Long-Term Rights for New Resources: 
A Crucial Missing Ingredient in RTO Markets

By Cynthia Bogorad and William Huang

I. Introduction

Regional transmission organizations (RTOs) with locational marginal pricing (LMP) markets have come under increasing criticism. Key concerns include failure to deliver the low energy costs that competitive markets promised, lack of accountability to consumers, and the absence of long-term transmission rights. These concerns are related. RTOs rely on spot market price signals to spur generation and transmission construction and provide only one-year (or shorter) congestion hedges; instead of being directly accountable for getting transmission built, the RTO “clearinghouse” transmission planning process identifies needs and allows generation and participant-funded transmission solutions to compete with each other to meet them. These policies support, at best, gas-fired generation installed close to load and a minimalist grid.

We cannot remain on this course. Any short-run efficiencies that LMP markets produce will be worth less and less if such markets discourage needed investments in baseload generation and transmission. Short-term-focused RTO markets, although well-suited to some suppliers in retail access states, must be adapted to also meet the needs of the entities most likely to finance the next generation of baseload resources: load-serving entities (LSEs) obligated by contract or state law to provide reliable service at stable prices. Unless the generation that can produce low-cost energy is brought back into the mix, RTOs will become just a very expensive means to deliver high-cost energy and to allocate increasingly scarce, natural monopoly transmission resources to those prepared to pay the most.

This new direction requires long-term transmission rights, at least for baseload (e.g., coal or nuclear) and renewable (e.g., wind) generation that cannot be located close to load, to ensure delivery of their output at a predictable price. Restoring long-term rights, which have been a staple of this capital-intensive industry, will enable LSEs to make such generation investments and the long-term power purchases independent power producers (IPPs) require to support their financing. Integral to making long-term rights available is a revamped RTO planning and expansion process that is accountable for getting the transmission built to support them. Such a process would also create the transmission infrastructure required for competitive generation markets and to reduce
mounting congestion costs and growing dependence on complex and intrusive market power mitigation.

FERC has recognized the need to consider a new approach. It recently invited comments on a Staff Discussion Paper that documents the absence of long-term rights in LMP markets and provides options for how they might be structured, while identifying impediments. Long-term rights, and planning and expansion to meet the reasonable needs of LSEs, are also elements of the pending comprehensive energy legislation.

Pragmatic approaches to long-term rights can be accommodated within LMP markets; these markets’ claimed short-term efficiencies can be achieved without sacrificing LSEs’ ability to invest in baseload and renewable resources. New long-term rights should be made available at least where they are needed the most—for baseload and renewable resources that cannot be located close to load and therefore cannot otherwise be protected from congestion risk. Ten-year terms, with rolling renewal rights that cover the term of the associated resource commitment, would enable LSEs to achieve delivery-cost certainty over the life of a generating plant and fit into a realistic RTO transmission planning and expansion process, a link crucial to assuring the financial integrity of the rights. While alternative structures are possible, long-term rights are best structured as “dispatch-contingent FTRs” tailored to achieve their limited purpose of hedging congestion from specified generation-to-load, without creating opportunities for windfalls or excessive risk.

II. The Case for Long-Term Rights

Except to the extent affected by retail competition, LSEs in general, and public power and cooperatives in particular, have statutory or contractual obligations to serve wholesale and retail customers at the lowest reasonable cost over the long term, consistent with reliable service and good environmental stewardship. This objective requires them to maintain a cost-effective power supply portfolio. While some RTOs show increasing reliance on the spot market (due to credit issues), typically the overwhelming majority of the energy that such an LSE supplies its customers comes from its portfolio, although on a daily basis, if economic, it may substitute spot market energy.

LSEs make long-term commitments to generation, in large part, based on a delivered price expectation. Putting aside capital costs, this expectation is driven by a commodity component (fuel) and a delivery component (transmission). Transmission-dependent utilities (TDUs) historically have managed delivery component risk by obtaining firm transmission rights matching the resource commitment. To obtain long-term firm service under the Order 888 tariff, TDUs (typically as network customers) committed to pay a load ratio share of the embedded cost of the provider's transmission system, including upgrades necessary to maintain all firm service granted by the provider. This commitment gave the transmission owner long-term financial and planning certainty. In exchange, it was required to plan and expand its system to assure that firm transmission service from network resources was comparable to the service provided its native load customers.
Whether the Order 888 tariff in fact overcomes a vertically integrated transmission owner's significant disincentives to invest in transmission that exposes its generation to competition can be questioned. But the tariff's built-in accountability mechanism assured that if a transmission provider failed to fulfill its obligation to plan for network customer needs on a basis comparable to native load, the provider's native load shared the pain. If necessary to maintain firm service (after shedding non-firm transactions), all network resources were subject to redispatch on a least-cost basis with the increased cost shared among network users, including the transmission provider's native load.

