

MARKET POWER AND WITHHOLDING

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I. INTRODUCTION

The FERC has proposed that all market-based rate tariffs and authorizations be modified to include a provision that “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 competitive behavior or the exercise of market power.”² The operational test would be based on capacity utilization and pricing relative to incremental cost.

It is an established proposition in economics that the exercise of market power has the potential to reduce consumer welfare. For this reason, the antitrust laws impose sanctions on firms that collude to withhold output or raise prices and subject mergers, acquisitions and joint ventures to antitrust review. At the same time, most of economy operates on a market basis where producers control their production. For example, the marketing and sales of the output of Intel’s chip lines, GE’s jet engine production lines, Mitchell Energy’s gas wells, Cleveland Cliffs’ ore mines and Chevron-Texaco’s refineries are not conditioned by requirements that those facilities operate at physical capacity or offer their output for sale at any particular measure of incremental cost. This raises questions both as to isolating the mechanism for exercising market power and the significance of its impact.

It is appropriate from a public policy perspective that the FERC (and the antitrust agencies) should carefully review the potential for the unilateral or collective exercise of market power in their evaluation of mergers, acquisitions, divestitures and joint ventures in the electricity industry. Moreover, during this transition from regulation to competition there will be circumstances in which the ownership of assets developed under the previous regulatory regime

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² FERC Order in Docket No. EL01-118-000, hereafter FERC Order, p. 4.

would convey market power and market-based rate authority should be granted only in conjunction with some form of structural or conduct remedy for that market power.

While the idea of identifying the exercise of market power through economic and physical withholding can be appealing in principle, economic and physical withholding as defined in the Order do not necessarily reflect the exercise of market power, let alone indicate a significant exercise of market power. The definitions found in the Order do not take into account the relevant conditions found in the electricity system. Importantly, the definitions do not reflect an understanding of the physical conditions of the system wherein multiple generating units are scheduled over multi-hour periods, subject to numerous cost, operating, and transmission constraints. The application of bright-line withholding standards based on economic or physical withholding as described in the Order is not appropriate in an electric generation industry with energy limited generation resources, uncertain load and generation, commitment costs, and lacking well developed real-time markets. Correspondingly, refund obligations based on these conditions could be detrimental to FERC's objectives in developing a competitive electricity market.

A fundamental issue raised by the proposed order is that the routine operation of the electricity system through a competitive market entails behavior that appears to fall within the compass of economic or physical withholding as defined in the proposed order. In consequence, the order as proposed has the potential to deter both investment by generators and forward contracting by loads. By preventing least-cost operation, the order would raise the cost of serving load, and thus retail rates. In the extreme, literal application of the rule would undermine reliability by apparently mandating operating policies that would put the lights out.

While more effective mechanisms for deterring and remedying the exercise of market power could benefit electricity consumers, the proposed order could adversely affect consumers by preventing or penalizing pro-competitive behavior that is necessary to efficiently meet consumer demand in electricity markets. Further, subjecting all participants in the electricity supply industry to much more stringent regulatory obligations than even those historically imposed on regulated utilities holds the potential to compromise most or all of the potential competition, efficiency and reliability benefits from the open access policies the FERC has pursued so successfully in the electric industry over the past decade.

Moreover, absent a bright line standard for distinguishing the exercise of market power from efficient pro-competitive behavior, there is a potential for the Commission to become a court of appeals from unhappy outcomes resulting from poor public policy rather than the exercise of market power. This morass of regulatory litigation would add to the potential to both encourage bad public policy and undermine market responses to supply and demand conditions.

In explaining these concerns, we begin by briefly discussing the distinction between the exercise of market power and ordinary competitive behavior. With this background, we turn to a discussion of the circumstances in which economic withholding, as defined in the Order, arises not from the exercise of market power, but from the efficient operation of the electric system. We then turn to a similar discussion of the circumstances in which behavior that would apparently fall within the classification of physical withholding under the Order would also arise

not from the exercise of market power but from the reliable operation of the electric system. Finally, we summarize the connection with refund requirements.

II. COMPETITION AND MARKET POWER

It is necessary to be explicit about what is meant by market power. For instance, Greg Werden of the U.S. Department of Justice has defined the market power of sellers as the ability to profitably maintain prices above competitive levels by reducing output below competitive levels. He has further defined the competitive price level as the marginal cost of the highest marginal cost unit necessary to satisfy industry demand.³ His definition is consistent with that employed by the Department of Justice and Federal Trade Commission in evaluating mergers and acquisitions under the 1992 Merger Guidelines.⁴ Similarly, we have previously defined market power in the electricity industry as “the ability to withhold production on some units in order to increase market prices and profit more from production on other units.”⁵ Figure 1 illustrates the conventional analysis of withholding supply to increase profits.

To be sure, even this definition requires care in the presence of constrained electricity networks or during shortage conditions. A more general definition would be to reduce profits from production on some units in order to change market prices and profit more from production on other units. This would capture either withholding or overproducing on some units (to create transmission constraints) in order to profit from high prices for the output of other units. However, as we shall see, the problem is complicated enough without considering this special feature of constrained networks with loop flow, and we generally limit discussion to the simpler case.

In Figure 1, the underlying economics repeat the simplified textbook case of monopoly pricing. The demand intersects the marginal cost curve (MC) at the competitive price (p_c) and quantity (q_c). However, the monopolist would maximize profit at the point where the marginal revenue curve (MR) intersects the marginal cost curve. This results in the monopoly price (p_m) and quantity (q_m). This outcome could be achieved even in a bid-based market by the monopolist submitting the higher bid curve, which would intersect demand at the monopoly solution. The result would be withholding of supply by the final amount $q_m - q_c$.

