UNITED STATES OF AMERICA
FEDERAL TRADE COMMISSION
WASHINGTON, D.C. 20580

Before the
United States of America
Federal Energy Regulatory Commission

Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design

Docket No. RM01-12-000

Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission(1)

EXECUTIVE SUMMARY

The staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission (FTC) appreciates this opportunity to present its views concerning the Federal Energy Regulatory Commission's (FERC) notice of proposed rulemaking (NOPR) regarding standard market design (SMD) of wholesale electric power markets. FERC has proposed to remedy remaining discrimination in the provision of interstate transmission services and to ensure just and reasonable rates for sales of electricity within and among regional power markets by reforming the regulated use of transmission services and standardizing the design of regional wholesale electricity markets. We offer summary views on the premises and selected major elements of the NOPR and an appendix with more detailed views on the market power mitigation, monitoring, and resource adequacy sections of the NOPR (Sections IV.I and IV. J).

Structurally competitive wholesale electric power markets are likely to provide consumers with access to lower priced electric power than would be available without regulatory reforms in wholesale and retail electric power markets. Consistent design of regional wholesale markets and uniform operation of transmission assets is likely to help accomplish this goal and, therefore, to speed and enhance competition in wholesale electricity markets to the benefit of consumers. We make several suggestions and pose additional questions that FERC may wish to address in order to increase the likelihood that SMD will enhance consumer welfare.

First, we provide summary views on the premises and other selected major elements of the NOPR.

- Absent continued regulatory reform in wholesale electricity markets, discrimination in access to transmission services is likely to continue to the detriment of consumers.
- Regulators, market participants, and the financial community have gained substantial experience with a variety of wholesale electricity market design elements. Widespread adoption of the most successful design elements is likely to improve overall economic performance in the electric power sector.
- Use of Regional Transmission Organizations (RTOs) (and Independent Transmission Providers (ITPs) as an interim step in areas that do not have an operational RTO) is likely to increase competition in wholesale electricity markets.

- Network Access Service ensures comparable treatment for all uses of transmission and eliminates the "native load" preference and its associated discrimination. It also should harmonize how neighboring states treat native load requirements and eliminate the issues along state borders that arise when states address transmission access in different ways. Network access service also is likely to address similar "seams" issues between RTOs.
- Effective market power monitoring and mitigation policies in short-term wholesale electric power markets may or may not discipline anticompetitive pricing in bilateral trades in the same area. A stronger relationship is more likely to exist between short-term electric power markets and bilateral trades when spot markets are not too thin and when customers readily substitute financial hedging in short-term markets for longer-term bilateral contracts.
- Economic theory and experience support using locational marginal pricing (LMP) as the basis for transmission congestion pricing.
- Market power problems are particularly likely to occur in transmission-constrained areas with high market share concentration on the supply side, entry impediments, and lack of effective price-responsive demand policies.
- An exclusive focus on unilateral market power in horizontal market power monitoring and remediation efforts is not sufficient. Coordinated interaction between suppliers may also be of concern.
- FERC and market monitors should be closely integrated; however, the public interest may be harmed if market monitors are directly able to penalize market participants.
- Resource adequacy planning may offset policies that reduce investment incentives, but it is likely to be complex and difficult to administer. It is likely to result in less accurate and less efficient investment incentives than policies that directly develop structurally competitive markets with full entry incentives.

Our views on market power mitigation, monitoring and resource adequacy requirements (Sections IV.I and IV.J of the NOPR) are elaborated upon in the Appendix. Among these views are suggestions that FERC combine two of its proposed four market monitoring prongs (the local market power mitigation with mitigation prompted by regional conditions) because they address similar concerns, that FERC focus on price-responsive demand policies and entry barriers so that the proposed safety-net bid cap can be "sunset" sooner rather than later, and that FERC examine whether directly addressing free riding (by load-serving entities on capacity reserves of others) would allow FERC to employ a less complex design for resource adequacy.

In addition to the topics already included in the NOPR, FERC may wish to consider four issues that are closely related to elements in the NOPR: (1) efficiency and customer service in grid operations, (2) coordinated interaction as an element of market power monitoring and mitigation, (3) disclosures regarding increased risk of blackouts affecting retail customers of firms that do not maintain resource adequacy, and (4) integration of the market power assessment and remediation techniques utilized by FERC in different contexts.

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Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission(2)

I. INTRODUCTION AND SUMMARY

A. Background

The staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission (FTC) appreciates this opportunity to present its views concerning the Federal Energy Regulatory Commission's (FERC) notice of proposed rulemaking (NOPR) regarding standard market design (SMD) of wholesale electric power markets. FERC has proposed to remedy remaining discrimination in the provision of interstate transmission services and to ensure just and reasonable rates for sales of electricity within and among regional power markets by reforming the regulated uses of transmission services and standardizing the design of regional wholesale electricity markets. We offer summary views on the premises and selected major elements of the NOPR and more detailed views on the market power mitigation, monitoring, and resource adequacy sections of the NOPR (Sections IV.I and IV.J) in the attached Appendix.

Wholesale electric power markets, in which there are no incentives for discrimination in provision of transmission services, are likely to provide consumers with access to lower-priced electric power than would be available in markets that use behavioral rules to govern access to transmission services. Moreover, consistent design of regional wholesale markets and uniform operation of transmission assets are likely to help encourage structurally competitive electric power generation markets by increasing the scope of geographic markets, thereby increasing the number of generators that can economically supply customers in a given area. Locational marginal pricing (LMP) of transmission services, as proposed by the NOPR, is likely to provide efficient incentives for generation, transmission, and price-responsive demand investments that will contribute to structurally competitive wholesale electric power markets as well.

B. FTC Experience in the Electric Power Industry

The FTC is an independent administrative agency responsible for maintaining competition and safeguarding the interests of consumers. In this industry, the staff of the FTC often analyzes regulatory or legislative proposals that may affect competition or the efficiency of the economy in addition to its review of proposed mergers involving electric and gas utility companies. In the course of this work, as well as in antitrust research, investigation, and litigation, the staff applies established principles and recent developments in economic theory and empirical analysis of competition issues.

Our involvement in the evolution of the present NOPR stretches back to our initial comment of August 7, 1995, in the proceeding leading to transmission open access in Order No. 888.(3) It has continued with other comments including our August 16, 1999, suggestions for effective structural reform in the RTO proceeding and, most recently, our July 23, 2002, comment on efficiency and market power concerns regarding the working paper on SMD. In addition to filing comments with FERC and various state utility commissions, the Commission has issued two Staff Reports (July 2000 and September 2001) on electric power market restructuring issues at the wholesale and retail levels. The July 2000 FTC Staff Report established a policy framework for increased competition in wholesale and retail electric power markets.(4) The September 2001 FTC Staff Report reviewed those features of state retail competition plans that have provided benefits to consumers and those that have not. It also provided recommendations as to whether states had sufficient authority to implement successful retail competition programs.(5) The FTC also has reviewed proposed mergers involving electric and gas utility companies.

II. Summary Views on the Premises and Major Elements of the NOPR

Our views on the specific market power monitoring and mitigation and resource adequacy requirements in Sections IV.I and IV.J of the NOPR are presented in more detail in the Appendix. Discussed below are summary views on the premises, elements, and implementation of the NOPR proposals.

A. Premises of the NOPR

Absent continued regulatory reform in wholesale electricity markets, discrimination in access to transmission services is likely to continue to the detriment of electricity consumers.

FERC has identified four major deficiencies in current regulation of monopoly transmission services that it believes hamper sales of electricity within and among the states.(6) The first two deficiencies are not uncommon when monopoly firms continue to have incentives and the ability to engage in discrimination.(7) First, FERC's existing transmission regulations provide exemptions from open access requirements for some transmission services. FERC perceives that these exemptions result in discrimination in favor of the exempted services (native load).(8)

Second, public utilities that operate or control transmission facilities also participate in electric power markets (through ownership of generation facilities in the same areas). As a result, these utilities may continue to possess substantial transmission market power and retain the ability to discriminate in the provision of transmission service and in the dispatch of generation units to supply the grid. Third, wholesale electric power market designs, rules, and operations differ widely among areas. Lack of uniform wholesale power market designs, rules, and operations allows undue discrimination across regions (seams issues). For example, pancaking of transmission charges associated with inter-area wholesale electric power trades may preclude competition from generators that would be the low-cost suppliers if transmission pricing were efficient. Lack of uniformity has resulted in the exercise of market power in the allocation of transmission capacity and in wholesale electric power trading. Fourth, efficient transmission price signals are not being sent to marketplace participants. The result is that market-based rates for electricity in many places are distorted. Consequently, inefficient investment decisions are more likely. FERC believes that market forces alone will not correct these deficiencies, and that, therefore, FERC should act to provide regulatory reforms that it believes will improve market performance and help bring about structurally competitive markets.

Last year the FTC staff released a report on retail electricity competition that determined that it was imperative for wholesale markets to continue to move toward competition to ensure that all of the expected benefits of retail competition are realized. Effective wholesale and retail competition are mutually reinforcing. If more distant generators cannot compete effectively with local generators, or electricity marketers cannot obtain generation services, because of problems in obtaining transmission service, and there are entry barriers to building new generation, local generators may be able to exercise market power.(9) Thus, continued structural reforms for wholesale power markets are necessary for the benefits of wholesale and retail competition to enure to consumers.

Regulators, market participants, and the financial community have gained substantial experience with a variety of wholesale electricity market design elements. Widespread adoption of the most successful design elements is likely to improve overall economic performance in the electric power sector.

In 1996, FERC ordered public utilities to provide open access to their transmission lines on the same basis on which they provide those services to themselves. FERC implemented a functional separation, rather than operational unbundling, because it was potentially more intrusive and costly. Since that time, various sections of the country have implemented different institutional and market design approaches to increase competition in wholesale electricity markets. The flaws in functional unbundling and the lack of consistent market institutions and rules across regional markets have become apparent, as anticipated by the FTC staff in 1995.(10)

It is now over six years later and FERC, market participants, and the financial community have gained substantial experience about the benefits that increased competition in wholesale electricity markets can bring. Many of these benefits have been highlighted in FERC's efforts to encourage the voluntary formation of regional transmission organizations (RTOs) since 1999 - an effort that has yet to be completed. Now is the time to remove remaining structural barriers to competition that continue to delay the benefits of competitive markets from enuring to consumers.

