

January 4, 2002

Hon. David P. Boergers  
Secretary  
Federal Energy Regulatory Commission  
888 First Street, N.E.  
Washington, DC 20426

Re: **AEP Power Marketing, Inc., AEP Service Corp., CSW Power Marketing, Inc., CSW Energy Services, Inc., and Central and South West Services, Inc., Docket Nos. ER96-2495-015, ER97-4143-003, ER97-1238-010, ER98-2075-009, ER98-542-005 (Not Consolidated)**

**Entergy Services, Inc., Docket No. ER91-569-009**

**Southern Company Energy Marketing L.P., Docket No. ER97-4166-008**

**Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, Docket No. EL01-118-000**

Dear Secretary Boergers:

Attached for filing via the FERC's Electronic Filing Program is an electronic file containing this transmittal letter, the "Comments of the New Mexico and Rhode Island Offices of Attorney General and the Rhode Island Division of Public Utilities and Carriers," and the "Certificate of Service" for the same in the above-referenced proceedings.

Thank you for your assistance.

Sincerely,

/s/

Deborah R. Tope  
Paralegal  
New Mexico Attorney General's Office

cc: Service List

Enclosures

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Investigation of Terms and Conditions Of Public Utility Market-Based Rate Authorizations</b>	)	<b>Docket No. EL01-118-000</b>
	)	
<b>AEP Power Marketing, Inc., <u>et al.</u></b>	)	<b>Docket Nos. ER96-2495-015, <u>et al.</u></b>
	)	
<b>Entergy Services, Inc.</b>	)	<b>Docket No. ER91-569-000</b>
	)	
<b>Southern Company Energy Marketing, L.P.</b>	)	<b>Docket No. ER97-4166-000</b>

**COMMENTS OF THE  
NEW MEXICO AND RHODE ISLAND OFFICES OF ATTORNEY GENERAL  
AND THE RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS**

Patricia A. Madrid, in her capacity as Attorney General of the State of New Mexico (“New Mexico”); Sheldon Whitehouse, in his capacity as Attorney General of the State of Rhode Island and the Rhode Island Division of Public Utilities and Carriers (collectively, “Rhode Island”)<sup>1</sup>; jointly submit this filing pursuant to the Commission’s authorization for filing comments in response to its Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations in Docket No. EL01-118-000, and in response to the Commission’s concurrent Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy in several Dockets, including ER96-2495-015, both issued on November 20, 2001.

---

<sup>1</sup> Rhode Island filed a Motion to Intervene in Docket EL01-118-000 on November 30, 2001, and a Motion to Intervene out-of-time in the pending AEP and related proceedings on December 7, 2001. New Mexico has filed its Motion to Intervene in Docket EL01-118-000 simultaneously with the filing of these comments.

## **1. SUMMARY OF THE ORDERS AS PERTAINS TO OUR COMMENTS**

In its Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations (hereafter the ‘Tariffs Order’), the Federal Energy Regulatory Commission (hereafter ‘FERC’ or the ‘Commission’) recognizes and acts on its responsibility under Section 206 of the Federal Power Act to maintain just and reasonable prices in wholesale power markets. The Order states: “We have a responsibility under the FPA to monitor wholesale markets to ensure that jurisdictional rates in the markets remain within a zone of reasonableness.” (Tariffs Order, 5.) As a remedy to anticompetitive market behavior and the exercise of market power, the Order proposes that a seller’s market-based rate authority be conditioned upon the absence of market power and a prohibition against anti-competitive behavior, and be “subject to refunds or other remedies as may be appropriate to address any anticompetitive behavior or exercise of market power.” (Tariffs Order, 5.)

In its Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy (hereafter the ‘Market Power Order’), the Commission replaces the hub-and-spoke methodology for market power screening on an interim basis with a Supply Margin Assessment (SMA) screen. The Commission had previously “looked to a benchmark for generation market power of whether a seller had a market share of 20 percent or less in each of the markets.” (Market Power Order, 7.) Under the interim SMA screen, a threshold for generation market power concerns will be “whether at least some of the applicant’s capacity must be used to meet the market’s peak demand” or, in other words “if its capacity exceeds the market’s surplus of capacity above peak demand” (i.e., supply margin). Mitigation is achieved through the required offering of uncommitted capacity to the market at cost-based rates, and by splitting the savings between supplier and buyer “which was the

traditional cost-based ratemaking model.” (Market Power Order, 12.) To accomplish this, the Order requires the supplier to post projected hourly variable-cost data each day for all energy offered for spot market sales. For mitigating market share that exceeds the Supply Margin, the Order requires that potential supply interconnections will be evaluated as a competing network resource without having to formally designate a particular load or having to be selected as a designated network resource. In addition, a requirement that applicants post on their websites optimum locations for new generation facilities will “facilitate least cost integrated planning.” (Market Power Order, 14.)

New Mexico and Rhode Island submit these comments to FERC in both of the above captioned sets of dockets. We hope that these dockets represent the beginning of a new attempt by FERC to ensure that all wholesale electricity markets within the US maintain just and reasonable rates under Section 206 of the Federal Power Act. It is very important, in our view, that FERC adopt consistent policies throughout the nation to accomplish this end. For example, we urge FERC to establish effective market monitoring and mitigation policies for all types of wholesale power markets, whether they are ISO-run day-ahead spot markets with bilateral contract markets on the side as in New England, or just bilateral contract markets, as currently exist in the desert Southwest. To us, effective market monitoring and mitigation necessarily implies that wholesale electric rates should be, on average, no higher than cost-of-service based rates for the types of products involved would have been if these power markets had never been deregulated. If FERC does not rely on cost-based rates as a price ceiling, then how can deregulation ever be clearly demonstrated to have been of value to electric consumers? In fact, we believe that some of the very court precedents that FERC cites in its June 19, 2001 Western Order are clear that cost-based wholesale rates provide the only reasonable basis for determining

the proper “zone of reasonableness” into which all actual wholesale prices must fall. In our opinion, one can not have a zone of reasonableness without knowing precisely what specific prices that zone centers on, and without knowing how big the zone of reasonableness can be. In general, prices below cost-based rates would clearly fall into a zone of reasonableness as long as they were not confiscatory relative to the legitimate interests of generation owners. However, it is not clear that there would be any valid rationale, given today’s electricity markets, for wholesale electric rates to be higher than cost-based rates. Clearly, if there is any such rationale, FERC will have to clearly describe such a rationale, which it has never done in previous orders.

Thus, in submitting these comments we applaud the general objectives that FERC has cited in each of these two orders that we will discuss from November 20. Similarly, we agree with the language of the proposed tariff amendment from page 4 of the Tariffs Order, and we agree with the proposed Refund Effective Date. However, we still find that many of the specific issues related to market power addressed in these Orders are not addressed consistently, logically, and effectively. For example, we still do not find that FERC has defined the mechanisms for being able to sufficiently identify when market power has been exercised by generation owners, which marks a fundamental disappointment with these orders. This is because we do not believe that FERC has yet developed a coherent theory of how market power is exercised, and, therefore, how it can be cured. Thus, most of our comments below are provided with the intention of helping FERC understand what, in our view, must be the starting point for a better approach to both implementing that proposed tariff amendment, and to monitoring and mitigating market power for utilities like AEP, the Southern Company, and Entergy. Since the tariff language is so general, the real value of such an amendment comes almost solely from how the language is implemented in US wholesale power markets. If it turns

out, as some have already claimed, that the proper implementation of comprehensive market power monitoring and mitigation schemes is too “intrusive” into market operations, and will make the operation of the resulting markets too mechanical and over-determined for pro-market advocates, then it may be the case that it will prove to be far better to simply return to cost-of-service based ratemaking for wholesale electric markets, just as many states have continued with, and are returning to, traditional regulation at the retail level. Thus, if it turns out to be the case that our only choice is between wholesale electric markets that are permanently and inevitably riddled with market power, and traditional cost-of-service based regulation of wholesale market prices, which used to work quite well, then traditional regulation will be our only legal course of action under the Federal Power Act.

