by MAPP, provide useful qualitative information, they provide no quantification of the costs of congestion.

Some of the plans we reviewed are more limited in scope than the ones discussed above. Often, the plans do not fully integrate planning for reliability with planning for commerce (reduction in congestion). Because some of these entities have received so many generator-interconnection requests, their plans are dominated by the specific projects required to connect these new generators to the grid. Correspondingly, the plans do not anticipate possible problems that might occur in the future as a consequence of load growth; generator retirements; other new generators being built within the control area; or additional bulk-power transactions into, out of, or through the control area. In particular, these plans generally do not provide sufficient guidance

[15] FirstEnergy (1999) analyzed the effects on the transmission grid of adding one or more combustion turbines that would run at least 500 hours a year in various locations. The study identified 16 nodes where more generation would relieve transmission congestion, the amounts of generation that would be helpful (100 to 500 MW), and the transmission problem the new generation would solve (violation of thermal limit on lines or transformers or low voltages).

to market participants on desirable locations for new generation, load-reduction programs, or merchant transmission.

Transmission planning, as often practiced today, is more reactive than proactive. Transmission planners do not have enough time to develop plans that look out several years and offer guidance on where to locate new generators. Instead, the planners are often overwhelmed with requests for new generation interconnections. The Bonneville Power Administration (BPA 2001) wrote:

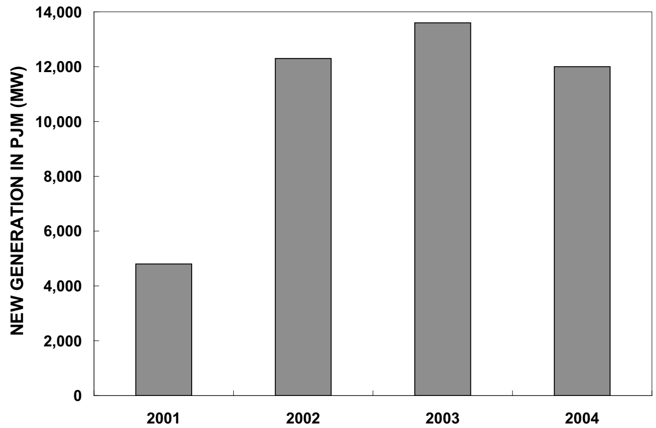

Fig. 15. Planned generating capacity in the PJM area.

> BPA has received requests for transmission integration studies for more than 13,000 megawatts of new generating capacity at sites around the Northwest. More are pouring through the door. In just the last two weeks, BPA has received eight formal requests for studies on integrating new combustion turbines totaling 3,850 MW. … The Transmission Business Line is informing developers that it will take at least nine to 12 months to complete the required studies.

As of March 2001, PJM had seven queues of new generating capacity. The first five queues represent over 40 GW to be completed between 2001 and 2004, enough to add more than two-thirds to PJM's current generating capacity (Fig. 15). Similarly, ISO New England had, as of Spring 2001, a queue with 40 GW of new generation, far more than the region's peak demand of 23 GW.

RTO Transmission Planning

The RTO filings of October 2000, required by FERC's Order 2000, pay little attention to Function 7 on transmission planning and expansion. As was true for the operation of real-time (intrahour) markets (Hirst 2001), the need to resolve other RTO issues, such as governance, regional scope and membership, and transmission-cost allocation and revenue requirements, dominated the prefiling deliberations. Perhaps because of these factors, FERC (1999) gave the RTOs three years after becoming operational to meet the requirements of this Function 7.

The RTO West plan (Avista Corp. et al. 2000) "anticipates that RTO West's approach [to transmission planning] will evolve over time." The initial plan anticipates transmission expansion for two purposes: (1) "for reliability of service to load" and (2) "to relieve congestion." As noted elsewhere in this report, distinguishing between reliability and commercial needs is very difficult and perhaps a distraction. With respect to relief of congestion, RTO West anticipates a "market-driven expansion mechanism," which, in principle at least, should reduce the need for RTO West to develop its own plan in this area.

