

SPARK

Letter #26
Feb. 2006

The on-line gateway for readers of Public Utilities Fortnightly magazine.



This issue of Fortnightly's Spark looks at electric transmission reliability. There is growing interest in the subject because of FERC's proposed rulemaking on promoting transmission investment through pricing reform. That of course, was spurred by the EPACT 2005, which requires incentive ratemaking treatment be used to encourage investment in transmission infrastructure. According to Ed Krapels at consulting firm, ESAI, one of the consequences will be to create the decade of the transco. But first, FERC has to sort through a myriad of comments on the road to the final rule.

Lori A. Burkhardt
Editor

TRANSMISSION WATCH

Decade of the Transco

By Edward Krapels and Stephan Conant

Is the decade of the Transco upon us? FERC's Notice of Proposed Rulemaking on "Promoting Transmission Investment through Pricing Reform" issued last November sets the stage for more than just "pricing reform." It's clear that FERC is opening the door to further support the creation of stand-alone transmission companies or Transcos. Chairman Kelliher is impressed with what the country's handful of existing Transco's have accomplished already. "Transcos are a proven vehicle for transmission investment," he noted at a FERC open meeting in November. "The Commission's analysis shows that the three Transcos in the Midwest are investing at five times the rate as their prior owners. We want to reinforce that success. The proposed rules would do just that."

FERC and Stand-Alone Transcos

On November 18, 2005, the Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking (NOPR) titled "Pro-

moting Transmission Investment through Pricing Reform" and invited responses by January 11, 2006.¹ The title of the NOPR is a little too narrow: a careful reading indicates that FERC has a lot more on its mind than mere transmission pricing reform. It appears to be committed to incubating new stand-alone Transcos, in the belief that these institutions are a key ingredient to a higher rate of sustained investment in new transmission.

The NOPR would consolidate a number of transmission-oriented rulings and opinions that FERC has issued in the last five years. These include approval for market-based rates for a number of new merchant projects (of which Cross Sound Cable, Path 15 and Neptune are the early movers), approval for incentives for the sale of transmission assets (American Transmission Company and International Transmission Company), and enhanced rates of return and/or cost recovery for investment in new transmission projects by existing utilities.

FERC is proposing several incentives »

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to encourage the sale of existing transmission assets by utilities to Transcos. These incentives include "(1) a higher ROE which is both sufficient to encourage Transco formation as well as to attract new investment in transmission facilities; and (2) an adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities."²

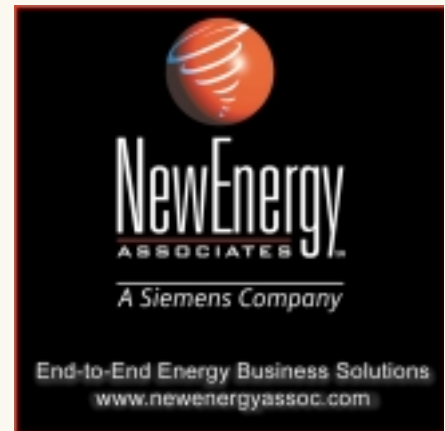
While the incentives are distributed broadly, the comments of FERC Commissioners at the Open Meeting of November 17th left little doubt about their hopes that new transmission development institutions, namely, stand-alone Transcos, would emerge. Chairman Joe Kelliher observed, "Transcos are a proven vehicle for transmission investment. The Commission's analysis shows that the three Transcos in the Midwest are investing at five times the rate as their prior owners. We want to reinforce that success. The proposed rules would do just that."³

FERC defines a Transco as a "stand-alone transmission company," approved as such by FERC, which is engaged solely in selling transmission

at wholesale or on an unbundled retail basis. In the proposed rule, FERC proposes that Transcos must be independent. They may have some passive ownership interests by affiliated traditional vertically integrated public utilities (traditional public utilities)⁴, but the interest is restricted to 49 percent. The restriction is important. With it, FERC is trying to ensure that Transcos are not the tail end of utility conglomerates, but entities that will live and die by how well they acquire, manage, and build transmission.