## **2. A CONCEPTUAL FRAMEWORK FOR REVIEWING THE NOVEMBER 20, 2001 ORDERS**

### **a. We believe that in these orders, and in others preceding them, the Commission’s approach to its objectives fails in fundamental ways. The core of its failure is to avoid the critical question of exactly what constitutes just and reasonable rates.**

The immediate objective in these Orders is to define how market power can be exercised, and to set an interim mechanism in place that mitigates and prevents market power in certain wholesale markets. However, the ultimate objective is to “ensure” just and reasonable rates in all wholesale power markets, as is described in the text of the Orders. Unfortunately, these Orders proceed to formulate a market power test that is merely *structural*, without any *behavioral* performance parameters attached to it. Therefore, the Commission seems willing to accept on *faith* that electric power markets will produce just and reasonable rates as long as high-level structural screens are put into place. Thus, it is FERC’s lack of willingness to define in concrete terms what would define a just and reasonable rate, and its continued propensity to assume that

the market will deliver such rates with only limited structural screens in place, which is at the heart of our skepticism regarding the approach to actually achieving just and reasonable rates as proposed in these Orders.

As noted above, the subject of these Orders is really much broader than simply how to define and control market power. The Orders rightfully frame the whole discussion of market power in the context of FERC's obligation to ensure just and reasonable rates, but the proper conceptual, evidentiary, and quantitative connections between market power, market-based rates, zones of reasonableness, and just and reasonable rates are still missing. FERC still has not followed the necessary procedures that it described for itself on page 26 of its June 19 Western Order for when it adopts market-based rates. "The Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a 'zone of reasonableness'." Thus, even if FERC believes that it has done #1 above, though we do not believe that it has, it certainly has never even attempted to do #2 or #3 for either the New Mexico region, for the New England markets, or for any US wholesale electric market. If FERC believes that they have carried out #2 and #3 above for these regions, we request that FERC list the specific Orders and page references which contain those analyses in its response to these comments.

We propose to frame the detailed discussion responding to the two new November 20 Orders that appears in Section 3 below through our responses to three basic questions. This will help provide what we believe is the proper theoretical framework for analyzing the two Orders:

1. How far above cost of service can rates be before they become unjust and unreasonable, i.e., how should the zone of reasonableness be determined for either individual generating units, or for portfolios of units?

2. Are market-based rates, in the absence of market power, always just and reasonable rates? Does perfectly competitive long-run marginal cost-based pricing in an electricity market result in just and reasonable rates even when the resulting prices are significantly higher than cost-of-service rates?
3. How should FERC define the mechanisms for exercising market power and for controlling market power? A critical element of this discussion is how should market structure be taken into account when establishing methodologies to monitor and mitigate market power? What kind of market structure is most likely to lead to just and reasonable rates, if any can? (The interaction between capacity and energy markets is particularly important in this regard.)

**b. How far above cost of service can rates be before they become unjust and unreasonable?**

The Commission's objective in these Orders, and its statutory mandate, is to "ensure" just and reasonable rates. However, the Commission has never defined such rates in relation to cost-based rates. Without a notion of what the result should look like, we believe that FERC cannot truly know if it is likely to reach its objective.

One would presume that defining the objective before embarking on a project would not be an outlandish notion. Nonetheless, the Commission has repeatedly failed in this regard in the context of its discussion of market-based rates and market power mitigation. Prior to these two November 20 Orders, the best example may be the Order of June 19, 2001, on market power mitigation in the Western States (hereafter the 'Western Order'). In that Order, the Commission acknowledged that when authorizing market-based rates, it must still "assure that the resultant market-based rate falls within a 'zone of reasonableness', even if market power is completely absent."<sup>2</sup> Such ambiguous terminology, derived from a previous court finding, allowed FERC to speak of its obligation under Section 206 of the Federal Power Act without actually acknowledging in any concrete terms what that obligation would constitute. The Commission

---

<sup>2</sup> Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference, (June 19, 2001), 26.

never referred to any other studies, analyses, or previous Orders that described and implemented a methodology for determining such a zone of reasonableness, except in reference to the court's finding that the court could not "invalidate rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'"<sup>3</sup> This language used by the Court certainly sounds like a result obtained by setting a fair ROE in the process of traditional cost-of-service ratemaking.

FERC needs to understand that using traditional cost-of-service methodologies for setting rates helps to illustrate how small a zone of reasonableness might be, at least if it were to move upward from traditional cost-based rates. For example, a five percentage point spread in the return on equity (ROE) allowed to a generation owner, from 10-15 percent per year, might only change the underlying cost-based rates by 2 percent. This implies that even if FERC wanted to allow market-based rates to compensate generation owners at a very generous level of a 15 percent ROE, it could only allow market-based rates to average 2 percent above a more traditional ROE based cost-of-service level. This is a rigorous standard, and FERC has certainly not provided the public with any numerical analyses of which we are aware to show that deregulated wholesale market-based rates in the southwest or New England have routinely averaged within 2 percent (or any similar number) of what traditional cost-based rates would have been.

One related question, then, that was left unanswered in its June 19, 2001 Order, and that remains unanswered, is how high can rates be, above a level that is merely compensatory to generation owners, before they become "excessive"? The Commission did not emphasize the

---

<sup>3</sup> See footnote 52 in the June 19 Order: Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984)

fact that the Court concluded in the same case noted above that “without empirical **proof** that competition will ensure that actual prices are just and reasonable, a regulatory scheme may not rely on prices established through bilateral negotiations or other market-based means as satisfying its [FERC’s] statutory obligations.” (Emphasis added.)<sup>4</sup> If FERC does not agree with the reasoning behind our example above, it should state why not, and should also state what methodology FERC will rely on to determine a zone of reasonableness. This language of the Court would also appear to require FERC to directly monitor and mitigate prices in the long-term bilateral markets, which it has refused to do.

Providing such proof that competitive electricity markets will ensure just and reasonable rates would require the Commission to do two things. First, it would have to actually define just and reasonable rates to know when they were achieved. Secondly, it would then have to analyze different market structures, both empirical data from existing markets as well as the predicted outcomes of alternative market structures, and determine whether the rates generated by these market structures meet the requirements of what constitutes just and reasonable rates by the Commission’s own definition. Unfortunately, the Commission chose not to produce such proof in its Western Order, and it has not stated how this would be done now for the entire US in order to implement the Tariffs Order language. Instead, the Western Order only cited court decisions in defense of FERC’s decision to implement price caps as market power mitigation, noting that the Commission “has never bound itself to a rule requiring either rigid regulation or textbook markets.” The conclusion was that “nothing requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure.” (Western Order, 26) This was the Commission’s conclusion even though actual cost of service is the only reasonable default for determining the upper limit for whether competitive market prices are just

---

<sup>4</sup> Op. cit. 2.

and reasonable. The obvious implication was that, on June 19, FERC was willing to accept less than competitive “textbook markets” as long as prices did not exceed a certain capped level regardless of what the average embedded cost of production might be. Again, the Commission never defined in the June 19 Order how far above the average cost of service the mitigated rates could be before concern about excessive market power might legitimately arise. The Commission merely assumed that the price caps it set would lead to average rates being just and reasonable.

Specifically, by setting a price cap for the Western markets that reflected a competitive energy market price set during a single hour, FERC appears to have assumed that doing so would lead to just and reasonable rates for all other hours of the year, in all affected wholesale markets. Yet, clearly, that is a huge leap of faith. Thus, even if there was no remaining market power in that single hour, every other hour might have been impacted by large amounts of market power. For example, a \$92 per MWH price cap as derived from incremental variable costs in a Stage 1 deficiency hour, would clearly not constitute a just and reasonable rate in hours in which a competitive energy market price based on the same measure of incremental variable cost was only \$30 per MWH. And all prices between the two would also not be just and reasonable, based on similar logic. (Ignore other markets except the energy market for a moment.)

We realize that the Commission’s reticence to define its objective in sufficient detail may be born out of apprehension of the consequences of doing so. Once the right question is asked, i.e., what truly is a just and reasonable price, the result may be that FERC has to defend deregulated wholesale markets from an impossible position in face of the fact that cost of service would be the only definitive test of competitive prices, and the actual basis for just and reasonable rates. As long as FERC does not ask the dreaded question, it does not have to face the

answer and defend its position with respect to certain (or all) wholesale market structures that may be incapable of producing just and reasonable rates.

