

Justifying Transmission Investment in the Markets

Haibin Sun, Mark Sanford*, Louie Powell

Abstract--The restructuring of the electric power industry started with introducing competition into the generation sector, while leaving the transmission sector under regulation. With the accumulation of problems caused by this inconsistency and the criticisms incurred, the issue of how to position transmission in the market comes to the forefront of today's discussion and research. The lack of investment incentives and effective cost recovery mechanisms has contributed to problems with transmission adequacy. Market environments that encourage generators to respond to opportunities by transferring larger quantities of power more frequently and over longer distances further threaten transmission adequacy. Statistics show a clear and increasing lag between transmission construction and generation development in recent years. We analyze the incentives for transmission investments from the perspectives of reliability, economic efficiency, competitiveness, and environmental concerns. Obstacles arising from incomplete markets, physical constraints, and regulatory uncertainty are identified. We investigate transmission investment procedures and cost allocation methods in U.S. markets. An analysis of the positive and negative aspects of these schemes leads us to propose alternative regulatory and market-based mechanisms to encourage transmission investment.

Index Terms--Transmission inadequacy, investment incentives, cost allocation, property rights

I. INTRODUCTION

Economies of scale and scope within the electric power industry, as well as the desire to avoid duplicating infrastructure, led to the formation of regulated monopolies in most of the U.S. The industries adopted cost of service regulation (COSR) to achieve a pre-approved rate of return. Although this structure was successful in balancing development of generation and transmission and other operational aspects, COSR lacked clear cost-reduction incentives, retarded innovation, and failed to properly assign cost and decision risks. The perceived failures of the monopoly structure ultimately led regulators to gradually introduce competition to the industry. The public utility regulatory policies act (PURPA) enacted in 1978 and the energy policy act (EPA) of 1992 promoted wholesale power transactions by non-utility generators, and opened the door to the market for independent power producers (IPPs). The

This work was supported GE Energy, Energy Consulting at Schenectady, NY. H. Sun is with Georgia Institute of Technology, Atlanta, GA. He worked as a summer intern at GE Energy, Energy Consulting, Schenectady, NY in 2004. (Email: hsun@isye.gatech.edu).

*M. Sanford is the corresponding author, GE Energy, Energy Consulting, Schenectady, NY 12345. (Email: Mark.Sanford@ps.ge.com).

L. Powell is with GE Energy, Energy Consulting, Schenectady, NY 12345. (Email: louie.powell@ge.com).

Federal Energy Regulatory Commission (FERC)'s orders 888 and 889 represent another major milestone by requiring non-discriminatory access to the transmission network. Additional state and federal regulatory policies promoted the formation of independent system operators (ISOs), and, in some cases, the divestiture of generation assets. ISOs, where they were formed, separated operational control from ownership of the transmission and generation assets to increase efficiency and inhibit detrimental activities from conflicting interests. FERC's order 2000 continued this trend by promoting the voluntary formation of regional transmission organizations (RTOs) and transmission pricing reform.

Regulatory changes in the transmission system were accompanied by large-scale changes in generation. New generation technologies, particularly gas-fired combined-cycle turbines, allowed electricity to be produced in more modular and flexible quantities with higher efficiency. A building boom ensued adding over 200GW of new generation between the years of 1999 and 2004 [1]. In many cases, these units were built by relative newcomers to the industry who located the plants where construction was easiest. Developers often failed to fully consider the limitations of the transmission system.

With the building boom reaching its end and the evolution to competitive markets well advanced, the transmission system is becoming increasingly vital. Indeed, the contribution of transmission to market trading is far more important than the relatively small percentage of the capital cost it represents in the industry.

At the same time, however, transmission investment, as compared to generation, declined. In 1972 approximately 30GW generation was added supported by \$7.4billion (in year 2004 dollars) in transmission investment. In 2001, 40.6GW generation was added with only \$4.6billion in transmission. By year 2003, the numbers further diverged to having 52.4GW of new generation versus \$3.9billion invested in transmission. Normalized transmission capacity, as measured in MW-miles/MW-demand and MW/MW-demand, is declining at rates of 1.5% and 1.6% per year, respectively [2]. The market environment strains the system further because generation companies are encouraged to transfer larger quantities of electricity over longer distance more frequently in capture market opportunities.