The components of standard market design address the existing barriers to effective wholesale competition. The principal components of SMD include the following:

Network Access Service eliminates discrimination associated with native load preferences afforded to vertically integrated public utilities by providing a single open access service to all transmission users.

Locational Marginal Pricing (LMP) provides efficient pricing of transmission services and electric energy, improves investment signals, and increases the efficiency of grid operations by charging higher rates on electric power trades that cause or increase congestion on transmission lines.

Market Power Monitoring and Mitigation addresses situations in which existing electricity suppliers are likely to have market power. Circumstances that may contribute to market power problems are congestion of the transmission system (for example, into load pockets), underdevelopment of price-responsive demand policies, and entry barriers.

Resource Adequacy Requirements compensate for potential underinvestment in generation capacity, transmission capacity, and price-responsive demand programs (due to free riding by load-serving entities on the capacity reserves of others and other reasons for inadequate investment incentives, such as the market power mitigation policies proposed by FERC).

Real-Time and Day-Ahead Spot Markets increase the efficiency and transparency of wholesale trading (transactions costs are low and market clearing prices are publicly available), improve reliability (provide efficient prices for use in energy balancing required by the grid operator in lieu of potentially inefficient balancing orders), and facilitate price-responsive demand programs (provide a publicly available real-time price for the energy component of retail electric power service).

Transmission Access Charges pay for some or all of the fixed costs of using the transmission system. Transmission access charges reduce the risk associated with transmission investments and allow transmission use charges to better reflect marginal costs.

Congestion Revenue Rights (CRRs) are financial contracts that allow a transmission customer to reduce its exposure to volatile transmission prices (risk) associated with potential transmission congestion in the context of LMP. Under LMP, transmission users causing congestion pay higher prices for using the transmission grid.

State Participation in Governance of Independent Transmission Providers (ITPs) or Regional Transmission Operators (RTOs)(11) should lead to increased coordination between state and federal policies on the siting of transmission and generation, price-responsive demand programs at the retail level, resource adequacy, and security concerns.

Independence of All Transmission Operators reduces incentives for discrimination in supplying transmission services in areas where RTOs are not yet operating.

Required Compliance with Reliability Standards will reduce the threat that individual market participants will undermine system reliability.

B. Elements of the Proposals

Use of RTOs (and Independent Transmission Providers (ITPs) as an interim step in areas that do not have an operational RTO) is likely to increase competition in wholesale electricity markets.

The minimum characteristics and functions of RTOs expressed in FERC Order 2000 continue to ensure nondiscriminatory access to the transmission grid. As stated previously, we encourage FERC to add efficient, customer oriented operation of the grid to its list of RTO requirements.(12)

Network Access Service ensures comparable treatment for all uses of transmission and eliminates the "native load" preference and its associated discrimination. It also should harmonize how neighboring states treat native load requirements and eliminate the issues along state borders that arise when states address transmission access in different ways. Network access service also is likely to address similar "seams" issues between RTOs.

Network Access Service represents a federal assumption of regulatory authority over all transmission uses. It also resolves the potential discrimination in favor of transmission customers serving native load that inhibits efficient operation of the grid and accentuates uncertainty concerning available transmission for unaffiliated trades on vertically integrated providers' transmission wires.(13)

Effective market power monitoring and mitigation policies in short-term wholesale electric power markets may or may not discipline anticompetitive pricing in bilateral trades in the same area. A stronger relationship is more likely to exist between short-term electric power markets and bilateral trades when spot markets are not too thin and when customers readily substitute financial hedging in short-term markets for longer-term bilateral contracts.

Bilateral trades within the context of market arrangements that include a competitive spot market are less likely to reflect supplier market power. The spot market can provide a backstop for buyers concerned about supplier market power by reducing the cost of finding alternative suppliers if spot markets are not too thin and buyers find that longer-term financial hedges on the spot market are a close substitute for longer-term bilateral supply contracts.

Economic theory and experience support using locational marginal pricing (LMP) as the basis for transmission congestion pricing.

As we have commented previously, LMP provides transmission suppliers and customers with price signals that reflect transmission congestion.(14) By providing market participants with more efficient prices, LMP provides more efficient incentives regarding transmission, generation, and demand-response investments. The practical application of LMP to complex transmission systems has been demonstrated in the Eastern ISOs.

Market power problems are particularly likely to occur in transmission-constrained areas with high market share concentration on the supply side, entry impediments, and lack of effective price-responsive demand policies.

The goal of structurally competitive electric power markets may be pursued directly through policies that reduce concentration, ease entry impediments, and facilitate price-responsive demand programs. If direct approaches are too costly, slow, or otherwise unavailable, then less direct means to curtail market power, including bid caps and must run obligations such as those proposed in the NOPR, may warrant consideration on an interim basis. In general, the indirect approaches are less efficient and may undermine investment incentives, thereby delaying structurally competitive markets. Consequently, we encourage FERC and the states to emphasize direct approaches to achieving structurally competitive electricity markets.

An exclusive focus on unilateral market power in horizontal market power monitoring and remediation efforts is not sufficient. Coordinated interaction between suppliers may also be of concern.

Where firms are accustomed to coordinated interaction and the use of the regulatory process to bar or disadvantage new entry, industry members may attempt to use cartel behavior to protect their entrenched positions after restructuring. For example, if distribution companies in an area agreed on excessive interconnection standards for distributed generation, the use of distributed generation would be less likely.

C. Implementation of the NOPR Proposals

FERC and market monitors should be closely integrated; however, the public interest may be harmed if market monitors are directly able to penalize market participants.

The RTO's market monitors should report directly to FERC. FERC needs the detailed regional information and analyses developed by the market monitors. The market monitors need the authority and independence of a strong relationship with FERC to accomplish their tasks in a timely and coherent manner. Application of SMD nationwide and increased comparability in the reports of monitors will enhance FERC's ability to refine its policies and to provide useful guidance to individual monitors based on the experience of other monitors. Market monitors should not have the authority directly to penalize market participants. (These issues are discussed in the Appendix, NOPR paragraphs 444 and 445.)

Resource adequacy planning may offset policies that reduce investment incentives, but it is likely to be complex and difficult to administer. It is likely to result in less accurate and less efficient investment incentives than policies that directly develop structurally competitive markets with full investment incentives.

A resource adequacy program may be a means to compensate for other aspects of SMD that result in reduced incentives to invest in new generation, transmission, or demand-response programs. Taking a resource adequacy approach, however, rather than implementing policies to develop structurally competitive markets with full entry incentives, is likely to result in less accurate and less efficient entry and other investment incentives. FERC may wish to consider less costly alternatives to increasing investment incentives.

D. Market Power Monitoring and Mitigation Including Resource Adequacy

FERC's proposals combine some policies that directly promote structurally competitive markets for electric power. For example, ITPs and RTOs are likely to increase the scope of geographic market, thereby decreasing concentration and reducing impediments to supply by distant generators. Other elements, behavioral rules and bid caps with must-run obligations for generators with market power, for example, do not directly promote structurally competitive markets, but rather seek to prevent generators from exercising their existing market power. Such indirect policies often involve substantial administrative costs and create distortions such as inefficient and insufficient investment incentives. When and if the direct approaches to promoting structurally competitive electric power markets are adequate, FERC should discontinue the other policy elements.

Because of the costs and distortions often associated with behavioral rules and pricing constraints,(15) we generally favor direct structural approaches that create incentives for market participants to behave competitively. However, we recognize that unusual historical circumstances may make implementation of direct structural approaches difficult and time-consuming. Under these conditions, consideration of indirect approaches and interim behavioral rules, may be warranted if the market power assessments used in developing alternative approaches to remedying market power are based on sound economic principles. The costs and benefits of such non-structural remedies and the accuracy of the analyses supporting them should be periodically reviewed by FERC. We encourage FERC and the states to emphasize the direct approaches to creating structurally competitive markets including policies that reduce concentration where it is a source of market power, ease entry impediments, and facilitate price-responsive demand.

When indirect approaches are taken, it is essential that FERC and market monitors use sound economic analysis that encompasses the principal components of competition analysis, including market definition, structural assessment, and entry conditions. The Horizontal Merger Guidelines developed by the Department of Justice and the Federal Trade Commission incorporate such principles and present these components.(16) We are concerned about the market power assessments proposed in the NOPR because FERC's methodologies to analyze market power aspects of proposed mergers and grant market-based rates do not adhere to the principles encompassed in the Merger Guidelines.(17) Failure to utilize these principles is likely to lead to inaccurate assessments of market power, faulty remedies, and harm to consumers. Our comments favoring consideration of the market power assessments and non-structural market power mitigation measures presented in the NOPR are conditioned on adoption by FERC and the market monitors of market power assessment approaches that are based on sound economic principles.

More detailed views on market power mitigation, monitoring, and resource adequacy requirements (Sections IV.I. and IV.J. of the NOPR) are elaborated upon in the Appendix. Among these are suggestions that FERC combine two of its proposed four market monitoring elements (the local market power mitigation with mitigation prompted by regional conditions) because they address similar concerns, that FERC focus on price-responsive demand programs so that the proposed safety-net bid cap can be sunset sooner rather than later, and that FERC examine whether directly addressing free riding (by load-serving entities on capacity reserves of others) would allow FERC to employ a less complex design for resource adequacy.

E. Four Additional Issues to Increase Effectiveness of the NOPR.

In addition to the topics already included in the NOPR, FERC may wish to consider four issues that are closely related to elements in the NOPR. Aspects of these issues are discussed in the Appendix.