**c. Does perfectly competitive long-run marginal cost pricing result in just and reasonable rates even when the resulting rates are substantially higher than cost-of-service rates?**

First, in the June 19 Western Order discussed above, the Commission defended its use of short-run marginal cost pricing as a useful point of reference in competitive markets. Yet, it remains ambiguous whether marginal cost pricing, particularly as represented by strict short-run marginal cost bidding into energy markets (variable cost pricing), is what FERC would consider to be the definitive test of competitive markets and, thus, the bidding strategy that would presumably lead to just and reasonable rates. Or would FERC stress the need to use long-run marginal costs (including fixed costs) to define a competitive market price, as would be more appropriate? Again, one of the mitigation methods imposed by the Commission in that Order was the imposition of variable-cost bids. Yet, if strict variable-cost bidding behavior is the test that FERC would look for in determining whether electricity markets are competitive, as opposed to using it only as a mitigation tool after much looser structural screens have identified market power by any number of market participants, one must ask whether strict short-run marginal cost pricing always (or ever) leads to just and reasonable rates.

Second, what FERC seems never to have acknowledged is that it is entirely possible that in a given market, rates based on cost of service (i.e., the average embedded costs of the resource base) could be significantly lower than the competitive marginal cost, market-based rate in the same market. This could be true even if higher long-run marginal costs rather than short-run marginal costs were used as the basis for deriving the market-based rates. For example, a study prepared by Stone & Webster Management Consultants for the Colorado Electric Advisory Panel

in May 1999 found that, projected into the future, market rates based on full long-run marginal costs in Colorado (and most of the West) would be significantly higher than cost-of-service rates. This was true even though the market rates yielded a full 15 percent ROE to generation owners. The primary reason for this is the low average embedded cost of generation resources serving Colorado (and most of the West) today. Without a sudden and significant drop in long-run marginal costs (an unlikely occurrence), this condition would prevail for a long time – perhaps forever. In such an instance, would FERC insist that marginal-cost based rates were still just and reasonable because they resulted from a competitive market, even if they were substantially higher than cost-of-service based rates? Assuming that the Colorado study was correct, it appears that in the long run, market-based rates in the West will be inherently unjust and unreasonable for precisely this reason.

**d. How should FERC define and control market power?**

As we discuss the issue of controlling market power, we need to keep in mind that even when the Commission is confident that market power does not currently exist in any given market, there is no assurance that the market will produce just and reasonable rates. Just how far we are from such assurance depends on how we define market power, and how long-run marginal costs compare to cost-based rates. FERC now acknowledges that its traditional very loose approach to controlling market power that relied on structural screens, as opposed to behavioral parameters, and that set a threshold for market power concerns at very large market shares such as 20 percent, will yield no assurance at all that the market is producing rates that are just and reasonable. Conversely, a definition of market power that is more aggressive, and that leans more on behavioral parameters rather than broad structural conditions, is likely to give greater relative assurance that rates may approach just and reasonable levels. After all, market

power is a behavioral phenomenon; it is the outcome of certain complex behaviors that may be enhanced or suppressed depending on the details of the market structure and the market rules.

We agree, then, with the Commission's conclusion in the current Orders that the hub-and-spoke methodology, and its market-share threshold for market power concerns, is not adequate. Similarly, the Commission's past reliance on the HHI index was also never sufficiently justified, and had similar substantial flaws, since it was also a purely structural index. Thus, it is clear that new methodologies for detecting the potential for market power are needed, whether for merger applications, or for market-based rate applications. Aside from the need to incorporate transmission constraints into such market power screens, a more robust test of market power cannot simply rely on an arbitrary market share for any single market participant, which in the past had been 20 percent, or so. (The 1800 point HHI level that FERC used as a screen was equivalent to equal market shares of about 5.5 firms, which was an 18 percent market share for each.) Unfortunately, in these new Orders of November 20, FERC only starts to address the flaws of the existing market monitoring methodologies that it has relied on in the past by introducing the Supply Margin Assessment (SMA) methodology. However, this change does not address the fundamental problem with FERC's past approaches, which is the exclusive use of structural screens to detect market power. Structural screens that look at relative market share are always arbitrary in nature, do not take market structure and rules into account, and are not based on any precise determination of how much and under what precise conditions market power is likely to exist. Unfortunately, the proposed SMA screen is also purely structural.

We will describe in greater detail below where the major problem with FERC's new proposed approach lies, and what a better market power screen would look like, but the essence of such a screen would consist of behavioral thresholds for market power mitigation. It needs to

be understood that market power is a condition, or a consequence of the structure of the market, that allows certain behaviors to exist. A market participant who is in a position to manipulate the market price does not have to act on this ability and actually exercise his market power.

Therefore, a purist's perspective might be that the potential for exercising market power could be detected by structural screens, while only the actual exercise of market power should be targeted with behavioral remedies, such as imposing variable cost bidding.

We believe that this would not be correct. One reason is that a simple structural screen will not be able to take into account all conditions which lead to market power, especially when it is set at an arbitrary level of market share, which is a problem that even the new SMA screen has not overcome. The "bottom line" for measuring market power impacts is to measure actual prices in comparison to what competitive prices would be. There is no way around the need to do this. Second, if the structural screen were set too low, it could target too many market participants who may, in fact, not have been able to exercise market power. Third, structural screens target all market participants that may be able to exercise market power, whether they can act on that ability or not. This last point may be a minor concern, but the solution for all is the same, which is the use of behavioral tests. If the Commission were to set a performance standard such as limiting energy market bids to a range that is close to the variable operating cost of each generating unit, all attempts to exercise market power would be able to be detected and mitigated simultaneously, without fail.

The difference between a structural screen like the SMA, and a behavioral one, can be described as follows: A structural screen looks for the "usual suspects" and rounds them up to preempt a possible offense, with the hope that the remaining population behaves within the law. A behavioral screen goes farther and actually monitors the entire population continuously once

the market has been structured properly, thereby preventing any offense. This second approach, which is a solution to the failures of previous market power screens, may be simple and even obvious. Yet, we realize the “ideological” resistance that is present in some circles against accepting such methods that call for cost-based monitoring and mitigation tests. However, such resistance is unfortunate because it appears to derive from the ideological tendency to support “market autonomy” above all, rather than any implications of a particular market structure for the health of the markets, or for the reasonableness of the rates that would result. Or, this resistance may instead derive from a lack of consideration of how alternative market structures would help solve market power problems.

**e. A reasonable market structure is a critical element for ensuring the possibility of competitive markets, where separate capacity and energy markets are a key to success.**

Having recognized that behavioral screens based explicitly on price must be used to fully control market abuses, we must identify which types of tools are useful to accomplish comprehensive market monitoring and mitigation. The single most important element in detecting the exercise of market power is the ability to identify the true marginal cost of each market resource, including potential market entrants, at each moment in time. If the market monitors know the incremental fixed and variable costs of each existing or potential new power producer, market power mitigation becomes the relatively simple task of curtailing bids and prices to fairly closely match incremental costs, on average. For example, if the Commission had determined that resource bids into an energy market that were more than five percent above the variable operating cost of each generating unit were uncompetitive, then any bid that was placed above this level could be immediately adjusted downward. The market monitor, presumably the system operator, could keep daily logs of the marginal variable costs for each resource. When a

bid was placed that strayed from this cost baseline, the monitoring authority could replace the bid with a default variable cost-based bid.

A similar procedure could be followed in an installed capacity market, and it would be relatively straightforward if the market were only operated once per year, based on the need for capacity to cover the annual peak load plus an adequate reserve margin. Here the focus would be on whether the ROE earned by the generation owner on that asset, or on its entire portfolio of generation assets was reasonable, once all sources of revenues for that unit were taken into account including all infra-marginal revenues recovered from the energy or ancillary services markets. (This could be done based on prior year revenues from those markets, or some other approach.) The benefit of this type of monitoring and mitigation scheme goes beyond its comprehensive nature and effectiveness to mitigate anti-competitive bids. The immediacy and inevitability of such mitigation would actually be such that any attempt at exercising potential market power would be preempted by the system operator, making the *attempt* at exercising market power relatively futile. In other words, market power monitoring and mitigation might become a single integrated function so that market prices would rarely have to be corrected, and so that refunds would almost never be required. In fact, refunds could be determined in the course of adjusting capacity prices in the installed capacity market, perhaps only once per year. However, while the type of scheme outlined above might work for formal spot markets, other types of monitoring and mitigation schemes would have to be developed for bilateral markets, especially non-spot bilateral markets.