Statistics by NERC [3] on the number of level 2 or higher transmission loading relief (TLR) logs as shown in Fig. 1 illustrates the increasing frequency of transmission system challenges in today's system.

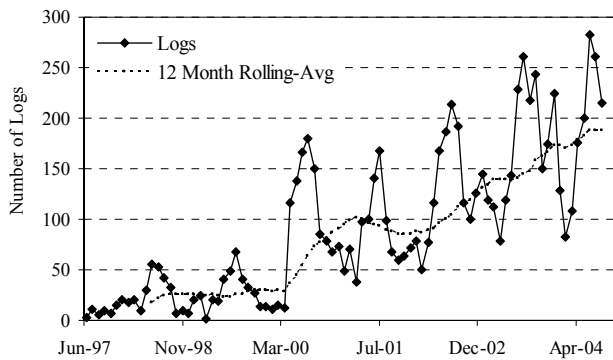


Fig. 1. Statistics of Level 2+ TLR Logs

While regulators devoted considerable effort to energy markets, they largely ignored the transmission system. Without effective market mechanisms and absent clear rules on how to respond to generator needs, the incentives for transmission investment became vague. Today, industry and academia are frequently engaged in intensive discussions about how to create appropriate incentives for transmission investment. This paper analyzes the incentives, obstacles, and motivations for transmission investment in a market environment.

II. TRANSMISSION INVESTMENT INCENTIVES AND OBSTACLES

Traditionally, the most common justification for transmission investment was to enable low-cost power to be delivered to consumers. Later, the impact of transmission on enhancing system reliability was also recognized. As industry restructuring proceeds, the list of benefits is expanding. Today, the transmission system serves a multitude of purposes including reliability enhancement, economic efficiency improvement, and market power mitigation. Correspondingly, the following transmission values are identified:

Reliability: This general category addresses the adequacy, reliability, and security concerns associated with assuring sufficient transmission capacity to meet consumer power needs by accommodating fluctuating transaction quantities, planned and unexpected transmission facility unavailability, and sudden disturbances, etc. The reliability value originates from higher transmission reliability margin, fuel source diversity, and interconnection certainty.

Economic Efficiency: This category is a measure of the ability of the system to supply consumer's needs at the lowest cost. Costs can be measured in a number of different ways including societal costs, or aggregate prices paid by end consumers. Economic efficiency arises from assuring sufficient transmission capability to enable use of the lowest cost power sources.

Market Power Mitigation: Markets may fail to produce economic efficiency if market participants can manipulate prices by creating shortages. These actions may also degrade

reliability. The elimination or mitigation of market power benefits a broad range of market participants.

Environmental Concerns: Typically, the environmental impact represented by right-of-ways is most frequently associated with transmission investment. However, given the environmental impact new generation brings, especially to high-populated regions, transmission investment may be a more environmentally sound alternative in some cases [4].

In spite of the range of benefits, potential transmission investors face uncertainties underlying the diverse factors that can affect the potential revenues needed for capital recovery. Besides the public objection from environmental and health concerns, some of these obstacles are organization structure related while others are related to physical and economical characteristics. The following are examples of some of these obstacles:

Multiple Stakeholders: Only rarely is there a clear governance structure to drive key decisions. To make the problem more troublesome, the interests of stakeholders may be at odds with each other.

Free Riders: As for most public goods, an investment in the transmission system benefits many market participants. In most cases it is impossible to fully isolate the benefits to those who pay for them. Consequently, the potential for free riders, that is people who benefit but do not bear the cost of the service, arises. Many market participants would choose to be potential free riders expecting positive externalities induced by other participants' investment.

Lumpiness: Transmission investments typically add large blocks of capacity. The size of these projects complicates the investment decision. The important linkage between expected benefit and marginal cost might be greatly obscured.

