DEREGULATED ELECTRICITY PRICING IN THE U.S.
DRAMATIC NEW RULES FROM THE FERC

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INTRODUCTION

More than five years ago one of us had a conversation with a FERC commissioner who was deeply involved in revising the Commission's policies on electricity market power. The Commission was starting to realize that its method of checking whether a generator was entitled to deregulated pricing — market-based rates (MBRs) in Commission vernacular — was too simplistic. The Commission had already changed its method of analyzing market power in electric utility mergers to a much more sophisticated approach.

We suggested that consistency between the tests for market power in the two settings might make sense. The Commissioner — who shall remain nameless — replied that using the more complex merger analysis for MBRs was totally unacceptable to the industry.

What a difference five years makes. On April 14, 2004, the FERC issued a new interim approach to analyzing market power for MBRs.[1] The approach contains a hierarchy of analyses and screens, including the delivered price test (DPT) — the same test used for mergers. The MBR analytical framework is arguably more challenging than the merger DPT, and it is certainly more variegated. It is unquestionably a massive improvement over the original test, and holds the promise of a somewhat coherent — if complex — framework for analyzing market power in the bulk power sector.

The new framework replaces an interim test issued in 2001 called the Supply Margin Assessment (SMA).[2] The SMA test was heavily criticized as being too restrictive — traditional utilities were nearly guaranteed to fail in their own control areas — and for its automatic mitigation. Many commenters found that the SMA was unsuited to its task, creating little or no improvement in the prevention of market power.[3] Others noted that it examined only unilateral market power by large sellers, ignoring the remaining market structure.

THE NEW BASIC TESTS

Over the years electric power economists have drawn on antitrust economics and industry specifics to develop several tests or *screens* for seller market power. Some of these tests focus on the ability of the seller to exercise market power unilaterally, while others focus mainly on the possibility of collusive or oligopolistic pricing. As with all market power analyses, the application of screens should never be purely mechanical, and passing or failing a screen is almost never an adequate analysis by itself.[4]

The first new test, the Pivotal Supplier Analysis (PSA) is similar to the Residual Supplier Index (RSI).[5] The idea behind the PSA is quite straightforward. If power demand in a specific market cannot be met without at least *some* power from a supplier, that supplier is *pivotal* and faces a rebuttable presumption that they possess market power. For example, if demand in a single hour is 100 MW and the total uncommitted supply of sellers other than Supplier X is 90 MW, then demand cannot be met unless X sells at least 10 MW to the market. Intuitively, if X's supply is needed to keep the lights on, X is probably able to charge extremely high prices for at least a portion of its supply.

Although the PSA is intuitive, many choices are required to specify the proper test parameters, including product definition and geographic market. One of the most controversial parameters used in conducting the market power analysis is a utility's ability to sell in a short-term market. Most commenters argue that traditional utilities have an obligation to serve native load, and thereby uncommitted capacity should be used to make additional spot sales. The Commission agreed and chose to define the *uncommitted capacity* as total capacity controlled less capacity unavailable to the market (a.k.a. net long-term sales, operating reserves, and native load commitments). The native load commitment, however, is measured as an average daily peak load of the needle peak month. Hence, under this test, the product or "wholesale load" is defined as the annual peak load less the average daily peak load of the peak month. The Commission also defined potential competing suppliers as all generators in the same control area (CA), plus those generators in the first-tier control areas that are able to supply power which does not exceed the simultaneous transfer limit (STL).

The second test is the basic market share test. If a seller has a proper defined market share of less than 20 percent, the seller passes the test. While the concept is again intuitive, it remains necessary to specify the product and geographic markets. With some adjustments, the product is defined essentially the same as in the PSA, *i.e.*, uncommitted capacity.[6] The default geographic market is also the same. In addition, the Commission requires the test to be conducted for all four seasons (Summer, Fall, Winter, and Spring).