Note that FERC seems to always gloss over the need for ensuring that longer-term prices in bilateral markets are also just and reasonable under the Federal Power Act. It is certainly not obvious that long-term bilateral contract prices will always be disciplined to just and reasonable

levels based on the option that buyers could simply rely on future spot markets if they do not sign longer-term bilateral contracts, especially if formal spot markets do not exist as is currently the case in most of the US. In addition, spot market prices might temporarily be too high to be indicative of what average wholesale rates should be, especially if those markets are very thin, as they may be for new RTOs, especially if spot markets are really limited to being energy balancing markets. Finally, there is the possibility that spot market prices, even if competitive, might be above a zone of reasonableness with respect to cost-based rates, as discussed above. In that case, by definition, the establishment of spot markets can not possibly help bilateral contract prices be just and reasonable. These are difficult issues which FERC needs to address at much greater length than they have in the past when considering the need to monitor and mitigate bilateral contract markets. In fact, in its December 19, 2001 Order on the Western markets, FERC has gone the wrong way on this issue by confirming on rehearing its decision not to impose price caps on any other Western bilateral contract sub-market other than contracts for 24 hours or less. (Order on Clarification and Rehearing, December 19, 2001, p. 151.)

If the general approach to monitoring and mitigating spot markets that we presented above were workable, at least two conditions would have to be met. The requirement to report incremental fixed and variable costs would have to be imposed on all generating units and generation owners, and the reported incremental cost of each resource would have to be verifiable. Pure traders, as opposed to generators of power, could be required to be price takers in spot markets by bidding zero, as FERC has recently ordered in its new December 19, 2001 Order on the Western markets, though this requires further thought. (See page 47.) Thus, the costs of purchase to traders would not have to be revealed if this approach were taken. Naturally, the market monitor would have to be vested with the authority to mitigate bids to a level reasonably

close to reported incremental cost. Perhaps a maximum increase of 5 percent in the energy market would be reasonable in order to get the price signals to be reasonably accurate, as long as the actual infra-marginal revenues were accounted for in setting reasonable limits for bids into the annual installed capacity market so that total wholesale prices would not be too high by 5 percent.

The first condition is necessary to apply to all generators because, as discussed above, limiting the reporting requirement to those market participants that fail any particular structural screen may not detect all, or even most, actual market abuses. We must remember that the Commission has not offered any proof that only “pivotal” market participants as defined by the SMA screen can exercise economic or capacity withholding, or strategic bidding (which FERC ignored). The second requirement, verifiability, is obviously necessary because the market monitor needs to be able to confirm, with a fair amount of certainty, that reported costs are not inflated. Penalties for false reporting will probably be needed. In addition, we support FERC’s previous rulings that opportunity costs, scarcity rents, etc. will not be included in any definition of incremental costs used for the purposes of market monitoring or mitigation. This should also pertain to hydro-electric power, and similar zero incremental cost generation options. The reason for this is that the lowest-cost way for society to dispatch hydro that can be stored is to dispatch it in a manner to lower net peak demands and the high actual variable costs needed to meet those peak demands. If the bids into the energy market are limited to direct incremental costs, the opportunity costs for storage hydro become equal to future avoidable direct costs. But if the bids of hydro resources into an energy market are not restricted in this way, then the system operator should dispatch hydro based on when the operator computes that overall system prices can best be minimized.

In the November 20 Market Power Order, the Commission has also taken an important step toward incorporating incremental-cost reporting for a monitoring and mitigation scheme, though they have neglected the need to report annual fixed costs including the fixed carrying costs of capital investments, for use in monitoring and mitigating capacity markets. Another problem is that in the Market Power Order such reporting is only required of those who have failed a structural market power screen; namely, the Supply Margin Assessment. Another problem is that the Order does not acknowledge the need for having the reported incremental or annual costs be transparent and verifiable to FERC. We believe that such cost transparency can be accomplished fairly easily. In addition, the reporting requirement must also be applied to all generators selling into RTOs/ISOs as part of their market power monitoring and mitigation schemes. Of course, the reality of being able to keep up with the potential workload related to market power issues is that FERC might best just start over by revoking market-based ratemaking authority for all transactions not made in the context of an RTO/ISO, unless FERC puts into place some other set of institutional structures designed to allow for routine monitoring and mitigation of all the other types of power markets throughout the U.S.

**f. The prime rationale for identifying the separate fixed and variable marginal costs of each market resource for an effective market monitoring and mitigation scheme in wholesale power markets is the separation of capacity and energy markets.**

As the discussion of market monitoring and mitigation above indicates, in the absence of an installed capacity market, resource bids into the energy market over the course of a year must, on average, reflect the equivalent of the full revenue requirement of the unit in order that the owner can make a reasonable profit on the investment. Thus, if there were only an energy market, it would be very difficult for FERC to be able to determine if such bids were truly competitive. FERC would be required to establish individual cost-of-service rates on an average

basis by forecasting a likely capacity factor for each generating unit. Of course, it is quite unrealistic for FERC or an RTO/ISO to be able to accurately forecast such an annual capacity factor prior to being able to determine if any given energy market bid for each generator is reasonable so that the fixed costs per operating hour in addition to variable operating costs are known. Yet, this is the only way in which the Commission or the RTO/ISO could know whether a particular bid were even approximately competitive or not, and that judgment would still depend on what the actual bids from the unit would be for the remainder of the year. (We assume that no one would bid the exact same price in each hour.) The fact that this would be a cumbersome and inaccurate process may have led the Commission to believe that it would be impractical as an effective means to control abuse of market power when it considered establishing price caps in the June 19 Western Order. The Commission argued on page 34 of that Order that the explicit recovery of fixed costs was not necessary. The Commission argued that “by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs.” The Commission also dismissed concerns of the generation owners that the last unit dispatched would not be able to recover any of its capital costs by stating that “the amounts earned on the more efficient plants will cover the investment in the marginal plant.” (Western Order, 34.)

We believe that this argument of FERC’s is quite confused. But even if it were correct, the Commission has not shown that their argument is likely to be correct numerically, for any likely system of generators. Thus, here we support the concern of the generators that the Commission’s approach to setting price caps might under-collect fixed costs, including a fair return on investment. Of course, the recovery of fixed costs could easily go the other way too,

which the generators do not mention. Given the fact that the same price cap would apply in all hours of the year, bids that would fall below the price cap but which would be far above a competitive energy market clearing price in other hours of the year might lead to higher revenues being collected over the course of a year than required for full annual fixed cost recovery.

Amazingly, in this Order FERC does not discuss alternative market structures that it could have established in California that would be much closer in form to the market structures that it had already established in the Northeast, namely a structure which includes an installed capacity market. This would have allowed FERC to solve the difficulty with the potential for over- or under-collection of fixed costs given the way FERC set price caps for the West. Of course, FERC could still do this since the conceptual and regulatory problem continues to this day. This same potential problem also applies to FERC's approach to price mitigation if an applicant for market-based rates fails the SMA test. There FERC also relied strictly on variable costs, and did not propose a means for checking the adequacy of capital cost recovery.

The big advantage, then, of the alternative market structure that we have suggested is that having a separate annual installed capacity market removes the final consideration of fixed-cost recovery out of the realm of the energy market. As long as a functional capacity market is in place, the Commission can be assured that a variable-cost bid in an energy market, or a bid that is reasonably close to the incremental variable cost of the generating unit, is both a competitive bid and a fair bid, since any additional fixed cost recovery required will be allowed in the installed capacity market.