Order 888's nearly perfect hedge against congestion costs provided the certainty needed to support the financing, and protect the economic value, of high capital cost investment in baseload resources and commitments to long-term power purchase agreements. Once firm transmission was granted based on source-to-sink deliverability, the delivery price was locked in, except for gradual and broadly shared changes – i.e., a load ratio share of the increased embedded cost transmission revenue requirement as upgrades were made, plus a load ratio share of cost-based redispatch.

All this changed with the introduction of LMP markets. Network resource designation, now judged on aggregate deliverability, assures no delivered-price certainty. Instead, LSEs are subject to volatile congestion charges reflecting the difference between the marginal price of energy at their generators and the marginal price of energy at their loads. For baseload and renewable resources that cannot be sited close to load, the only way to achieve delivered-price certainty roughly comparable to that enjoyed under Order 888 is through an FTR, which pays (or charges) the holder for this locational price difference. To maintain the financial integrity of the FTR system, RTOs generally limit FTRs to those that are simultaneously feasible. LSEs are annually at risk that the rights they need to hedge congestion on existing or new resources will be pro-rated. The only long-term rights offered – for transfer capacity created by participant funded upgrades – are ill-suited to supporting generation investments. No RTO offers new long-term rights for new resources.

Thus, in today's LMP markets, not only is the value of pre-existing generation investments at risk, but new baseload investments are highly risky. LSEs may incur high baseload capital costs only to pay (due to congestion) delivered energy costs at their load that reflect gas-fired generation.

For example, a 600 MW coal unit costs roughly $1 billion to construct, while 600 MW of gas-fired peaking capacity costs only about $300 million. At today's prices, the variable production cost from a baseload coal plant would be less than $20 per MWh. In comparison, the variable production cost from an older gas-fired peaking plant would be about $80 per MWh. Under Order 888, if an LSE paid the coal plant's high capital costs, it would be assured delivery of the $20 per MWh coal-fired energy produced (assuming the plant achieved network resource designation). Under LMP, it could spend $1 billion on coal-fired capacity and still face the risk that, due to congestion between the
resource and its load, the delivered energy price would reflect the $80 per MWh production cost of gas-fired capacity.\textsuperscript{16}

No one needs to spend an extra $700 million to risk paying for $80 per MWh energy. To incur the high fixed cost of baseload coal-fired generation and end up paying a gas-fired energy price at the load due to congestion would be disastrous for customers. But this is the risk LSEs are forced to take absent long-term congestion protection. Annual FTRs won’t do the trick.

Financial rating agencies recognize this risk. In a report prepared in September 2004, Moody's indicated:

\begin{quote}
[T]here is potential risk in the short-term marginal pricing model being used in various regional energy markets in the U.S. Without long-term contracts for transmission rights and price certainty for the transmission of energy from new generation facilities, cost recovery in the long term may not be assured. The certainty of cost recovery represents a major factor in the credit assessment of financings for new generation projects.\textsuperscript{17}
\end{quote}

According to \textit{Megawatt Daily}, Moody's recently commented that “use of locational marginal pricing by [RTOs], which may eliminate long-term transmission contractual agreements, could impair certainty of transmission access to recover debt financing costs for new generation projects.”\textsuperscript{18}

This is not a transitional issue. The assumption that spot market pricing will result in needed generation and transmission investment has been debunked by rating agency reports,\textsuperscript{19} at FERC technical conferences,\textsuperscript{20} and by experience. Its track record on producing the baseload coal units that would lower LMPs is particularly grim. It is no mere coincidence that virtually all new plants planned for construction in MAAC are gas-fired,\textsuperscript{21} even with eastern coal nearby.

The current model is not working even in the most mature LMP markets. PJM's board has concluded that eastern PJM reliability may be compromised as early as 2008, and that it “would be imprudent to rely on energy market scarcity prices” to ensure needed generation gets built because experience has shown that short-term market signals simply will not encourage the investment needed for long-term generation capacity needs.\textsuperscript{22} Short-term markets have not encouraged the construction of needed transmission, either. PJM has been “very, very disappointed” by the results of its planning process for “economic” transmission expansion, and views long-term rights as part of the solution to a “minimalist transmission policy” that has produced a “transmission system on life support as opposed to that robust system we want.”\textsuperscript{23}

This issue cannot be put off. Many LSEs are currently considering participation in new baseload or renewable facilities. The lack of the long-term rights needed to support these investments distorts today's power supply choices, which will affect the delivered cost of energy to consumers for decades. Absent access to stable delivery prices over the long term, baseload generation will lose out to peakers. If load must pay high gas-driven
LMPs anyway, why not take the cheap installed-cost way out, instead of paying for high installed-cost baseload coal generation? Wind alternatives will similarly suffer. This is not good policy.

