Key Transmission Planning Issues

One conclusion: 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.

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When the popular press (e.g., the Los Angeles Times, Washington Post, and Fortune) run articles on a topic as dry and abstract as the nation’s high-voltage transmission grids, something important must be happening. Clearly, 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) 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 nondiscriminatory 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

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nondiscriminatory 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.²

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.

Because of the many changes under way in the structure and operation of the U.S. electricity industry, transmission planning faces many challenges. 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. This article, part of a larger project conducted for the Edison Electric Institute, discusses some of these changes, including the distinction between reliability and commerce, economies of scale, the role of congestion, new technologies, lack of control, and difficulties in obtaining data needed for transmission planning.³

I. Reliability versus Commerce

Traditionally, vertically integrated utilities planned their transmission systems with two goals in mind: (1) meet the reliability requirements of North American Electric Reliability Council (NERC) and regional reliability councils, 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 Standards⁴ 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 transmission loading relief is invoked. Where congestion (locational) pricing is used, this goal is met by reducing congestion costs (discussed below). Some people believe that congestion pricing eliminates the distinction between reliability and commerce by explicitly pricing reliability.

Many experts feel that the distinction between reliability and commerce in transmission planning is increasingly irrelevant.

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, the people we interviewed 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 informants 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.

II. Economies of Scale

It is generally cheaper per megawatt of capacity to build larger transmission lines (Table 1). For example, 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 (Figure 1).

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. Overbuilding a line now 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 (e.g., one can build a 345-kV line or a 500-kV line but not a 410-kV line) can complicate decisions on what to build and when. 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.

III. 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.

Decisions on whether to build new transmission are complicated by uncertainties over the future costs of congestion. 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/MWh. The load in Region B ranges from 20 to 50 GW, with a load factor of 63 percent.

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.

Figure 2 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 Figure 2, 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.

The relation between the benefits of adding transmission capacity between A and B to reduce congestion costs and the costs of doing so are highly nonlinear because of (1) nonlinearities in congestion costs, (2) economies of scale in transmission investments, and (3) the lumpiness of transmission investments. 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 2 for the addition of a 500-kV line to expand capacity by 1.5 or 2.0 GW.

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.

The congestion-reduction benefits of each additional MW of generating capacity are less than the benefits of earlier additions. This effect is especially pronounced as the bid prices of the new units increase. For the more expensive of the two units 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.

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, respectively. Such increases in load make transmission investments substantially more cost-effective.

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, respectively. Figure 3 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 transmission 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.

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.

**IV. Generation and Load Alternatives**

The Department of Energy Task Force on Electric System Reliability 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 [RTOs’] 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.
larly, 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 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).

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 (1) less expensive and (2) provided the same or better reliability and commercial benefits than the original transmission project.

 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., 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).

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 are intended to be competitive markets. The California Independent System Operator (ISO) has had considerable experience, and many problems, with its reliability-must-run contracts. 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. 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.” Alternatives were required to be available between the hours of 8 AM and 1 AM for up to 500 hours between April 1 and Oct. 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, which involved satisfaction of the ISO’s reliability criteria, commencement approved construction of the San Diego Gas & Electric Valley-Rainbow transmission project. In part because of the California electricity crisis, 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 being 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.”

We uncovered only one instance in which transmission planners explicitly considered distributed-resource alternatives.

Niagara Mohawk 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.”11

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. These analyses, however, were conducted primarily by transmission engineers who are more comfortable with transmission and understand transmission better than they understand 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.

V. New Technologies

Superconductivity, power electronics, and other new technologies could revolutionize transmission and make it easier to expand the system through merchant, rather than regulated, projects. According to J.B. Howe, “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.”

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.

- **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 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, 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 on-site 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. 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 widespread use. (To date, they have been deployed in a few locations, primarily by utilities to improve the performance of their systems.) As the technologies are improved and demonstrated, however, their costs will likely continue to drop enough so 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).

### VI. 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 insists that system operators be independent of merchant functions and regulated, and that the entire transmission system be available to all users on a non-discriminatory 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 versus generation**: The split and differences between competitive generation and regulated transmission com-
pound 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.

- **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. Although little scientific evidence supports this concern about transmission lines, public perceptions and fears may lead to opposition to construction of new transmission lines.

### VII. 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 the Energy Department’s Energy Information Administration 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. 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.

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

VIII. 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 5 and 10 years show continued declines in adequacy.

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. Although some plans consider congestion (either congestion costs or curtailments and denial of service), such considerations are more implicit than explicit. As shown here, 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.

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 under-building, 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 population grows and the economy expands.

On the other hand, overbuilding can increase financial risks for the transmission owners.

Endnotes:
2. Id., at 275.
10. Id., at 5.
14. Supra note 1.
17. Supra note 3, ch. 2.