Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets

Prepared for

PJM Interconnection, LLC

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I. PURPOSE AND SUMMARY

A. PURPOSE OF THIS STUDY

The Brattle Group has been asked by PJM to examine the market power mitigation practices used in PJM and other organized electricity markets, to assess the extent to which "best practices" have developed with respect to market power mitigation processes in electric power markets and, if appropriate, offer recommendations as to possible changes in PJM's current practices in this regard. Specifically, this report encompasses the following tasks:

- Review the antitrust and academic literature, as well as the guidelines used in various organized power markets, in order to assess and develop an appropriate definition of "market power " and "market power abuse," and to clarify the objective standards that should be applied to monitoring electricity markets and mitigating market power in these markets;
- Review and document the scope of and approaches toward market monitoring and market power mitigation applied in other organized electricity markets, considering differences in market structure and design;
- Assess the effectiveness of the various approaches for identifying and mitigating market power used in electric power markets, possibly establishing what should be considered as "best practices"; and
- Recommend possible modifications, if any, to PJM's current market monitoring and market power mitigation practices.

In performing our analysis, we relied upon our experience with U.S. and international electricity markets as well as our expertise in antitrust, regulation, and industrial organization economics. Our analysis is based on an examination of various sources of documentary evidence. These include, but are not limited to, the following: (i) Regional Transmission Organization (RTO) tariffs and operating manuals documenting the implementation of specific mitigation policies; (ii) RTO training manuals or other background materials designed to educate participants about market design in general and mitigation practices in particular; (iii) RTO stakeholder committee documents outlining proposed modifications or reassessments of market power mitigation procedures; (iv) filed testimonies, protests, and orders in cases before the Federal Energy Regulatory Commission ("FERC") and other relevant adjudicatory bodies, addressing the conceptual foundation and technical implementation of market power mitigation procedures; (v) periodic market monitor assessments and data analyzing the effectiveness of market power mitigation procedures; (vi) federal, state, or international regulations governing the development of market power mitigation procedures; (vii) academic articles focusing on issues related to market power and electricity markets; and, (viii) articles in the trade press discussing emerging trends in market power mitigation in electricity markets. We also had several discussions with the market monitors of PJM and the other U.S. organized power markets to clarify our understanding of mitigation processes and the reviewed documents.

Our report focuses on the market power mitigation processes employed by the RTOs and their market monitoring groups. It does not address broader market structure and market design options that can mitigate market power (such as transmission expansion or long-term contracts) nor does it address the structure and governance of the RTOs' market monitoring functions (such as their relationship to the RTOs' management, boards, and stakeholders). The report also does not estimate the implementation cost or the specific market impact of prospective changes in the current mitigation approach used in the PJM market.

A draft of this report was shared with Joseph Bowring (independent market monitor for PJM), Keith Casey (Director, CAISO Department of Market Monitoring), Diana Moss (Vice President, American Antitrust Institute and Adjunct Professor, University of Colorado), Karsten Neuhoff (Economics Faculty, University of Cambridge, London), Andy Ott (PJM, Vice President, Markets), David Patton (independent market monitor for ISO-NE, MISO and ERCOT and independent market advisor for NYISO), and Frank Wolak (Professor, Stanford University and Chairman, CAISO Market Surveillance Committee). We thank Keith Casey, Diana Moss, Karsten Neuhoff, Andy Ott, and Frank Wolak for their valuable input and comments. However, the expressed views and conclusions, as well as any errors or omissions, are the authors' alone.

B. SUMMARY

1. Introduction to Market Power Concepts, Standards, and Issues

Section II of the report defines market power (citing definitions used by regulators, antitrust agencies and academics) and explains the distinction between possessing, exercising, and abusing market power. We further explain why market power matters and discuss the various approaches used by regulators and antitrust authorities to identify, quantify, and mitigate the abuse of market power. This section, which focuses on the abuse of market power in terms of excessive pricing, lays out much of the conceptual basis that we use for assessing, comparing, and critiquing the different approaches to market power mitigation that are described later in this report.

Market power is a critically important concept in economics, though there is no single definition of the term. The two principal U.S. antitrust agencies define market power as "the ability profitably to maintain prices above competitive levels for a significant period of time." The definitions used by FERC vary and they do not generally consider whether it is *profitable* to raise price above competitive levels. The latter implies that FERC apparently is more focused on the *ability* than the *incentive* to exercise market power. Consistent with the definition used by the antitrust agencies and in recognition that both the ability and the incentive to exercise market power are needed to trigger market power concerns, we recommend that market power be defined as "*the ability of an individual supplier or group of suppliers to profitably maintain prices above competitive levels for a significant period of time*." However, given the unique nature of power markets, we note that a "significant period of time" might be as short as several dispatch periods during adverse market conditions.

The *exercise* of market power can result in "deadweight" losses of social welfare as well as large wealth transfers from buyers to sellers (and occasionally the reverse). This is an especially important consideration in electricity markets because electricity is a necessity purchased by virtually every household and business, and is vital to our nation's health, safety, and economic viability. In addition, since electric power prices are intended to guide the efficient dispatch of generation resources involving multiple technologies and fuel types, as well as investment in transmission facilities, a distortion in power prices can alter production and investment decisions in a manner that creates substantial additional inefficiencies.

However, the mere *possession* of market power is not uncommon or illegal in itself. In fact, it is common in many markets, including electricity markets, for sellers to have a modest amount of market power (*i.e.*, some ability to raise price). Policymakers, recognizing this fact, have created the notion of "workable" competition as a more realistic goal than that provided by the theoretical concept of "perfect competition." Under workable competition, price may exceed marginal cost to some extent and firms may engage in limited exercises of market power. Based on this concept of workable competition, the abuse of market power means exercising market power beyond a level determined by public authorities to be the limit of reasonable pricing and proper market operations. In other words, market power is abused in electricity markets when it is exercised beyond allowable levels or benchmarks, thereby leading to prices that are <u>not</u> considered *just and reasonable* under the Federal Power Act (FPA, which is administered by FERC). Since the FPA is a regulatory statute and not an antitrust law, its primary regulatory goal is the attainment of just and reasonable prices, not the preservation of competition itself, which is the essential goal of antitrust laws. Regulatory policy toward market power abuse in electricity markets is oriented toward avoiding excessive pricing—an issue that is not generally addressed by the U.S. antitrust laws.

The rules governing organized U.S. wholesale electricity markets typically do not directly define the term "abuse of market power." Instead, they tend to identify either structural conditions conducive to the exercise of market power or specific practices (*e.g.*, economic or physical withholding) that must be mitigated. Under this indirect definition of market power abuse, most U.S. RTO tariffs require the mitigation of practices that "substantially" or "unreasonably" distort or impair the competitiveness of any of the markets which they administer. However, only the Electric Reliability Council of Texas (ERCOT) explicitly categorizes such conduct as an abuse of market power. Moreover, none of the RTOs define a "bright line" as to what constitutes a substantial or unreasonable distortion of competition.

We recommend that market power abuse be defined at least qualitatively as "*any conduct that ultimately harms consumers by substantially distorting or impairing competition, and that would not be in the economic interest of the market participants but for the presence of market power*." However, more regulatory guidance is needed on what should be deemed "substantial" deviations from fully competitive outcomes based on the just and reasonable pricing standard.

2. Tradeoffs in the Design of *Ex Ante* and *Ex Post* Mitigation Processes

Enforcement against abuses of market power may arise in the form of pre-specified *ex ante* restrictions on firms and their behavior—such as price caps, bidding restrictions, or mandated prices that reflect anticipated costs—or the *ex post* deterrence of harmful conduct through the prospect of investigations, after-the-fact mitigation, and costly punishment (*e.g.*, fines, damages payments, etc.) In either case, the choice of specific mitigation regimes (as well as the screening methods that trigger mitigation) has much to do with policymakers' beliefs about two key issues:

- What is the likelihood and cost of mistakenly applying pre-emptive controls that may prevent sellers from charging prices that actually enhance economic efficiency? In diagnostic terms, this problem (*i.e.*, the false identification of market power abuse when it does not exist) is known as a "false positive" or "type I" error.
- Conversely, what is the possibility that the enforcement regime will fail to detect market power abuse, or fail to do so in a timely manner, and what will be the economic and political cost of this failure? In diagnostic terms, this problem (*i.e.*, the failure to identify market power abuse when it exists) is known as a "false negative," which is sometimes referred to as a "type II error."

In order to choose the optimal mitigation regime, policymakers need to develop "loss functions" that accurately represent their assessment of the likelihood of false positives or false negatives and the associated costs of such errors. One also needs to consider the costs of enforcement regimes relative to alternatives, which include the costs associated with monitoring, evaluating, and mitigating market power, as well as the costs of evaluating and modifying the monitoring and mitigation processes as experience is gained and market conditions change over time.

Once such information is developed, one can choose among enforcement regimes so as to reduce mitigation errors and the expected costs. For example, a policymaker who believes that false negatives are associated with much higher societal cost than false positives might choose a mitigation approach that errs on the side of avoiding false negatives (*i.e.*, a relatively more "stringent" approach from the perspective of the market participants being examined.) Conversely, a policymaker who is concerned that the mitigation of false positives creates costly inefficiencies (*e.g.*, distorted resource usage and investment disincentives) might choose an approach that errs on the side of avoiding false positives (*i.e.*, a less stringent approach from the perspective of the market participants being examined.)

While it is well recognized that consumer harm resulting from false negatives and inadvertently unmitigated market power abuse can be extensive, the long-term cost of false positives and associated over-mitigation must not be underestimated. Mitigation actions, if they are erroneous or unnecessary, can promote both short-term and long-term inefficiency. This can lead to costly changes in the operations of generating plants and distorted prices that adversely affect investment incentives, contracting behavior, demand response, innovation, and dynamic (*i.e.*, long-run) efficiency. Even if over-mitigation does not have significant price impacts, it may create a perception of having such price impacts, which may in turn create a perception of regulatory risk and undermine supplier and investor confidence—which can also result in higher long-term costs to consumers.

The implementation of automatic *ex ante* mitigation in U.S. organized electricity markets (or, more precisely, the addition of *ex ante* mitigation to *ex post* monitoring and enforcement capability) differs significantly from the almost sole reliance on *ex post* mitigation regimes (*e.g.*, enforcement of the antitrust laws) used in most other markets, including many organized electricity markets overseas. The combination of *ex ante* and *ex post* mitigation is also generally viewed to be a more stringent enforcement regime than those arising in most other markets, although electricity markets present unique challenges and, as a theoretical matter, the stringency of a combined *ex ante* mitigation and *ex post* enforcement regime depends on the specified screening methods and the nature of mitigation (or sanctions) chosen by the policymaker.

In general, advocates for *ex ante* mitigation argue that market participants prefer this approach because of its greater transparency and the reduced regulatory risk compared to sole reliance on *ex post* enforcement. In addition, *ex ante* mitigation avoids the often slow, potentially costly, uncertain, and burdensome investigations associated with *ex post* enforcement regimes. It is also feared that, due to their costs and delays, *ex post* enforcement processes do not reliably deter or mitigate market power abuses (particularly in markets where such abuses are likely to arise frequently) or are unable to undo fully the harm caused by such abuses. Thus, concerns naturally arise that exclusive reliance on *ex post* enforcement may lead to excessive regulatory risk and under-mitigation of market power abuse in markets where the conditions are ripe for frequent abuse of this nature.

Advocates for *ex post* mitigation claim that, while *ex ante* mitigation can be comparatively quick and formulaic, it risks being too prescriptive, overly broad, and having unintended consequences—notably a larger fraction of false positives (*i.e.*, the implementation of mitigation actions when market power abuse does not exist). Thus, *ex ante* rules may impose costs that exceed their corresponding benefits if they force market participants to alter their behavior under conditions where the market is performing efficiently. By contrast, *ex post* mitigation can be less formulaic and more specifically tailored to those instances in which a market participant is demonstrated to have engaged in anticompetitive or otherwise inefficient behavior. By conducting a full investigation that considers the specific facts and circumstances of a claimed abuse of market power, *ex post* mitigation regimes can more reliably avoid false positives and the costs of over-mitigation.

3. Structural vs. Conduct-and-Impact Mitigation of Market Power

Regardless of whether enforcement is *ex ante* or *ex post*, every well-designed market power mitigation regime must explicitly or implicitly rely on sound definitions of the relevant product and geographic markets. A measurement of the ability or incentive of an individual seller or group of sellers to exercise market power is meaningful only if it appropriately identifies "relevant markets." By its very nature, this market-definition process identifies the collection of sellers of a specified product (or products) within a specified geographic area who would find it potentially profitable to collectively raise price by a significant amount. Based on this framework for defining relevant product and geographic markets, as reflected in the U.S. Department of Justice and Federal Trade Commission "Horizontal Merger Guidelines," approaches to assessing market power can be developed that are suitable and appropriate for mitigation processes.

The *ex ante* mitigation processes developed to date are generally based on either "structural" or "conduct-and-impact" approaches. The *structural approach* to mitigation is based on structural tests used to identify conditions under which the exercise of market power is likely. Structural tests examine the number and distribution of sellers, sometimes relative to demand levels, in order to assess the potential for exercising market power. Structural tests, which include the

Herfindahl-Hirschman Index (HHI) and the pivotal supplier test, are the least direct means of measuring market power. However, they can readily be applied to trigger *ex ante* mitigation. PJM, as well as ERCOT and the California ISO (CAISO) in their new market designs, use variants of pivotal supplier tests as a structural screen in their *ex ante* mitigation processes.

One of the advantages of mitigation protocols based on structural screens is that, if designed properly, the screen can be used readily and routinely on an *ex ante* basis to identify the markets, time periods, and suppliers for which market power concerns are most likely to exist. Relying on a purely structural screen also avoids the politically difficult challenge of setting explicit bid or price-impact thresholds that trigger mitigation. Finally, through the implementation of stringent screens that err on the side of caution, the currently used structural approaches may provide more effective protection against exercises of market power.

A disadvantage of structural approaches is the difficulty of devising structural screens and thresholds that: (i) are applied to correctly-defined relevant product and geographic markets; and, (ii) are able to accurately identify the likely exercise and abuse of unilateral and multilateral market power within these relevant markets. Consequently, while the choice and specific implementation of a structural screen might appear to be relatively simple, it is associated with substantial uncertainties about the ultimate reliability of the mitigation process that can lead to both under- and over-mitigation. The reliability of a specified structural screen depends critically on correctly defined markets (*e.g.*, is it the market for energy within a well-defined local geographic area or is it the market for "congestion relief" on individual transmission facilities?) as well as the screen's ability to reliably reflect actual incentives for exercising market power. For example, a supplier's ability and incentive to exercise market power may depend on its load obligation, contractual commitments, extent of vertical integration, and regulatory constraints (*e.g.*, cost-of-service regulation for vertically integrated utilities). The difficulty of addressing such factors means that many structural screens are implemented primarily to assess a supplier's ability (*i.e.*, as opposed to its incentive) for exercising market power within a simplified and often somewhat hypothetical market environment that does not consider suppliers' obligations, pricing constraints, or actual competitive interaction.

The *conduct-and-impact approach* to analyzing market power is to directly assess supplier conduct and its impact on market prices, such as bidding above cost or engaging in physical and economic withholding of output. Such conduct-and-impact tests are currently used in the *ex ante* mitigation processes of several RTOs including Midwest ISO (MISO), New York ISO (NYISO), ISO New England (ISO-NE), and until the Market Redesign and Technology Update (MRTU) initiative is implemented, CAISO. The currently used conduct-and-impact tests trigger mitigation if bids and their market impacts exceed certain pricing thresholds. They are applied *after* bids are submitted, but bids are then mitigated to appropriate reference levels (based on the test outcome) *before* the "official" market-clearing price is determined. In theory, an exercise of market power under this testing approach can be observed directly by comparing bids and associated prices with competitive reference levels (*e.g.*, marginal cost). This approach, however, requires that competitive reference levels be observable with sufficient accuracy. Even more of a challenge, this approach requires that the regulator specify the price-cost markup threshold that is unacceptable. It is difficult to establish such a threshold in any general or abstract way, especially in the absence of substantive analysis or data pertaining to underlying cost and demand conditions and the likely nature of seller interaction absent regulatory intervention. Many healthy markets will show prices that can be substantially in excess of short-run costs (*e.g.*, prices that are more consistent with the recovery of long-run costs), even though this outcome is not necessarily consistent with the textbook notion of perfect competition.

The advantages of mitigation protocols triggered by conduct-and-impact tests are that, if designed properly, this approach explicitly identifies and mitigates only substantial or unreasonable exercises of market power based on an explicit choice of bid and market impact thresholds. This reduces the risk (and perception) of over-mitigation. The use of simple bid and price impact thresholds also generally results in a mitigation process that is relatively transparent to market participants. Finally, threshold-based conduct-and-impact approaches readily accommodate after-the-fact analysis of the extent to which firm conduct is deviating from some competitive norm, particularly if mitigation is triggered when an individual participant deviates significantly from either past behavior (during a competitive benchmark period) or a designated cost-based standard.

The disadvantages of conduct-and-impact-based mitigation is that the chosen bid and price thresholds used in the RTOs' mitigation processes may either be too low (resulting in excessive mitigation) or too high (resulting in the failure to detect abuses of market power below threshold levels). The bright-line thresholds also potentially allow (or arguably encourage) behavior in which market participants (unilaterally or through coordinated behavior) exercise some degree of market power, but do so without exceeding the specified thresholds. Finally, over-reliance on conduct-and-impact screens may cause regulators to pay insufficient attention to structural indicia that can help focus mitigation on those specific markets where market power concerns are greatest.

4. Competitive Reference Levels

Once a prospective exercise of market power has been identified through a structural screen, or an apparent actual exercise of market power has been identified through a conduct-and-impact screen, the appropriate form of market power mitigation then must be determined. Frequently, either prices or bids are restricted to conform with a competitive "reference level."

The decision regarding an appropriate competitive reference level to which prices or bids will be mitigated necessarily balances short-term and long-term considerations. While trying to achieve prices in conformity with short-run marginal costs may be efficient in the short-term during most market conditions, this type of mitigation may suppress price signals that would stimulate long-term investment which may lessen the need for aggressive market power mitigation in the future. In part, this is due to the difficulty of accurately determining marginal costs for some types of generating units (*e.g.*, combustion turbines), including opportunity costs.

In addition, many well-functioning markets periodically exhibit prices that substantially exceed short-run marginal costs. Consequently, holding electricity markets to a standard of perfect competition, where prices typically reflect short-run marginal production costs, may stymie attempts to transition to more light-handed regulation. Indeed, the application of overly idealized competitive standards for determining excessive pricing in electricity markets, and imposing mitigation when such abuse occurs, could be tantamount to applying a standard that can never be met by a workably competitive electric power market. That would, by necessity, imply that the electric power market would remain heavily regulated as long as it is being held to this unrealistic standard.

5. Market Monitoring and Market Power Mitigation in Overseas Electricity Markets

Section III of our report describes the market monitoring and mitigation approaches used by the regulatory and antitrust authorities in three well-established non-U.S. electricity markets with significant operating histories: Great Britain (GB), Nord Pool, and Australia. As we shall see, these markets rely primarily on *ex post* rather than *ex ante* market power mitigation.

We find the experience with market performance and market power mitigation in these three international markets offers only limited insights for the mitigation of U.S. power markets. While there are few examples of *ex ante* mitigation of market power, it appears that some restraint on the abuse of market power is achieved through a combination of: (1) reliance on *ex post* mitigation through local antitrust laws; (2) the regulator's ability to change market rules quickly if abuses are detected; (3) partial government ownership of generation and transmission facilities; (4) significant transmission investments; (5) increased use of long-term contracting; and/or, (6) the regulator's ability to impose structural remedies (*e.g.*, forced divestiture) as a measure of last resort. Some of these tools are not readily employed in U.S. power markets.

It is also important to recognize that the three international markets reviewed differ from most U.S. RTO-operated markets by being energy-only (*i.e.*, one-part) markets without installed capacity or resource adequacy requirements. This means that high prices in the spot energy market are the primary means for attracting entry of additional generation. This appears to be an important reason why the policymakers and regulatory authorities in these markets seem less "sensitive" to high prices than their U.S. counterparts.

However, past efforts (although unsuccessful) by the British regulatory authorities to implement *ex ante* market power mitigation measures, as well as the recent sectoral inquiry by the European Commission into competitive conditions within EU power markets, indicate that significant market power concerns remain in the European electricity sector. These concerns suggest that the current exclusive reliance on *ex post* enforcement may be insufficient to deter significant exercises of market power. Whether they ultimately lead to increased use of *ex ante* mitigation, as used in U.S. RTO-operated markets, remains to be seen.

6. Market Power Mitigation Processes Used in U.S. Electricity Markets

Section IV of the report compares and contrasts PJM's market power mitigation approaches with those of other U.S. RTOs that operate centralized energy markets and employ or plan to employ Locational Marginal Pricing (LMP) in the near future, namely: ISO-NE, NYISO, MISO, CAISO, and ERCOT. All of these entities are mature RTOs that have operated some form of centralized energy market for at least several years. For CAISO and ERCOT, we focus on the impending market redesigns that include locational marginal pricing, as opposed to the current market structures.

This section begins with an outline of each RTO's basic wholesale power market design, and then proceeds to characterize each RTO's approach to market power mitigation. The sequence of market power mitigation procedures—from the initial identification of actual or prospective market power, to daily or hourly mitigation, to *ex post* market monitoring and mitigation—is essential for understanding differences among the RTOs. We also describe how the reference levels for mitigation are determined in each region. With those levels clearly defined, we proceed to compare market power mitigation techniques across RTOs for all market-based electricity products.

We initially examine the mitigation of market power in energy markets. Our comparison of various RTOs' methods for preventing the economic withholding of output in energy markets highlights critical differences between the two principal market power mitigation methods: the structural approach and the conduct-and-impact approach. After examining mitigation in energy markets, we subsequently examine the mitigation of market power in capacity markets in the three RTOs that have formal capacity markets. Lastly, we review market power mitigation in ancillary services markets. In addition, we briefly describe market mitigation that applies to specific practices, such as physical withholding or virtual bidding.

We find that, while U.S. RTOs have certain similarities in market structure and design, they rely on two substantially different approaches in their *ex ante* market power mitigation processes. PJM's market power mitigation process and the new market designs of CAISO and ERCOT rely primarily on structural screens intended to prevent any firm with the potential ability to exercise market power from abusing it. By contrast, other RTOs—MISO, NYISO, and ISO-NE—rely on conduct-and-impact tests that determine whether a firm has likely exercised market power and whether this exercise of market power has had a material impact on prices. The structural approach is more restrictive in that it assumes that a supplier with the ability to exercise market power has the incentive to do so, whereas the conduct-and-impact approach mitigates markets only if there is evidence that market power has been exercised in a manner that would affect market prices.

7. Lessons Drawn from Our Review of Mitigation Processes

Given that PJM and the other U.S. RTOs are very likely to continue to rely on *ex ante* market power mitigation, we develop a strawman "best practices" framework for *ex ante* market power mitigation. While clear best practices mitigation processes have not yet evolved, we are able to provide a best practices framework and make certain suggestions that should help with the design of effective mitigation processes. The development of such mitigation processes ideally involves the following three-step approach:

(i) Define market power abuse;

(ii) Develop testing frameworks that detect market power abuse and are compatible with the policymaker's loss function with respect to mitigation errors; and,

(iii) Specify mitigation actions.

First, it is essential to define what constitutes market power abuse. This definition should not be determined indirectly by the nature of the tests that are applied and the mitigation that is imposed. Rather, it should require specifying when market behavior is incompatible with workable competition and prices fail to remain just and reasonable.

Second, it is necessary to develop tests (*i.e.*, screens), thresholds, and analyses that can identify the specified unacceptable levels of market power. Irrespective of whether these tests rely on a structural or conduct-and-impact approach, the development of an appropriate screening process for market power abuse should also involve a determination of their effectiveness and reliability. In particular, the screens should be analyzed to determine the following: (i) what is the likelihood of falsely identifying market power abuse when none exists (*i.e.*, false positives or type I errors); and, (ii) what is the likelihood of not identifying market power abuse when it does exist (*i.e.*, false negatives or type II errors)?

Once the likelihood of false negatives and false positives arising from various candidate screening processes are determined, an appropriate test framework can be chosen by the policymaker if the policymaker has a clear idea as to the magnitude of the "losses" (*i.e.*, aggregate social costs) associated with each type of testing error. The appropriate screen (or combination of screens) for market power abuse is the one that minimizes the total expected losses that arise from unavoidable testing errors, considering also the transactions costs of the mitigation process.

Third, it is necessary to specify the appropriate mitigation actions that should be taken if the exercise of market power has been identified. For example, this requires the determination of the proper competitive reference level to which bids or prices should be mitigated, and an assessment of how reliably such a reference level can be determined. The chosen reference level should be compatible with the manner in which the policymaker distinguishes between abuses of market power and otherwise acceptable behavior. There may be some desire in setting the reference level to deter anticompetitive conduct assuming that such conduct may not always be discovered by the chosen screening process.

PJM, CAISO, and ERCOT use structural screens, whereas MISO, NYISO, and ISO-NE rely primarily on conduct-and-impact tests. Through the manner in which these screens are applied, it appears that the former set of RTOs may place more emphasis on avoiding false negatives in their market power mitigation approach, whereas the latter set of RTOs places more emphasis on avoiding false positives. Based on our review of the strengths and weaknesses of both approaches, we find that a more integrated structure, conduct, and performance framework is advisable for triggering market power mitigation measures. A sole structural test could be improved by taking advantage of the ability to assess individual firm conduct and its impact on actual market performance, so that mitigation errors are reduced. Arguably, RTOs have information on prior participant behavior, as well as reasonably refined cost information, that allow them to assess whether an apparent abuse of market power is taking place.

In other words, we find that these two approaches, structural and conduct-and-impact, do not need to be substitutes for one another. Rather, they are naturally complementary. Purely structural screens can benefit from an added conduct-and-impact assessment that avoids mitigation actions if market behavior does not suggest that significant market power is being exercised. Similarly, a conduct-and-impact screen can benefit from the inclusion of an additional structural screen that can identify market conditions or geographic regions where significant market power concerns exist.

Applying a fully integrated approach using both conduct-and-impact and structural screens also allows the RTO to more easily engage in self-assessments of the effectiveness of the market-monitoring process. For example, if the conduct-and-impact screen finds many instances where there is no significant exercise of market power occurring when a particular structural screen indicates cause for concern, then the RTO may choose to consider alternative structural screens. Similarly, by examining the structural conditions under which market power mitigation is warranted under a conduct-and-impact approach, the RTO can develop an appropriate "early warning" structural screen to identify conditions that raise cause for concern. This will increase the effectiveness of mitigation and reduce the costs imposed by the mitigation process.

We also have identified additional best practice screening guidelines. Market power screens should be based on a transparent screening framework that appropriately considers relevant product and geographic markets and that can be readily understood by market participants. Timing considerations suggest that relatively simple threshold-based conduct-and impact-screens should be performed on a real-time or day-ahead basis, while more data and time-intensive structural screens can be performed ahead of observed market behavior. *Ex ante* mitigation of both day-ahead and real-time markets may be warranted whenever market participants would not be expected to "arbitrage" effectively differences between mitigated real-time and un-mitigated day-ahead markets.

The screening tools used in *ex ante* mitigation processes need to be evaluated periodically to identify adjustments and modifications that could improve the reliability and effectiveness of the applied screens. Careful *ex post* monitoring of market performance will be necessary to evaluate unusual market events and screen for the exercise of market power and inappropriate conduct that may elude *ex ante* mitigation processes. If such an exercise of market power or inappropriate conduct is detected, the market design and *ex ante* mitigation screens then can be adjusted accordingly (*e.g.*, through modified bidding rules or modified reference levels). The *ex post* assessment of *ex ante* mitigation processes also needs to focus on whether those processes appropriately allow for a transition to workably competitive electricity markets. Stringent *ex ante* mitigation processes that lead to outcomes inconsistent with workable competition raise the prospect of continually price-regulated markets. Such an outcome (being "stuck" in transition) would be undesirable.

It also is important that market-clearing prices reflect the bids (or mitigated bids) of *all* dispatched supply and demand-side resources. With respect to imposed mitigation actions, where possible and reliable, reference levels for market participants' bids or the associated market prices should be reflective of bids or market prices during competitive conditions. If marginal-cost-based reference levels are used, they should reflect true marginal costs, including full opportunity costs and the potentially difficult-to-quantify operating costs of certain resources such as combustion turbines. Adders to marginal costs or to marginal-cost-based market clearing prices should reflect (1) the likely magnitude of estimation errors (which will be larger for resources with difficult to quantify marginal costs); as well as (2) the scarcity of available supply or demand-side resources. However, while several RTOs have addressed scarcity pricing, more research is needed to accurately quantify and implement scarcity pricing provisions that appropriately address supply and demand-side resource balances, including the value of ISO-controlled or utility-dispatched demand response resources. The appropriate scarcity pricing approach also should consider the fundamental interaction between energy and capacity market pricing. In any event, reference levels should be revised periodically to improve pricing accuracy.

With respect to structural screens in general, we find that pivotal supplier tests can be reliable indicators of market power, specifically the single pivotal supplier test. However, while we do not recommend that PJM abandon the use of structural screens, we question whether the three jointly pivotal supplier test (3JPS) used by PJM represents a best practice structural test. We have several concerns with the 3JPS test. First, very little theoretical and empirical academic research has evaluated the performance of the 3JPS test at this point. The 3JPS test is a very stringent test under which over-mitigation is difficult to avoid. It is possible that individual suppliers can fail the 3JPS test under conditions where their ability and incentive to exercise market power may be quite limited. As merely one example of this, if the two largest suppliers are jointly pivotal, all other suppliers would necessarily fail the 3JPS test and be subject to mitigation, regardless of their individual ability or incentive to influence price.

Second, we find that critical implementation details of how the 3JPS test is applied by PJM in the real-time and day-ahead markets are not sufficiently transparent to allow for a thorough understanding of the test and resulting mitigation actions by market participants and industry analysts. Insufficient documentation exists on how the demand for congestion relief and effective supply of congestion relief are determined for individual interfaces, both of which have to be measured relative to a largely undocumented “baseline” of interface flows and generating unit dispatch.

Third, we are concerned that this approach does not define the relevant geographic markets and the suppliers within these markets correctly. For example, PJM’s pivotal supplier test currently is applied throughout the RTO on a constraint-by-constraint basis. Given that a supplier’s bid and output choice may affect multiple constraints simultaneously, performing the test for one constraint at a time (as done in PJM and planned by ERCOT) may not correctly capture the suppliers’ incentives. Moreover, the supplier might be expected to make output (or bidding) decisions based on their likely aggregate nodal price impact, and not on their impact on an individual constraint. This raises the issue that the current approach does not reliably define relevant geographic markets for the purpose of analyzing market power.

Fourth, PJM’s threshold for measuring the “effective supply” of congestion relief consists of those generating units that can economically provide congestion relief at less than 150 percent of the constraint’s “shadow price,” as opposed to the actual market-clearing price in the constrained area. This 150-percent shadow price threshold creates counter-intuitive variances in the determination of available “supply” for congestion relief. For example, if a constraint binds “tightly” and therefore is associated with a high shadow price, the 150-percent threshold will be high as well. Consequently, more generators will be included in the “market” when performing the pivotal supplier test, which will make it easier to pass the 3JPS test. By contrast, if a constraint can be managed at a low shadow price, the 150-percent threshold will exclude more generators from the test calculation, thus making it more difficult to pass the test. This suggests that the 3JPS test as implemented is more difficult to pass for interfaces which are less severely constrained (*i.e.*, have lower shadow prices when compared to more severe transmission constraints).

Finally, we are concerned over some implementation details that determine which bids are mitigated. These implementation details, particularly the exemption of "grandfathered" units from mitigation, lead to the under-mitigation of market power. Other implementation details may induce over-mitigation.

8. Recommendations

Our recommendations to PJM involve a thorough review of the 3JPS screen described above, as well as a series of actions to make PJM's market power mitigation approach more consistent with a best practices framework:

(1) Work with FERC to define "market power" and "market power abuse" more clearly.

(2) Eliminate the exemption of "grandfathered" generating units from automatic mitigation.

(3) Make the application of the market power screens more transparent to market participants.

(4) To increase the reliability of the screening process, consider adding a conduct-and-impact assessment to the existing structural screen, using the structural screen as a first step and the conduct-and-impact assessment as a second step.

(5) Consider alternative structural screens to the 3JPS screen and analyze the potential for over-mitigation implied by the 3JPS screen.

(6) Analyze whether identifying suppliers that can provide congestion relief to an individual constraint results in economically sensible delineations of geographic markets.

(7) If the 3JPS test is retained, consider modifications to address the identified concerns as well as applying it less frequently, particularly if the test is used only as a first-stage screening mechanism.

(8) Analyze the appropriateness of the reference levels used for mitigation, and the treatment of frequently mitigated suppliers.

II. INTRODUCTION TO MARKET POWER CONCEPTS, STANDARDS, AND ISSUES

This section of the report defines market power, citing definitions used by regulators, antitrust agencies and academics, and explains the distinction between possessing, exercising, and abusing market power. We also explain why market power matters and discuss the various approaches used by regulators and antitrust authorities to identify and mitigate abuses of market power. Herein, we present much of the conceptual basis that is relied upon to assess, compare, and critique the different approaches to market power mitigation described later in this report.

A. MARKET POWER – CONCEPTUAL ISSUES

1. Why Market Power Matters

Exercises of market power pose a concern to policymakers for many reasons, but principally because they can result in "deadweight" losses of social welfare as well as large wealth transfers. In simplified terms, society *as a whole* sustains losses whenever the market price for a product exceeds, rather than equals, the cost of producing an additional unit of that product. Under these circumstances, buyers pay more for the product than it costs to produce.[1]

An exercise of market power results in a product price that exceeds underlying marginal production costs because less output is produced relative to a "perfectly competitive" market, where price equals marginal cost. The deadweight loss attributable to market power is then measured as the difference between what buyers would be willing to pay for the forsaken output and its associated production costs.[2] Market power also is important because it can enable large wealth transfers from buyers to sellers (and occasionally the reverse). This is an especially important consideration in electricity markets because it is a necessity purchased by virtually every household and business in America, and it is vital to health, safety, and economic viability.

However, perfect competition is a theoretical paradigm, and does not appropriately describe behavior in most markets observed throughout the U.S. economy. Policymakers, recognizing this fact, have created the notion of "workable" competition as a more realistic goal. Under workable competition, price may exceed marginal cost and firms arguably may engage in limited exercises of market power.

It should be noted that constraints exist on the loss of social welfare sustained through exercises of market power that arise in a dynamic environment, where market entry or capacity expansion

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1 Our discussion focuses on the abuse of market power by *sellers* of a specified product, which means prices will exceed competitive levels if market power is exercised. Conversely, it is also possible that buyers may possess market power, known as monopsony power, that can result in prices that are below competitive levels. In this situation, buyers withhold making purchases in order to drive down the product price. Once again, the marginal cost of the product is less than the marginal value of the product to consumers, causing a loss to society.

2 See Carlton and Perloff (1994), p. 144.

can occur. If the exercise of market power by market participants creates excess profits in wholesale electric markets, new participants will enter the market until wholesale power prices fall to a level associated with a normal, risk-adjusted return on investment. Consequently, the ability of firms to enter the market will act as a constraint on the exercise of market power, except when the market is characterized by barriers to entry or inherent monopoly conditions. However, entry or capacity expansion in electric power markets often requires several years, so entry cannot be expected to alleviate near-term market power.

2. Formal Definitions of Market Power

Market power is a critically important concept in economics defined by the two principal U.S. antitrust agencies as "the ability profitably to maintain prices above competitive levels for a significant period of time."[3] Leading economic textbooks concur with this basic definition, although they do not require that prices must be maintained above competitive levels "for a significant period of time."[4] Many other scholars, experts, and government agencies have promulgated definitions of the term. Table 1 describes various definitions of market power, gathered from the economic literature, court cases, regulatory authorities, and other documents discussing wholesale electricity markets.

FERC, in its proposed rules regarding Standard Market Design released in 2002, defined market power as the "ability to raise prices above competitive levels."[5] In its "Guide to Market Oversight" on its website, FERC defines market power as "the ability of any market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases."[6] It is notable that FERC did not specify in these two definitions that the price increase must be sustained for a "significant period of time," perhaps in recognition of the fact that electric power markets have been susceptible to price spikes lasting a matter of hours. However, in its Citizens Power & Light and CAISO MRTU orders, FERC defines market power as a "seller's ability to significantly influence price in the market by withholding service and excluding competitors for a significant period of time."[7] In these cases, it appears that FERC requires an exercise of market power to be associated with (1) a significant price impact that (2) lasts for a sufficient duration of time. This definition consequently not only addresses whether market power can be exercised, but also whether such exercise would be "significant" enough to be objectionable (that is result in prices that are not just and reasonable). Implicitly, this defines a threshold beyond which the ability to exercise market power would be deemed unacceptable—a notion that is similar to the distinction between "market power" and "abuse of market power" discussed below.

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3 See U.S. Department of Justice and Federal Trade Commission (1997), section 0.1.