1. Efficiency and Customer Service in Grid Operations: As discussed in our July 23, 2000, SMD comment to FERC, efficiency and customer service concerns in grid operations may arise if the grid operator lacks incentives to perform efficiently and provide strong customer service. A hybrid grid governance model combining for-profit and non-profit features may be a relatively efficient option. A for-profit operator increased profit by operating efficiently and attracting customers with good service. At the same time, the hybrid model may reduce incentives to discriminate in providing grid services. A non-profit grid operator lacks profit incentives to discriminate against generators whose siting decisions for new generation facilities (near a city) may reduce demand for transmission services. In particular, a hybrid governance model consisting of an independent non-profit governing board that determines and enforces market rules and that contracts with a for-profit firm to operate the grid may be appealing. In this model, grid maintenance tasks could be unbundled and contracted out by the ITP or RTO to independent transmission companies (ITCs). We discuss this issue in the Appendix (Section L).

2. Coordinated Interaction as an Element of Market Power Monitoring and Mitigation: Economic consideration of market power includes two types of market power. The first, unilateral market power, involves the ability of a firm to profitably raise prices above competitive levels for a significant period of time without relying on the concurrence of other firms in the market or on coordinated responses by other firms. The second form of market power is associated with coordination between suppliers to raise prices (or lessen competition on dimensions other than price, such as product quality, service, or innovation). FERC's monitoring and mitigation proposals focus on detecting and remedying unilateral market power and do not address coordinated interaction. FERC should rebalance its market power monitoring program to give more explicit recognition to the risk of coordinated interaction. Antitrust merger enforcement has been concerned about the impact of mergers on the likelihood of tacit coordination in highly concentrated markets with impeded entry, in part, because tacit coordination is difficult to prove and difficult to remedy.

3. Disclosures Regarding Increased Risks of Blackouts Affecting Retail Customers of Firms That Do Not Maintain Resource Adequacy: As an incentive for load-serving entities to maintain resource adequacy, FERC proposes that transmission operators apply surcharges and institute black outs (when load shedding is necessary for system reliability) of load served by firms that do not maintain resource adequacy. Although both steps may make it more difficult for load-serving entities to free ride on the resource planning of other load-serving entities, implementing such a policy may have important consequences for retail customers of affected load-serving entities. In order to avoid imposing increased risk on consumers without informing them, we urge FERC to work with the states to assure that affected customers are notified about the consequences for them of their suppliers' decisions regarding resource adequacy. In a competitive retail context, it is also important that suppliers that do maintain resource adequacy be able to alert retail customers to the advantages of using a supplier that maintains resource adequacy.

4. Integration of Market Power Assessment and Remediation Techniques Utilized by FERC in Different Contexts: As discussed in our July 23, 2000, SMD comment, FERC engages in market power assessments in several contexts, but presently utilizes different approaches to measure the same phenomenon. FERC may wish to unify its various market power assessment approaches because the underlying concept of market power and its assessment are similar. We continue to encourage the use of computer simulation modeling and related techniques that allow analysts to more accurately take into account loop flows and other sources of congestion to more accurately measure potential market power. Increased use of these techniques by FERC and market monitors may enhance FERC's market power analysis in all contexts.

III. CONCLUSION

Implementation of standard market design is timely and likely to promote benefits to consumers by improving the accuracy of investment and consumption signals and by reducing existing market power or its exercise. Further, we agree with FERC's enumeration of the major components that should be included in standard market design. In the long term, efficient investment in generation, transmission, and price-responsive demand programs are likely to be the best remedies for market power. These approaches are likely to be preferable (with respect to efficiency and administrative costs) to bid caps and resource adequacy requirements for assuring that wholesale electricity prices are just and reasonable. We encourage FERC (and the states), therefore, to treat price-responsive demand programs and reduction of remaining entry barriers as urgent priorities. Efficiency in market operations and grid maintenance is also likely to be important for market performance. Therefore, FERC may wish to emphasize strong efficiency incentives for these organizations.

Respectfully submitted,

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APPENDIX

This appendix contains more detailed comments on the market power mitigation and monitoring sections of the NOPR. Section numbering and the bracketed items refer to the numbering used in the NOPR, as requested.

IV. THE PROPOSED REMEDY

I. Market Power Mitigation and Monitoring in Markets Operated by the Independent Transmission Provider

1. Principles and Objectives [390 to 397]

Structurally competitive wholesale electric power markets with many buyers and sellers each of which individually cannot profitably influence price are likely to provide benefits to consumers (compared to what would otherwise occur) in the form of lower wholesale prices, increased variety of products and services, and enhanced innovation. The DOJ and FTC Horizontal Merger Guidelines emphasize the potential importance of market power exercised both by coordinated interaction among two or more sellers and by unilateral action. Section 0.1 of the Merger Guidelines states that "in some circumstances, where only a few firms account for most of the sales of a product, those firms can exercise market power, perhaps even approximating the performance of a monopolist, by either explicitly or implicitly coordinating their actions. Circumstances also may permit a single firm, not a monopolist, to exercise market power through unilateral or non-coordinated conduct - conduct the success of which does not rely on the concurrence of other firms in the market or on coordinated responses by those firms. In any case, the result of the exercise of market power is a transfer of wealth from buyers to sellers or a misallocation of resources."

It follows from the preceding statement that exclusive focus on unilateral exercise of market power is not sufficient in addressing market power concerns in wholesale electric power markets. We encourage FERC to include consideration of coordinated interaction among sellers in evaluating market power and in its policy decisions and market assessment and monitoring requirements. Sellers may be likely to exercise market power collectively even if they cannot do so individually. Under regulation, firms in the electric power industry were accustomed to coordinating their activities, and they will continue to do so for legitimate reasons, for example, through regional organizations. Firms accustomed to coordination may attempt to coordinate their actions to enhance or exercise their market power. Some additional conditions in wholesale electric power markets, such as public availability of information on sellers' generating capacities, costs, native loads, and contracts, may facilitate coordination.

We also encourage FERC, in its policies and its discussions with state utility commissions, to give high priority to developing market structures that facilitate real-time pricing and metering for electricity at the retail level and to implementing other programs that provide retail customers with efficient incentives to reduce electricity consumption when wholesale prices are high.(18) Such programs have the dual benefits of increasing the efficiency of consumption and investment decisions and reducing the extent of market power. Specifically, at present, retail customers typically face retail prices that do not vary over the day or from day to day. Retail customers therefore pay a price for electricity during high demand hours that is often less than the marginal cost of supplying the electric power that they consume. Consequently, retail customers do not have a sufficient incentive to conserve electricity during periods when wholesale prices, costs of generation, and costs of transmission are high. To avoid blackouts, it is necessary to make large investments in generating capacity that is used relatively few hours of the year, even though the cost of the electric power that they produce exceeds the value of this power to consumers. If consumers faced retail prices that reflected the hour-by-hour cost of supplying electricity to them, they would reduce consumption during high-priced hours and switch consumption from high-price to low-price hours. The result would be to reduce substantially the cost of providing electric power, to increase the reliability of the electric power system, and to reduce opportunities for the exercise of market power.

We also encourage FERC to focus on alleviating transmission bottlenecks in areas with high levels of concentration and entry impediments, where doing so is efficient, because these are areas in which market power problems are particularly likely to arise and persist.

[391: Limitations to cost-of-service regulation.] We concur with FERC's discussion of factors that make cost-of-service regulation of wholesale rates outmoded and inefficient.

[392 and 395: New regulatory tools to produce just and reasonable results.] FERC recognizes that market power mitigation policies, even if they are designed to approximate market mechanisms, are costly to implement and enforce. Consequently, FERC proposes to apply mitigation measures primarily in areas that are not structurally competitive and which, therefore, are most exposed to the risk that suppliers will exercise market power. Such an approach is likely to avoid unnecessary costly interventions in markets that are likely to be competitive and provides a convenient framework for removing restrictions when and where structural conditions make them unnecessary.

[394: Lack of price-responsive demand.] The lack of price-responsive demand is a critical defect in electric power markets. Therefore, we encourage FERC to maintain a sense of urgency about encouraging price-responsive demand programs.(19) Proxy measures, such as the proposed bid caps and resource adequacy requirements, do not emulate the consumption and investment signals that consumers would receive with retail real-time pricing or other demand response programs. For example, caps placed on suppliers' bids in wholesale markets do not create incentives for retail customers to curtail consumption during periods when wholesale prices are high, and caps interfere with investment incentives. The longer that proxy measures for price-responsive demand are in place, the

longer inefficient consumption and investment incentives will persist. In-home energy conservation during peak demand hours, on-site generation, and new technologies to popularize price-responsive demand are unlikely to flourish while proxy measures for price-responsive demand are in place.

2. Overview of Market Power Mitigation Measures [398 to 405]

FERC's proposed market power mitigation measures are divided into four components. The first component is an obligation for a supplier to supply the market when FERC or a market monitor considers it to have market power. Such generators would be required to offer their electricity supply at a bid that is capped,(20) although the generator will receive the market clearing price. This component is intended to address local market power problems and is similar to the reliability must-run agreements used in ISOs at present. The second component consists of a bid cap that is intended to reduce suppliers' ability to exercise market power. FERC proposes this cap as a proxy for price-responsive demand. The third component is a resource adequacy requirement intended to counter the reduced investment incentives caused by the first two components and by free riding of some load-serving entities (retail suppliers) on the capacity reserves of others. The resource adequacy requirement would penalize retail suppliers that do not procure sufficient generation, generation contracts, or demand reduction commitments to meet projected future demand. The fourth component involves bid caps that are triggered by specified unusual events in the region or nation (e.g., drought) that may increase market power.

We raise two general concerns about the overall market monitoring and mitigation proposals before discussing issues related to each component.

[402: The fourth market power mitigation component.] FERC may wish to combine the first and fourth components of its market power mitigation proposals because they are similar and overlap. Both employ bid caps coupled with must-run obligations to address the same concern, namely, periods of time in which various triggers designated by FERC or the market monitoring unit indicate that a generator has market power. We are concerned that maintaining two separate remedy components using the same techniques toward the same ends may lead to redundancies and other inefficiencies in the administration of these remedies or overapplication of market power remedies.

