UNITED STATES OF AMERICA

BEFORE THE

FEDERAL REGULATORY COMMISSION

Preventing Undue Discrimination and	)	Docket No. RM05-25-000
Preference in Transmission Services	)	

COMMENTS ON PREVENTING UNDUE DISCRIMINATION AND PREFERENCE IN TRANSMISSION SERVICES

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These comments are submitted on my own behalf in connection with the Commission's Notice of Inquiry on Preventing Undue Discrimination and Preference in Transmission Services (NOI)[1] in electricity systems. The Commission raised a number of questions "on whether reforms are needed to the Order No. 888 pro forma open access transmission tariff (OATT) and the OATTs of public utilities to ensure that services thereunder are just, reasonable and not unduly discriminatory or preferential."[2] The focus of my submission is to answer one of these questions:

> "In Order No. 888, the Commission stated that its use of the contract path model of power flows and embedded cost ratemaking was intended to <u>initiate</u> open access, but was not intended to signal a preference for contract path/embedded cost pricing for the future. The Commission further stated that it would entertain non-discriminatory tariff innovations to accommodate new pricing proposals in the future. Order No. 888 at 31,734-

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1 Federal Energy Regulatory Commission, "Notice of Inquiry on Preventing Undue Discrimination and Preference in Transmission Services," Docket No. RM05-17-000, Washington D.C., September 16, 2005.

2 NOI, p. i.

> 35. Should the Commission continue to use the contract path model in the future?"[3]

No.

The present comments elaborate on the importance of this answer and discuss the implications for many interconnected issues that face the Commission. Despite the Commission's expressed desire to narrow the inquiry "… to pursue instead a pragmatic approach to reforming Order No. 888 that focuses on the specific problems that continue to exist and targeted remedies to address them,"[4] many persistent problems of open access flow from the fundamental choice of the contract path model. The effects have implications beyond the narrow questions posed by the NOI, and spill over into other areas that the Commission is considering independently. These other matters include mandatory reliability rules, procedures for calculating available transfer capability (ATC), security-constrained economic dispatch (SCED), native load protection, transmission investment, long-term transmission rights, and resource adequacy, to name just a few.

Implicit in most of the Commission's approach to these topics is a view that the subjects can be separated from each other and dealt with more or less in isolation through pragmatic approaches without raising much concern about a more general framework. But the implicit assumption needed to make such separation possible is that the

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[3] NOI (emphasis in original), p. 13.

[4] NOI, p. 8.

underlying simplification of the contract path model is valid, or at least workable if not correct in detail. Unfortunately, this implicit assumption is without foundation. And without this foundation, the whole edifice crumbles under pressure. The supposed simplification of the contract path model is a costly illusion. Fundamental reform is required to achieve the Commission's objectives. Inconsistent targeted remedies whose principal appeal is a superficial simplicity are likely to be at best ineffective and at worst counterproductive.

Fortunately, the reform required is fundamental but not dramatic. The necessary elements are relatively few and the benefits should be substantial. The most difficult task would be to change perspective to accept the reality of the electricity system and adopt the natural alternative to the contract path model for open access. The alternative approach provides an organizing framework that the Commission could apply in many areas to guide analysis and design of new policies to address the problems ahead. The alternative model would also change the nature and focus of many of the other questions raised in the NOI. Until the fundamental issue is resolved, the conversation has nowhere to go.

Open Access, Network Interactions and Transmission Capacity

The Commission undertook a major task in Order 888. The purpose was to remove impediments to competition in the wholesale electricity bulk power market. A critical impediment is access to the integrated transmission system under terms and conditions that would avoid undue discrimination. As stated in Order 888:

> "Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace … . The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce."[5]

The idea is simple in concept. The technology for electricity systems implies that there is only one interconnected transmission grid over very large geographic, economic and political regions. It would be neither practical nor desirable for competitors to duplicate this grid. Hence, access for all parties to use the same grid without undue discrimination must be a cornerstone of policy. The goal, therefore, is important and essential.