In some instances (explained below), the analysis may go on to the well-known Herfindahl-Hirschman Index (HHI). The HHI is a numerical index equal to the sum of the squares of the market shares of each seller in the market — ranging from 10,000 for a monopolist (100 percent squared) to essentially zero for atomistic competitive markets. HHIs have long been used by antitrust authorities to gauge the degree of concentration in a market, which is an important general indicator of the propensity for collusive behavior.

Each of these tests has its strengths, weaknesses, champions, and detractors. Although relatively few observers challenge the basic premises of the tests, there is often room for disagreement over the correct measures of the product, the geographic market, and the data used to establish these two measures. For example, when we analyzed the merger creating Progress Energy we discovered that no STL had ever been estimated for one area; we therefore had to prepare and file a transfer capability study.[7] Recognizing this, the new order directs all transmission-providing utilities seeking or retaining MBR authority to measure and file the STL into their control areas or to pass the tests without considering any control area imports whatsoever.[8]

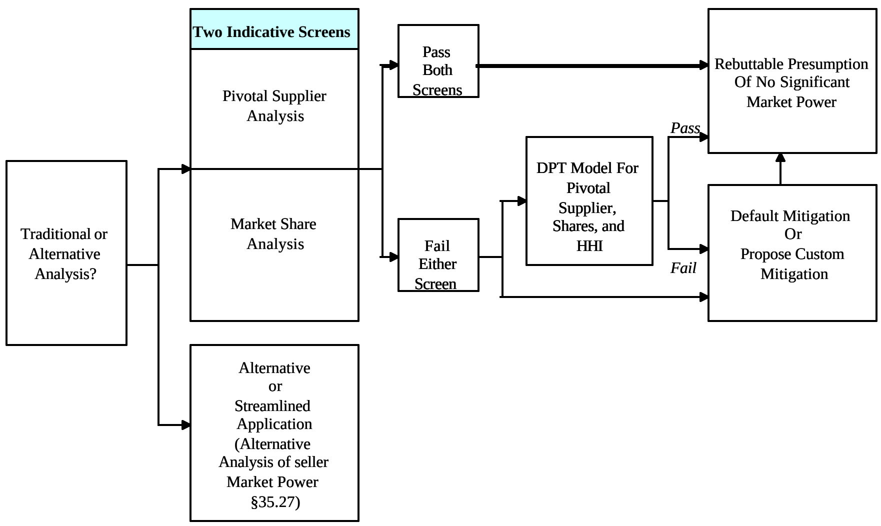
Appendix A shows a more complete description of the three tests and a simple example.

SEQUENCE OF ANALYSES

Figure 1 shows the somewhat complex sequential approach which Applicants will now have to step through as they determine their eligibility for MBRs. Proceeding from the leftmost box in the figure, the first choice is between the pre-specified tests and a customized analysis of the applicant's choosing. The advantage of the pre-specified approach, of course, is that there is a much clearer route to a rebuttable presumption that allows MBRs. In unusual circumstances, however, a customized analysis may yield more accurate results.

Figure 1

New Market-Based Rates Screens From FERC



Along the pre-specified route the next two steps are the basic PSA and market share tests for uncommitted capacity as described above. The PSA is done for the peak hour in the year and is passed if the index is above 100, *i.e.*, that all other sellers in the market have enough uncommitted capacity to meet the Commission-defined wholesale load in that hour. In this test, it is ordinarily assumed that all unforced capacity is available because unit outages are rarely planned to coincide with the system peak.[9]

The market share test measures the seller's share of the uncommitted capacity market. Interestingly, while the FERC recognized that "a more thorough analysis of market concentration would be more informative about the likelihood of coordinated behavior," it decided that any applicant with a share below 20 percent would receive a rebuttable presumption that coordinated behavior was not a concern. This leads to the possibility, as in the prior regime, that large sellers in highly concentrated markets will not receive MBR, while smaller ones in the same market may pass the test.