Market Risks: The market conditions are ever changing. It is hard to forecast the future load demand, generation costs, market rules, and transmission topologies. As a result, it is hard to predict future electricity prices and the economic benefit that might accrue from a transmission investment over the life of the investment.

Regulatory Risk: One key element for success of a transmission project is regulatory approval. In many cases, however, alignment at federal, state, and local regulatory levels results in project delays and rejection is a very real possibility. Consequently, funds expended early in the project may be at substantial risk.

The issues above are confounded by fragmented ownership that can easily produce sub-optimized solutions based on the interests of one or more owner segments. A comprehensive way to encourage investment and expand the transmission system that considers the full benefit of the improvement while avoiding investment obstacles is urgently needed

III. INVESTMENT FORMS

Based on underlying investment incentives, some transmission projects will be proposed by the system operator, while others may be proposed by one, or a group of, market participants in response to market signals. Accordingly, a transmission investment can take one of the following three forms:

A. Covering the projects in the system operators' baseline plans when they are required to meet regional and NERC reliability criteria in thermal capability, stability response, and short circuit capability, etc.

Since these transmission investments bring widespread benefits to most system customers, the cost of these required transmission investments tend to be allocated over a large group of consumers. In some cases the project is awarded through a request for proposals (RFP) process. The competitive RFP process promotes obtaining the lowest possible cost while also assigning the project related risks to the contractor. Investments such as these should be limited to those projects that are not provided as a result of market signals since the cost is involuntarily assigned to the consumer. A potential refinement of this approach is to allocate project costs through a cost-benefit analysis where those who benefit most pay a higher portion of the total cost [5]. FERC approved the use of an RFP process in coordination with merchant transmission as a way to encourage unmet need for transmission expansion.

B. Authorizing voluntary transmission investment by some group of market participants when they believe it to be in their economic interest to do so.

Projects in this category include generation/load interconnection requests, upgrades and expansions that reduce congestion energy cost for consumers, or increases in production and delivery for suppliers. Voluntary economic expansion projects are to be sponsored, and paid for, by the market participants who would gain the benefits. Certain transmission rights can be awarded for congestion risk hedging purposes. This process will not eliminate free riders, nor will it necessarily assure that individual parties are not injured by the action. It will be necessary, however, to assure that any proposed projects do not degrade service below accepted standards nor create additional opportunities for the exertion of market power.

C. Merchant projects from investors seeking the right to impose a market-based transmission service charge as well as to obtain incremental transmission rights to recover the cost.

A pure market-based approach to new transmission investment is the extension of the locational marginal pricing (LMP) mechanism with tradable financial transmission rights (FTR). Three components are necessary for viable market-motivated transmission investments. First, price signals are needed to determine where and how much to invest. Second, property rights are needed to increase the certainty that investors can earn a return on their investment. Third, a

mechanism must exist for transferring the access rights to the line at market-based rates.

The merchant investment model relies on competition, free entry, property-rights allocation mechanisms, and market based pricing of transmission service to govern transmission investments. The model allows unfettered competition to govern investment in new transmission capacity, placing the risks of investment inefficiencies and cost overruns on investment decision-makers instead of consumers [6] As such, however, the pure merchant model can only value those benefits that have associated markets potentially omitting some of the public good benefits from the investment decision.

All three of the investment forms described above must address the following three issues:

A. Impact of Network Externality

The proposed transmission change must be analyzed to demonstrate that it improves instead of degrading system reliability, and it promotes instead of deteriorating fairness in market competition. Kirchhoff's laws govern system power flows based on the physics of the interconnected system. Power flow changes that result from the altered system may require operators to restrict directing flows in a manner that can degrade reliability or undermine fairness to some consumers. The complexity of this grows with the network size.

Complete information of the network is needed to define the transmission capacity and to assess the impact of transmission changes. This raises two issues: First, the information must be made available to parties considering transmission investment. Second, objective criteria are needed to evaluate the acceptability of the change. Note that these criteria will not necessarily be the same for each of the investment forms.