FERC could use the same contractual framework for both components by including a section in the contract between the generator and the RTO or independent transmission provider (ITP)(21) that gives to the RTO (or ITP) (at FERC's direction) the authority to invoke these caps and must-run obligations when regional conditions make the exercise of market power likely.

[404 and 405: Mitigation focused on spot markets.] FERC's monitoring and mitigation proposals focus on market power in day-ahead and real-time spot markets. The focus on spot markets appears to be premised on the view that market power mitigation in electricity spot markets also mitigates market power in electricity bilateral trades. As a general matter, the validity of this assumption is likely to depend on the degree of substitutability between spot market trades and bilateral trades from the customers' perspective and on the closeness of other potential substitutes available to customers facing efforts by suppliers to raise prices above competitive levels in bilateral trades. There is evidence that having both a spot market and bilateral trades helps improve economic performance for electricity markets,(22) but FERC may wish to develop a stronger understanding of relationships between spot and bilateral trading before proceeding on the apparent assumption that they are close substitutes from the perspective of customers.(23)

We raise an additional caution about FERC's reliance on market power mitigation in short-term markets. FERC may wish to assure itself that trading on each day-ahead and spot market is not so thin that the market is readily subject to inefficiencies and manipulation. As FERC has observed in some installed capacity markets,(24) thin trading may put market efficiency and effective competition at risk. It may wish to consider requiring a larger ITP area if trading on the day-ahead or real-time markets for energy or ancillary services is likely to be thin in a proposed ITP.

3. Market Power Mitigation for Local Market Power [406 to 412]

This section describes the first of the four components of FERC's proposed market power mitigation program.(25) FERC proposes an initial market power assessment followed by annual updates conducted by each market monitoring unit. A finding of local market power by the market monitor triggers market power mitigation for that generator in the form of bid caps and must-run obligations. System reliability requirements and high concentration of generator ownership within a load pocket are the focus of the market power assessments. We urge FERC to require that market monitors utilize economically appropriate techniques for conducting market power assessments. The DOJ and FTC Merger Guidelines provide such a framework. As discussed below, accurate assessment of the geographic market during different time periods is particularly challenging in assessing electric power markets, and computer simulations of grid congestion conditions are often an important element in such assessments.

[409: Effects of bilateral contracts on market power in spot markets for load pockets.]

Under the first component, when a generator is found to have market power, the generator will have an obligation to supply the market and to bid at or below a predetermined bid cap. FERC may wish to allow such generators to meet a must-run obligation (under bid caps) with a forward contract (long-term or short term) that obligates the generator to supply its full capacity to the market at prearranged prices. Such a contract would accomplish the same policy objectives as the must-run requirement with bid caps -- it assures that the generator's capacity is not physically withheld from the market and that the supplier is not responsible for increasing the market-clearing price above competitive levels in the real-time spot market or the day-ahead market. Because the two arrangements have equivalent effects and because forward contracts are more likely to efficiently reflect market supply and demand conditions, FERC may wish to allow generators to satisfy a must-run obligation through forward contracts.(26)

FERC references our comment of July 23, 2002, for the proposition that bilateral contracts are an effective way for a buyer to mitigate the market power of a seller. We wish to note that bilateral contracts do not inherently mitigate market power. Rather, bilateral contracts can mitigate market power, for example, because their terms can encompass longer time periods than spot market transactions and, within these longer time periods, buyers have a greater range of alternative sources of supply. One of the most important of these alternative sources of supply is entry of new generation or transmission capacity. Demand response programs are also a form of entry because they can be bid into the ancillary services market as a form of capacity reserves. Bilateral contracts can also mitigate market power if they reduce concentration (and there is no precommitment by the seller to reduce output during the period of the contract). Once the contract sets the price for some output, the seller has a lesser incentive to raise prices on remaining output by restricting remaining output. In that case, prices under bilateral contracts should reflect the expectation of more competitive spot prices.

[409: Bilateral contracts between load-serving entities and generators.] FERC states that whenever a generator has a must-run obligation under a bilateral contract, this will fulfill its must-offer obligation (as part of market power mitigation). We caution that FERC should modify this provision to specify that this bilateral contractual obligation must be consummated if it is to substitute for a must-offer obligation. Otherwise, there is a risk of a supplier gaming the market power mitigation requirements. The risk to competition is that a bilateral contract could be cancelled by the buyer at the last moment, thereby relieving the supplier of its bilateral supply obligation and allowing the generator to withhold output and raise prices above competitive levels. FERC may wish to avoid creating a loophole through which a supplier subject to a must- run requirement is frequently able, nonetheless, to withhold by agreeing to bilateral contracts that are unlikely to be consummated.

[410: The must-run obligation under participating generator agreements.] In triggering a generator's must-run obligation, FERC (and market monitors) may wish to take into consideration conditions in the day-ahead market. This may help to avoid market power or reliability problems that could arise (because of lags required to ramp up some types of generators) if only real-time conditions are used in determining when must-run obligations apply.

[411: Invitation to comment on how noncompetitive conditions should trigger mitigation.] FERC requests comment on how to structure local market power mitigation, particularly on how to define the noncompetitive conditions which should trigger the mitigation, and on how bid caps should be structured. We encourage FERC to base its market

power assessments on the conceptual framework incorporated in the Merger Guidelines. That approach entails defining the relevant product and geographic markets, calculating market shares for each supplier and concentration in each of the relevant markets, and assessing entry conditions and potential theories of anticompetitive behavior. We have found that each segment of time constitutes a separate product market. Relevant geographic markets depend on numerous supply and demand factors, including geographic patterns of demand, of generating capacity, and of fuel costs, as well as transmission capacity, pricing, and competing demands for use of the transmission system (e.g., loop-flows). The sizes of relevant geographic markets vary greatly with changes in the geographic pattern of demands, which vary with time of day, season, and random weather and other events.

Some of the methodologies that FERC has used to assess market power have not been reliable.(27) Computer simulation modeling is likely to be a particularly useful technique for assessing the relevant geographic market and the market power of one or more suppliers within it. Recent research indicates that the results of such assessments may be sensitive to several model specifications.(28) This makes it appropriate to test the robustness of these assessments.

Generalizations from the modeling completed in the market monitor's annual structural market power assessments may suggest that some indicators provide a reliable shortcut for defining the relevant market in which to measure concentration and individual market shares. For example, persistent congestion on the transmission paths leading into a major population center during summer daylight hours may be sufficient to define the geographic markets for those time periods.(29)

Once the relevant market is identified for one or more time periods, it is also necessary to measure market shares and concentration in an appropriate manner that reflects the competitive roles of the various suppliers. If market shares or concentration suggest a potential market power problem, additional analysis could be conducted to confirm the potential for a competitive problem before a bid cap and must-run obligation is triggered.

4. The Safety-Net Bid Cap [413 and 414]

The second component of the market power mitigation plan is a safety-net bid cap used to simulate the effect of price-responsive demand. Under price-responsive demand programs, high spot wholesale prices that translated into high retail prices in real time would cause some retail customers to reduce consumption of electricity or shift consumption to other time periods. Bid caps simulate price-responsive demand in a crude way by forcing suppliers to bid more like profit-maximizing suppliers would if retail demand were more sensitive to wholesale prices.(30) For example a $1,000 per MW-hour bid cap is in place in the Northeast and Texas.

[413: Safety-net bid caps to emulate demand response and prevent price run ups when imports set the market clearing price.] FERC's discussion regarding the application and rationale for safety-net bid caps raises important questions about market definition and the appropriate geographic scope of ITPs. FERC states the following:

... lack of demand response can result in dramatic increases in market-clearing prices, even with comprehensive mitigation on the supply-side, if imports can bid in at unrestricted levels. In this case, imported power from adjacent markets could set a market-clearing price above the marginal cost of the highest cost unit dispatched within the market.

This statement appears to be at odds with the economics of defining geographic markets for wholesale electric power. It is important that relevant markets be delineated based on sound economic principles and that market shares be computed in a manner that reflects the competitive roles of different sellers.(31) The statement in the NOPR implies that geographic markets are to be defined without reference to changes over time in the alternative sources of supply to which customers would turn in the face of a price increase. Ill-defined geographic markets likely will result in incorrect market structure assessments and remedies.

Alternative sources of supply may vary greatly over time due to changes in transmission congestion, equipment outages, and relative fuel prices, for example. Economic analysis of wholesale electric power markets generally finds that the geographic market varies over the course of the day and between seasons based on these factors. We encourage FERC to adhere to the economic meaning of geographic markets as described in the Merger Guidelines and not to a static geographic construct, even if using such a construct would be administratively convenient.

If FERC finds that suppliers outside of an ITP are exercising market power on sales within the ITP at times when market power is likely to be exercised, then it may wish to reevaluate whether the geographic scope of the ITP is too small to provide effective market power mitigation. FERC may wish to examine the proposition that to provide effective market power mitigation, the geographic scope of an ITP should be at least as large as the relevant geographic markets (which vary over time) in which prices for power in the ITP are determined during periods when there are market power problems.

FERC is implementing the safety-net bid cap as a proxy for demand response programs.(32) It follows that, where price-responsive demand programs are better developed, a safety-net bid cap is less likely to be warranted.(33)

[414 Request for comments on the level of the safety-net bid caps.] FERC poses a question regarding trade-offs between the level of safety-net bid caps and the extent of resource adequacy requirements (the third component of the market monitoring and mitigation proposals). FERC views resource adequacy requirements as a means to restore investment incentives that may be diminished by the safety-net bid cap and by free riding on the capacity reserves of other load-serving entities. We concur that the level of safety-net bid caps is likely to be a critical component of an assessment of the costs and benefits of the components of FERC's market power mitigation proposals. We encourage FERC to explicitly study these tradeoffs, particularly the sensitivity of generation investment to changes in the safety-net bid cap.(34) If, for example, a somewhat higher safety-net bid cap would provide most of the incentives for generation investment of a system with no safety-net bid caps, the costs of the potentially extensive and complex resource adequacy program might be avoided with relatively little harm to consumers by adopting a somewhat higher safety-net bid cap. A cap that is too low may be more harmful to consumers than no cap at all. FERC will be in a better position to access the costs and benefits of different potential safety-net bid cap levels once it better understands the sensitivity of investment incentives to different safety-net bid cap levels.