We must go back to basics. As RTOs substitute financial for physical rights, the paramount objective must remain the same—i.e., providing long-term certainty that the economic value of generation investments can be delivered to customers. If LMP markets are to provide value to customers, they must offer long-term rights that support investment in the new baseload and renewable resources required for fuel diversity, to maximize energy independence, and to provide consumers adequate supplies of energy at stable prices.

III. Long-Term Rights that Work with LMP Markets

While new long-term rights fully equivalent (in terms of eligibility, term, and attributes as a congestion hedge) to those available under Order 888 would be desirable, we outline below more limited rights, designed to overcome impediments identified in the Staff Paper. However, we first briefly address existing long-term rights, which must be protected as part of developing new long-term rights for new resources.

Existing rights come with a strong reliance interest, and their preservation is crucial to the ability of LSEs to meet ongoing statutory and contractual obligations to provide reliable service at affordable, predictable delivered prices. TDUs, in particular, fought hard for the long-term firm transmission rights that support billions of dollars of generation commitments, many of which have years to run. Because they often were forced to look remotely for power sources that would put them in competition with the surrounding utility, TDUs are particularly vulnerable to congestion risk if the existing long-term transmission rights, on which those resource decisions were predicated, are undermined, i.e., if continued generation-to-load deliveries, for which the transmission provider was obligated to plan, are subject to volatile unhedged congestion charges. (Large, vertically integrated utilities, which typically rely on generation on their own transmission systems, are less exposed to congestion, especially given their role in planning those systems.)

Recognizing the strong equities involved, FERC, in its April 28, 2003, White Paper, committed that in LMP markets, existing customers would be held harmless and would retain their pre-existing transmission rights. While individual RTOs handle FTR allocations for existing resources, all regions should be required to satisfy this commitment. This is a particular concern in MISO, which provides less complete protection of existing rights than PJM and NYISO, and appears poised to discard even those protections after only five years—a result inconsistent with the White Paper.

In addition, all RTOs should offer new long-term rights: (1) for new baseload and renewable resources; (2) on a rolling 10-year term with renewal rights; and (3) with hedging characteristics tied to use of the resource (dispatch-contingent FTRs).
A. Eligibility: new baseload and renewable resources

While LSEs would benefit from more broadly available long-term rights, at minimum they must be offered where they are needed the most – for generation that often cannot be sited close to load. New nuclear units plainly will not be built at load centers. New baseload coal resources must be sited near rail, water, and high-voltage transmission, and must take account of air quality attainment areas and other limiting factors. Renewable resources too must often be located remote from load. In regions where new baseload resources will be gas-fired, long-term rights may be appropriate – especially where zonal-for-load/nodal-for-generator LMP treatment can result in congestion charges even for generation at the load.

To hedge congestion costs associated with delivery of a new generator's output to load, the rights should be defined as real source (or border, if the source is located outside the RTO) to real sink.

Limiting eligibility for long-term rights facilitates their integration into RTO markets, addressing liquidity concerns and leaving room for those market participants with a short-term business model.

B. Term: a rolling 10-year term that affords the LSE unconditional renewal rights

Under Order 888, LSEs were able to obtain transmission rights that spanned the life of the resource in exchange for a long-term commitment to take service from the transmission provider. In the RTO context, long-term rights could be structured to reproduce key elements of this bargain.

To balance the LSEs’ need for delivered-price certainty with concerns expressed in the Staff Paper, long-term rights should have a rolling 10-year term. An LSE that makes at least a 10-year commitment both to a qualifying new resource and to pay the transmission system costs could receive a 10-year right with rolling renewal rights. Assuming a 10-year renewal notice, if the renewal right is not exercised in any given year, the long-term right would expire 10 years later, when the LSE would have to take its chances in the annual FTR allocation process. In any event, the long-term right would not be renewable beyond the term of the associated resource commitment.

A 10-year term with an assured right to renew would meet the needs of LSEs seeking to finance generation, e.g., over a 30-year term, so long as the renewal right was unilateral to the LSE, unconditional, and not subject to imposition of any additional charges (e.g., for upgrades required to maintain those rights). The LSE could show it had a right to a congestion hedge for the full 30-year financing term, with no added costs for renewal so long as it timely exercised its renewal rights.

This structure mitigates risks to LSEs of committing to very long-term FTRs in markets whose structure is still evolving. It also mitigates the risk to RTOs, by tying initial and renewal rights to a realistic RTO transmission planning horizon, and pairing
them with a long-term payment commitment on the part of the LSE. RTOs will have the advance notice necessary to integrate long-term rights into their planning process. The long-term commitments should allow RTOs to justify construction of transmission upgrades, if necessary to support the long-term rights.