A certain transmission investment may have positive or negative impacts on the capacity of other transmission links and therefore, on the financial position of other transmission owners/investors. As discussed in reference [7], a network-deepening project that increases the transmission capacities of existing facilities does not reduce the size of the set of feasible injections, which is not necessarily the case for an independent expansion of the network. Generally, the feasible power injection/withdrawal set changes after the implementation of such an investment. An example is given in Fig. 2 as an illustration. The expansion of the simple network by the addition of low-capacity transmission line AB as proposed by GEN B actually decreases the transfer capacity from node A to node C. In this example, the network externality brings benefits to GEN B but affects GEN A and LOAD C negatively.

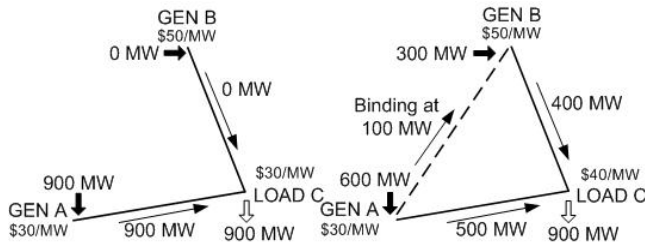


Fig. 2. Detrimental Impacts Due to Negative Externalities

A small expansion of the network does not necessarily have a small effect. The way these externalities are internalized in the pricing scheme strongly influences where rents are collected and whether an investment is profitable. Besides, the handling of the externalities is crucial regarding the trade-off between co-operation and competition in long-term investment in electricity.

One theory of public economics suggests that one way to proceed with a line expansion is to make the investor pay for the negative externalities generated. For example, if the feasibility of previously allocated transmission rights is unavoidably violated, the investor has to buy back some transmission rights from those who held them initially, or the system operator has to retain some transmission rights during the long-term FTR auction to assure that the expansion project does not violate the rights of the original FTR holders.

B. Award of Transmission Rights

A transmission investment usually increases the quantity and variety of FTRs that can be issued. The merchant transmission model grants the investors a number of incremental transmission rights. This will at least reduce the degree to which it relies upon the traditional regulatory mechanism. The selection of incremental transmission rights that the ISO can issue is limited by a simultaneous feasibility test procedure, which verifies that the transmission system could simultaneously accommodate injections and withdrawals corresponding to every outstanding transmission right. It also ensures that the congestion rents collected by the ISO will be sufficient to fund the amounts it must pay to the holders of transmission rights. This means the ISO will be revenue adequate and no cost becomes socialized from this aspect. Incremental FTRs can be identified based on the changes in the feasible FTR sets due to the investment. The awarding of FTRs can be based on investors' choices. An auction process for incremental FTRs associated with the specific transmission investment can be designed.

In a similar manner, FTRs created by transmission enhancements that are funded by consumers can be used to offset transmission usage fees.

C. Quantitative assessment of Economic Value

There are two competing approaches for predicting the direct economic benefit of a transmission change: a fundamental approach that relies on simulation of system and market

operation to arrive at market prices, and a technical approach that attempts to model directly the stochastic behavior of market prices from historical data and fundamental analysis. While the fundamental approach provides more realistic modeling under specific scenarios, it is computationally prohibitive due to the large number of scenarios that would need to be considered. One proposal is to combine the strengths of the two approaches by developing specific market models that are based on stochastic modeling of prices that are calibrated using probabilistic simulation of the overall electric power system [8]. Long-term transmission rights can also be evaluated based on probabilistic power flow analysis. The value and availability of transmission rights is defined in terms of probability of the occurrence of system congestion. The Monte Carlo approach, with importance sampling techniques, can be employed to compute circuit flow probability distribution based on given load curve and generation/transmission characteristics. Different levels of firmness establish the likely value of transmission rights.