Attachment P (Description of RTO West Planning and Expansion) focuses on decision-making authority: who decides what facilities are to be built and who pays for these investments. The Attachment commits RTO West to develop:

> (1) criteria to be applied by RTO West in determining the level of transfer capability that should be maintained from existing facilities, (2) transmission adequacy standards, (3) further definition of the market-driven mechanism [for transmission expansion], (4) the [new-transmission-cost] allocation procedure, including objective criteria, (5) interconnection standards, and (6) the details of the relationship/participation of RTO West with appropriate interconnection-wide and regional reliability organizations.

The Southwest Power Pool (SPP 2000) filing includes Attachment O on "Coordinated Planning Procedures." This attachment appears to give primary responsibility for transmission planning to the transmission owners. As examples, the attachment states that the (1) "individual planning criteria of each Transmission owner" shall be used to decide whether reliability requirements are being violated and when new facilities are needed and (2) the "required transmission planning studies shall be performed by individual Transmission Owners." The RTO role, exercised through its Transmission Assessment Working Group, is primarily one of "review and approval" as well as coordination among the individual transmission-owner plans.

The Alliance RTO (American Electric Power Service Corp. et al. 2000) proposal is included in its Attachment H: Planning Protocol. The RTO is responsible for "coordinating" the planning rather than for doing the planning itself. The RTO's Reliability Planning Committee will be "the vehicle through which coordinated reliability planning activities will be conducted." RTO staff and representatives from each transmission owner and local distribution utility will be members of this committee, but not other market participants. This committee will be responsible for the planning models and data, reviewing and approving planning studies, determining the need for system expansion to meet reliability needs and transmission-service requests, participating in NERC and regional reliability processes, and coordinating transmission planning and expansion with other RTOs. The committee will produce a 10-year plan every year. The RTO's Planning Advisory Committee "will provide a forum for stakeholders and interested parties to have input in the planning process." With respect to transmission projects intended to reduce congestion, the Alliance RTO "will encourage market-driven operating and investment actions … ."

The GridSouth Transco (Carolina Power & Light et al. 2000) Planning Protocol (Attachment P to its proposed open-access tariff) is very similar to that of the Alliance RTO. It emphasizes that "GridSouth will be responsible for coordinating development and annual updating of the regional transmission plan." Planning will be conducted through the GridSouth Reliability Planning Committee, which will consist of GridSouth staff and representatives from each transmission owner in the region. Other market participants will have opportunities to "review and comment" on the plan but will not participate directly in the planning process. The GridSouth approach appears to emphasize reliability in its planning process, with no mention of transmission investments to reduce congestion costs.

The proposal from the New England Transmission Owners et al. (2001) builds on the experience with ISO New England. It envisions a binary RTO with a nonprofit ISO and a for-profit independent transmission company (ITC). The proposed three-phase planning process "combines the knowledge and objectivity of ISO-NE [ISO New England] with the strengths of an investor-owned business focused on transmission … ." The process consists of the following steps:

- The ISO will lead a needs assessment, which will integrate data and projections on regional loads, generation (existing, planned retirements, and potential additions), transmission, and inter-control area transactions to forecast the region's needs for additional transmission. The needs assessment will be consistent with regional reliability planning standards, address congestion costs, and consider transmission-system performance.

- The ITC will develop a Regional Transmission Facilities Outlook, which will identify transmission alternatives that may be needed based on a range of plausible scenarios.

- Finally, the ISO will assess the ITC's Outlook and approve a regional plan. This assessment will consider other alternatives proposed by the ISO and stakeholders. The ISO review will provide "a check that the Outlook is not biased in favor of transmission solutions at the expense of generation or other market-based solutions." "The decision to proceed with [transmission projects] will be made by the market [participants] for market based proposals (including merchant transmission) and by the ITC for regulated transmission proposals."

Our review of the transmission-planning proposals from a few RTOs suggest that much work remains to be done to define a comprehensive transmission-planning process. Deciding on a specific transmission-planning approach is difficult in some regions because the participants cannot agree on whether transmission investments should be driven by the market participants or by reliability requirements. In the former case, generator owners and large customers might pay for new facilities, while in the latter case the transmission owners, in response to RTO plans, would pay for such projects.

The New England proposal is more developed than the others reviewed here, probably because it builds on the existing relationships among the ISO, transmission owners, and other market participants.

