BACKGROUND

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing.

Since beginning to grant market-based rates to electric utilities, the Commission has focused on the applicant and employed the "hub-and-spoke" test to determine whether an individual entity has the ability to exercise generation market power. In a "hub and spoke" analysis the applicant computes its market share of installed and uncommitted generation in a particular market. The Commission's benchmark for generation market power is whether a seller has a market share of 20 percent or less in each of the markets. In addition, under Order No. 888 there was a rebuttable presumption that new generation for which construction commenced after July 9, 1996 did not have market power. 18 C.F.R. § 35.27 (2000).

As stated above, the assessment of market power also considers whether the applicant has transmission market power, whether there are barriers to entry, and whether there is reciprocal dealing. The typical test for demonstrating the requisite absence or mitigation of transmission market power is whether the applicant and its affiliate have an approved open access transmission tariff. With regard to barriers to entry, we rely on an applicant's representation and public policing.

The "hub and spoke" was employed at a time when trading was predominantly between vertically integrated IOUs and market-based rates functioned as an incentive for vertically integrated utilities to file open access transmission tariffs into what were then largely closed and concentrated markets. Hub and spoke worked reasonably well for almost a decade when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market. Since that time, markets have changed and expanded. All utilities provide open access transmission service and there are bid based markets. Concerns with market power today have been expressed by numerous parties. Because markets are fundamentally different from years ago, the hub and spoke may no longer be a sufficient test for granting market-based rates.

DECISIONAL ISSUES

Issue 1: Should we continue processing requests for market-based rates on an applicant-by-applicant basis until the Commission has a long-term regional comprehensive plan in place? And, if so, what analysis do we use?

Issue 2: Should we condition the authorizations we grant on an applicant-by-applicant basis; or, should we also institute a section 206 investigation into existing market-based rates?

Issue 3: What should be our process for determining a longer-term, comprehensive test for market power?

Issue No. 1 Should we continue processing requests for market-based rates on an applicant-by-applicant basis until the Commission has a long-term regional comprehensive plan in place? And, if so, what analysis do we use?

Yes, though it is not what we would recommend for the long-term. It is clear that there are certain natural markets and trading patterns and to continue processing requests for market-based rates on an applicant-by-applicant basis ignores this. In the short-term, however, such a broad regional market undertaking is not feasible from a public policy, regulatory or internal resource standpoint. Presented below are five options for analyzing generation market power for new requests for market-based rates in the short term. These options are not mutually exclusive and not one of them independently addresses all instances of market power (e.g., concentration, inadequate supply, collusion, withholding, strategic bidding). In fact, several focus on measuring concentration or market share, while others focus on behavior.

Option 1: Limited Competing Supplier Test

This option focuses on a request by an applicant for authorization to make sales at market-based rates. One homogenous product, megawatts, is considered under this approach. In this regard, this approach allows the program to operate largely the same as it does currently where requests for market-based rates and tariff provisions are approved on a case-by-case basis. No changes are being proposed in the analysis for transmission market power, barriers to entry, or reciprocal dealing.

This generation dominance analysis builds off the Commission's existing "hub and spoke" analysis to directly consider the impact of transmission constraints in the grant of market-based rates. Transmission constraints have been and continue to be a source of contention in the grant of market-based rates. Historically, when the issue of transmission constraints was raised by interveners, the Commission set the issue for hearing while allowing the applicant to charge market-based rates with no refund provision; or, accepted the applicant's proposal to not sell at market-based rates in the transmission constrained area. Under the proposed "Limited Competing Supplier Test", staff will systematically incorporate available transmission (measured by total transmission capacity (TTC)) from OASIS sites and factor it into the analysis of installed and uncommitted capacity. Where TTC figures are unavailable from OASIS sites, a zero TTC will be assumed. On occasion, if other information is required (such as with load pockets within a control area), staff may need to issue a deficiency letter to the applicant and/or other relevant interest (such as the ISO). The effect of this test is to limit the amount of competing supply to the amount of transmission capability. This approach would continue to apply the 20 percent benchmark in each market.

Option 2: Supply Margin Assessment

This option focuses on a request by an applicant for authorization to make sales at market-based rates. One homogenous product, megawatts, is considered under this approach. In this regard, this approach allows the program to operate largely the same as it does currently where requests for market-based rates and tariff provisions are approved on a case-by-case basis. No changes are being proposed in the analysis for transmission market power, barriers to entry, or reciprocal dealing.