4 See, among others, Carlton and Perloff (1994), p. 8 and Mas-Collell Whinston, and Green (1995), p. 383.

5 See Federal Energy Regulatory Commission (2002), p. 393.

6 See http://www.ferc.gov/market-oversight/guide/glossary.asp#M.

7 See Federal Energy Regulatory Commission (2006b) and Federal Energy Regulatory Commission (2007b), n. 511.

Table 1

Definitions of Market Power

Source	Definition
Economics and Antitrust Literature	
Dennis W. Carlton and Jeffrey M. Perloff, Modern Industrial Organization, Second Edition (New York: HarperCollins College Publishers), 1994, p. 8.	The ability to price profitably above the competitive level
Andreu Mas-Collell, Michael D. Whinston, and Jerry R. Green, Microeconomic Theory, (Oxford: Oxford University Press), 1995, p. 383.	The ability to alter profitably prices away froom competitive levels.
Jeffrey Church and Roger Ware, Industrial Organization, (Boston: Irwin McGraw Hill), 2000, p. 29.	A firm has market power if it finds it profitable to raise prices above marginal cost. The ability of a firm to profitably raise price above marginal cost depends on the extent to which consumers can substitute to other suppliers
Steve Stoft, Power System Economics, (Piscataway: IEEE Press), 2002, p. 318.	Market power is the ability to affect the market price even a little and even for a few minutes. […] Two more qualifications are needed to complete the formal definition: The effect must be profitable,and the price must be moved away from the competitive level.
Peter Cramton, Report on Competitive Bidding Behavior in Uniform Price Markets, FERC Docket No. EL00-95-075, 2003, p. 10.	Economists define market power as the ability of a supplier to affect the market-clearing price. Under economic theory, the only markets in which suppliers do not have the ability to affect the market-clearing price are perfectly competitive markets.
Peter Cramton, Report on Competitive Bidding Behavior in Uniform Price Markets, FERC Docket No. EL00-95-075, 2003, p. 11.	The law uses the term market power in a different way from economists. Market power is often defined to mean anticompetitive or manipulative conduct that is not acceptable under legal norms and has direct and sustained effects on market prices.
http://en.wikipedia.org/wiki/Market_power	In economics, market power (sometimes called monopoly power) is a market failure which occurs when one or more of the participants has the ability to influence the price or other outcomes in some general or specialized market. The most commonly discussed form of market power is that of a monopoly, but other forms such as monopsony, and more moderate versions of these two extremes, exist
Phillip E. Areeda, Herbert Hovenkamp and John L. Solow, Antitrust Law 86 (1995).	The ability to raise price by restricting output.
William Landes and Richard A. Posner, *Market Power in Antitrust Cases* , 94 Harvard Law Review, 937, 937 (1981).	The ability of a firm (or group of firms, acting jointly) to raise price above the competitive level without losing so many sales so rapidly that the price increase is unprofitable and must be rescinded.
Regulatory Authorities and RTOs	
U.S. Department of Justice and Federal Trade Commission, "Horizontal Merger Guidelines," April 2, 1992 (revised April 8, 1997), section 0.1	The ability profitably to maintain prices above competitive levels for a significant period of time.
48 FERC ¶ 61,210 at 61,777 (1989) (Citizens Power & Light Corp).	A seller's ability to significantly influence price in the market by withholding service and excluding competitors for a significant period of time.
100 FERC ¶ 61,138 (2002) (SMD NOPR), at p. 393	The ability to raise prices above competitive levels.
119 FERC ¶ 61,076 (2007) (CAISO MRTU Order), footnote 511.	A seller's ability to significantly influence price in the market by withholding service and excluding competitors for a significant period of time.
FERC's Guide to Market Oversight: http://www.ferc.gov/market-oversight/guide/glossary.asp#M (2007)	The ability of any market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases.
Glossary prepared by the services of the European Commission's Directorate-General for Competition: http://ec.europa.eu/comm/competition/general_info/m_en.html	Strength of a firm on a particular market. In basic economic terms, market power is the ability of firms to price above marginal cost and for this to be profitable. In competition analysis, market power is determined with the help of a structural analysis of the market, notably the calculation of market shares, which necessitates an examination of the availability of other producers of the same or of substitutable products (substitutability). An assessment of market power also needs to include an assessment of barriers to entry or growth (entry barriers) and of the rate of innovation. Furthermore, it may involve qualitative criteria, such as the financial resources, the vertical integration or the product range of the undertaking concerned.
Public Utilities Commission of Texas, Substantive Rule 25.504, effective date 9/13/06.	The ability to control prices or exclude competition in a relevant market.
Midwest ISO Business Practices Manual for Market Monitoring and Mitigation, August 8, 2005, p. 2-1.	The ability to raise Locational Marginal Prices (LMPs) significantly above competitive levels and/or unjustifiably increase the value of Offer Revenue Sufficiency Guarantee Payments (ORSGPs).

Table 1 (continued)

Definitions of Market Power

Supreme Court and Court of Appeals Cases	
Eastman Kodak Co. v. Image Technical Services, Inc., 504 U.S. 451,464 (1992).	The ability of a single seller to raise price and restrict output.
NCAA v. Board of Reagents of the University of Oklahoma, 468 U.S. 85, 109 n.38 (1984).	The ability to raise prices above those that would be charged in a competitive market.
United States v. E.I. du Pont de Nemours & Co. 351 U.S. 377, 377 (1956).	Monopoly power is "the power to control prices or exclude competition."
Coastal Fuels of P.R., Inc. v. Caribbean Petroleum Corp., 79 F.3d 182, 196 (1st Cir. 1996).	The power "to raise price by restricting output."
K.M.B. Warehouse Distributors, Inc. v. Walker Mfg. Co., 61 F.3d 123, 129 (2d Cir. 1995).	The ability to raise price significantly above the competitive level without losing all of one's business.
Orson, Inc. v. Miramax Film Corp., 79 F.3d 1358, 1367 (3d Cir. 1996).	The ability to raise prices above those that would prevail in a competitive market.
Murrow Furniture Galleries, Inc. v. Thomasville Furniture Industries, Inc., 889 F.2d 524, 528 n.8 (4th Cir. 1989).	The ability to raise prices above the levels that would be charged in a competitive market.
Muenster Butane, Inc. v. The Steward Co., 651 F.2d 292, 298 (5th Cir. 1981).	If a firm lacks market power, it cannot affect the price of its product.
PSI Repair Services, Inc. v. Honeywell, Inc., 104 F.3d 811, 817 (6th Cir. 1997).	The ability of a single seller to raise price and restrict output.
United States v. Rockford Memorial Hospital Corp., 898 F.2d 1278, 1283 (7th Cir. 1990).	The ability to increase price above the competitive level without losing so much business to others suppliers as to make the price increase unprofitable.
Ryko Mfg. Co. v. Eden Services, 823 F.2d 1215, 1232 (8th Cir. 1987).	Tthe power of a firm to restrict output and thereby increase the selling price of its goods in the market.
Rebel Oil Co. v. Atlantic Richfield Co., 51 F.3d, 1421, 1441 (9th Cir. 1995).	The ability to control output and prices [is] the essence of market power.
Westman Commission Co. v. Hobart Int'l, Inc., 796 F.2d 1216, 1225 (10th Cir. 1986).	The ability to raise price by restricting output.
Graphic Products Distributors, Inc. v. Itek corp., 717 F.2d 1560, 1570 (11th Cir. 1983).	The ability to raise price significantly above the competitive level without losing all of one's business.
Superior Court Trial Lawyers Ass'n v. FTC, 856 F.2d 226, 249 (D.C. Cir. 1988).	The ability profitably to raise price.

Sources: The Brattle Group. Course case definitions from Gregory J. Werden, "Market Power in Electricity Generation," notes accompanying presentation, IBC Conference on Market Power, Washington D.C. May 24, 1999, and Thomas G. Krattenmaker, Robert H. Lande, and Steven C. Salop, "Monopoly Power and Market Power in Antitrust Law," The Georgetown Law Journal 76(241: 1987).

Note that none of the alternative definitions used by FERC explicitly requires that increasing price above competitive levels is profitable for the parties involved in exercising market power. This means that the focus is mostly on the ability to affect prices, as opposed to the incentive to do so. FERC's concern appears to be limited primarily to the fact that market participants with large market shares may have a greater ability to induce price increases through the physical or economic withholding of output, since they have more generation resources at their disposal.

We believe the definition of market power should address both the ability and incentive of market participants. We consequently recommend that, consistent with the definition used by the antitrust agencies, market power should be defined as "*the ability of an individual supplier or group of suppliers to profitably maintain prices above competitive levels for a significant period of time*." However, given the unique nature of power markets as discussed below, we note that a "significant period of time" might be as short as a few dispatch periods during adverse market conditions.

3. Unilateral vs. Multilateral Market Power, and the Concepts of Explicit and Tacit Collusion

The modern theory of industrial organization distinguishes between *unilateral* and *coordinated (i.e., multilateral)* exercises of market power.[8] *Unilateral* exercises of market power arise through the actions of a single firm, possibly a dominant or pivotal supplier, who has the ability and incentive to raise price or restrict output without the complicity of other firms. *Coordinated* exercises of market power arise when a *group* of firms takes collective action to raise price or restrict output that are profitable for each firm only because of the accommodating reactions of other firms that are a party to the coordinated activity.[9]

While unilateral exercises of market power can occur over relatively short-time frames, coordinated or collusive outcomes generally involve longer time frames that require repeated interaction among the involved market participants. For example, coordinated exercises of market power are maintained through dynamic interaction among firms. Collusive behavior is monitored by members of the "collusive agreement" to ensure compliance with the agreement.[10] The effectiveness of the agreement depends on the ability of its members to monitor other participants and swiftly and effectively punish behavior that deviates from the collusive agreement. When the policing of a collusive agreement becomes ineffective, the agreement typically breaks down.

Explicit collusion, particularly price agreements established through meetings among rivals, is illegal. Such agreements are typically prosecuted by antitrust authorities, particularly the U.S. Department of Justice. However, anticompetitive agreements among competitors can be reached without direct contact, through market "signaling" and other activities.[11] This "tacit" collusion also may not be lawful, but it is much harder for antitrust authorities to detect and successfully prosecute this type of anticompetitive activity. Such activity is a concern in electric power markets, particularly those with organized energy exchanges where the same market participants repeatedly offer (nearly) identical products into the market on a daily and hourly basis. In this environment, depending on the available sources of market information, such as prior hourly bid curves and generator schedules, conditions may exist that allow for the effective policing of a coordinated agreement to elevate prices (or restrict output).

Since the carrying out of a successful collusive scheme unfolds over time, it may be difficult to identify the existence of a collusive agreement until well after-the-fact. Moreover, the ability to sanction tacit collusion through the antitrust laws is difficult because of the standard of evidence required to sustain the existence of an agreement. Therefore, if conditions hypothetically arise that would promote conditions under which firms would tacitly collude in electric power markets, the prevention of the coordinated exercise of market power may depend on *ex ante* screening to determine whether these conditions are present and, if so, to appropriately mitigate firm behavior in order to prevent its occurrence.

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8 See U.S. Department of Justice and Federal Trade Commission (1997), sections 2.1 and 2.2.

9 *Ibid*.

10 See Tirole (1988), chapters 5 and 6 and Carlton and Perloff (1994), chapters 6 and 7.

11 For a discussion of tacit collusion, see Tirole (1988), chapter 6.

As will be discussed in further detail later in this report, *ex ante* market power mitigation measures triggered by "structural" screens (*e.g.*, HHI or pivotal supplier tests) are intended to prohibit supra-competitive pricing (*i.e.*, anti-competitive pricing) before it actually occurs when conditions arise that are deemed conducive to either unilateral or coordinated exercises of market power. By contrast, "conduct-and-impact" screens are intended arguably to thwart actual behavior that represents an apparent exercise of significant market power. In practice, however, conduct-and-impact screens are typically focused on identifying unilateral exercises of market power that may occur over a short time period, rather than collusive exercises of market power that require an extended period to carry out. Nonetheless, since collusive behavior may frequently lead to market prices that are higher than those observed under unilateral exercises of market power, and since the extent of output withholding and above-cost bidding under collusion also may exceed that observed under unilateral exercises of market power, coordinated exercises of market power may still be mitigated under a conduct-and-impact approach even if they are not separately distinguished from unilateral market power in the process.

4. Special Features of Electricity Markets and their Relevance to Market Power Concerns

The mitigation of market power in electricity markets is an important and frequently-addressed topic because electricity markets are particularly susceptible to the exercise of market power by suppliers for several reasons:[12]

(i) Suppliers in electricity markets face high sunk costs with lumpy, irreversible, and long-lived investments. These characteristics limit quite substantially the entry of new players in the market in reaction to relatively short-term price increases.

(ii) Network limitations of transmission systems impede the movement of electric power across geographic areas when transmission lines are congested. Transmission constraints (which may be aggravated by outages of transmission or generation facilities) can temporarily isolate geographic regions, giving local generators the ability and incentive to exercise market power by withholding capacity and artificially boosting prices. Pervasive transmission constraints also may make specified geographic areas susceptible to significant exercises of market power under wide-ranging demand conditions.

(iii) Short-term demand for electricity is very price-insensitive,[13] largely because of the currently limited exposure of consumers to real-time market prices under the prevalent fixed-priced service offerings, as well as the limited use of technology to allow demand response or even monitor the real-time energy use of residential electricity customers.

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12 For further discussion, see García and Reitzes (2007) and Fox-Penner, *et al*., (2002).

13 Empirical studies indicate that the price elasticity of demand for electricity is quite low, typically ranging from -0.15 to -0.25 for households. In a study of market power in the electricity market of England and Wales, Wolfram (1999) used an elasticity of -0.17. That number was based on a study by Green and Newbery (1992), who also examined competition in the England and Wales power pool. Patrick and Wolak (2001) analyzed the price elasticity of demand for electric power, using four years of data from a regional electricity company in the United Kingdom. They found that the demand elasticity for most consumer classes was below 0.1 (in absolute value). Branch (1992) estimated a demand elasticity of -0.2 for California customers. Finally, in an analysis of the Norwegian electricity market, Bye, *et al.* (2003) estimated a demand elasticity of -0.23 using data from October 2002 to April 2003.

(iv) Electricity typically cannot be stored. Since system reliability requires that supply and demand has to be balanced instantaneously at every instant in time and at every location in the transmission network, and since intertemporal demand substitutability by consumers is limited, the non-storability of electricity implies that intertemporal supply substitutability cannot constrain attempts to exercise market power over relatively short time periods (*e.g.*, a few hours of a given day).

(v) The supply of electricity is fairly inelastic and the marginal cost of incremental supply often increases substantially when output is close to full capacity. Moreover, electricity supply curves (based on the marginal cost of production) are often like step functions, where each step change represents a movement to a different fuel source (*e.g.*, from nuclear, to coal, to natural gas, and to fuel oil) or a change in technology. This implies that, under certain demand conditions, the withholding of small amounts of electricity output may produce a large impact on energy prices since the market-clearing price moves to a higher step in the supply curve.

(vi) In wholesale electricity markets, sellers and buyers interact regularly, typically every day or even every hour. This repeated interaction of competitors in electricity markets may enhance firms' abilities to tacitly collude and consequently achieve higher prices and lower quantities.

(vii) Some argue that electricity markets are characterized by boom-bust investment cycles due to the high sunk costs involved in building generation plants. According to this view, boom periods in power generation construction are followed by periods of insufficient generation investment. When demand grows sufficiently, this leads to episodes of high prices induced by the presence of limited generation capacity.

The high sunk costs facing generation suppliers and the limitations of the transmission system (*e.g.*, constraints and losses) in moving power across geographic areas, coupled with the inherent difficulty in siting new transmission lines, may often lead to highly concentrated, localized generation markets. In addition, electricity markets prior to liberalization were dominated by vertically integrated utilities. The manner in which formerly vertically integrated utilities divested their generation assets in order to unbundle electric generation service may not have de-concentrated the market sufficiently in some regions to support healthy competition under all load conditions (or under particular realizations of fuel prices).[14] As a result, market power concerns are a common problem affecting electric power markets worldwide due to market concentration and the aforementioned conditions that are potentially conducive to anticompetitive behavior.

[14] Arguably, in some cases, the divestiture of generation assets has created more competitive power markets. For instance, in the United Kingdom, generation assets of the former state-owned monopoly were divested through a variety of means. While the UK Electricity Pool appeared to have suffered from substantial exercises of market power (as described below), the mandated divestiture of generation assets and institution of the New Electricity Trading Arrangements (NETA) appear to have mitigated market power concerns to some extent. A similar approach was followed in Australia when the government decided to deregulate its electricity market. In the United States, New York, New England, and some of the PJM member states also forced their utilities to divest generation ownership in order to facilitate increased wholesale and retail competition.

Concerns about market power appear to be particularly prominent during high load conditions, or when important transmission or generation outages occur. High load conditions are problematic because they may create a situation where the reserve capacity margin is relatively small. Under these conditions, a single firm or a small number of firms may be pivotal suppliers whose supply is necessary in order to satisfy the outstanding demand. In this case, even modest amounts of economic or physical withholding of electric generation by prominent market participants may lead to substantial increases in the market-clearing electricity price.

It should be observed that the above conditions make wholesale electricity markets susceptible to the exercise of market power under a range of circumstances. This arguably explains the more comprehensive use of market monitoring and market power mitigation in electricity markets relative to other markets. At the same time, wholesale electric markets have been liberalized in the United States under the premise that scale economies in electric generation are relatively modest (and therefore generation does not have "natural monopoly" characteristics),[15] and that substantial cost savings can be attained in the long-term if generators achieve operational and other technological efficiencies as a result of competition. Thus, the above market power concerns are not deemed to outweigh the benefits provided by competition. However, from a regulatory viewpoint, the case can still be made that the use of *ex ante* market power mitigation is necessary to improve market efficiency and enhance consumer welfare.

Lastly, it should be noted that distorted prices in electric power markets seem to attract more attention than similar distortions in other markets for a variety of reasons. First, as we shall see in the next subsection, the FERC has an ongoing regulatory responsibility to ensure that electric power prices are just and reasonable. Presumably that responsibility arises because electricity is a widely consumed commodity, so the loss of consumer welfare associated with a significant increase in electricity prices is extensive and widespread. Second, since electric power prices are intended to guide the efficient dispatch of generation resources involving multiple possible technologies and fuel types, a distortion in these prices can alter production and investment decisions in a manner that creates an inefficient mix of generation technology and fuel types. Third, locational prices of electric power are an important guide for transmission investment, and distortions in power prices can trigger inappropriate investment decisions. Fourth, given available heat rate and fuel cost information, generation costs arguably are easier to observe than production costs in many other industries, which may create further incentive to more closely monitor and mitigate market power in electricity markets.

5. Market Power and Its Relationship to "Just and Reasonable" Rates

Most products sold in the United States are not subject to price regulation. In that context, the need for active market monitoring and *ex ante* prohibitions against certain behavior by firms participating in liberalized wholesale electricity markets must be spurred by underlying policy concerns regarding particular characteristics of these markets that produce significant inefficiencies. Of these concerns, the undue exercise of market power appears to be the most prominent, due to the general inefficiency and potentially significant consumer harm it creates.

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15 For more on scale economies in electric generation, see Atkinson and Halvorsen (1984), Nerlove (1963), Christensen and Greene (1976), Cowing and Smith (1978), and Considine (2000).

Facing the prospect of potentially significant exercises of market power in liberalized wholesale electricity markets, the FERC nonetheless has the regulatory responsibility, under Section 205 of the Federal Power Act (FPA), to assure that all rates charged in connection with wholesale power sales and the transmission of electric energy in interstate commerce are *just and reasonable*.[16] In this context, FERC arguably has the duty to prevent "excessive pricing" (*i.e.*, the abuse of market power in the context of this report) when it arises, even in energy markets that are subject to competitive interaction.

Not surprisingly, there does not seem to be a consensus on the proper definition of *just and reasonable* rates. Courts have determined that an unjust and unreasonable rate is one that falls outside the zone of reasonableness, where that zone excludes rate levels that are "less than compensatory" to producers or "excessive" to consumers.[17] That is, on the one hand, rates should be high enough to give producers a reasonable opportunity to recover their costs, including a risk-adjusted return on capital, but sufficiently low to avoid consumer harm.

Since the FPA is a regulatory statute and not an antitrust law, its primary regulatory goal is the attainment of just and reasonable prices, not the preservation of competition itself, which is the essential goal of antitrust laws. While we recognize this distinction, the analysis contained within this report is nonetheless focused on the diagnosis and mitigation of market power alone and does not attempt to discuss or reconcile fully any differences between regulatory and antitrust approaches. We focus on market power in electricity markets in general and PJM's electricity markets in particular, and analyze PJM's specific process for measuring and rectifying market power relative to those processes used in other jurisdictions.

In the next section of this report we examine the issue of "abuse of market power," which is closely related to the notion of whether firms are charging just and reasonable prices for electric power. Our principal basis for judging whether prices may be excessive (*i.e.*, not just and reasonable) throughout this report is by reference to what prices would be for similar products in competitive markets, if such markets could or do exist. While there may be other considerations in determining just and reasonable prices, such as equity considerations, we do not consider them explicitly in this report. However, the typical behavior of competitive markets implies that prices are related to costs in a sufficiently close manner to prevent consumer exploitation through abuses of market power.

FERC's ability to rectify market power abuse and market manipulation that leads to prices which are not just and reasonable has evolved over time. Recently, the Energy Policy Act of 2005 (EPAct) has given FERC broad authority to prohibit market manipulation,[18] which FERC has implemented through its Order No. 670.[19] Under EPAct, Congress authorized FERC to impose

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16 Federal Power Act § 205(a), 16 U.S.C. § 824d(a) (Supp. 2004).

17 Farmers Union Central Exchange v. FERC, 734 F.2d 1486 (D.C. Cir 1984), cert denied, 469 U.S. 1034 (1984).

18 Federal Energy Regulatory Commission (2006a).

19 Although FERC recognized the need to proscribe the manipulation of electricity markets, before the implementation of EPAct 2005 there was no express prohibition of market manipulation in federal electricity law. However, Federal Energy Regulatory Commission (2003b) and Federal Energy Regulatory Commission (2004a) at Appendix A established a general prohibition of market manipulation and proscribed specific manipulative practices (hereinafter *Market Behavior Rules Order*). See also

civil penalties of up to $1 million per day for each violation of rules, regulations, and orders issued under the FPA.[20] The ability of FERC to seek criminal penalties against those who willfully manipulate energy market prices also has been expanded.[21]

FERC also grants the authority for wholesale market participants to engage in market-based sales and has proscribed specific manipulative practices as a condition associated with that authority.[22] Thus, through *ex ante* mitigation measures, such as the refusal to grant market-based sales authority, and *ex post* mitigation measures, such as imposing fines on those manipulating electricity markets, FERC has particular tools at its disposal to lessen or discourage exercises of market power. These tools for mitigating market power are supplemented by *ex ante* mitigation processes and *ex post* monitoring in RTO markets in an effort to prevent and deter market power abuse.

B. THE ABUSE OF MARKET POWER – CONCEPTUAL ISSUES

Mitigation measures against market power will not be correctly administered unless there are reliable methods of diagnosing and quantifying the extent of actual or potential market power, which can then be compared with legal or regulatory definitions of market power abuses that warrant mitigation. In the process of devising appropriate tests for assessing market power, and fashioning appropriate mitigation for abuses of market power, several key conceptual issues must be confronted. The treatment of these issues aids in determining which methods of assessing market power are appropriate in a given market and how the results of these tests should be interpreted. In particular, this subsection examines three key conceptual issues:

- Are both incentive and ability required to demonstrate the existence of market power?
- What is the conceptual distinction between market power, exercise of market power, and abuse (or excessive exercise) of market power?
- Should market power be mitigated through pre-conditions placed on the market (*i.e.*, an *ex ante* approach) or be policed only by prosecuting those suspected of having abused market power after the fact (*i.e.*, an *ex post* approach).

Each of these questions has critical empirical dimensions which will be examined below. For example, any test that measures whether individual sellers have the incentive to exercise market power requires at least a qualitative assessment of the seller's ability to profit from such behavior.

Kelliher (2005), pp. 16-19. The *Market Behavior Rules'* prohibition of market manipulation was supplanted when the FERC implemented the authority granted to it by Congress in EPAct 2005 by issuing Order No. 670 in January 2006.

[20] Before EPAct 2005, FERC lacked civil penalty authority for most violations of the Federal Power Act (for instance, sections 205 and 206.) Section 316A of the FPA limited civil penalties to not more than $10,000 per day per violation (See Federal Power Act § 316A(b), 16 U.S.C. § 825o-1(b) (2000).

[21] A knowing and willful violation is subject to a maximum penalty of $1 million ($5000 before EPAct 2005), and imprisonment for up to five years (two years before EPACT 2005), and an additional $25,000 ($500 before EPAct 2005) per day for continuing violation.

[22] See Market Behavior Rules Order.

1. Incentive vs. Ability to Exert Market Power

In market power enforcement by U.S. antitrust agencies, it is recognized that sellers must have both the incentive and the ability to raise prices before intervention is warranted. While certain definitions of market power focus only on the ability of a seller to raise price, it would not be rational for a seller to raise price if it results in reduced profits because of competition from alternative products or sources of supply.

It may well be the case that a seller who has the ability to raise price also profits from such increases. However, if it can be shown that the seller does not profit from restricting its output sufficiently to increase price above competitive levels, then regulators may choose to forego any remediation of a proposed transaction or market design.[23] Thus, evaluating the incentive for a seller to raise price is important in distinguishing anticompetitive conduct from otherwise competitive behavior.

In some testing frameworks for purported market power, both the ability and incentive to exercise market power are considered explicitly. For example, certain structural tests, such as tests that rely on the Herfindahl-Hirschman Index (HHI), analyze both the ability and incentive to exercise market power based on a particular model of oligopoly competition that yields prices which are directly related to that specific concentration index.[24] Thus, one might argue that HHI-based tests implicitly consider the incentive to exercise market power, though they may be applied in circumstances that may deviate significantly from the particular model of oligopoly behavior that was used to develop the index. However, in many situations, it may be possible to analyze seller incentives and behavior more directly from actual data, so that one can assess whether the assumed type of competitive interaction underlying the structural test is truly representative of observed market behavior. If not, a different type of screen may be more accurate in assessing the propensity for exercising market power.

2. Distinguishing among Market Power, the Exercise of Market Power, and the Abuse of Market Power

The terms market power, exercise of market power, and abuse of market power are often used interchangeably and in a confusing manner. As we saw above, FERC, in contrast to the U.S. antitrust agencies and many economic textbooks, has defined market power as merely the <u>ability</u> to raise price above competitive levels, rather than the <u>ability and incentive</u> to raise price. If market power is defined only as the ability to raise price above competitive levels, then an

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[23] With respect to a proposed electric utility merger, the absence of an incentive to exercise vertical market power was examined in Fox-Penner (2007).

[24] The HHI index is a concentration measure (between 0 and 10,000) that is calculated by summing the market shares of all individual market participants. The HHI equals 10,000 in a monopoly market and, more generally, 10,000/N in a market with N equally sized firms. HHI-based structural tests are arguably based on the Cournot model of oligopoly competition. Under Cournot competition, sellers strategically choose an output level, recognizing that output reductions will induce increases in the market-clearing price. Under this particular model of oligopoly behavior, the sales-weighted price-cost mark-up in the market is directly related to the HHI index. For proof, see among others, Carlton and Perloff (1994), Appendix 9B, p. 375.

exercise of market power arguably would be defined as engaging in behavior that leads to supra-competitive prices in actuality. While sellers theoretically could exercise their market power even if it is not profitable to do so, economists generally believe that exercises of market power are observed only because producers have both the ability and incentive to raise prices above competitive levels.

Consequently, defining market power as only the <u>ability</u> to raise price also includes the generally benign case in which a seller may have the ability to raise price, but not the incentive to do so. As a result, the definition of market power used by most economists and the U.S. antitrust agencies typically requires that a seller also have the <u>incentive</u> to engage in supra-competitive pricing.

As explained in more detail below, the term "abuse of market power" is more of a regulatory than an antitrust term in the United States. By contrast, European antitrust law allows action against "abuse of dominance." Arguably, abuse of market power means exercising market power (for which, one can infer, there is an incentive) beyond a level determined by public authorities to be the limit of proper pricing and market operations. In other words, market power is abused when it is exercised beyond allowable levels or benchmarks, which leads to prices that are not just and reasonable. We examine in more detail in the following sections the tests used to identify the actual or potential abuse of market power in electricity markets, where abuse represents setting price at an unacceptably high level. In this context, an abuse of market power simply refers to the excessive exercise of market power.

3. Abuse of Market Power in Different Jurisdictions

In the European Union (EU), antitrust authorities (*e.g.*, the Directorate-General for Competition) consider whether "an abuse of dominance" has arisen under conditions where a single firm unilaterally or multiple firms collectively wield significant market power. While an abuse of dominance may arise when firms take specified actions (*e.g.*, exclusionary conduct regarding suppliers or customers) to harm competitors and solidify their market position in a manner that ultimately raises prices above the level that would prevail absent these actions, it also appears that the EU law permits authorities to intervene solely on the basis of excessive pricing. Thus, there is a more direct parallel regarding the notion of excessive pricing in European than arguably in U.S. antitrust law.

Under U.S. antitrust law, there is limited scope to take legal action against so-called "exploitative practices." Sometimes referred to as the exercise of "classical market power," these represent practices by which a firm *directly* harms consumers through excessive pricing or output restrictions that directly lead to higher market prices. Absent collusion or other illegal anticompetitive behavior, firms are permitted by U.S. antitrust law to enjoy the benefits of classical market power that they are capable of wielding as a result of superior efficiency, other competitive advantages, and natural impediments to market entry. However, under the Sherman and Clayton Acts, there is scope to prohibit firms from attempting to "monopolize" the market or harm competition through certain actions that allow them to maintain or enhance their market power and harm consumers in the process. These actions, the so-called "exclusionary practices," typically are intended to prevent competition or restrict competitors, leading indirectly to consumer harm by ultimately inducing higher prices, lower product quality, or less innovation in the market as a result of the lessening of competition.[25] Under appropriate conditions, firms may not be able to engage in the specified actions, such as exclusionary agreements with customers or suppliers and bundled product sales, which enhance their ability to exercise market power due to the harm that they impose on competitors.

Under either EU or U.S. law, there is little jurisprudence to separate a modest exercise of market power from an abuse of market power, where that abuse represents excessively high pricing based on the unilateral market positions of individual suppliers. However, since U.S. antitrust law does not recognize high prices in themselves as a basis for legal action (except when they are the result of collusion), one naturally starts by looking abroad for guidance as to what constitutes an abuse (or the excessive exercise) of market power.

a. Abuse of Market Power under EC Antitrust Law

The cornerstone of European antitrust law on abuse of market power is Article 82 of the European Community (EC) Treaty. Under European antitrust law, this article is applied only to situations in which a single firm unilaterally or multiple firms collectively may be considered to have a dominant position. EC competition law does not punish the creation of a dominant position, just its abuse.[26]

According to EC law, dominant firms should act as if constrained by competition. Firms may engage in "performance competition" (offer better deals to customers), but may not engage in "impediment competition" (hindering rivals' ability to offer better deals to customers). In practice, a dominant firm might not be entitled to engage in the same practices as non-dominant firms. Certain aggressive competition practices might be permissible for competitors, but not for a dominant firm, since it has a "social responsibility." A dominant firm "*has a special responsibility, irrespective of the causes of that position, not to allow its conduct to impair genuine undistorted competition in the common market.*"[27] As a result, under EU antitrust law, both exclusionary conduct by dominant firms and exploitative conduct, such as excessive pricing, may constitute an offense against antitrust law.

In the European Union, for an abuse of dominance to exist, it must be established that a dominant position exists and that the dominant firm or firms have engaged in abusive behavior. The European Court of Justice (ECJ) has defined when a firm is considered to be dominant in several decisions.[28] According to the ECJ, a firm is deemed to be dominant if it can behave

25 Exclusionary practices are *indirectly* exploitative of consumers. In this sense it could be argued that no conduct is properly characterized as exclusionary unless it is ultimately exploitative.

26 See Motta (2004), pp. 69-70 and 411 n. 1. Motta argues that "*excessive pricing should not be dealt with by competition policy*." In his opinion, the competition authority should intervene only if the dominant firm engages in exclusionary practices aimed at preserving its market position (for instance, predatory practices). The author further notes that dominant position acquired as a result of legal barriers to entry should be solved by regulation. He adds that dominant position acquired through investments, innovation and advertising should not be punished. Similar opinions are shared by Evans and Padilla (2004).

27 See Ct. First Instance (2003), at ¶ 242.

28 See for instance, European Court of Justice (1983) and European Court of Justice (1978).

independently of its competitors and experience little loss of business or profitability.[29,30] Neither the EC, nor the ECJ, have been explicit in defining market-share thresholds to identify a dominant firm.[31] Past jurisprudence does, however, seem to confirm that a firm with 40-50 percent of the relevant market might well be a dominant one, although it cannot be ruled out for undertakings with a lower market share. This market-share level, though, is neither a necessary nor a sufficient one to prove dominance. The EC concluded that firms with market shares of no more than 25 percent are unlikely to enjoy a (unilateral) dominant position in the market concerned.[32]

The EC Treaty does not provide an explicit definition of abuse of dominance, but merely offers a non-exhaustive list of certain conduct (both exclusionary as well as exploitative) which, if engaged in by a dominant firm, will amount to abusive behavior.[33] In particular, Article 82 prohibits "*directly or indirectly imposing unfair purchase or selling prices....*" by a dominant

[29] The general definition of dominant position (or market power) in the United Kingdom, Australia, South Africa, Germany, and India considers the ability of a firm or enterprise to behave independently of its competitors and the extent to which the behavior of those competitors constrains the actions undertaken by the dominant firm (or firms).

[30] For "collective dominance" to exist under Article 82, two or more undertakings must present themselves or act as a collective entity with respect to a specified market. For example, two or more firms engaged in parallel or (tacitly or explicitly) collusive behavior, where that behavior differs from that of their competitors, may be considered to exercise collective dominance when they serve a sufficiently large share of the market. (See DG Competition discussion paper related to the application of Article 82 to exclusionary practices at http://ec.europa.eu/comm/competition/antitrust/art82/discpaper2005.pdf.)

[31] On the contrary, in the UK, the Office of Fair Trading (OFT) has explicitly indicated two market share thresholds to define dominance. In the "Assessment of Market Power" Guideline (available at http://www.oft.gov.uk/shared_oft/business_leaflets/ca98_guidelines/oft415.pdf), OFT indicates that a firm with market share below 40 percent it is unlikely to be dominant; above 50 percent dominance can be presumed. Under German law a firm is presumed to be dominant if it has a market share of at least one third. The German Law also provides for joint dominance, where three or fewer undertakings have a combined market share of 50 percent or five or fewer undertakings have a combined market share of about 66.66 percent. However, the market share tests in Germany are not conclusive. Under the South African Competition Act a firm is considered to be dominant (without taking into account any other factors) if (i) it has at least 45 percent of that market; (ii) it has at least 35 percent, but less than 45 percent, of that market, unless it can show it does not have market power; or it has less than 35 percent of that market, but has market power. No market-share threshold has been specified in Australia.

[32] See DG Competition discussion paper of the application of Article 82 to exclusionary practices at http://ec.europa.eu/comm/competition/antitrust/art82/discpaper2005.pdf. See also OECD Paper on competition law in the EU, where it notes that in current practice there seems to be a safe harbour at 25 percent and a rebuttable presumption of dominance of about 40-50 percent (available at http://www.oecd.org/dataoecd/3/24/2497266.pdf).

[33] The competition laws of the United Kingdom, Germany and India also contain a general prohibition on the *abuse of dominance* by undertakings/enterprises. These jurisdictions enumerate certain conducts which the dominant undertaking is not to engage in. The *South African Competition Act* does not contain a general prohibition of abuse of dominance but it prohibits dominant firms from engaging in certain specified conducts (including, charging an *excessive price* to the detriment of consumers). The *Trade Practices Act, 1974* of *Australia* does not prohibit the "abuse of dominant position." The provision corresponding to abuse of dominance in this Act is "*misuse of market power*" and provides that undertakings having a 'substantial degree of power in the market' cannot take advantage of such power for certain specified purposes.

firm and *"limiting production ... to the detriment of consumers."*[34] However, it is difficult to translate into economic terms the precise meaning of the legal expression “unfair prices.” Nor is there a sufficiently predictable and concrete legal definition of what constitutes excessive pricing in the EC law, since “unfair prices” are not defined under European law but instead left to judicial interpretation.

For instance, the ECJ has held that it may be a violation of Article 82 for an undertaking in a dominant position to charge a price which is excessive in relation to the economic value of the service provided or the good supplied.[35] According to the ECJ, excessive pricing practices can be identified using different methodologies: (i) comparing prices with cost measures for the dominant firm; (ii) comparing prices with those of firms offering substitute products; (iii) comparing prices with firms operating in different geographic areas but offering similar products.[36] Table 2 below, based on Gal (2004), provides a summary of indicative cases of alleged excessive pricing and the approach used by the EC or the ECJ to identify excessive prices.

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[34] This provision has been interpreted as proscribing high monopolistic prices, with no need to prove that competition has been harmed. This possibility was first acknowledged by the ECJ in European Court of Justice (1971a)

[35] See European Court of Justice (1975) and European Court of Justice (1978).

[36] In the UK, the OFT requires two conditions to intervene: (1) evidence that prices are substantially higher than would be expected in a competitive market; and (2) no (actual or potential) effective pressure to bring them down to competitive levels. See UK Office of Fair Trading (2004a), at 2.6. OFT also notes that supra-normal profits (*i.e.*, profits earned in a particular market which are sustained at a level in excess of the risk-adjusted cost of capital) might also be a signal of excessive pricing behavior.

Table 2: Indicative Cases of Alleged Excessive Pricing in the European Union

Case	Alleged Price Differentials that Constitute an Abuse	Permissible Price	Test for Excessiveness
Sirena (ECJ)[a]	“Particularly high”	Not determined	Not determined
Deutsche Grammophon (ECJ)[b]	“Particularly marked difference”	Not determined	Price comparisons
General Motors (EC and ECJ)[c]	40 times actual costs	EC: 8 times actual costs ECJ: Not determined	ECJ: Price/cost in light of all circumstances
United Brands (EC and ECJ)[d]	Up to and over 100% price margins	EC: Price decrease of 15% ECJ: Not determined	EC: price comparison ECJ: Price/cost
British Leyland (EC and ECJ)[e]	Over 500% price differences	34% of observed price	Price of comparable service
Ahmed Saeed (ECJ)[f]	"excessively high"- interpretative criteria: “long-term fully allocated cost…the need for satisfactory return on capital”	Not determined	Interpretative criteria inferred from EC Directive in the same sector
SACEM (ECJ)[g]	Several times higher	Not determined	Price comparison
Bodson (ECJ)[h]	Prices of others “markedly lower”	Not determined	Price comparison
ITT Promedia (EC)[i]	Margins over 900%	10% of observed price	
Deutsche Telecom (EC)[j]	100% differences	22% and 62% of observed price	International price comparisons and cost/price differences

Source and Notes: Gal, Michal S., (2004), "Monopoly Pricing as an Antitrust Offense in the U.S. and the EC: Two Systems of Belief About Monopoly?," *Antitrust Bulletin*, Vol. 49, pp. 343-384, at Table 1.