Chapter 6: CONCLUSIONS

Maintaining a healthy transmission system is vital for both reliability and commerce. Unfortunately, the historical record shows a clear and long-term decline in U.S. transmission adequacy. Specifically, the amounts of new transmission added during the past two decades have consistently lagged growth in peak demand. To make matters worse, projections for the next five and ten years show continued declines in adequacy.

Maintaining transmission adequacy at its year-2000 level would require a quadrupling of transmission investments during the present decade (to add almost 27,000 GW-miles vs the 6,000 GW-miles planned). The cost of building these new facilities, including the cost to replace retired capacity, is roughly $56 billion during this decade. This transmission-investment cost is about half of the investment likely to be made in new generating units during the same time.

To further compound the problem, transmission planning is not keeping pace with the need for such planning. Because transmission owners and ISOs are receiving so many requests for generator interconnections, they are unable to devote the staff resources needed to develop proactive transmission plans. That is, they are focused primarily on preparing the system-impact and facility studies required for these new interconnections. Thus, many transmission plans are little more than compilations of individual generator-interconnection studies.

Because transmission planners have insufficient time and resources, little information is being provided to energy markets on the costs and locations of congestion. Such information could help potential investors in new generation decide where to locate new units. Such information could also help load-serving entities decide what kinds of dynamic pricing and load-reduction programs to offer customers in different locations.

Because generation and load can serve, in some instances, as viable alternatives to new transmission, transmission plans need to explicitly consider such nontransmission alternatives. Whether the transmission system (i.e., transmission users in general) should pay for these generation and load projects is unclear and hotly contested. At a minimum, transmission planners should provide information (again based on analysis of past and likely future congestion costs) on suitable locations for new generation and load management.

Transmission planning may be too narrowly focused on NERC's planning standards. In other words, transmission planning may pay insufficient attention to the benefits new transmission investments might offer competitive energy markets, in particular, broader geographic scope of these markets and a reduction in the opportunities for individual generators to exercise market power. As NERC (2000b) noted, "A robust, reliable transmission system is needed to develop a competitive market and to achieve its full benefits." Although some plans consider congestion (either congestion costs or curtailments and denial of service), such considerations are more implicit than explicit. As shown in Chapter 4, congestion costs can provide valuable information on where and what to build.

Advanced technologies offer the hope of better control of transmission flows and voltages. Such improved control would permit the system to be operated closer to its thermal limits, thereby expanding transmission capability without increasing its footprint. Thus, new technologies may reduce fights about transmission siting. In addition, these technologies, because they permit control of power flows over individual elements (e.g., DC lines), may make it attractive for private investors to build individual facilities (what is sometimes called merchant transmission). Unfortunately, these advanced technologies are still too expensive for widespread application, although some are economic in niche applications (e.g., to solve stability problems).

The separation of generation from transmission and of retail service from transmission poses difficult information problems for transmission planning. Specifically, transmission planners need detailed information on the timing, magnitudes, and locations of new generating units; the developers of these facilities are unwilling to share competitive information until required to do so (e.g., for environmental permits and for transmission-interconnection studies). Planners also need detailed information on the locations and magnitudes of future loads. In a retail-competition world, it is not clear what entities will have the information necessary to produce reliable projections of retail load and whether those entities will be willing to share these projections with transmission planners.

The economies of scale in transmission investment argue for overbuilding, rather than underbuilding, transmission. It is substantially cheaper per GW-mile to construct a higher-voltage line than a lower-voltage line. The higher-voltage line also requires less land per GW-mile, which should reduce opposition from local landowners and residents. Also, building a larger line now eliminates the need to build another line in several years. This situation can eliminate the need for another potentially bruising and expensive fight over the need for and location of another transmission line. Also, the availability of suitable land on which to build transmission lines can only go down in the future, as the population grows and the economy expands. On the other hand, overbuilding can increase financial risks for the transmission owners.

Finally, the RTO proposals for transmission planning are generally vague. The RTOs need to devote more time and effort to developing the specifics of their transmission-planning processes, including consideration of the factors discussed in this report. RTOs are critical to the long-term viability of transmission systems and the regional planning needed to justify grid expansion.

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