The proposed "Supply Margin Assessment" (SMA) measures whether a seller is pivotal in the market, i.e. whether the market's peak day demand can be met in the absence of the applicant's generation. To the extent this is true, the applicant would not have market power. Rather than separately analyzing the applicant's committed and uncommitted generation capacity, this test compares the applicant's generation capacity to the difference between available supply (as measured by total transmission capacity (TTC) at the control area interfaces) and peak demand. Available supply includes all generation (including the applicant's) that can reach the market once the TTC at the control area interfaces are factored in. To the extent the applicant's generation is less than or equal to the effective supply margin (the remaining supply after the peak demand is met), that applicant would not have the ability to exercise market power since its generation would not be needed to meet the peak demand. In this manner, the SMA does not rely on a static 20 percent threshold.

This option applies in all non-ISO or non-RTO markets. For ISO and RTO markets, we would propose Option 5.

As with the hub-and spoke, if the screening test is not passed for any of the applicant's proposed markets, the request for market-based rate authority should be denied.

Option 3: Delivered Price Test

Under this option, an applicant with generation in the relevant market in excess of 100 MW would be required to submit a delivered price test as the screen for generation market power. The delivered price test identifies suppliers that can reach a destination market at a cost of no more than five percent over an assumed price. If a seller's generation can reach a destination market, including the cost of delivery, within five percent of the destination market price, the supply is considered economic. The test is performed for first tier markets and can be performed for more broadly (or narrowly) defined geographic markets, if necessary. In addition, the test is not limited to one product and may consider short-term capacity, energy, peak and off-peak products. If the screening test is not passed, the Commission may deny market-based rate authority or impose remedies to reduce potential anti-competitive effects of market power such as requiring divestiture or mitigation.

Option 4: Residual Supply Index

Under this option, FERC staff would calculate a residual supply index (RSI) to give an indication of whether a specific seller has potential market power as a result of tight supply conditions relative to demand. The RSI is a measure of the percentage of demand that can be met without relying on the individual seller's capacity. When demand cannot be fully met without at least some production from the individual seller, the resulting RSI is less than 1. In ISOs/RTOs that operate hourly markets, the ISO should determine the RSI thus allowing the ISO/RTO to decide whether to mitigate on an hourly basis. In other areas, RSI will be calculated for summer and winter for the current and prior year to be used as an indicator. The supply figures used in this calculation would be the installed capacity adjusted by equivalent availability factors to account for outages; demand data are available from FERC Form 714. This calculation also conservatively assumes inelastic demand, except to the extent reflected in demand data already.

Option 5: Assess and Mitigate Market Power by Type of Market Design

Under this approach, we would assess and mitigate generation market power differently, depending on whether or not the applicant is in an ISO or RTO that operates bid-based spot markets. In particular, for sales into bid-based markets operated by the four existing ISOs, all sellers would be granted market-based rate authority. Thus, all sellers would be exempt from cost-of-service regulation in their sales into such markets, and such exemption would be given without any need to pass any of the structural screens discussed in the previous options. However, all entities selling into markets operated by the four existing ISOs would be subject to the ISO's existing monitoring and mitigation mechanisms. By contrast, for sales in markets located outside of the four ISOs, market-based rate authority would be granted only after passing one of the structural screens discussed above.

Cost of service regulation is an imperfect method for mitigating market power. Cost of service regulation blunts incentives for sellers to reduce their costs, and its prices are not sensitive to rapidly changing supply and demand conditions. Also, cost of service regulation introduces supply rationing problems. Suppliers with different costs have different prices, and customers naturally want to buy from the supplier with the lowest prices. So cost of service regulation requires regulators to develop non-price rationing rules to allocate the cheaper supplies.

The existing ISOs operate bid-based markets with Commission-approved monitoring and mitigation mechanisms that avoid many of the problems of cost of service regulation. Cost of service regulation should not be imposed on the sellers in these markets because it would disrupt these benefits. However, markets outside the existing ISOs lack these bid-based markets and alternative mitigation measures, so using one of the structural screens to determine whether to continue cost of service regulation for sellers in non-ISO markets is necessary for the short term

Bid-based ISO markets establish separate market-clearing prices in each hour that reflect changing supply and demand conditions, encourage suppliers to minimize their costs, and ration supplies efficiently. The mitigation mechanisms used by ISOs can force sellers with market power to act in a more competitive manner without disrupting the efficiency benefits of the markets. The details of the mechanisms differ among the ISOs. However, all of them include capping individual supplier bids when identified conditions indicate the potential for market power. For example, bid caps may be imposed during reserve shortages, when transmission constraints create the potential for market power in load pockets, or when individuals submit bids substantially in excess of their previously accepted in-merit bids. In most instances when the seller's bid is capped, the seller receives the applicable market-clearing price, which may be higher than the bid. Thus, sellers have incentives to minimize their costs, and market-clearing prices avoid the need for administrative rules to allocate supplies among customers.