The precise meaning of the term "undue" is not clear. My understanding is that the Commission has taken the approach that "undue discrimination" sets a high standard even though it does not necessarily eliminate all differences. The problem is not in defining the degree of non-discrimination further. Rather, the problem arises in the rules to define the constituent parts of open access.

The core problem arises from the inherent nature of the electricity transmission grid. As the Commission explained at length in Order 888, the interconnected grid

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[5] Order 888, April 24, 1996, p. 1.

produces strong physical interactions among all sources and uses of power.[6] The "transportation" process between source and destination is not like that presumed for other controllable networks with a simple "path" that can be assigned for the transaction. To a first approximation, the actual flow of power disperses across every possible path in the proportions required to equalize the marginal impedance across all paths. As the Commission stated:

> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." [7]

This observation has extensive implications. For example, because of these parallel flows it follows that every transaction has some impact on every constraint in the interconnected grid. These impacts can be so substantial that it is not possible to define or calculate the transmission capacity between locations without also specifying how the grid is used in other locations. This fact is not news to the Commission, and many parties contributing to the discussion leading to Order 888 and the associated Real Time Information Network (RIN) made this point. For example, consider:

> "A primary purpose of the RIN is for users to learn what Available Transmission Capacity (ATC) may be available for their use. Because of

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6 Order 888, pp. 92-98

7 Order 888, April 24, 1996, footnotes 184-185, p. 93.

> effects of ongoing and changing transactions, changes in system conditions, loop flows, unforeseen outages, etc., ATC is not capable of precise determination or definition."[8]

However, at the core of the Commission's contract path approach in Order 888 is idea that ATC can be defined, calculated and allocated in advance so that the participants can make decisions on how to use the network. But if ATC is not capable of precise determination or definition, the contract path cannot be the tool for evaluating or allocating use of the grid.

This inherent circularity in the definition of the contract path model for ATC is not unique to the Commission's approach or to the United States. It is a fundamental property of the current technology for electric power transmission grids. The same problems faced by the Commission appear throughout the world, and appeals to the contract path approximation fail for the same reasons. For example, in a desire to "simplify" the rules for transaction between countries, the European Union has been trying to resolve the contradictions of the contract path definition. However, the contradiction is fundamental and it does not go away, as summarized in a discussion of the European Transmission System Operators (ETSO) attempts to define the equivalent of ATC:

> "Does the draft Regulation set the right objective when it requires TSOs to compute and publish transfer capacities? ETSO says both yes and no …in many cases the (Net transfer capacity or NTCs) may be a somewhat

[8] Comments of the Members of the PJM Interconnection, Request for Comments Regarding Real-Time Information Networks, Docket No. RM95-9-000, FERC, July 5, 1995, p. 8.

> ambiguous information…The core of the difficulty raised by transfer capacities lies in the fact that they do not obey usual arithmetic: 'it makes no sense to add or subtract the NTC values…' Put it in other ways, in order to compute the maximal use of the network, one needs to make assumptions on the use of the network! This definition is restated and elaborated in ETSO (2001a) (p. 6)."[9]

The same issues arise in every interconnected transmission grid. Despite the discomfort of its implications, the basic fact is persistent and pervasive. The central problem with the contract path model and the associated ATC is that they are fictions. The gap between the fiction and reality is material and the actual ability to move power between two locations can vary from a great deal to zero, depending on the configuration of other sources and uses at different locations. This substantial gap between the fiction and the reality allows, sometimes even requires, the transmission provider to exercise undue discrimination.

In its recent request for comments on issues related to the problems with ATC calculations, the Commission noted that there were many difficulties that inhibited open access. However, the Commission argued that a principal problem was a lack of standardization that left too much room for discrimination.