To that end, as discussed later, FERC proposes to give Transcos financial and other incentives to buy transmission assets from utilities, to expand capacity on existing transmission corridors, and to build new capacity. Some of these incentives are independent of utility rates; others create a positive spread between the regulated rates of return of Transcos and utilities.

We believe the NOPR should be seen as an important institution-building initiative, as important to the transmission sector as the development of non-utility generators (NUGs) has been to the generation sector. NUGs and their cousins (qualifying facilities



(QFs), exempt wholesale generators (EWGs)) wrought tremendous changes to the electricity business since regulators created them in the 1970s. By and large, the fact that these changes have occurred is the result of deliberation and intent on the part of state and federal regulators of the electricity sector.

Since 1907, when the states of New York and Wisconsin first created public service commissions, those commissions have engaged in an intensive search to make regulated business more efficient, dynamic, and productive. FERC's "transmission institution" NOPR, therefore, can be seen as the next step in a century-old effort.

The Essentials of "Economic Transmission" Development

Notwithstanding the enormous attention it gets, *ROEs are not at the center of the transmission development conundrum.* Important new transmission lines needed to maintain reliability are being built now and will continue to be built, even at current rates of return. Utilities would certainly like higher rates of return for such projects, but, as FERC Commissioner Kelly said, *(Cont. on p. 7)*

FERC is trying to ensure that Transcos are not the tail end of utility conglomerates, but entities that will live and die by how well they acquire, manage, and build transmission.

FORTNIGHTLY'S

SPARK

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TRANSMISSION INVESTMENT

Do Incentives Hold The Key?

By Lori A. Burkhart

Stymied by lack of electric transmission and resulting costs of congestion, the Federal Energy Regulatory Commission (FERC) is proposing new rules it hopes will spur investment in new transmission facilities. The solution sounds simple: It wants to establish incentive-based rates, including performance-based rates, for the transmission of electric energy.

As part of enforcement of the Energy Policy Act of 2005 (EPACT), FERC proposes transmission-pricing reforms with the hope that the promise of more income would encourage investment in electric transmission infrastructure. The goal is to ensure reliability while cutting the cost of delivered power by reducing transmission congestion. EPACT gives FERC one year to implement new section 219 on the Federal Power Act (FPA), requiring such rates be used to help offset the decline of investment in transmission infrastructure, while load concurrently continues to increase.

The need for more electric transmission is real. FERC cites studies showing transmission investment declined in real dollars for 23 years, from 1975 to 1998, before increasing again. But it points out that such investment in the most recent year available—2003—still is below 1975 investment levels. Over the same time period, electric load more than doubled, causing a significant decrease in transmission capacity relative to load in every North American Electric Reliability Council (NERC) region.

Edison Electric Institute (EEI) estimates that capital spending must increase by 25%, from \$4 billion annually to \$5 billion annually, to assure system reliability. Also, it finds the 2.5 percent growth rate in transmission mileage constructed since 1999 is insufficient to meet the expected 50 percent growth in consumer demand over the next twenty years.

According to the Secretary of Energy's Advisory Board at the Department of Energy (DOE), transmission grid investment only will occur when regulatory policy provides reasonably certain cost recovery, regulatory certainty and a return making transmission investment a reasonable option.