However, this alternative market structure that allows for such an effective check on potential market power abuses will certainly evoke the image of cost-based rate regulation in many people's minds, and, to some, that may be sufficient reason enough to denounce it because

the “principle” of “market autonomy” is being challenged. While this market structure does allow both the energy and installed capacity market to set their own prices over various time periods, assuring some degree of continued market autonomy, the market prices would not be allowed to stray far from annual average cost-of-service based rates before mitigation would be imposed. However, if thresholds for market power concerns and mitigation are truly based on cost of service, it is difficult to argue against such methods. As discussed previously, how could one attest that average prices significantly above cost of service could result in just and reasonable rates? Note also that “market autonomy” would still exist on an hour-by-hour basis in the spot energy market. Prices in the energy market would still vary by time of day and season, thus giving power purchasers better price signals than existed in the past under bundled rates. Another alternative to the above approach to market mitigation for each individual generating unit, would be to allow bids into the annual installed capacity market that would only be capped for the generation owner’s entire portfolio of generation options, and not for a single generation unit. In fact, FERC has offered generation owners a somewhat similar portfolio-based approach to wholesale rate regulation in recent orders, including the Western Order, if these owners do not believe that they will be able to successfully recover all their fixed costs on an annual basis given the manner in which FERC has developed price caps for the Western markets. (Western Order, 24.)

**g. The only regulatory option that FERC has for monitoring and mitigating market-based rates is to use cost-of-service as the baseline.**

In its June 19 Western Order, the Commission found that a return to cost-of-service ratemaking in the Western markets would be unwarranted at that time. Although the possibility of fully dismantling market-based rates in the U.S. is not the subject of these comments, FERC’s

remarks on this topic in June are relevant to the issue of whether market power monitoring and the assurance of just and reasonable rates should be accomplished through cost-based restrictions on all bids and market prices during all hours, and for all types of spot markets and bilateral contracts. In the event that FERC might have some of the same objections as expressed in its Western Order to the suggestions made here in favor of cost-based market power monitoring and mitigation, we will address some of those possible arguments here. It is reasonable to give FERC a little longer to try to sort out these complex issues in order to actually achieve just and reasonable rates, as long as more rapid progress is forthcoming in the near future. We hope that the relative quiescence exhibited recently in electricity markets continues while FERC wrestles with these issues, but it may not. Furthermore, FERC must always remember that the existence of relatively low electricity market prices does not mean that market power is not being exercised on a daily basis. Thus, the current relatively low market prices should not be used as an excuse to ease up on one's vigilance relative to market power issues. If certain generation owners can not make prices spike during times of peak demand, they might equally attempt to raise prices to a lesser extent in most other hours.

In its June 19 Order, the Commission also suggested that the complexity of establishing the cost of service and an appropriate rate of return for each generator would be time consuming and "that would not provide price certainty to the market." (Western Order, 24.) This is an odd statement since clearly the market never had "price" certainty. In the context of the approach to cost-based, full-time market power mitigation that we propose here, we argue that if market participants knew that FERC had set in place a strict market power mitigation system that was cost-based, there would be far less uncertainty about prices than under any other scheme, except to the extent that electricity market prices are determined by exogenous factors such as fuel

prices. However, uncertainty regarding fuel prices is always a problem regardless of market structure.<sup>5</sup> What is very clear about a scheme like the one we have presented here is that the market would not suffer from uncertainty generated by a lack of clarity about how market power monitoring and mitigation would work. Moreover, the obvious remedy to any ambiguity about what competitive prices might be in each hour, where mitigation thresholds would be set, is the transparent separation of marginal costs into fixed and variable costs, between the capacity and energy market, respectively. Doing this would give all market participants a clear sense of what to expect in both the energy and capacity markets, helping to stabilize bids at competitive levels, and sending a much less ambiguous price signal to potential new market entrants than current energy markets do which yield very volatile prices precisely when new capacity is needed. Price signals in a well-run installed capacity market to new market entrants need not be inflated to induce market entry. They need to be accurate and transparent, as discussed further below. Of course, if FERC systematically creates annual installed capacity markets across the US as we suggest, then appropriate reserve margin requirements can also be set, and the installed capacity markets can be structured in a way to induce the needed amount of new market entry to meet the reserve requirements. If it turns out that market prices do need to be inflated above just and reasonable levels to induce new market entry even when reserve requirements are established, then it is clear that market mechanisms will not be defensible in the electricity industry at all.

The Commission also remarked in the Western Order that cost-of-service rates penalize those generators who make an effort to improve the efficiency of their operations and denies them appropriate scarcity rents. (Western Order, 24.) Being outside the scope of these comments,

---

<sup>5</sup> Indeed, uncertainty in fuel markets introduces risk premiums and greater volatility into deregulated markets than under cost-of-service regulation. This can also ultimately result in higher average market-based rates than cost-of-service rates.

we will set aside the question of whether this statement is true, and if true, whether it is something that FERC should be concerned about. In the context of cost-based monitoring and mitigation of market-based rates we would argue that it is always in the interest of the generation owner to improve the efficiency of its production. This is true even though the generator's "allowable" bid price would follow the variable cost of its production downward as efficiency improves. The reason is that for all generating units, except perhaps the ones with the highest variable cost and those that are dispatched the fewest number of hours each year, most of their annual revenue is generated when they are not the marginal unit (i.e., setting the market price). During those hours, generating units collect the infra-marginal revenues determined by the difference between the variable cost of the unit and the market price in any given hour. Increasing the efficiency of a unit increases the collection of these revenues, and the generation owner would therefore be given ample incentive to improve efficiency relative to the fixed cost recovery that the generator was allowed to collect in the annual installed capacity market when that payment was last set according to our proposal. This would be the same kind of "regulatory-lag" based incentive that currently exists to encourage efficiency improvements under traditional rate-regulation between rate cases. Therefore, setting market-monitoring thresholds based on a unit's cost-of-service would neither hurt price certainty, transparency, nor efficiency. The contrary would be true.

Separate capacity markets, when combined with energy markets with cost-based monitoring thresholds, would also be "pro-competitive" because by allowing for the proper allocation of costs and revenues between product markets, they provide less ambiguous price points for new market entry. Conversely, for existing market participants, relying on energy markets alone for full cost recovery increases the risk of under-collecting fixed capacity costs.

Since this risk is clear to market participants, they are likely to ‘price-in’ the risk premium associated with such uncertainty. Therefore, not only does a cost-based market monitoring model reduce the effects of market power, it would reduce the risk premium that inevitably accompanies deregulated power markets where guaranteed fixed cost recovery has been abandoned. We conclude that an appropriate market structure, particularly one where annual installed capacity and energy markets work side-by-side in a complementary manner, will facilitate market power monitoring and mitigation and will improve the likelihood of competitive behavior at rates which do not have excessively high ROEs built into them. Thus, such an approach would greatly increase the probability of achieving just and reasonable rates.

**h. Installed capacity markets and a required reserve margin are also critical for maintaining system reliability.**

One question that is bound to surface in response to our call for behavioral cost-based market monitoring and mitigation, is whether such a mechanism would not impede needed investment in generation resources. This was discussed briefly above. A traditional concern about market price mitigation is that with variable-cost screening of market bids, the inability of market participants to collect prices well in excess of short-run marginal cost might reduce investment due to the perceived inability to collect adequate total revenues. However, as we have discussed, this is not a reasonable concern provided that two conditions are met: A *required reserve margin* must be in place, and the energy market must be supplemented with an installed capacity market. We believe that that the key to ensuring adequate investment in generation resources continues to be the regulated reserve requirement which, in a deregulated market environment, we believe necessitates a separate market for generation capacity.

It can easily be argued that it is unimpeded market power in particular, and deregulated markets in general, rather than cost-based market power mitigation methods that are likely to hurt system reliability by resulting in shrinking reserve margins. Even in the absence of market power that may keep out new market entrants, the market is likely to deliver a tighter reserve margin if left to its own devices than if a regulated reserve margin of, perhaps, 18-20 percent were in place. What happened in California is a perfect example of this phenomenon. The reason is due to the significant risk of not collecting an adequate return on capital investment in generation resources in only an energy spot market, especially when bilateral contracts were discouraged. An “adequate” return in this context must, therefore, be adjusted for the risk involved when cost recovery is not assured. The result will likely be quite different, however, depending on whether or not a required reserve margin is in place. Without it, the result is likely to be an unacceptable reduction in reliability, because prices may not rise to cover the risk premium of adequate reserves.<sup>6</sup> In addition, there is a system cost (or social cost) associated with reducing system reliability that does not face the individual generators. Likewise, the relative lack of system resources tends to raise revenues for each unit due to making market power easier to exercise during times of peak demand, converting the relative lack of reliability into an economic incentive to keep reserves too low. With a required reserve margin and an installed capacity market in place, the result is likely to be adequate system reliability.