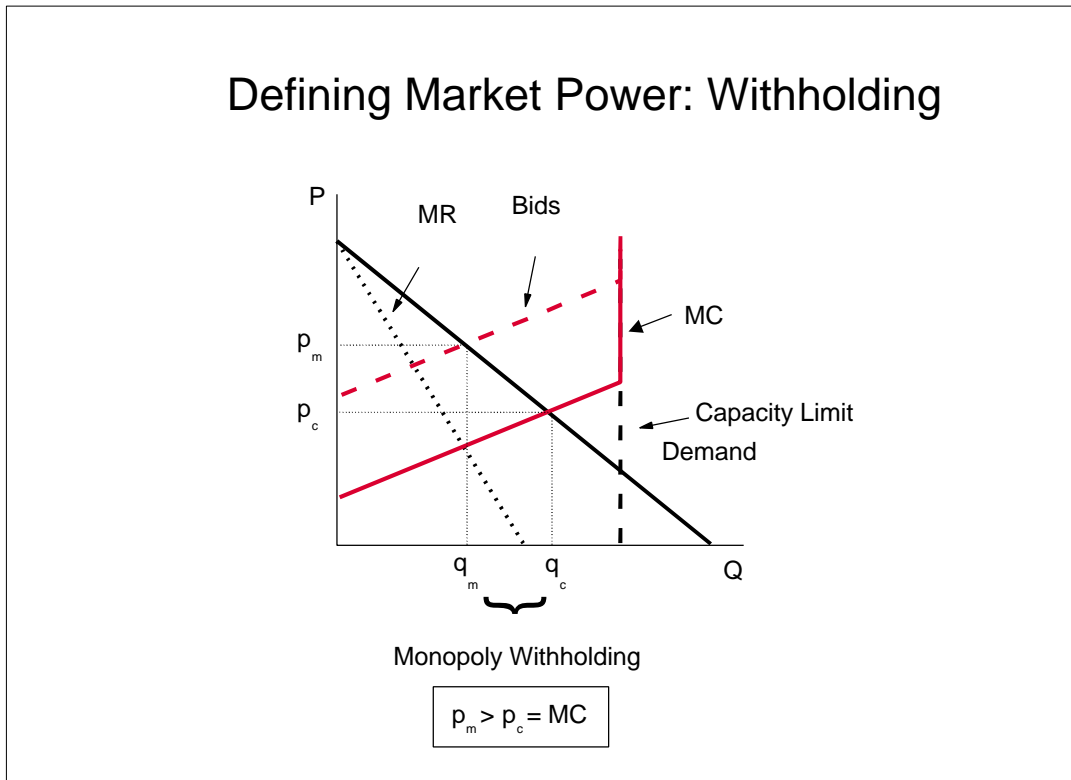
The resulting inefficiency is the reduced production resulting from the monopoly withholding. Given the demand bids, there is an apparent loss of economic efficiency over this range of withholding where the value of the output would be greater than its incremental cost. In addition, there is a large transfer of rents caused by the higher monopoly price. This transfer of rents does not affect efficiency per se, but is of great political importance.

³ See Gregory J. Werden, “Identifying Market Power in Electric Generation,” *Public Utilities Fortnightly*, February 15, 1996, p. 1.

⁴ Department of Justice and Federal Trade Commission Horizontal Merger Guidelines, April 2, 1992, p. 4.

⁵ Scott M. Harvey and William W. Hogan, “On the Exercise of Market Power Through Strategic Withholding in California,” April 24, 2001 (hereafter Harvey-Hogan (April)), p. 1.

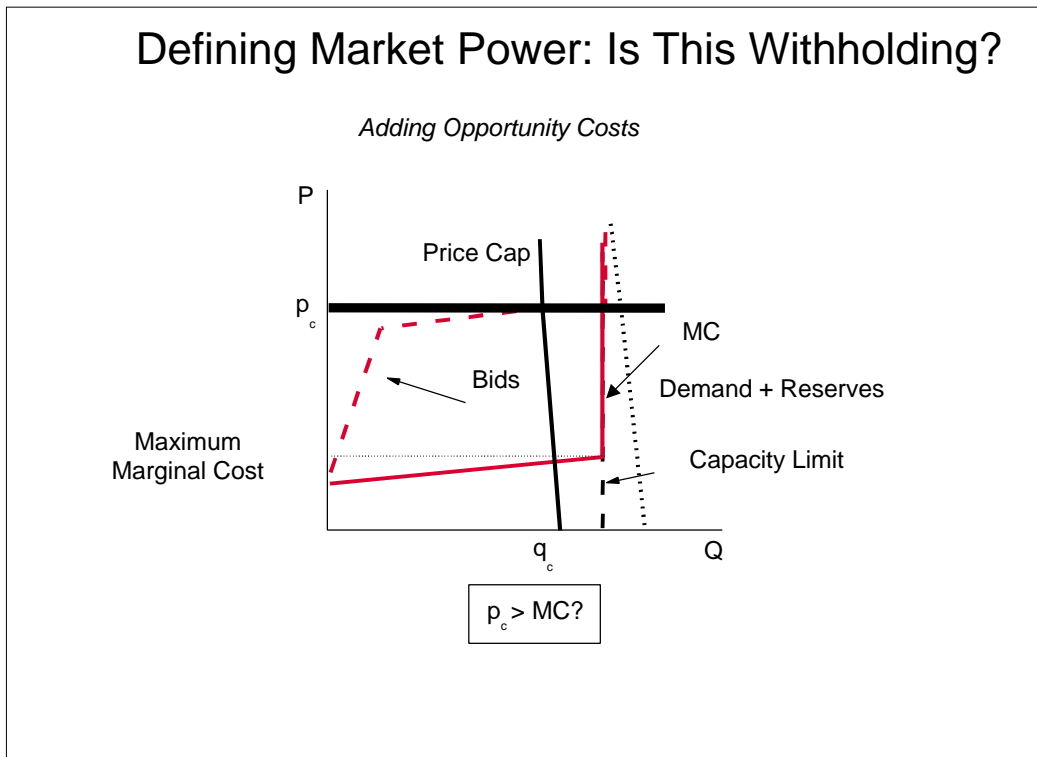
Figure 1



However, it is not an exercise of market power for a generator to sell all its output at an offer price that exceeds its incremental cost. In this circumstance no output has been withheld from the market. This distinction is important. Many complaints regarding the alleged exercise of market power appear directed simply at higher prices. The objection is to an unwillingness of market participants to sell power for less than the market-clearing price. The result is to categorize as the exercise of market power conduct that does not entail withholding output from the market.

Once we move beyond the simplified textbook model, the incentives to offer supply at bid prices above marginal cost are not limited to the monopolist. Faced with price discrimination, shortages, reserve requirements, price caps, energy limits on output, and opportunities to sell in other markets, generators would have incentives to offer supply at bid prices well above marginal cost. As shown in Figure 2, this can lead to outcomes with high bid prices, energy production below capacity, overall shortages relative to aggregate requirements for energy and reserves, and high prices; but there is no withholding of capacity and no exercise of market power.

Figure 2



Firms exercise market power by reducing output below competitive levels so as to raise market-clearing prices. It is not an exercise of market power for firms to refuse to sell their output at prices below the competitive, market-clearing level. In a shortage situation, the competitive market-clearing price may be far above the incremental cost of the highest unit running and far above the price or bid cap. In such a shortage situation, a competitive firm, even one with a tiny percent of the market, would bid to ensure that it is paid the market-clearing price (i.e., the price cap). Depending on the pricing rules, this could entail bidding its costs or bidding the price or bid cap.

The existence of a shortage can be more subtle in an electric system than in other markets because the system operator can be short of capacity and reserves before it reaches the point that it actually has to shed load.

Hence, a shortage can exist without apparent supply interruptions. While the price for net buyers would be lower if supplies were offered at a price below the price cap, an unwillingness to offer supplies for less than the market-clearing price does not reflect an exercise of market power but normal competitive behavior.