If FERC adopts a safety-net bid cap, we recommend that FERC also adopt sunset provisions for the cap or establish a periodic reassessment procedure regarding the level of the cap. If concerns about market power decline because of adoption of demand response programs or for other reasons, there will be less justification for a safety-net bid cap and one would expect that the level of the cap prompted by concerns about residual market power problems should increase. Consequently, FERC may wish to periodically reevaluate the appropriate level of safety-net bid caps, if any.

5. Mitigation Triggered by Market Conditions [415 to 417]

As indicated above [402], FERC may wish to combine the first market power mitigation component (local market power mitigation) with the fourth component (mitigation triggered by market conditions such as drought or heat waves). These two remedy components appear to overlap extensively, and treating them separately may result in conflicting or excessive mitigation requirements.

6. Establishing Bid Caps or Competitive Reference Bids [418 to 427]

FERC states its intention that bid caps reflect the marginal cost - including opportunity cost - of offering the full capacity of a generator when it has a must-run obligation.(35) Conceptually, this is the appropriate economic criterion in the short run when the bid cap is intended as a proxy for competitive bids and if marginal cost is known. We note, however, that if such requirements are applied for extended time periods, they may materially affect a supplier's ability to cover its variable costs. When a supplier cannot cover its variable costs, the supplier has incentives to exit, and other suppliers will lack incentives to enter or expand. Further, the proportion of total costs that are variable increases when a longer time period is considered. Variable cost approaches total cost in the long-term because more costs are variable in that time frame. This caveat may be particularly important in considering the recovery of variable costs and potential exit of existing generators, particularly generators other than base-load units (peaking units and mid-merit units).

[422 and 423 Opportunity costs of pondage hydro plants.] As expressed in our comment on the SMD strawman proposal,(36) accurately assessing opportunity costs of pondage hydro units (hydro plants with dams and water levels that are allowed to vary) and non-hydro units with limited hours of operation presents a serious challenge. We continue to have concerns about the accuracy and workability of the proposed methodologies for assessing opportunity costs of these units. One concern is the apparent assumption that the value of water is stable over time. On the basis of recent experience in the West, for example, it appears that the value of water increases as actual or forecast drought conditions continue. As a result, FERC's statement that hydro units will want to run any time electricity prices are relatively high appears questionable. FERC may wish to incorporate temporal changes in the value of water into its opportunity cost assessments for hydro plants. Additional complexities are likely to be associated with the role of risk aversion in determining opportunity costs. A decision maker's degree of risk aversion will enter into cost and benefit calculations about running a hydro plant and will affect its judgment about opportunity costs. For example, the hydro operator may be concerned that if a drought continues and generators are run now, then next month there will not be enough drinking water or electric power. Risk aversion is subjective and, therefore, difficult to quantify. The best that could be done to detect withholding of capacity by pondage hydro units in circumstances in which risk assessments differ would be to show that the degree of risk aversion demonstrated in the withholding decision was at odds with the degree of risk aversion in other decisions under similar circumstances made by the same decision maker. Our experience in sham litigation cases suggests that demonstrating intent of this sort can be difficult.(37)

7. Exemptions [428]

FERC asks for suggestions on classes of suppliers that might be exempted from market power mitigation. FERC may wish to consider an exemption for suppliers that are short in the positions they hold. That is, they have firm obligations to supply power that are more than their available capacity. The rationale for such an exemption would be that suppliers that are short are net buyers and, therefore, lose more than they gain by physical or economic withholding of the generation they own or control under contract.(38)

We note, however, that the determination of some suppliers' actual positions may be complex. If FERC decided to grant exemptions for suppliers that are short in the positions they hold, it may wish to set conditions for exemptions of firms that hold a wide variety of financial positions that are difficult to net out, or that have financial relationships with other parties that are difficult to trace.

8. Monitoring [429 to 456]

FERC proposes that market monitoring be conducted by a unit that is autonomous of the Independent Transmission Provider's management and market participants and that reports directly to FERC. It also details the responsibilities of each market monitor.

[430 Market monitors will report directly to FERC.] We commend FERC for clarifying and tightening the relationship between market monitors and FERC. The market monitoring units should benefit from closer communication and reporting guidance and feedback from FERC. FERC should benefit from obtaining more comparable reports from all market monitoring units that it can use in maintaining a stronger overview of U.S. electric power markets. FERC may wish to facilitate coordination with the antitrust agencies by requiring the market monitors to file their reports also with the antitrust agencies.(39) FERC may wish to request that market monitors keep in mind that some anticompetitive activities of market participants (attempted, but unsuccessful, coordination between generators, or use of "unfair" trade practices, for example) may raise antitrust enforcement concerns even if they do not raise concerns under FERC's statutory framework.

[432 Request for comments on whether market monitor should report on market neutrality of ITPs.] FERC asks if market monitors should report regarding the market neutrality of the ITP. In our view, market neutrality is a hallmark of the ITP's (RTO's) independence. Evaluating each ITP's market neutrality, therefore, is part FERC's task of ensuring compliance with FERC Order 2000. Market monitors are likely to be able to make a timely and informed contribution to FERC's evaluations because the market monitor is in close, regular contact with ITP staff and market participants.

[439 and 441 Structural analyses performed by market monitors.] FERC proposes to require each market monitor to perform a structural analysis that includes market concentration measures, entry, demand response, and transmission constraints. These are all important elements in market power assessments. In addition to overall concentration measures, it may be informative to evaluate concentration along different segments of the supply curve. However, it must be kept in mind that ownership of inframarginal units may significantly affect incentives to withhold output of marginal units.

In light of the complexity of the transmission network, market monitors should be required to employ computer simulations(40) as part of their competitive market analyses.(41) Doing so will help market monitoring organizations prepare for the initial market power assessment and subsequent annual updates. Computer simulation analysis is particularly valuable given, not only the complexity of the transmission network, but also the potential importance of determining the robustness of market power assessments,(42) and the significant changes in load flows caused by ongoing transmission and generation investments and changes in technology and fuel prices. We also encourage FERC and market monitors to include potential coordinated interaction scenarios in this modeling where conditions for coordinated interaction exist.

FERC's list of structural analysis elements contains important aspects of structural analysis, but does not include the prerequisite for all of them -- appropriate market definition. We have found that each segment of time constitutes a separate product market and that the size and shape of the associated relevant geographic markets vary greatly depending on the geographic patterns of demands, fuel costs, and other factors. We are concerned that FERC's statement of requirements for market monitors not be based on a static geographic market definition coinciding, for example, with the boundaries of the ITP.(43) Basing structural analyses on inaccurately defined markets will likely lead to inefficient or misdirected market power mitigation remedies. We also encourage FERC to require that market monitors continue to evaluate and report on how market rules are affecting configuration of the relevant geographic markets.

Finally, we note that the task of accurately assessing the relevant geographic market in each time period and examining the likely market power of suppliers (individually or under a coordinated interaction scenario) is often facilitated by using computer simulation models.(44) Accomplishing these tasks in a timely manner without such modeling may be problematic in many situations.

[442, 447 to 449 Evaluation by monitors of participants' conduct.] FERC requests suggestions about core questions and analytic techniques for monitors to use to evaluate the conduct of market participants. In our view, the same techniques and approaches used for structural assessments should also be used in assessments of individual firm behavior. In addition, we have found that review of internal documents of suppliers and customers (including planning, strategy, and marketing documents as well as the data submissions suggested in paragraph 447) on a confidential basis (accompanied by investigative hearings with the authors or compilers of these documents and data sets) is often essential in such evaluations.(45) If a market monitor does not have access to such documents and is unable to conduct depositions of market participants, it is unlikely that the monitor can produce a definitive analysis of an individual firm's behavior. FERC may wish to consider approaches under which its own investigative authority can be used by market monitors, or if it determines that its own authority is insufficient, it may wish to seek legislative changes sufficient to allow it to conduct thorough investigations consistent with its statutory responsibilities.

[444 and 445: Market monitors penalize violations of market rules.] FERC states that market monitors must have the necessary tools to investigate and punish violations of existing market rules. We respectfully disagree with the latter

half of this assessment.(46) One concern is the potentially limited investigative techniques available to monitors. These limitations may make it difficult for a market monitor to draw conclusions with sufficient basis to sustain court review of punishments imposed by the market monitor. Combining monitoring with punishment authority may also chill informal communication between the market monitor and market participants that may be important in providing informal advice to market participants about market rules and in identifying and curbing incipient rules violations. A broader potential concern is the delegation of FERC's federal law enforcement authority to an outside, non-federal entity.

J. Long-Term Resource Adequacy

FERC has proposed a long-term resource adequacy requirement to remedy both a public goods problem (free riding on other suppliers' capacity reserves) and its own market power mitigation policies. [461 to 473] As FERC observes in paragraph 414, policies that reduce market clearing prices (such as the proposed bid cap) also reduce incentives to invest and this may lead to high prices and reliability problems, including blackouts, later. Resource adequacy requirements attached to load-serving entities and accompanied by penalties for non-compliance are one approach to restore investment incentives.(47) FERC's efforts in this area may be eased by the long tradition of state regulators employing related requirements.

We raise two general questions that FERC may wish to address before adopting the proposed resource adequacy requirements. The first question is whether some form of augmented investment incentives would increase efficiency and consumer welfare. If the answer is yes, then the second question arises: do resource adequacy requirements provide more net benefits than alternative policy instruments. If not, then resource adequacy may not be an effective policy approach.(48) Included in assessing the benefits and costs of the resource adequacy requirements is potential gaming of the requirements and potential costs of administering and enforcing the requirements. FERC may wish to review its present proposals with a focus on these two potential sources of costs.

The answer to the first question likely depends on the extent to which free riding on the capacity reserves of others takes place and on the extent to which bid caps reduce market clearing prices.(49) We encourage FERC to evaluate the independent and joint effects of free riding and bid caps on generation investment incentives. In so doing, FERC may wish to examine a variety of potential bid cap levels.(50) With this information in hand, FERC would be in a better position to understand the tradeoffs between remedies for free riding, various levels of bid caps, and investment incentives.