The proposed rules, issued Nov. 18,

**Some parties to the
NOPR are unhappy
the proposed rules
perhaps would favor
the independent
transmission
company (transco)
model.**



2005, would provide pricing reforms applicable to the entire electric grid, in both organized and in other markets, and to both vertically integrated utilities and transcos. [*Re Promoting Transmission Investment Through Pricing Reform, Docket No. RM06-04-000, 113 FERC ¶ 61,182, 18 CFR Part 35, Nov. 18, 2005 (F.E.R.C.)*]

Return on Equity

So what is the best method to encourage investment? EEI wants to avoid the discomfort of long rate cases. EEI advocates FERC using return on equity (ROE) adders enacted via single-issue ratemaking proceedings in order to provide meaningful incentives in a timely manner. It believes such adders can spur transmission investment by removing the lengthy, comprehensive rate-case process. EEI supports a 100-basis point ROE adder incentive for all new transmission investment. And because ROE adders can serve as an incentive mechanism to foster regional transmission planning, it urges FERC to provide an ROE adder for all transmission facilities planned through a regional process.

EEI supports a 50-basis point ROE adder for all utilities that join or have joined and continue as members of RTOs, ISOs and other transmission organizations.

But some instead prefer continuation of FERC's prior policy. The New »

England Transmission Owners (TOs) complain that its members have been engaged in litigation before FERC for over two years over whether the TOs should receive a pricing incentive for new transmission investment and for joining an RTO, which they say was the deal offered by FERC prior to EPACT. Despite that prior policy needing to be tightened up to ensure promised incentives are indeed given, they would prefer it remain in place. They believe TOs require pre-incentive ROEs that fully reflect the cost of capital, including recognition of the financial risks borne

by utilities that construct new transmission facilities. They want FERC to “take more concrete action” in the rulemaking, rather than simply offering TOs the right to make section 205 filings under the FPA to request incentives. They point to being in their third year of litigation over entitlement to a transmission incentive (adders) made available by FERC pursuant to previous policy. TOs nonetheless hope FERC will continue its prior policy of granting a 50-basis point adder to utilities that participate in RTOs, both rewarding the initial decision to join an RTO and then the



TRANSMISSION PRICING PROPOSAL

FERC proposes rules for incentive-based (including performance-based) rate treatment for transmission of electricity in interstate commerce. It would authorize the following upon application by all utilities, including transcos:

- A rate of return on equity sufficient to attract new investment in transmission facilities;
- 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base;
- Recovery of prudently incurred pre-commercial operations costs;
- Hypothetical capital structure;
- Accelerated regulatory book depreciation;
- Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility;
- Deferred cost recovery; and
- Any other incentive approved by the Commission determined just and reasonable and not unduly discriminatory or preferential.

In addition to the incentives listed above, FERC would authorize the following incentive-based rate treatments only for Transcos:

- A higher return on equity that both encourages Transco formation and attracts investment; and
- An adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.

FERC also is considering authorizing an ROE for a utility joining a regional transmission organization that is higher than the ROE it might otherwise approve if the utility did not join one. It will allow utilities joining an RTO to recovery prudently incurred costs of joining, either through transmission rates charged by the utilities or through transmission rates charged by the RTO that provides services to the utilities.

It also would approve prudently incurred costs for compliance with mandatory reliability standards.

[Re Promoting Transmission Investment through Pricing Reform, Docket No. RM06-04-000, 113 FERC ¶ 61,182, 18 CFR Part 35, Nov. 18, 2005 (F.E.R.C.)]

decision to remain in the RTO.

In agreement are the Transmission Dependent Utility Systems (TDU Systems), a group of nine rural electric generation and transmission cooperatives, which believes the current transmission incentive pricing policies are better than the policies proposed in the rulemaking. It argues that the new incentives contemplated by FERC in the NOPR are not likely to encourage added investment in new or upgraded transmission infrastructure. It believes the factors responsible for the low levels of transmission investment are not related to equity returns or cash flow concerns. “Better means of encouraging new investment include encouraging participation in an open, regional planning process that includes authority to order construction of needed new transmission capacity, encouraging public power system participation in planning, financing and constructing these facilities, and providing greater regulatory certainty in recovery of costs associated with such investment,” says TDU Systems. It wants FERC to implement policies to accomplish those factors, prior to consideration of financial incentives.