Apparently in recognition of these facts, FERC instituted required reserve margins in all three of the northeastern ISOs. Secondly, FERC established capacity markets in these ISOs to allow generation owners a facility through which to recover their fixed costs of production.

---

<sup>6</sup> It is popular to think of reliability being yet another commodity in power markets that can be procured through competitive market structures, specifically capacity reserve markets. However, relative degrees of system reliability is not an exclusive good that can be traded. Individual units of capacity sold as reserves are not “units of reliability” Reliability is a system condition that affects all customers.

However, it has always been surprising that FERC failed to do the same in California, allowing that state to fall victim to natural market forces. As should have been expected, the market saw no reason to maintain reserves at a level that would have been determined necessary based on any reasonable loss-of-load analysis. Instead the market determined that reserves should be lower, reducing the price risk for marginal units, while creating relative scarcity that ultimately raised market prices and unit profits significantly over competitive prices that might have been realized from a more reasonable market structure with capacity requirements in place. It was only at this much higher price level which reflected scarcity rents that generators finally became interested anew in adding capacity, but only after reserve margins had fallen far below adequate levels. Unfortunately, FERC affirmed the market's "right" to extremely high risk premiums in the June 19 Western Order by implementing inflated price caps that were unjustly presented as providing proper mitigation of market power. In contrast, those high price caps simply validated and locked in the implications of a condition of seriously inadequate reserve capacity, because the price caps were based on the prior actual stage 1 deficiency prices. This continued a situation in which it was claimed that the full capital cost of new capacity could be recovered in only a year or two, a pricing scenario that would never be considered to be reasonable under cost-of-service regulation, where assumed depreciation rates have been 15-30 years, or more.<sup>7</sup> This outcome is even more perverse due to the fact that the capacity shortage in California was

---

<sup>7</sup> Consider an example of how the price caps introduced in the June 19 Order might validate non-competitive market results: If the highest variable dispatch cost in the worst stage #1 deficiency hour were \$100 per MWH, which is quite possible, then the price cap for all non-deficiency hours in California would be \$85 per MWH plus 10 percent for the California credit risk premium. This totals \$93.50 per MWH. It could also be the case that the average variable dispatch cost in the non-deficiency hours would be only \$50 per MWH, or lower. Over the course of 8760 hours per year, the extra revenues that could be derived from this market would be up to \$43.50 per MWH for every hour of the year (except for a few hours during stage #1-#3 emergencies). This could happen if FERC's proposed price caps effectively set a price floor under all spot market prices. Thus, for every MW of capacity available 80 percent of the time, this amount of money would total about  $\$43.50 \times 0.80 \times 8760$ , or about \$305,000 per MW-year. This is about \$305 per kW-year, or almost the full capital cost of a combustion turbine peaker.

directly linked to FERC's own failure to impose reserve requirements in the state. Needless to say, if sufficient new market entry had occurred in California in a timely fashion, the heat rates of the unit that set the market clearing price during the Stage 1 emergency might have been much lower.

Our conclusion is that the Commission should insist on adequate reserve margins in all regional wholesale electricity markets, provide for the proper pricing of capacity through installed capacity markets, and subsequently ensure that energy prices do not exceed competitive levels by monitoring energy markets on the basis of the incremental variable cost of generation from each unit. The Commission must reverse its apparent position of placing market autonomy first on its list of priorities, especially if it means accepting a lock-in of very high risk premiums and high market prices when supposedly attempting to mitigate the results of market power. We are mindful of the fact that under cost-based rates and rate regulation, risk premiums for generation were a much lesser concern, and the cost-of-capital for new generating units was much lower than may now prove to be the case in deregulated generation markets. FERC should remember that traditional cost-of-service regulation provides many advantages that deregulated markets may find difficult to deliver, just and reasonable rates being the chief one among them.

### **3. OUR COMMENTS ON THE SPECIFIC COMPONENTS OF THE TWO NOVEMBER 20<sup>TH</sup> ORDERS**

- a. We support inclusion of the proposed language on page 4 of the Tariffs Order in all market-based rate tariffs and authorizations, including those for RTOs and ISOs. Of course, the implementation process for market monitoring and mitigation must be defined in much greater detail than the Commission does in this Order.**

We agree that the language: "As a condition of obtaining and retaining market-based rate authority, the seller is prohibited from engaging in anticompetitive behavior or the exercise of market power. The seller's market-based rate authority is subject to refunds or other remedies as

may be appropriate to address any anticompetitive behavior or exercise of market power;” should be included in all past and future market-based tariffs and authorizations. But while inclusion of such language is a necessary condition for attempting to establish competitive markets, substantially more detail and a more comprehensive theory of market power is necessary in order to implement such conditions than is presented in the Tariffs Order, or in the AEP Market Power Order. We, therefore, support the idea that FERC should issue a Notice Of Proposed Rulemaking to solicit comments as to how this language should be implemented, both procedurally and conceptually, and on what market structures should be created to achieve this goal.

**b. While the Commission has, in principle, identified some of the necessary steps toward identifying, preventing and correcting anti-competitive behavior, the language of the Tariffs Order implies a serious ambiguity regarding the Commission’s determination to take those steps when needed.**

In its Tariffs and Market Power Orders, the Commission has identified what we believe to be the three basic steps necessary to prevent anti-competitive behavior and the resulting wholesale power prices that can neither be regarded as just nor reasonable. These steps are the *detection* of market power and anti-competitive behavior, the proactive *mitigation* of such behavior by restricting market-based rate authority or by other appropriate means, and the *correction* of the effect of anti-competitive behavior through refunds of illicit revenues generated by such behavior. However, the language of the Tariffs Order, in particular, remains weak and somewhat ambiguous on FERC’s commitment to comprehensive and aggressive mitigation and correction of market prices in the face of market abuses: “Should public utility market participants engage in prohibited behavior, their rates will be subject to **increased scrutiny** by the Commission, and **potential** refunds or such other remedies as may be appropriate.” The

Commission goes on to specify that prohibited behavior “**could** result in further **conditions or restrictions** on [market participant’s] market-based rate authority...” (Tariffs Order, 6 – emphasis added.) We believe that this type of language falls far short of describing the kind of aggressive and robust market power response that the Commission implies is necessary in the context of its obligation under the Federal Power Act to “**ensure** that sellers not charge unjust and unreasonable wholesale rates.” (Tariffs Order, 5 – emphasis added.)

The vastly improved monitoring and detection methodologies for anti-competitive behavior that are required to accomplish the Commission’s objective would, presumably, negate the need for any further *increased scrutiny* upon detection of market abuse by individual market participants. We would also anticipate that the illicit revenues derived from prohibited behavior would be subject to full and unconditional refunds, and not merely *potential* refunds. Finally, we would expect that a market participant that had abused its position in the market, and had been “caught in the act” by a more robust system of market monitoring, would, after appeal, pay a price by losing outright its market-based rate authority. The only reasonable exception would be if a substantial monetary penalty were imposed on the market participant in place of the revocation of market-based rate authority, provided that sufficient safeguards (i.e., restrictions on rate authority as opposed to revocation) were set in place to prevent the recurrence of abuse by the power supplier.

Indeed, it would seem reasonable that a monetary penalty should always accompany a need for market power mitigation, whether or not market-based rate authority is revoked or simply restricted in some fashion. The principle that should apply is that the offending party should never be indifferent financially between the two options of following the market rules, or facing Commission action upon the detection of market abuse. If a mere price correction is the

final action taken when market abuse is detected, the deterrence of a financial penalty would be missing, and the market participant would receive the wrong message from the Commission, which would simply be to try to avoid detection next time a violation is planned. Unfortunately, the specific language of the Tariff Order implies that corrective action by FERC may waiver from this principle, leaving the prospect of appropriate penalties if price mitigation is required in serious doubt.

**c. The Commission's definition of market power and anti-competitive behavior is flawed.**

On page 4 of the Tariffs Order, the Commission states that exercises of market power “include behavior that raises the market price through physical or economic withholding of supplies.” It continues by stating that “physical withholding would occur when a generator declares a forced outage when its unit is not, in fact, experiencing mechanical problems.” This definition for physical withholding is basically correct, but no reference is then required to a market price in the next sentence. Either the unit is declared able to operate, or not. This situation is one of the few that is either “black or white.”