> “Transmission providers have incentives to understate ATC on those paths valuable to power sellers that are competitors to a transmission provider’s own (or its affiliate’s) power sales. The lack of clear and consistent methodologies for calculating ATC can allow transmission providers the discretion to control the transmission system to favor their own power sales

[9] J. Boucher and Y. Smeers, "Towards a Common European Electricity Market--Paths in the Right Direction…Still Far From an Effective Design," Belgium. September, 2001, pp. 30-31. (see HEPG web page, Harvard University).

> or those of their affiliates. ATC can vary considerably depending on the criteria they use to calculate it and the order in which the calculations are made. Although the Commission has required transmission providers to post the formula for calculating ATC, the transmission provider has sole responsibility for, and a great deal of discretion in, its calculation. More rigorous and consistent standards and procedures for ATC calculations would help ensure that transmission providers' exercise of discretion in their calculation of ATC does not result in undue discrimination with respect to interstate transmission."[10]

This focus on standardization makes an implicit assumption that there is a possible standardized definition that would meet the Commission's objectives. If there were such a possibility, then standardization would have merit. But if the basic idea is without foundation, then standardization is an illusion.

The more fundamental point was addressed in the North American Electric Reliability Council (NERC) Long-Term AFC/ATC Task Force Report that the Commission cited as a principal source of its analysis. In particular:

> "The Transfer Capability between two areas is typically assessed or determined by modeling a generation excess in the "from" area at a specific source point(s) and a generation deficiency in the "to" area at a specific sink point(s). The increased source level at which the loading on a transmission element is at its normal rating (with no contingencies) or its emergency rating (with an outage of a generation unit or a transmission element) is be defined as the incremental Transfer Capability.
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> Selection of the specific source and sink points will impact the calculated 'power transfer distribution factors' and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service

[10] FERC, "Information Requirements for Available Transfer Capability," Notice of Inquiry, Docket No. RM05-17-000, May 27, 2005, p. 6.

> request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values."[11]

Hence, it is far more than a general interface between two regions that matters. The precise location of the sources and uses determine the possible incremental transfers. Symmetrically, the same observation applies to all other transactions which have to remained fix. The very concept of incremental (and hence total) transfer capability depends on establishing the pattern of use of the grid. If the ATC on the contract path is to be used to determine how to use the grid, the definition becomes circular. The problem is not that the calculation of ATC is not standardized. The problem is that the concept of ATC on a contract path, with the capacity determined independent of the usage of the grid, is not well defined.

In Order 888, the Commission recognized these difficulties with the contract path approach, and considered the use of alternatives that would define ATC and establish an associated pricing methodology that was consistent with the actual pattern of power flows in the grid. At the time the Commission judged the alternatives as unproven even though they had appeal. However, in an attempt to speed the move to open access the Commission adopted the contract path model and its associated pricing principles.

> "We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize

[11] NERC, "Long-Term AFC/ATC Task Force Final Report," Revised April 14, 2005, Appendix B, p. 1.

> that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule."[12]

Much has happened since. The hope that the "longstanding approach" of the contract path model could support "a non-discriminatory open access transmission environment" has proven vain. In fact, it was the inherently closed access nature of the old system in preventing a significant volume of third-party transactions that hid the defects of the contract path model.

Evidence of the immediate seriousness of the problems created by Order 888 was readily at hand. For example, shortly after the adoption of Order 888, the NERC recognized that contract-path scheduling would undermine reliability by creating incentives to overload the electricity network system. The NERC immediately adopted transmission loading relief (TLR) protocols to undo the damage whenever the system became constrained.[13] In essence, NERC created an administrative un-scheduling system

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[12] Order 888, April 24, 1996, p. 96.

[13] Rajaraman, Rajesh, and Fernando L. Alvarado. 1998. "Inefficiencies of NERC's Transmission Loading Relief Procedures." Electricity Journal, October 1998, pp 47-54.

to counteract the effects of the mandated contract-path scheduling system.[14] The NERC system did not work well.[15] However, something was necessary in order to keep the lights on.