(a) Case 40/70 Sirena v. Eda (1971) CMLR 260.
(b) Case 78/70 Deutsche Grammophon Gesellschaft mbH v. Metro-SB-Gro market GmbH & Co., (1971) ECR 487.
(c) General Motors v. Commission (26/75) [1975] ECR 1367,[1976] 1 CMLR 95.
(d) United Brands Co. v. Commission (27/76) [1978] ECR 207, [1978] 1 CMLR 429.
(e) Case 226/84 British Leyland Plc. v. Commission [1986] ECR 3263 [1987] 1 CMLR 185.
(f) Case C-242/95 GT-Link v. DSB [1997] CMLR 601.
(g) C-395/87 Ministere Public v. Tournier [1989] ECR 2521, [1991] 4 CMLR 248 (“SACEM II”), Joined cases 110, 241 and 242/88 Lucazeau v. SACEM [1989] ECR 281 (“SACEM III”).
(h) Case 30/87 Bodson v. Pompes Funebres [1988] ECR 2479, [1989] 4 CMLR 984.
(i) ITT Promedia/Belgacom, EC Commission 27th Report on Competition Policy, section 67 (1997).
(j) Deutsche Telekom, EC Commission, 27th Report on Competition Policy, section 77 (1997).

All but a few recent EU cases relating to the abuse of dominance have focused on exclusionary conduct by dominant firms,[37] rather than unfair prices.[38]

b. Abuse of Market Power under U.S. Antitrust Law

An important aspect of the U.S. antitrust law, which distinguishes it from European antitrust law (as well arguably as those of Australia and South Africa), is that the terms, "dominance" or "abuse of dominance," are not used. The corresponding concepts under U.S. antitrust law are those of "monopoly" and "attempt to monopolize." More specifically, Section 2 of the Sherman Act has been interpreted to prohibit specified acts intended to induce or further monopolization, but not the existence of a monopoly position alone. Although no specific conduct is enumerated under this section, actions which further a specified firm's market position and harm consumers in the process are potentially subject to legal action. In other words, the key difference between the U.S. and EU approaches is that it is the conduct that is made illegal in the U.S.—there is no reference to price levels *per se* as a basis for action.

In reality, the U.S. approach to monopolization and the European approach to abuse of dominance appear to be converging. In both jurisdictions, a significant or monopoly market position needs to be accompanied by some behavioral component—abuse of that position—in order to trigger an investigation. The market-share threshold that constitutes a monopoly position in the U.S. is somewhat imprecise, as is the European definition of a dominant firm. Frequently, a firm with a market share above two-thirds of the market is presumed to enjoy a monopoly (or dominant) position.[39] While market share is important, it is far from the sole factor in determining dominance or the presence of a market position capable of attempted monopolization. Other relevant factors to consider are the existence of barriers to entry, the viability of competitive alternatives, the speed of innovation in the market, and the financial power of the firm. In both the EU and U.S., the fundamental issue is to distinguish between anticompetitive behavior, such as practices that impair competitors while ultimately elevating prices and harming consumers, and aggressive competition against competitors that produces lower prices and consumer benefits in the process.

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37 Including pricing issues (for instance, predatory pricing, selective price cuts, margin squeezes, and discounts or rebates) and non-pricing issues (including tying, bundling, exclusive dealing and refusal to supply).

38 A few recent cases of exploitative excessive pricing in the EU are European Commission Case (2001a), European Commission Case (2001b), European Commission Case (2001c), European Commission Case (2002), European Commission Case (2005), and European Commission Case (2007). Motta and de Streel (2003) sustains that the Commission initiated numerous cases of excessive pricing (most of them in recently liberalized network industries, like airlines, electricity and telecommunications) that "*did not lead to formal decisions but nevertheless resulted in price decreases*."

39 Fox and Pitofsky (1997) at p. 247 states that "*leading cases upholding monopolization claims involved defendants that controlled from 70 to 100 percent of the market*." Cases cited to support this statement are *Broadway Delivery Corp.* v. *United Parcel Service of America, Inc.*, 651 F.2d 122, 131 & n.15 (2d Cir.), cert. denied, 454 U.S. 968 (1981) and *Hiland Dairy Inc. v. Kroger Co.*, 402 F.2d 968, 974, n.6 (8th Cir., 1968). In the *Alcoa* case, the Judge concluded that a market share of 33 percent was certainly not sufficient to establish dominance. A 30 percent market share was also deemed far too low for dominance in *Jefferson Parish Hospital*. In *Times-Picayune*, a firm with 40 percent market share was not found to be dominant.

Absent collusion, firms are allowed to enjoy the benefits of market power under U.S. antitrust law. Exploitative pricing behavior by an entity possessing market power does not violate U.S. antitrust law if the "monopolist" has legitimately gained its market position through superior skill and efficiency.[40] U.S. antitrust law is violated only if there is a causal link between a firm's conduct, typically actions taken to harm competitors (*e.g.*, exclusive dealing with customers or input suppliers) and the enablement of market power that ultimately harms consumers. By contrast, as discussed previously, even a pure exploitation of unilateral market power through excessive pricing can breach EU competition law.[41] However, in reality, excessive pricing cases under EU competition law are relatively uncommon. Philip Lowe (Director General of DG Competition) apparently supports this assessment when he states as follows:[42]

> In practice, most of our enforcement focuses therefore as in the US on exclusionary abuses, *i.e.* those which seek to harm consumers indirectly by changing the competitive structure or process of the market.

c. Abuse of Market Power in U.S. RTO Markets

In general, the rules governing organized U.S. wholesale electricity markets typically do not directly define the term market power or what constitutes an abuse or excessive exercise of market power. Instead, they tend to identify either structural conditions conducive to the exercise of market power or specific practices that must be mitigated.

ERCOT, however, is an exception. First, it defines market power as: "*the ability to control prices or exclude competition in a relevant market.*" Second, it defines the abuse of market power as: "*practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. Market power abuses include predatory pricing, withholding of production, precluding entry, and collusion.*"[43] Thus, ERCOT's definition of abuse of market power shares some similarity with the EU antitrust definition of abuse of dominance and the U.S. antitrust notion of attempted monopolization, as it focuses on certain practices (*e.g.*, predatory pricing, practices that inhibit entry) which harm competitors and

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40 United States Court of Appeals for the Second Circuit, (1980) states:

> *"Setting a high price may be a use of monopoly power, but it is not in itself anticompetitive … Judicial oversight of pricing policies would place the courts in a role akin to that of a public regulatory commission"*

Likewise United States Supreme Court, (2004) states:

> *"The mere possession of monopoly power, and the concomitant charging of monopoly prices, is not only not unlawful; it is an important element of the free-market system. The opportunity to charge monopoly prices—at least for a short period—is what attracts "business acumen" in the first place; it induces risk taking that produces innovation and economic growth."*

41 A similar opinion is shared in Motta (2004) at p. 35, where the author maintains "*This is an area where European competition law differs from US law, which does not provide the competition agencies with the power to intervene in case of "too high" prices.*" See also Fox (1997) at p. 344, Vickers (2005), and Evans and Padilla (2004) at p. 31.

42 See Lowe (2003).

43 See Public Utilities Commission of Texas (2006).

lead ultimately to consumer harm, as well as collusive behavior. This definition also implicitly recognizes the concepts of workable competition and just and reasonable prices by focusing on practices (including withholding) that "unreasonably" restrict, hinder, or reduce competition.

With the exception of PJM, the other RTOs define abuse of market power only indirectly by describing the types of conduct that they will mitigate. ISO-NE notes in its tariff that it will mitigate conduct that *"would substantially distort or impair the competitiveness of any of the markets administered by the ISO."*[44] This behavior is specifically defined as: (i) conduct that would reduce the net revenue for the resource, but for the effect of the conduct on market outcomes, or (ii) conduct that would reduce the transmission system's capability so as to raise prices. Also, this conduct must increase prices in the marketplace beyond specified thresholds under the ISO's conduct-and-impact approach to mitigation.[45] So, ISO-New England appears to identify the withholding of output, which would reduce revenues but for its associated price impact, and the explicit manipulation of transmission constraints as potential abuses of market power. The conduct also has to represent a "substantial" distortion of competition in order to warrant mitigation.

NYISO follows a similar approach by stating only that it is mitigating conduct *that "would substantially distort or impair the competitiveness of any of the ISO Administered Markets."* [46] This is defined as conduct that would not be in the economic interest of the market participant in the absence of market power. It includes, but is not limited to physical withholding, economic withholding, or uneconomic production. Once again, the conduct must increase prices or uplift payments in the marketplace "substantially" beyond specified market-impact thresholds.[47]

MISO follows a virtually identical approach to ISO-NE and NYISO in identifying abuses of market power indirectly by stating that it mitigates conduct that *"would substantially distort competitive outcomes in the Energy Markets or other markets administered by the Transmission Provider, while avoiding unnecessary interference with competitive price signals."*[48] Once again, this conduct would "(i) reduce the net revenue associated with the Electric Facility, but for the effect of the conduct on market outcomes, or (ii) inefficiently reduce the capability of the Transmission System."[49] In MISO, mitigation will only occur for: (i) physical withholding, (ii) economic withholding, (iii) uneconomic production, and (iv) uneconomic virtual bidding. This conduct also must produce "substantial" changes in market prices or uplift payments in the marketplace in order to be subject to mitigation.[50]

Finally, the CAISO similarly notes in its redesigned tariff that its mitigation measures are intended to provide the means to "*mitigate the market effects of any conduct that would substantially distort competitive outcomes in the CAISO Markets while avoiding unnecessary interference with competitive price signals*."[51] CAISO notes that conduct which may warrant

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44 See Independent System Operator New England Inc. (2004), Section III.A.2.
45 *Ibid.*
46 See New York Independent System Operator (2005), Attachment H, 2.3-2.4
47 *Ibid.*
48 See Midwest Independent Transmission System Operator, Inc. (2005), Sections 62-63.
49 *Ibid.*
50 *Ibid.*
51 See California ISO (2007b), Section 39.

mitigation includes physical withholding, economic withholding, uneconomic production, and certain bidding strategies. Similar to NYISO and others, it focuses on conduct that "would not be in the economic interest of the Market Participant in the absence of market power."[52]

Thus, while RTOs other than ERCOT do not directly define what constitutes an abuse of market power, they implicitly define market power abuse through their statements regarding the types of conduct that are subject to mitigation. There is also a high level of consistency across RTOs in these statements. Generally, the RTOs appear to recognize the notion of workable competition (or, arguably, a zone of reasonableness), since they focus on mitigating conduct that would "substantially" or "unreasonably" distort competitive outcomes. By implication, smaller distortions of competitive outcomes would not be subject to mitigation. Many of the definitions of practices that would be subject to mitigation also appear to focus on the profit incentives of the participant (or participants) engaging in such conduct, including an analysis of whether the abusive conduct would be in the economic interest of the market participant but for the presence of market power.

4. Abuse of Market Power - Summary

In summary, the distinction between the exercise and abuse of market power is unclear. Arguably, U.S. and EU antitrust authorities and U.S. RTOs are more likely to define abuses of market power through the identification of practices that they consider abusive. For the antitrust authorities, these practices are typically specific actions that both harm competitors and lead to higher prices (or lower product quality). This connection between harm to competitors and harm to consumers is essential. If a firm engages in aggressive (but not predatory) price-cutting behavior and aggressive tactics to secure customers, its competitors will be harmed since actual or prospective profits will be lower for those firms, but consumers will benefit. This behavior is therefore not deemed to be anticompetitive by the antitrust authorities. However, other behavior that impedes entry or induces competitors to exit the market, such as a large firm entering into exclusive agreements with customers or suppliers, or making tied or bundled product sales, that do not allow its competitors to gain a market foothold, may lead to higher prices and harm consumers. These types of actions may spur antitrust investigations under appropriate conditions.

U.S. regulatory authorities and RTOs go beyond the U.S. antitrust authorities in identifying exploitative practices, particularly unilateral output withholding that substantially distorts price outcomes, as potentially constituting abusive conduct that needs to be mitigated. The U.S. antitrust authorities would not typically take action against such behavior, because a firm is not prohibited under U.S. antitrust law from unilaterally exploiting market power that it has legally acquired (*e.g.*, through superior efficiency or innovation). Note, however, that the RTOs only concentrate on specifying what constitutes objectionable behavior, such as output withholding, rather than identifying an explicit pricing (or price-cost mark-up) threshold that distinguishes an abuse of market power from a mere exercise of market power that is not considered excessive. This is likely purposeful, out of concern that defining an abuse of market power in terms of a bright-line price threshold may induce the "gaming" of that threshold in the marketplace.

[52] *Ibid*., Section 39.2.

However, based on the regulatory mandate faced by the FERC in ensuring that electricity prices are just and reasonable, this invariably raises the issue of what price threshold is implicitly being used by RTOs to distinguish just and reasonable pricing behavior from that which is not just and reasonable.

Finally, we note that in certain circumstances, the EU antitrust authorities have considered excessive pricing to constitute an abuse of dominance. However, the levels of prices and price-cost mark-ups which have spurred antitrust action are varied, and no clear-cut thresholds have emerged from jurisprudence in this area that separate an abuse of market power from otherwise permissible behavior.

Given the above discussion and considerations, we recommend that market power abuse be defined at least qualitatively as "any conduct that ultimately harms consumers by substantially distorting or impairing competition, and that would not be in the economic interest of the market participants but for the presence of market power." More regulatory guidance is needed on what should be deemed significant or unreasonable distortions from fully competitive outcomes. However, as we discuss further below, the acceptable range of outcomes must consider the accuracy of the regulatory oversight process (including its accuracy in measuring deviations from competitive conduct). It also must consider the cost of imposing mitigation when there is no significant exercise of market power, as well as the cost of not imposing mitigation when there is significant market power.

C. IDENTIFICATION, QUANTIFICATION, AND MITIGATION OF MARKET POWER – CONCEPTUAL ISSUES

Once the conceptual issues surrounding market power abuses and potential enforcement actions are understood, it is possible to develop an effective testing framework for detecting and mitigating these abuses in electric power markets. As the definition of market power abuse emphasizes, such a testing framework must begin with the articulation of a measurable (quantifiable) threshold level of market power. Thus, every market power test has a measurement yardstick (metric) and a specified or implied threshold at which mitigation may begin.

1. Defining Appropriate Product, Geographic, and Temporal Markets

Regardless of whether enforcement is *ex ante* or *ex post*, and the precise form of the metric and threshold for market intervention, every well-designed market power mitigation regime must explicitly or implicitly rely on sound definitions of the relevant product and geographic markets. A measurement of the ability or incentive of an individual seller or group of sellers to exercise market power is meaningful only by an appropriate identification of relevant markets.

This does not mean that every framework requires an extensive quantitative analysis to determine a relevant product and geographic market. In some cases, market boundaries are effectively set by regulation itself, or they can be determined in a reasonably straightforward manner. In electricity markets, however, the network topology that results from the location of load and generation sources and the nature of the transmission system may complicate the determination of a relevant geographic market for purposes of analyzing actual or prospective market power. Whatever the level of analysis needed, the imperative point is that the testing framework must take into account all substitute products and the location of all production sources supplying those products that could limit the market power of sellers in the market.

a. Relevant Product Markets

Even though it is intended to define product and geographic markets in merger reviews, the approach used in the U.S. Department of Justice and Federal Trade Commission's "Horizontal Merger Guidelines" (*Guidelines*)[53] is increasingly accepted in various jurisdictions (including the European Union and Canada) as a useful conceptual framework for defining markets for more general antitrust and regulatory purposes. Under this approach, a product market is defined by taking an individual product and assessing whether it would be profitable theoretically for all producers of that product within a specified geographic area to *collectively* institute a "*small, but significant, and nontransitory increase in price*" ("SSNIP"),[54] which typically is 5-10 percent, assuming the terms of sale of all other products are held constant. If, in response to the price increase, consumers would turn to other alternatives such that the reduction in sales of the candidate product would be sufficiently large, then the hypothetical price increase would be unprofitable. Producers of that product alone would have failed the SSNIP test, and therefore are not considered to possess significant market power. The candidate product market would then be expanded to include "the next-best substitute",[55] and the SSNIP test would be applied to all producers of the original product and the substitute product. This process continues until the candidate product market passes the SSNIP test.

The conceptual approach underlying the SSNIP test, if not the test itself, is useful for identifying appropriate product and geographic markets for electric power that may be susceptible to significant exercises of market power. For example, decisions regarding the purchase of energy products subject to differing term lengths and conditions are equivalent to deciding between products with differing attributes. Consequently, energy products with different term lengths, such as day-ahead or real-time energy, are part of the same "relevant product market" only if energy purchasers showed sufficient willingness to switch from purchasing under one set of terms and conditions to another set of terms and conditions. If the ability of energy purchasers to substitute between day-ahead and real-time power is limited, then each of these power products would constitute a separate relevant product market to be examined separately for conditions conducive to the abuse of market power. That is the approach often used by individual U.S. RTOs.

Similar issues arise with respect to mitigating market power in capacity markets and ancillary services. Providers of a particular ancillary service, such as spinning reserves, potentially may be able to raise prices profitably if the RTO purchasing that ancillary service does not show sufficiently flexibility in switching to other types of ancillary services in the event of a price increase.

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[53] See U.S. Department of Justice and Federal Trade Commission (1997), section 1.0.

[54] *Ibid*., section 1.1.

[55] *Ibid*.

b. *Relevant Geographic Markets*

Analogous to the SSNIP test conducted to define relevant product markets, one can determine relevant geographic markets for purposes of assessing market power in the provision of electricity by taking a group of generators located within a relatively confined geographic area, and assessing whether it would be profitable for that group of generators to collectively attempt to impose a "*small, but significant, and nontransitory increase in price*"[56] (*i.e.*, based on the theoretical assumption they could collectively act like a single monopolist). Such an attempt to impose a price increase may be unprofitable because customers within that candidate geographic market could turn to alternative suppliers (*e.g.*, located outside of the area), provided there was sufficient transfer capability to import electricity from that outside area. However, if transmission constraints sufficiently limit transfer capability, it is possible that an attempt to raise the price of electricity may be profitable for generators located within a very confined geographic area (*e.g.*, in a load pocket). That geographic area arguably should be considered to be a separate "relevant geographic market" for purposes of assessing and mitigating potential market power.

Note that the definition of the relevant geographic market is not independent of the market design used. For example, an LMP-based RTO, as opposed to a zonal or single-priced region, can be susceptible to more localized exercises of market power because market pricing is location-based. Two relatively proximate geographic locations may have substantially different prices as a result of significant transmission constraints encountered in sending power from one location to the other. In any case, during market conditions where transmission constraints are binding, generators operating in a "constrained-on" area can potentially wield market power because an attempt by those generators to raise prices cannot be offset by increased imports from generators operating outside of the area. Consequently, as we show later, U.S. RTOs focus heavily on transmission constraints in formulating their tests for market power and triggering mitigation.

c. *Temporal Dimensions of Relevant Markets*

In electric power markets, the need to continuously balance supply and demand implies that the relevant product market has a time dimension. Very few energy consumers face real-time pricing that might provide them with an economic incentive to switch their energy consumption patterns in reaction to changing wholesale energy prices. Even if end users desired to limit or delay their energy consumption in response to a temporary increase in energy prices, there is a lack of installed metering technology at the residential (and commercial) level to measure these demand responses. It is therefore quite possible that generators would find it profitable to raise price by a small, but significant, amount over a limited time frame, since end users likely would not be exposed to the price change and there would be limited diminution of energy consumption.

Consequently, despite the *Guidelines*' focus on a "small, but significant, and nontransitory" increase in price, market power in electricity markets can be abused over a relatively transitory

56 *Ibid*., section 1.2.

period. Thus, significant exercises of market power can take place over short time intervals, such as an hour or a few peak hours, particularly when load conditions are such that there is limited capacity in the marketplace and suppliers can anticipate those particular market conditions.

2. Tradeoffs and Reliability Considerations in the Design of Market Power Mitigation Processes

The design of appropriate market mitigation processes necessitates decisions on how well-specified and "stringent" those processes should be. The pre-specification of mitigation processes is fundamental to the *ex ante* mitigation of market power abuse, as there is little time and opportunity to evaluate fully whether individual mitigation actions have correctly identified and mitigated abusive conduct. Rather than relying on full investigations of all the facts surrounding certain events, as may be the case with *ex post* enforcement actions, *ex ante* mitigation processes generally rely on: (1) clearly prescribed analytical "tests" or "screens"[57] for market structure conditions or market conduct that likely is associated with an abuse of market power; and (2) clearly prescribed mitigation actions.

The choice of an appropriate screen-based enforcement regime against exercises of market power has much to do with policymakers' beliefs about two key issues:

- What is the likelihood and cost of mistakenly applying pre-emptive price (or bid) controls that may prevent sellers from charging prices that actually enhance economic efficiency? In diagnostic terms, this problem (*i.e.*, the false identification of market power abuse when it does not exist) is known as a "false positive" or "type I" error.
- Conversely, what is the possibility that the enforcement regime will fail to catch market power abuse or fail to do so in a timely manner, and what will be the economic and political cost of this failure? In diagnostic terms, this problem (*i.e.*, the failure to identify market power abuse when it exists) is known as a "false negative," which is sometimes referred to as a "type II error."

Policymakers implicitly must develop "loss functions" that relate the likelihood of false positives or false negatives to the associated costs of such errors. One also needs to consider the costs of a specified enforcement regime relative to other alternatives, which include the costs associated with monitoring, evaluating, and mitigating market power, as well as the costs of evaluating and modifying the monitoring and mitigation process as experience is gained and market conditions change over time. The appropriate enforcement regimes is the one that produces the maximum benefits (or minimum losses) to society in terms of mitigation errors, net of the cost of the enforcement regime.

For example, a policymaker who believes that a failure to detect market power abuse (*i.e.*, false negatives) is associated with much higher social cost than the misidentification of reasonable conduct as market power abuse (*i.e.*, false positives) might choose a more stringent approach that errs on the side of avoiding false negatives (*i.e.*, an approach where mitigation of market

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[57] In this document, the terms "test" and "screens" are used interchangeably to refer to quantitative analyses that assess whether the mitigation of actual or potential market power is needed.

participant behavior occurs more frequently). Conversely, a policymaker who is concerned that false positives induce substantial inefficiencies might choose an approach that errs on the side of avoiding false positives (*i.e.*, an approach where mitigation of market participant behavior occurs less frequently).

It is important to recognize that the probability of obtaining false positives or negatives is critically related to the nature of the abuse-of-market-power standard promulgated (*i.e.*, is the standard clearly or vaguely stated) and the nature of the precise tests and thresholds adopted and implemented by the RTO. It is also worth noting that controls on market power impose risks and costs on both sellers and buyers, and that these risks are costly whether or not they are fully observable or measurable in monetary terms. Thus, the cost of under-enforcement versus over-enforcement against abuses of market power can only be evaluated in the full context of specific markets and their political and economic environments.

If there is the prospect for frequent exercises of significant market power as a result of underlying market conditions, a relatively unrestrictive policy toward mitigating market power may lead to elevated prices that encourage long-term investment, but at a potential very large short-term cost in terms of inefficient and politically unacceptably high prices. For markets dealing with the frequent and significant exercise of market power for sustained periods of times, the short-term cost of under-enforcement could easily trump any long-term gains from entry.

However, while it is correct that the consumer harm resulting from inadvertently unmitigated market power can be extensive, the long-term cost of over-enforcement (*i.e.*, mitigating false positives) should not be underestimated. For example, it is widely viewed by economists that regulation (in this case, enforcement of market power mitigation rules) is not costless, because regulation can be associated with errors and those errors can engender both short-term and long-term inefficiency. With respect to the monitoring of wholesale electric power markets, regulatory errors can lead to the imposition of mitigation in unwarranted situations, which induces potentially costly changes in the operations of generation units (such as additional wear-and-tear on the units). If cost-based mitigation is applied, and costs are mis-measured, then the imposition of mitigation can create inefficiencies by inducing particular firms to produce more output than is socially optimal. Also, the application of unwarranted mitigation can depress prices artificially and thereby impede efficiency-enhancing innovation and the use of demand-response mechanisms. Longer-term inefficiencies also may arise from downward price distortions, since they adversely affect the incentives of firms to build new capacity (or add capacity to their existing plants) and consumers to invest in demand-reducing technology. As a consequence, overly aggressive mitigation can suppress the very price signals that encourage efficient supply-increasing and demand-reducing investment. Over-mitigation of spot prices can also encourage retailers to rely excessively on spot market and short-term purchases, which will reduce the role of forward contracting in mitigating incentives to exercise market power.[58]

Even though imposing unnecessary mitigation may not always have significant price impacts (*e.g.*, because the reference levels used under mitigation may be close to unmitigated competitive outcomes), over-enforcement may create a perception of having such distorting price impacts.

[58] See Wolak (2005), p. 8.

This may undermine supplier and investor confidence, potentially deterring investment by creating increased regulatory risk—which also can result in higher long-term costs to consumers.

Some of these costs associated with over-mitigation have also been recognized by FERC in its 2004 MISO order:

> Over-mitigation would mean that generators will not be able to recover all of the costs that they should, and generators may exit the market, or be less likely to enter. Even the threat of over-mitigation may keep market participants out of the market. Fewer competitors can mean less system flexibility and thus ultimately less reliability, and for this reason it is also appropriate to avoid over-mitigation.[59]

3. *Ex Ante* vs. *Ex Post* Mitigation of Market Power Abuse

Enforcement against abuses of market power in electricity markets may arise in the form of *ex ante* restrictions on firms and their behavior, such as price caps, bidding restrictions, or mandated prices that reflect anticipated costs, or the *ex post* deterrence of harmful conduct through the prospect of investigations and costly punishment (*e.g.*, fines, damages payments, etc.)[60] Typically, RTO-based electricity markets rely on a combination of both types of enforcement, with *ex ante* enforcement provided through automated mitigation protocols that are triggered by pre-specified market power screens, and *ex post* enforcement provided through market monitoring by the RTO (and the FERC) along with the ability to impose sanctions and modify market rules and mitigation protocols. In addition, antitrust action represents another type of *ex post* enforcement against anticompetitive activity that can be applied in electric power markets.

Ex ante mitigation focuses on identifying when conditions or conduct are present that enhance the potential for market power abuse, and then imposing restrictions or rules that eliminate the potential for abuse in the presence of those conditions before market prices are determined. *Ex ante* mitigation measures include bid caps and market price caps and other prohibitions that do not rely on extensive fact-finding, analysis, and prosecution. By contrast, *ex post* enforcement focuses on identifying after-the-fact instances of anticompetitive conduct (*e.g.*, evidence of collusion, significant output withholding) or other inefficient behavior and punishing such behavior through fines or other actions.

Advocates for *ex ante* restrictions in electric power markets generally argue that market participants prefer this approach (as opposed to only *ex post* enforcement) due to its greater transparency, the reduced regulatory risk (compared to sole reliance on after-the-fact reviews), and the prevailing market power concerns that still exist in liberalized electricity markets. In addition, *ex ante* mitigation avoids the often slow, potentially costly, uncertain, and burdensome investigations associated with *ex post* enforcement regimes. It is also feared that, due to their costs and delays, *ex post* mitigation processes do not reliably address significant

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59 Federal Energy Regulatory Commission (2004c), paragraph 239.

60 For further discussion of the tradeoffs between *ex ante* and *ex post* enforcement, see Fox-Penner, *et al.*, (2002), pp. 286-291.

market power abuses or are unable to undo fully the harm caused by such abuses. Advocates for *ex ante* mitigation are generally more concerned about the cost of under-enforcement (false negatives), although the degree to which false negatives (as well as false positives) can be avoided depends on the nature and quality of the specific market power screens and mitigation techniques utilized. Policymakers operating under an *ex ante* regime who, within that framework, are relatively more concerned about the cost of false negatives may approve stringent *ex ante* mitigation mechanisms *(i.e.*, stringent screens and mitigation actions). Others who, within the *ex ante* framework, are relatively more concerned about the cost of false positives may approve less stringent *ex ante* mitigation mechanisms.

Regarding electricity markets in particular, Frank Wolak of Stanford University notes that *ex ante* mitigation as well as industry-specific market monitoring are necessary because "unilateral market power problems can be extremely difficult to predict," and "they can impose significant economic harm for a sustained period of time when they do occur."[61] These concerns had also been voiced by FERC in its original notice of proposed rulemaking on standardized market design:

> …[t]o be effective, market power mitigation measures must be applied before the fact, since remedies after the withholding has occurred are disruptive to the market and increase regulatory risk to its participants, which increases costs to customers.[62]

Even though that rulemaking has not directly led to an order, FERC's strong preference for *ex ante* mitigation procedures is evident in the fact that all FERC-regulated RTO markets rely on *ex ante* mitigation processes. ERCOT similarly relies on *ex ante* mitigation protocols. However, while *ex ante* mitigation processes are widespread in U.S. organized electricity markets, they are not commonly employed overseas (as we will discuss in Section III below).

Advocates for relying primarily on *ex post* mitigation claim that while *ex ante* mitigation can be comparatively quick and formulaic, it risks being too prescriptive, overly broad, and having unintended consequences—notably a larger fraction of false positives (*i.e.*, resulting in mitigation actions when market power abuse does not exist). Thus, *ex ante* mitigation may distort market dynamics, and it necessarily imposes social costs when it forces market participants to alter their behavior under conditions where the market is acting efficiently. By contrast, reliance on *ex post* enforcement allows for full investigations that consider the specific facts and circumstances behind particular forms of market behavior. This process helps avoid over-mitigation and facilitates enforcement actions (including sanctions) that are more specifically tailored to those instances in which a market participant is demonstrated to have engaged in anticompetitive or otherwise inefficient behavior. In that sense, *ex post* enforcement is arguably less likely to distort market behavior and market dynamics, since mitigation is imposed only if anticompetitive behavior is discovered and sufficiently documented after the fact.

61 See Wolak (2005)

62 See Federal Energy Regulatory Commission (2002), p. 396.

However, as a general matter, sole reliance on *ex post* regulatory enforcement may be less preferable than explicit *ex ante* restrictions when the likelihood of abuses of market power and other market inefficiencies is sufficiently great that it would be both costly and cumbersome to investigate and punish them on a case-by-case, after-the-fact basis. Sole reliance on *ex post* enforcement also may be less desirable when informational asymmetries make it difficult for the regulator to identify specific episodes of market misconduct. Thus, one might view *ex ante* mitigation of certain market conduct that is likely to be frequent and that could impose significant harm as not a substitute for, but a complement to, *ex post* enforcement geared toward other activities that are infrequent and reasonably observable after the fact.

Since it represents a potentially more precise method of fostering market efficiency than an overly restrictive set of *ex ante* rules and regulations, increased reliance on *ex post* mitigation (coupled with less stringent *ex ante* mitigation protocols) becomes more attractive in less concentrated markets where both the likelihood and frequency of abuse of market power are expected to be sufficiently small. In these types of markets, *ex post* mitigation can be applied to the relatively few instances in which it is demonstrated that a market participant committed an actionable violation.

Finally, we note that the advantages and disadvantages of *ex ante* vs. *ex post* enforcement depend on the effects of the specific mitigation actions employed as well as those that, perhaps by statute, cannot be employed. The total costs and risks associated with either over-enforcement or under-enforcement of market power abuses cannot be measured without evaluating the condition of the market following mitigation.

4. Structural vs. Conduct-and-Impact Tests of Market Power

Assessments of market power may be based on very different approaches. One common approach is a "structural approach," which assesses the prospect for market power abuse by analyzing the structure (*e.g.*, concentration) of relevant markets. The other common approach, the "conduct-and-impact approach" analyzes suppliers' specific conduct (*e.g.*, bid prices) and their potential market impact (*e.g.*, impact on market clearing prices). Both of these approaches are used in RTO-based electricity markets as a basis for imposing *ex ante* mitigation through automated mitigation processes.

Each approach has its advantages and disadvantages, and each has its own critical data requirements. Depending on the details of their implementation, the different approaches will have differing probabilities of producing false positives or false negatives in the process of addressing market power abuse. Evaluating the effectiveness and reliability of specific mitigation approaches can only be done in the context of a complete and specific market analysis.

a. Structural Tests

The first approach to assessing actual or prospective market power is to rely on "structural tests." Structural tests (including the HHI) examine the number and distribution of sellers, sometimes relative to demand levels, in order to form a hypothesis concerning sellers' market power. Although these tests arguably represent an indirect means of assessing the potential for exercising market power, they can be applied readily in *ex ante* mitigation processes, and their data needs can be less demanding relative to other alternatives.

One particular structural issue affecting electric power markets is the potential for dominant or pivotal suppliers. In the case of a pivotal supplier(s), the market reaches a point where customer demand cannot be met without including the output of the pivotal firm (or pivotal firms) because of capacity limitations affecting other market participants. With a highly inelastic short-run elasticity for electric power (*i.e.*, highly price-insensitive demand), the situation is ripe for the pivotal supplier to exercise substantial market power. Even if a supplier or a group of suppliers are not pivotal producers unilaterally, the supply conditions in electric power markets are such that individual firms may perceive that the "residual demand" for their output is relatively insensitive with respect to price.[63] This provides incentives for suppliers to withhold output by raising the prices at which they are willing to sell power (or through strategically determined plant outages to achieve physical output withholding). Both PJM and CAISO use a variant of a "jointly" pivotal supplier test as the primary screen for *ex ante* market power mitigation.

One of the advantages of mitigation protocols based on structural screens is that, if designed properly, the screen can be used routinely to identify the markets, time periods, and suppliers for which market power concerns are most likely to exist. Relying on a purely structural screen also avoids the politically difficult challenge of setting explicit "allowable" bid or price impact thresholds—though the need to choose an acceptable price impact directly is simply replaced by the need to choose a structural test and associated mitigation threshold. Finally, through the implementation of stringent screens that err on the side of caution, the currently used structural approaches may provide more effective protections against short-term exercises of market power.

A disadvantage of structural approaches is the difficulty of devising screens and thresholds that: (i) are applied to correctly-defined relevant product and geographic markets; and (ii) are able to accurately identify the likely exercise of unilateral and multilateral market power within these relevant markets. Consequently, while the choice and specific implementation of a structural screen might appear to be relatively simple and less controversial than choosing explicit pricing thresholds, it is associated with substantial uncertainties about the ultimate reliability of the mitigation process that can lead to both under- and over-mitigation. The reliability of a structural screen depends critically on correctly defined markets (*e.g.*, is it the market for energy in a well-defined local geographic area, or is it the market for "congestion relief" on individual transmission constraints?), as well as the screen's ability to reliably reflect suppliers' actual incentives for exercising market power. For example, a supplier's ability and incentive to exercise market power may depend on its load obligation, the extent of vertical integration, the type of regulatory constraints (*e.g.*, cost-of-service regulation of vertically integrated utilities), as well as the extent to which the pricing of resources is constrained by long-term contracts. While properly constructed structural tests should assess both the ability and incentive to exercise

[63] The residual demand curve of a firm is defined as the total market demand less the supplies (or capacity) offered by rival producers at any given price. Wolak (2003) examines residual demand elasticities in studying unilateral market power in the California wholesale electricity market for the period from 1998 to 2000.

market power and thereby predict likely market performance as a function of structural indicia, the actual implementation of structural tests generally falls short of that goal.

The difficulty of addressing such factors means that structural screens may be focused more directly on a supplier's ability, rather than its incentive, to exercise market power under a hypothetical market environment that does not consider fully suppliers' obligations, pricing constraints, or actual competitive interaction. This reduces the reliability of the structural screening process, and runs the risk of producing a significant number of false positives (and consequent over-mitigation) under a relatively stringent structural screen. By contrast, a significant number of false negatives (which potentially leads to under-mitigation on an *ex ante* basis) may arise under a more permissive structural screen.

b. Conduct-and-Impact Tests

The second common approach to analyzing market power is to directly assess supplier conduct and its impact on market prices, such as bidding above cost or engaging in physical and economic withholding of output. These are known as "conduct-and-impact" tests. In theory, an exercise of market power can be observed directly by comparing the levels of price and cost. This approach requires that prices and costs both be observable with sufficient accuracy. Even more of a challenge, this approach requires that the regulator specify the price-cost markup threshold that is unacceptable and therefore worthy of mitigation. It is very difficult to establish such a threshold in any general or abstract way, and in the absence of substantive analysis pertaining to underlying cost and demand conditions and the likely nature of seller interaction absent regulatory intervention. Many healthy markets will show prices periodically that are substantially in excess of short-run costs (*e.g.*, prices that are more consistent with the recovery of long-run costs), even though this outcome is not necessarily consistent with the textbook notion of perfect competition.

As may be obvious, the conduct-and-impact approach to mitigating market power has several inherent traits. First, conduct cannot typically be policed before the fact, so conduct tests are typically applied *ex post*. A notable exception, though, is that in markets with bids submitted to a central market-maker, such as an RTO, the conduct of individual market participants can be evaluated prior to accepting a specified bid, thereby enabling that bid to be mitigated prior to determining the market-clearing price and making the actual sale. Thus, as will be discussed later in further detail, several RTOs (*e.g.*, Midwest ISO, New York ISO, ISO New England) have used screens for specific conduct (*e.g.*, output withholding, bidding in excess of costs), augmented by tests that measure market price impacts. When bidding behavior is deemed unacceptable based on these conduct-and-impact tests, the bids are mitigated to a competitive reference level, and the market-clearing price is determined on the basis of this *ex ante* mitigation of the submitted bids.

The advantages of mitigation actions triggered by conduct-and-impact tests are that, if designed properly, this mitigation approach explicitly identifies and mitigates only substantial (*i.e.*, unreasonable) exercises of market power based on an *explicit* choice of bid and market impact thresholds, which reduces the risk of over-mitigation (and the perception of over-mitigation). The use of simple price-based bid and price impact thresholds that trigger mitigation generally also results in a mitigation process that is relatively transparent to market participants. By focusing on actual market impacts, conduct-and-impact-based mitigation potentially addresses both unilateral and coordinated exercises of market power. Finally, the threshold-based, conduct-and-impact approaches readily accommodate *ex post* analysis of the extent to which market participants' conduct is deviating from some competitive norm, particularly if mitigation is triggered when an individual participant deviates significantly from either past behavior (*e.g.*, during a competitive benchmark period) or a designated cost-based standard (*e.g.*, as measured by the markup of its price over marginal cost or average variable costs). The results of such analyses facilitate dynamic improvements in the testing and mitigation processes to address market power problems.