Also disagreeing with FERC’s proposals are the Transmission Access Policy Group, (TAPS) an informal association of transmission-dependent utilities, which calls the proposed rule “deficient,” because it offers a »

range of incentives, including return, and “even worse,” accelerated depreciation, without tying them to major reforms. “But also because it provides only upside incentives and does not simultaneously penalize poor performance and maintenance of a clearly inadequate system,” says TAPS. It believes the new rule should expressly provide for a downward adjustment of returns of transmission providers that perform poorly.

Industrial Consumers, made up of eight groups, including the Electricity Consumers Resources Council (ELCON), advises FERC proceed with caution, arguing that insufficient transmission investment was not caused by deficiency in FERC pricing policy. Instead, “it is the result of long neglect coupled with a climate of regulatory uncertainty that has created, in many instances, an unwillingness to invest.”

It urges FERC to measure risk against performance, adopt guidelines ensuring net benefits to consumers exceed costs, including any incentive premium, and establish a screening process to prevent windfall profits to free riders. It says only a minimum incentive should be offered, and that FERC should insist on a *quid pro quo* for each incentive: (1) prudence review; (2) independent regional stakeholder planning process; (3) applicant’s willingness to accept third-party ownership; (4) a requirement to see third-party funding that would reduce the amount of investment exposed to the incentive; (5) a requirement that long-term capacity rights in a new facility be offered in an open-season bidding process; or (6) ensuring that the transmission expansion accommodates economic needs and not just the more narrow need for reliability.

Another subject of debate in the proceeding involves how to calculate ROE. For example, many commentators are asking whether the Discounted Cash Flow (DCF) model that presently is used by FERC properly incorporates

risk and is perhaps outdated.

Southern California Edison (SCE) believes FERC needs to consider alternatives to its present DCF methodology for estimating ROE. It points out the DCF method is only one of several used outside of FERC to estimate the cost of equity capital for electric utilities. SCE argues the DCF model is not the most accurate or appropriate method in many cases. It says the Capital Asset Pricing Model (CAPM) and Arbitrage Pricing Theory (APT) model more explicitly incorporates measures of risk in their analyses. Since the utility’s appropriate rate of return inextricably is tied to risk, SCE finds it fitting to employ a model that directly incorporates that factor. Although FERC has rejected use by SCE of the CAPM and historical risk premium models, both have been used for cost of capital estimates in numerous state jurisdictions. It advocates FERC allowing use of risk-premium or risk-positioning methods to estimate allowed ROE.

But the American Public Power Association (APPA), disagrees, finding the DCF approach analytically sound. It believes that if the FERC were to switch methods mid-stream, it might increase investor uncertainty as to which method FERC might use three, five or fifteen years from now.

Transcos and RTOs

Some parties to the NOPR are unhappy the proposed rules perhaps would favor the independent transmission company (transco) model by providing added incentives for creating one, and also would reward RTO membership, as well (*see Box, “Transmission Pricing Proposal, p. 4*) But should the new rule favor any entity?

Northeast Utilities (NU) and TransCanada Pipelines Ltd., among others, argue FERC should target incentives directly at companies that are actually investing in transmission, regardless of corporate structure. TransCanada, which through subsidiaries is develop-



ing two major, high-voltage direct current (HVDC) transmission projects in the Western Interconnection, called the Northern Lights Projects, believes the incentives should be blind to corporate structure, as directed in EPACT. TransCanada believes “the final rule should be expanded to provide incentives to business models that include merchant developers or that the definition of transco should be clarified to include a merchant-led business group, thereby providing incentives for development work on major transmission lines before a formal tariff is filed with the commission.”

NU warns, “The proposed rule’s favoritism toward an independent transmission company (ITC) model is neither necessary nor does it provide the most effective means of securing the end desired by the Commission.” It urges FERC not to provide disincentives to TOs that have made the commitment to form RTOs, as RTOs provide the same focus and independence as ITCs in transmission planning.