IV. PROPOSED TRANSMISSION INVESTMENT SCHEMES

The three investment forms discussed above address different aspects of transmission enhancement. Consequently, some combination of investment forms is needed if all benefits are to be considered in the investment decision. These combinations are discussed below.

A. Cost Allocation of Reliability/Required Enhancements

For reliability enhancing or system-wide economic efficiency improving transmission investment, the principle of having the beneficiaries pay is generally accepted at least on some level. In many cases, this principle is applied either to an entire control area, or to some local zone. The former approach is based on the belief that everyone in the system benefits and the cost should be socialized. The latter approach recognizes that specific zones may choose to increase reliability beyond that typically acceptable to a larger area (New York City, for example).

It is difficult to assign costs equitably to local zones. The needs and desires of consumers within a zone vary but the actual level of reliability will essentially be the same for all. Consequently, these improvements must be endorsed through a political process rather than a pure technical or economic assessment. The fairness principle also arises in the treatment of surrounding zones. A change made to benefit one zone rarely stops at the zone boundary. Other zones in the electric vicinity may also benefit from the change. A flow-based method, as outlined below, can be applied to determine who benefits.

Cost allocation is based on beneficiary distribution factors of the proposed transmission facilities to each transmission zone. A representative network topology needs to be constructed with appropriate details for the scale of the transmission project. Each zone is represented by a few aggregated power

injections or withdrawals on the representative network. The beneficiary distribution factors are calculated, based on power transfer distribution factors of representative injections and withdrawals, with respect to each invested facility being aggregated to each zone. These beneficiary distribution factors should be normalized to prevent over or under cost coverage. Within each zone, the cost share can be further allocated to each load serving entity (LSE) according to its load percentage. A few specific points worth being noted follow:

- a. A number of representative system loading scenarios need to be identified to calculate the beneficiary distribution factors. And the factors need to be updated over time with the changing of transmission network topologies.
- b. For an economic efficiency-improving project, loads being hedged by transmission rights should not be counted for cost allocation over the hedging periods. Otherwise, the corresponding LSEs over-pay for the potential congestion.
- c. The beneficiary distribution factors of through-transfer customers need be calculated as well in the corresponding time-periods.
- d. To take the various postulated contingencies into account, which lead to various beneficiary distribution factor values, the maximum or weighted average value rule applies.

B. Invest in and Sell Reliability

High reliability means that the system maintains adequacy and can rapidly restore operating margins following a disturbance. With the recognition of potential disturbances and other persistent uncertainties, generation owners and consumers usually expect higher reliability to support power transactions.

On the transmission level, taking into account thermal/stability constraints, postulated contingencies, and different market scenarios, a number of performance indices can be defined. Conceptually, associating the quantified changes to performance indices with economic values provides a mechanism for assessing reliability investment that could serve as a basis for justifying cost recovery. The basic idea behind this is to sell reliability as a quality factor of the service. Of course, investment in transmission alone cannot achieve a desirable reliability level; similar mechanisms need to be established for generation and distribution sectors as well to achieve the coordination.

Examples of such mechanisms include transmission reliability margin (TRM), defined as the margin between transmission facilities' capacity and their commitment, and capacity benefit margin (CBM), defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems in order to meet generation reliability requirements. Reliability requirements of consumers can be collected, aggregated and transformed to these indices on the underlying transmission facility, and reflected in the valuation and beneficiary identification of the investments.

Consumers' requirements for reliability can be proactively reflected by their preference for firm load serving or supply contracts, or willingness to join demand side response programs or other innovative service contracts. The reliability-enhancing cost can also be recovered by adding an additional component in the location marginal price. Basically, the reliability requirements constitute another set of constraints in system dispatching and the incremental cost incurred can be identified. Again, however, since any group of consumers will have varying preferences, this system depends on political processes to define acceptable performance criteria and value curves.

C. Awarding More Rights for the Market

One potential problem with market-based merchant transmission investment is the insufficiency of the potential revenue flow as compared with the cost incurred. Of course one method to solve this problem is to combine regulatory and market-based mechanisms, depending on regulatory cost allocation to make whole the cost recovery. However, establishment of more awardable rights with market-dependent values could make the mechanism closer to its original objective. Capacity reserve payment rights could serve as one of the market-based value mechanisms.