Issue 2: What, if any conditions do we impose on market-based rate tariffs and do we impose them on an applicant-by-applicant or do we institute a section 206 investigation into existing market-based rates?

Conditions should be imposed on an industry-wide basis. Conditioning authorizations on a case-by-case basis would result in an unlevel playing field among market participants. Future market-based rate authorizations would be conditioned while existing ones would not. Instead, issue an instant industry-wide section 206 investigation broadly prohibiting any anti-competitive behavior on all existing market-based rate authorizations and conditioning market-based rates on potential refunds. The order would establish a refund effective date, would mention that we are initiating a generic proceeding on analytical methods for assessing markets and market power, and would seek comments. The order would not require immediate compliance filings from market participants and instead direct them to amend tariffs the next time they file an amendment or seek continued authorization to sell at market-based rates. The order would serve to put new applicants on notice of the conditions.

Issue 3: What should be our process for determining a longer-term, comprehensive test for market power?

Any longer-term assessment of market power should recognize that there are multiple sources of market power, that there are appropriate tools for measuring the specific types or instances of market power, and that there are solutions to each type of market power. For instance, concentration is a market power issue, it can be measured by an Appendix-A type analysis and it can be remedied through divestiture. The Commission has several initiatives underway, e.g., RTO formation, interconnection procedures, generation market power analysis, and generation market power should be addressed in the broader context of the Commission's policy objectives and goals with respect to these initiatives. For instance, the Commission may want to consider whether there should be one method for all market power assessments, market-based rates and mergers; the Commission may not want to consider the issue of generation market power for market-based rates in isolation. The Commission may want to revisit the code of conduct, barriers to entry and tariff issues (such as standardization and conditions) regarding market-based rate authorization.

Staff recommends a three-step plan: (1) data, information and idea generation; (2) proposals; and (3) final rule. The benefit of this approach is that staff has the benefit of external experts prior to offering a proposal, and industry comment on the proposal. Of course, a stage could be skipped and there are various options for accomplishing each stage of the plan.

<u>Stage 1</u>

Option 1: Outreach or Market Assessment Meetings

Hold a series of outreach meetings with industry experts (market participants, other government agencies, and think tanks) in October and November. At the conclusion of these meetings, staff will put forth a recommendation to the Commission for a NOPR.

Option 2: Advanced NOPR

Issue an Advanced NOPR that requests the submission of proposals for assessing market power. Proposals would be required to be filed by January 1, 2002 containing detailed proposals for assessing market power, <u>e.g.</u>, market power screens, mitigation, modeling. The Commission would review the proposals received in response to the Advanced NOPR and issue a Notice of Proposed Rulemaking or take other appropriate action.

Option 3: NOI

This operates largely like a general inquiry, seeking response to a variety of questions which could include whether the Commission needs to act on this issue now, and types of screens for market power.

Option 4: Staff White Paper

Staff would prepare a paper to the Commission and for industry comment. The paper would detail the staff's plans for a market power assessment.

<u>Stage 2</u>

Option 1: NOPR

Stage 2 NOPR could be as a result of Stage 1 or staff could draft a NOPR without the benefit of Stage 1. If the latter, staff has several ideas, as shown below, for a longer-term approach to assessing generation market power. The downside of a NOPR without the benefit of external input prior to issuance is that we forego the benefit of outside expertise and run the risk of framing options too narrowly, limiting possible solutions, and stifling dialogue to what it is perceived that the Commission wants.

1. Regional/Market Competitive Supplier Test

Under this approach, applicants would continue to file requests for market-based rate authority but the generation market power analysis would be performed by FERC staff at specified intervals, e.g., six month cycle for natural geographic markets (e.g., the four RTOs or other natural markets). Staff would screen for potential market-power in the same four broad areas of demand, supply, barriers to entry, and affiliate abuse.

On a six month basis a market assessment would be made for each staff identified natural geographic market. This assessment would entail an analysis of the committed and uncommitted capacity in the region, market shares of market participants, transmission constraints, market concentration, and seasonal supply and demand. FERC staff will review and analyze the above factors to assess whether a given market (or sub-market) is competitive for the purpose of allowing market participants to sell at market-based rates. If the analysis shows that the market (or sub-market) is competitive, all market participants in that market will be granted market-based rate authority. Any new market participants (i.e., not included in the assessment) will get an automatic pass to sell at market-based rates except if the applicant is an affiliate of a participant in that market. In this instance, a market concentration analysis will be performed. Where a market has sub-markets due to transmission constraints and that sub-market is a known load pocket, the existing and any new applicants are subject to mitigation or conditions pending the results of the next two six month assessments (e.g, sell at cost based rates where there is no bid-based market or be subject to existing mitigation). If circumstances change following those assessments, mitigation or conditions may no longer be warranted, or market-based rate authority may not longer be warranted.