By contrast, over subsequent years several regions implemented versions of the "new and innovative proposals" the Commission anticipated. There is now extensive empirical evidence of the pervasive and consistent problems that arise when the notional transmission model deviates significantly from reality, and subsequent experience that illustrates the benefits of building the open access rule on a foundation that reflects the critical realities of the flow of power on the grid.

Open Access Framework

There are several ways to approach a description of the necessary elements of an open access framework that reflects the actual flow of power on the grid.[ii] The subject has received a great deal of attention, but many misconceptions survive. It is important to understand what is required and what may be a choice. This is especially important in comparing well-defined open access models versus vaguely described alternatives that do not withstand scrutiny.

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14 Scott M. Harvey, William W. Hogan, and Susan L. Pope. "Transmission Capacity Reservations and Transmission Congestion Contracts, "Center for Business and Government, Harvard University, 1997. Available through the author's web page.

15 NERC Market Interface Committee Congestion Management Working Group, 1999.

First, this is not a debate about centralized systems versus decentralized systems. With current transmission technology, centralized control of scheduling and operations is required. Whether through the control area operator or the TLR-created reliability coordinators, there is explicit central control and coordination of transmission system use. As illustrated by the creation of the TLR process, to do otherwise would be to threaten the reliability of the whole system. The choice, therefore, is in the form of centralized scheduling, control and the associated pricing of transmission use, not between "centralized" and "decentralized," or between "centralized" and "bilateral" frameworks. To be sure, it is possible and desirable to allow for a wide range of bilateral contracting and scheduling to support wholesale bulk power market competition, but at some point near real time these decentralized decisions must be coordinated through the central system operator.

Second, this is not a brief for organized markets and Regional Transmission Organizations (RTO). While there are benefits from giving explicit attention to organized real-time and day-ahead markets while expanding the scope of coordination across larger regions, the RTOs do more than is absolutely necessary for an open access system. That benefit of an RTO is a separate subject. And the necessary elements for an open access framework follow from principles that apply to any grid, not just the transmission systems organized under RTOs.

Third, the open access framework does not arise as an issue of market design *per se*. However, the rules and associated pricing for transmission access naturally have implications for the design of wholesale bulk power markets. As the Commission has concluded, open access is a requirement to remove impediments to competition in the wholesale bulk power marketplace. The open access framework constrains and influences the resulting market design.

One natural way to approach the problem would be through an examination of "Balancing Services." The NOI recognizes that transmission service includes many functions other than simple "transportation." The list of so-called ancillary services includes balancing. To maintain frequency, any electricity system must maintain essentially instantaneous balance between generation and load plus thermal losses. Unlike delivery of commodities with substantial inventories or storage, electricity systems have a very limited tolerance for any imbalance between generation and load. If such imbalances occur, the change in system frequency can damage connected equipment and soon destabilize the system. This requires system operators to coordinate the inputs and outputs across the grid in order to maintain system balance.

To achieve this balance, the system operator adjusts flexible generating plants and loads. Whether this is described in terms of dispatch, net dispatch, or redispatch relative to schedules, the result is the same. Changes in load or generation, whether scheduled or not, must be balanced in real time, all the time.

Transmission limits and other constraints restrict the dispatch choices available to the system operator. There is a reliability requirement to stay within the operating limits of the grid, in order to protect against events which could cause cascading failures. Many of the constraints depend on possible contingencies, and the dispatch must be set so that power flows would still be feasible in the event of the contingency. This inherently requires calculation and central coordination. The constraints cannot be monitored by observing only the state of the system, or simply posted and used by market participants.

These requirements for system balancing and dispatch existed before electricity restructuring, and continue in the context of wholesale electricity markets. Thus the balancing system and management of transmission constraints in real time requires a system operator. The system operator adjusts flexible load and generation in order to dispatch or redispatch the system and respect the security constraints. Whether intentionally or as a byproduct, by whatever name, these actions amount to providing a security constrained dispatch.