III. ECONOMIC WITHHOLDING IN COMPETITIVE MARKETS

The proposed order states that “Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental costs and the market price (and thus,

the output is not sold).”⁶ This criterion is further elaborated by the statement that “during periods of high demand and high market prices, all generation capacity whose incremental costs do not exceed the market price would be either producing energy or supplying operating reserves.”⁷ There are many circumstances in which these criteria are capable of identifying or at least suggesting the exercise of market power. Nevertheless, the proposed criterion does not always identify conduct reflecting the exercise of market power and the exceptions are not trivial. Indeed, firms entirely lacking market power, and even net buyers, would routinely engage in conduct that would be categorized under this standard as economic withholding, and this conduct is in some cases essential to maintaining the reliability of the electric system.

Considerations that would cause firms entirely lacking market power to engage in “economic withholding” as defined in the order include:

- Energy limited units.
- Start-up costs, minimum load costs, and unit inflexibilities.
- Reserves and outage risk.
- Pay-as-bid markets.
- Transmission constraints.

A. Energy Limited Units

The Order’s definition of incremental costs appears to conform to the usual notion of incremental or even marginal energy costs. Given relatively constant heat rates, the required natural gas per kilowatt hour would determine the incremental costs as the gas price times the heat rate, plus emission allowance costs (if any), plus an allowance for variable operating and maintenance costs. This simplified definition would not capture all that would be implied by a more expansive view that included all opportunity costs consistent with the economic incentives for firms without market power.

For example, a criterion for economic withholding based on a comparison of full incremental costs and the market price does not distinguish between energy limited and other resources. Many electricity generating resources are or can at times be subject to energy limitations such that generating a MW of energy in one hour correspondingly reduces the amount that can be generated in another hour. The kinds of units that can be energy limited include pondage hydro units,⁸ pumped storage units, thermal units with daily, weekly, seasonal or annual emissions limits, geothermal units, and gas fired generation subject to daily gas balancing. The offer prices

⁶ FERC Order, p. 4.

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⁸ I.e., hydro generation that can store water at least over the course of a day and thus vary the rate at which water passes through the generator and shift energy from period to period.

of such units can be and are used by firms lacking market power to allocate the limited output to the hours with the highest value. If the output of such units were offered into the market at variable costs without regard for energy limits, the units could be scheduled to generate too much output in relatively low priced hours, reducing the supply of energy in higher priced hours. Were the output of energy limited units to be offered into the market at incremental cost this would not only reduce the efficiency of the market (raising the cost of meeting load), it could also have a material adverse impact on electric system reliability.

The difficulty arises because both the monopoly price and the competitive price would be above the narrowly defined incremental cost. It is possible to distinguish the two cases, in principle, but not by looking only at the differential between prices and incremental costs in hours when production was less than capacity.

The efficient criterion for allocating the output of energy limited units is to offer their output into the market at the expected price for the marginal output of the unit in any hour. If a unit is energy limited, its offer price will therefore exceed the unit's incremental cost and the more energy limited the unit, the greater the margin by which the efficient offer price would exceed the unit's direct incremental costs. This economic withholding can conceptually be distinguished from the exercise of market power in that even if the entitlement to the value of the output of plant were divided among hundreds of sellers that would unambiguously lack market power, they would still offer the output of the plant to the market at prices exceeding their incremental costs.

The efficient pricing of the output of an energy limited unit can in principle be empirically distinguished from the exercise of market power in that efficient pricing would fully utilize the energy of the unit in the highest price hours over the period of the limitation. In practice, however, the unit manager will lack perfect foresight and will sometimes sell too much output in low priced hours and not enough in high priced hours, but this will not necessarily reflect the exercise of market power but only the impact of uncertainty and less than perfect judgment. Moreover, the degree of inefficiency in the scheduling of such energy limited units is further impacted by market rules, which could have a larger impact on reducing supply than would the exercise of market power.

B. Start-up and Minimum Load Costs

The FERC Order appears to define economic withholding in terms of a comparison of full incremental costs and the market price. Such a criterion is not capable of isolating the exercise of market power because it does not take account of start-up and minimum load costs, or operating inflexibilities. Many types of electricity generators have the characteristics that costs are incurred to start them, and once started the units must operate at a minimum load level. The units are relatively inefficient when operated at minimum load (the average cost of output at minimum load is materially higher than the average cost of output at high load), the units require a number of hours to start-up, may also need to remain on line for a minimum number of hours once started, and finally, may need to remain off-line for a minimum number of hours before

restarting.⁹ The impact of these facts is that the cost of meeting incremental load with an off-line unit cannot be measured solely with respect to its incremental energy costs, but must take account of start-up and minimum load costs.

A competitive firm lacking market power would not offer the output of a unit with start-up and minimum load costs to the market at its incremental energy costs, unless the firm believed that the operation of the unit as a whole would be economic. There is no method by which the economics of committing such a unit to meet load can be evaluated in terms of a one-part bid based on incremental energy cost. The profitability of using such a unit to meet load depends on how many hours the unit would be able to sell energy at a price exceeding its incremental cost (i.e., would be fully dispatched), how many hours the unit would need to operate at minimum load (i.e., the market price would be less than its incremental energy costs) and the magnitude of its start-up costs and minimum load costs.¹⁰ These kinds of unit commitment decisions can only be made on the basis of multi-part bids evaluated over a multi-hour commitment period.

This reality is reflected in the structure of the day-ahead markets coordinated by both PJM and the NYISO. Both markets make commitment decisions based on multi-part bids and evaluate the economics of unit commitment over the day as a whole, not on an hour by hour basis. Absent this market design, the failure of a seller to offer the output of such a unit into forward markets for a single hour at a price reflecting the incremental cost of generating an incremental MW in that hour could be fully consistent with competitive behavior. Indeed, it is a routine circumstance in New York for units not to be committed in the SCUC evaluation, despite prices that exceed their incremental costs in some hours, because the units could not recover their costs of starting or remaining on line over the day as a whole. The same economic evaluation of commitment must be undertaken by all generators, whether or not there is a centralized unit commitment process as in PJM and New York. Even if each seller owned only one such plant and would not benefit from withholding their plant from the market, they would not offer their output into longer-term forward markets unless they expected to be able to recover their start-up and minimum load costs over their operating period, without regard to their incremental costs in any particular hour.

In markets in which generators have start-up costs, minimum load costs and operating inflexibilities, conclusions regarding the exercise of market power cannot be drawn based on a comparison of prices and incremental costs of off-line units. Moreover, prices that are too low relative to the competitive level can be as detrimental as prices too high. Both deviations from efficient market outcomes should be considered when the Commission makes judgments about the nature of market imperfections and the justness or reasonableness of rates.

⁹ Not all generating units have these properties. Gas turbines can be started quickly, with relatively small start-up costs but also usually have high heat rates and high emission rates, which make them a high cost source of electricity.