If an applicant fails either the PSA or market share test, the applicant may proceed directly to mitigation or to conduct the DPT analysis used in merger proceedings. The default mitigation that applies depends on the duration of the sale. Sales of duration under one week must be priced at marginal cost plus 10 percent; sales of up to a year are at any rate up to the embedded costs of the units providing service; and sales of more than a year are at the same rate, but subject to a contract that must be approved by the Commission. Applicants may propose their own customized mitigation as well — an important issue we return to below.

Applicants who choose to conduct the DPT must estimate the shares of seller capacities that can be physically and economically delivered to an area within 5 percent of the market price prevailing during a season and load period. DPT tests are much, much more complex than the share analysis, but if the data and transmission representations are accurate they can reveal much more about the true product and geographic markets (more on this below).

The results of the DPT can be used for calculating PSA, market share, and HHI. If the DPT reveals that the applicant has a share less than 20 percent and the HHI of the relevant market is less than 2500, the applicant is back to a rebuttable presumption of no significant market power.[10] If not, they confront the same mitigation options that follow screen failures for the basic tests.

SOME ASPECTS WORTHY OF NOTE

In an approach of this breadth there is an endless list of items that we could comment on. A few of the aspects of the new scheme that could be important are as follows:

Load Pockets and Geographic Markets.
Although the Commission acknowledged that regions smaller than one control area could be legitimate geographic markets, applicants and other parties must ferret this out to test for geographic markets themselves. As the traditional hypothetical monopolist test for defining geographic markets is not obviously correct for power markets, there remains no accepted test for a geographic power market. Because load pockets and other constrained sub-areas often have the greatest vulnerability to market power, this aspect of the new framework is unexplored and important. In addition, while the Commission withdrew the portion of its prior SMA approach that exempted sellers within Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) from requiring tests, it allows applicants to argue that the entire area under the control of an RTO is a single geographic market.[11]

Uncommitted Capacity Measures and Native Load.
Although the Commission struck a reasonable compromise on paper, it remains to be seen how well its native load offset will work in practice. Furthermore, the Commission made no explicit allowance for the load commitments of other types of sellers; its framework as a whole seems designed around traditional vertically-integrated utilities.

Renewable and Distributed Resources.
With the exception of hydroelectric plants, the 2004 MBR Order is silent on how to treat renewable and distributed generation plants, which are becoming an increasingly important part of supply in some areas.[12] In a bow to Western concerns, the Commission

allowed hydro resource owners to use seasonal capacity measures other than rated maximum capacity

Transmission Data and Simultaneous Transfer Limits.
As noted above, STLs are not generally published for all control areas at peak times, much less by load and seasonal markets. Many assumptions are required to estimate STLs, and these have rarely been filed or litigated. More importantly, the true STL in any market is going to depend strongly on system conditions over multiple control areas. More generally, transmission providers, NAERO and its successors, and RTO/ISOs must focus on providing timely and accurate grid data required for these analyses. The Commission attempted to respond to this concern with Appendix E to its 2004 MBR Order, which clarifies the transmission data it requires.

DPT Modeling.
In our experience, DPT modeling is equal measure art and science. DPT models are large and complex and require massive amounts of data, much of which is difficult to obtain or verify. This includes extensive data on actual transfer capabilities by interface as well as simultaneous transfer limits. As we have explained in much prior testimony, these models must attempt to mimic the allocation of transmission to market participants on scarce flowgates, including the effects of redispatch.

The state of the art in electric system modeling continues to grow. This better reflects the highly interdependent and fast-changing nature of these markets, but it also raises questions as to the requisite accuracy of the modeling, including whether outcomes are durable enough to be of concern. Essentially every time we have filed a DPT analysis with the FERC in the past we have customized or updated our model significantly to reflect changes in regional markets, FERC rules, and/or industry economics. We would not be surprised to see this trend continue.