In addition, system operators have traditionally considered cost in order to achieve an economic dispatch. This is not new. There must be some criterion to guide the choice of which generation and load should be adjusted to achieve the security constrained dispatch, and the natural choice is to seek the most economical combination within the many constraints. In a traditional system the costs might be determined by engineering estimates. In wholesale markets the offers of generation and bids by load would serve the same function. In some cases, market power mitigation rules may restrict bids to reflect engineering estimates of costs. But in all systems, this criterion leads to a bid-based security constrained economic dispatch.

Following the requirements of the Energy Policy Act of 2005 (EPAct 2005) the Commission has underway a separate process to examine the benefits of security constrained economic dispatch.

> "Within one year, FERC shall convene regional joint boards under sec. 209 of the FPA to study security constrained [economic *sic*] dispatch in various market regions and submit to Congress a report on the recommendations of the joint boards. A member of the Commission will chair each board and participate. (sec. 1298)"[16]

This is another example of the connection, rather than independence, of the various issues. The NOI covers transmission service rules and pricing, and this includes balancing service. By necessity balancing services entail security constrained dispatch. Hence, unless there is some intent to structure balancing and congestion management services so that they are purposely uneconomic, a practice which contributed to the California fiasco,[17] the transmission balancing and congestion management services are the same thing as security constrained economic dispatch.

If a transmission provider operates a balancing service that does not amount to a security constrained economic dispatch for all participants, then by definition there would

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[16] FERC Web Page on EPAct 2005 initiatives, http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act.asp.

[17] "The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced." Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61,000, Washington DC, January 7, 2000, p. 9. See also Federal Energy Regulatory Commission, "Order Denying Requests for Clarifications and Rehearing," 91 FERC 61,026, Docket ER00-555-001, Washington DC, April 12, 2000, p.4.

be economic opportunities available to the transmission provider that were not available to other market participants. In addition to the increased cost, administrative rules would be required to limit participation. The resulting lack of transparency would ensure that there were ample opportunities for discrimination in choosing which generation or load to redispatch. In many cases it might be a necessity for the transmission provider to turn to the plants it controls in order to meet the needs of system balancing and congestion management.

If the transmission provider operates a balancing service that does follow the principles of bid-based security constrained economic dispatch, then an immediate issue is the definition of the prices that will apply for transmission usage. It is by now well known that there is only one system of real time prices that is consistent with the results of a security constrained economic dispatch and the actual flow of power on the grid. This is the system that produces prices that in principle differ at every location to reflect the marginal cost of meeting an additional unit of load at each location under the security constrained economic dispatch. The generic term is locational marginal price (LMP) reflecting both the effect of marginal losses and marginal system congestion costs. The LMP at a location is the consistent price to apply for imbalances in scheduled load or generation. In addition, the difference between the prices at the source and destination provides the marginal opportunity cost of transmission incorporating the effect of the actual power flows.

Applying these locational prices to the actual payments and real time settlements provides a number of advantages. Most importantly, by construction these are the prices that reinforce reliability by making the individual incentives for generators and loads reflect the requirements of reliability and system constraints. Using any other pricing system would guarantee, by definition, that the resulting operating incentives for the market participants would be to behave in ways that are in conflict with reliability and the constraints on the system.

One major challenge is to operate the wholesale power market in a way that reinforces reliability. As described by the Blackout Task Force:

> "The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices." [18]

The use of prices and balancing rules that do not reflect the reliability constraints would seriously compromise the ability to meet this challenge. Thus the system operator would have to devise and implement administrative rules to prevent perverse behavior, reducing the efficiency of the system and making it again difficult to avoid the

[18] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004, p. 140.

opportunity or necessity for apparently undue discrimination among participants. However, with transparent locational pricing that reflects the full constraints of the bid-based security constrained economic dispatch, there would be no need for discrimination and the same real time prices would apply to all participants at or between locations.