FERC may wish to be particularly alert for bid cap levels at which small increases in the bid cap provide disproportionately large increases in investment incentives. The likely costs, complexities, and uncertainties of the resource adequacy requirements should only be undertaken if bid caps have a strong detrimental effect on investment incentives and reducing these detrimental effects requires major increases in bid caps.

The answer to the second question requires evaluation of alternative approaches to curtailing free riding as well as an understanding of the tradeoffs between bid cap levels and investment incentives. To the extent that FERC's primary concern (i.e., insufficient investment incentives) stems from the free riding problem, FERC may wish to explore methods to exclude those load-serving entities with inadequate reserves from the benefits of the pooling of reserves. Government and private market interventions to solve free riding problems often focus on creating property rights that exclude those who do not pay.(51) Alternatively, the pricing of access to pooled reserves could penalize load-serving entities with inadequate reserves when they are allowed access to these reserves. Either of these alternative approaches could solve the free rider problem and allow FERC to avoid the complexities and uncertainties of projecting future demand and administratively allocating the burden of future supply adequacy. Both of these alternatives would force load-serving entities that are short of reserves and their customers to bear the costs of inadequate reserves.(52) By so doing, these alternative policies would create incentives to hold reserves that match their customers' risk preferences.(53)

Both potential exclusion and pricing penalties in accessing capacity reserves should be disclosed to retail customers of the affected load-serving entities. Absent such disclosures, load-serving entities that are short on future generation reserves could free ride on the reputations of load-serving entities with adequate reserves and gain commercial advantage up to the point at which their customers would face power disruptions or price spikes. Failure to disclose that a retail supplier has been found by FERC to have inadequate resources to meet its future load could constitute a form of consumer deception. A supplier so designated would be offering a lower quality service with higher risk of power disruptions or price spikes than customers expect. For this reason, if it adopts the penalties in accessing capacity reserves, we recommend that FERC work with the states and the FTC to assure that affected retail customers receive adequate and timely disclosures in this regard. Through the disclosure of a supplier's reserve position, customers in a retail choice environment would be able to select the combination of price and risk that they prefer. Customers especially concerned about reliability and price volatility could then identify and avoid entirely the load-serving entities that are short on reserves or only contract with such a firm if its lower prices compensate the customer for the increase in risk. A retail customer with an emergency generator, for example, might well have lower overall electricity costs and equivalent reliability by picking a low-cost supplier with a higher risk of blackouts and relying on his or her own generator during blackout periods.

As in the case of safety-net bid caps, FERC may wish to sunset the resource adequacy requirements so that they do not persist beyond the date at which they are providing net benefits to customers.

[462 and 466: Spot market prices may not provide sufficient incentives to secure long-term reliability.] FERC points out that the demand for electricity and the supply of new generating capacity respond very slowly to price changes. We agree that under present conditions this has been true. However, this observation should serve to underline the urgency of implementing price-responsive demand programs. Such programs are likely to make consumption more responsive to changes in wholesale prices. Further, by flattening load profiles, price-responsive demand programs should reduce average costs of the grid system and allow better utilization of existing generating capacity.

[474 to 540 Administration of the Proposed Adequacy Reserve Requirements] The discussion of these paragraphs over the next several pages leads us to question the administrative feasibility of the proposed resource adequacy requirements. While each aspect taken separately may not be insurmountable, the aggregation of difficulties suggests that the task would be formidable.

[474, 498 and 499 Assignment of responsibility for future resource adequacy.] FERC raises the possibility that slow growth areas would face disproportionate burdens in paying for future generation reserves because these requirements would be based on the proportion of present consumption served by each entity. We note that the alternatives of excluding or charging higher prices for access to pooled reserves for load-serving entities with inadequate reserves at the time the entity needs reserves would not disproportionately burden low growth areas.

[477 and 478 Restrictions on spot market purchases when load must be curtailed.] If some load-serving entities will subject their customers to greater risk of blackouts than others or than in previous periods, retail customers should be notified as described above at the beginning of Section J. In a retail choice environment, customers may be deceived absent such disclosures. In a non-choice environment, customers of suppliers with deficient future capacity may wish to buy emergency generators or take other steps if they are facing lower reliability or the state may wish to require that load-serving entities meet the FERC requirements at a minimum. We suggest that FERC work with the states and the FTC to implement such disclosures where appropriate.

[479 The time horizon for resource adequacy assessments.] Within the context of FERC's resource adequacy proposals (or the alternative approaches to prevent free riding described above), FERC's use of a time horizon sufficient to allow entry of new generation, transmission, or price-responsive demand programs is important to avoid the possible exercise of market power in short-term capacity markets by incumbent generators.

[480 Complementarity and compatibility of FERC and state resource adequacy programs.] FERC states that its resource adequacy proposal is designed to complement state resource adequacy programs by expanding the

geographic scope of the area within which adequacy is assessed. FERC may wish to emphasize this point when it considers the geographic scope of ITPs. Since resource adequacy may relate to broad geographic areas up to the size of the interconnect, FERC is most likely to be able to avoid seams issues in resources adequacy planning by insisting on large ITPs.

[489 Adequacy of future supply to meet projected demand.] FERC highlights the relationship between the degree of reliance on hydro and what should constitute adequate capacity reserves in a region. We agree that reliance on hydro is one important factor in establishing adequate reserve levels. FERC may wish to consider other factors as well since the reliability of other types of units is also subject to change. For example, oil, natural gas, and nuclear units may face fuel shortages or other types of disruptions as a group. In general, changes in relative fuel prices may also give rise to changes in the shape of the supply curve that can induce greater volatility in wholesale prices in a region, even if they do not cause blackouts. For this reason, resource adequacy planning might also address the diversity of generation resources in a region or by a particular load-serving entity.

[493 Proposed minimum 12% reserve margin.] FERC proposes to establish a minimum requirement for the capacity reserve margin of 12% in each region. FERC may wish to study relationships between capacity reserve margins and evidence of pricing above competitive levels. The research of the California ISO in this regard may serve as a model for such studies.(54) FERC may wish to establish its minimum capacity reserve requirements on the basis of such research. FERC may also wish to consider minimum capacity reserve margin assessments in sub-areas of the region that constitute relevant markets during some periods of time. In particular, separate reserve margin assessments for load pockets may be appropriate because regional reserves may not be available to an area with transmission constraints.

[507 Demand response can substitute for generation in resource adequacy assessments.] FERC proposes to include demand response (i.e., a retail customer's commitment to reduce consumption) as an alternative to generation, in meeting resource adequacy requirements. We applaud FERC's proposal to treat demand response as a substitute for generation in resource adequacy assessments. This provides a constructive and meaningful incentive for load-serving entities and states to implement retail real-time rates and metering and other price-responsive demand programs.

[509, 512, 516 Resource adequacy standards.] FERC asks whether new capacity being built should count toward fulfilling resource adequacy requirements. We believe that verifiable entry should count toward resource adequacy requirements in order to avoid exercise of market power in capacity markets by incumbent generators as well because in-process entry may affect future prices in wholesale (and retail) electricity markets in a manner similar to completed generation entry.(55)

Earlier we noted that by using a planning window sufficient to allow entry, FERC could avoid the potential exercise of market power by incumbent generators in near-term capacity markets. If FERC selects a planning window shorter than the entry period for the slowest form of entry, it may allow exercise of market power for particular types of generation or distort entry decisions unless it allows partially completed projects to count toward resource adequacy requirements. For example, if FERC picked a three year planning horizon, but a new hydro project in the region requires four years for planning, permitting, and construction, then load-serving entities in the region would have incentives to pay above competitive prices to access existing capacity of this type or to invest in other types of generation with shorter entry lags even if the hydro project would be more efficient. Similar distortions could arise in transmission investment decisions absent consideration of in-process entry projects.

[524 Planning horizon determined by Regional State Advisory Committees.] For the reasons discussed in response to paragraphs 479, 509, 512, 516, FERC may wish to prevent regions from establishing short planning horizons for resource adequacy requirements and from excluding verifiable entry in resource adequacy assessments.

[525 and 536 Request for comments on interim resource adequacy requirements.] If interim resource adequacy requirements are implemented, FERC may wish to accompany them with less restrictive treatment of planned entry

or planned expansion of generation, transmission, and price-responsive demand programs. Doing so would help to avoid the exercise of market power in short-term capacity markets by incumbent generators.

[538 Effects of inadequate resources on a firm's customers served by the firm's own generation and bilateral contracts.] FERC asks whether penalties for inadequate resource planning should apply to all loads of such an entity or exclude self-generation and bilateral contracts of the load-serving entity. FERC may wish to consider the potential complexity and ad hoc discrimination between customers that may be endangered by the proposed exemptions. FERC also may wish to consider starting with a wide application of penalties and then granting exemptions if the broader penalties prove unnecessary to augment investment incentives in order to compensate for free rider problems and FERC's own market power mitigation policies.

[539 and 540 Incentives to avoid future penalties and curtailments.] FERC identifies alternatives to penalties for a load-serving entity with inadequate future reserves that involve procurement of capacity reserves by the ITP on behalf of such entities (and assignment of such costs to the load-serving entity) . FERC identifies two disadvantages of such arrangements. The first is the exclusion of demand response programs in such arrangements. The second is erosion of the ITPs independence under this approach because it could be seen as taking a financial position in the market. In our view, both of these concerns are valid and important. We add a third. Some suppliers and customers may prefer a different combination of price and reliability than the traditional electric power system provides. Some customers may prefer a combination of lower prices and lower reliability. Penalties and pricing arrangements should be sufficient to assure that such suppliers and their customers bear the full consequences of lower reliability or higher price volatility,(56) but using the ITP to force such load-serving entities to adopt the same combination of price and reliability as other suppliers may not be efficient and may harm consumers who prefer lower prices.