The disadvantages of conduct-and-impact-based mitigation is that the chosen bid and price thresholds may either be too low (and result in over-mitigation) or too high (and result in the failure to detect significant abuses of market power). Moreover, the bright-line thresholds allow and potentially encourage behavior in which market participants (unilaterally or through coordinated behavior) exercise some degree of market power (*i.e.*, pricing above short-run marginal cost), but without exceeding the specified thresholds. Finally, over-reliance on conduct-and-impact screens may cause regulators to pay insufficient attention to structural indicia that can help focus mitigation on product markets and market areas where market power concerns are largest.

Once again, policymakers who elect conduct-and-impact approaches must have a clear view of the perceived losses that arise from false positives and false negatives in the screening process. If mitigation thresholds are set "high," the conduct-and-impact approach will represent a less stringent form of *ex ante* mitigation that errs on the side of avoiding false positives. Similarly, if mitigation thresholds are set "low," conduct-and-impact approaches will result in more stringent mitigation that errs on the side of avoiding false negatives. At high mitigation thresholds, this paradigm could run the risk of creating short-term, significant costs to consumers if the exercise of market power is frequent and significant. Although as we will show, conduct-and-impact approaches also have been fashioned that trigger swift mitigation and subject market participants to relatively strict standards.

As discussed in more detail in Section IV, several RTOs primarily rely on a conduct-and-impact approach (*e.g.*, NYISO, ISO-NE, MISO, and CAISO under its current market design), while other RTOs mainly use a structural approach (PJM, CAISO MRTU, ERCOT's new market design). Although either approach can be effective under certain conditions, little research to date has been devoted to comparing the effectiveness and reliability of these alternative approaches.

5. Reference Levels and Thresholds for Market Power Mitigation and the Relevance of "Workable Competition"

Once an exercise (or likely exercise) of market power has been identified through screening processes, the appropriate form of market power mitigation then must be determined. Frequently, this means either prices or bids are restricted to conform to a competitive "reference" level.

The decision regarding an appropriate reference level to which prices or bids will be mitigated necessarily balances short-term and long-term considerations. While trying to achieve prices in conformity with short-run marginal costs may be efficient in the short term, this type of mitigation can suppress price signals that would stimulate long-term investment and potentially lessen some of the need for aggressive market power mitigation in the future.

The definitions of market power cited in Table 1 all include some notion of a competitive price level, so it is important to understand what such a level should represent. In perfectly competitive markets, firms are small and act as price-takers. Since they have no ability to influence market price in this idealized setting, firms supply output up to the level where their marginal (*i.e.*, incremental) cost of producing additional output equals market price. Thus, in a strict sense, the perfectly competitive price level is one where the market price equals the marginal cost of production for the firm supplying the last unit of output. And, for that reason, it is generally common to measure market power in terms of the mark-up of price over marginal cost.[64]

However, even many well-functioning markets may periodically exhibit prices that substantially exceed short-run costs (*e.g.*, prices that are more consistent with the recovery of long-run costs). Consequently, holding electricity markets to a standard of perfect competition, where prices reflect short-run marginal production costs, may stymie attempts to transition to a state of less regulation. The concern therefore arises that both the threshold for the mitigation of market power abuse, and the competitive reference level to which prices or bids are mitigated, which generally will not be the same, may constitute an unrealistic representation of how competitive wholesale electric markets might behave even under the best of circumstances.

Since perfect competition is a theoretical paradigm and does not appropriately describe behavior in the numerous unregulated markets that we observe, policymakers have created the notion of "workable" competition as a more realistic goal for a competitive market. As discussed previously, under workable competition, price arguably may exceed short-run marginal cost and firms arguably may engage in limited exercises of market power (where prices would exceed short-run competitive levels). Thus, the notion of workable competition may naturally be considered as a possible alternative to a marginal-cost standard (or a "cost plus adder" standard) for identifying and mitigating abuses of market power. Workable competition, however, is largely a regulatory doctrine and is thus ill-defined from an economic perspective. In fact, many years ago, a group of economists summed it up as follows:[65]

> The 'doctrine' of workable competition is only a rough and ready judgment by some economists, each for himself, that a particular industry is performing reasonably well – presumably relative to alternative industrial arrangements which are practically attainable. There are no objective criteria of workable competition and such criteria as are preferred are at best intuitively reasonable modifications of the rigorous and abstract concept of perfect competition.

64 See Carlton and Perloff (1994), p. 137.

65 See U.S. Attorney General's National Committee on Antitrust Laws as referenced and quoted in Bonbright, Danielsen, and Kamerschen (1988), p. 147.

Alfred Kahn, in *The Economics of Regulation*, similarly speaks of "effective competition" as the ultimate goal of the policymaker. Moreover, he sums up nicely why pure or perfect competition, characterized by numerous small firms with no market power, is not the ideal objective standard for the regulator to pursue:[66]

> The main reasons why pure competition is in fact not ideal are familiar: (1) economies of scale in production and distribution will typically require that sellers (and buyers) be larger in size and fewer in number than would be consistent with an utter absence of monopoly (or monopsony) power; (2) consumers want variety in service quality and characteristics, which means that there cannot always be a large number of sellers of the same (standardized or undifferentiated) product; (3) effective innovation may, similarly, require firms too large and, hence, too few in number for monopoly power to be completely absent… (4) competitive structure may, in the presence of serious imperfections of competition, be too pure in other respects—entry too free and rivalry too intense—for optimum performance. All of these considerations make the determination of what kinds of policy will produce the most effective competition difficult enough in unregulated industry generally; they make it even more difficult in the public utility arena, which has been subject to more direct regulation precisely because of the presence there of unusually strong circumstances making unrestrained competition both infeasible and undesirable.

In general, the concerns expressed above suggest that the application of overly idealized competitive thresholds for determining market power abuse in electric power markets, and imposing mitigation when such idealized thresholds are crossed, could be tantamount to applying a standard that can never be met even by a healthy, workably competitive electric power market. Even if one could determine precisely what bids and market prices would actually look like under perfect competition, mitigating to that standard would require continuous intervention in market outcomes. That would, by necessity, imply that the electric power market would remain heavily regulated as long as it is being held to this unrealistic standard.

As a consequence, the tests used to determine whether market power might have been abused, as well as the mitigation actions taken after such abuse (or potential for abuse) has been identified, should recognize that workable competition, not perfect competition, is a more reasonable (and certainly more attainable) policy goal. This, of course, requires that policymakers define what a reasonable range of workably competitive outcomes would be, which leads us back to our discussion of how market power abuse should be defined.

We also note that, under certain conditions, it may be sensible for the policymaker to set the structural or behavioral thresholds for triggering automatic *ex ante* mitigation, if not the reference levels used when applying mitigation, toward the upper end of the range of workably competitive market outcomes. This might be the case, for example, if the chosen screening methods create significant numbers of false positives, and the policymaker considers the imposition of mitigation when market power does not exist as sufficiently costly.

[66] See Kahn (1989), p. 114.

Perhaps more importantly, since they are necessarily prescriptive in nature, *ex ante* mitigation processes typically are not intended to represent the sole means of deterring substantial exercises of market power. This is why *ex ante* mitigation is typically supplemented by *ex post* monitoring processes that investigate and punish abusive conduct which was not previously detected and mitigated.[67] If abusive conduct is identified through the *ex post* monitoring process, the RTO can file with FERC to request sanctions or authorization of appropriate additional mitigation measures, including a modification of the existing *ex ante* mitigation processes. With the backstop of an *ex post* monitoring process designed to catch market power abuses that elude the *ex ante* screening process (*i.e.*, to catch false negatives), it becomes more attractive for the policymaker to set sufficiently tolerant *ex ante* mitigation thresholds in order to reduce the number of false positives.

Finally, the reliability of an *ex ante* mitigation process arguably can be improved based on insights gained through the *ex post* monitoring process. Thus, particularly in markets where the risk of market power abuse is relatively low, it may make sense to initially establish more permissive *ex ante* mitigation procedures and rely more on *ex post* monitoring and enforcement until additional market experience is gained. This also may facilitate the development of clearer standards for market power abuse over time, as greater familiarity with market behavior and underlying conditions is obtained.

By contrast, when structural conditions and other market features raise the prospect of frequent market power abuse, or the *ex post* monitoring process is perceived to be slow, costly, or inaccurate (as it often is), it becomes attractive to rely upon more stringent *ex ante* mitigation procedures with lower thresholds for triggering automatic mitigation in order to be less dependent upon *ex post* enforcement.

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[67] For example, California ISO (2007b), Section 39.1 specifically states that "the [ex ante] Mitigation Measures authorize the mitigation only of specific conduct identified through explicit [ex ante] procedures specified….In addition, the CAISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but is not addressed by the market power mitigation procedures."

III. MARKET MONITORING AND MARKET POWER MITIGATION IN OVERSEAS ELECTRICITY MARKETS

This section describes the market monitoring and mitigation approaches used by the regulatory and antitrust authorities in three well-established non-U.S. electricity markets with significant operating histories: Great Britain (GB), Nord Pool, and Australia. As we shall see, these markets rely primarily on *ex post* rather than *ex ante* market power mitigation. An overview of the key market-monitoring features is provided below, followed by a brief discussion of possible conclusions that can be drawn from this review with respect to mitigation in U.S. RTO markets.

A. GREAT BRITAIN

1. Market Overview

Prior to April 1, 2005, the electricity market in England and Wales was not fully integrated with the electricity market in Scotland. Since then, Great Britain (England, Wales and Scotland) has had an integrated market with a single set of trading arrangements, known as the British Electricity Trading and Transmission Arrangements (BETTA). BETTA is based on the New Electricity Trading Arrangements (NETA), which were introduced in England and Wales in 2001. NETA replaced the initial pool design implemented during market liberalization in England and Wales in the early 1990s. Generation assets are owned by various private, for-profit entities. The transmission grid in England and Wales is generally owned and operated by an independent for-profit entity, National Grid. The exception to this is the Scottish electricity transmission network, which is owned by the two Scottish transmission companies (Scottish Power Transmission Ltd and Scottish and Southern Energy Ltd). To ease transmission constraints and expand market areas, National Grid made substantial transmission investments since market liberalization, particularly in the early 1990s.

The electricity markets in Great Britain feature a mix of bilateral trading (long-term contracts and over-the-counter, or OTC, trades[68]) and short-term trading on several organized trading exchanges (mainly the APX Power UK, formerly known as UKPX). There is no centralized physical spot market comparable to that administered by PJM. The GB system operator (SO) only runs a pay-as-bid balancing mechanism which has relatively low volume (about 5 percent of the total delivery in GB). Most of the power traded in GB (over 90 percent) is through bilateral transactions. In addition, BETTA is a "one-part" market without any form of capacity payment. While there is no minimum reserve margin imposed in the GB market, the SO holds reserves to maintain operational reliability and there is a negotiation between the regulator, Ofgem, and the SO regarding the volume and cost of reserves it is allowed to hold.

[68] OTC trading typically operates from a year or more ahead of real time up until 24 hours ahead of real-time.

2. Market Power Mitigation Authorities

Ofgem, and its governing body, the Gas and Electricity Markets Authority (GEMA), are both the energy sector regulator and the competition authority with full antitrust powers in the energy sector. Antitrust laws provide the statutory basis for any actions taken by Ofgem or others against electricity generators engaged in an alleged anticompetitive exercise of market power. Ofgem has concurrent powers with the Office of Fair Trading (OFT) under the Competition Act 1998 (CA1998) to investigate and take enforcement action in relation to suspected infringements of United Kingdom (UK) and European Community (EC) competition laws.[69] The CA1998 (which mirrors the provisions of European competition law which apply throughout the European Union) prohibits agreements between companies (*i.e.*, collusion) which have the object or effect of preventing, restricting, or distorting competition. It also prohibits conduct by one or more companies which amounts to the abuse of a dominant position in a market.[70] (This ability to prosecute unilateral dominance is in stark contrast to U.S. antitrust agencies, which do not have such enforcement authority with respect to exploitative exercises of market power.) Consistent with EC competition laws, the CA1998 specifies that both exclusionary and exploitative practices by dominant firms in the market may constitute anticompetitive behavior.

Ofgem (joint with OFT) has published guidelines on how it would apply its antitrust powers in energy markets if a case were to be brought.[71] One of the most relevant elements contained in the guidelines is Ofgem's acknowledgement that due to the particular economic characteristics of electricity markets (including relatively inelastic supply and demand conditions), the traditional market share thresholds used to assess dominance in other markets might not apply to the electricity market.[72] Ofgem maintains that even market participants with low market shares (below normal thresholds for considering dominance) "may have the ability substantially and consistently to influence prices, and therefore to act independently of customers and competitors."[73]

Ofgem further maintains that "large price increases that are sustained only for a short period or small price increases over a long period of time" may both constitute a breach of competition law.[74] In assessing potential abuses of dominance in temporal markets, Ofgem will consider the effects of any deviations from competitive price levels. However, Ofgem's guidelines on how it would apply its antitrust powers in energy markets focus exclusively on the assessment of whether a dominant market participant is engaging in exclusionary practices. No specific

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69 See UK Parliament (1998), Chapter I.

70 *Ibid.*, Chapter II.

71 See Ofgem (2004).

72 European jurisprudence has traditionally stated that dominance can be presumed, in the absence of evidence to the contrary, where an undertaking has a market share persistently above 50 percent. Additionally, the OFT in the UK considers it unlikely that an undertaking will be individually dominant if its market share of the relevant market is below 40 percent. OFT further considers that dominance could be established below this figure if there are other relevant factors (such as weak position of competitors and high entry barriers), which provide strong evidence of dominance. See UK Office of Fair Trading, (2004b), ¶ 2.12.

73 See Ofgem (2004), at ¶ 3.20

74 *Ibid.*, at ¶ 3.25

guidelines are provided in order to asses whether a dominant incumbent is engaging in exploitative practices.

Finally, Ofgem adopts an *ex post* conduct-and-impact approach to mitigate abuses of market power in electricity markets when it claims that "*an investigation will focus on the commercial conduct of the relevant undertaking(s) and on the effects on customers of the conduct or agreements entered into by undertakings.*"[75] [emphasis added]

Ofgem's guidelines are based on similar guidance from the OFT, which is the principal competition authority in the UK. If a market participant is found to have infringed UK or EC competition law, Ofgem has a range of remedies available to it including: (i) issuing an order to stop the behavior, and (ii) imposing a financial penalty of up to 10 percent of the businesses' world-wide "turnover" (*i.e.*, total revenues). To address structural problems in power markets, Ofgem also can require generators to divest some of their assets, which it has done on one occasion. All decisions about enforcement action in the electricity markets are made by Ofgem staff, using power delegated to them by GEMA.

3. Screens/Triggers for Market Power Mitigation

The generation market in GB currently is considered to be relatively unconcentrated and relatively competitive. A recent report commissioned by the European Commission estimated market concentration measures on an hourly basis over the 2003-2005 period and concluded that the two largest generators in GB accounted for about 32 percent of the total available installed capacity.[76] The HHI for the GB market was about 1,068.[77] In addition, the report shows that only in very few hours (1 hour in 2004 and 6 hours in 2005) is any one large company pivotal in the overall market.

There currently are no *ex ante* mechanisms, such as price caps, in place to prevent the exercise of market power by GB generators; market power mitigation relies exclusively on *ex post* enforcement actions. The exercise of market power by electricity generators is controlled only by the standard framework of the UK's antitrust law.

Ofgem has a market surveillance team which monitors market prices (electricity and gas) on a daily basis. In addition, Ofgem investigates unusual episodes (for example, price spikes or periods of low reserve margin). Ofgem further conducts investigations of companies that it believes may be acting anti-competitively or breaching consumer protection law.[78] Any evidence of such behavior is reviewed by Ofgem to reach a decision and, if necessary, undertake

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75 *Ibid.*, at ¶ 3.24.

76 London Economics in association with Global Energy Decisions (2007).

77 Similar figures were obtained when controlling market concentration measure by long-term contracts and reserve commitments. The joint market share of the two largest generators was estimated to be about 31 percent and the HHI became slightly larger at 1,072.

78 In practice, Ofgem tends to rely on informal routes for obtaining information from the companies (mainly through publicly- or commercially-available data). However, it also has powers under the electricity-sector legislation to obtain information that is not otherwise published (for example, the hour-by-hour output of individual power stations, and bidding behavior).

enforcement actions. Third-parties can trigger an investigation into possible market power abuse by making a complaint to Ofgem.

Ofgem has argued in the past that electricity generation is special in a number of ways that make the *ex ante* mitigation of market power particularly important and difficult, and that, as a result, *ex post* mitigation through application of general antitrust law is insufficient. For example, it has noted that even generators with relatively small overall market shares may be able to exercise market power for short periods.[79] There are no 'special' rules designed to deal with such issues, although Ofgem has indicated that it would take such factors into account in its economic analysis of a case of possible abuse of dominance within the standard legal framework. However, Ofgem has rarely used its antitrust powers to obtain information or to sanction behavior in the wholesale electricity market, particularly since NETA was implemented.

Ofgem has attempted, unsuccessfully, to add market power provisions to the licensing conditions placed on electricity market participants. In 2000, Ofgem attempted to add several "market abuse" conditions to the licenses of the seven largest generators in England and Wales. Market abuse was defined as acts that (i) prejudice the efficient and economical operation of the transmission system; (ii) limit generation capacity availability in such ways as to materially increase wholesale electricity prices; and (iii) pursue discriminatory pricing policies by determining wholesale prices that differ unduly between times when market demand and cost conditions are similar.[80] A breach of these conditions by a licensee would have triggered an investigation by Ofgem and the possible imposition of the financial penalties cited above. However, two generators complained to the Competition Commission and succeeded in having these conditions removed from their licenses and those of the other affected generators.

In 2001, Ofgem sought to add similar license conditions (the so-called Market Abuse License Condition or MALC) which would have prohibited generators from: (i) taking any actions that would compromise the operation or efficient balancing of the bulk-power transmission system; and (ii) withholding their capacity without reasonable cause.[81] The latter condition would have applied both to the physical withholding of capacity in service and the closure or mothballing of capacity that would be economic to operate. However, discussion over these licensing conditions stalled and the conditions were never implemented. In the view of some economists, the proposed licensing conditions were rejected in large part because they never found a satisfactory way to distinguish acceptable levels of unilaterally exercised market power from a so-called "abuse of market power."[82] As a result, today's licenses do not have any conditions that specify abusive market practices, although this issue reappears periodically when prices in the UK begin to rise.

Under the MALC guidelines, a license-holder was regarded as having a position of "substantial market power" if it had the ability to provoke a "substantial change in wholesale electricity

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79 "The combination of inelastic supply and demand can provide significantly enhanced opportunities for the exploitation of market power, enabling parties with relatively low market shares to affect prices" from Ofgem (2004).

80 See Ofgem (2000), p. 49.

81 See Ofgem (2001a), p. 1.

82 See Wolak (2004), p. 11.

prices." Both the first and second set of proposed MALC guidelines stated that a substantial change in wholesale electricity prices would be a change of:

(i) 5 percent or more for a cumulative duration of more than 30 days (1,440 half-hours) in any one year; or

(ii) 15 percent over 480 half-hours in any one year (ten days in total); or

(iii) 45 percent over 160 half-hours in any one year.

According to Ofgem, if defined in terms of the quantum of the effect on revenues, the equivalent implicit relevant price trigger is about £30 million (or about $60 million).[83]

With respect to the ancillary services market, the SO has an implicit responsibility and role in preventing the exercise of market power. The SO is the sole procurer of ancillary services (*e.g.*, spinning reserve and black-start), and its license requires it to procure these services efficiently and at least cost. More importantly, the SO faces an incentive mechanism, such that Ofgem allows the SO to keep a proportion of the savings (20 percent for year 2007) if it can procure ancillary services at less than a pre-set target level (and imposes a penalty payment if costs are above the pre-defined target).[84] Therefore, the SO may have a keen interest in reporting abusive practices in the market, as such practices will cause it to lose money. The SO also has the equivalent of 'must run' contracts, to enable it to deal with local transmission constraints and voltage support issues in the GB market. Note, however, that the prices for these contracts are negotiated bilaterally, rather than set according to a regulated, cost-based methodology. So far there have been no published incidents where generators have refused to sign must-run contracts on terms that were deemed reasonable by the SO.

4. Types of Mitigation Used

The privatization of electricity generation in England and Wales in 1990 was accompanied by the creation of a mandatory, centralized power pool and the divestiture of the formerly state-owned generation sector into two companies. During the 1990s, the Office of Electricity Regulation (known as Offer, and predecessor to Ofgem) and many economists concluded that the two largest generators in England and Wales—National Power and Power Gen—were exercising market power. For example, as early as 1991 Offer issued a report stating that "There is no doubt that the two major generators have recently been able to increase Pool Prices

83 According to UK Competition Commission Report, (2001) at p. 198, in 1999/2000 total energy payments into the Pool amounted to about £6.9 billion, or around £575 million a month. If total generation Pool revenues were £600 million over 30 days and the price threshold for that cumulative duration time period is 5 percent, the associated increase in total revenues for one episode of behaviour would thus amount to approximately £30 million.

84 On April 2006, the SO rejected Ofgem's proposed System Operator incentive scheme for the period 2006/07. As a result SO's external system operator costs for the period April 2006/March 2007 were regulated by Ofgem using existing licence powers. According to Ofgem, "previous incentive schemes, have been very successful in reducing the costs of system operation. Since the introduction of NETA in 2001 the incentive scheme target costs would have been reduced by around £70million (or about $140 million.) See Ofgem (2006), at p. 11.

significantly."[85] Offer issued subsequent reports throughout the 1990s, all of which concluded that the dominant generating companies were exercising market power. In addition, several studies conducted by academics and consultants over this period found that the realized market price (know as the system marginal price, or SMP) tended to be well above the system marginal cost. Prices that reflected a significant markup above marginal cost were considered to be inconsistent with efficient market behavior, particularly since the pre-NETA market design had two-part pricing, in which generators available to supply energy or ancillary services received a capacity payment in addition to energy payments.

The British regulatory authorities were well aware that wholesale prices were not as linked to costs and underlying market conditions as one would expect in a competitive environment. Ofgem made the following comment in a May 2000 report to the Competition Commission:

> Since the introduction of the Pool in 1990, concerns about abnormal patterns of pricing, where prices do not appear to reflect changes in demand and supply and underlying market conditions, have been a recurring issue. Offer and Ofgem have conducted a number of investigations into the levels and patterns of Pool prices over the last nine years. These inquiries have highlighted some fundamental problems in the wholesale electricity market in England and Wales. These problems relate to the manipulation of price, capacity, complex rules and contractual positions by generators. When undertaken by a generator with substantial market power, such conduct can potentially have adverse effects on the public interest in a variety of ways.[86]

Offer took several actions in response to the identified market power problems. At one point, the agency required National Power and PowerGen collectively to divest 6,000 MW of generation to a new company, Eastern Group. In addition, Offer imposed an annual average price cap during two years in the mid-1990s. However, the Pool was governed by its members, with limited oversight by Offer. In theory, the Pool had a process to identify and rectify a market design defect, but the Pool's process was cumbersome and subject to delay by "adversely affected parties." Because of this, Offer had little ability to implement prospective market rule changes to address market design flaws before they caused significant harm.[87]

Offer ultimately concluded that none of these mitigation actions were fully successful.[88] As a result, in October 1997, the Minister for Science, Energy and Industry invited Offer to consider how the electricity trading arrangements might be revised. Finally, in October 1998,[89] the UK Government decided to restructure the mandatory pool in favor of the NETA market design that,

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[85] See Offer (1991).

[86] See Ofgem (2000), p. 11.

[87] See Wolak (2004), p. 5.

[88] For the period 1991 to 1999 Offer and Ofgem launched a number of investigations into the levels and patterns of prices in the UK market and found that certain conduct by the two dominant generators represented an abuse of the companies' dominant market position. Offer investigations found that the increase in wholesale prices, and the systematic pattern of substitution between the system marginal price in the pool and capacity payments, reflected an unacceptable extent of market power. See UK Competition Commission (2001) at Chapter 8 for an extensive discussion on the pool price investigations opened by Offer and Ofgem during the period 1991 to 1999.

[89] See UK Department of Trade and Industry (DTI) (1998).

as noted above, features bilateral trading and the absence of a centralized pool (*i.e.*, a market structure in which the SO does not administer an energy market or set spot energy prices on either a day-ahead or real-time basis). Market performance has improved considerably with significant reductions in market prices since NETA was implemented.[90]

The experience of GB's electricity markets provides a clear example of how changes in market design or structure can affect the nature of the market power mitigation regime needed to ensure efficient market behavior and, specifically, the need for activist intervention. Also, it raises the question of whether less complicated market designs require less complicated forms of market monitoring and market power mitigation. Not surprisingly, there has been extensive discussion and analysis as to whether changes in the concentration of GB's electricity markets (mainly through divestment requirements and diversification of ownership requirements) or changes in the trading system (the introduction of NETA) deserve the major credit for the reduced market power observed in the current GB wholesale power market. Two main advocates of the theory that changes to market structure alone deserve all the credit for the vibrant competitive wholesale market in the UK are Bower and Newbery.[91] By contrast, Ofgem maintains that the change to NETA was pivotal to explain the reduction in wholesale prices in the GB market.[92] An intermediate position is taken by Fabra and Toro (2003) and Evans and Green (2005) who maintain that a combination of market structure and market redesign have both played an important role in creating a competitive market in the UK.[93] Thus, there is no consensus as to which actions deserve the primary credit for transforming the GB wholesale power market from one suffering frequent market power abuse to one that is arguably yielding competitive prices.

B. NORD POOL

1. Market Overview

The Nord Pool power exchange market is a voluntary, energy-only market that consists of both a financial market (Nord Pool ASA) and a physical market (Nord Pool Spot AS, which has a physical day-ahead market, *Elspot*, in the Nordic countries and an intra-day market, *Elbas* in Finland, Sweden and Eastern Denmark). The Nord Pool spot exchange, the market for physical delivery of power, accounted for more than 42 percent of the total electricity consumption in the Nordic countries in 2004. The remaining power is traded bilaterally, usually under long-term contracts. A separate real-time balancing mechanism also exists within Nord Pool.

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90 Ofgem reports that, over of the course of first year of NETA, baseload electricity prices fell by 20 percent, and prices at peak times by 27 percent. Spot prices also showed similar declines, with prices down by 32 percent over the same period. Overall, they estimate that wholesale electricity prices fell by around 40 percent in real terms from the time that the reforms to the trading arrangements were proposed in 1998 until 2001/2002. They attribute the falls to NETA, alongside other factors such as a large margin of capacity over demand and increased competition in generation ownership. See Ofgem (2002).

91 See Bower (2002) and Newbery (2004).

92 See for instance, Ofgem (2001b).

93 See Fabra and Toro (2003), and Evans and Green (2005).

While Nord Pool does not have an explicit capacity requirement, the transmission system operators (TSOs) in each of the member countries maintain operating reserves (including both generation and demand response).[94] In contrast to most U.S. markets, which are dominated by thermal generation, a large percentage of energy sold through Nord Pool comes from hydro units (around 60 percent of the annual generation in a year with normal precipitation). The transmission companies in the Nordic countries are generally owned by the national government. Three of the TSOs (Energinet.dk in Denmark, Statnett in Norway and Svenska Kraftnät in Sweden) are fully state-owned, while the fourth (Fingrid in Finland) has mixed private and state ownership (12 percent owned by the State of Finland).

Ownership of generation companies is mixed. The largest generation companies in both Norway and Sweden—Statkraft and Vattenfall—-are state-owned. The largest generation companies in Finland (Fortum) and Denmark (DONG Energy) have a mix of private and state ownership. However, in both cases, the majority of the shares are owned by the national government. The Finnish government has a 51.1 percent stake in Fortum, while the Danish government owns about 73 percent of DONG Energy.

2. Market Power Mitigation Authorities

Originally, most market monitoring in the Nordic countries was performed by the national regulatory authorities of the member countries. However, at end of 2000, Nord Pool decided to strengthen its market surveillance and did so by establishing an independent Market Surveillance department responsible for monitoring the Nordic Power Exchange's physical and financial markets. Nord Pool ASA and Nord Pool Spot AS share this responsibility, although they have decided that Nord Pool ASA will actually perform market-monitoring activities for both the physical and financial markets. Nord Pool ASA has established a separate market surveillance department specifically for this task. This surveillance extends only to the spot market—bilateral trading is not supervised by the Norwegian ASA or the Nord Pool exchange.

The main objective of the market surveillance department is to monitor trading, clearing, and settlement of Nord Pool's physical and financial markets to ensure that these activities comply with the Norwegian Energy Act, the Exchange Act, the Securities Trading Act, and the Nord Pool market conduct rules.[95] The conduct rules describe the requirements on market participants when making trades and settling transactions. In particular, these rules govern the disclosure of price-relevant information, the misuse of insider information, market manipulation, and reporting requirement.

Market surveillance is responsible for ensuring that market participants do not misuse any *inside information* (information regarding incidental or planned limitations related to production, consumption and transmission facilities within or directly connected to the Nordic electricity area that is likely to impact prices) by entering into exchange trading while holding specific types of non-public information that is considered to have an influence on market prices.

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94 For instance, in Sweden the system operator is required to hold up to 2,000 MW of generation or demand response maintained through agreements with generators and customers. The system operator is required to pay a 'capacity fee' as consideration for these agreements (System Operator Capacity Requirement).

95 Available at http://www.nordpool.com under "Regulation and Compliance" link.

The market surveillance department also investigates and gathers information related to suspected breaches of the other laws and regulations identified above.

3. Screens/Triggers for Market Power Mitigation

Nord Pool applies only light-handed regulation with respect to physical electricity products. The Nord Pool mitigation approach emphasizes structural solutions as opposed to behavioral mitigation measures. There are no price caps applied to the energy market. The actual monitoring of the day-ahead physical energy market is generally designed to react to observed market abuses, with Nord Pool having the ability to fine participants for exercises of market power and acts of market manipulation. Structural measures, such as the reduction of barriers to entry and the promotion of regional integration, are two approaches that have been used by the Nordic Regulatory Authorities in Nord Pool to address market power.

Market participants in Nord Pool are not allowed to engage in so-called "market manipulation" (both in the physical and financial markets), as defined in the Nord Pool Rulebook. According to the *Market Conduct Rules*, market manipulation means: (i) transactions, orders or other actions giving false or misleading signal as a price, demand, or supply for a financial instrument; and (ii) giving false or misleading information through media, including internet, or in any other way.[96] However, there are no specific references in the Market Conduct Rules to a specific prohibition of anti-competitive practices such as withholding capacity (physical or economic) or transmission manipulation. Similarly, the Market Conduct Rules do not include any discussion on abuse of market power practices in the Nord Pool markets.

4. Types of Mitigation Used

Consistent with the preference for structural solutions, the Nordic regulatory authorities have imposed specific measures to encourage competition and promote entry within Nord Pool, including the expansion of the transmission system, abolition of border transmission tariffs, and institution of homogeneous market rules across the countries comprising Nord Pool. By facilitating electricity trading, these actions have effectively expanded the geographic market over which suppliers compete within Nord Pool.

Nord Pool appears to rely mainly on *ex post* enforcement mechanisms, where its markets are monitored for potential abuses that are addressed after-the-fact through an investigative process and fines. Financial electricity products, such as options, futures, and contracts for differences, are monitored to protect against market manipulation. Also, as mentioned previously, the release of pertinent market information is regulated to support market liquidity and efficient price formation. The actual monitoring of the day-ahead physical energy market reflects a similar philosophy.

The duty to disclose certain types of information is viewed by the Nordic authorities as an important tool in mitigating against market power abuse and market manipulation. These

[96] For a more extensive definition, see "Market Conduct Rules" at http://www.nordpool.no/products/clearing/rulebook/Marketconductrules.pdf.

duties include: (i) a requirement that participants of the financial markets submit a report on all non-exchange trades which the market participant is involved within 15 minutes; and (ii) a requirement that participants in both the financial and physical markets disclose to Nord Pool all "inside" information (information which is likely to impact prices about incidental or planned limitations related to production, consumption and transmission facilities within or directly connected to the Nordic electricity area).

5. Market Performance

The Nord Pool wholesale market is generally considered one of the most liquid power markets in the world, and is also considered to be competitive. Several independent statistical studies have rejected the presumption of market power in Nord Pool.[97] Nevertheless, since 1992, there have been numerous allegations of market power when prices have peaked. However none of the claims have been substantiated: dry weather conditions seem to adequately explain the high prices.[98] For example, there was an episode in 2002/03, when daily spot prices reached about US$150/MWh, two to three times the normal level for the time of year.[99] There were accusations of market power abuse, but it seems that most of the high prices could be explained by the relatively low reservoir levels.

The Finish Competition Authorities initially found anticompetitive behavior associated with excessive pricing practices for electricity transmission and district heat prices and cross subsidization between the two branches of business in two cases: Kuopion Energia in year 2000 and Helsingin Energia in year 1999. The Finnish Competition Council overruled the findings by the Finnish Competition Authority and concluded that companies were not guilty of abusing a dominant position regarding the pricing of electricity and distant heating. The Council reached this conclusion after analyzing the profits and sales prices of the energy companies. Furthermore, the Council stated that the competition authorities "should only directly intervene with pricing in cases where the preferred methods have been shown to be inadequate or when the company's pricing is *manifestly* unfair."[100]

Furthermore, in 2003 the Danish Competition Authorities investigated the behavior on the electricity spot markets in 2000 and 2001 of the two major Danish power generators, Elsam (West Denmark) and E2 (East Denmark). The Danish Authorities investigated intermittent episodes of price peaks that were observed in Eastern Denmark.[101] The basic question was whether the peaks could be explained as normal fluctuations in a competitive market or whether it should be seen as a consequence of abuse of a dominant position. No final decision was taken since the Competition Council entered a settlement with the companies. Møllgaard and Nielsen (2003) analyzed the behavior of these two firms for the period December 2001 to October 2002

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[97] See for instance, Hjalmarsson (2000), for an analysis of market power in the Nord Pool for the period 1996 through April 1999. Similar conclusions are also achieved by Vassilopoulos (2003) in a statistical study covering the period January 1997 to April 2003.

[98] See von der Fehr and Harbord (1998), p. 16.

[99] For further discussion, see von der Fehr, Amundsen, and Bergman (2005), p. 73.

[100] See Finnish Competition Authority (2002).

[101] See Danish Competition Authority (2003).

and concluded that prices were excessive.[102] The authors suggest that two factors might have limited the ability of the Danish Competition Authorities to prove market power abuses by Elsam and E2: (i) the abuse is not continuous or uninterrupted during the sample period, but is temporally transitory and irregularly intermittent; and (ii) at the time in which the investigation took place, it has not yet happened in EU practice that a company has been charged with setting unreasonably high prices. Copenhagen Economics (2002) reached similar conclusions when, in the context of the application to EU competition law to the electricity industry, it stated:[103]

> ...there is a complete absence of cases where the Commission ex post has challenged suspected abusive behavior from a company with a dominant position on the market. Most of the cases in the electricity sector are cases dealing with the ex ante approval of an agreement or a merger between companies that have been notified in advance by the companies themselves.
>
> The complete absence of cases where the competition law has been used ex post to challenge abusive behavior from a company with a dominant position, in particular excessive pricing or cross-subsidization, may demonstrate the inherent problems in using competition law to challenge abusive behavior in the electricity sector.

C. AUSTRALIA

1. Market Overview

In December 1998, the National Electricity Market (NEM) began operating in much of Australia as a wholesale market for the supply of electricity to retailers and end-users. The NEM initially included Queensland, New South Wales, the Australian Capital Territory, Victoria, and South Australia, with Tasmania joining in 2005. Today, NEM serves all of Australia except for Western Australia and the Northern Territories. Operations currently are based in six interconnected regions that largely follow State boundaries.

The NEM pool is a mandatory, energy-only centralized spot market. Generators cannot contract directly with customers for the physical delivery of electricity and must trade through the National Electricity Market Management Company (NEMMCO), the market operator. NEMMCO was established in May 1996 to implement, administer, and operate the wholesale NEM, and to manage the security of the power system. Thus, NEMMCO, much like U.S. RTOs, has the dual role of Market Operator and System Operator. NEMMCO is owned by the six jurisdictions who are members of the NEM.

Pool market participants can buy or sell ancillary services as well as energy. There is no capacity market or mandatory level of reserve margin—decisions on new generation investments and supply adequacy are left entirely to market participants. However, there is a short term minimum reserve margin requirement, which is used to trigger limited intervention powers given to NEMMCO. The current standard for reliability is that there should be sufficient generation

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[102] See Møllgaard and Nielsen (2004).
[103] See Copenhagen Economics (2002).

and bulk transmission capacity so that, over the long term, no more than 0.002 percent of the annual energy of consumers in any region is at risk of not being supplied. Each region in the NEM Pool must fulfill this minimum reserve level criterion. NEMMCO may enter into reserve contracts for the provision of reserve services to ensure that the reliability of supply in a region meets the reliability standard.

Generators are allowed to rebid their capacity commitment in response to load changes and other factors, up to the start of any 5 minute dispatch period. There are no limits on the number and magnitude of rebids which can be made. In addition, generators are under no specific obligation to offer their capacity to the market, to start specific units at the request of NEMMCo, or to bid power at a price pegged to their actual marginal cost. Electricity is generated by a mix of public and privately owned businesses in NEM. In all states except Victoria and South Australia generation assets are predominately government owned.[104]

2. Market Power Authorities

The Trade Practices Act 1974 (TPA 1974) is the key antitrust law in Australia. The Act provides for protection of consumers, prevents some restrictive trade practices, and also gives some rights for private action.[105] Restrictive trade practices, contained in Part IV of the TPA 1974, include, among others, the "misuse of market power".[106] A market participant with substantial market

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104 The Victorian and South Australian electricity generation sector is fully privatized. The level of ownership concentration in South Australia is particularly high (the two largest generators, NRG Flinders and TRUenergy have a market share of over 67 percent.) The market concentration in Victoria is slightly lower than in South Australia. The market share of the two largest generators in Victoria (Loy Yang Power and TRUenergy) is about 54 percent. In New South Wales, the government owns the three largest generators (Macquarie Generation, Delta and Eraring), which account for over 80 percent of the market for generation capacity in that state. In Queensland, there is a mix of public and private companies, but three government owned generators (Tarong, Stanwell and CS Energy) collectively account for the majority of the generator market (around 70 percent). For a more extensive discussion on the degree of market concentration in the NEM in Australia see Energy Reform Implementation Group (2007), pp. 4-6.