The Commission's major conceptual error, both here and in most previous orders which deal with market power, lies in what they leave out of their list of ways in which market power can be exercised. We maintain that physical and economic withholding may be relatively easy to prevent, once the correct market rules are in place. However, what the Commission has omitted entirely from this list is the concept of strategic bidding as the main way in which market power can be, and has been, exercised. Certainly, strategic bidding played a major role in causing the high market prices that persisted in Western markets for about a year.

Strategic bidding is simply bidding above one's incremental operating costs in the energy, ancillary service, or capacity markets, thus attempting to drive the market clearing price

as high as possible above a competitive level. Certainly, FERC needs no reminder that most generating units in the Western spot markets did this often over the last two years, and many generating units do this in the Northeastern ISO markets, as well. Perhaps the confusion that led to this key omission by FERC is that strategic bidding could end up with a unit being withheld, even if unintentionally, due to the high bid it submitted. This result could be called “economic withholding” using FERC’s terminology, especially if a bid were submitted at such a high level that there would be little likelihood of the unit being dispatched. What FERC needs to realize, though, is that there is a broad continuum between the extreme case of planned economic withholding and routine strategic bidding, which might not cause a unit not to be dispatched, but which, due to the submission of a high price bid, might raise the market clearing price. In fact, strategic bidding is a rational strategy for generation owners to utilize in almost every hour for each of their generating units, in contrast to the more extreme case of economic withholding which would probably be done only occasionally.

It is particularly strange that FERC has omitted strategic bidding from its discussion of market power mechanisms on page 4 of the Tariffs Order. After all, in its June 19 Western Order FERC made it very clear that it expected units to bid incremental variable costs even when supplies were tight, and this was the basis of its price cap setting methodology. This FERC action was, then, implicit recognition of the existence of strategic bidding. Thus, it is especially surprising that FERC does not explicitly recognize on page 4 that generating units that bid above their incremental variable operating cost is the prime way in which market power is exercised.

**d. The Commission’s definition of market power erroneously implies the existence of a legitimate and “autonomous” competitive market price that can somehow exist during periods of anti-competitive market behavior. This error seems to contribute, in part, to FERC ignoring the more common exercise of market power through strategic bidding.**

When defining two of the generally recognized means of exercising market power, economic and physical withholding, the Commission seems to posit a market price that both results from anti-competitive behavior, but which is still as being distinguishable from a legitimate, competitive market price. We are concerned that this confusion could lead to ineffective market monitoring methodologies. The Tariff Order states: “Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental cost **and the market price** (and thus, the output is not sold).” (Tariff Order, 6 – emphasis added.) The problem is that FERC is not clear whether the term “market price” here refers to a competitive market price or one inflated by the exercise of market power. If FERC believes this could be a competitive market price, they are likely to be mistaken.

What FERC is ignoring is the fact that by attempting to economically withhold capacity by raising a bid, the offending party is likely to indirectly raise the market price above a competitive level. This is the new higher price that the bidder will recover on its other units that are being dispatched. That is the whole point as to why a party might be motivated to attempt economic withholding. The way in which economic withholding works is to force the market price up by making the supply curve steeper.

Therein lies the difference between the two main forms of market abuse, capacity withholding and strategic bidding/economic withholding. Capacity withholding serves to *shift* the supply curve to a higher price range by completely removing a resource from where it would have been in a competitive supply curve. On the other hand, strategic bidding is not aimed at necessarily withholding capacity altogether, but it is aimed at raising the market clearing price in

the neighborhood of where that specific capacity normally would fall in a competitively-based supply curve. Each time either economic withholding or strategic bidding occurs, the resource moves up the supply curve, also making the whole curve steeper, thus usually raising the market clearing price, whether that resource is actually dispatched, or not. Thus, when economic withholding occurs, the market price even after being raised due to market power, would still end up somewhat lower than the resource bid price, causing the resource not to be dispatched, as in FERC's definition.

Therefore, the Commission should clarify its definition of economic withholding by recognizing that when market power is being exercised, there will not likely be a concurrent competitive market price that is not tainted by this exercise of market abuse. One reason why this clarification is necessary is so the Commission can, again, be clear that there is no bright line between strategic bidding and economic withholding, since in the exercise of strategic bidding the offending party can never be quite sure if raising the bid on a resource above its incremental variable operating costs will cause it not to be dispatched. Thus, even if the output of a resource is sold (dispatched), and economic withholding does not occur, this fact does not imply that the market price is competitive and not in need of mitigation.

**e. The Commission's apparent notion of an autonomous market price during periods of anti-competitive behavior in the Tariffs Order mirrors similar concepts contained in market rules that they have approved for the Northeastern ISOs, and suggests a preference for market "autonomy" over market discipline.**

Other types of self-referential tests for market power abuse also plague the market monitoring rules that FERC has previously approved for the Northeastern independent system operators. An example of this is when a market monitoring rule looks to historic bidding behavior as a baseline, and compares this to current bidding behavior to determine whether

market abuse currently exists. This is obviously troublesome because the monitoring rule may look to an historic baseline period that is already affected by non-competitive bids, thus serving to allow even more market power in the current time-period than occurred in the baseline period. Market simulations have shown that the exercise of market power by generation owners is not likely to be an occasional affair, but rather a consistent and ever-present element. Therefore, establishing baselines from historical bidding behavior is likely to be useless when monitoring future bidding behavior. The alternative, of course, is to simply compare current bids to incremental variable costs, and not in a self-referential way to past bidding behavior in order to provide a meaningful baseline.

FERC's past approach to monitoring for market power seems to reflect its general resistance to ever abrogate the autonomy of the market and to question the results it delivers, because to do so would somehow negate the principles of deregulation in which it believes. This sentiment may stem from the fact that the only reasonable remedy to market prices that have been manipulated through the exercise of market power is the imposition of cost-based bids, and that, to some, is tantamount to a restoration of cost-of-service regulation, which FERC is resisting even when it is necessary. That is a sensitive situation that ISOs and other market operators want to avoid facing because it raises the ever-looming question of whether there has been any true benefit, relative to traditional rate regulation, that the deregulated wholesale markets have delivered. In the context of these Orders, the question is whether market autonomy should have precedence over the quest for lower prices and rates that are just and reasonable.

Fortunately, the Commission has demonstrated with its new Market Power Order that it has no objection to imposing cost-based bids on offending power suppliers in some contexts (but not all). Therefore, we would suggest that the Commission clarify its position on this matter and

denounce the self-referential tests for market power that refer to “the market price” as conceptually autonomous from the effects of market power. Furthermore, FERC should acknowledge that the marginal costs of electric generation provide the only true test of whether generation owners have placed non-competitive bids. FERC should, therefore, revise all its market power monitoring rules for the three Northeastern ISOs to make them cost-based.

**f. The Commission should recognize that its Supply Margin Assessment screen is just as arbitrary as the hub-and-spoke methodology for detecting a “safe” level of market share, and that it cannot “ensure” protection against market power irrespective of its attempt to incorporate transmission constraints. Therefore, this interim measure should not be a model for either an interim or a permanent market power test.**

The previous benchmark for establishing whether a market participant had market power was a market share of 20 percent in each market delineated by the hub-and-spoke methodology. The SMA test attempts to improve on this approach in two ways. First, it considers transmission constraints as a potential factor. Secondly, “in determining the size that triggers generation market power concerns,” the SMA sets the threshold where the “applicant’s capacity must be used to meet the market’s peak demand” within any given control area. (Market Power Order, 7.) The commission calls this test a determination of whether the seller is “pivotal” in the market: “When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity.” (Market Power Order, 7.) The SMA test has been presented as an interim improvement on the previous methodology “to **ensure** that customers are protected against market power in generation.” (Market Power Order, 7 – emphasis added.)

In contrast, we believe that there can be absolutely no assurance that this test will eliminate most market power, because it certainly cannot ensure competitive bids. Instead, this test is intended to screen for only those suppliers who hold the most insidious form of market

power, which is when the market is an *absolute price taker* in relation to a single supplier. It is true that during a period of high demand, when the supply held by a single market supplier is greater than the supply margin, some of the output of that supplier must be bought if the generation resources are not committed to any specific load. Therefore, the purchase will take place at any cost in the absence of a price cap in the market. However, the absence of absolute pricing power during periods of high demand does not mean that market power does not exist during other periods, even when monopoly pricing power is not feasible.