The locational price differences can be quite substantial, often as a result of the same underlying network interactions that invalidate the assumptions of the contract path. Despite repeated attempts to dismiss this reality and assume away the problem, it is now commonplace that the costs of marginal losses and congestion can have major effects on the value of power at different locations.[19]

The locational prices provide a further advantage in addressing the problem of defining both ATC and long-term transmission rights. The volatility of these prices, especially the volatility of the difference in the prices between locations, would create an obvious need for a hedging instrument to provide long-term predictability of the cost of transmission on average if not at the margin. The natural approach that follows from the use of locational prices and bid-based security constrained economic dispatch would be the system familiar to the Commission under the generic heading of financial transmission rights (FTR). In the simplest case, an FTR would be a contract to pay (or charge) the holder the difference in the locational prices between two locations. When

[19] A simple perusal of the locational prices for any of the RTO web pages would confirm this reality. For further discussion, see William W. Hogan, "Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999, The First Anniversary of Full Locational Pricing," Center for Business and Government, Harvard University, April 2, 1999. (available at www.whogan.com)

combined with the corresponding but opposite payment for the actual use of the transmission system between the two locations, but not on a contract path, the net effect of holding an FTR would be to allow the transmission at the fixed price of contract, not at the volatile price of the real time transaction. In other words, the FTR provides a service that is similar to a physical "right" to "transport" power between two locations.[20]

A critical advantage of FTRs is that they provide an alternative approach to defining ATC. Unlike the contract path approach, the FTRs reflect the actual power flows in the transmission system under the many system constraints. A standard test is that the collection of FTRs awarded should be simultaneously feasible. As long as the set of FTRs continues to be feasible on the grid, this guarantees that the real time prices and charges for transmission use would be sufficient to fund the FTRs. However, it is not necessary that the set of FTRs be feasible in conjunction with the actual uses of the grid. Thus unlike the contract path approach, changing patterns of transmission use do not change the capacity of the grid in terms of the feasibility of the collection of FTRs. Coupled with a corresponding rule for awarding incremental FTRs for grid expansions, the FTRs become long-term rights without the fundamental defects of the contract path model. The long-trm rights are not affected by the day-to-day changes in the patterns of use of the grid. Furthermore, the FTRs do not constrain the actual pattern of use.

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[20] The actual FTR implementations allow for more diversity, including options, hub-and-spoke trading, and so on. However, the simple two location example provides the intuition that carries over in large part to the more diverse examples.

It follows that the alternative definition of ATC would be the collection of FTRs. To be sure there could be many possible configurations of FTRs that would be within the ATC of the existing grid. But once the collection is identified and allocated, future changes in patterns of grid use would not invalidate the definition. The set of FTRs could be reconfigured as participants choose, as long as the reconfigurations always satisfied the simultaneous feasibility rules. The long-term rights conferred by FTRs could be a critical ingredient in supporting transmission investment.[21]

With this definition of ATC and the long-term rights for transmission according to FTRs, there is a natural tool for providing priority for native load without violating the principle of open access and without creating undue discrimination. The FTRs could be allocated to the native load customers that are paying the fixed charges for the grid. This would provide the native load with the hedges for transmission usage charge. But the FTRs would not translate the priorities into actual limits on the use of the grid. All participants, and other peoples' native load, would be able to schedule transactions and participate in the bid-based security constrained economic dispatch at locational prices.