105 Individuals or corporations can bring private actions in Federal Court for contravention of restrictive trade practices provisions (contained in Part IV of the TPA 1974), and in any court of competent jurisdiction for contravention of the consumer protection provisions (contained in Division 1, Part V of the TPA 1974.) Remedies include (i) damages, (ii) injunction, (iii) ancillary orders in favor of persons who suffer loss or damage, including return of property, return of money, specific performance, rescission or variation of contracts, and provision of repairs or spare parts, and (iv) divestiture of shares in relation to an unlawful merger.

106 Other prohibited practices are:
(i) *Agreements adversely affecting competition*—These are prohibited if they have the purpose or effect of substantially lessening competition. Outright prohibitions apply to: (a.1) most price agreements; and (a.2) agreements containing exclusionary provisions, commonly known as primary boycotts (*i.e.* collective refusals to deal with another party). Certain joint pricing agreements between competitors may be authorized if significant benefits to the public can be demonstrated.
(ii) *Exclusive dealing*—It is unlawful for a supplier to attempt directly or indirectly to interfere with the freedom of buyers to purchase from other suppliers (*e.g.*, by imposing territorial or customer restrictions on the buyer). Similarly, buyers cannot use an exclusive arrangement to restrict suppliers from selling to other prospective buyers. However, most forms of exclusive dealing are prohibited only if they have the purpose or likely effect of substantially lessening competition.

power in a particular market is prohibited from taking advantage of such power for one or more proscribed purposes; namely, to eliminate or damage an actual or potential competitor, to prevent a person from entering a market, or to deter or prevent a person from engaging in competitive conduct.

The TPA 1974 does not prohibit the "abuse of dominant position" in Australia; rather, the provision corresponding to abuse of dominance in this Act is "*misuse of market power*." The TPA 1974 provides that firms having a "substantial degree of power in the market" cannot take advantage of such power for certain specified purposes. Market power in Australia is not defined in the TPA 1974, but it has been defined by various Australian courts and tribunals in a number of decisions. Factors such as the firm's ability to raise prices and to act independently of competition are key elements in determining whether a firm has "market power".[107] However, to breach Part IV of the TPA 1974, a firm must take advantage of its market power for the purpose of eliminating or substantially damaging a competitor, preventing or deterring a person from entering a market, or engaging in anti-competitive conduct in that or any other market. Thus, in theory, while exclusionary conduct is an offense against antitrust law in Australia, excessive pricing generally does not breach Australian law.[108]

One of the distinctive features of the Australian regulatory model is that the Australian Competition and Consumer Commission (ACCC) is both the national electricity regulator and the competition authority. This is due to the fact that the Australian Energy Regulator (AER) in Australia is a constituent part of the ACCC. The ACCC can bring a civil action in Federal Court seeking the imposition of pecuniary penalties—up to AUS$10 million (or US$7.8 million) for a corporation and up to AUS$500,000 (or US$390,000) for an individual—or can seek injunctions or ancillary, punitive or non-punitive orders, or, in relation to a merger, divestiture. The ACCC also may seek compensation for third parties. Individuals and corporations can, through private action, seek various remedies from the Federal Court for breaches of the restrictive trade practices provisions of Part IV of the Act. The remedies include injunction (except for mergers), damages, ancillary orders, or, in relation to a merger, divestiture.[109]

(iii) *Resale price maintenance*—This involves setting a price below which resellers cannot sell (or advertise). However, this practice may be authorized provided that it can be shown to deliver a public benefit.

(iv) *Mergers and acquisitions* that would result in a substantial lessening of competition.

107 For instance, in *Queensland Wire Industries Pty Ltd v The Broken Hill Proprietary Co Ltd* (1989) market power is defined as the ability 'to raise prices above supply cost without rivals taking away customers in due time, supply cost being the minimum cost an efficient firm would incur in producing the product'. Whereas other jurisdictions define explicit market share thresholds to define dominance, no market-share threshold has been specified in Australia.

108 An exception, of course, is enforcement action against cartels. The ACCC has in place an immunity policy, which grants immunity from prosecution to the first party in a cartel that provides information to the ACCC (and therefore allows it to prosecute). This policy facilitates the gathering of evidence about price-fixing behavior.

109 Beginning in January 2007, there are significant increases to the penalties for breaches of the competition law provisions contained in Part IV of the TPA. The penalty for a company found to be in breach will now be the greater of $10 million, or 3 times the benefit that the company has obtained directly or indirectly as a result of the breach, as determined by a Court.

3. Screens/Triggers for Market Power Mitigation

The NEM has two primary mechanisms to alleviate market power concerns in the wholesale electricity market: (1) a price cap in the spot market and (2) the right by NEMMCO to intervene in the market if reserves are below the so-called "reliability standard." In addition, the NEM follows a data release policy of full disclosure of all bids (subject to a one-day lag), schedules, and output levels as a way to increase market transparency and promote market competition.

The default price cap in any given hour is equal to the Value of Lost Load (VoLL), which is currently set at AUS$10,000 per MWh (approx. US$7,750 per MWh). This cap initially was set at AUS$5,000 per MWh but was raised to AUS$10,000 per MWh in 2002. A more restrictive price cap is imposed when the sum of prices in any seven-day period reaches the cumulative price threshold (CPT) of AUS$150,000 (approx. US$116,260).[110] Once the seven day CPT is reached, a system of administered prices is triggered. The *administered price cap* is AUS$100/MWh (or US$78/MWh) between 7:00 a.m. and 11:00 p.m. on business days and AUS$50/MWh (or US$39/MWh) at other times. The administered pricing caps, however, are effective only until the end of the trading day on which the rolling seven-day cumulative summation of uncapped prices falls below the CPT. If the CPT is not reached, the price cap reverts back to the assumed VoLL.

Analogously, the ancillary services market is capped if the sum of the ancillary service price in any seven-day period reaches six times the CPT of AUS$900,000 (approx. US$697,590). The administered price caps for ancillary services are identical to the ones applied in the energy market.

The Market Operator also has the right to intervene in the market if reserves fall below the reliability standard. NEMMCO can intervene in the market in two ways: (i) by acting as a "reserve trader" and purchasing ahead of time the additional reserve generation and/or demand side reductions to ensure that the reliability of supply in a region meets the reliability standard; and/or (ii) by requiring generators to provide additional supply at the actual time of dispatch to meet those minimum reserve levels.

4. Market Performance

Since the creation of the NEM in Australia, several studies have found the existence of market power in the wholesale market. Market power practices exhibited are:[111] (i) physical withholding; (ii) economic withholding; (iii) manipulation of bidding and rebidding strategies; and (iv) manipulation of transmission capacity.[112]

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110 This is equivalent to an average spot price of AUS$450/MWh (or about US$349/MWh) for 1 week.

111 See Bardak Ventures Pty Ltd. (2005) for an extensive discussion of these manipulative practices in Australia. Other relevant studies supporting the same conclusions are Hu, Grozev, and Batten (2005), pp. 2075-2086 and Short, *et al.* (2001), p. 81.

112 Either creating artificial constraints to prevent competitive responses from market participants in adjacent regions, or alternatively, artificially releasing transmission constraints if it allows connection to a higher priced region.

The Bardak Ventures Report (2005) concludes that the change in the default price cap from AUS$5,000/MWh to AUS$10,000/MWh in 2002 led to generators "roughly halving the number of price spikes but doubling the value of them, achieving about the same level of annual revenue. This increased the level of price volatility and risk significantly."[113] The ACCC also has analyzed in detail the actions of market participants and the exercise of market power in Australia.[114] As noted by ACCC Commissioner Ed Willet, episodes of significant market power arise periodically in the market:[115]

> It is widely acknowledged that generators, at times, have the incentive and ability to withhold capacity from the spot market in order to cause high prices. Generators can exercise market power by 'withholding' generation capacity in peak periods and spiking prices. It only takes a few such events to have a large impact in overall prices.

The ACCC seems to accept the notion that some degree of market power needs to be exercised by generators because, unless they can push their wholesale market revenues above short-run marginal costs, they may not be able to recover their fixed costs. If this is the case, long-run competition may suffer as generators exit the market, or an insufficient amount of new generation capacity comes onto the market. The ACCC has been explicit that short-run marginal cost (SRMC) does not constitute a reasonable benchmark for competitive prices in Australia:[116]

> The competitive level in the electricity market is not necessarily SRMC, as prices that only cover marginal costs could lead to under investment because of limited return to cover fixed costs especially where economies of scale exist. SRMC pricing is unlikely to be sustainable or desirable in this context.

This concern about insufficient investment incentives for new generation results in an apparently increased tolerance for price spikes, relative to other jurisdictions. This attitude may stem from the belief that, as an energy-only market, generation companies must bid above their marginal costs or receive scarcity rents (under appropriate market conditions) in order to achieve a satisfactory level of annual revenue. As the ACCC notes, "in practice it may be necessary to tolerate some short-term price spikes in order to encourage efficient investment."[117] Furthermore, Professor Allan Fels, Chairman of the ACCC in 2002, maintained that:[118]

> The existing market structure means that generators have market power at times. Since the NEM started we have seen many "price spikes." Price spikes are an intrinsic part of the market, and are necessary to provide price signals for new investment, particularly for peaking generation.

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[113] See Bardak Ventures Pty Ltd. (2005) at section 5.1.

[114] See Biggar (2004).

[115] See Willett (2005).

[116] See ACCC (2002), p. 31, n. 51.

[117] *Ibid.*, p. 30.

[118] See Fels (2002). The Independent Pricing and Regulatory Tribunal of New South Wales in Australia (2002) shared a similar opinion in an Interim Report in 2002 when it claims: "*Price spikes are a natural and necessary feature of competitive electricity markets*."

The ACCC may thus be sacrificing the achievement of short-run efficiencies *(i.e.*, marginal cost pricing) in favor of long-run competition being fostered by entry of new generation and added transmission capacity. That is, the ACCC may be giving priority to promoting competition in the long run rather than the short run. As a result, the Australian regulatory authorities appear to view the entry of new generation as a key element of mitigating the abuse of market power:[119]

> The Commission is of the view that <u>some generators in the NEM possess substantial market power.</u> Further, the Commission recognises that under some circumstances, the <u>current market rules enable such generators to take advantage of that power in their pursuit of profits</u>. <u>To date such behaviour has fallen within the market rules</u>.
>
> …Nevertheless, the Commission concedes there is evidence of behaviour that appears to have no economic justification and which has a greater than proportional detrimental impact on competitive market outcomes. The consultants' reports show that the dollar increase in price that is due to behaviour that may represent an exercise of market power is not insignificant in the spot market.
>
> …However, some consultants say that <u>the ability to exercise market power is decreasing due to increased competition</u> and a decrease in constraints in the NEM. <u>This is attributable to increased competition through new entrants and</u> the use of soft constraints on interconnectors. [emphasis added; footnotes omitted]

Nevertheless, the Bardak Ventures Report (2005) concludes that generators appear to have succeeded in achieving annual revenue significantly above Long Run Marginal Costs (LRMC) in four of the five years of NEM operation.[120] Similar conclusions also were reached by other independent studies.[121]

D. RELEVANCE OF INTERNATIONAL EXPERIENCE TO THE MITIGATION OF MARKET POWER IN U.S. ELECTRICITY MARKETS

Table 3 below summarizes the market design and mitigation approaches in the three international wholesale markets described in this section.

We find the experience with market performance and market power mitigation in three international markets offers only limited insights for the mitigation of market power in U.S. electricity markets. Since few examples exist of *ex ante* market power mitigation in the international electricity markets that we examined, it appears that some degree of protection and enforcement against market power abuse is achieved through various alternative means. Based upon our review, these means include: (1) *ex post* enforcement through local antitrust laws; (2) the regulator's ability to change market rules quickly if abuses are detected; (3) partial government ownership of generation and transmission facilities; (4) significant transmission

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[119] See ACCC, "Changes to Bidding and Rebidding Rules", July 2002; cited in Bardak Ventures Pty Ltd. (2005), p. 17.

[120] Based on the analysis in this report, the average markup above LRMC is estimated to have been 21 percent. See Bardak Ventures Pty Ltd. (2005), p. 75.

[121] See for instance ACIL Tasman (2005).

investments; (5) increased use of long-term contracting; and (6) regulators' ability to impose structural remedies (*e.g.*, forced divestiture) as a measure of last resort. Some of these tools are not readily employed in U.S. power markets.

It is, however, also unclear that the observed market outcomes in international wholesale markets would be acceptable under the still evolving U.S. standards of what constitutes just and reasonable prices in a market framework.[122] Without provisions in U.S. antitrust laws to mitigate substantial price increases derived from the unilateral exercise of exploitative (rather than exclusionary) market power, or the threat of structural remedies imposed by regulatory authorities, additional mitigation measures to prevent the exercise of substantial market power appear necessary in U.S. electricity markets. This does not necessarily mean that these additional measures would have to be in the form of *ex ante* mitigation. However, unless *ex post* measures could be imposed quickly and employ remedies that act as a deterrent, sole reliance on *ex post* measures to constrain market power does not seem to be advisable for U.S. electricity markets.

In fact, the GB experience shows that, despite the presence of significant *ex post* mitigation authority, the GB regulator (Ofgem) has documented and struggled to address numerous market power abuses over the first decade of experience with a liberalized power market. Moreover, even though Ofgem ultimately was able to address market power problems with structural and market design remedies, Ofgem also has clearly stated its strong preference for *ex ante* mitigation measures (which it has been unsuccessful in implementing so far).

Given the desire of the British regulatory authorities to implement *ex ante* market power mitigation measures, as well as the recent sectoral inquiry by the European Commission into competitive conditions within EU power markets, significant market power concerns apparently remain in the European electricity sector. These concerns suggest that the current exclusive reliance on *ex post* enforcement may be insufficient to deter significant exercises of market power. Whether they ultimately lead to the increased use of *ex ante* mitigation, as used in U.S. RTO-operated markets, remains to be seen.

It is also important to recognize that the three international markets described in this section differ from most U.S. RTO markets in that they are energy-only markets without installed capacity or resource adequacy requirements. This means that energy market prices serve as the primary means for attracting the entry of additional generation or the expansion of existing generation facilities. This appears to be an important reason why policymakers in these one-part markets seem less sensitive to high prices when compared to their counterparts in two-part U.S. markets (such as PJM, NYISO, and ISO-NE).

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[122] There is much legal precedent with regard to just and reasonable prices, but it was largely established in an era of cost-based ratemaking.

Table 3

Basic Wholesale Power Market Structure in International Power Markets

	Operating Markets		
	GB	Nord Pool	Australia
General Basis for Market Power Mitigation	*Ex post* mitigation by Ofgem and through antitrust law (monitoring through Ofgem surveillance team)	*Ex post* enforcement mechanisms (monitoring through independent market surveillance department) Structural measures (*e.g.*, the reduction of barriers to entry, the promotion of regional integration) Information-disclosure requirements	*Ex ante* price caps and *Ex post* enforcement through antitrust laws (Surveillance and monitoring and special investigations of specific market events or unusual market behavior) Data release policy of full disclosure the next trading day of all bids, schedules and output levels
Settled Energy Markets	Mix of bilateral trading and short-term trading on several organized trading exchanges No centralized physical spot market. The SO runs a pay-as-bid balancing mechanism	Day-Ahead and Hour-Ahead Real-Time Balancing Market	Real-Time
Default Energy Offer Cap	None	None	AUS$10,000/MWh (approx. US$7,750/MWh) and AUS$150,000 over 7 days
Flexibility in Energy Bid Curves	n.a.	Constant each day	Can vary by hour
Installed Capacity, Reserve Margin, or Resource Adequacy Requirement	No minimum reserve margin on market participants; the SO holds reserves to maintain operational reliability	The TSOs in each of the member countries do maintain operating reserves (including both generation and demand response)	No mandatory level of reserve margin on market participants. Short term minimum reserve margin requirement for each region in NEM
Formal Capacity Market	No	No	No
Ancillary Service Markets	Yes	Yes	Yes
RMR / RSG Payments	Yes	No	No

Of the three international markets that we examined, only Australia currently has a price cap. However, there are some interesting aspects to the Australian treatment of price caps. While an hourly cap is set equal to the assumed value of lost load (a value well above U.S. price caps), there is also a much lower cap based on the 7-day average of power prices. As we discuss in the next section of our report, ERCOT already uses a similarly "tiered" prices cap and the GB regulator has attempted unsuccessfully to implement a similar approach. Such tiered approaches, which allow for short-term price spikes but less significant elevation of market prices over a prolonged period, would appear to merit broader consideration in the United States. They would allow for higher short-term price signals (consistent with scarcity conditions), while protecting consumers against more sustained elevations of market prices.

Also, our case-study international markets, particularly the GB and Australia markets, appear to rely more heavily on long-term contracting as a means of insulating consumers from price shocks and mitigating against exercises of market power. For example, the use of vesting contracts arguably facilitated the transition to more liberalized electric power markets in Australia and Great Britain. While the primary aim of these contracts may have been to reduce the risk to purchasers of privatized assets in the context of newly created retail electricity markets, some analysts suggest that hedging contracts may have played a significant role in maintaining wholesale prices close to marginal costs after the restructuring in Australia.[123] A similar conclusion was reached by Newbery (2002) in studying mitigation measures in GB electric power markets. He notes that, during the early stages of the transition period in Britain, the market was characterized by extensive use of vesting contracts. He concludes that when the "*provided contract coverage is (almost) complete, the incentive to manipulate spot markets is (almost) eliminated*."[124] Many economists studying U.S. RTO markets have argued that increased use of long-term contracting in these markets would both lessen the ability of generators to exercise market power and also reduce the reliance on administered capacity markets as a means of inducing increased generation investment.

Finally, there appears to be an emphasis in certain of our case-study markets, specifically Australia and Nord Pool, of trying to release substantial market-related information subject to a very short time lag. These information disclosures are expected to serve three main purposes: (1) to boost the liquidity of both physical and financial markets by reducing information disparities among potential market participants; (2) to achieve more efficient resource allocation decisions (*e.g.*, releases of price or bidding information may encourage lower-cost generators to expand their output); and, (3) to provoke competitive responses that reduce the profitability of attempts to exercise significant market power.

However, the disclosure of certain types of market information may have some offsetting risks. While providing information about rival bidding strategies may provoke sharper competitive responses, which may serve to lessen incentives for exercising marker power, the release of this type of information also may facilitate collusive behavior in an environment where the same players repeatedly bid against one another on a daily basis.

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[123] See Kee (2001) and Wolak (2001).
[124] See Newbery (2002).

IV. MARKET MONITORING AND MARKET POWER MITIGATION IN U.S. ELECTRICITY MARKETS

A. INTRODUCTION

This section of the report compares and contrasts PJM's market monitoring and mitigation approaches with those of the other U.S. RTOs that operate centralized energy markets and employ or plan to employ Locational Marginal Pricing (LMP) in the near future, namely: ISO New England (ISO-NE), New York ISO (NYISO), Midwest ISO (MISO), California ISO (CAISO), and the Electric Reliability Council of Texas (ERCOT).[125] All of these entities are mature RTOs that have operated some form of centralized energy market for at least five years. For CAISO and ERCOT, this section focuses on the impending market redesigns that include locational marginal pricing, as opposed to the current market structures.[126]

This section begins with an outline of each RTO's basic wholesale power market design, and then proceeds to characterize each RTO's approach to market power mitigation. The sequence of market power mitigation procedures—from the initial identification of actual or prospective market power, to daily or hourly mitigation, to *ex post* review through market monitoring—is essential for understanding differences among the RTOs. Next, we describe how the reference levels for mitigation are determined in each region. With those levels clearly defined, we proceed to compare market power mitigation techniques across RTOs for all market-based electricity products.

First, we examine mitigation of market power in energy markets. Comparison of the various RTOs' methods for preventing the economic withholding of output in energy markets highlights critical differences between the two principal market power mitigation methods: the structural approach and the conduct-and-impact approach. Second, we examine mitigation of market power in capacity markets in the three RTOs that have formal capacity markets. Third, we review market power mitigation in ancillary services markets. Lastly, we briefly describe market monitoring of other specific practices, such as physical withholding or virtual bidding.

The bibliography at the end of this report provides appropriate references for the RTO-level description of market monitoring provided in this section.

B. BASIC WHOLESALE POWER MARKET DESIGN

All market power mitigation approaches are influenced by the prevailing basic wholesale electricity market design, so an initial comparison of these designs is warranted.

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125 ERCOT is subject to the jurisdiction of the Public Utility Commission of Texas whereas the other RTOs are FERC jurisdictional. The other U.S. RTO, the Southwest Power Pool (SPP), initiated an energy imbalance market in February 2007. SPP does not, however, operate a day-ahead or day-of energy market and has no plans to do so.

126 CAISO's MRTU is slated to be implemented in April 2008 and ERCOT's planned nodal market design is slated to go live in January 2009.

All of the RTOs have a similar market design, featuring a day-ahead and real-time hourly market with two-part settlement, meaning that transactions cleared in the day-ahead (or real-time) market are settled financially at the day-ahead (or real-time) price. All of the RTOs have some form of offer cap as well as some form of revenue guarantee payments for units that cannot recover their costs in the formal markets. Most of the RTOs have some form of resource adequacy requirement; however, the existence and design of formal capacity and ancillary service markets varies substantially across the regions.

As described in Table 4, the energy market designs are quite similar across RTOs, but other design features are different. First, ERCOT is unique in that it is an energy-only market: no form of resource adequacy requirement is imposed on load-serving entities; hence suppliers receive no capacity payment to supplement their revenues from energy (and ancillary services). In order for these revenues to be sufficient for suppliers to be able to build and maintain adequate capacity and still recover their fixed costs, ERCOT allows the energy market to set “scarcity prices” with higher price caps. ERCOT’s price caps are substantially higher than those in other RTOs, and its price caps are adjustable.[127]

Second, RTOs differ in the frequency with which they permit suppliers to vary their energy bid curves within a given day. PJM and New England do not permit suppliers to vary their bid curves from hour to hour within a given day, whereas, the other RTOs do.

As Table 4 shows, there is more variety among RTOs with respect to the design of their capacity markets. The three eastern RTOs (PJM, NYISO, and ISO-NE) initially had similar capacity market designs in which load-serving entities were required to procure capacity sufficient to meet their peak load requirements, plus a specified reserve margin. This essentially implied that the demand for capacity was insensitive to the market-clearing price level, thus creating the conditions for a substantial exercise of market power in the capacity markets. The specific reserve margins were set based on the traditional one-day-in-ten-year probability standard for lost load to which the electric power industry has adhered for many years. Subsequently, each of these RTOs reformed their capacity markets, but in different ways.

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[127] ERCOT’s planned default energy offer cap is not a fixed level for an entire year, but rather can vary from a high of $3,000 per MWh to a low of $500 per MWh. The latter value is invoked if a hypothetical peaking unit's net margin (revenues from energy sales less variable costs) exceeds $175,000 per MW-year.

Table 4
Basic Wholesale Power Market Structure in U.S. RTO Markets

	Operating Markets				*Planned Market Design*	
	PJM	ISO-New England	New York ISO	Midwest ISO	California ISO (MRTU)	ERCOT (Nodal Market)
General Basis for Market Power Mitigation	Structural Tests	Conduct and Impact Tests	Conduct and Impact Tests	Structural and Conduct and Impact Tests	Structural Tests	Structural Tests
Settled Energy Markets	Day-Ahead and Real-Time	Day-Ahead and Real-Time	Day-Ahead and Real-Time	Day-Ahead and Real-Time	Day-Ahead and Real-Time	Day-Ahead and Real-Time
Default Energy Offer Cap	$1,000/MWh	$1,000/MWh	$1,000/MWh	$1,000/MWh	$500/MWh increasing to $1,000/MWh over 2 years	$3,000/MWh or $500/MWh if a new peaker's net margin for a given year exceeds $175,000/MW
Flexibility in Energy Bid Curves	Constant each day	Constant each day	Can vary by hour	Can vary by hour	Can vary by hour	Can vary by hour
Installed Capacity, Reserve Margin, or Resource Adequacy Requirement	Yes	Yes	Yes	Yes (evolving from regional/local requirements)	Yes (through CPUC)	No, only an "Energy Only" Resource Adequacy Program
Formal Capacity Market	Yes, Reliability Pricing Model	Yes, Forward Capacity Market	Yes, single price spot market for various products.	No	No	No
Ancillary Service Markets	Regulation and Synchronized reserves	Forward reserve markets for spinning and non-spinning reserves, real-time reserves, and regulation	Regulation and operating reserves	None, but regulation and contingency reserve markets planned for Spring 2008	Regulation, spinning, and non-spinning reserves.	Regulation, non-spinning, and responsive reserves
RMR / RSG Payments	Yes, but only for a small number of units	Yes	Yes	Yes	Yes	Yes

PJM's Reliability Pricing Model (RPM), which was approved by FERC in 2006 and implemented this year, establishes separate locational delivery areas within which the market price is determined on a three-year forward basis by the intersection of locally-available supply (including imports) and administratively-determined price-sensitive demand curves that are pegged to the cost of new entry and other parameters. ISO-NE also has implemented a forward capacity market (which was approved by FERC in 2006), but there are no administratively-determined capacity demand curves. In the absence of identified transmission constraints, a single forward price for all of ISO-NE is set on a 3-year forward-looking basis through a descending-clock auction, an auction format that also has been used by some electric utilities in retail-access states to procure power supply for their retail customers. However, ISO-NE will determine annually whether there is a need to establish local delivery areas, and if so will conduct simultaneous but separate descending-clock auctions to clear each area.

New York's revised locational installed capacity market is somewhat similar to PJM's RPM, in that New York has a downward-sloping capacity demand curve and zonal markets in which capacity prices can and do separate. MISO does not have an RTO-administered capacity market, but it does ensure compliance with the pre-existing reserve margin and resource adequacy requirements imposed on load-serving utilities by the constituent NERC reliability councils and state regulators. Similarly, CAISO currently is enforcing the resource adequacy requirements recently established by the California Public Utility Commission (CPUC). The CAISO is reviewing various capacity market designs but has not committed to a specific approach.

ERCOT is the exception with regard to a capacity market—as noted, there is no resource adequacy requirement placed on load-serving entities, and thus no capacity market. Instead, ERCOT has a single-price energy market, meaning a market in which generators derive all or most of their revenue from selling one product—energy.

With the exception of MISO, the RTOs currently operate spot markets for certain ancillary services that are occasionally cleared separately from the energy market, but often are optimized along with energy market dispatch. (MISO plans to add ancillary service markets by the spring of 2008.) In general, regulation and operating reserves (spinning and non-spinning) are the ancillary services procured through these markets, and other ancillary services are procured through non-market mechanisms. ISO-NE has both a real-time and a forward market for operating reserves (in addition to a real-time regulation market), and conducts two forward auctions per year to procure operating reserves to meet local reliability needs. Resources selected in the forward reserve auction are obligated to be available to produce electric energy in real time when called on by ISO-NE.

All of the RTOs also commit and dispatch generating units out of merit order because of transmission constraints or local reliability requirements within load or generation pockets. Units that frequently are dispatched out of merit order to provide energy or ancillary services (such as local voltage support) in transmission-constrained areas are commonly known as must-run generating units. In some cases, these units have high production costs and therefore make little or no money in the energy market. This, in turn, can make it difficult for these units to recover their fixed costs. The marginal cost of units committed or dispatched for reliability reasons often is not reflected in locational market clearing prices.

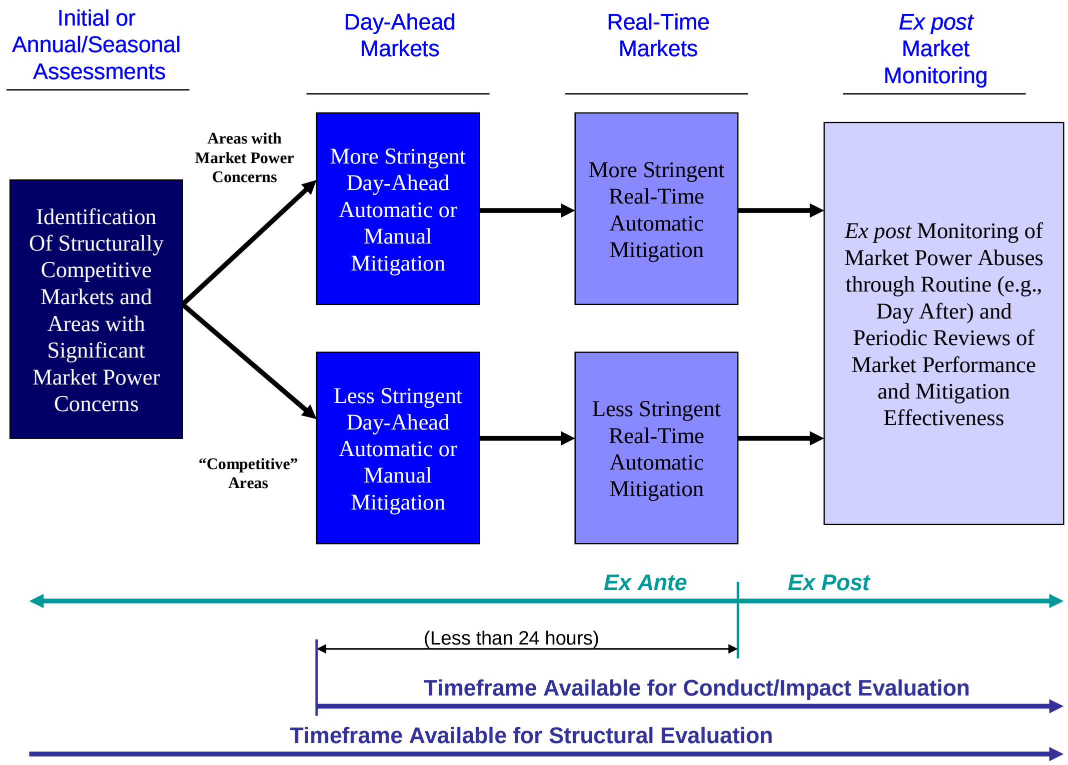
Four of the RTOs (ISO-NE, CAISO, ERCOT, and rarely, but on occasion PJM), offer cost-based Reliability Must Run (RMR) contracts to high-cost units that need to stay in operation to serve transmission-constrained areas. These contracts provide a level of compensation through fixed monthly payments that is similar to what the generation units would receive under cost-of-service ratemaking. Other RTOs, such as MISO and NYISO, do not offer cost-based RMR contracts, but do allow units frequently dispatched out of merit order to sell at a price substantially above their short-run marginal cost. For example, MISO does not have any mechanism that compensates RMR units for their fixed costs, but it does provide Revenue Sufficiency Guarantee (RSG) payments, which compensate RMR units for all of the production costs they incur, such as start-up and no-load costs, when following MISO dispatch orders. Thus, the two basic approaches used by RTOs to give RMR units a reasonable opportunity to recover their fixed costs are: (1) contracts that provide RMR fixed monthly payments; and, (2) relaxed price mitigation.

C. TYPE AND TIMING OF *EX ANTE* AND *EX POST* MARKET POWER MITIGATION PROCESSES USED BY RTOS

All of the RTO's use some form of *ex ante* mitigation in both the energy and capacity markets. However, timing considerations in the development and application of *ex ante* structural or conduct-and-impact screens are extremely important. Also there are *ex post* mechanisms used in all RTOs that effectively serve as backstops to core *ex ante* mitigation techniques. Figure 1 shows that there are significant constraints as to when some *ex ante* mitigation measures can be applied.

While most *ex ante* mitigation processes based on structural screens for market power can be performed prior to real-time and day-ahead market processes, conduct-and-impact screens cannot be performed before the actual market conduct is observed (*e.g.*, bidding into the DA or RT markets). As the figure shows, there are less than 24 hours from the time period at which conduct first becomes observable (*i.e.*, bids are submitted in the day-ahead market) to when the operating hour concludes. Any screen applied in real-time will have to be able to be performed very rapidly and repeatedly, possibly for each 5-minute dispatch interval. In the real-time market, there are generally less than 30 minutes (*i.e.*, from the time bids are submitted to the actual operating period) to perform *ex ante* conduct-and-impact screens. Even on a day-ahead basis, a time frame of only a couple hours is available if screening processes should be concluded before day-ahead markets close. Because the RTOs' real-time and day-ahead dispatch and market settlement processes are already highly complex, this limited timeframe for an *ex ante* evaluation of conduct and market impact means there are clear practical limits to the complexity of screens that can be used to run automatically on a real-time or even day-ahead basis.

Figure 1
Sequence of Market Power Mitigation Procedures



In contrast, as also shown in Figure 1, mitigation processes based on structural screens have the advantage that the screening can generally be performed ahead of observed market conduct. This is because the market structure information utilized in many structural screens will not generally change materially on an hourly or daily basis.

Once the operating hour has passed, it is of course possible to analyze market participants' conduct and associated market outcomes in greater detail – which leads to the *ex post* market monitoring routinely undertaken by the RTOs and their regulators. This *ex post* review generally involves daily, monthly, quarterly, annual, and targeted event-driven analyses of market conduct and performance to screen for the exercise of market power and inappropriate conduct that may have escaped the *ex ante* mitigation processes or that those processes were not designed to identify. Based on these *ex post* analyses, market monitoring can not only lead to proposals to adjust market rules or adjust *ex ante* mitigation processes to address the identified concerns but also may lead to requests to FERC to impose sanctions and certain retroactive actions to address and rectify the identified conduct. The *ex post* measures can also address concerns over market participants' abuse of the mitigation thresholds (*e.g.*, bidding up prices to just below the thresholds) used in the *ex ante* conduct-and-impact screens.

Table 5 summarizes how each step illustrated in Figure 1 is addressed in the various RTOs' mitigation processes.

Table 5
Detailed Sequence of Procedures for Market Power Mitigation

	Operating Markets				*Planned Market Design*	
	PJM	ISO-New England	New York ISO	Midwest ISO	California ISO (MRTU)	ERCOT (Nodal Market)
Initial or annual/seasonal identification of market power concerns in relevant product and geographic markets	1997 Joskow-Frame study concludes only "local must-run for reliability" generation poses market power concerns	Based on historical transmission patterns, identified "Designated Congestion Areas" (CT, SW CT, and NEMASS-Boston)	Identified a "Constrained Area" (New York City) subject to transmission constraints that give rise to significant local market power	Identified "Narrow Constrained Areas" (WUMS and Northern WUMS) through a structural test	Annually and eventually seasonally, use structural test to identify non-competitive transmission constraints requiring mitigation	Annually, with monthly and daily updates, use structural test to identify non-competitive transmission constraints requiring mitigation
Day-Ahead *ex ante* market power mitigation	Automatic mitigation (generally to cost + 10%) for units dispatched to relieve binding constraints,[1] unless a dynamic structual test provides an exemption	Manual mitigation of bids failing conduct and impact tests, with more stringent thresholds for Designated Congestion Areas	Automatic mitigation of bids (in New York City) failing conduct and impact tests, with more stringent thresholds for New York City	Manual mitigation of bids failing conduct and impact tests, with more stringent thresholds for Narrow Constrained Areas	Automatic mitigation of suppliers' incremental output to relieve non-competitive constraints[2]	None
Real-Time *ex ante* market power mitigation	Automatic mitigation (generally to cost + 10%) for units dispatched to relieve binding constraints,[1] unless a dynamic structual test provides an exemption	Manual mitigation of bids failing conduct and impact tests, with more stringent thresholds for Designated Congestion Areas	Automatic mitigation of bids (in New York City) failing conduct and impact tests, with more stringent thresholds for New York City	Automatic mitigation of bids failing conduct and impact tests, with more stringent thresholds for Narrow Constrained Areas	Automatic mitigation of suppliers' incremental output to relieve non-competitive constraints[2]	Automatic mitigation of suppliers' incremental output to relieve non-competitive constraints
Ex post market power mitigation	Recommends mitigation or market design changes or files complaint with FERC to impose sanctions					

Notes:
[1]: AP South, Western, Central, and Eastern interfaces exempt from mitigation.
[2]: Interzonal transmission paths not subject to market power mitigation.

We observe that RTOs employ structural and conduct-and-impact screening approaches as core elements of their market power mitigation processes. In simple terms, these approaches ultimately alter the bids of certain suppliers to a pre-defined reference level in order to prevent abuses of market power. Structural tests are used to: (i) identify geographic regions to be subject to more stringent conduct testing; (ii) identify the particular transmission constraints that will be subject to default mitigation; or, (iii) in the case of PJM, determine if suppliers can be exempt from default mitigation. Whenever a structural test is failed, bids are frequently capped at a reference level that is meant to prevent an exercise of significant market power. Alternatively, structural screens are used in certain cases to identify markets in which a more stringent conduct-and-impact mitigation processes are applied.

PJM, CAISO, and ERCOT employ a structural approach throughout the sequence of market monitoring and employ price mitigation when bids are deemed to be submitted in what is considered a non-competitive market. There is, however, important variation in the timing of structural techniques applied to energy markets. In PJM, there is automatic mitigation of bids from generating units dispatched for congestion relief unless a structural screen (the Three Jointly Pivotal Supplier or 3JPS test) is passed on a day-ahead and real-time basis. Thus, the structural screen in PJM is unique in that it is performed after bids are submitted in the day-ahead and real-time markets. In contrast, under their new market designs, ERCOT and CAISO will use their structural screens only on a periodic basis (well before bids are submitted by market participants) to identify which transmission constraints should be considered "non-competitive" and be subject to default mitigation. Table 5 also shows that CAISO automatically mitigates bids needed to relieve "non-competitive" transmission constraints in both day-ahead and real-time markets, while ERCOT performs such mitigation only in the real-time energy markets.

As noted in the discussion of Figure 1, conduct-and-impact screens can be used for *ex ante* mitigation only after bids are submitted in the day-ahead and real-time markets. Under such conduct-and-impact approaches, each supplier's bids are compared to a predefined reference level that approximates competitive bidding. If such bids exceed predefined thresholds over those reference levels, the supplier is said to have failed the conduct test. Then, the market price impact of the observed bidding behavior is measured, and if the unmitigated bids result in price increases above some predefined market impact threshold, suppliers that have failed the conduct test have also failed the impact test. Suppliers who fail the conduct-and-impact tests have their bids replaced with a reference level which is meant to approximate bidding under competitive conditions.