“The NOPR fails to acknowledge that the ITC model was adopted by states and/or utilities as an effective way to de-couple transmission and generation,” states NU. It further argues that the same goal was achieved in New England when the New England Power Pool was transformed into the ISO-NE and then the RTO was approved. “NU is in the process >>

of implementing one of the largest capital transmission programs in the nation, arguably the largest relative to its size, and is involved in many transmission projects to assure reliable service to a growing load," the utility points out. NU attributes those large projects to the RTO structure in New England, which provides a robust regional planning process for determining infrastructure needs to serve growing load.

But regardless of form, International Transmission Co., an ITC, believes new investment in transmission to achieve Congress' desired consumer benefits will not occur unless three changes are made:

- Formula rates should govern all transactions (such as the Midwest ISO's Attachment O);
- Transmission should be owned and operated by entities independent of market participants; and
- Rates, terms and conditions for all transmission of electricity in interstate commerce should be regulated exclusively by FERC.

Pointing to proposed section 35.35(e) of the new rule authorizing incentive-based rate treatment for utilities that join a transmission organization, International Transmission Co. urges FERC to calibrate such incentives according to whether transmission investments actually are being made that improve reliability and reduce congestion to benefit consumers served by those transmission organizations. It believes incentives should not be provided simply for RTO membership that does not result in transmission investment that benefits consumers by ensuring reliability and reducing congestion. Mere membership in an RTO, it says, bears no direct correlation to increased transmission investment.

Taking a different view is Kohlberg Kravis Roberts & Co. (KKR), which provides capital for investment in transmission facilities. It believes incen-

tives should be tailored to accommodate different organizational structures and regional perspectives. KKR does find substantial benefits associated with transcos that merit added incentives as set forth in the NOPR. It advocates further distinguishing among three models in structuring incentives: (1) transcos with structural independence; (2) transcos with decision-making for operations, investment and capital allocation "fully insulated" from relevant market participants; and (3) transcos with active involvement by market participants in operations, investment or capital allocation decision-making.

Citing need for regulatory certainty, American Electric Power (AEP) sees the issue differently. It instead looks to the 50-basis point adder for RTO participation proposed by FERC in its transmission pricing inquiry and implemented for the Midwest ISO. "There was criticism from some stakeholders who colorfully characterized such incentives as "FERC candy" and urged the Commission to forgo incentives in favor of a command-and-control approach," AEP explains. So when AEP requested the adder in its transmission cost of service, intervenors argued AEP did not need an incentive to join an RTO because it has been ordered to do so as a merger condition. FERC set the issue for hearing, which AEP believes "removes any degree of regulatory certainty and considerably dampens the efficacy of the measure as an incentive." AEP sets forth another approach to proposing pricing incentives in a rate proceeding: "FERC should develop a few basis criteria, and state that an entity proposing a project that meets the criteria will be eligible for the indicated rate treatments." ■

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Next Month's FORTNIGHTLY

In March, *Public Utilities Fortnightly* magazine takes on the upswing in energy trading. Find out who the players are and how the business has changed since its decline post-Enron. This issue is full of valuable information as our editor-at-large, Michael T. Burr, takes on the *Energy Trading Resurgence*. Burr looks at how utility executives face volatile energy markets, skyrocketing fuel prices, and changing federal energy policies. He also tells you how utilities are benefiting from the turnaround in energy trading.

Here is more of what you will find:

▶ Long-Term Transmission Rights: A High-Stakes Debate

Power-industry restructuring redistributed financial uncertainties that discourage generation investment and ultimately raise the price of electricity to consumers.

▶ LNG's Final Hurdle

Gas composition issues have become a significant hurdle for the industry. Resolving these challenges will not be easy, requiring all stakeholders to apply a thoughtful approach to understanding the issues.

▶ Mergers: It's All About Timing

Companies that relied heavily on mergers and acquisitions generated more than half of the value in the power industry during the past 10 years. Furthermore, more than half that value was generated by a handful of companies. How did they do it?