C. Design: dispatch-contingent FTRs and other alternatives

1. Dispatch-contingent FTRs

Conventional FTRs produce a stream of revenues or charges based on the difference in LMPs at the source and sink every hour, even when the associated resource is idle. The resulting mismatch exposes long-term right holders to additional risk and potential windfalls.

Offering new long-term rights that produce revenues or impose charges only when the identified plant runs would eliminate this mismatch. If the plant is operating, the value/cost of the dispatch-contingent FTR would be the difference between the LMPs at the source and sink; if the plant is not operating, the FTRs value/cost would be zero. A long-term dispatch-contingent FTR, in the amount of the LSE's resource commitment, would more accurately hedge congestion for the associated resource than a conventional FTR. This is especially true for renewable resources with low capacity factors.

In theory, such long-term rights could encourage dispatch of units that would otherwise be uneconomical. However, this theoretical issue should not be a problem in practice given the limited resources eligible to receive long-term rights. Baseload coal and nuclear units will run virtually all of the time. LSEs have virtually no dispatch control over renewable resources such as wind, run-of-the-river hydro, and geothermal.

By affording a hedge similar to that provided under Order 888, dispatch-contingent FTRs would eliminate creditworthiness concerns identified in the Staff Paper. By restricting FTR payments and charges to hours when the resource is actually running, dispatch-contingent FTRs would essentially eliminate exposure to unhedged FTR charges when congestion reverses. If LMPs are higher at the generator than at the load, the LSE holding the dispatch-contingent FTR would incur an FTR charge for the difference in LMPs only when its generator is producing energy and therefore receiving offsetting LMP revenues. When the eligible generator does not run, the LSE would be relieved of any FTR payment obligation.

By the same token, an LSE holding a dispatch-contingent FTR would not receive FTR revenue if LMPs at its load are higher than at the generator, but the LSE's generator does not run. It would therefore have no incentive to acquire the FTR for its value as an FTR, separate and apart from its role as a hedge against congestion between a specific generator and the load to which it is dedicated. Particularly in the context of renewable resources with low capacity factors, this restriction would limit the revenues required to fund dispatch-contingent FTRs, compared to conventional FTR obligations.
RTOs should be able to accommodate long-term dispatch-contingent FTRs without significantly disrupting short-term markets. The eligibility criteria will restrict the pool of resources for which LSEs may seek long-term rights; the real-source-to-real-sink requirement and 10-year minimum term may deter some who otherwise would be eligible for such rights. Because they eliminate payments to FTR holders when the unit is not operating, dispatch-contingent FTRs should have limited appeal for market participants interested in FTR speculation.

2. Other alternatives

While dispatch-contingent FTRs are the best way to address generation-to-load congestion risk for baseload and renewable generation investment, while minimizing short-term market impacts, long-term FTRs, or an FTR allocation protocol that gives priority (with meaningful assurance of full allocation) to long-term right holders in annual FTR allocation processes could theoretically be designed to provide many of the same benefits. However, they pose additional challenges.

a. Long-term FTRs/ARRs

Long-term FTRs could be structured like today's annual FTRs, but with a longer term – rolling 10-year FTR obligations in the amount of the LSE's resource commitment, or in the case of intermittent renewable resources, some lesser amount designed to hedge the associated congestion.

The rights could also be configured as rolling 10-year auction revenue rights (ARRs), entitling the holder to revenues from successive auctions of shorter-term (e.g., annual) FTRs. However, ARR holders must have the right to convert those rights directly to FTRs without participating in an auction, consistent with the practice in PJM. Automatic conversion allows ARR holders to avoid risk of inaccurate valuation by bidders, as well as the transaction costs (including creditworthiness issues) of “bidding the max” at auction to ensure they win the associated FTRs.

As compared with dispatch-contingent FTRs, long-term FTR/ARRs not only may cost RTOs more to fund, but subject their holders to greater potential risks (when congestion reverses and the identified resource is not running) and associated creditworthiness issues. For intermittent resources – e.g., wind and run-of-the-river hydro plants – a conventional FTR obligation equal to the LSE's commitment to the resource could significantly overpay or overcharge the LSE as compared with congestion costs incurred. While a conventional FTR could be designed that has the same expected value as congestion between a given generator and the LSE's load, it would require very complex calculations and projections for each unit, both in terms of projected dispatch and projected congestion charges, taking account of sometimes dramatic year-to-year variations.

b. Assured priority for long-term right holders in allocation processes for short-term rights
PJM and NYISO have developed approaches that provide full protection for historical resources without necessarily allocating conventional long-term FTRs. In both RTOs, holders of existing long-term rights receive priority in the FTR allocation process, either by allowing them first crack at the available FTRs each year before the allocation process begins, or by reserving the transmission capacity necessary to honor those rights, so that it is not included in the FTR allocation process.