To equate market power with the capability for absolute pricing power contradicts the Commission's own definitions in the Market Power Order as to how market power is exercised. Economic withholding that results in rising market clearing prices is an example of the exercise of market power without absolute pricing power. The same is true for capacity withholding and for the more common mode—strategic bidding. In other words, the exercise of market power has been defined and described by the Commission in the Tariff Order in a context where the offending party does not have to be in a “pivotal” market position. Given this serious inconsistency between the two Orders, how can the Commission defend its use of the SMA screen as a tool “applied to ensure that customers are protected against market power”? Again, FERC needs to be clear that the exercise of market power is a behavioral problem that occurs within the context of a particular market structure, but no structural screen can possibly detect all possible opportunities to exercise these types of undesirable behaviors.

**g. The Commission should correct and augment the definition of anti-competitive behavior as it appears in the Tariff Order. An improved behavioral definition, and all relevant tools for market monitoring based on that definition, are far more important than the new SMA market power test which is highly flawed because it is structural. Otherwise, the proper conceptual basis for detecting all abuses of market power will be missing, as will be the ability to mitigate and correct such abuses.**

There are two components to detecting the abuse of market power. One step is to apply a test that determines with a high level of confidence whether market participants actually possess the potential to exercise market power. The second step is to apply a test that shows whether that market power has actually been exercised on an ongoing basis. The Commission's Market Power Order presents an interim structural market power test, which is intended to determine whether a single market participant has the potential to exercise market power. In contrast, it is the Tariff Order that attempts to define what *behavior* actually constitutes market power. However, both Orders fail to do their jobs adequately, as discussed previously.

We believe that for FERC to develop a strong and unequivocal definition of anti-competitive behavior is far more important a task in the ongoing effort to improve the competitiveness of wholesale power markets than the institution of a subjective, and largely arbitrary, new structural threshold for determining the existence of market power. In summary, the reason why we believe this is true is very simple: A strong and effective behavioral test will always detect market power abuse when it occurs, regardless of the market share held by the offending party, while a structural market power test targets market participants based on their market share irrespective of whether or not market power was, or even could be, exercised. Even more fundamentally, structural tests are never able to detect all situations in which there is the potential for the exercise of market power. Structural tests alone can never be adequate because they can not be comprehensive.

The superior quality of a behavioral test over a structural one is apparent because it targets the offensive behavior directly, rather than merely targeting market share or other structural features of a market which only determine in part to what extent market power can be exercised. If this is true, then why would the Commission maintain a preference for structural tests? Again, we suspect that the problem lies in the Commission's reticence to curtail the autonomy of the operations of the energy and/or capacity markets in setting "the market price." A strict behavioral test must continuously monitor the market for anti-competitive bids, preferably applying marginal cost-based tests, as discussed above. A structural screen only leads to intervention if a single participant holds a disproportionate share of available supply. Otherwise, it assumes that the market will produce just and reasonable prices. Therefore, the behavioral test will tend to be perceived as a much greater constraint on the free movement of prices within the range that the market might produce. Again, FERC may see this as antithetical to the principle of deregulated power markets. However, we believe that the continuous monitoring of bids and market clearing prices, with reference to the marginal cost curves of the resources making up the supply in that particular type of market, is the only certain path to adequate protection against market abuses. In particular, energy market bids must be monitored for correspondence with marginal operating costs, and capacity markets must be examined for correspondence with marginal fixed costs based on a regulated range of return on equity.

**h. If the Commission intends to continue to use structural screens at all in evaluating wholesale power markets, it should recognize them to be merely crude safeguards or “gate keepers,” and not sufficient protection against market power, which can only be accomplished through behavioral screens. However, to avoid confusion, it would be better not to use structural screens at all in order to avoid “false negative” diagnoses for the existence of market power.**

In the Market Power Order, the Commission has not even attempted to show that a “pivotal” market share is the appropriate threshold for all market power abuses. Moreover, any such structural screen is, by definition, at odds with behavioral definitions of how market power is exercised, since economic and capacity withholding, and strategic bidding, are not dependent on a single generation owner being in a pivotal market position, as discussed above. Therefore, the Commission cannot defend the presentation in these two concurrent Orders of fundamentally contradictory definitions of what constitutes anti-competitive behavior. The only remedy is to recognize that structural screens are only crude tools that might reduce the probability of the worst offenses, and that such screens must be followed quickly by a more refined analysis of market behavior during all hours *irrespective of load conditions and market ownership shares*.

**i. The Commission should require all electric generating units selling into U.S. wholesale markets to post their projected 24-hour incremental costs for energy offered for spot market or other market sales, to enable full-time monitoring of all bids and bilateral contracts for competitive behavior. Such monitoring should not be limited to generation owners that fail the SMA screen. The annual fixed costs of each generating unit based on a generic ROE value set by FERC should also be reported for use in monitoring capacity markets and longer-term bilateral contracts.**

Since the SMA screen cannot prevent abuses of market power, it is obvious that behavioral screens must be used to replace (or supplement) structural screens like the SMA for all generation owners in the U.S., irrespective of their passing the SMA screen. The use of behavioral screens that are based on the marginal cost structures of market resources would

require that all resources post their incremental marginal cost data—both the variable and fixed costs for use by all agencies responsible for market monitoring and mitigation.

**j. The Commission's actions in issuing its two key November 20, 2001 Orders are to be praised, even if they are long overdue.**

It is a significant moment in the development of deregulated wholesale power markets when the Commission moves to recognize and act more broadly on its obligation to ensure just and reasonable rates under provisions of Section 206 of the Federal Power Act. It would be extremely unfortunate if this were also the occasion of widespread cynicism and disbelief among wholesale market participants who seriously mistook the Commission's actions as an underhanded move to simply further the agenda of RTO formation. It is particularly important for the Commission to affirm its wholehearted commitment, above all secondary objectives, to quell market abuse because the assurance of just and reasonable rates, along with reliable service, should be its first priority as the federal administrator of the wholesale power markets. Therefore, the Commission should make a further effort to prevent these Orders from being seen as sacrificing the principle, or trivializing the objective, of just and reasonable rates for the sake of furthering the formation of RTOs, which some might believe would not ultimately be subject

to equally rigorous standards to prevent the abuse of market power. After all, the Tariffs Order, which is the more sweeping and fundamental of the two Orders, applies equally to ISOs, RTOs, and all other market-based rate tariffs.

Respectfully Submitted,

SHELDON WHITEHOUSE,  
IN HIS CAPACITY AS ATTORNEY  
GENERAL OF RHODE ISLAND

PATRICIA A. MADRID, IN HER  
CAPACITY AS ATTORNEY GENERAL  
OF NEW MEXICO

RHODE ISLAND DIVISION OF  
PUBLIC UTILITIES AND CARRIERS

By their Attorney,

By her Attorney,

---

Paul Roberti  
Assistant Attorney General  
Chief, Regulatory Unit  
Rhode Island Department of Attorney General  
150 South Main Street  
Providence, RI 02903  
Phone: (401) 274-4400  
Fax: (401) 222-3016

---

Jeff Taylor  
Assistant Attorney General  
Regulatory Law Division  
Office of the New Mexico Attorney General  
PO Drawer 1508  
Santa Fe, NM 87504  
Phone: (505) 827-7484  
Fax: (505) 827-4098

DATED: January 4, 2002

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day filed the foregoing documents at the Federal Energy Regulatory Commission by electronic filing and served a copy upon each person designated on the official service list compiled by the Secretary in this proceeding.

I further certify that the paper copies mailed to the parties on the official service list contain the same information as contained in the electronic media filing, that I know the contents of the electronic media and the paper copies and that the contents as stated in the copies and on the electronic media are true to the best of my knowledge and belief.

Dated at Providence, RI, this 4th day of January, 2002.

---

Paul Roberti  
Assistant Attorney General  
Chief, Regulatory Unit  
Rhode Island Department of Attorney General  
150 South Main Street  
Providence, RI 02903