▶ After EPACT: A Mad, Mad Scramble for Talent

Hidden in the 1,700-plus pages of the Energy Policy Act of 2005 is a set of regulatory requirements that will redefine the technology, leadership, training, culture, compensation, job design, and organizational models currently employed in the industry.

PLUS McKinsey & Co.: On When, and When Not to Merge

LNG: Will Interchangeability Issues Derail Import Plans?

The High Stakes for Long-Term Transmission

Commission Watch

TRANSCO

(Cont. from p. 2)

11 percent is a “pretty good return” for an investment with very limited risks.⁵

FERC’s NOPR is aimed at transmission that goes beyond mandatory reliability: it is aimed at transformative transmission projects – if you will, “economic” transmission — that have a substantial positive economic impact on the power markets.

It is aimed at projects like the Frontier Line concept in the West, and Mountaineer in the East.

A few transformative projects – like the InterMountain project from Utah to southern California, and the Hydro-Quebec ties into New England and New York — were built in the past by collaboratives of utilities, municipals, equipment suppliers, and state and federal regulators. The collaboratives were led by the entity with a desire to export surplus energy, and one or more representatives of load which, at the end of the day, is who paid for the project.

Today, such projects still need collaboratives of participants. There are still willing exporters of energy and areas of enduring large energy+capacity spreads, but what is much harder today is organizing the representatives of load. In restructuring areas, there is an ever-clearer distinction between (1) the *load-serving entity*, (2) the *transmission owner*, (3) the *transmission manager/planner*, and (4) the *transmission developer*.

In restructured areas,

1. The *load-serving entity* (LSE) is responsible for maintaining adequate reserve margins, but, because it does not know how much load it will have one, five or twenty years from now in a competitive retail environment, it cannot make 20-year+ commitments to build generation or transmission. It is often, therefore, an unwilling transmission developer.
2. The *transmission owner* (TO) may or may not have transmission

assets that are congruent with its load-serving obligations. In some cases, it sees transmission as a necessary evil, to be developed only to meet minimum reliability obligations. In other cases, especially where the TO and the LSE roles are congruent, it will develop “economic transmission,” but only to the extent needed to fulfill its LSE-based reserve adequacy requirements.

3. The *transmission manager/planner* – or the ISO/RTO – has reliability as its prime directive, while economic efficiency is secondary. So, from a transmission development standpoint, the ISO/RTO has a relatively short time horizon (five to ten years), and its role (at least so far) is to point out where transmission must be built to keep the lights on five years from now.
4. It is the *transmission developer* that FERC is addressing in its NOPR. It is the developer (which may be an independent company, or a part of a utility) who is expected to have the vision of what is economic now, ten years from now, and twenty years from now, and who finds a way to navigate between the LSE, the TO, and the ISO/RTO.

In considering how to motivate transmission developers, it is crucial to remember that under the current rules of the game, the independent transmis-

sion company *cannot be in the power trading business*. Quite unlike the NUG, the Transco cannot get upside from a transmission project by trading around the asset. FERC requires that 100 percent of the capacity of an independent transmission line be made available to the market, whether or not the purchase price of the capacity is “economic” for the owner.⁶

Therefore, not having an opportunity to optimize the asset in the market, the transmission developer must invest on the basis of its ability to sell access to its transmission line. Its customers are power marketers, generators desiring access to a different market, and load-serving entities. Its product is the right to sell energy and capacity services from one market into another market.

Given these essentials of transmission development, there are two fundamental reasons why there has not been — so far — a rush to develop new economic transmission projects:

1. *It is difficult for transmission projects to capture capacity spreads:* as long as the capacity values and regulations between control areas are undefined, the only way a transmission project can capture capacity spreads is indirectly – *i.e.*, by means of a long-term contract. Thus, the Long Island Power Authority, which is acutely aware of the differences in the cost of generating capacity between Long Island and PJM, gave a long-term contract to Neptune to build a controllable transmission line into PJM. »

It is crucial to remember that under the current rules of the game, the independent transmission company cannot be in the power trading business.

a. The protracted wrangling over capacity market design, is, therefore, an enduring obstacle to the development of economic transmission projects without long-term contracts.