A similar process could be used to allocate rights to LSEs that make long-term commitments to eligible new resources. Before the annual FTR allocation process begins, each LSE with a long-term right would be entitled to designate FTRs from the eligible resource to its load, up to its full resource commitment (or, for low-capacity-factor renewable resources, some quantity calculated to reflect the expected value of congestion between generator and load). This approach enables LSEs to decide on an annual basis whether they want the FTRs, but may make it harder for the RTO to plan for simultaneously feasible FTRs over time.

The priority right to an annual allocation process would be meaningless if insufficient FTRs are available to the long-term right holders and the LSE's FTRs are subject to availability, and thus pro-rationing, on an annual basis. To avoid being a hollow promise, or simply displacing existing rights, adoption of this mechanism must be accompanied by assurance that the RTO would achieve and maintain simultaneous feasibility of these FTRs, in combination with FTRs for existing resources, or be accountable for a failure to do so.

**IV. Transmission Planning and Expansion that Supports Long-Term Rights and Competitive Markets**

Although a key purpose of RTOs was to improve transmission planning and expansion to achieve a robust regional grid,33 the opposite has occurred. Transmission investment has fallen behind; new transmission lines are needed to prevent reliability problems, reduce congestion costs, and enable growing loads to be served from new baseload generation consistent with environmental limitations.34

Despite the clear need for transmission expansion to address these problems, as well as to minimize opportunities for the exercise of market power and the need for intrusive mitigation, little gets built while we dissect the purposes for upgrades and determine beneficiaries for projects that necessarily have broad benefits. Even PJM has conceded that the current regimen, with its sharp distinction between (rolled-in) reliability and (participant-funded) economic upgrades, is producing “disappointing results.”35

Do we want a “minimalist” transmission grid that essentially serves as an “add-on” facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant
generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? ....

In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. … Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of “building blocks” is needed.36

While many reasons contribute to the lack of transmission investment,37 one is an unintended side effect of RTO creation: diffuse responsibility and lack of accountability for ensuring an adequate grid. Order 888 transmission providers were responsible for planning their systems to assure that firm transmission service was as reliable as the service they provided to their native load customers, and faced consequences for failing to do so: load ratio sharing of redispatch charges. Transmission owners that have turned over control of their transmission systems to RTOs no longer feel responsible for planning and expanding those networks, and LMP pricing eliminates the consequences for failing to make upgrades others need. Nor are RTOs accountable for failing to do so.

The lack of load-specific deliverability for network resource designations also contributes to the ever-more-congested RTO grid. Under Order 888, network resources were required to pass a source-to-sink deliverability test. In the RTO context, “aggregate” deliverability is used instead,38 which assumes delivery of particular resources to load is irrelevant because LMP markets will accomplish delivery through redispatch.39 By relieving RTOs of responsibility to assure that LSE resources are deliverable on a source-to-sink basis, aggregate deliverability severs the crucial link between transmission planning and LSE resource planning. At the same time, RTOs are relying on a more extreme source-to-sink deliverability test – 24 × 7 simultaneous feasibility – to assess the availability of FTRs.

We must set a new course to achieve the robust grid required for wholesale competition, not a minimalist grid where load is served from local generation. RTOs must be held accountable for resolving bottlenecks that burden consumers with high prices and for creating the transmission highways required for new baseload generation – the types of generation that have traditionally driven transmission development – and associated long-term rights.40

A robust grid will require discarding misguided efforts to draw a bright line between “reliability” and “economic” upgrades in the RTO planning process. The key is to provide loads access to competitive markets. Economically beneficial upgrades should be constructed. Regional transmission plans must accommodate future load growth; and the RTO transmission planning horizons should reflect realistic processes for siting and constructing transmission.

These objectives will never be achieved if we rely on participant funding, which localizes upgrade costs on individual market participants. Participant funding is poorly
adapted to a dynamic AC grid, where “lumpy” upgrades assigned to a single project may provide broad benefits, specific beneficiaries are difficult to identify and change over time, and benefits can be enjoyed by “free riders.” It invites a game of “chicken” where would-be beneficiaries sit back in the hope that others will step forward to bear the cost of an upgrade, delaying transmission construction. Participant funding’s justification of upgrades based on private benefits to specified market participants, rather than public benefits, will make the state siting process even harder. At a time when getting transmission built promptly is imperative, it is unwise to rely on a mechanism that has produced disappointing results.

The best way to achieve a robust grid is some form of regional rate that addresses the equity issues associated with transmission investment by assigning costs to reflect regional benefits, rather than to the “license plate” pricing zone where the costs are incurred. Due to the dynamic and highly integrated nature of the AC grid, high-voltage, backbone transmission lines provide benefits beyond the immediate geographic area where they are constructed. Broadly spreading major backbone facilities across regional (and/or, in very large RTOs, subregional) load, will match costs and benefits, reducing each consumer’s burden and resistance to construction. Failure to spread the costs of regionally significant facilities is likely to cause needed transmission not to be built, because of objections from local areas that would be unfairly assessed its entire costs, or cause facilities to be built at less-than-optimal size to make them more affordable.