[547 ICAP focuses exclusively on generation.] FERC observes that many parties object to existing ICAP programs because they focus on power generation to the exclusion of demand response programs. This critique is accurate. Price-responsive demand programs are likely to be the greatest surety against the exercise of market power in electric power wholesale markets. With accurate and timely prices that reflect wholesale prices, retail consumers will be positioned to make well-informed consumption and investment decisions that are likely to flatten load profiles and reduce average system costs.

K. State Participation in RTO Operations [551 to 555]

FERC proposes a formal process (through Regional State Advisory Committees) in which states can engage in dialogue with the independent entity that will operate the grid under Standard Market Design.(57) We urge FERC and the states to give priority to development and implementation of price-responsive demand programs in all states and to regional transmission siting issues because price-responsive demand programs and relieving transmission bottlenecks in load pockets are likely to be the most effective methods of addressing market power concerns.

L. Governance of Independent Transmission Providers [556 to 574]

FERC confirms the high priority that it places on the independence of the governance of regional organizations in order to prevent bias or the appearance of bias in the rules and operations of wholesale electric power markets. We continue to support FERC's insistence on independence of regional market organizations and agree that further defining the elements of independence of their governing boards is timely.

Beyond the independence of the ITP's board(58) and the market rules the board creates, we encourage FERC to consider how ITPs will organize to operate the bid-based markets and maintain transmission services.(59) We believe that an important consideration in the organization of ITP functions should be operating efficiency and the incentives which support it. Past experience suggests that efficiency does not flow from good intentions alone. Rather, efficiency requires economic incentives to perform efficiently, including the risk of being displaced if performance lags. An attractive approach to promote efficiency may be for the independent ITP's board to contract with an independent for-profit entity to operate the day-ahead and real-time markets and for the ITP's board to allow independent, for-profit transmission companies (ITCs) to maintain the grid within the ITP's boundaries.(60) Both the market operator and the ITC's within an ITP would work under rules created and monitored by the ITP's governing board (and also monitored by the market monitoring unit). We believe that a hybrid ITP governance model of this type that combines independence with strong efficiency incentives may be attractive for both wholesale market participants and retail consumers. The independence stems from provisions regarding the qualifications and selection of board members, as FERC proposes. The strong efficiency incentives stem from the profit motive and the ability of the ITP's board to displace the operating entity or the ITCs if they do not perform efficiently. One of the responsibilities of the ITP's board should be to develop measures and criteria for evaluating the performance of the market operator and ITCs.

[560 and 561 Stakeholder participation.] FERC describes its concerns about the narrow composition of existing market participant advisory committees. We concur that broader representation to include demand-side approaches to resource management and market power mitigation would strengthen the advisory committees by eliminating potential biases in their composition at present.

STATEMENT OF COMMISSIONER SHEILA F. ANTHONY

Before the United States of America Federal Energy Regulatory Commission Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design

Docket No. RM01-12-000

Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission

Today the Federal Trade Commission (FTC) voted to authorize its staff to submit the above-captioned comment. I concurred in the vote, but I write separately to highlight several concerns relating to the Federal Energy Regulatory Commission's (FERC's) deregulatory efforts, particularly FERC's notice of proposed rulemaking regarding standard market design.

As recent events have demonstrated, deregulation of electricity markets is not the panacea some once envisioned. Not surprisingly, deregulation efforts have stagnated. I believe that this trend reflects well-founded wariness about deregulation's potential impact on consumers. When a state chooses deregulation as its preferred path for electricity reform, the goal must be to transform a highly regulated market into a truly competitive one, in structure and function as well as in name. If strict government oversight is removed, but the market is allowed to evolve in non-competitive ways, profit-seeking generators may have both the incentive and the ability to discriminate in access to transmission services, or otherwise exercise market power, to the detriment of consumers.

The FTC staff has a long history of providing comments and feedback to FERC (since at least 1995). Throughout that time, staff's comments have embraced a consistent theme, perhaps best paraphrased as, "if you're going to do it, do it right." In short, for deregulation to work, it must be accomplished in a manner that creates efficient, competitively healthy, self-sustaining market structures. We have all seen the disastrous consequences of deregulation done wrong. FERC has an obligation to protect the public interest by learning from these unfortunate experiences.

If FERC intends to establish a framework for future deregulatory efforts, FERC should proceed cautiously and deliberately. The FTC staff comment provides a number of useful suggestions. Notably, the comment urges FERC to employ long-standing antitrust principles to measure market power and to evaluate a market's overall competitiveness. It also warns that an exclusive focus on unilateral market power is not sufficient, because highly concentrated markets often are susceptible to coordinated interaction (especially markets undergoing deregulation, where the once-regulated participants already are accustomed to communicating with each other). Overall, FERC should focus on alleviating transmission bottlenecks in deregulated markets with high levels of concentration and entry impediments - because, as antitrust teaches us, these markets are the most susceptible to anticompetitive harm.

Endnotes:

1. This comment represents the views of the staff of the Bureau of Economics of the Federal Trade Commission and the staff of the General Counsel's Office of Policy Studies. They are not necessarily the views of the Federal Trade Commission or any individual Commissioner. The Commission has, however, voted to authorize the staff to submit these comments. See Attached Statement of Commissioner Sheila F. Anthony. Inquiries regarding this comment should be directed to John C. Hilke, Economist and Electricity Project Coordinator in the Bureau of Economics (801-524-4440 or jhilke@ftc.gov) or Michael Wroblewski, Assistant General Counsel for Policy Studies (202-326-2155 or mwroblewski@ftc.gov).

2. This comment represents the views of the staff of the Bureau of Economics of the Federal Trade Commission and the staff of the General Counsel's Office of Policy Studies. They are not necessarily the views of the Federal Trade Commission or any individual Commissioner. The Commission has, however, voted to authorize the staff to submit these comments. See Attached Statement of Commissioner Sheila F. Anthony. Inquiries regarding this comment should be directed to John C. Hilke, Economist and Electricity Project Coordinator in the Bureau of Economics (801-524-4440 or jhilke@ftc.gov) or Michael Wroblewski, Assistant General Counsel for Policy Studies (202-326-2155 or mwroblewski@ftc.gov).

3. FTC Staff comments are available at <http://www.ftc.gov/be/advofile.htm>

4. FTC Staff Report: Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform (Jul. 2000), available at <http://www.ftc.gov/be/v000009.htm>.

5. FTC Staff Report: Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform, Focus on Retail Competition (Sep. 2001), available at <http://www.ftc.gov/reports/index.htm>.

6. NOPR at ¶¶ 31-35.

7. FTC Staff Comment on Order No. 888, FERC Docket No. RM95-8-000 (Jul. 25, 1995).

8. The native load exception allows a utility (the transmission provider) to bundle electricity and transmission services and to have preferential access to the transmission grid (over non-affiliated grid users) to serve its captive retail customers.

9. FTC Staff Retail Competition Report at iii.

10. The staff noted in 1995 that operational unbundling would likely be more effective than functional unbundling and less costly than industry-wide divestiture. FERC's plan for "functional unbundling" of power generation from transmission services "would leave in place the incentive and the opportunity for some utilities to exercise market power in the regulated system. Preventing them from doing so by enforcing regulations to control their behavior may prove difficult. The problem would be most effectively prevented by completely separating ownership and control of generation from transmission. This separation would remove both the incentive and the opportunity to exercise market power, by eliminating the utilities' ability to discriminate in favor of their own generation operations. The additional benefits of full divestiture may be outweighed, however, by the costs and difficulties of implementing it industry-wide. It may be sufficient to require 'operational unbundling,' in which the dispatch of generating capacity and/or the operation of the transmission grid would be controlled by an independent entity. Operational unbundling could prevent discrimination and achieve the competitive benefits of open access more effectively and efficiently than would an attempt to mandate, regulate, and monitor access." FTC Staff Comment on FERC Order No. 888 at 2.

11. An ITP is an interim independent provider of transmission services pending formation of an RTO in the region where the ITP is located. An ITP may encompass the transmission assets of only a single utility, for example, whereas an RTO encompasses all of the transmission assets in a region.

12. FTC Staff Comment, FERC Docket No. RM01-12-000 (Jul. 23, 2002).

13. FTC September 2001 Staff Report, pp. 19-21.

14. *See* FTC Staff Comment on Order No. 2000, FERC Docket No. RM99-2-000 (Aug. 16, 1999).

15. We note positively that FERC's price control proposals focus on bid caps rather than price caps. Price caps often have particularly deleterious effects on investment incentives because price caps do not allow for price increases that are due to scarcity of generating capacity. In contrast, bid caps do not preclude price increases that exceed an arbitrary level and that are due to scarcity of generating capacity. Under the FERC's proposals, a firm with (1) market power, (2) a must run obligation, and (3) a bid cap requirement is unable to withhold capacity from the market, but will receive the market clearing price which may well be above its bid cap (marginal costs). When generating capacity is scarce enough that this generator is dispatched by the grid operator, such a firm will receive the market clearing price, a price that is at or above its marginal costs, even if the firm is not allowed to drive market prices higher by withholding capacity. Thus, bid caps generally undermine investment incentives to a lesser degree than price caps.

16. *See* U. S. Dept. of Justice and Federal Trade Comm., Horizontal Merger Guidelines (Apr. 2, 1992, revised Apr. 8, 1997), *reprinted* in 4 Trade Reg. Rep. (CCH) ¶ 13,104 [hereinafter Merger Guidelines].

17. *See* FTC Staff Comments, FERC Docket No. RM98-4-000 (Sep. 11, 1998); FTC Staff Comment, FERC Docket No. EL01-118-000 (Jan. 7, 2002). *See also* Mark W. Frankena, "Geographic Market Delineation for Electric Utility Mergers," The Antitrust Bulletin (Summer 2001) at 357-402; Mark W. Frankena, "FERC Must Fix Its Electric Utility Merger Policy," 9 The Electricity Journal at 32-43 (Oct. 1996).

18. While implementation of real-time pricing is likely to reduce market power concerns in electric power markets, it is unlikely to eliminate market power, particularly in transmission constrained areas with high concentration among suppliers and entry impediments.