Table 5 illustrates that ISO-NE, NYISO, and MISO rely on such conduct-and-impact tests for *ex ante* mitigation. However, conduct-and-impact tests based on more stringent thresholds are often applied in transmission-constrained sub-regions that are more prone to market power abuses. These sub-regions are selected using structural techniques. For example, the energy and capacity bids of generators located in the transmission-constrained load pocket of New York City are subject to tighter thresholds. Similarly, the bids of generators located in transmission-constrained regions of New England, such as the Boston metropolitan area, also are subject to tighter thresholds. MISO employs a structural test to define Narrow Constrained Areas, to which stricter conduct-and-impact tests are applied. One common theme unites all of the RTOs:

structural tests in some form identify transmission-constrained regions requiring more mitigation. Tables 8 and 9, discussed later in this report, provide more detail behind the nuances of the structural and conduct-and-impact tests.

Table 6 extends this overview of market power mitigation processes to all types of product markets within each RTO. The three eastern RTOs employ *ex ante* mitigation in their respective capacity markets, though the form of mitigation differs somewhat, reflecting, in part, the differences among the capacity market designs. Table 6 illustrates that NYISO caps the bids of units located in New York City, while in ISO-NE, the forward capacity auction is subject to a floor and ceiling price, with further mitigation potentially imposed based on the examination of the bids and the competitiveness of the auction. PJM's mitigation of capacity prices essentially mirrors its mitigation of energy prices, in that the bids of suppliers in constrained zones will be mitigated unless the supplier passes the 3JPS test. Table 10, discussed later in this report, provides more detail about the mitigation of the RTO's capacity markets.

Ancillary services markets are typically mitigated only through pre-defined bid caps. Table 6 shows that offer caps are tools common to all markets. In PJM, cost-based offers are required for certain units. Conduct-and-impact tests are currently in place for ancillary service markets in NYISO and are proposed for the MISO ancillary service markets planned for spring 2008. Table 11, discussed later in this report, provides more details related to the mitigation of ancillary services markets.

Finally, specific market behavior that has the potential of creating non-competitive outcomes is also monitored in some RTOs. Monitored behavior includes: the physical withholding of generation when it is not in the supplier's economic interest to do so; uneconomic production away from dispatch levels to create congestion; bidding load in a way that causes an unwarranted divergence between real-time and day-ahead prices; and, Virtual Bidding in a way that causes a similar unwarranted divergence. Table 6 shows that RTOs relying on conduct-and-impact market power mitigation techniques have developed specific screens to monitor these behaviors. Other regions do not employ explicit, pre-defined screens, but, for example, CAISO's Market Monitoring Unit (MMU) is still tasked with monitoring these classes of behavior. Table 12, discussed later in this report, provides more detail about the explicit screens used to monitor these specific types of market behavior.

Table 6
Overview of Market Power Mitigation Techniques, Summarized by Product and Region

	Operating Markets				*Planned Market Design*	
	PJM	ISO-New England	New York ISO	Midwest ISO	California ISO (MRTU)	ERCOT (Nodal Market)
Day-Ahead Energy Markets	Automatic mitigation of bids for units dispatched to relieve binding constraints unless three pivotal supplier test is passed for all monitored constraints (*i.e.*, all constraints except four major interfaces)	Conduct and Impact tests (CT, SW-CT, and NE-MASS Boston more stringently monitored)	Conduct and Impact tests (New York City more stringently monitored)	Conduct and Impact tests (Structural tests to define more stringently monitored Narrow Constrained Areas)	Automatic mitigation of incremental output to relieve constraints determined to be not competitive based on a structural screen	No screens
Real-Time Energy Markets	Automatic mitigation of bids for units dispatched to relieve binding constraints unless three pivotal supplier test is passed for all monitored constraints (*i.e.*, all constraints except four major interfaces)	Conduct and Impact tests, (CT, SW-CT, and NE-MASS Boston more stringently monitored)	Conduct and Impact tests (New York City more stringently monitored)	Conduct and Impact tests (Structural tests to define more stringently monitored Narrow Constrained Areas)	Automatic mitigation of incremental output to relieve constraints determined to be not competitive based on a structural screen	
Capacity Markets	Automatic mitigation of bids for units required to serve constrained zones unless three pivotal supplier test is passed for relief of zonal constraint	Bid caps and floors, structural tests for competitiveness, and market monitor examination of particular bids	Proposed measures apply Conduct and Impact tests to ConEd divested units. Currently, bids for these units are capped	n/a	n/a	n/a
Ancillary Service Markets	Offer caps, and cost-based offers for specified units	Offer Caps	Offer caps, and Conduct and Impact tests	n/a	Offer Caps	
Physical Withholding	No explicit screens	Conduct and Impact tests			No explicit screens, but CAISO MMU monitors this practice	No explicit screens
Uneconomic Production	No explicit screens	Conduct and Impact tests			No explicit screens, but CAISO MMU monitors this practice	No explicit screens
Load Bidding	No explicit screens	Pre-set screens trigger requirement to procure load day-ahead or Section 205 investigations			No explicit screens, but CAISO MMU monitors this practice	No explicit screens
Virtual Bidding	No explicit screens	Pre-set screens trigger limits to virtual bidding			No explicit screens	

D. REFERENCE LEVELS

Before comparing the implementation details of these market power mitigation techniques, it is useful to define the reference levels that are an important aspect of every mitigation approach. These reference levels are meant to approximate competitive bids or bidding under workably competitive conditions and are generally used as a substitute for an entity's original bid if a structural or conduct-and-impact test is failed. The RTOs differ in the ways they define reference levels, and some RTOs allow suppliers the option to choose from among several approaches. These reference levels can be grouped into five broad categories (plus a category for exceptions):

- *Bid-Based Reference Levels*: generally based on average bids from the unit that were accepted in competitive periods
- *LMP-Based Reference Levels*: generally based on the average LMP for the unit during low-priced periods
- *Cost-Based Reference Levels*: generally reflects a unit's incremental operating costs
- *Frequently Mitigated Unit Options*: a cost-based adder for units that are frequently mitigated over the recent year
- *Negotiated Reference Levels*: generally used when data is insufficient to employ the other options, and is routinely required to be cost-based
- *Exceptions:* In addition, there are various exceptions for new units or units located in particularly constrained locations.

Table 7 compares these reference levels used in the various RTOs.

1. Bid-Based Reference Levels

As Table 7 indicates, bid-based reference levels are most common in regions employing conduct-and-impact tests, and in fact are the first choice for calculating reference levels in ISO-NE, NYISO, and MISO. Such reference levels are based on average bids accepted in merit order over the previous 90 days, adjusted for changes in the unit's fuel price.

Table 7
Determination of Reference Levels or Offer Caps for Mitigation

	Operating Markets				*Planned Market Design*	
	PJM (Offer Caps)	ISO-New England (Reference Levels)	New York ISO (Reference Levels)	Midwest ISO (Reference Levels)	California ISO (MRTU) (Offer Caps)	ERCOT (Nodal Market) (Offer Caps)
Bid-Based Reference Levels	None	The lower of the mean or the median of a Supply Offers accepted in competitive periods over the previous 90 days, adjusted for changes in fuel prices			None	None
LMP-Based Reference Levels	The weighted average LMP at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order	The average LMP during the lowest-priced 25 % of the hours that the unit was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices			LMP Option - weighted average of the lowest quartile of LMP's at the generating unit PNode during the preceding 90 days	None
Cost-Based Reference Levels	Incremental operating costs + 10% Costs include incremental fuel, maintenance, and labor costs as well as emissions allowance costs	Negotiated level is required to be cost-based Costs should be calculated as (heat rate * fuel costs) + (emissions rate * emissions allowance price) + other variable and operating maintenance costs		Negotiated level is required to be cost-based; costs should reflect marginal costs, including legitimate risks and opportunity costs	Variable cost plus 10%; variable cost includes incremental fuel costs + O&M adder ($2 generally, $4 for CTs and reciprocating engines)	Max of [10.5MMBtu/MWh times fuel index price; or (resource's verifiable incremental heat rate times fuel index price plus variable O&M) times multiplier that declines with capacity factor]
Negotiated or Consultative Reference Levels	A negotiated level agreed upon in advance between market participant and PJM.	A negotiated level intended to reflect marginal costs.		A negotiated level intended to reflect marginal costs and can specifically include opportunity costs.	A negotiated level agreed upon in advance between market participant and CAISO.	None.
Frequently Mitigated Units	a) if mitigated more than 80% of time: incremental cost + 10%, incremental cost + $40 or unit-specific going forward costs, b) if mitigated between 70 and 80% of time: incremental cost + 15% (not to exceed incremental cost + $40) or incremental cost + $30, c) if mitigated between 60 and 70% of time, incremental cost + 10% or incremental cost + $20	If a unit is frequently dispatched out of merit order for reliability purposes, it is required to choose the negotiated, cost-based level	None	None	If mitigated more than 80% of time, units can request a cap of variable cost + 10% + $24	None
Method for Selecting Reference Levels or Offer Caps	Suppliers can freely specify in advance their choice of LMP-based, cost-based, negotiated, or frequently mitigated unit offer caps	Given data availability, select caps in following order 1) bid-based, 2) LMP-based, 3) negotiated cost-based; units frequently mitigated for reliability must choose 3); i data unavailable, use ISO estimate or average of competitive bids from similar units	Given data availability, select caps in following order 1) bid-based, 2) LMP-based, 3) negotiated cost-based; if data unavailable, use ISO estimate or average of competitive bids from similar units		Suppliers can freely specify in advance their choice of LMP-based, cost-based, negotiated, or frequently mitigated unit offer caps	Cost-based levels are used for offer-capping
New Unit Exceptions	New units generally built between 1999 and 2003 in specified geographic zones are not subject to offer capping	None	For new units, reference level for 3 years following installation is higher of a) Standard reference levels and, b) the average of the peak LBMPs over previous year in zone for hours when unit would have likely operated	None	None	Max of [14.5MMBtu/MWh times fuel index price; or (resource's verifiable incremental heat rate times fuel index price plus variable O&M) times multiplier that declines with capacity factor]
Locational Exceptions	None	For Peaking Unit Safe Harbor (PUSH) units located in DCAs, an energy reference level can be calculated as [Fixed Costs Net of Market Revenues / 2002 Actual Output] + Marginal Cost	In-city generators must be price takers in the spinning reserve market	None	None	None

2. LMP-Based Reference Levels

Table 7 also shows that the LMP option is commonly calculated over the lowest-priced 25 percent of hours of dispatch during the previous 90 days. In most regions, this is calculated without regard to whether or not the unit was dispatched in merit order, although in PJM, the LMP-based reference level is calculated only over hours where units were dispatched in merit order. Because locational market-clearing prices can be significantly greater than an individual unit's incremental operating costs except when the unit is marginal, using the lowest-priced hours minimizes the difference between the LMP-based reference level and the affected suppliers' incremental costs. It is worth noting that in its MRTU proposal, CAISO sought to limit the LMP option only to units that were dispatched in merit order at least 50 percent of the time, but FERC rejected that competitive threshold requirement for CAISO'S LMP option.

3. Cost-Based Reference Levels

The RTOs considered here have slightly different approaches to defining cost-based reference levels. ISO-NE and NYISO require that the negotiated option be cost-based, and they explicitly state that such costs should include fuel, emissions, and the other variable operating and maintenance expenses. However these regions also allow for adjustments to reflect other costs. MISO and PJM explicitly include "opportunity cost" as an allowed component of cost, although neither region defines opportunity cost very specifically.[128] The regions pursuing structural approaches to market power mitigation (PJM, CAISO, and ERCOT) have explicit cost-based options that include at least a 10 percent adder. In the case of ERCOT, that adder can be higher for units with lower capacity factors.

4. Frequently-Mitigated Unit Options and Negotiated Reference Levels

PJM and CAISO allow bid adders for units that are mitigated during a high percentage of their operating hours over a given year. Both regions allow for the highest bid adder if units are mitigated more than 80 percent of the time: PJM allows a bid adder of $40/MWh over cost while CAISO allows a bid of cost plus 10 percent plus (another) $24/MWh. Also in PJM, units mitigated 70 percent or 60 percent of the time can opt to receive lower bid adders. With the exception of ERCOT, all RTOs also allow units to choose a negotiated reference level or offer cap that is generally meant to be reflective of cost. In PJM and CAISO, these negotiated levels are specifically mentioned as options for frequently mitigated units, and ISO-NE requires units that are frequently dispatched for local reliability reasons to select the negotiated, cost-based option. In NYISO, ISO-NE, and MISO, negotiated levels are meant to approximate marginal costs, which MISO explicitly states may include opportunity costs.

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[128] Opportunity costs are created by factors such as alternative sales options and operational constraints. For example, if a generating unit can operate only for a certain number of hours within a year (*e.g.*, because of environmental constraints, hydro storage limitations, or fuel delivery constraints), markets bid prices in fully competitive will rise above variable operating costs such that dispatch occurs during those hours of the year that provide the highest value for the energy which the unit is able to produce.

5. Exceptions to Reference Levels

Notwithstanding this relatively common framework for calculating reference levels, two important exceptions also exist in some of the RTOs. One exception involves the treatment of new units. Originally in PJM, all units constructed after 1996 were exempt from offer capping, but FERC found this to be unjust and unreasonable under Section 206 of the Federal Power Act. Instead, FERC concluded that within PJM, only a group of units built between 1999 and 2003 in specified geographic zones were constructed relying upon on this exemption from mitigation. These "grandfathered units" are today not subject to offer capping under any circumstance, although FERC stated that this status could be rescinded if PJM or its market monitor concluded these units were exercising significant market power. ERCOT allows a higher default heat rate for resources that commenced operations after January 1, 2004, and NYISO allows new units to use peak historical LMPs to calculate reference levels for three years following the commencement of those units' operations.

The second exception involves different offer caps for critical units in highly constrained zones. In New England, certain Peaking Unit Safe Harbor (PUSH) units can select an offer cap that allows recovery of average fixed costs on top of marginal costs.

E. MARKET POWER MITIGATION OF ECONOMIC WITHHOLDING IN ENERGY MARKETS

1. Structural Approaches

a. Purpose

Structural tests are used by RTOs for two major purposes: (1) to determine whether to impose offer caps and (2) as a screen to determine whether to subject particular suppliers to further tests. PJM, CAISO, and ERCOT all use structural tests to determine offer capping directly. In PJM, structural tests are used dynamically to identify resources dispatched for congestion relief that will be *exempted* from default offer caps. In CAISO and ERCOT, structural tests are used periodically (annually or seasonally with the potential for periodic updates) to identify transmission constraints that will be considered non-competitive. Then, as part of the *ex ante* mitigation process, two dispatch model runs are performed: one incorporating competitive constraints only, and another incorporating all constraints. Suppliers are then automatically offer-capped for any incremental output above the level from the competitive constraint run, since this incremental output is by construction serving non-competitive constraints. The offer is capped at the higher of a unit's accepted bids in the competitive constraint run or a unit's reference level.

In contrast, ISO-NE's structural test merely screens suppliers to identify those subject to a general, systemwide conduct-and-impact test. MISO's structural test is also used as a screen for further testing. MISO's annual test identifies chronic "narrow constrained areas" (NCAs) within which all resources are to be subjected daily to more stringent conduct-and-impact tests than resources in the rest of MISO. NYISO does not use explicit structural tests, although New York City and Long Island have long been subjected to special market power mitigation procedures due to their relative isolation and market concentration, so structural considerations also identified those regions.

Table 8 provides more details behind the key elements of the structural tests.

b. Definitions Used to Characterize the Relevant Market

Whereas ISO-NE defines the relevant geographic market as the entire ISO, all other RTOs' structural tests define the relevant market as a constraint or set of constraints prone to market power problems. These constraint-based market definitions all recognize that generating resources located generally on the receiving side of constrained transmission elements can relieve the constraint by increasing their output while those on the sending side can relieve the constraint by decreasing their output. The electrical location and effectiveness of each generator for reducing congestion on each constraint are typically described by generation shift factors, but the RTOs' tests differ in how they define these factors and how they use them to define the relevant market.

- *Reference Bus Definition*. Shift factors must always be defined with respect to a certain sink point, such that shift factors describe the amount of incremental flow on a particular transmission element when 1 MW is injected at the generator in question and extracted at the reference bus. PJM defines the reference bus as the load-weighted average of all load buses in the system; MISO defines the reference bus as the base generation-weighted average of all generation buses in the system. CAISO's structural screen does not require the definition of a reference bus, since it is implemented by removing three suppliers from a power flow model and determining if all transmission constraints can be feasibly solved. ERCOT is unique in that it defines two reference buses for each constraint – the sending end of the constrained element is the reference bus for the "import market" to which one structural test is applied, while the receiving terminus is the reference bus for the "export market" to which a separate test is applied.

Table 8
Mitigation of Economic Withholding in Energy Markets - Structural Approaches

	Operating Markets			*Planned Market Design*	
	PJM	ISO-New England*	Midwest ISO*	California ISO (MRTU)	ERCOT (Nodal Market)
Goal of Structural Tests	To exempt suppliers dispatched to relieve bindig constraints from default mitigation of energy offers if they are not jointly pivotal for relieving real-time and day-ahead transmission constraints	To identify regionwide pivotal suppliers, who are then subject to ISO NE-wide conduct and impact tests	To define Narrow Constrained Areas **(NCA)**, requiring more stringent conduct and impact screens, by identifying heavily-constrained flowgates that require one pivotal supplier for relief	To distinguish competitive from non-competitive local transmission paths, which are constraints that cannot be feasibly resolved without the output of three or fewer pivotal suppliers	To define Competitive Constraints, or constraints served by an unconcentrated group of effective suppliers without any single pivotal supplier
Name of Structural Test	Three (jointly) pivotal supplier test (3JPS)	Single pivotal supplier test		Three pivotal supplier test	Element Competitiveness Index (ECI) test and a single pivotal supplier test
Mechanics of Structural Test	A 3JPS test is performed for all suppliers providing effective supply of congestion relief for binding constraints in either the DA or RT markets. If a supplier passes the 3JPS test for congestion relief on all local constraints for which its supply is needed, it is exempt from default mitigation	If a market participant's aggregate energy offers exceed the difference between aggregate systemwide energy offers and total demand, then it is subject to ISO-NE-wide conduct and impact tests	If a single supplier can change output to create a binding constraint on a flowgate within a potential NCA, and all other suppliers cannot feasibly adjust their output to resolve that constraint, then the NCA is designated	If any three suppliers can be removed from a seasonal power flow model, and the limit on a specified intra-zonal constraint can still be met, then that constraint is considered competitive	If ECIs (HHIs) on the import side of a constraint are lower than 2000, ECIs (HHIs) on the export side are lower than 2500, and there is no single pivotal supplier on the import side of a constraint, then the constraint is deemed to be competitive
Frequency of Testing	Whenever binding transmission constraints arise in any interval of the DA and RT markets	Hourly	Annually	Annually (seasonally after first year)	Annually, with monthly and daily reassessments
Products Analyzed	Day-ahead and real-time energy			Day-ahead and real-time energy	Real-time energy
Geographic Markets Analyzed	Each individual local transmission constraint (regional transmission interfaces and PJM market as a whole deemed competitive)	ISO New England as a whole	Groups of flowgates serving an electrically contiguous region that are expected to be binding in at least 500 hours per year	All intra-zonal transmission constraints (inter-zonal transmission constraints deemed competitive)	Each individual monitored constraint, with a set of import side and export side suppliers
Sequence of Testing	Test applied to individual constraints, one at a time	Test applied to each supplier in ISO-NE	Test applied to individual constraints, one at a time	Test applied to all combinations of three pivotal suppliers, and constraints are checked simultaneously	Test applied to individual constraints, one at a time
Result of Failing Structural Tests	Raise-help units are offer capped at the reference level (usually marginal cost + 10%)	A participant is subject to general conduct and impact tests.	A Narrow Constrained Area (NCA) is defined where more stringent conduct and impact tests are applied	If any unit's incremental output is required to serve a non-competitive constraint, that unit is offer-capped at the higher of its reference level or its highest accepted bid from the competitive constraint run	
Structural Test Exceptions	Structural tests used to mitigate market power only on local transmission constraints (not on regional interfaces and PJM market as a whole)	None	Test is only applied to flowgates serving an electrically contiguous region that are expected to be binding in at least 500 hours per year	Inter-zonal transmission branch groups are not tested	None

Notes:
* ISO-NE and MISO rely primarily on conduct and impact tests for ex ante mitigation.

- *Two Sides of a Constraint*. ERCOT's separate tests for the import and export-side of a constraint reflect the concern that generation must often be incremented on one side of the constraint but decremented on the other in order to obtain relief. CAISO and MISO automatically recognize this fact by using a dispatch model that attempts to resolve each constraint while maintaining supply-demand balance by incrementing and decrementing resources simultaneously. PJM's test is unique in that it considers generation on the import and export sides of a constraint (*e.g.*, as indicated by positive and negative shift factors) to be interchangeable in its determination of "effective supply" of generation available for congestion relief, which does not adequately address the fact that incremental generation on one side of the constraint must be "matched" by decrements on the other side.[129]

- *Thresholds to Include Resources*. All RTOs that use shift factors exclude resources with low shift factors (as these units are electrically "distant" from the constraint), but the levels of these thresholds vary. ERCOT has a complicated process for defining the market, but the result is the same as if it determined a different (small) threshold for each side of each constraint. PJM also adds an economic factor to the shift factor threshold: a generator is included in the relevant market only if it can provide congestion relief at less than 150 percent of the shadow price on the constraint, given its bid-based offer curve. MISO's test only includes generators with shift factors producing a significant impact on the relevant flowgates in NCAs.

c. Applied Structural Screens

As Table 8 indicates, there are several types of structural tests that the RTOs apply to the relevant markets, including a traditional HHI-type test, a single pivotal supplier test, or a "three (jointly) pivotal supplier test." PJM and CAISO use three jointly pivotal supplier tests to determine whether any three suppliers are jointly pivotal for resolving any transmission constraints, *i.e.*, one or more constraints could not be resolved if three candidate suppliers all refused to increment or decrement their output from their base levels. MISO and ISO-NE both use a less stringent *single* pivotal supplier test in which failure occurs only if one supplier is large enough to prevent unilaterally the constraint from being resolved. ERCOT will apply both an HHI-like test called the "Element Competitiveness Index" and a single pivotal supplier test to the relevant markets it defines around each constraint.

Yet even where these RTOs use seemingly similar structural screens, there are substantial differences in the mechanics of the tests.

- *Definition of Base Generation and Flows*. All of the constraint-based tests consider market power with respect to relieving some level of baseline flow on each constraint. The baseline generation and flow in the RTOs with less frequently-applied tests, (*i.e.,* MISO, CAISO, and ERCOT) are taken directly from the seasonal or monthly power flow models that are used for planning purposes or for allocation of FTRs. It is important to note that PJM's dynamic baseline is not explained clearly in publicly available documents and certain elements remain unclear to us at this time.

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[129] In certain cases, congestion relief can also be provided by substituting a unit with a low shift factor for a unit with a high shift factor.

- *The Test for Pivotality*. All constraint-based pivotal supplier tests determine whether congestion can be resolved without the help of the candidate supplier(s). In the MISO test, the candidate supplier dispatches its portfolio in order to maximally exacerbate the constraint, whereas in the CAISO test the three candidate suppliers merely turn off their generation. Both of these tests are performed within a dispatch model that attempts to resolve the constraint by incrementing and decrementing other resources. In contrast, PJM's and ERCOT's tests are performed outside of a dispatch model by using formulae to determine whether a defined "demand" for congestion relief can be met without the help of candidate supplier(s). In PJM, pivotality occurs if the supply of constraint relief available from all non-candidate suppliers is not sufficient to meet the demand for relief, and any supplier that is found to be jointly pivotal with the two largest suppliers fails. In ERCOT, an export-side and an import-side set of suppliers is determined for each constraint, and if the concentration on either side exceeds the defined threshold, the constraint is designated as non-competitive. Even if a constraint passes the concentration tests, it is also checked to see if a single pivotal supplier exists on the import side of the constraint. If not, the constraint is considered to be competitive.

- *Resource Weighting Factors Embedded in the Test*. The constraint-based tests differ from more traditional structural tests in that each resource's contribution to the total supply is weighted by its shift factors. PJM's and ERCOT's tests apply these factors explicitly, embedding the arbitrariness of their choices of reference bus. Because ERCOT defines its reference buses at the termini of the constrained element, all resources have significant shift factors (weights), whereas PJM's load-distributed reference bus results in much lower weights for resources that are electrically more distant from the constraint. In MISO's and CAISO's tests, the weighting is applied automatically within dispatch models that respect the electrical location of each resource with respect to the constraint.

- *Sequencing*. All of the constraint-based structural tests consider each constraint individually except for CAISO's test, which recognizes that suppliers' incentives are related to the simultaneous effect of all constraints.

- *Frequency*. There is no uniformity across RTOs in the frequency with which structural tests are applied. Among the three RTOs using structural tests to determine directly whether to apply offer caps (PJM, CAISO, and ERCOT), PJM applies its test the most frequently. PJM runs its day-ahead tests whenever binding transmission constraints arise. This means for each constraint, the tests are run as frequently as each hour of the day-ahead market and as frequently as every five minutes for the real-time market. ERCOT also performs its tests daily, but only as an update to annual and monthly tests. In contrast, CAISO currently performs its tests annually, although it may eventually move to a seasonal evaluation. The two RTOs using structural tests to determine whether to perform conduct-and-impact tests (ISO-NE and MISO) differ greatly in their frequency of application. MISO performs its test annually to designate NCAs, but ISO-NE applies its structural tests hourly, followed immediately by conduct-and-impact tests for all failures. However, in 2005 and 2006 there have been <u>no</u> instances of mitigation triggered by conduct-and-impact tests applied to ISO-NE's system-wide pivotal suppliers.

d. Scope of Default Mitigation

Table 8 also describes the scope of default mitigation. For example, in PJM resources dispatched to relieve the AP South, PJM Western, PJM Central, and the PJM Eastern interfaces are not subject to offer capping because those interfaces are deemed to be competitive. Also, the structural screens are not applied to the PJM market as a whole, but only individual, binding transmission constraints. In CAISO, the inter-zonal transmission interfaces, including all major import and export interfaces, are also deemed competitive and are similarly exempt from mitigation. In PJM, an exemption from mitigation is also applied to generating units installed in certain zones between 1999 and 2003.

In all three of these RTOS, PJM, CAISO and ERCOT, mitigation actions are applied only if generating units are actually dispatched for congestion relief (*i.e.*, mitigation is not applied to units that could provide but are not needed for congestion relief) and the mitigation applies only to generating units that are incremented for congestion relief (*i.e.*, mitigation is not applied to generating units that are decremented to provide congestion relief). In CAISO and ERCOT mitigation is applied only to the incremental amount of output needed for congestion relief on the non-competitive transmission interfaces, which is determined for every dispatch period. In PJM, the need for mitigation is determined (for the most part) only in the dispatch period in which the generating unit is first committed, but mitigation is then applied to the entire output of the unit for the duration of its commitment period.

The prices to which bids are mitigated also differ slightly across the RTOs. In PJM, bids are capped at the reference level. In ERCOT and CAISO, bids are capped at the higher of the reference level and the highest accepted bid for the unit from the "competitive constraint run" (*i.e.*, the bids that would be accepted if congestion was managed only on competitive constraints). The capping process means that no mitigation action needs to be undertaken if bids are already below the capped levels.

2. Conduct-and-Impact Approaches

Of the six RTOs described in this report, three (ISO-NE, NYISO, and MISO) rely upon conduct-and-impact (C&I) tests for purposes of *ex ante* mitigation. The C&I tests used by these RTOs are quite similar. The C&I tests establish criteria for determining whether a generator is economically withholding its capacity and, if so, whether it is increasing the market price or out-of-market uplift payments. When generators fail the C&I tests, their bids are mitigated to reference levels.

The conduct tests consist of comparing a supply bid to a pre-defined threshold (*e.g.*, 300 percent above the reference price). The impact tests, which are performed only where the conduct tests fail, detect whether the specific bids in question increase prices or out-of-market uplift payments above pre-defined thresholds relative to reference-level bids. Conduct-and-impact thresholds typically apply uniformly to all supply resources in the entire RTO. However, all three RTOs utilize more stringent conduct-and-impact thresholds that apply to localized geographic markets that are presumed to be more prone to noncompetitive outcomes due to transmission limitations.

Table 9 provides a summary of the conduct-and-impact tests used by ISO-NE, NYISO, and MISO.

Panel A of this table outlines the general C&I tests, where generators' energy offers are compared to the reference levels described in the previous section to determine if the offer merits further examination. Note that different conduct thresholds are developed for the main components of the energy offer, including parameters not denominated in dollars such as startup-time and minimum or maximum output levels. If an offer exceeds the reference level by a pre-specified margin, (*e.g.,* 300 percent or $100/MWh, whichever is lower for energy offers), the offer is examined to determine its impact on the market-clearing price. All offers exceeding reference levels by a pre-specified margins are examined to determine their impact on the market clearing price. If the offers increase the hourly market-clearing price in either the DA or RT market by, for example, a minimum of 200 percent or $100/MWh for energy offers, the bids are found to have caused a material change in the market price and are subject to mitigation. In addition to changes in LMP, conduct that also increases uplift payments to a supplier above the specified thresholds also results in a failure of the impact test. In all three regions, the result of failing conduct-and-impact tests is the substitution of default reference levels for the bid in question.

Table 9 also documents one difference in the application of the general conduct-and-impact thresholds: the use of dynamically-identified Broad Constrained Areas (BCAs) in MISO. While ISO-NE and NYISO consider a geographic market that is essentially the entire region, MISO only analyzes BCAs, which are flowgates facing binding transmission constraints (*i.e.*, possessing a non-zero shadow price of congestion). The relevant generators monitored for these BCAs are those that generally have Generator Shift Factors in absolute value greater than 6 percent. In short, conduct-and-impact tests in MISO only are applied to generators that significantly impact binding transmission constraints that may sporadically arise on flowgates.

The three RTOs all apply a more stringent conduct-and-impact test in chronically transmission-constrained local areas, known as load pockets, and Panel B of Table 9 documents these stricter C&I tests. A stricter test is applied because it is assumed that generators located in chronically-constrained areas will have market power during much of the year. The approach is essentially the same as that used at the regional level; a generator's bid is compared to a reference level and, if it exceeds it, is subject to mitigation if all offers failing the conduct test are found to have a material impact on the market-clearing price or uplift payments. The difference is that the thresholds prompting investigation are more stringent—a generator's offer is investigated if it exceeds the reference price by a more modest amount, such as 50 percent or $25/MWh in ISO-NE. In ISO-NE, there is no additional impact threshold—any bid that exceeds the conduct (reference price) threshold is subject to mitigation. In MISO and NYISO, the stricter threshold values for load pockets were developed to reflect different levels of acceptable deviations from incremental or marginal cost. In New York, the threshold is calculated as a percentage by which a monopolist could raise prices during constrained hours without being mitigated, and the current level for the threshold is 2 percent.

Table 9
Mitigation of Economic Withholding in Energy Markets - Conduct and Impact Approaches*
Panel A: General Conduct and Impact Thresholds

		Operating Markets		
		ISO- New England** [1]	New York ISO [2]	Midwest ISO [3]
Monitored Locations		ISO-New England region as a whole	New York ISO region as a whole	Units are monitored for mitigation if they are in a Broad Constrained Area **(BCA)** with a binding constraint and have a Generator Shift Factor with absolute value > 6%
Conduct Thresholds	Energy Offers	Offers exceed the minimum of 300% of reference level or reference level + $100/MWh (Offers below $25/MWh exempt)		
	Startup Offers	Offers exceed 200% of reference level		
	Minimum or No-Load Offers	Offers exceed 200% of reference level		Offers exceed the minimum of 300% of reference level or reference level + $100/MWh. (Offers below $25/MWh exempt)
	Time-Based Parameters***	An increase of 2 hours over reference level or an increase of 6 hours across multiple parameters	An increase of 3 hours over reference level or an increase of 6 hours across multiple parameters	
	Other Offer Parameters****	A 100% increase over reference levels for minimum values or a 50% decrease from reference levels for maximum values		
Impact Thresholds	LMP Impact	An increase of the minimum of 200% or $100/MWh		
	Uplift Payment Impact	An increase in Net Commitment Period Compensation (NCPC) credits of 100% for a day (increase must exceed $10/MWh)	An increase in Guarantee Payments of 200% for a day	An increase in Offer Revenue Sufficiency Guarantee Payments of 200% for a day
Result of Failing Conduct and Impact Tests		Default offers, set equal to reference levels described in Table 7, are substituted for the unit		

Notes:
* See Table 7 for a definition of the reference levels documented in this table.
** General conduct and impact thresholds only applied to suppliers that pivotal on a systemwide basis.
*** This category includes, for example, Hot/Intermediate/Cold Notification/Startup Times, Minimum/Maximum Run Times and Minimum Down Time.
**** This category includes, for example, Maximum Daily/Weekly Starts and Ramp Rate Curve.

Table 9
Mitigation of Economic Withholding in Energy Markets - Conduct and Impact Approaches*
Panel B: Locational Conduct and Impact Thresholds

		Operating Markets		
		ISO- New England** [1]	New York ISO [2]	Midwest ISO [3]
Locations Subject to More Stringent Thresholds	Method for Identification	Based on historical operations patterns and forecast reliability requirements, ISO-NE identifies Designated Congestion Areas (DCAs) where a limited number of suppliers are regularly required to be run to relieve transmission constraints.	NYISO has identified Constrained Areas as regions subject to transmission constraints that give rise to significant local market power	Narrowly Constrained Areas **(NCAs)** are defined as groups of flowgates serving an electrically contiguous region that a) are expected to be constraiined 500 hours or more per year and b) include one flowgate where one supplier is pivotal for relieving the constraint.
	Current Regions	Connecticut, SW Connecticut, and NEMASS-Boston	New York City	Wisconsin Upper Michigan System (WUMS) and Northern WUMS
Conduct Thresholds	Energy Offers	Offers exceed the minimum of 50% of reference level or reference level + $25/MWh	Offers exceed the reference level by the following formula: (2% x Average LMP x 8760) / # of Historically Constrained Hours	Offers exceed the reference level by the following formula: Net Annual Fixed Cost of New Peaker / # of Historically Constrained Hours
	Startup Offers	Offers exceed 25% of reference level	Offers exceed 50% of reference level	
	Minimum or No-Load Offers	Offers exceed 25% of reference level	Offers exceed the reference level by the following formula: (2% x Average LMP x 8760) / # of Historically Constrained Hours	Offers exceed the reference level by the following formula: Net Annual Fixed Cost of New Peaker / # of Historically Constrained Hours
Impact Thresholds	LMP Impact	Offers exceed the minimum of 50% of reference level or reference level + $25/MWh	In addition to statewide thresholds, if energy offers or minimum load offers result in price increases exceeding (2% x Average LMP x 8760) / # of Historically Constrained Hours, then the impact test is failed	In addition to general thresholds, if economic withholding results in price increases exceeding (Net Annual Fixed Cost of New Peaker / # of Historically Constrained Hours) then the impact test is failed
	Uplift Payment Impact	Same as general threshold	An increase in Guarantee Payments of 50% for a day	Same as general threshold
Result of Failing Conduct and Impact Tests		Offers are capped at reference levels described in Table 7		

Notes:
* See Table 7 for a definition of the reference levels documented in this table.
** General conduct and impact thresholds only applied to suppliers that pivotal on a systemwide basis.
*** This category includes, for example, Hot/Intermediate/Cold Notification/Startup Times, Minimum/Maximum Run Times and Minimum Down Time.
**** This category includes, for example, Maximum Daily/Weekly Starts and Ramp Rate Curve.

In MISO, the lack of established locational capacity or operating reserve requirements led to the development of a threshold based on the levelized annual fixed cost of a new peaking generator. This threshold was specifically designed to provide efficient economic signals for new generator entry within Narrow Constrained Areas. However, prices in excess of that needed to support the fixed cost of a new combustion turbine (CT) are deemed excessive and are mitigated to the reference price. One important common feature of the NYISO and MISO locational C&I thresholds is that they are calculated in a manner to produce more stringent thresholds if a region is constrained in more hours.

In contrast to the geographic markets analyzed under the general C&I screens which are either regionwide or dynamically defined, the locational C&I screens focus on well-defined geographic regions prone to chronic congestion. As shown in Table 9, the RTOs either use historical incidence of significant transmission constraints or, in the case of MISO, employ structural tests to identify those regions. The results of these analyses lead to stricter mitigation thresholds for Connecticut, SW Connection and NEMA-Boston in ISO-NE, New York City in NYISO, and Wisconsin Upper Michigan System (WUMS) and Northern WUMS in MISO. The C&I approach recognizes that the thresholds used to identify and mitigate the exercise of market power must be adjusted for specific geographic markets experiencing significant congestion.

F. MITIGATION OF CAPACITY MARKETS

Market power mitigation techniques are also an important component of capacity market design. We focused our review on market power mitigation in the two new forward capacity markets being developed in PJM and ISO-NE,[130] and contrast those approaches with market power mitigation in NYISO's existing Installed Capacity (ICAP) market. Market power mitigation of capacity markets tends to follow a general philosophy similar to that underlying energy market power mitigation: PJM uses a structural approach while ISO-NE and NYISO focus more on the conduct of the individual bidders. All three regions employ a locational component in their market design, and all incorporate energy market performance into capacity pricing in some form. Finally, PJM and ISO-NE include specific provisions for new entrants, and in many ways treat new entrants as the competitive price setter.

Table 10 provides a detailed comparison of market power mitigation techniques for the three formal capacity markets.

[130] PJM’s market is termed the Reliability Pricing Model, and recently became active for the June 2007 – May 2008 and June 2008 - May 2009 delivery periods. ISO-NE’s market is called the Forward Capacity Market (FCM), and its first auction is scheduled to occur in February 2008.