The robust grid that results from a revamped planning and expansion process should amply support the limited long-term rights defined above. As a further check and particularly in the transition, a load-specific deliverability test should be reinstated, at least for resources for which long-term rights are sought, to determine their initial simultaneous feasibility. Where long-term rights are secured, their continued simultaneous feasibility, taking into account other rights that require preservation, must be maintained as part of the “base plan.” It is reasonable for the grid to be planned to accommodate $24 \times 7$ delivery to load of baseload resources, with appropriate consideration accorded to renewables. Whatever cost allocation method is adopted for the upgrades required to support initial assignment of a long-term right, future upgrades (if any) required to maintain the simultaneous feasibility of these rights over time and upon renewal should be “rolled in” (or regionally assigned), rather than directly imposed on the long-term right holder. Such treatment is consistent with the planning obligations borne by transmission providers under Order 888.

V. Who Bears the Risk of the System Being Inadequate to Support the Long-Term Rights?

In the Order 888 world, once firm service was granted, the transmission provider was obligated to expand its system to support such service over time (with rolled-in upgrades) or share the costs of redispatch required to maintain firm service. Both the transmission provider and its native load customers had “skin in the game.”
The tariff's accountability mechanism got lost in the transition to LMP markets. Instead of assigning redispach costs to the pricing zone that would bear the cost of upgrades that would relieve the constraint, LMP markets directly assign congestion costs to the specific LSEs whose resources are removed from their loads, on the theory that these entities (who may well have secured firm transmission rights years ago) are now “causing” the congestion. Not only is the transmission owner relieved of responsibility for the ongoing costs of any past failures to expand the system to accommodate the firm service it granted in pre-RTO days, but the RTO itself takes no responsibility to ensure sufficient FTRs to offset congestion associated with either historical or new network resources.

Accountability must be restored. Unless a transmission owner fails to follow through in good faith to construct facilities as the RTO directs, the costs of failure of the grid to support the long-term rights granted should be broadly shared throughout the RTO, or at least the pricing zone(s) that would bear the costs of upgrades required to support the long-term rights on a simultaneously feasible basis.

Under Order 2000, the RTO is the entity with the planning and expansion responsibility. It is both necessary and appropriate to hold the RTO accountable for at least meeting this responsibility as to those resources that qualify for long-term rights. Because a not-for-profit RTO is pocketless, it cannot directly bear the financial consequences of failure to do so. However, by assigning the resulting costs through an identified uplift, the cost of the RTO's planning failure can be compared to upgrade costs, so a form of accountability can be reinstated that fosters stakeholder consensus in favor of making needed upgrades, rather than delay.

In contrast, it would be unfair and inappropriate to saddle long-term right holders – who have made generation investments in reliance on the long-term rights, but have no control over transmission expansion – with the costs of the RTO's failure to maintain those rights on a simultaneously feasible basis. If the long-term rights holders were subject to pro-rationing in the event the grid is not expanded sufficiently to support the simultaneous feasibility of those rights, the RTO (and transmission owners) would be relieved of accountability for planning and expansion decisions. Such a regime would all but invite opposition to upgrades that would be more broadly assigned, playing into the hands of those who benefit from a minimalist grid, with maximum congestion and opportunity to exploit market power.

VI. Impediments to Long-Term Rights in RTO Markets Are Not Insurmountable

The Staff Paper identifies five potential impediments to long-term rights in RTO markets: (1) uncertainty about future changes in the transmission network and generation; (2) unpredictable congestion prices and patterns; (3) creditworthiness of market participants who hold long-term financial rights; (4) concern that long-term rights will tie up valuable hedging instruments, becoming an entry barrier in retail competition states; and (5) concern that long-term FTRs may be less liquid than shorter-term FTRs.
The first three impediments boil down to a concern that issuing long-term FTRs is too risky for RTOs because of the inherent unpredictability of LMP markets. Unavailability of long-term rights does not eliminate that underlying risk – it just shifts it to LSEs seeking to invest in generation that benefits the region but cannot be constructed near load (e.g., baseload coal, nuclear, and renewable generation), and in particular to LSEs who do not have the power to fix transmission problems contributing to price volatility.

The solution to the uncertainties associated with long-term rights is not to play “hot-potato” with the risk, but to give RTOs the tools they need to reduce or eliminate congestion pricing risk by fixing the bottlenecks that cause congestion: i.e., a strong transmission planning obligation, coupled with the authority to mandate construction of transmission facilities for both reliability and economic purposes. Requiring RTOs to plan and upgrade the system to support the continuing simultaneous feasibility of long-term rights, places responsibility where it belongs and restores the fundamental link between baseload plant construction and transmission expansion.