Getting the Prices Right

The basic open access framework recognizes that efficient and non-discriminatory balancing and congestion management service would conform to the principles of bid-

[21] For further details, see William W. Hogan, "Transmission Market Design," Center for Business and Government, Harvard University, April 4, 2003, (available at www.whogan.com).

based security constrained economic dispatch. Once this principle is established, it has implications for many other elements of the open access framework. For example, the revenues from payments for real-time transmission usage would be redistributed to the holders of FTRs. Hence, payment of the fixed charges for the grid would be structured as separate access charges, preferably according the license plate model already approved by the Commission. Payments for gird upgrades might be added to the license plate charges or assigned to the upgrade beneficiaries, along with the incremental FTRs made possible by the infrastructure investment.

An important requirement would be to do everything possible to ensure that the locational prices reflected the real operating conditions, especially during periods of scarcity. A repeated problem in early incomplete implementations of the bid-based security constrained economic dispatch model with locational prices was reluctance to fully reflect the locational impacts. For example, in PJM in 1997, New England in 1998, and California in 1999, the Commission recognized that attempts to aggregate locations into a few zones had undermined the very principles outlined above and threatened reliability and economic efficiency.[22]

These "zonal" models represent another example of false simplicity that actually had substantial unintended consequences. The comments of the California Independent System Operator (CAISO) capture the essence of the difficulty:

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[22] William W. Hogan, "Electricity Restructuring: Reforms of Reforms," Journal of Regulatory Economics, January 2002, Vol. 21, Issue 1, pp. 103-132.

> "…in reality, the 'simplicity' of the zonal system only appears so because the complexity is assumed away, allowing market participants to ignore it in scheduling while the CAISO must manage it through real time adjustments and periodic modifications to the rules to mitigate novel gaming strategies as they arrive. ... it will be far simpler, and more transparent, to design forward [congestion management] procedures to be as consistent as possible with the real-time operating needs of the grid."[23]

The results led the Commission to find that the system was "fundamental flawed" and this precipitated the subsequent effort to reform the entire California market design. More recently, a similar scenario has played out in the Texas case, with an early "simplified" zonal model producing unwanted results that made the market both less transparent and less effective. The outcome was a new effort for reform:

> "The most complete long-run remedy for both the interzonal and intrazonal issues identified in this report would be to implement nodal markets, an option that is currently being evaluated in ERCOT. These markets would provide transparent prices for both generators and loads that would fully reflect all transmission constraints on the ERCOT network."[24]

Without a locational model that truly reflects the locational differences, prices cannot be consistent with the real system conditions. This invariably creates a need for further administrative intervention to counteract the defects of the muted price signals.

In addition to the failed zonal models, implementations of the LMP approach have lingering problems that operate through various price mitigation mechanisms and special dispatch dispensations that do not fully reflect the locational scarcity conditions.

[23] CAISO proposal, "Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal," January 8, 2002, p. 14.

[24] Potomac Economics, Ltd., 2004 State of the Market Report for the ERCOT Wholesale Electricity Markets, July 2005, p. xxv.

This creates the so-called "missing money" problem wherein market prices are not sufficient to support enough infrastructure investment to meet reliability requirements. The problem is most immediate in the concerns about generation resource adequacy. The typical situation is not that there is not enough generation capacity in the aggregate. Rather the typical concern is the lack of adequate capacity of the right types and in the right locations. This in turn leads to calls for various types of capacity requirements that are intended to make up for the inadequate prices and provide the missing money. However, these resource adequacy proposals are themselves problematic. The alternative would be to address the root cause of the problem by getting the locational prices to reflect the real value of generation, especially in scarcity conditions.[25]

In short, getting the prices right reinforces many virtuous intended consequences and would reduce or eliminate related problems that confront the Commission. In the context of competitive wholesale bulk power markets, it would be astonishing if anything would work very well if the price signals were systematically distorted. And without adequate price signals, everything is more difficult. But when prices do reflect the real and unavoidable physics and economics of the interconnected grid, the price incentives reinforce the requirements of reliability, support better investment for infrastructure and resource adequacy, simplify the operation of transmission service, provide a consistent