Table 10
Market Power Mitigation of Formal Capacity Markets
Panel A: Capacity Market Design and Market Power Mitigation Approaches

	PJM	ISO-New England	New York ISO
Name of Capacity Market	Reliability Pricing Model	Forward Capacity Market	Installed Capacity Market
Frequency of Procurement	Annually for a single delivery year three years forward; up to three incremental auctions allowed during intervening years to allow for changes in supply and demand for capacity	Annually for a single delivery year three years forward; reconfiguration auctions include: (i) three incremental auctions allowed during intervening years (ii) monthly auctions held prior to each commitment month, and (iii) seasonal auctions held prior to June and October of each year to sell a "seasonal strip" product	Seasonal, monthly, and spot auctions
Geographic Markets	Local Deliverability Areas (up to 23 specific zones)	Capacity zones will be determined prior to the auction to identify import constrained zones	New York City, Long Island, and Rest of State
Demand Curve	Downward sloping variable resource requirement curves, specific to groups of constrained LDAs, that is a function of the Cost of New Entry (CONE)	None: based on administratively-determined fixed Installed Capacity Requirement (ICR)	Administratively-determined demand curve
Structural Mitigation	A preliminary market screen (based on unforced capacity) is triggered if one of the following occurs: a) the market share of any seller exceeds 20%, b) HHI is 1800 or higher, c) there are not more than three jointly pivotal suppliers -- if screen is triggered, all suppliers submit cost data and only supplier passing the TPS test are exempt from automatic offer capping	The Insufficient Competition rule sets prices for capacity resources if a region is short of capacity, the total amount of new capacity bid is small, and any of the new capacity bid is needed to meet the requirement; if the rule is triggered, then new capacity resources are paid the market clearing price, but existing capacity resources are paid no more than 1.1 x Cost of New Entry (CONE)	None
Bid Conduct Analysis	None	ISO-NE can examine the validity of a variety of bid types: de-list bids priced above 0.8 x CONE, bids for quantities less than seasonal summer claimed capability (for evidence of physical withholding), all import bids, entities submitting both new capacity aand de list bids, new capacity bids below 0.75 x CONE	Proposed mitigation measure specifies conduct and impact tests for the ConEd divested units (DGOs) in the ICAP Spot Market Auction; any actual DGO offer in an auction fails the conduct test if it is 3 percent or more above an auction reference price of $82/kW-year, and in aggregate result in a clearing price at or above that level

Table 10
Market Power Mitigation of Formal Capacity Markets
Panel B: Market Power Mitigation Details

	PJM	ISO-New England	New York ISO
General Caps or Floors	None	For first three successful auctions, existing generators face price caps of 1.4 x CONE and a price floor of 0.6 x CONE is in place	Under the proposal, revenues to the DGOs would remain capped at the current $105/kW-year, should prices ever rise above that level as a result of a non-DGO unit becoming marginal
Nature of Mitigation	Entities that do not pass the TPS test are offer capped at avoidable costs net of PJM energy and ancillary historical profits; entities can also submit support for being capped at opportunity cost	Generating units are capped at various levels described above, or invalidated based on market monitor review	In-City offer price caps described above
Different Mitigation for Planned Generation	Offers from planned generation resources will be presumed to be competitive and not be subject to offer capping; however, offers from planned resources can be rejected if the collective amount of new entry is less than twice the incremental amount required to meet demand in a given region or if all of the new entry comes from only one market participant	Planned generation is generally not subject to the caps described above.	None
Cost Recovery Incentives for Planned Generators	After it clears for one year, a new unit is treated as existing (and potentially subject to offer capping) in the auctions for subsequent years; such resources may, however, receive certain price assurances for two additional years under a New Entry Price Adjustment mechanism	New capacity suppliers that win the auction are entitled to a one-time option to lock-in capacity prices for up to five years	None
Links to Energy Markets	Offer caps are reduced by historical net profitability of unit; net revenues used as offset for constructing demand curve	Capacity payments will be reduced by Peak Energy Rents, or energy market profits for a marginal proxy unit	Net revenues used as offset for constructing demand curve

In PJM and ISO-NE, capacity markets are cleared for a one-year obligation three years ahead of time, but there are subsequent incremental auctions to allow for changes in supply and demand conditions in the intervening years. In NYISO, ICAP markets are conducted seasonally, monthly, and on a spot basis, but there is no current three year forward product that results from a formal market. All regions recognize transmission constraints, and will procure capacity in varying levels of locational specificity: from the three core zones of New York City, Long Island, and Rest of State in NYISO to up to 23 specific local deliverability areas in PJM.

Structural tests define market power mitigation in PJM, but are also incorporated to some degree in ISO-NE. In PJM, a Preliminary Market Structure Screen (PMSS) checks each geographic region[131] to determine if (i) any individual market share exceeds 20 percent, (ii) HHI is at a level of 1800 or higher, or (iii) there are three jointly pivotal suppliers. If any of these simple screens are failed, then all entities within the geographic region are required to submit more specific cost data for subsequent 3JPS tests during the auction or select a resource class-specific default cost value. If no data is submitted and no default value is selected, offer caps for existing generation resources are set to zero. Thus, the PMSS is an initial indicator that mitigation may be needed and provides the opportunity to collect relevant cost data in advance of the actual auction week.

The 3JPS test performed during the auction week relies upon a similar conceptual framework as PJM's energy market test. In this case capacity suppliers are subject to default mitigation to cost unless they are not jointly pivotal with the two largest capacity suppliers providing relief for the constraint isolating the region. Supply and demand for congestion relief in RPM depends upon whether the region is constrained or unconstrained. For constrained regions, the “demand” for congestion relief is defined as all bids that were accepted and were priced above the PJM-wide unconstrained capacity clearing price. The “supply” for congestion relief in constrained regions is defined as all bids above the PJM-wide unconstrained capacity clearing price and below 150 percent of that region’s constrained market clearing price. For unconstrained regions, demand is simply all accepted offers in the region, and supply is simply all offers at or below 150 percent of the unconstrained market clearing price. Only those suppliers who pass the test avoid default mitigation of bids to a level that reflects avoidable costs or, if justified, opportunity costs. In both cases, offer caps are reduced for historical net profitability of the unit in question.

ISO-NE employs a structural screen termed the Insufficient Competition Rule. In cases where a region is short on capacity, and planned generation resources are required to meet the requirement, then new generating resources receive the market clearing price while existing generators are capped at 110 percent of the cost of new entry (CONE). Thus, both regions employ caps for existing capacity if it is determined that structural conditions may produce noncompetitive outcomes, but PJM’s mitigation is deployed solely from a structural analysis.

In addition, ISO-NE, and to some extent NYISO, examine particular bid conduct in their mitigation approaches. In ISO-NE, various practices are monitored, including bids from new capacity resources that might be unjustifiably too low, bids to retire resources at prices that are unjustifiably too high, and bids for quantities that are less than capability levels on file for a unit. Table 10 shows that NYISO is proposing mitigation measures specifically for units located in

[131] Geographic regions subject to examination in PJM’s capacity market are the entire region, as well as individual Local Deliverability Areas (LDAs) or groups of LDAs.

New York City, and to monitor bids in excess of 3 percent above a reference price that reflects the net cost of new entry in the region. Suppliers failing these screens face offer capping or outright rejection of uncompetitive bids. On top of these conduct measures there are also specific price ceilings and floors in place. In ISO-NE, market clearing prices are "collared" at levels between 60 percent and 140 percent of CONE, and certain units in New York City are subject to specific price caps of $105/kW-year.

Table 10 illustrates that planned generation is treated much differently in both the PJM and ISO-NE forward markets. In both regions, offer caps for new generation do not exist, based upon the assumption that new generation offers should be priced competitively. PJM explicitly checks that assumption by only allowing generation bids from new resources if the new entry is of a sufficient magnitude and comes from at least two suppliers. Moreover, both RTOs offer specific options to provide price assurances for new generation. New units are afforded a one-time choice to lock in the capacity price that it received in the first auction for various lengths of time (3 years in PJM and 5 years in ISO-NE). Thus, explicit mechanisms to foster new generation investment are included in the two forward capacity market designs.

Finally, linkages between earnings in the energy market and prices in capacity markets exist in all regions. The rational underlying this linkage is that capacity prices need to account for the net revenues or margins that generators can earn in the energy market—the greater the earnings in the energy market, the less revenue needed from capacity sales to support new generation entry. PJM and NYISO implicitly recognize this linkage by including energy market earnings for a hypothetical new peaking plant in the construction of the demand curves for each auction. PJM and ISO-NE also provide more explicit linkages. In PJM, offer caps based on avoidable costs are reduced for historical profits in the energy and ancillary service markets for that unit. In ISO-NE, where there is no downward sloping demand curve but rather a descending clock auction for capacity, the resulting capacity payment is reduced by Peak Energy Rents, or energy profits earned by a hypothetical peaking unit.

G. Mitigation of Ancillary Service Markets

All of the eastern RTOs have caps on the price of ancillary services, and CAISO and ERCOT plan to have caps for ancillary services once their revised markets are in place. (MISO does not currently have separate ancillary service markets.) These price caps along with other ancillary service design features are shown in Table 11.

Price caps for ancillary services, unlike those for energy, vary more significantly among the RTOs, in part, because the nature and characteristics of ancillary service markets vary somewhat among the RTOs. Both PJM and ISO-NE cap regulation service offers at $100/MW. PJM caps offers for synchronized/spinning reserve at cost plus $7.50/MW, while NYISO caps offers for non-spinning reserves at $2.52/MW. This latter cap is the only specific price cap for ancillary services in NYISO.

Table 11
Market Power Mitigation of Ancillary Services Markets

		Operating Markets			*Planned Market Design*	
		PJM	ISO-New England	New York ISO	California ISO (MRTU)	ERCOT (Nodal Market)
Price Caps	Regulation	$100/MW		$1,000/MW	$250/MW	$1,000/MW
	Responsive Reserve	n/a	n/a	n/a	n/a	$1,000/MW
	Spinning Reserves	Cost + $7.50/MW + lost opportunity cost	n/a	$1,000/MW	$250/MW	n/a
	Non-Spinning Reserves	n/a	n/a	$1,000/MW, but non-synchronized 10-minute reserve reference levels capped at $2.52/MW	$250/MW	$1,000/MW
	Forward Reserves	n/a	$14,000/MW-month	n/a	n/a	n/a
Locational Procurement		Yes for Spinning Reserves, no for Regulation	Yes for Forward Reserves, no for Regulation	Yes for Operating Reserves, no for Regulation	Yes	No
General Conduct Thresholds		n/a	n/a	For Operating and Regulation Reserves, threshold is offer that exceeds the minimum of 300% of reference level or reference level + $50/MWh (Offers below $5/MWh exempt)	n/a	n/a
Locational Mitigation Exceptions?		Certain AEP and VEPCO units specifically capped at cost + $7.50/MW	n/a	In-city generators must be price takers in the spinning reserve market	n/a	n/a
Impact Thresholds		n/a	n/a	Identical to economic withholding impact thresholds	n/a	n/a

Only one RTO, the NYISO, currently applies a C&I test in ancillary service markets. Under NYISO's test, offers for operating and regulation reserves are potentially subject to mitigation if they exceed the lower of 300 percent of the reference level price or the reference level price plus \$50/MWh. Reference prices for ancillary services bids are calculated using the same techniques as described in Table 7. The impact threshold for determining mitigation is identical to the impact thresholds identified for economic withholding. A similar conduct-and-impact mitigation method is being proposed for MISO's forthcoming markets.

PJM and NYISO also have specific caps or rules for certain sub-regions. For example, New York City generators must be price takers in the NYISO's spinning reserve market. In PJM, offers to provide spinning reserves are capped for some companies, such as American Electric Power and Dominion Power, at their cost plus \$7.50/MW.

All of the RTOs in question have some recognition of locational constraints for procurement of ancillary services, except for ERCOT. In addition, there is a significant trend toward co-optimization of energy and ancillary services procurement.

H. MITIGATION OF SPECIFIC MARKET BEHAVIOR

Structural approaches to market power mitigation do not explicitly look at suppliers' specific market behavior (*e.g.*, bidding practices), but rather the market in question as a whole for potentially non-competitive conditions. Conduct–and-impact approaches, however, generally also examine particular market behavior. In the discussions above we have only examined C&I screens for economic withholding, but there are a variety of other practices that RTOs explicitly monitor using the conduct-and-impact approach. These include physical (as opposed to economic) withholding of generation resources, uneconomic production that cannot be justified, and load bidding or virtual bidding practices that create unwarranted divergence between day-ahead and real-time prices. Most of these practices are mitigated *ex post*, and even in regions relying more heavily on structural approaches, such as CAISO under MRTU, market monitors still are tasked with monitoring for the existence of such practices.

Table 12 provides a comparison of the explicit mitigation practices for these categories of market conduct. This table shows that these practices are monitored in very similar ways across the three RTOs. The first page of Table 12 documents physical withholding screens. In many respects, these mitigation techniques are quite similar to economic withholding screens. There are more relaxed standards in the general market, but in constrained zones any detection of physical withholding results in market power mitigation, regardless of price impact. The critical difference relative to economic withholding is the manner in which mitigation is implemented. By nature, *ex post* mitigation is required, because the practice cannot generally be detected until after the fact. The RTOs apply sanctions to identify violators, usually in the form of requiring entities to pay the LMP for the identified quantity of output withheld. Multipliers are generally assessed for frequent occurrences of physical withholding.

Table 12
Conduct and Impact Screens for Specific Market Behavior
Panel A: Physical Withholding

		Operating Markets		
		ISO- New England [1]	New York ISO [2]	Midwest ISO [3]
Physical Withholding	Definition	Can include but is not limited to: scheduling false outages; refusing to bid or schedule a unit when it is, absent market power, in the economic interest to do so; operating at lower than instructed dispatch levels, or; operating a transmission facility in a way that is not economic and contributes to congestion	Can include but is not limited to: scheduling false outages; refusing to bid or schedule a unit when it is, absent market power, in the economic interest to do so, or; operating at lower than instructed dispatch levels	Can include but is not limited to: taking an unapproved derating or outage; refusing to provide Generation Offers or schedules; falsely declaring a Generation Resource derated, unavailable or forced out-of-service, or; changing a time-based Generation Offer parameter or a Generation Offer parameter expressed in units other than time or dollars when it is too late to prospectively substitute a Default Offer
	General Conduct Thresholds	Thresholds: a) physical withholding of greater than the minimum of (10% of a resource's capacity or 100 MW), b) physical withholding of greater than the minimum of (5% of a portfolio's aggregate capacity or 200 MW), or c) operating in real-time at 90% or less than dispatch instruction		If physical withholding causes transmission constraints and exceeds one of the following thresholds: a) physical withholding of greater than the minimum of (5% of a portfolio's aggregate capacity or 200 MW), or b) operating in real-time at less than 90% of dispatch instruction
	Different Treatment in Constrained Areas?	Any withholding triggers impact test		
	Impact Thresholds	Identical to economic withholding impact thresholds		
	Result of Failing Conduct and Impact Tests	Ex-post sanctions (pay Administrative fixed charge plus generally 0.5 x LMP x withheld quantity)	Ex-post sanctions (pay the LMP or multiples of LMP times the withheld quantity)	

Table 12
Conduct and Impact Screens for Specific Market Behavior
Panel B: Other Market Behavior

		Operating Markets		
		ISO- New England [1]	New York ISO [2]	Midwest ISO [3]
Uneconomic Production	Conduct Thresholds	Energy schedules causing transmission congestion that meet either of two thresholds a) energy scheduled at an LMP that is less than 20% of unit's reference Level or b) output from a resource that exceeds 110% of the dispatch instruction		Energy schedules causing transmission congestion that meet either of two thresholds a) energy scheduled at an LMP that is less than 50% of unit's reference Level or b) output from a resource that exceeds 110% of the dispatch instruction
	Impact Thresholds	Identical to economic withholding impact thresholds		
	Result of Failing Conduct and Impact Tests	Default offers, set equal to reference levels described in Table 7, are substituted for the unit		
Load Bidding	Mitigation Approach	ISO-NE can initiate a Section 205 filing with FERC to investigate new mitigation measures if: a) over a rolling four week period, RT and DA prices consistently diverge by 10% b) load-serving entities purchase a significant amount of load in RT, c) these real-time purchases are contributing to the price divergence, and d) these real-time purchases create operational problems	NYISO can require market participants to schedule load DA or incur penalties for scheduling in RT if: a) over a rolling eight week period, the relationship RT and DA prices is not what would be expected under conditions of workable competition, b) load-serving entities purchase a significant amount of load in RT, and c) these real-time purchases are contributing to the price divergence	MISO can require market participants to schedule 95% of their load DA or incur penalties for scheduling in RT if: a) over a rolling four-week period, RT and DA prices diverge by 10%, b) a load-serving entity purchases over 10% of its load in RT, and c) these real time purchases are contributing to the price divergence, and d) these real-time purchases create operational problems
Virtual Bidding	Mitigation Approach	ISO-NE can limit a participant's virtual bidding at a location for six months if: a) over a rolling four week period, RT and DA prices consistently diverge by 10%, and b) a participant's virtual bidding contributes to that divergence	NYISO can limit a participant's virtual bidding if: a) over a rolling four-week period, the relationship between RT and DA prices is not what would be expected under conditions of workable competition, and b) a market participant's virtual bidding contributes to that divergence	MISO can limit a participant's virtual bidding if: a) over a rolling four-week period, RT and DA prices diverge by 10%, and b) a market participant's virtual bidding contributes to that divergence

The second page of Table 12 provides a comparison of mitigation measures for uneconomic production, load bidding, and virtual bidding. Uneconomic production involves deviations from schedules or scheduling energy at an LMP that is significantly priced below a unit's reference level. To the extent possible, such detected action is mitigated on an *ex ante* basis. Load bidding and virtual bidding measures are designed to prevent divergence between day ahead and real-time prices that would not be expected under competitive conditions. For load bidding, this implies imposing limits or penalties on load serving entities that consistently schedule load in real-time. For virtual bidding, this implies imposing limits on entities engaging in virtual bidding that produces divergences in day-ahead and real-time prices.

I. CAISO CASE STUDY: FROM CONDUCT-AND-IMPACT TO STRUCTURAL MARKET POWER MITIGATION

CAISO's approach to *ex ante* market power mitigation will change substantially from the conduct-and-impact approach used today to a structural approach under its Market Redesign and Technology Upgrade (MRTU) initiative to be implemented in April 2008. The debate over this change in technique provides important insights into the strengths and concerns associated with both approaches. Also, the specific structural approach envisioned under MRTU differs in important ways from the structural mitigation techniques employed by PJM. Thus, CAISO provides an important case study for evaluating the two approaches to market power mitigation.

Today, CAISO employs a standard conduct-and-impact approach that is quite similar to that used in NYISO:

- Conduct tests measure whether bids into the energy imbalance market exceed competitive reference levels by the lower of 200 percent or $100/MWh.
- Reference levels can take various forms, but the average or median of competitive offers from the previous 90 days, adjusted for fuel prices, is the preferred approach.
- Impact tests measure whether unmitigated bids would result in an increase in market price of 200 percent or $50/MWh.
- Entities failing these conduct-and-impact tests, or being dispatched out of merit order to relieve intra-zonal congestion at a price that is 200 percent or $50/MWh greater than the market price, are mitigated down to their reference levels automatically.

Under MRTU, CAISO will implement a PJM-style structural mitigation approach that also has similarities to the planned mitigation approach currently considered in the context of ERCOT market redesign:

- Market power is assessed based on the CAISO's ability to resolve existing transmission constraints. All inter-zonal constraints are presumed to be competitive and exempt from mitigation. In contrast, intra-zonal constraints are presumed to create local market power concerns and are mitigated unless a three jointly pivotal supplier ("3JPS") test is passed
- On an annual basis, these intra-zonal transmission constraints will be designated as competitive or non-competitive using a three pivotal supplier test. The test will determine

if it is feasible to solve intra-zonal constraints without various combinations of three suppliers using power-flow models under various seasonal load conditions.

- Constraints requiring the output of three or fewer suppliers for feasible solution in any case will be designated as non-competitive for the first year of MRTU. Subsequently, the test will be performed seasonally, and constraints may be designated differently depending upon the test results in each season.
- In MRTU's day-ahead and real-time energy markets, any incremental output required to relieve non-competitive constraints will be mitigated to a reference level such as variable cost plus 10 percent. This mitigation will be implemented by comparing output from a model run over competitive constraints with output from a model run over all constraints, and mitigating the portion of a unit's bid curve above the competitive constraint model run results.

In public testimony, articles, and decisions, CAISO personnel and FERC recognized several nuances in developing the structural approach, important distinctions between the structural and C&I approaches, and also important differences between CAISO and PJM's implementation of the three pivotal supplier test, as explained below.

1. CAISO Structural vs. Conduct-and-Impact Approaches

CAISO decided to switch from its current conduct-and-impact approach to a structural approach based on several concerns it identified with conduct-and-impact approaches. CAISO's primary concern with conduct-and-impact approaches is that they define an "acceptable level of market power," and thus might provide suppliers an incentive to bid just below that level. In contrast, structural approaches provide no such bright lines.

Moreover, in line with its preference for conservative screens, CAISO personnel expressed support for mitigating to cost-based reference levels rather than the bid-based reference levels which are more common under conduct-and-impact approaches. CAISO stated that cost-based reference levels are less likely to be able to be manipulated by suppliers, but CAISO also offers an LMP-based reference level. However, CAISO personnel conceded that stricter conduct-and-impact thresholds can be imposed on areas of known potential for the exercise of market power (*e.g.,* load pockets like New York City).

2. Nuances in Developing a Structural Approach

CAISO recognizes that a three pivotal supplier test is relatively strict in that it assumes all transmission paths are non-competitive unless the three pivotal supplier test shows otherwise.[132] However, the screen is designed to err on the side of caution because false positives (*i.e.*, designating a truly noncompetitive path as competitive) have, in CAISO's eyes, more severe economic consequences than false negatives (*i.e.*, designating a truly competitive path as non-competitive). Notwithstanding this preference for relatively conservative tests, CAISO will, under FERC's direction, re-evaluate the three pivotal supplier test during the first year of

[132] See Casey (2006), p. 61 and Isemonger (2007).

implementation to determine if it is overly stringent or if another test more accurately identifies market power opportunities for generators in load pockets.

In developing its test, CAISO also considered a “price movement” screen that would result in paths being designated as non-competitive even without a finding of three jointly pivotal suppliers, if it could be shown that price increases would remain limited. It concluded that the complexity of this approach was too high to warrant implementation at this time.

3. CAISO vs. PJM Structural Approaches

Both CAISO and PJM exempt major regional transmission interfaces or inter-zonal transmission paths from mitigation under the presumption that these paths are competitive. However, despite the CAISO’s implementation of a PJM-style structural approach based on a 3JPS test, it is instructive to consider how the CAISO implementation of this approach differs from PJM’s.

- PJM predefines which transmission constraints are competitive and which are non-competitive and thus subject to mitigation based on the presumption of local market power. PJM then uses the 3JPS screen to exempt certain suppliers that are dispatched to relieve binding local constraints from default mitigation. In contrast, the CAISO approach uses a 3JPS screen to determine which local constraints should be mitigated by default.
- The CAISO approach also does not rely on a supplier-by-supplier assessment of individual constraints and on shift factors to determine effective supply for relief of transmission constraints. Since constraints interact and shift factors depend on selection of reference buses, CAISO tests for simultaneous feasibility of the entire system to avoid a potentially inaccurate assessment of the competitiveness of transmission paths.
- The CAISO identifies non-competitive constraints simultaneously by determining with a power flow model if any three suppliers are pivotal in resolving any constraint. While PJM tests for whether default mitigation can be lifted one constraint at a time, supplier by supplier, the CAISO approach does not allow for temporary, supplier-specific exemption to mitigation.
- CAISO performs its three pivotal supplier test for purposes of identifying competitive and noncompetitive constraints annually, and eventually will do so seasonally. In contrast, PJM performs its three pivotal supplier test whenever local transmission constraints are binding, which means as often as every hour of the day-ahead market, and as often as every five-minute interval of the real-time market.

* * *

This section of our report has shown that U.S. RTOs have chosen two substantially different approaches to market power mitigation. PJM’s market power mitigation relies primarily on structural screens that prevent any firm which appears to have market power from abusing it. CAISO and ERCOT, in their new market designs, largely followed the PJM-style structural approach, although implementation details differ considerably. The other RTOs, notably MISO, NYISO, and ISO-NE, rely on conduct-and-impact tests that determine whether a firm likely has exercised market power and whether this exercise of market power has affected prices materially.

V. LESSONS DRAWN FROM OUR REVIEW OF MITIGATION PROCESSES IN RTO MARKETS

In this section of our report, we first develop a "strawman" framework for assessing "best practices" in market power mitigation that is consistent with our prior discussions of market power and market power abuse. We then attempt to identify the extent to which specific best practice mitigation processes have evolved in the existing RTO markets to date.

As discussed in Sections II and III, mitigation of market power is one of the most challenging tasks faced by regulators of liberalized electricity markets. It is broadly recognized that electricity markets were generally not structurally competitive prior to liberalization. Though many of these structural concerns may have been addressed in part by divestiture efforts and entry of new suppliers, market power concerns prevail particularly in more concentrated local market areas created by binding transmission constraints. While we do not address how broader market structure and market design options can mitigate market power, the importance of such structural and design options—including transmission expansion, reducing concentration of generation ownership, and increased reliance on forward contracts—cannot be understated. The need for *ex ante* and *ex post* mitigation measures depends critically on the extent of competition resulting form a market's structure and design.

To the extent market power concerns exist, they are partly addressed through the *ex post* enforcement of regulatory rules and competition laws. However, the available *ex post* measures incompletely address market power concerns in electricity markets because: (1) lags inherent in *ex post* approaches can mean consumers are insufficiently protected against immediate harm from market power abuses; and (2) available *ex post* remedies may not be able to fully remedy the associated harm. This is particularly true in the U.S. where, unlike in Europe, antitrust laws do not protect consumers against high prices due to unilateral output withholding. Similarly, U.S. energy industry regulators do not have the authority to impose structural remedies (*e.g.*, divestiture) to address unilateral or multilateral market power, and U.S. antitrust authorities rarely succeed in imposing structural remedies (outside of merger cases).

As a consequence, there is widespread recognition, particularly in the U.S., that some level of *ex ante* mitigation of market power is advisable. In fact, as shown in Section IV of this report, *ex ante* mitigation processes are prevalent in all U.S. organized electricity markets. In several cases, these *ex ante* mitigation processes involve the application of default mitigation measures to address local market power concerns that rely upon estimates of individual generating units' marginal costs. This means that market prices in these local markets essentially are determined through marginal-cost-based regulation. (Note that these regulated cost-based prices also apply to generators who have received market-based rate authority.) However, for markets that are deemed to be more conducive to competition, the existing mitigation processes generally do involve a more light-handed form of regulation through bid caps and price caps that may allow market prices to deviate substantially from available measures of marginal cost. It is against this backdrop that we have attempted to develop a strawman best practice framework and identify the extent to which we feel best practice mitigation processes may have evolved.

A. A STRAWMAN "BEST PRACTICES" FRAMEWORK FOR *EX ANTE* MARKET POWER MITIGATION

The development of an effective *ex ante* market power mitigation framework *ideally* would involve the following three-step framework:

1. Define market power abuse

Through the regulatory process, it is essential to define how much exercise of market power is acceptable. This will require specifying at which point: (1) prices fail to remain just and reasonable, (2) firm actions are incompatible with workable competition, and (3) a firm possesses "substantial" market power.

2. Develop screens that detect market power abuse and are compatible with the policymaker's "loss function"

It is necessary to develop tests (*i.e.*, screens)[133], thresholds, and analyses that can identify unacceptable levels of market power. Irrespective of whether these tests rely on structural or conduct-and-impact approaches, the development of an appropriate screening process for market power abuse should involve a determination of their effectiveness and reliability. In particular, the screens should be analyzed to determine the following: (i) what is the likelihood of falsely identifying market power abuse when none exists (*i.e.*, false positives or Type I errors)?;[134] and, (ii) what is the likelihood of not identifying market power abuse when it does exist (*i.e.*, false negatives or Type II errors)?

Once the likelihood of false negatives and false positives arising from various candidate screening processes are determined, an appropriate test framework can be chosen by the policymaker (*e.g.*, RTOs, the FERC) if the policymaker has a clear idea as to the magnitude, or at least nature, of the "losses" (*i.e.*, aggregate social costs) associated with each type of testing error. The appropriate screen (or combination of screens) for market power abuse is the one that provides the maximum social benefits (or leads to the minimum social losses), taking into account the direct cost of implementing the screen and adjusting it as market conditions change.

For example, if the policymaker considers false negatives (*i.e.*, failing to recognize market power abuse when it exists) as being much more costly than false positives (*i.e.*, falsely identifying

133 In this document, the terms "test" and "screens" are used equivalently to refer to quantitative exercises that indicate whether particular transactions have market power impacts that exceed identified thresholds. In some instances the term "screen" is used to refer to one type of test that is preliminary or intentionally coarse in nature, followed by a more detailed test. We do not recognize this distinction in our terminology. However, many testing processes have an initial or screening stage. Our discussion here refers to the entire test process, regardless of whether it employs one of more stages.

134 Note this definition of "false positives" and "false negatives" applies only to tests designed to determine the presence of market power. If a test is applied to determine the presence of competitive conditions, a "false positive" is the incorrect designation of a market as competitive when it is not. Also note, for example, that a test that is designed to reliably determine the presence of competitive conditions (*i.e.*, few false positives) may generate many false negatives (*i.e.*, not designate a market as competitive when it is).

market power abuse when it does not exist), then the policymaker may wish to choose a particularly stringent screen, since over-mitigation would be viewed as being less costly than under-mitigation. On the other hand, if false positives are considered to be relatively costly, then the policymaker may wish to rely on a less stringent screening approach. These tradeoffs have also been recognized by FERC in its 2004 MISO order:

> In applying mitigation, the difficulty is to set appropriate thresholds that balance under-mitigation and over-mitigation. Each has its costs. In particular, setting thresholds too high and thus under-mitigating the market means that some exercise of market power will not be mitigated or will not be fully mitigated. Setting thresholds too low results in over-mitigation, which could lead to more frequent intervention in the market, and that some competitive market results will be mitigated, decreasing market confidence and, therefore, investment in needed infrastructure.[135]

Regardless of the type of screen chosen, it is important to recognize that the overall reliability of any screen will depend on the accuracy of the process used to identify relevant product and geographic markets, as well as the screen's underlying accuracy in identifying the likely abuse of market power when it is applied to correctly-defined relevant markets.

3. Specify mitigation actions

As the last step in this framework, it is necessary to specify the appropriate mitigation actions that should be taken if the exercise of market power has been identified. For example, this requires the determination of the proper reference level to which bids or prices should be mitigated, and an assessment of how reliably such a reference level can be determined.

Although the chosen reference level should be compatible with the manner in which the policymaker distinguishes between abuses of market power and otherwise acceptable behavior, there may be some merit in setting the reference level to deter anticompetitive conduct under the prospect that such conduct may not always be discovered by the chosen screening process.

* * *

This three-step framework is the one against which we judge best practices. Thus, the rest of this section is organized as follows. First, we examine best practices as they apply to defining market power abuse. Second, we analyze best practices involving the choice of testing frameworks for market power abuse. Third, we examine best practices with respect to choosing reference levels for applying mitigation.

Lastly, we focus on the particular market power mitigation approach used by PJM. This analysis proceeds in three stages. Initially, we examine the desirability of using a three jointly pivotal supplier (3JPS) test in general, as compared with other possible tests. Then, we examine issues involving PJM's specific application of its 3JPS test. Based on this discussion, we then offer

[135] Federal Energy Regulatory Commission (2004c), paragraph 238.

recommendations that PJM may wish to consider with respect to its market power mitigation processes in Section VI of this report.

B. Challenges Created by the Absence of a Clear Definition of Market Power Abuse

With respect to the first step, it is clear that RTOs and FERC need to make more progress in defining consistently what constitutes market power abuse—a definition that is elusive, as discussed previously. In some instances, there is no clear articulation of market power abuse by regulators other than that which can be inferred from the particular testing framework and chosen thresholds. In this case, the definition of abuse of market power is conflated with the choice of screen.

For example, in PJM, when either a single supplier or two suppliers are jointly pivotal in relieving a specified transmission constraint, all suppliers necessarily fail the three jointly pivotal supplier (3JPS) test and are potentially subject to mitigation, regardless of their market share magnitude or their ability to influence price. Because PJM imposes mitigation using a screen that does not assess the magnitude that price can be raised by an individual supplier (or the incentive of the supplier to raise price), but rather uses a somewhat inclusive screen that merely assesses the joint *ability* of suppliers to influence a particular transmission constraint, PJM is implicitly defining market power abuse based on a particularly strict standard of the ability to raise price. This stringent standard is also reinforced in the application of mitigation, where the reference price in PJM is typically marginal cost plus ten percent. However, because PJM has not attempted to define market power abuse in a sufficiently distinct manner, one cannot assess whether the application of the current testing framework is actually consistent with the policymaker's view of what constitutes abuse.

It is unhelpful to conflate the definition of market power abuse with the chosen screening methods, since the results of two different screening methods are unlikely to be the same. For this reason, we believe it is best practice to define the abuse of market power in a manner that is separate from the testing approach. The chosen testing approach should depend on both the definition of the abuse of market power and the policymaker's loss function associated with screening errors.

Policymakers may on occasion fall back on an overly general definition of market power abuse due to concerns that an excessively concrete standard for market power abuse leads to a bright line testing framework that is subject to gaming behavior by market participants. This need not be the case. Concerns regarding the transparency of the standards for triggering market power mitigation are a separate issue from the need to define market power abuse clearly, particularly the conduct or behavior that is considered to represent abuse. In this regard, clear benefits would arise from FERC's development of a definition for market power abuse that can be used consistently across all RTOs and that leads to just and reasonable prices when mitigation is applied.

C. Differences in the Loss Function across RTOs and Best Practices in Choosing an Appropriate Screen

1. Discussion

Despite an often imprecise definition of what constitutes an abuse of market power, two general market power testing and mitigation approaches have evolved. The first approach is a "cautious approach" that imposes fairly stringent mitigation (*e.g.*, based on short-run marginal costs) under a direct or indirect presumption that many (if not all) sellers in a constrained local market are likely to possess undue levels of market power. Several RTOs, including PJM and CAISO, arguably employ this approach when dealing with localized geographic markets as defined by transmission constraints. However, the structural screens relied upon by PJM and CAISO also can cause mitigation to be applied to very small market participants who may not possess substantive market power, simply because they are dispatched to relieve transmission constraints that are deemed non-competitive.

The second approach relies on a deliberately higher threshold for market power abuse and imposes mitigation more sparingly. This approach, arguably followed by NYISO, MISO, and ISO-NE, reflects more of "an innocent until proven guilty" framework, presuming that competitive conditions exist in most of the RTOs' service areas (*e.g.*, outside of the NYISO's New York City zone or MISO's narrowly constrained area) until individual generator behavior is observed, or specified market conditions arise, that appear inconsistent with workable competition. These two approaches (more stringent mitigation based on a presumption of market power as compared with more permissive mitigation based on a presumption of competitive conditions) are integrally related to the design of the various screens and thresholds used to determine when market power should be mitigated.

As we indicate above, the appropriate mitigation testing and approach depends on the policymaker's estimate of the "losses" resulting from any errors produced by the chosen market power screening method. The approach of either presuming market power or alternatively presuming workably competitive conditions, unless evidence shows otherwise, is (in the absence of thorough testing) an implicit judgment about the consequences (*i.e.*, the loss function) associated with not identifying market power abuse when it is present, as opposed to falsely identifying market power abuse when it is absent. If false negatives (*i.e.*, failing to recognize market power abuse when it exists) are viewed as much more costly than false positives (*i.e.*, falsely identifying market power abuse when it does not exist), then a stringent screen that may lead to over-mitigation is potentially more desirable than a permissive screen that may lead to under-mitigation of actual market power.

Thus, the right mitigation approach and, accordingly, the right screen, differ depending on the degree to which market conditions can be measured definitively over a broad range of time periods (which in electric markets is quite rare) and the policymaker's view of the losses resulting from errors in this screening process. It is possible though, that the screen used to impose mitigation is not a best practice based on the policymaker's loss function because: (i) the screen is too lenient (or too strict) when false negatives (or false positives) are perceived to be relatively costly; or (ii) another screen or combination of screens is more accurate than the proposed screen, thereby leading to lower losses in general.

For example, although the 3JPS tests used by PJM and CAISO may be overly strict structural screens (as we discuss later), the use of this screen may be appropriate if the policymakers' loss function places a much higher cost on false negatives than on false positives. This appears to be the case. The director of market monitoring at the CAISO has noted that a cautious approach to mitigation based on a presumption of localized market power is necessary to reduce the likelihood of significant consumer harm until more experience with market performance is gained.[136] As he explains, this is justified because the cost of designating a local market as competitive when it is not can be far more harmful than designating a local market as non-competitive when it is actually competitive. This view, which the FERC recently endorsed on an interim basis, reflects a corresponding implicit assumption that incorrectly designating a competitive path as non-competitive has a relatively small impact on final prices (or leads to only modest losses of economic efficiency).

In contrast to the CAISO market redesign effort, the MISO, NYISO, and ISO-NE markets have been operational under a consistent market design over a longer time period and therefore offer a larger set of market outcome observations upon which to base their mitigation framework. Based on these observations and their apparent loss function, they apparently attribute a larger cost to false positives. Consequently, the market power mitigation practices in MISO, NYISO, and ISO-NE depend on a conduct-and-impact approach that imposes mitigation only when market power is being exercised to a significant degree. As David Patton (the independent market monitor for ERCOT, MISO, and ISO-NE, and the independent market advisor for NYISO) explains: "[conduct-and-impact mitigation] minimizes intervention in the market by ensuring that evidence of substantial market power abuse exists before mitigation is imposed."[137] This contrasts with structural screens that may trigger mitigation when market participants merely have the potential ability, but not necessarily the incentive, to exercise market power. Patton also alludes to this potential deficiency of structural screens: "[PJM's approach as of March 2004] does not require any showing that the generator is attempting to raise prices, or that the generator in fact has market power."[138]

2. Best-Practice Recommendations

Based on our review of the strengths and weaknesses of both approaches, we find that a more integrated structure, conduct, and performance testing framework is advisable for triggering market power mitigation measures. A sole structural test could be improved by taking advantage of an RTO's ability to also assess individual firm conduct and its impact on actual market performance, so that mitigation errors are reduced. Arguably, RTOs have detailed information on prior participant behavior, as well as reasonably refined cost information, that allow them to assess whether market power is being abused.

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[136] See Casey (2006), pp. 59-61.
[137] See Patton (2004b), pp. 7-8.
[138] *Ibid.*

The conduct-and-impact mitigation approach could similarly be improved by taking advantage of available structural market information, which can help identify serious market power concerns that should be the subject of more intense scrutiny through a conduct-and-impact testing framework. This will help lessen the prospect that false negatives arise because the conduct-and-impact test is not applied in a sufficiently focused manner.