Our approach also addresses FTR market liquidity concerns. It is narrowly tailored to correct the generation investment disincentives created by the current LMP markets, so eligibility for long-term rights would be limited to new baseload and renewable resources. The remaining transfer capability (beyond that required to preserve existing rights in accordance with FERC's White Paper) would still be available for shorter-term FTRs. Particularly if RTOs’ mandate to strengthen regional transmission networks is enhanced, the resulting robust grid should be able to accommodate both long-term and shorter-term (e.g., annual) FTRs.

Finally, the fact that long-term rights may not be attractive to certain LSEs subject to retail competition should not deprive those who retain an obligation to serve of the opportunity to plan for their needs and invest in generation that will broadly benefit consumers. LSEs subject to retail competition are unlikely to finance new capital-intensive generation like new clean coal and nuclear units without PUC-assured rate recovery.44 If some LSEs in retail competition states are unwilling or unable to make long-term commitments and choose to rely exclusively on short-term transactions to serve their loads, and that is acceptable to their state PUCs, then they should be free to do so. However, this choice should not deprive all consumers of the benefits of baseload generation that depends on long-term commitments and associated long-term rights.

Many states have chosen not to adopt retail competition; even where states have adopted retail competition, some LSEs, including public power systems and rural electric cooperatives, have retained their obligation to serve. These LSEs must be able to assemble cost-effective, fuel-diverse power supply portfolios over the long term. To tell them that they should be denied long-term rights in order to maximize the availability of short-term rights is tantamount to saying, in an Order 888 world, that a transmission provider should be required to deny available transmission service because that service will tie up the capacity otherwise available to those who choose not to make long-term commitments. In a capital-intensive industry that requires long-term contracts for
financing infrastructure, a lowest-common-denominator policy approach is bad policy and contrary to the Administration's goals of encouraging the construction of new clean coal, nuclear, and renewable resources.

Long-term rights in LMP markets are not an impossible dream. We must make them a reality so that consumers can enjoy the long-term benefits of baseload and renewable generation delivered at a reasonable, predictable cost.

End Notes

⁴ H.R. 6, 109th Cong. § 1236 (as passed by House, Apr. 21, 2005) and 1235 (as passed by Senate, June 28, 2005).
⁵ These approaches are consistent with the June 27, 2005, comments of the Transmission Access Policy Study Group (TAPS) in response to Staff’s Paper, Docket No. AD05-7.
⁶ Even in retail access states, public power and cooperative systems have typically maintained their obligation to serve.
⁸ Vertically integrated transmission owners must designate network resources in the same way as network customers. OATT § 28.2.
⁹ Id.
¹¹ Curtailments or TLRs of firm service are extremely rare and non-discriminatory among firm point-to-point, network, and native load customers. See OATT §§ 13.6, 33.4–5.
¹² OATT §§ 33.2–33.3, 34.4.
¹³ If a transmission request passed, firm transmission service was granted. If not, a study identified needed system upgrades and firm service was granted subject to the completion of the upgrades.
¹⁴ Aggregate deliverability does not demonstrate that a resource can be delivered to the LSE's load on a firm basis. Instead, the resource must be deliverable to the RTO's “aggregate” energy pool without overloading the transmission system. If so, it will be granted “network resource” status, enabling any LSE in the RTO to designate the resource as its network resource even if it would not pass a source-to-sink deliverability test.
¹⁵ Assume an LSE was proposing to make a 300 MW commitment in a generator at a location with sufficient transmission capacity for delivery of 250 MW of output to the LSE's load, but which required an upgrade to create an additional 50 MW of transfer
capability. Under a participant funding approach, it would be entitled to a 50 MW long-term FTR for the new capacity created, which is hardly sufficient to support a 300 MW investment. Only generators choosing really bad locations could obtain long-term rights in amounts close to the capacity of the new generation, and then only for the segment upgraded.

The specific congestion charges will depend on the LMP at the generator, as well as the load. For example, in hours when those LMPs separate, if the LMP at the load reflects the $80 per MWh production cost of gas-fired capacity and the LMP at the coal plant remains close to $20 per MWh, then the difference would be $60 per MWh. Even if that does not occur in every hour, LSEs would face the real and difficult-to-quantify risk of large, unhedged congestion charges over the life of the unit.