¹⁰ These considerations are discussed at length in Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000 (hereafter Harvey-Hogan (October)); and Harvey-Hogan (April).

C. Reserves, Regulation and Forward Markets

It appears that the intent of the order is that capacity that is not used to generate energy but is providing reserves would not be considered to be economically withheld from the market. Thus, it is stated that: “during periods of high demand and high market prices, all generation capacity whose incremental costs do not exceed the market price would be either producing energy or supplying operating reserves.” We agree with the view that capacity that is supplying operating reserves is not being withheld from the market.¹¹ Similarly, generating capacity that is not offered in the energy market but is scheduled to provide upward regulation is not withheld from the market, although this capacity would not on average be used to generate energy.

With this qualification, generators lacking market power would be willing to offer the capacity of units that are not energy limited and not providing operating reserve or regulation for dispatch in real-time at a bid reflecting the incremental costs of operating and selling energy in the market, including fuel cost, emission costs, variable O&M costs, and credit costs. It needs to be kept in mind, however, that outside the Northeast, generators do not have the opportunity to be dispatched in real-time markets such as those coordinated by PJM and the NYISO. In these other markets, generators generally sell their output on a forward basis. This feature of these markets is important in distinguishing economic withholding that reflects ordinary competitive behavior from the exercise of market power.

Market participants entirely lacking market power, including net buyers, would engage in economic and physical withholding of capacity from forward markets (in excess of the minimum level of operating reserves and regulation) in order to maintain reserves for outage risk, demand uncertainty and load following. The further in advance of real-time the forward market operates, the larger the likely amount of economic withholding from the forward market by suppliers/buyers lacking market power.

Outage Risk

Generators selling energy in forward markets (whether a few hours forward or many months forward) must recognize that the theoretical capacity of their units or even the capacity available to them at the moment of the sale may be greater than the capacity that will likely be available to them to cover the sale in real-time. For example, a generator might have 1,000 MW of capacity that is on-line 24 hours before real-time, yet anticipate that on an expected value basis it would only have 975 MW available in real-time. While reasonable people can disagree as to whether forward energy prices should in general exceed real-time prices, equal real-time prices, or be less than real-time prices depending on the relative degree of risk aversion, we believe that there would be a consensus that it would be economically irrational for a competitive firm to offer in forward markets to sell energy in excess of its expected generating capacity at a price that is much less than the expected real-time price. Such sales would reduce expected profits at the same time that they increased the variability of profits. As a result, a competitive firm would not rationally offer such forward sales at incremental cost but only at offers at least close to the

¹¹ This provision is also consistent with the NY ISO’s AMP mitigation which does not mitigate the bids of generation that is scheduled to provide reserves. See NYISO Technical bulletin #67, p. 2.

expected real-time price. A competitive firm pursuing such a policy would at times appear to be engaged in economic withholding, because in some hours it would have fewer than expected outages, real-time prices would be less than the expected price but higher than its incremental costs and it would have unsold capacity.

In regions in which the ISO or RTO coordinates a real-time bid-based dispatch, generators or loads can offer excess capacity into the real-time market without incurring financial or reliability risk. Thus, capacity not sold into forward markets because of outage risk or demand uncertainty can, if not needed by the owner, be made available for sale in ISO-coordinated real-time spot markets at incremental cost. This option is not as easily available, however, in regions lacking an ISO-coordinated real-time dispatch and spot market. In regions lacking an ISO/RTO coordinated real-time dispatch, however, both LSEs (including net buyers) and generators will often be found after the fact to have withheld more capacity from forward markets than will turn out to have been necessary. This, withholding, however, may not reflect the exercise of market power but merely the reality that load and outages are uncertain.

Furthermore, depending on the distribution of outage risk, rational firms lacking market power but having some risk aversion might be unwilling to offer even their expected real-time capacity into the market except at a premium to the expected real-time price. Indeed, firms that were net buyers might buy sufficient capacity to more than cover the expected outage risk on their own units and would be unwilling to release this capacity into the market except at a premium over the expected market price.

Demand Uncertainty

The impact of demand uncertainty on the offer prices of a vertically integrated seller is almost identical to that of outage risk. In evaluating forward sales, a seller must recognize that not only may it lose generation between the time of the sale and real-time, but that its expected real-time load of 975MW, might turn out to be 925MW or 1050MW. Thus, the more generation is sold forward, the greater the likelihood that the seller will actually be short in real-time. This risk would make the seller unwilling to offer output in forward markets at a price lower than that which it might need to cover any resulting short-fall or the penalties it would incur were it short in real-time.

Hourly Markets

Finally, load serving entities must economically withhold from markets not only enough capacity to meet their average load during each hour, but enough to meet the peak load in each hour. This consideration does not exist in the Northeast as real-time markets such as those coordinated by PJM and New York permit sellers to offer excess capacity to the market in real-time on an interval by interval basis. No such real-time markets exist in much of the rest of the country, however, and firms lacking market power, including net buyers, may economically or physically withhold sufficient capacity to provide load following over the hour and meet peak load, not average load.

Moreover, if market participants not only lack market power but also lack access to real-time markets, the price at which they would be willing to offer energy for sale in non-recallable

hourly markets could greatly exceed their after-the-fact incremental cost of generating that energy. In these circumstances, their offer price must reflect the potential for higher than expected load or outages that would cause them to violate reliability criteria, or in the worst case shed load, were they to sell additional capacity in hour-ahead markets.

D. Pay-as-Bid Markets

The proposed order states that “Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental costs and the market price (and thus, the output is not sold).” In defining economic withholding through a comparison of offer prices to both incremental costs and market prices, the Order appears to recognize that energy offered at prices in excess of incremental cost is not necessarily economically withheld from the market. This recognition is important because there are only two markets (PJM and New York) in the U.S. in which market participants can offer their energy output into the market at incremental cost and in most circumstances be paid the locational market-clearing price for that energy. All other U.S. electricity markets operate in varying degrees as pay-as-bid markets and market participants can ensure that they are paid the market-clearing price only by offering their energy output at the locational market-clearing price. In such markets the capacity of infra-marginal generation may be fully scheduled to generate energy or provide reserves, but the energy output would likely not have been offered to the market at incremental cost. The FERC rule should not preclude market participants from selling their output at market-clearing prices.¹²

Hence, it is important in preserving competition, maintaining reliability, and promoting economic efficiency that sellers in such pay-as-bid markets be permitted to offer their output for sale at the market-clearing price. Offering capacity at prices in excess of incremental cost in pay-as-bid markets may not reflect the exercise of market power, but merely reflect an effort to be paid the market-clearing price. Rules that require that output be offered and sold at incremental cost when that is less than the market-clearing price would themselves be unduly discriminatory because they would, in effect, require merchant generators to accept lower compensation for their output than would be realized by the vertically integrated owner of the same plant. Such discrimination could effectively end the development of merchant generation projects, because low cost generation would receive lower prices than high-cost generation and would not be able to recover its fixed operating and investment costs. Strictly applied, wind, solar and run-of-river hydro generators would be required to offer their output to the market at a zero price under such a standard, making it impossible for them to recover any fixed operating or capital costs. This would force vertically integrated utilities to once again take on responsibility for making investments in generating capacity. Requiring that generators offer their output into pay-as-bid markets at incremental cost would soon end trade, and undo all of the positive things that the FERC has sought and achieved in the electricity industry through open access.