[25] William W. Hogan, "On an "Energy Only" Electricity Market Design for Resource Adequacy," Mossavar-Rahmani Center for Business and Government, Harvard University, September 23, 2005. (available at www.whogan.com)

instrument for long-term transmission rights, produce a workable definition of transmission capacity, allow the financial transmission rights to be awarded to native load that pays for the grid, increase transparency, and substantially reduce any opportunities for transmission providers to exercise undue discrimination. Furthermore, if there is a transition to more organized markets, the necessary foundation of bid-based security constrained economic dispatch with locational prices and financial transmission rights provides a consistent approach that could be extended to more formal day-ahead markets with economic and reliability unit commitment.

Conclusion

The Commission should replace the contract path model, anywhere and everywhere. In Order 888, the Commission recognized the flaws of the contract path model. The Commission argued that it would be premature to impose generically a new pricing regime without the benefit of any experience with such pricing. The present review of the open access framework under the NOI presents a very different set of facts. There now is ample evidence that the contract path model is fundamentally flawed in material ways, and these flaws cannot be corrected with limited reform. Further the Commission has ample evidence that the basic open access framework built on the principles bid-based security constrained economic dispatch with locational prices and financial transmission rights works well both in theory and in practice. Whatever the merits of the choice of the contract path model in Order 888, there is no real alternative to replacing that model if the Commission is to fashion transmission service policies and address many other related problems to meet the Commission's stated objectives.

Endnotes

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[ii] William W. Hogan, selected submission to the Federal Energy Regulatory Commission: “Response to Notice of Public Conference and Request for Comments on Utility Issues,” ["Transmission Capacity Rights for the Congested Highway: A Contract Network Proposal"] Docket No. PL91 1 000, April 1991; “Response to the Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,” Docket No. RM93-19-000, November 1993; "Coordination for Competition in an Electricity Market." Response to an Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000. March 1995; "Electricity Transmission Policy and Promoting Wholesale Competition." Initial Response to the Notice of Proposed Rulemaking Regarding Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, August 1995;

“Comments for the Technical Conference Concerning Independent System Operators and Reform of Power Pools Under the Federal Power Act,” Docket Nos. RM95-8-000 and RM94-7-001, January 1996; "Capacity Reservation Open Access Transmission Tariffs," Comments for the Technical Conference Concerning Capacity Reservation Open Access Transmission Tariffs, Notice of Proposed Rulemaking, Docket No. RM96-11-000, September 1996; "Capacity Reservation Open Access Transmission Tariffs," Response to Notice of Proposed Rulemaking, Docket No. RM96-11-000, October 1996; “Statement at the Conference on the Commission's Policies on Independent System Operators,” Docket No. PL98-5-000, April 1998; "FERC Policy on Independent System Operators, Supplemental Comments," re the Inquiry Concerning the Commission's Policies on Independent System Operators, Docket No. PL98-5-000, May 1998; “FERC Policy On Regional Transmission Organizations: Comments In Response To The Notice Of Proposed Rulemaking,” Docket No. RM99-2-000,August 16, 1999; “Initial Comments regarding the Standard Market Design NOPR,” (with John L. Chandley), Docket No. RM01-12-000, November 11, 2002; “Comments on a Working Paper re Standardized Transmission Service, Electricity Market Design and Structure,” (with Scott M. Harvey and Susan L. Pope), Docket No. RM01-12-000, May 1, 2002; "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," Center for Business and Government, Harvard University, May 2000, available on the author's web page also filed with the Commission; “Electricity Market Design and Structure: Avoiding the Separation Fallacy,” Comments, Submitted to the Federal Energy Regulatory Commission, Docket No. RM01-12-000, Washington, D.C., March 12, 2002; “Electricity Market Design and Structure: Working Paper on Standardized Transmission Service and Wholesale Electric Market Design,” Comments, Docket No. RM01-12-000, Submitted to the Federal Energy Regulatory Commission, Washington, D.C., April 10, 2002.