2. *The lack of competition in the retail segment of the power sector* creates a binary situation for the transmission developer: if the LSE in the sink market is unwilling to buy capacity services across the transmission line, the line will get no capacity revenues at all. From this perspective, the LSE is a monopoly (or monopsony) buyer of this product of the independent transmission company. Without a long-term contract from the monopoly buyer, it would be foolhardy to build the transmission line.

As long as these conditions exist, substantial transmission projects will only get built with the backing of long-term contracts.

The Likely Development Of Transcos

In spite of these obstacles, we believe FERC's NOPR points to the "decade of the Transco" and suggest that the ideal emerging Transcos will balance two competing, but in this case often complementary, business lines: transmission development and transmission acquisition from incumbent utilities. Of the two, transmission development has some distinctive risks, especially in the early stages of the incubation of projects.

New transmission projects can be divided into two categories:

1. Projects that are developed in competitive situations, take development cost risk, or have substantial amounts of merchant (uncontracted) capacity should be allowed to charge market-based rates. We expect to see:
 - a. Projects pursuing contracts from utilities or generators or marketers (although »

BEST PRACTICES

THE TOP TRANSMISSION PROJECTS UNDER CONSTRUCTION IN THE UNITED STATES

Our focus on best practices features seven of the top transmission projects currently under construction in the U.S. The projects have run the gauntlet of permitting and public utility commission approvals. They have secured the financial backing needed to get shovels in the ground and to string lines overhead (or bury them beneath the ground or along the sea bottom in some cases). In all, the seven projects represent more than \$2.1 billion in new investment in the country's electricity grid.

The featured projects range in length from 18 to 220 miles. (See Figure 1.) The per mile cost varies from between \$1.8 million to \$11.7 million. Collectively they demonstrate that no two transmission projects are alike, yet they are similar in their ability to succeed to the construction phase by combining the right mix of technology, regulatory savvy, and creative financing to get a project built.

FIG. 1 TOP SEVEN TRANSMISSION PROJECTS UNDER CONSTRUCTION IN THE U.S



Project Name	Developer	Length (Miles)	Size	Cost (Million)	\$/Mile (Million)	Estimated Completion
Arrowhead-Weston	ATC	220	345 kV	\$396	\$1.80	Jun-08
Bethel-Norwalk 345 kV Project	Northeast Utilities	31	115/138/345 kV	\$350	\$11.30	Dec-06
Jefferson-Martin	PG&E	27	230 kV	\$220	\$8.15	Jun-06
Neptune	Atlantic Energy Partners	65	500 kV DC	\$422	\$6.50	Jun-07
Schultz-Wautoma	BPA	64	500 kV	\$175	\$2.70	Nov-05
Stoughton-Boston Reliability	NSTAR	18	345 kV	\$210	\$11.70	Jul-06
Wyoming-Jackson Ferry	AEP	89	765 kV	\$287	\$3.20	Jun-06

Three of the projects illustrate how new technologies associated with buried transmission cables are being used to make use of existing rights-of-way in order to avoid community opposition and lengthy permitting delays. The projects are shorter in length (averaging 25 miles, which is about the technical limit of buried cable) and carry the highest per mile cost (averaging \$10.1 million per mile). Two projects, ATC's Arrowhead-Weston project and AEP's Wyoming-Jackson Ferry 765 kV project, are long regional projects between two states. They connect areas where transmission constraints are a problem and which in the future may be areas that are candidates for designation as National Interest Electric Transmission Corridors as defined under the 2005 Energy Policy Act. With the exception of the Neptune project, all the projects are being constructed to improve system reliability. ■

for the next few years most of the opportunities will be from utilities).