Basically, a complete electricity market should have an energy transaction market (forward and spot) a generation capacity market (forward and spot) and a transmission market, which is actually a derivative market based on the former two. The financial transmission rights, as widely established, are actually defined for, and get monetized in, the energy transaction market. Similar reasoning argues for capacity reserve payment rights, which can be defined for, and get monetized in, the generation capacity market.

Transmission investments that relieve generation capacity reserve requirements convey a benefit that is not monetized today. Usually, load-serving entities are required to set up or buy generation capacity reserve for their service area. The marginal cost of this capacity reserve differs at different locations and it changes as the available transmission capacity changes. For example, a large spread is acknowledged as existing between the marginal cost of installed capacity in New York City and the rest of the state. Therefore, capacity reserve payment rights can be defined and be awarded to a merchant transmission project that lowers this requirement and lowers the prices of this capacity reserve.

D. Combined Benefits

Incentives from one group of potential investors, who seek direct economic benefits through reducing congestion cost for consumers or increasing production and delivery for suppliers, can be combined with another group of interested investors, who seek the right to impose a market-based transmission service charge as well as to obtain incremental transmission rights to recover the cost. Fig. 3 illustrates this concept for a simple system.

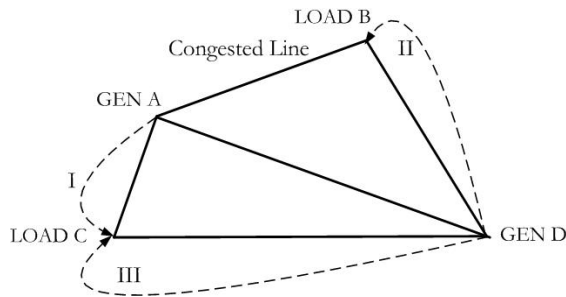


Fig. 3. A Simplified Illustrative System

In the 4-node system, a low-price generator and a high-price generator are connected at nodes A and D respectively. Two consumers reside at nodes B and C. Suppose that a transmission line between nodes A and B limits the power transfer from A to B. Due to the externalities of the transmission network, this transmission capacity bottleneck also limits the power transfer from A to C and D to B.

Suppose generators at node A and consumers at node B are interested in initiating an economic expansion project to improve the transmission capacity on transmission line AB. Suppose another merchant transmission investor might be interested in expanding the current capacity of line AB, not necessarily for supporting the transactions between A and B, but for the revenue-collection potential of resulting incremental transmission rights. An example would be incremental point-to-point financial transmission rights from nodes A to C, D to B and D to C. By identifying willingness on both parts to invest, the involved potential investors can share the capital cost and make the transmission project more possible.

Improved reliability could also provide additional benefits for a project. If, as suggested above, reliability can be represented by a value curve rather than a minimum threshold requirement, then it should be possible to assign a reliability benefit to a transmission change. The recovery of this value could be accomplished through an adder to the transmission usage fees for benefiting consumers. Of course, if the transmission change decreases reliability, it can also be argued that the project sponsor should pay to reduce the transmission fee for affected consumers.

V. PROPOSED TRANSMISSION INVESTMENT SCHEMES

A. Coordination of Generation and Transmission Investments

Up to and into the 1990s, transmission and generation resources in each franchised service territory were generally planned through an integrated process. Some entities, such as PJM, the New York Power Pool, and the New England Power Pool, coordinated resource planning on a regional basis. Utilities built generating resources and transmission infrastructure as required under regulation to reliably meet consumer demand. However, as a result of electric power industry restructuring, planning was dispersed among multiple parties. Decisions to add merchant generation to a competitive marketplace are made in isolation without considering the

potential for substituting a transmission project. Generation investment is made in response to market opportunities in energy, capacity and ancillary service markets. These decisions can generally be made quickly with relatively short implementation times. As a result, transmission planning is often placed in a reactive posture.