In other words, we find that these two approaches, structural and conduct-and-impact, do not need to be substitutes for one another. Rather, they are naturally complementary. Purely structural screens can benefit from an added conduct-and-impact assessment that avoids mitigation actions if individual participant behavior does not suggest that significant market power is being exercised. Similarly, a conduct-and-impact screen can benefit from the utilization of a structural screen that can identify specific market conditions or geographic regions where significant market power concerns exist.

Applying an integrated approach using both structural and conduct-and-impact screens also facilitates the assessments of the effectiveness of the market-monitoring process. For example, if the conduct-and-impact screen identifies many instances where there is no significant exercise of market power occurring when a particular structural screen indicates cause for concern, then the RTO may choose to consider alternative structural screens that are less stringent. Similarly, by examining the structural conditions under which market power mitigation is warranted under a conduct-and-impact approach, RTOs can develop an appropriate “early warning” structural screen to identify conditions that raise cause for concern. This will increase the reliability and effectiveness of the mitigation process and thereby reduce the costs imposed by the mitigation process.

As it turns out, some of the RTOs have already taken significant steps towards developing an integrated structural and conduct-and-impact screening process. As discussed in Section 4, for example, the Midwest ISO periodically applies an *ex ante* structural screening process to distinguish between narrowly-constrained markets within which significant market power concerns exist and broadly-constrained markets for which market power concerns are limited. Automated conduct-and-impact screens are then applied in these markets on a real-time basis, with lower bid and market-impact thresholds for narrowly-constrained markets and higher thresholds for broadly constrained markets. Structural screens are then, again, used to assess market performance and the reliability and effectiveness of the mitigation process on an *ex post* basis.

The process of developing best-practices structural and conduct-and-impact screens should also consider the timeframe available to conduct the screening process. As discussed above, very little time is available for the *ex ante* evaluation of supplier conduct and market impact (*i.e.*, the interval between the submission of bids and the finalizing of market prices). Since the RTOs’ real-time and day-ahead dispatch and market-settlement processes are already highly complex, there are clear practical limits to the complexity of screens that can be used to run automatically on a real-time or even day-ahead basis. These timing considerations suggest that relatively simple threshold-based, conduct-and-impact screens might be preferable in such applications.

More data-intensive and time-intensive structural screens can be performed ahead of the observed market conduct (*i.e.,* submission of bids), because the information used in conducting most structural screens will not typically change materially on an hourly or daily basis. Nonetheless, these screens have to be performed with sufficient frequency (or a sufficiently wide range of market conditions) to account for relevant demand and supply conditions that affect the ability and incentive of market participants to exercise market power.

There is also the question of whether *ex ante* mitigation screens should be applied to real-time markets only, or on both a real-time and day-ahead basis.[139] As discussed above, some of the RTOs apply automated *ex ante* mitigation protocols to both the real-time and day-ahead markets (*e.g.*, PJM, CAISO), while others apply such mitigation only on a real-time basis (*e.g.*, ERCOT). Yet others, such as MISO, apply a hybrid approach in which automated mitigation processes are applied in the real-time market, but only semi-automated processes are used to monitor and, if necessary, mitigate day-ahead markets for the following day. We find that *ex ante* screening processes may be warranted in both real-time and day-ahead markets whenever "virtual bidding" (also called "convergence bidding") would not be expected to arbitrage effectively differences between mitigated real-time and un-mitigated day-ahead markets. For example, *ex ante* mitigation of day-ahead markets may be warranted in narrow local markets. If automated processes are not used in day-ahead markets, the RTO should still have access to manual or semi-automated day-ahead mitigation processes that can be imposed (*e.g.*, during the following day) if the *ex post* monitoring of the day-ahead markets identifies significant market power concerns.

We also have identified the following additional best practice guidelines. Market power screens should be based on a transparent screening framework that appropriately considers relevant product and geographic markets and that can be readily understood by market participants. The screening tools used in *ex ante* mitigation processes need to be evaluated periodically to identify adjustments and modifications that could improve their reliability and effectiveness. Careful *ex post* monitoring of market performance will be necessary to evaluate unusual market events and uncover market power abuse that may elude the *ex ante* mitigation processes. If substantial market power abuse is detected through the *ex post* review of firm behavior and market performance, then market design features, *ex ante* market power screens, and reference levels used for mitigation may be adjusted to prevent and deter such behavior in the future.

D. COMPATIBILITY OF MITIGATION ACTIONS AND REFERENCE LEVELS WITH THE DEFINITION OF MARKET POWER ABUSE

1. Discussion

It is important to note a proper relationship between the stringency of the testing approach and the specifics of the mitigation applied when market power thresholds are exceeded. If the regulator's loss function places a high cost on false negatives, and the screen chosen to support the loss function accordingly errs on the side of over-mitigation, then the choice of reference level (to which offers or prices are mitigated) should consider that mitigation may frequently be

139 Note that in today's organized RTO market, 100 percent of available supply and demand is dispatched and balanced in real-time markets. This will also be the case under ERCOT and CAISO's proposed nodal market designs.

applied to "non-guilty" parties. Consequently, there should be a very low risk that the reference level used when applying mitigation could be punitive.

On the other hand, if the regulator's loss function places a high cost on false positives, and the screen chosen to support the loss function accordingly errs on the side of under-mitigation, then the reference level could be chosen to be more stringent, considering that "guilty" parties may not always be caught. However, such an approach may be inefficient as a deterrent because it would not only affect the individual supplier whose behavior is being mitigated, but also the entire market.

As documented in the above description of U.S. markets, the mitigation actions designed to address screen violations typically result in market participants' bids being reset prospectively to so-called competitive reference levels. For the most part, these reference levels are determined to be one of the following: (i) the average level of accepted bids during competitive market conditions in the past 90 days, adjusted for changes in fuel prices (*e.g.*, used as the first choice in ISO-NE, NYISO, and MISO), (ii) the average LMP during the lowest-priced 25 percent of hours during the past 90 days when the unit was dispatched, adjusted for changes in fuel prices (*e.g.*, used as the second choice in ISO-NE, NYISO, and MISO), or (iii) the marginal cost of the individual resource (*e.g.*, used primarily by PJM, CAISO). Due to the difficulty in exactly measuring marginal costs and the importance of not creating below-cost bidding through the imposition of mitigation, a 10 percent adder is usually applied to marginal cost calculations. We find that a 10 percent adder may represent a too tight tolerance band for some types of generating units, given the difficulty of determining marginal costs for some generating units, such as combustion turbines. As a result, not only might RTOs incur the prospect of over-mitigation in their choice of fairly stringent structural screens, but the cost that over-mitigation may be compounded by the choice of "marginal cost plus 10 percent" as the primary reference level if marginal costs are underestimated.

The challenge of correctly measuring marginal cost for the purpose of determining a perfectly competitive market outcome should not be underestimated. This challenge arises from the difficulties in identifying and measuring certain operating and maintenance costs (*e.g.*, for combustion turbines), certain fuel supply costs (*e.g.*, natural gas pipeline balancing or backup fuel storage costs), and opportunity costs created by alternative sales opportunities and various operational constraints.[140] As a result of these difficulties in determining the marginal cost associated with certain resources, mitigation actions that use reference levels based on proxies for the generating units' marginal operating cost bear the risk of constraining market clearing prices to levels that are inconsistent with even perfectly competitive outcomes.

In recognition of this challenge and risk facing certain generating units, RTOs have implemented (or are considering implementing) a variety of mechanisms to improve the reference levels applied in mitigation actions. This includes negotiated reference levels for individual generating units, bid adders for frequently mitigated generating units, contracts that provide monthly fixed

140 As noted previously, opportunity costs are created, for example, if a generating unit can operate only during a certain number of hours within a year (*e.g.*, because of environmental constraints, hydro storage limitations, or fuel delivery constraints). In this case, bid prices in fully competitive markets will rise above variable operating costs such that dispatch occurs during those hours of the year that provide the highest value for the energy which the unit is able to produce.

payments to cover all or most of the generator's fixed costs, and scarcity pricing provisions that allow for market price adders during operating reserve deficiencies. In PJM, this issue is also addressed implicitly through the exemption from *ex ante* mitigation of 56 generating units that were built between 1999 and 2003.[141]

While reference levels based on considerations other than marginal operating cost (including negotiated reference levels) are an improvement, we are nonetheless concerned that several of these approaches do not reliably address the challenge of setting appropriate reference levels. For example:

(i) It is unclear why bid adders are justified for frequently mitigated units but not for other units. It is not clear that the frequency of mitigation accurately determines the resource, time period, and location for which adders should be applied to supplement pre-existing measures of marginal cost.

(ii) PJM's exemption of the newer, "grandfathered" generating units from mitigation unnecessarily limits the ability to achieve efficient energy pricing if owners of these units have the ability and incentive to exercise substantial market power.

(iii) Even if reference levels are determined correctly for individual units, the market will still be over-mitigated if market clearing prices do not correctly reflect the bids (or marginal costs) of the most expensive supply or demand-side resources that are actually dispatched. This problem exists in some of the RTOs, where the currently-used pricing software may not allow combustion turbines to set the market-clearing price in certain circumstances (*e.g.*, in MISO), or where the market-clearing price does not accurately reflect the bids (or value) of demand curtailment programs (*e.g.*, in NYISO).

2. Best-Practice Recommendations

Given these considerations, we can identify the following best practice guidelines. Market-clearing prices should reflect bids (whether mitigated or not) of all dispatched supply-side and demand-side resources (including the value of non-bid-based demand-response programs), and appropriate scarcity premiums (depending on the nature of the capacity markets). With respect to imposed mitigation actions, where possible and reliable, reference levels for market participants' bids should be reflective of bids or market prices during competitive conditions (*e.g.*, bids prices during competitive periods adjusted for changes in fuel prices or bids capped by fuel-adjusted market prices during competitive conditions). However, the extent to which the use of competitive reference periods results in workably effective mitigation needs to be monitored carefully to avoid gaming of bids and market prices during the reference period.

If marginal-cost-based reference levels are used to mitigate bids or market clearing prices, they should reflect full marginal costs, including opportunity costs and the potentially difficult-to-quantify operating costs of certain resources such as combustion turbines. Adders to marginal costs or marginal-cost-based market clearing prices should reflect: (i) the likely magnitude of estimation errors (which may be larger for resources with difficult to quantify marginal costs);

141 See PJM Market Monitoring Unit (2007a), p. 12.

and, (ii) the scarcity of available supply or demand-side resources (considering the particular design of capacity markets and inclusion of demand-side resources).

While several RTOs have addressed scarcity pricing, more research is needed to accurately quantify and implement scarcity pricing provisions that appropriately consider supply and demand-side resource balances, including the value of ISO-controlled and utility-dispatched demand-response resources. In addition, the appropriate level of scarcity pricing (which typically sets prices above marginal-cost-based market clearing prices) will necessarily be a function of the extent to which generators receive separate payments for capacity or resource adequacy, as well as the specifics of the design of the capacity markets. The existence of capacity markets or resource adequacy requirements, though, does not compensate for inaccuracies in energy market pricing. Also, heavy reliance on administered capacity markets to produce dynamic market efficiencies, such as appropriate levels of generation investment, may dull incentives to undertake proactive investments in demand-side resources that could stem directly from energy market pricing signals (or to use long-term contracts as a means of stimulating the building or expansion of generation plants).

In any event, reference levels (such as marginal cost calculations, bid adders, or scarcity adders to marginal-cost-based market clearing prices) should be reviewed periodically to improve pricing accuracy.

E. ASSESSMENT OF PIVOTAL SUPPLIER TESTS FROM A "BEST PRACTICES" PERSPECTIVE

1. Discussion

A number of RTOs have implemented (or are about to implement) structural screens based on the concept of pivotal suppliers. Conceptually, a pivotal supplier is a seller whose output must be purchased in whole or in part in order to satisfy demand at any market price. For example, if total market demand is 100 MW, Seller A owns 50 MW of capacity, and all other sellers own a total of 80 MW of capacity, Seller A is pivotal. Market wide demand cannot be satisfied without at least 20 MW of sales from Seller A.

The pivotal supplier index (or the closely related but continuous "residual supply index") competes with other structural measures such as market shares and HHIs. While market shares and HHIs are widely used by antitrust and regulatory agencies, recent mitigation processes implemented by RTOs rely more heavily on the concept of pivotal suppliers.[142] Pivotal supplier screens are already used by FERC in its MBR process, are used by MISO as part of its structural screen to identify Narrow Constrained Areas, will be used by CAISO and ERCOT in determining if transmission constraints should be deemed competitive, and are used by ISO-NE to assess system-wide market conditions.

[142] The wider use of pivotal supplier tests in power markets is motivated in part by the low elasticity of demand in electric spot markets, the concentrated structure of power markets, the fixed nature of power capacity in the short-term, and the significant amount of market and competitor information available.

In the context of our analysis, this raises the question of whether pivotal supplier tests should be considered best practices in terms of available structural screens. In general, we find that the single pivotal supplier test—or similar screens based on the (single) residual supplier index—is one of several well-accepted structural screens for market power. Conceptually, if performed appropriately, a single pivotal supplier test identifies whether one or several suppliers have the *unilateral* ability to substantially raise market prices under the identified current or pre-specified market conditions. Depending on the amount of economic withholding that is needed to induce this substantial price increase, the unilaterally pivotal supplier(s) also may have the incentive to exercise market power. There also is empirical support that the pivotal supplier and residual supply indices are reliable indicators of potential market power.[143] For example, the CAISO found that bids start to reflect markups over marginal cost slightly before individual suppliers become pivotal (*i.e.*, at the point when the residual supply index falls below 1.2).[144] The extent of the markup, however, is also a function of the extent to which suppliers' revenues depend on spot prices (*i.e.*, the portion of supply unhedged, which is a function of suppliers' long-term contracts and load-serving obligations).[145]

PJM has first proposed and implemented an extension of the (single) pivotal supplier test to develop a screen that determines if three suppliers jointly are pivotal. This three jointly pivotal supplier or 3JPS test is a unique approach that, since implementation by PJM, also has been adopted (although in a modified implementation format) by CAISO in its MRTU effort.

While the concept of a single pivotal supplier test is sound and supported by both theoretical and empirical research, it is less clear whether the 3JPS test constitutes a best practice structural test. At this point, very little theoretical and empirical academic research has evaluated the performance of the 3JPS test. We are aware of only one working paper that has evaluated the 3JPS test along with other structural metrics such as the single pivotal supplier test, the two jointly pivotal supplier test, and market concentration measures such as the HHI – all of which may be relevant to predicted market outcomes.[146]

As others have recognized, the 3JPS is a fairly stringent test (*i.e.*, it errs on the side of caution) and is arguably more likely to falsely identify market power when it does not exist (false positives) than to fail to identify market power when it actually does exist (false negatives). For example, CAISO specifically noted that the three [jointly] pivotal suppliers test is a fairly stringent criteria, also pointing out that CAISO Market Surveillance Committee recognized that

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143 See for example: Genc and Reynolds (2005); Blumsack and Lave (2005), Sheffrin (2002), and Borenstein, Bushnell, and Knittel (1999).

144 The residual supply index identifies whether a specified supplier, typically the largest supplier in a market, is needed to meet market demand. It is measured as the ratio of output (or capacity) of all suppliers other than the specified supplier relative to market demand. If, for example, the residual supply index equals 1.2, then all suppliers other than the largest firm in the market can supply only 1.2 times the level of market demand in total.

145 See Sheffrin (2002).

146 See Perekhodtsev, Blumsack, and Lave (2002). The working paper has not yet been published in a peer reviewed journal and appears to rely on very limiting assumptions that may be driving its results. These assumptions include (1) suppliers can bid only their marginal costs or at the price cap; (2) market prices can only be based on marginal cost or be equal to the cap; and (3) if market prices are at the cap, all high-bidding suppliers are dispatched in proportion to their share of total capacity.

“the three-pivotal-supplier approach is unlikely to be too lenient (*i.e.*, it is unlikely to falsely designate transmission paths as competitive if they truly are not).”[147]

The 3JPS test also tends to be more stringent than commonly-used other structural tests, including those used in FERC’s MBR guidelines, which screen for single pivotal suppliers, HHIs of more than 1800, and market shares in excess of 20 percent. For example, assume that a market contains 20 identical suppliers (5 percent market share each) and has a 14 percent reserve margin overall. Even though the HHI is only 500, and no supplier has a market share exceeding 20 percent, every one of the 20 suppliers would fail the 3JPS test and be subject to mitigation. While the existence and exercise of market power cannot be ruled out entirely, most antitrust economists are not likely to be concerned that this market structure would be inherently non-competitive.

Intuitively, the stringent nature of the 3JPS test also can be understood by evaluating its implications. If the two largest suppliers in a market are not jointly pivotal, but the three largest suppliers are, the three suppliers would need to jointly withhold more capacity than the combined capacity of the two largest suppliers in order for there to be insufficient output to meet market demand. This means that the amount of withheld output would be greater than two thirds of the combined supply capabilities of the three suppliers. It may be very difficult to achieve such a coordinated withholding outcome simply because the incentives to defect from it may be too strong, and such significant withholding behavior would be obvious. While these illustrations and considerations are not conclusive and do not dispel the potential accuracy and usefulness of the 3JPS screen for the purpose of some *ex ante* mitigation efforts in RTO markets, they do illustrate its stringent nature compared to other already commonly-used structural screens that are applied in similar contexts.

When 3JPS tests are applied as a screen (individually or in concert with other structural screens), one needs to consider more fully what the consequences are for suppliers that are not part of a jointly pivotal triumvirate. As implemented by CAISO, the existence of three jointly pivotal suppliers with respect to an intra-zonal transmission constraint triggers the mitigation of all suppliers that are dispatched for congestion relief on that constraint, irrespective of the suppliers’ size or market share. Similarly, while PJM applies the test on a supplier-specific basis, the application of the test can still result in screen failures of many suppliers who have only minimal market shares and ability to relieve a specified constraint. This would appear to result in over-mitigation with respect to a potentially large number of small suppliers of congestion relief on individual interfaces, which can result in market-wide over-mitigation. For example, in situations where there already is a single pivotal supplier or two jointly pivotal suppliers of congestion relief for a particular local interface, PJM would necessarily mitigate all suppliers that are selected to relieve the congestion. Whenever mitigation to marginal costs (plus a 10-percent adder) is so broadly applied, local market prices are essentially determined through cost-based regulation.

[147] See Casey (2006), p. 61 and Isemonger (2007).

2. Best-Practice Recommendations

Overall, we find that the concept of a single pivotal supplier test, or a residual supply index test, has reasonable theoretical and empirical support and is thus consistent with a best practices framework. However, based on the discussion above we cannot find that a 3JPS test constitutes best practice at this time. More analysis is needed to evaluate the effectiveness and reliability of the 3JPS test. FERC already made a similar point in a September 2006 order addressing the CAISO's MRTU when it stated: "we agree with commenters that a three-pivotal-supplier test may be overly stringent and therefore direct the [CAISO] Market Surveillance Committee, during the first year of implementation, to examine whether an alternative competitive screen to identify market power opportunities for generation in load pockets should be considered."[148] We also find that some of the implementation details of 3JPS tests, which vary significantly across RTOs, are questionable from a best practice perspective.

Given the relatively stringent and untested nature of the 3JPS test and the fact that the pivotal supplier concept leaves out other structural information, it is likely that a combination of structural tests (*e.g.*, single-supplier pivotality, HHIs above a specified threshold, and individual market share exceeding a specified threshold) could more reliably identify market power problems without producing as many false positives. ERCOT, for example, uses a combination of HHI and single-pivotal-supplier tests in determining whether suppliers affecting a particular transmission constraint should be deemed as behaving competitively or subject to mitigation. In general, a combination of structural screens may prove more reliable than a single screen in determining whether market conditions are conducive to the existence and abuse of market power. For example, the performance of a market with 3 jointly pivotal suppliers likely depends on how concentrated the remaining supplies are (*e.g.*, is there one other supplier with substantial capacity or a competitive fringe of many other suppliers?).

F. Concerns Raised by PJM's Specific Implementation of its 3JPS Test

Putting aside any general issues raised by the stringent nature of 3JPS tests, we have identified a number of specific concerns associated with particular aspects of PJM's implementation of its 3JPS test.

1. Transparency and Complexity

We find that critical implementation details of how the 3JPS test is applied in the real-time and day-ahead markets are not sufficiently transparent to allow for a thorough understanding of the test and resulting mitigation actions by market participants and industry analysts. While the theoretical concept is well documented, and examples and training materials explain the formulas used, it is unclear how certain variables are derived. For example, insufficient documentation exists on how the demand for congestion relief and effective supply of congestion relief are determined for individual interfaces, both of which have to be measured relative to a largely undocumented baseline of interface flows and generating unit dispatch. It is also unclear

[148] See Federal Energy Regulatory Commission (2006b), p. 283.

from existing documentation how mitigation actions are applied based on the 3JPS test result (*e.g.*, in the unit commitment process, or on a dispatch-period by dispatch-period basis). We found that other RTOs provide more thorough documentation of similar implementation details.[149] The difficulty involved in developing a thorough understanding of how PJM uses the 3JPS test to impose mitigation necessarily leads to confusion, and a possibly exaggerated perception of over-mitigation, all of which could serve to undermine the confidence of market participants and deter investment in new generation.

The following discussion is based on our current understanding of these implementation details. Although we have reviewed the available documentation and had the benefit of several conversations with PJM staff and PJM's MMU staff, our understanding of the implementation details is still limited.

2. Implicit Definition of Geographic and Product Markets

PJM's pivotal supplier test currently is applied on a constraint-by-constraint basis and "effective supply" is determined based on the absolute value of generation shift factors. We are concerned that this approach does not correctly define the relevant geographic markets and the suppliers within these markets. For example, we are concerned that, because a supplier's output choice may affect multiple constraints simultaneously and there may be suppliers which have influence over the same multiple constraints, performing the test for one constraint at a time (as done in PJM and planned by ERCOT) will not reliably define relevant geographic markets for the purpose of analyzing market power. The MISO approach of identifying geographic areas that become separated as a result of transmission constraints, or the CAISO approach of simultaneously testing the impact of particular suppliers on all local constraints, would appear to be more appropriate.

A similar issue arises from the fact that generators submit a single bid curve but likely are able to provide congestion relief for multiple constraints. If most of these constraints are deemed competitive, a concern over the generators' joint market position on one non-competitive constraint may not be indicative of a substantive ability or incentive to exercise significant market power. The competitive pressures experienced on the other constraints may effectively address that concern and deter the exercise of market power. In other words, a particular seller may lack the incentive to withhold capacity to affect a particular constraint, because its capacity may be simultaneously providing congestion relief services to several other competitive constraints.

We are also concerned that defining the "effective supply" available for congestion relief by multiplying generating capacity by the absolute value of "shift factors" (or power distribution factors) may incorrectly assign suppliers to relevant geographic markets. PJM's approach implicitly assumes that generators on "either side" of the constraint (*e.g.*, as indicated by with

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[149] In part, this difference is likely due to the fact that PJM applies the structural screen on both a real-time and day-ahead basis, while other RTOs (*e.g.*, CAISO) apply their structural screens less frequently (*e.g.*, once a year or seasonally). However, these RTOs also need to determine some aspects of their mitigation actions on a real-time and day-ahead basis, which similarly requires market simulation software to determine the incremental demand and supply for congestion relief in each dispatch interval.

positive and negative shift factors) are in the same market. This ignores the fact that generation on the low-priced side of a constraint may not be able to compete with generation on the high-priced side of a constraint. ERCOT, for example, has recognized this issue by applying its structural screens separately for the import and export side of each constraint.

3. The 150 Percent of the "Shadow Price" Threshold for Determining Available Generation Supply

PJM's threshold for measuring the effective supply of congestion relief consists of those generating units that can economically provide congestion relief at less than 150 percent of the constraint's shadow price, as opposed to the actual market-clearing price in the constrained area. This approach can result in an improper identification of the actual and possible competitors in the market and thus substantially affect the calculation of the amount of generation capacity that is available to counteract hypothetical economic withholding behavior. For example, the 150-percent threshold may not be sufficiently limiting when shadow prices are high, effectively including in the market output that would be economically viable only in the event of a substantial market price increase. On the other hand, if the shadow price is low, then the 150-percent threshold does not necessarily identify output that would become economically viable in the event of a small but significant price increase, and thus could prevent the exercise of market power.

The 150-percent shadow price threshold also creates counter-intuitive variances in the determination of available supply for congestion relief. For example, if a constraint binds "tightly" and therefore is associated with a high shadow price, the 150-percent threshold will be high as well. Many generators will fall within the screen, which will make it easier to pass the 3JPS test. In contrast, if a constraint can be managed at a low shadow price, the 150-percent threshold will screen out many more generators, thus restricting supply and making it more difficult to pass the test. This suggests that the 3JPS test as implemented is increasingly more difficult to pass for interfaces that may have low shadow prices, which applies more stringent mitigation to constraints that have less impact on market prices. Since shadow prices can change quickly, test results may change often and in a counter-intuitive fashion.

The fact that both distribution factors and price thresholds change frequently further decreases the transparency and possible effectiveness of the screen. A generator may have limited awareness of its impact on certain constraints and therefore limited intent to raise bids to take advantage of this rapidly changing and difficult-to-measure impact.

4. The "Baseline" for Defining Demand for and Supply of Congestion Relief

The 3JPS test relies on a baseline against which the demand for incremental congestion relief is measured. Based on our current understanding, the baseline for the first hour of the day-ahead market is set by PJM's unit commitment software that considers only the 25 most significant constraints. The difference in flows and generation dispatch between this baseline commitment run and the actual system dispatch is then used to define the incremental demand and supply for congestion relief in the first hour of the day-ahead market. In the following hours of the day-ahead and real-time markets, the incremental demand and available effective supply for congestion relief in one dispatch period is then simply measured relative to the power flows and dispatch levels in the prior period.

We are concerned that this approach does not determine the relevant baseline against which the demand and effective available supply of congestion relief should be measured. The demand for congestion relief on a particular transmission constraint during a particular time period likely should not be based on the managed flows from the last dispatch period, but instead on an unconstrained baseline. The latter approach is used by both CAISO and ERCOT in their application of their structural screens. To determine this baseline both CAISO and ERCOT will first simulate the market by enforcing only the transmission constraints deemed competitive. The demand and available supply for congestion relief on the non-competitive transmission constraints is then determined by comparing the market simulation that includes all transmission constraints with the simulation results that include only the constraints that are deemed competitive.

The combination of changing shadow-price thresholds and shift factors, coupled with the use of the prior period as a baseline in determining the demand and supply of congestion relief, can lead to screening results that differ greatly over the course of a few dispatch periods. For example, preliminary analyses by PJM staff have shown that the 3JPS test as currently implemented in the real-time market can fluctuate between pass and fail up to 16 times a day. These fluctuations are likely to reflect substantial "noise" in the mitigation process, as opposed to correctly identifying circumstances where the ability and incentive to exercise market power has changed materially.

5. Potential Inconsistencies in the Triggering and Implementation of Mitigation

As discussed in Section IV of our report, a failure of the 3JPS test does not *per se* lead to mitigation actions based on PJM's current implementation procedures. For this and other reasons, we are concerned that there are certain inherent inconsistencies in the mitigation process.

A failure of the 3JPS test currently does not trigger mitigation actions in a number of settings. First, a supplier's bid is mitigated only if the resource is dispatched for the purpose of providing incremental congestion relief on the specific transmission constraint for which the 3JPS test has been conducted (*i.e.*, a bid is not mitigated if it could provide but is not dispatched to provide the required congestion relief). However, incremental congestion relief is typically determined only relative to the prior dispatch period. We are concerned that this does not accurately assess the true magnitude of the generation dispatch needed to manage individual constraints for which market power concerns have been identified.

Second, with some exceptions, mitigation actions are applied only when the unit is first committed for dispatch. If the 3JPS screen is not violated when that commitment decision is made, the unit would not generally be subject to mitigation during subsequent dispatch periods even if changes in market conditions produce failures of the 3JPS test. If it truly is appropriate to test each dispatch period (*e.g.*, run the 3JPS test every 5 minutes in real time), it is not clear why mitigation actions should be determined largely on the basis of market conditions that occur only during the initial commitment of generating resources.

Third, as noted previously, the 3JPS test will not trigger any mitigation action for a set of "grandfathered" generating units (*i.e.*, over 50 units built between 1999 and 2003), which have been exempt from mitigation. We are concerned that exempting grandfathered generating units from mitigation will undermine the mitigation processes, because the exemption is not based on an assessment of market conditions, including specifically the resource owners' ability to exercise market power.

Finally, as mentioned above, we are concerned that the use of a marginal-cost-plus-10-percent reference level for imposing mitigation may represent an overly stringent standard in light of the inherent inaccuracies in measuring marginal cost for some units and the frequency of mitigation which is likely to be triggered under the 3JPS (despite the above exceptions to mitigation). We are also concerned that bid adders for frequently mitigated units and the current approach to scarcity pricing do not accurately address this issue. If mitigation is frequently applied in congested areas, and that mitigation leads to prices reflective of "marginal cost plus bid adders," then the competitive paradigm has been largely replaced by cost-based regulation. While it is possible that this is the desired policy goal, many workably competitive markets would be hard-pressed to satisfy such an administratively determined standard, implying that PJM's combined screening and mitigation processes may produce results that are inconsistent with outcomes that electric power markets would achieve under workable competition. This naturally raises the question as to whether the screening process or the imposed mitigation, or both, are consistent with the intended policy definition as to what constitutes abuse of market power.

VI. RECOMMENDATIONS TO PJM

From the above discussion, and based upon our review and experience with market monitoring practices in various jurisdictions, we recommend that PJM take the following actions, as described below. These actions should not be considered an exhaustive list; we have noted other more technical issues associated with PJM's application of its market power screens and mitigation protocols in Section V.

1. Work with FERC to define "market power" and "market power abuse" more clearly.

Consistent with the definition used by the antitrust agencies, we recommend that:

> market power be defined as "*the ability of an individual supplier or group of suppliers to profitably maintain prices above competitive levels for a significant period of time.*" Given the prospect for significant price spikes in electric power markets, an "extended period of time" might be as short as several dispatch periods.

We also recommend that

> market power abuse be defined at least qualitatively as "*any conduct that ultimately harms consumers by substantially distorting or impairing competition, and that would not be in the economic interest of the market participants but for the presence of market power*."

However, more regulatory guidance is needed as to what constitutes a substantial distortion or impairment of competition. In this context, we recommend that PJM work with FERC to more clearly articulate appropriate standards for market power abuse, that are consistent with the Commission's own standards for just and reasonable pricing. Then, market power screening and mitigation protocols should be evaluated and, if necessary, modified so they are not only consistent with such standards, but also consistent with an explicit assessment of the costs arising from the under-mitigation or over-mitigation of abusive behavior.

At present, the structural screen used by PJM appears to be quite stringent, also focusing more on a market participant's ability to increase price and less on its incentive to actually carry out such a price increase (through the economic withholding of output). This raises the questions as to what PJM believes is the appropriate standard of market power abuse, and whether the currently-used screen is consistent with that standard.

2. Eliminate the exemption of "grandfathered" generating units from automatic mitigation.

There does not appear to be an inherent reason to suggest that owners of grandfathered generating units which are not subject to *ex ante* mitigation processes are any less likely to engage in market power abuse than owners of other generating units. Exempting the generating units built between 1999 and 2003 from mitigation will likely undermine mitigation processes no matter how well designed. We consequently recommend that PJM reconsider the extent to which such units should be exempted from *ex ante* mitigation.

3. Make the application of the market power screens more transparent to market participants

Regardless of the ultimate market power screen or screens chosen, PJM should produce more detailed documentation of how market power mitigation is implemented and how the necessary variables are determined in both the day-ahead and real-time basis. While some documentation already exists, it should be extended to include more detailed descriptions of all elements of the market power screening and mitigation procedures for day-ahead, real-time, and capacity markets. As it currently stands, it is very difficult (if not impossible) for market participants to determine how the screens are applied and when or why they are subject to mitigation. The lack of transparency also makes it very difficult for policy analysts to evaluate the effectiveness and reliability of a screen.

4. Consider adding a conduct-and-impact assessment to the existing structural screen, using the structural screen as a first step and the conduct-and-impact assessment as a second step.

There are strong arguments for using both a structural screen and a conduct-and-impact test in a complementary manner, rather than viewing these two types of screens as substitutes for one another in the market-monitoring process. Adding to a structural screen a conduct-and-impact test with mitigation thresholds that are consistent with an explicit definition of market power abuse offers the prospect of increasing the accuracy of the overall screening process, leading to fewer false positives (while not necessarily increasing the number of false negatives) and a lower overall cost associated with mitigation errors. This is because structural screens, such as joint pivotal supplier tests, are better at identifying the ability to exercise market power, rather than the incentive. Conduct-and-impact screens assess whether market power is actually being exercised, which would seem to confirm that the "suspect" market participant had the incentive to exercise market power.

The implementation of a conduct-and-impact screen would not appear to impose a substantially greater burden on PJM than its current application of the 3JPS, which is performed at 5-minute intervals and requires substantial data on bids and marginal costs in order to apply mitigation and recalculate market-clearing prices. The impact part of the conduct-and-impact analysis relies on similar information since it requires an assessment of how market prices would respond to an alteration of a participant's bidding behavior, along with the calculation of the market-clearing price under mitigation. Moreover, under a two-step screening approach where an initial structural screen (*e.g.*, 3JPS) is followed by a subsequent conduct-and-impact analysis, the structural screen can be performed less frequently than the 3JPS is currently performed.

5. Consider alternative structural screens to the 3JPS screen and analyze the potential for over-mitigation implied by the 3JPS screen.

As a basis for triggering automatic mitigation, the application of the 3JPS by PJM runs the risk of mitigating the behavior of market participants who have limited ability or incentive to engage in market power abuse. PJM should examine past instances of mitigation of individual market participants, looking at whether the application of mitigation was warranted based on market participants ability and incentive to increase market price, as well as the participants' actual bidding behavior relative to mitigation thresholds and reference levels used in mitigation.

While the use of the 3JPS as the sole screen for triggering automatic mitigation raises the prospect of substantial over-mitigation, along with its attendant costs, the use of the 3JPS as a first step in a two-step screening process would appear to be less problematic. Using a stringent initial screen to identify market participants that need to be examined more closely under a subsequent screening method might be a sensible approach for reducing both false positives and false negatives. It is also worthwhile to study whether other structural screens, such as a combination of (single) pivotal supplier and market concentration measures, would be more effective and reliable in identifying market power concerns, and thus would be less likely to register false positives (*i.e.*, the presence of market power abuse when it does not exist) without raising the prospect of a substantially increased number of false negatives. In general, to improve the effectiveness and accuracy of market mitigation screens over time, their effectiveness and reliability should be monitored and analyzed periodically and compared with other available screens.

6. Analyze whether identifying suppliers that can provide congestion relief on individual transmission constraints results in economically sensible delineations of geographic markets

The current application of the 3JPS screen effectively identifies a relevant geographic market as consisting of suppliers that can relieve congestion on individual transmission constraints. We are concerned that this approach does not correctly identify relevant markets from an antitrust perspective. It would be useful to analyze whether the grouping of suppliers that occur under this method is meaningful from a market power perspective.

PJM's application of the 3JPS test on a constraint-by-constraint basis puts the same generating unit in multiple "markets," which inherently may misrepresent the competitive arena in which the generating unit actually operates. Thus, an application of a pivotal supplier test that looks at the ability of an individual supplier to affect multiple constraints simultaneously, such as the one that will be used by the CAISO, may produce more consistent and accurate delineations of relevant geographic markets for purposes of analyzing the potential exercise of market power. Also, PJM may wish to consider whether MISO's method of designating narrow-constrained areas (NCAs) would lead to more reliable identification of relevant geographic markets.

7. If the 3JPS test is retained, consider modifications to address the identified concerns as well as applying the test less frequently, particularly if it is used only as a first-stage screening mechanism.

PJM should further evaluate and consider possible modifications of its 3JPS test to address the concerns noted in Section V.F. of our report. PJM also should consider less frequent application of the 3JPS test, particularly if it were going to be used in combination with a conduct-and-impact screen. For example, ERCOT plans to update its structural screens on a monthly basis and CAISO eventually will likely employ seasonal 3JPS screens to determine whether particular local constraints are non-competitive under different supply and demand conditions. Although less frequent structural tests have the disadvantage of potentially missing short-term periods of non-competitive conditions that may sporadically arise, PJM's day-ahead and real-time application of its 3JPS screen injects additional "noise" in the mitigation process. Test results can fluctuate frequently between passing and failing, which can trigger mitigation actions based on changes in market conditions and screening variables that could not be anticipated by market participants when bidding into the PJM markets. The frequent application of the 3JPS also makes the mitigation process less transparent and less flexible operationally in terms of adjusting the implementation details of the screening process to improve its effectiveness.

8. Analyze the appropriateness of the reference levels used for mitigation and the treatment of frequently mitigated suppliers.

The choice of an appropriate reference level to which offers or prices are mitigated is admittedly a difficult exercise. However, it would be worthwhile for PJM to analyze whether the current reference levels used in applying mitigation are consistent with an appropriate definition of market power abuse and PJM's "loss function" with respect to the mitigation errors that invariably result from the market power screening process. PJM also should assess whether the particular reference levels used in the energy markets, in combination with actual and expected capacity prices in PJM (and prices of other relevant products sold by generators), are sufficient to provide accurate price signals to both supply- and demand-side participants. Energy market clearing prices should correctly reflect the full marginal costs of all dispatched supply-side resources, the bids of demand-side resources, the value of non-bid-based demand-response programs, and arguably appropriate scarcity premiums (depending on the nature of the capacity markets).

In addition, PJM should assess whether the adders to the reference level that apply to frequently mitigated units are appropriate. Such adders may be necessary for adequate cost recovery if the frequently mitigated unit is a relatively high-cost generating unit that earns only limited revenues (net of fuel costs) from energy and capacity sales. For lower-cost generating units, such incentives may either have limited impact on the overall market-clearing price, or they may be unnecessary to ensure adequate recovery of all costs incurred by that generation unit. The notion of providing adders to frequently mitigated units implies, on its face, that those generation owners who are most persistently capable of market power abuse receive more favorable treatment than those generation owners who are less capable of such abuse.

*   *   *

Our recommendations, if pursued, may result in specific changes to PJM's current mitigation practices. We recommend that, once specific changes to PJM's mitigation practices are considered for implementation, PJM should analyze the impact of the proposed changes on the frequency of mitigation, the severity of mitigation, and likely pricing outcomes.

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