See, e.g., Conference, Transmission Independence and Investment, Docket Nos. AD05-5 and PL03-1, Apr. 22, 2005 (“Transmission Investment Conference”), Tr. 37–38 (Larson, Trimaran Capital Partners) (ratebase treatment with predictable earnings is needed to induce transmission investment; incentives “introduce uncertainty into it and … increase the rate. If I need to be able to predict say LICAP for the next 20 years in New England, without the rules even being clear to me how it's being done right now, much less in five years, then I’m going to price that into the returns that I require for that type of transmission investment.”). Nor will investors fund generation projects absent long-term contracts. Conference, Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets, Docket No. PL04-2, Feb. 4, 2004, Tr. 153 (Jonathan Baliff, CSFB). See also id., Tr. 149 (John Anderson, John Hancock: “Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We’re not in this to make a killing off of spiking peak power prices. We’re putting capital into this business in opportunities that we think can provide long-term stable reasonable returns and are on the low end of the risk adjusted spectrum.”).


See PJM's Audrey Zibelman at Transmission Investment Conference, Tr. 66, 72, 73.


See White Paper Wholesale Power Market Platform, Docket No. RM01-12, Apr. 28, 2003, at 5, 10; Appendix A at 7–9 and n. 8.

In NYISO and PJM, historical resources receive full protection through mechanisms
other than long-term FTRs. Staff Paper at 10, n. 11.

27 See Conference, Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources, Docket No. AD05-3, May 13, 2005 ("Coal Transmission Conference"), Tr. 49 (Jeff Wright, FERC Staff); Tr. 195–200 (Jacob Williams, Peabody).

28 See Wind Conference Notice at 12–13 ("[M]any of the best resource areas are located far from load centers …. While fossil fuel-fired counterparts locate near load centers to avoid transmission constraints, wind resources must be sited where the wind blows. Nationally, strong wind sites are located an average distance of 500 miles from major metropolitan centers ....").

29 Most RTOs with LMP pricing use nodal prices for both load and generation, so congestion risk should be minimal for generation located at the load. Because ISO-NE uses zonal LMPs for load and nodal LMPs for generation, the LMPs may be quite different even for generation located at the load.

30 The LSE would notify the transmission provider in year one if it wanted the FTR in year 11; in year two, it would notify the transmission provider if it wanted the FTR in year 12, etc. This assumes a 10-year planning horizon, consistent with PJM's plans to switch from a five- to a 10-year planning process. Letter from Philip G. Harris to PJM Members and Interested Stakeholders, at 1 (May 31, 2005). For a shorter planning horizon, a shorter renewal period may be appropriate.

31 It was due to concern about such inefficiencies that FERC restricted availability of MISO “Option B” treatment to grandfathered agreements that settled. Midwest Independent Transmission System Operator, Inc., 108 F.E.R.C. ¶ 61,236, PP 264–70 (2004), Order on Rehearings and Compliance Filings, 111 F.E.R.C. ¶ 61,042 (2005), appeal pending. While MISO Option B shares attributes with Dispatch-Contingent FTRs, the limitation on the resources eligible for such FTRs eliminates the potential problems some argued were associated with Option B.

32 Such ARRs must be configured on a source-to-sink basis, not on an aggregate load basis as in ISO-New England.


35 Zibelman Written Remarks for Transmission Investment Conference, at 5.

36 Id.

37 See TAPS White Paper.


39 Recent data on aggregate deliverability indicates that approximately 88 percent of the
generation fleet in the MISO footprint is available for designation as a network resource throughout the region. See Generator Deliverability Test Results, available at http://www.midwestiso.org/plan_inter/gen_deliver_test_results.shtml. Montana Dakota Utilities could designate all of its network resources from Ohio or Kentucky if it wished.

Of course, RTOs need clear authority to mandate transmission construction by TOs or others. The consortium approach being explored by PJM is consistent with the inclusive transmission investment models advocated in the TAPS White Paper. See Coal Transmission Conference, Tr. 68 (PJM's Karl Pfirrmann).


See, e.g., AEP's Mike Morris (Tr. 188) and National Grid's Paul Halas (Tr. 76) at the Coal Transmission Conference; Trimaran Capital Partners' John Larson (Tr. 53–54) and ITC's Joe Welch (Tr. 81–82) at the Transmission Investment Conference. See also TAPS White Paper at 19–20.

To the extent costs of the initial upgrades, if any, required to support the new long-term rights are not assigned on a regional or subregional basis, “or” pricing would be appropriate, especially in connection with the long-term commitment to take and pay for transmission service associated with long-term rights. See Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

See AEP's Mike Morris at the Coal Transmission Conference, Tr. 230.

Vitae

Cynthia Bogorad and William Huang are both Partners in the Washington, DC, law firm of Spiegel & McDiarmid, where they represent municipal and cooperative electric systems and others at the Federal Energy Regulatory Commission and in other regulatory, judicial, and legislative settings. Much of their work is focused on organized electricity markets. Their clients include the Transmission Access Policy Study Group (TAPS), an informal association of transmission-dependent electric systems in more than 30 states. Ms. Bogorad holds a J.D. degree from Harvard University; Mr. Huang holds a J.D. degree from Yale University, as well as graduate degrees in City Planning.