2. Regional Delivered Price Test

Establish natural markets for purposes of assessing market competitiveness. Rather than an applicant performing a study of market power, Commission staff will perform an Appendix A - Delivered Price Test as the competitive analysis for each region on a regular (six month) basis to determine concentration.

3. Regional Product Differentiated Modeling

Develop a model that simulates markets and prices on a product differentiated basis (e.g., seasonal, peak, energy, ancillary services) for a given region. The model develops a clearing price and then estimates prices in response to simulated behaviors to see the effect on market price. Unlike the other options presented, this is a non-structural (simulated) way of assessing the market.

4. Assess and Mitigate Market Power by Type of Market Design

Under this approach, we would assess and mitigate generation market power differently, depending on whether or not the applicant is in an ISO or RTO that operates bid-based spot markets. Different treatment is necessary because the causes of the market power and the tools available to mitigate it are different in the two different types of markets (RTO/ISO and non-RTO/ISO).

For areas of the country where ISOs or RTOs are not yet developed, strict cost-of-service regulation could be the principal market power mitigation tool. Even after several years under Order No. 888, vertically integrated utilities may continue to use their control over transmission to discriminate against their competitors and dominate the generation market. Indeed, the major source of generation market power is from the control over transmission by vertically integrated utilities. The most effective solution would be for the utilities to turn over their transmission assets to an RTO. Revoking the market-based rate authority for integrated utilities that do not join RTOs would help mitigate their market power, and it would create a strong incentive for them to join an RTO. Of course, independent generators that present no problems with market share or concentration should be free to charge market-based rates in these areas.

Where an ISO or RTO operates a bid-based spot market, any generation market power arises not from control over transmission, but rather from other factors such as seller concentration, demand inelasticity, tight supply conditions, market design flaws, and transmission constraints that create load pockets and must-run conditions. To mitigate market power that develops in bid-based RTO/ISO markets, sellers should be required to offer all of their available capacity to the market at their marginal cost while allowing them to receive a competitive market-clearing price. See Attachment A for details on the marginal cost bidding requirement. The specific methods for determining when market power exists (and thus, when the marginal cost bidding requirement should be invoked) would need to be developed. Currently, ISOs use different methods for triggering mitigation, such as during reserve shortages, when transmission constraints create the potential for market power in load pockets, or when individual submit bids substantially in excess of their previously accepted in-merit bids.

Stage 3:

Final Rule

<u>ISSUE : How to Remedy Market Power When it is Identified</u>

The previous discussion examined alternative ways to test for market power. Where a seller passes the test and thus is found not to have significant market power, the seller should be allowed to charge unmitigated market-based rates. On the other hand, where a seller fails the test and thus is found to have significant market power, the Commission should remedy the market power problem. Below, we discuss possible remedies.

Approach 1: Cost-of-Service Regulation

Cost-of-service regulation is the traditional remedy for market power in the electric utility industry, and has been used at the Commission for decades. The Commission has well developed methods and procedures for setting just and reasonable cost-based rates; and the results have been recognized by the courts as just and reasonable. However, implementing cost-of-service rates is a fact, labor, and time intensive process for all concerned. In addition, the results of cost-based rates often require regulators to make a host of decisions to allocate the benefits of low-costs, or the detriments of high costs, where there are no adequate market-driven mechanisms. (This need arises because cost-based rates for different facilities and/or companies are different, and from those differences arise fairness issues across customer communities, and competitive issues across the regulated service provider community–to the extent customers have any choice among service providers.)

Approach 2: Marginal Cost Bidding

Require marginal cost bidding in bid-based spot markets.[1] Wherever a bid-based energy spot market exists, the Commission should require generators to bid all available capacity at their marginal operating cost. All accepted sellers would receive the market-clearing price based on the highest accepted bid. As in California, hydro generators could be exempted from the marginal cost bidding requirement because hydro units often face intertemporal opportunity costs that are difficult to measure and that aren't reflected in marginal operating costs. As in California, marketers would be required to be price

[1]Mitigating bids in the forward markets is neither necessary nor desirable. Sellers may face significant opportunity costs in the forward markets that do not exist in real-time spot markets.

takers in the spot market.

Where bid-based markets do not currently exist, the Commission should require them to be developed because they can provide a transparent market for buyers and sellers to transact and for RTOs to acquire energy to provide energy and imbalance service. Such markets are also necessary to implement market power mitigation using a marginal cost bidding requirement. May want to disallow market-based rates until such markets exist. Alternatively, establish a reference price for markets where bid-based markets do not exist.

Approach 3: Divestiture

Require a seller to divest some of its capacity to reduce market power.