Even if economic withholding were not to be inferred unless the available output remained unsold and was offered at a price exceeding both incremental cost and the market price, the

¹² A rule lacking this provision could materially reduce the profitability of investments in efficient low cost generation, potentially giving rise to substantial adverse efficiency and reliability impacts.

economic withholding standard described in the order would, in practice, not be able to fully distinguish between the exercise of market power and ordinary competitive behavior. In understanding the reasons for this inability, it is necessary to recognize that in pay-as-bid markets and markets lacking real-time dispatch there will be many transaction prices (all of which are market prices), at many locations (all of which will generally differ from the location of the seller). It will inevitably be the case that some output will remain unsold yet have incremental costs lower than some of the transaction prices at some of the locations. This would be the case even if every seller were very small and thus lacked market power. Indeed, the problem would likely be exacerbated by many small sellers each of whom would have limited information regarding prices and markets.

Further, in such markets not all producers may even have been offered the opportunity to sell their output at the “market price.” This is particularly a problem in markets lacking a coordinated spot market and is exacerbated if sellers must buy and schedule transmission service in order to reach the buyer. Indeed, some of the motivation for moving to ISO coordinated markets in the Midwest is the belief that not all available resources are able to find a market at the reported “market price,” even during high price conditions. Finally, it may not always be clear what the market price actually was in markets that do not use locational marginal cost prices (LMP), particularly those not coordinated by an ISO.

E. Transmission Constraints

The difficulties above were developed largely in the context of the idealized model of an unconstrained energy system. In reality, all these difficulties would be compounded by the presence of transmission constraints. Regrettably, transmission constraints can be pervasive and the effects complicated. The FERC has recognized this reality both in the targeted mitigation strategies it has adopted such as for New York City and for the RMR units in California. Hence the problem is not new.

However, it is important to recognize that application of the Order’s test for economic and physical withholding would be more difficult whenever transmission constraints are or might have been binding. The ambiguities will arise at every step. The market-clearing price of theory should be the market clearing-price at the generator’s location, but this price will be difficult to estimate or even unknowable without an efficient market design, producing LMP prices. Furthermore, the incremental opportunity cost for all but the simplest cases would depend on an assessment of current and future (in the case of energy limited units) transmission congestion.

In going forward, therefore, it is important to recognize that the counterfactual comparison of observed results against possible monopoly of competitive alternatives must incorporate the sometimes large and often counterintuitive effects of transmission constraints.

IV. PHYSICAL WITHHOLDING IN COMPETITIVE MARKETS

Like economic withholding, physical withholding of generating plant output can be a mechanism for the exercise of market power. This mechanism would be a particular concern with respect to generators subject to regulatory requirements, such as bid caps, that prevent the exercise of

market power through economic withholding, if the generators are able to achieve the same result by physically withholding the plant's output from the market. At the same time, however, the existence of physical withholding as defined in the order does not necessarily reflect the exercise of market power, and may instead reflect efficient competitive behavior.

While the physical withholding of capacity from well functioning electricity markets is inefficient and can adversely affect reliability, it needs to be recognized that generating capacity may sometimes be physically withheld from the market, not in order to exercise market power, but because the markets are not well functioning, because of credit risk, because of bid or price caps, or in compliance with laws or regulations.

A. Physical and Economic Withholding

As explained above, economic withholding as defined in the Order is not necessarily motivated by the exercise of market power and may serve a variety of efficiency and reliability enhancing purposes.

If market participants are not able to economically withhold capacity from the market to serve purposes other than the exercise of market power, they will be forced to employ physical withholding to achieve purposes better achieved through economic withholding, including managing the operation of energy limited units, outage and demand uncertainty risk, and operating risks by physically withholding capacity from the market in hours in which they anticipate that operation would be uneconomic.

Energy Limited Units

If the output of energy limited resources cannot be economically withheld from low valued hours, it will need to be physically withheld from hours expected to be low-valued in order to maintain its availability in hours expected to be high-valued. This physical withholding reduces the system operator's flexibility and can reduce reliability if expectations turn out to be incorrect. However, if economic withholding is not permitted reliability would also be undermined if the capacity were not physically withheld from the hours expected to be low-valued.

Outage Risk

Similarly, if firms are not permitted to economically withhold some capacity from forward markets to hedge their outage risk, they would achieve the same result by physically withholding capacity in excess of their expected capacity from forward markets. This physical withholding would not, however, necessarily reflect the exercise of market power, and would be found among small as well as large sellers, and even among net buyers.

Operating Risks

Finally, if firms are not permitted to economically withhold capacity from real-time operation to reflect the operating risks associated with operating at high levels, generators lacking market

power will physically withhold that capacity from the market. Indeed, in some circumstances the operating and safety risks from running units at very high levels may be so high that the owner would be unwilling to operate the unit at those rates at any price.

B. Credit Risk

Capacity may be physically withheld from sale not to the market as a whole but withheld from sale to particular buyers as a result of credit concerns. It is neither uncommon nor bad public policy for market participants to limit transactions with firms having limited credit or even to simply forbid transactions with firms whose credit is perceived to be so poor that a credit premium is insufficient to mitigate the credit risk.

In the extreme case, we have seen that generators that are not being paid for their output can themselves become poor credit risks and be unable to pay for the gas they need to generate electricity and will then physically withhold their output from the market. The potential magnitude of this consideration was clearly shown in California, where the failure to pay the qualifying facilities (QFs) eventually reduced supply and helped put the lights out. In these circumstances, the physical withholding need not reflect the exercise of market power and it is not constructive to require market participants to generate energy for which they will not be paid using gas for which they cannot pay.

C. Price Caps

High cost capacity will likely be physically withheld from the market if bid and price caps are imposed at levels that are less than cost of generating electricity from those resources. As before, the problem in these circumstances is not the exercise of market power, but the bid or price caps. Rules that require that energy be generated below cost are neither procompetitive nor efficient.

D. Compliance with Law and Regulations

Many laws, regulations and other restrictions, most apparently environmental, require generators to physically withhold capacity from the market in a variety of circumstances. Compliance with these output limitations in no sense reflects the exercise of market power, but appears to fall within the definition of physical withholding under the Commission's order.