Merchant transmission projects, which will have as hard a time getting funded as merchant generators. The money has fled the merchant sector and won't return until the flaws in capacity market design are repaired.

c. Combination of the two...

We do expect to see projects evolve that have the bulk of their capacity committed to long-term (usually, 20-year) contracts. Over time, as confidence in market design recovers, both the percent contracted and the tenure will diminish.

2. Projects that are developed in non-competitive situations and provide some relief from development cost risk will usually sell transmission services under regulated rates. In this area, FERC is looking to encourage incentive-based rate proposals, including proposals to:

- a. *Provide a rate of return on equity (ROE), within the "zone of reasonableness," that is sufficient to attract new investment in transmission facilities. Thirteen and a half percent is likely to be a starting point for discussion, although we suggest that the rate should be tied to the underlying Treasury rates.*
- b. *Recover 100 percent of prudently incurred transmission-related Construction Work in Progress (CWIP) in rate base. Not unreasonable given that the project is under construction.*
- c. *Recover prudently incurred precommercial operations costs by expensing these costs*

instead of capitalizing them. Not unreasonable.

- d. *Adopt a hypothetical capital structure. Not unreasonable.*
- e. *Accelerate the recovery of depreciation expense. Not unreasonable.*
- f. *Recover all prudently incurred development costs in cases where construction of facilities may subsequently be abandoned as a result of factors beyond the public utility's control. We would expect FERC to be concerned that this policy would produce a proliferation of White Elephants.*

Early movers in this transmission development market segment are Trans-Elect and the Neptune development team, and (in the utility sector), NStar, Northeast Utilities and the other entities behind the development of major regulated transmission projects.

The other major business activity of Transcos – the one that would initially occupy more of Wall Street's attention – is the acquisition of transmission assets by Transcos from traditional utilities. There has been a lull in this area of activity recently (since ATC and ITC were set up several years ago, there have been virtually no such transfers), but FERC would stimulate a new round of activity by giving Transcos a higher rate of return on the acquired assets and by allowing the adjustment to "the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities." It remains to be seen how much this stimulates development of new transmission – the record is mixed.

Conclusions

As we have noted in previous *Transmission Watch* reports, we already see an increase in the pace of investment in transmission. That increase is a natural reaction to the decline in investment in

generation, in the maturation of ISOs/RTOs into competent and powerful transmission organizations, and in the response of developers to the opportunities that do exist out there, in spite of the deficiencies in market design. And so, what we think will go down in history as FERC's "Transco NOPR" is not to be taken lightly. It foreshadows the next step in the development of a power industry that, year-by-year, continues to evolve away from its past in ways that continue to be surprising. ■

Excerpted from ESAI's Transmission Watch, for more information, Edward Krapels and Stephen Conant can be reached at Energy Security Analysis, Inc. (ESAI), a strategic energy research and consulting firm, at 781-245-2036 or via the Internet at www.esai.com.

Footnotes

1. 113 FERC ¶61, page 182.
2. 113 FERC ¶61,182, page 9. FERC is looking for ideas on how to measure what these more attractive ROEs should be. It extended, for example, a 13.5 ROE for the Path 15 project in California. Whether this is enough to excite investors, however, depends on the underlying financial markets at the time. 13.5 percent ROE looks better when the underlying 10-year Treasury rate is 4 percent than when it is 6 percent. One reform, therefore, might be to make the ROE adder a function of the underlying rate of interest.
3. From "898TH Commission Open Meeting, Federal Energy Regulatory Commission, Thursday, November 17, 2005, pp 50-51. Hereafter, "November 2005 Open Meeting."
4. 113 FERC ¶61,182, page 7.
5. November 2005 Open Meeting, pp 56.
6. Some argue that such "use it or lose it" requirements should be dropped, making new, independent transmission lines more a part of the trading fabric of the power market. We expect to see such a change in the distant future, when both markets and market participants are further developed. For the moment, in most jurisdictions, that proposal will not fly.

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