In a market-driven restructuring environment, generation capacity decisions and transmission capacity decisions are separate functions. However, physics dictates their interdependence. The generation mix in the system influences the distribution of future electricity prices across the system and therefore influences the value of a potential transmission investment project. In turn, the need for transmission and the profit opportunities for transmission reinforcements are impacted, to a large degree, by future generation expansion. Generation and transmission investment may either compete with or complement each other, depending on the relative positions and situation of the electrical vicinity. If the transmission investment connects the load center to a remote low-price generation resource while a new generation resource enters the same load center, they will compete with each other. Under other conditions, a transmission line expansion may improve the profitability of a generator that is exporting power, as it increases the volume of power that the exporting generator can sell and deliver. When evaluating the value of a transmission investment over a long period of time, the investor in either sector needs to take layout of the other into consideration. Thus, the transmission valuation process ultimately needs to include some projection of generation investments and retirements in response to based on rational financial profit and risk criteria to projected market conditions such as fuel and electricity prices.

B. Identification of Price Distortion

The nodal pricing system is the most conducive framework for merchant investment because nodal prices provide a measure of locational scarcity that is necessary to make this framework a plausible option. The effect of a merchant transmission reward mechanism depends implicitly on the effectiveness of the pricing mechanism. It assumes that nodal electricity prices fully reflect consumers' willingness to pay, and all network externalities are internalized [4].

When imperfections that lead nodal spot electricity prices to depart from their efficient levels exist in the competitive wholesale electricity markets, investment incentives will be distorted. For example, when unregulated generators have market power, nodal energy prices will be distorted from their efficient levels. These distortions may lead to over-investment or under-investment depending upon where in the network electricity generators have market power. Imperfect government interventions to control market power in competitive wholesale electricity markets may also distort investment incentives.

The clearing price of transmission rights, as auctioned, may also include risk premiums. Researchers find that FTRs in the

New York market do not reflect the congestion rents, both for large exposure hedges and over large distances, and that the FTR holders pay excessive risk premiums. This may be due to the way the FTRs are defined, with fixed capacity over a fixed period and high transaction costs for disaggregating them in the secondary market. Market players, therefore, consistently predict transmission congestion incorrectly for all other hedges than the small and straightforward hedges. Also, the large number of possible FTRs decreases price discovery. Pricing of FTRs is based on anticipated and feasible congestion patterns which may not be realized in the actual dispatch.

C. *Strategic Interactions between Transmission Investors*

The transmission investment environment is constantly changing. Future revenue forecasts must include assumptions regarding other potential transmission projects. Scenario analysis may be an appropriate way to deal with uncertainty regarding these and other future conditions.

System-specific rules for assigning costs to individual transmission projects may make the order of the transmission investments important. For example, the first project may be assigned the entire cost of upgrading a supporting facility that also benefits a second project. In this case, there may be an advantage to going second. Alternatively, the first project may not require an upgrade while the two projects together do. In this case, going first may be a distinct advantage. These distinctions prompt strategic behaviors that can also distort pure economic analyses.

Another possible strategic behavior could come up in case of complementary merchant investments. A transmission investor has the incentive to choose a specific low transmission capacity to create transmission bottlenecks and grab the transmission right revenue from the congestion rents.

VI. CONCLUSIONS

Before the restructuring of the power industry, transmission investment decisions were made by central agents in balance with other issues, with all cost incurred being socialized among customers. However, situations have changed in the current market environment. An explicit benefit analysis is necessary to distinguish various incentives from all market participants for capital investment. Given the complexity in transmission investment due to the physical, economic, and regulatory characteristics of transmission system, together with the significant market uncertainty, the strength of various incentives should be combined to solve today's transmission inadequacy problem. Different cost allocation mechanisms can be employed in accordance with various benefits implied. This paper analyzes the incentives, obstacles, and motivations for transmission investment in the market environment, and investigates alternative regulatory and market-based mechanisms to contribute to the intensive discussion of the topic.

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