V. APPLYING THE COMMISSION'S ORDER

Because not all economic or physical withholding as defined actually reflects the exercise of market power, maintaining efficiency and reliability would require that any FERC rule distinguish between efficient economic and physical withholding and that which is designed to exercise market power. Important ambiguities in the Commission's order include the following:

a) *Will the existence of economic withholding be determined based on the offer price or output?*

Our reading of the proposed order is that it is not intended to require that energy be offered and sold at incremental costs, merely that it not be withheld from the market.¹³ This interpretation is important because as discussed above most U.S. electricity markets operate in varying degrees as pay-as-bid markets and market participants can ensure that they are paid the market-clearing price only by offering their energy output at the locational market-clearing price. FERC market-based rate authority which required that output be offered and sold at incremental cost when that is less than the market-clearing price would have such negative effects on the development of merchant generation projects, that it would effectively force electricity demand to once again be met through the investments of vertically integrated utilities.

b) *How will output not sold at the market price be identified?*

It is our understanding that the FERC Order would not infer the existence of economic withholding unless available output remains unsold and the output was offered at a price exceeding both incremental cost and the market price. Even so, the economic withholding standard will be very difficult to apply in the pay-as-bid markets prevailing outside PJM and NY.

What is the market-clearing price? In pay-as-bid markets lacking both an ISO coordinated market and LMP pricing there will usually not be a well-defined market price at the sellers location. Instead, there will be a range of transaction prices at a variety of locations, most of which may be trading hubs not located close to the generator. Each of these transaction prices is a market price. FERC will be able to observe whether energy is sold, but the comparison of incremental costs to market prices will not be equally straightforward. First, there will, in practice, be a range of transaction prices to which the incremental cost could be compared. A conservative approach might be to compare incremental costs to the lowest of the arm's-length transaction prices. Absent such a conservative approach, price dispersion would be characterized as economic withholding. Such a characterization would not identify the exercise of market power and would burden market participants and the Commission. Second, these constraints will generally not be at the same location as the seller being examined, and in non-LMP markets there will not be a well-defined locational differential on which to base a comparison.

Even if FERC is ultimately able to develop a reasonable after-the-fact measure of the minimum market-clearing price at the seller's location, how would FERC distinguish between output that was not sold due to economic withholding motivated by market power and output that was not sold due to poor information regarding the market-clearing price and the normal inefficiency of pay-as-bid markets?

Was energy withheld or not taken? In markets lacking a real-time dispatch, generation may not operate in real-time because it is being economically withheld from the market, because it was not economic in the market, or because the owner was unable to find a market. Sellers that did

¹³ "Economic withholding occurs when a supplier offers output to the market at a price that is above both its full incremental costs and the market price (and thus, the output is not sold)."

not receive any offers to buy at prices in excess of their incremental cost did not withhold energy from the market, they were merely unable to participate in the market. FERC will be able to observe whether energy was sold, but it may be difficult to determine whether it remained unsold because it was withheld by the seller or because buyers did not want it. In markets lacking an ISO coordinated real-time dispatch, not all producers may even have been offered the opportunity to sell their output at the “market price” as determined by FERC.

c) *Is the economic withholding standard to be applied in forward markets or only in real-time?*

The application of the proposed economic withholding standard in pay-as-bid forward markets operating in continuous time could make it virtually impossible for suppliers to recover the market clearing price and would appear to in practice require that much output be offered and sold at below market prices. It is not apparent how traders or any kind of risk manager could earn a positive margin if they were required to resell purchased power at the lower of the purchase price or the market clearing price at the time of resale.¹⁴ The Order would also appear to greatly increase the risk and cost of forward hedging by loads if the Order were to require that power be resold at the lower of cost or market. Under such an application of the Order, net buyers would also have to become more conservative in hedging their loads in forward markets as they would not be able to recover in resale markets the actual value of energy that they ultimately do not need to meet their load.

d) *How will capacity providing regulation, load following or operating reserves be treated?*

As observed above, the test of economic withholding stated by FERC appears to focus on whether output was actually sold, not the price at which it was sold. A critical issue in applying this test is how capacity providing operating reserves¹⁵ (or upward regulation or load following) would be accounted for.¹⁶ It appears that the intent of the FERC order is that capacity providing reserves would not be considered to be economically withheld. Thus, it is stated that: “during periods of high demand and high market prices, all generation capacity whose incremental costs do not exceed the market price would be either producing energy or supplying operating reserves.” As discussed above, however, this exclusion would need to be broadened to include generation providing upward regulation as well as reserves.

¹⁴ It is important to remember that generators and traders are constrained by the market as well as by these proposed regulations. Such an application of the Order would effectively recreate the lower of cost or market problem under regulation that has been an important motivation for moving to open access and the development of competitive generation markets.

¹⁵ Operating reserves are capacity that is kept available but not fully utilized so that the units can increase output in a short-term timeframe (10 to 30 minutes) to maintain the reliability of the system following the loss of a large unit or transmission line.

¹⁶ Regulating units vary their output on a very short-term basis (shorter than the 5-minute dispatch cycle) so as to match generation and load. Because these units must be able to both increase and decrease output, they must be scheduled to operate above minimum load and below capacity. On-dispatch units provide load following on a 5- or 10-minute basis during an hour.

A more difficult issue would be how to determine whether capacity is providing reserves or regulation. This determination is clear-cut in the markets coordinated by the NYISO as generation offers bids to provide reserves or regulation, those bids to provide reserves or regulation are explicitly accepted, and the level of reserves and regulation scheduled is determined by the NYISO. It is much less clear, however, how such a rule would be applied to a vertically integrated utility. All of the available capacity of such a utility is in a sense providing reserves. Some capacity will be providing short-term contingency reserves, while other capacity is providing replacement reserves that would be used to restore contingency reserves following their use by the utility or their activation under a reserve sharing agreement.

Finally, as discussed above, firms lacking market power have an economic incentive not to offer capacity in excess of their expected real-time capacity for sale in forward markets and would certainly not offer such capacity for sale for less than the expected price. A no withholding standard can be applied in real-time in markets such as PJM and NYISO, as capacity not sold forward can be offered at incremental cost in the real-time dispatch. The application of such a no withholding standard would be problematic, however, in regions lacking a real-time dispatch, for there is no mechanism for sellers to offer on a short-term basis capacity that turns out not to be needed in real-time.¹⁷

e) *How would the economic withholding test be applied to energy limited resources?*

As discussed above, economic withholding of energy limited resources does not necessarily reflect the exercise of market power, and is in fact necessary to the efficient and reliable operation of the electric grid.