19. Close cooperation with the states is essential for this to occur.

20. The bid cap would be based on estimated marginal cost, including the estimated opportunity cost, of the specific generator.

21. FERC proposes to require that all transmission assets (not already included in an ISO) be included in an ITP as an interim step prior to approval and implementation of an RTO to serve the area.

22. *See, e.g.*, Paul Kleindorfer "Comments and Conjectures on Needed Economic Theory for Power Systems," paper at the NSF/DOE/EPRI Workshop on Future Directions for CIEN (Nov. 16, 2000) citing J. Bower and D. Bunn, "A Model-based Comparison of Pool and Bilateral Market Mechanisms of Electricity Trading," London Business School Working Paper (Nov. 1999) and Dongjun Wu, Paul Kleindorfer, and Jin Zhang, "Optimal Bidding and Contracting Strategies for Non-storable Goods," Working Paper (Oct. 2000). See also Market Surveillance Unit - California ISO, "Annual Report on Market Issues and Performance, 1999" (Jun. 1999), Section 7.4.

23. The likelihood that FERC's assumption is valid would be enhanced if all load-serving entities readily could turn to the spot market for supply if they find that generators are seeking to exercise market power in available short-term bilateral trades and they readily could turn to entry or a futures market as alternatives for longer-term bilateral trades.

24. NOPR at paragraphs 544 and 545.

25. This discussion assumes that consumers are better off with triggered mitigation than with wholesale cost-of-service regulation or unmitigated prices when there are market power problems that cannot be addressed adequately by feasible structural remedies.

26. This suggestion is also made in the FTC Staff Comment in FERC Docket No. RM01-12-000 (Jul. 23, 2002) at Section II.D.

27. *See* John R. Morris, "Finding Market Power in Electric Power Markets," *International Journal of the Economics of Business*, Vol 7(2), 2000, pp. 167-78.

28. *See* Scott M. Harvey and William W. Hogan, "Market Power and Market Simulations" (Jul. 16, 2002), *available at* <http://www.kgs.harvard.edu/whogan>. Model specifications will include, for example, transmission capacity, line losses, and generators' capacities, fuel costs, and heat rates. If the market monitor uses the ITP's dispatch software in its modeling, some of the uncertainty regarding the correct model parameters should be reduced.

29. Over time, insights about facilitating or mitigating circumstances could lead to identification of additional shortcuts in the analysis.

30. When demand is more price sensitive, the profit-maximizing price for suppliers with market power is lower because the sales loss caused by a given price increase is larger. A bid cap causes sellers to behave as profit-maximizing sellers would if they faced a demand that became perfectly elastic with respect to price at the price equal to the bid-cap.

31. *See, e.g.*, Mark W. Frankena, "Geographic Market Definition for Electric Utility Mergers," The Antitrust Bulletin (Summer 2001), pp. 357-402.

32. The safety-net bid cap may proxy the effects of prices-response demand from the perspective of suppliers, but does not create corresponding incentives to reduce consumption. Thus the combination of safety-net bid caps and must-run obligations maintains the pre-mitigation output and consumption (because real-time retail prices remain largely unaffected), while reducing any price effects that might have been due to withholding.

33. If such variations increase system costs, then FERC may wish to evaluate the costs and benefits of allowing variations in the safety-net bid caps within an interconnect.

34. Several techniques could be used to study this type of issue. Two examples are financial case studies and econometric studies of the history of entry. The first involves examining how a variety of binding bid caps affect recovery of fixed costs for a variety of different types of generators under a variety of scenarios about demand levels. These case studies and financial simulations could then provide insights about how changing the level of the bid caps would affect recovery of fixed costs by entrants. The second is to study rates of entry by generators during different economic conditions. Differences in economic conditions would proxy different rate caps. Both domestic and foreign experience could be considered and econometric techniques could be used in this type of study.

35. This discussion applies to output decisions of existing facilities. If investment decisions are being made, then long-run impacts of bid caps may occur immediately in the form of reduced future capacity.

36. Comment of the FTC Staff, FERC Docket RM01-12-000 (Electricity Market Design and Structure: Strawman Discussion Paper for Market Power Monitoring and Mitigation) (Apr. 3, 2002) at Section IV.

37. *See* Christopher C. Klein, Economics of Sham Litigation: Theory, Cases, Policy, Washington, D.C.: Federal Trade Commission, 1989. To the extent that "... collateral market benefits of suing are necessary to justify the predator's expense of litigation, one can think of sham litigation as litigation that would not be undertaken if the parties were not competitors."

38. *See* Frank A. Wolak, "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market" (Jan. 2000).

39. Subject to confidentiality requirements, if any, for each report.

40. The market monitor may find the ITP's dispatch models to be particularly useful in its initial competitive market analyses.

41. We have advocated increased use of computer simulation models (or the actual generation dispatch software of the ITPs) in market analysis in our previous filings with FERC and the states. See, e.g., FTC Staff Comment, Alabama Public Service Commission, Docket No. 26427 (Restructuring in the Electric Utility Industry) (Jan. 11, 1999); FTC Staff Comment, FERC Docket No. RM98-4-000 (18 CFR Part 33, Revised Filing Requirements) (Sep. 11, 1998); FTC Staff Comment, Arkansas Public Service Commission, Docket No. 00-048-R (Generic Proceeding to Establish Filing Requirements and Guidelines Applicable to Market Power Analysis) (Apr.13, 2000).

42. *See* Scott M. Harvey and William W. Hogan, "Market Power and Market Simulations" (July 16, 2002), *available at* <http://www.kgs.harvard.edu/whogan>.

43. NOPR paragraph 413, for example, raises the possibility that geographic markets will be defined by FERC without regard to temporal variations in the level of congestion. This would be at odds with an economic understanding of geographic markets in the electric power industry.

44. Industrial organization economists have used a variety of approaches for assessing whether market power has been exercised in a variety of markets. These measures include adjusting and evaluating accounting profitability compared to economy-wide benchmarks, comparisons of profitability across geographic areas with different structural conditions, identification of price discrimination (a direct indication of market power), evaluation of past entry attempts, market share assessments, retrospective studies of the effects of events that change market power conditions on the stock prices of competitors, and reviews of firms' internal evaluations of their own profitability. The complexities of electricity transmission and the wide range of incumbent generators' costs make market power assessments through computer simulation analysis particularly appealing in electricity markets.

45. A discussion and listing of the investigative techniques and methods that we have found to be useful are presented in the FTC Staff Comment, FERC Docket No. RM98-4-000 (18 CFR Part 33, Revised Filing Requirements) (Sep. 11, 1998).

46. FTC Staff Comment, FERC Docket No. MR99-2-000 (Regional Transmission Organizations) (Aug. 16, 1999) at III.F.

47. FTC Staff Comment, FERC Docket No. RM01-12-000 (Working Paper on Standardized Transmission Service and Wholesale Electric Market Design) (Jul. 23, 2002) at V.B.

48. Even if a market failure is observed, the costs of the optimal remedy may exceed the benefits of correcting the market failure. If so, then consumers may well be better off if no government intervention is implemented.

49. Note, that second part of this inquiry is not whether bid caps reduce bids, but rather what their effects are on market-clearing prices.

50. *See also* the discussion of paragraph 414 above.

51. If it is costly or unacceptable to prevent free-riding by excluding load-serving entities with inadequate reserves when demand curtailment is necessary (or charging sufficiently high fees to discourage this behavior), the credibility of both FERC's proposals or the alternatives we identify will be undermined. In that case, FERC may wish to seek

reforms in the existing installed capacity (ICAP) framework, including methods to incorporate price-responsive demand programs into the ICAP framework. Because ICAP creates ongoing, gradual incentives for load serving entities to have adequate reserves, its application is less abrupt and less directly tied to demand curtailment incidents.

52. As with FERC's proposed program, these alternative methods to prevent free riding could be announced with specified future implementation dates. Using a future implementation date would help to avoid the exercise of market power in shorter-run capacity markets in which entry would not be a viable alternative source of supply (alternative to existing generating capacity held by incumbents) for load-serving entities.

53. This alternative approach likely would require policies that allow suppliers with adequate resources to reject or penalize retail customers that are switching from a supplier with inadequate resources.

54. *See* Anjali Sheffrin (Market Analysis, California ISO), "Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition," (*Revised* Nov. 19, 2001).

55. The Horizontal Merger Guidelines explicitly state that the entry period ends when entry substantially affects prices, not when the entry is physically completed. The point in time at which entry substantially affects prices may be before, after, or at the completion of the production facility. For discussion of entry lags, see, e.g., John C. Hilke and Philip B. Nelson, "The Economics of Entry Lags: A Theoretical and Empirical Overview," Antitrust Law Journal 61:2 (Winter 1993) pp. 365-385.

56. If market rules, metering, and distribution technology cannot accomplish this separation of service reliability levels and pricing, greater uniformity in service quality may be efficient.

57. The listed topics for these committees include resource adequacy standards, transmission planning and expansion, rate design and revenue requirements, market power and market monitoring, demand response and load management, distributed generation and interconnection policies, energy efficiency and environmental issues, and RTO management and budget review.

58. In our July 23, 2002 comment we associated independence of the ITC's governing board with non-profit status. We did so in recognition of independence issues that have arisen with stakeholder boards in the past. See FTC Staff Comment, FERC Docket No. EL00-95-000 et al. (Nov. 22, 2000) at Section II. We recognize, however, that a board with stakeholders may not be inherently subject to bias and gridlock Where the stakeholders are all customers of the grid with a primary incentive to obtain efficient, customer friendly service from the grid operator, stakeholders on the ITC's board may be particularly focused on efficiency incentives of the grid operator and the grid maintenance organizations. Broadening the types of stakeholders being represented in an advisory capacity, including retail customers, may be a good first step toward eventually reintroducing stakeholder representatives on ITC boards.

59. FTC Staff Comment, FERC Docket No. RM01-12-000 (Working Paper on Standardized Transmission Service and Wholesale Electric Market Design) (Jul. 23, 2002) at III.B.

60. These contracts would emphasize incentives for efficient operations and superior customer service.