- How would “full incremental costs” of pondage hydro, pumped storage, geothermal and gas turbine units with daily energy limits be measured?
- How would “full incremental costs” be measured for pondage hydro and fossil fueled thermal units subject to annual, seasonal, monthly or weekly energy limits?
- How would “full incremental costs” be measured for gas fired generation during periods in which daily gas balancing rules are in effect.¹⁸

Perhaps it is intended that these complications would be avoided through after-the-fact application of the no withholding standard. It could, for example, be determined after the fact whether energy limited units exhausted their available capacity over the relevant period. In practice, however, demand uncertainty will at times cause energy limited units to not fully utilize

¹⁷ In regions in which it is possible to sell energy on a recallable basis, such recallable sales might provide a market at which energy might be sold at incremental cost comparable to the spot sales in PJM and New York.

¹⁸ During periods in which daily gas balancing rules are in effect, the consumption of gas not scheduled day-ahead can be subject to imbalance charges that make it very expensive. Once gas schedules are fixed, gas fired generators in effect have a fixed amount of low cost energy that they can allocate over the day, with incremental generation available at a possibly much higher price. If this is not recognized in gas pricing, market participants could be required to offer supply into the market at below market prices.

their available capacity for a given day, so even if applied after the fact, this standard will mischaracterize as withholding efficient competitive activities intended to maintain reliability. Such an after-the-fact standard would be even more difficult to apply to resources facing weekly, monthly or annual energy limits as imperfect foresight will inevitably cause some energy to be sold at low prices that could have been sold in another time period at higher prices. Another approach would be to simply recognize that there must be economic withholding of energy limited resources and exempt them from the no economic or physical withholding standard.

f) *How will the measurement of output not sold take account of demand uncertainty?*

Load Serving Entities that have contracted forward for generation to meet their load will not always accurately forecast their load and could be determined after the fact to at times have contracted for capacity that in real-time was required neither to generate energy nor to meet reserve requirements. It is not clear how it is intended that the proposed rule would account for real-time load uncertainty and the reality that LSEs will at times have contracted for more generation than they actually turn out to need in real time.¹⁹

g) *Will the obligation to offer output at full incremental cost apply only to on-line units or to off-line units as well?*

It is not clear whether the obligation FERC intends to impose extends only to prices raised through the economic withholding of generation that was on line in real-time or is intended to also extend to the economic withholding of generation that could have been committed to be available in real-time.

A requirement that all generation be offered into the market at incremental cost, whether or not it is on line, and whether or not it is plausible that the seller has market power, would in practice require that suppliers offer capacity at prices that are actually less than the full costs of having that capacity available. Such a rule could increase the cost of meeting electric load in the United States.

On the other hand, the rule would be greatly complicated if the evaluation of economic withholding were broadened to take account of start-up costs, minimum load costs and the various unit operating parameters. The reality is that regions lacking day-ahead markets based on three part bids and security constrained unit commitment lack the ability for sellers to offer energy on such a basis. An after-the-fact finding that the commitment of additional generation may have been economic does not necessarily reflect the exercise of market power, but merely the efficiency costs arising from the lack of a day-ahead market.

¹⁹ A related issue is that any assessment of whether unsold generation was needed neither to provide energy or reserves needs to be based on peak hourly load rather than average hourly load.

h) What costs would be included in the measurement of full incremental costs?

The measurement of full incremental costs needs to take account of fuel costs (including potentially gas penalties when daily balancing requirements are in effect), variable O&M costs, incremental environmental costs,²⁰ normal credit costs²¹ and premiums for credit risk when this is appropriate. Moreover, the calculation of incremental fuel costs should be calculated for the appropriate operating level and the calculation of incremental costs should reflect any extraordinary costs that may be associated with operation at very high capacity levels.

i) Will the incremental cost standard be applied during periods of reserve shortage?

High prices in California, the Midwest, PJM, New York and NEPOOL have generally occurred during periods of reserves shortage during which all capacity is either generating energy or providing reserves. The order, however, appears to be restricted to the economic withholding of energy during periods in which there is no shortage and does not address the appropriate price level during a shortage, which is the more common circumstance in which prices are high. It is not clear whether the order is intended to require that capacity providing reserves be offered into the market at full incremental cost during periods of reserve shortage or not. This is important.

While current market rules may at times result in prices that are inefficiently high during periods of reserve shortage,²² prices capped at incremental cost during periods of reserves shortage would be too low, particularly in markets in which there is no additional capacity payment, i.e., no installed capacity (ICAP) market. Capping prices during reserve shortages in markets having an ICAP system would tend to raise the cost of ICAP, while diminishing the incentives for generators to have their units on line during the shortage hours or to incur extra-ordinary costs to get their units back on line.²³ Moreover, it should be kept in mind that high real-time prices during hours of shortage are applicable to generators as well as loads, and generators that sold forward but fail to deliver in real-time will be buyers at real-time prices. Artificially reducing the price at which they cover their shortfalls does not provide the correct incentives for generator operation or maintenance.

j) How will the physical withholding standard be applied to generation facilities with operating problems or restrictions?

The physical withholding standard will need to distinguish physical withholding from prudent operation. This would appear to require standards for when it is appropriate to reduce the output of a unit to reduce outage risk, when it is appropriate to reduce the output of a unit or to take it

²⁰ In particular the cost of any emission allowances must be included in the calculation of incremental costs.

²¹ That is, if the payment terms do not require that the seller be paid for 30, 45 or 60 days, the cost of the implicit credit should be included in the determination of full incremental costs.

²² Harvey-Hogan (October), pp. 25-26.

²³ FERC, Office of the General Counsel, Market Oversight and Enforcement and Office of Markets, Tariffs and Rates Division of Energy Markets, "Report on Plant Outages in the State of California," February 1, 2001, pp. 17-18, 42.

off-line for safety reasons, when it is appropriate to take a unit off line for repairs instead of continuing to operate it. Moreover, these evaluations will need to be made in regions lacking ISOs. After-the-fact second guessing of operating decisions by the FERC has the potential to affect behavior unrelated to the exercise of market power in ways that would reduce the availability of capacity and the reliability of the system and therefore should not be undertaken lightly.

In addition, it is presumed that output that is physically withheld because it could not be offered to the market as a result of laws, regulations or other restrictions, environmental or otherwise, would not be found to reflect the exercise of market power.

k) What will be the scope of refunds?

The scope of the refunds envisioned by the order is not clear. Would the refund obligation be limited to the entities determined to have been withholding output from the market or would it extend to competitors that increased output in response to high prices? How would the refund obligation be applied to sales by the withholding entity at different locations? The exercise of market power is unlikely without binding transmission constraints, so not all generation would benefit from the withholding. If transmission constraints were present, how would the refund obligation be applied? Moreover, even in circumstances in which transmission constraints were not binding in the real world, they might well have been binding at lower prices. Would this be taken into account in applying the refund obligation?

In pay-as-bid markets in which energy was sold at different prices at different times, would the refund obligation apply to the average sales price or would low priced sales be left unchanged but high sales prices reduced?

VI. ALTERNATIVES

The immediate concern addressed by these comments has been the FERC's proposed Order, in which it is posited that economic and physical withholding would be evidence of the exercise of market power. A broader concern, though not directly raised in the order, is how a complete assessment of market power issues should be handled on a going-forward basis. The starting point in addressing market power concerns should be a recognition that everybody does not have market power, everywhere, all the time. Policies mitigating the potential exercise of market power should address the circumstances in which particular entities are shown, using appropriately designed screens and market analyses, to likely be able and have the incentives to exercise market power. Policies for remedying the exercise of market power should likewise address real instances of the exercise of market power and not simply be tools for after-the-fact reductions in inconveniently high prices. Although difficult, the FERC needs to identify those firms having market power in particular regions, under particular circumstances and develop appropriate mitigation rules that apply to those firms, in those regions and under those circumstances.

The identification and mitigation of market power in electricity markets is a difficult problem, there is not an easy solution. This difficulty is compounded by the fact that no single regulatory

or anti-trust agency has authority over the entire range of possible steps that could be taken to mitigate or remedy market power. For example, FERC may not have authority to require such structural changes as divestiture. The suggestions below outline steps that should further the development of wider and more robust competitive markets.

There are a variety of policies the FERC could require or encourage that would reduce the potential for the exercise of market power:

- RTO coordinated real-time markets based on LMP pricing.
- Efficient pricing and minimum transmission grid interconnection standards for generation to facilitate entry.
- Loads with real-time meters should be permitted to enter into forward contracts and to buy energy at the real-time spot price.

A further step to approaching the issue is to identify the market participants to which mitigation should not be applied or should be applied only with mitigation procedures developed on a case by case basis. These are, generally, market participants that – for specific reasons - are unlikely to have the ability to exercise market power:

- Small single plant suppliers. It is generally not plausible that small single plants suppliers would be withholding output in order to exercise market power. The presumption should be that these suppliers are operating competitively. The application of market power mitigation to such firms is much more likely to suppress than benefit competition.
- Sellers from energy limited facilities. It is well-recognized that these suppliers must economically withhold their output in order to operate efficiently. Indeed, their ability to economically withhold output is critical to maintaining electric system reliability. While entities controlling multiple energy limited facilities with large capacities can have the potential to exercise market power, conventional market power mitigation should be applied cautiously even in these circumstances, and will need to be customized on a case by case basis.
- Medium sized sellers in large unconstrained markets. Absent transmission constraints, it will generally not be plausible that suppliers owning a few plants in large markets would exercise market power, These entities should also be exempted from market power mitigation, except in circumstances in which they are anticipated to have market power as a result of binding transmission constraints. Once again, any mitigation would need to be customized on a case by case basis.
- Net buyers. LSEs may have generating assets and may at times economically withhold output despite being net buyers. It is not plausible that net buyers would engage in economic withholding in order to exercise market power, so there is no reason to subject them to these kinds of market power mitigation mechanisms.

- New entrants. Firms that have entered the market by building new capacity have generally increased competition through their entry. Imposing bidding restrictions or refund obligations on entrants is unlikely to mitigate market power but could create risks that could slow or deter entry. Once again, the general presumption should be that these entities would not be subject to market power mitigation mechanisms.
- Sellers lacking market power. Firms lacking market power for any other reason should also not be subjected to market power mitigation, particularly mitigation that can constrain efficient, reliability enhancing behavior.
- Traders in Financial Contracts. Marketers who take a forward position without physical control and resell it in the spot market. By having taking a forward position, these marketers are in a “use-it-or-lose-it” situation. They cannot, by definition, withhold output.

The other side of the question is to identify some of the approaches that may be effective in mitigating market power in circumstances in which it is determined that some sellers are large enough relative to the market, in which they sell power that the characteristics of the market would permit them to exercise market power. If FERC does not have the authority to compel these actions, firms could take the initiative in order to qualify for market-based prices and avoid refund obligations.

- Physical asset divestiture. If an individual firm has such a large position within a constrained region that there is a serious potential for the exercise of market power, the preferred solution should be the physical sale of a portion of that capacity to one or more independent entities so as to create competition.
- Financial asset divestiture. Plant characteristics will sometimes preclude the sale of physical generating assets to enough different firms to maintain competition. These characteristics could include common sites and operation, common facilities and common environmental constraints. Competition can still be maintained in these circumstances by divesting financial assets that eliminate the incentive to exercise market power. These financial assets would be some form of vesting contract, such as a CFD, an option to buy at a pre-set or formula price, an FTR or an FTR option. The divestiture of these contracts, perhaps through an auction, would reduce the financial market share of the physical asset owner, reducing its ability to raise profits by reducing output. One of the advantages of financial asset divestiture is that it reduces the incentive to engage in either economic or physical withholding.
- Bid caps. Bid caps²⁴ may sometimes appear simpler to apply than financial asset divestitures, particularly on an after-the-fact basis. Bid caps can be circumvented through

²⁴ We are using bid caps in a broad sense to encompass not only caps on incremental energy bids but also evaluations that consider start-up and minimum load costs.

physical withholding, however, which can lead to difficult after-the-fact review of operating policies.²⁵

In undertaking this analysis FERC will likely want to improve its methods for identifying the potential for the exercise of market power and perhaps to initially be somewhat conservative. Nevertheless, it not necessary, appropriate or desirable to impose market power mitigation on net buyers, on small sellers, or on medium-size sellers in large unconstrained regions, on all sellers in all hours, or on any sellers that do not possess market power

Narrowing the focus and improving market design would allow FERC to develop more appropriate conduct remedies and limited after-the-fact reviews to deal with the few special cases where market power is unavoidable, unanticipated and of a scale significant enough to have a material effect on market performance. This will not be easy. Hence the priority should be placed on improvements in market design and structure. Imposition of conduct remedies on the market should be the last resort, not the first alternative. Market participants in the United States are subject to the antitrust laws that govern competitive interactions and attempt to provide bright-line standards defining acceptable and unacceptable conduct. The criteria proposed in the Order for the identification of the exercise of market power do not provide such a standard.

VII. CONCLUSION

It appears to us that the application of the no withholding standard, even on an after-the-fact basis, will entail much more extensive regulation of energy sellers than the regulation to which even the regulated vertically integrated utility has historically been subjected by its state regulators. There is a very fundamental choice before FERC that has profound implications for the future evolution of electricity markets. If market power exists everywhere, by everyone, all the time, then measures such as this may be necessary.

Market power does not, however, exist everywhere, all the time and is not possessed by everyone. A more appropriate policy is to impose appropriate mitigation on those entities that possess market power and allow those that do not possess market power to economically and physically withhold output in order to efficiently allocate the output of energy limited units, respond to outage risk, demand uncertainty and operating risk, avoid committing uneconomic generation and realize the market value of their generation in pay as bid markets.

²⁵ These kinds of problems can be reduced by bid caps that share some of the properties of financial asset divestitures.