CONCLUSION

The Commission's new approach to market-based rates is a giant leap forward in analytical sophistication and consistency. Although the complexity suggested by Figure 1 is probably not in itself going to win popularity awards, parties have a wide range of alternatives predicated on a reasonable economic foundation.

All the tests in the new framework focus specifically on generator market power. At the broadest level, the Commission's original checklist for allowing MBRs included three factors beyond an absence of generator market power: absence of transmission market power, absence of entry barriers, and affiliated company issues. These issues will be the subject of an upcoming technical conference and perhaps a rulemaking.

Unfortunately, electric markets do not lend themselves to the sort of one-time structural antitrust approaches used for analyzing bricks-and-mortar industries. Market power governance in the utility sector must take the form of tests and mitigation, always against a backdrop of changing industry structure, physical plant, and rules. These analyses are too complex to be certain that the new rules will work smoothly in all cases, but overall they are worlds apart from the methods of just a few years ago.

REFERENCES AND ADDITIONAL READING

Peter Fox-Penner, Gary Taylor, Romkaew Broehm, and James Bohn, *Competition in Wholesale Electric Power Markets*, 23 ENERGY L.J., 281 (2002).

James Bohn, Metin Celebi, and Philip Hanser, *The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings*, ELEC. J., May 2002, at 52.

Peter Fox-Penner, Gary Taylor, Romkaew Broehm, and Metin Celebi, Market Measurement and The Delivered Price Test Under Standard Market Design, presented to the Staff of the Federal Energy Regulatory Commission (Nov. 15, 2002).

Peter Fox-Penner, A "Securities" Versus "Antitrust" of the Competitive Power Industry and its Implication for RTO Market Monitoring, Remarks before the American Antitrust Institute Conference on Electricity Market Monitoring (Dec. 11, 2001).

Peter Fox-Penner and Frank Graves, *Monopoly Power After Reform? A Time for Soul-Searching*, PUB. UTIL. FORT., May 1, 2000, at 38.

PETER FOX-PENNER, ELECTRIC UTILITY RESTRUCTURING: A GUIDE TO THE COMPETITIVE ERA. VIENNA, VA: PUBLIC UTILITY REPORTS (1997).

William G. Moss and Peter Fox-Penner, Geographic Market Definition In Electric Power Markets (Rev. Jan. 2002) (Unpublished manuscript, on file with The Brattle Group).

Endnotes

1 Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 F.E.R.C. ¶ 61,018 (2004) [hereinafter 2004 MBR Order].

2 Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy, 97 F.E.R.C. ¶ 61,219 (2001) [hereinafter SMA Order].

3 Peter Fox-Penner, Gary Taylor, Romkaew Broehm, and James Bohn, *Competition in Wholesale Electric Power Markets*, 23 ENERGY L.J., 281, 281-348 (2002). James Bohn, Metin Celebi, and Philip Hanser, *The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings*, ELEC. J., May 2002, at 52, 52-65; Comments of Michael Wroblewski, F.E.R.C. Docket No. PL02-8-000, Supply Margin Assessment Technical Conference (Jan. 13, 2004), Transcript at 146-147.

4 For example, the Commission requires an applicant to use historical data. ("Historical data have been proven to be more objective, readily available, and less subject to manipulation than future projections…" Order, ¶ 118). However, the Commission should allow a sensitivity analysis using a forward looking data if there are changes affected the applicant such as transmission capacity, long-term commitments, or new capacity addition.

5 We use the term pivotal supplier and RSI interchangeably. See Appendix A for more explanation.

6 Minimum daily peak load is used for the proxy of native load. Capacity is adjusted for seasonal planned outages.

[7] Testimonies of Peter Fox-Penner (Exhibit No. CF-400) and Stanley H. Williams (Exhibit No. CF-500), Docket No. EC00-55-000 and ER00-1520-000.

[8] 2004 MBR Order ¶ 82 and ¶ 85.

[9] As noted above, these tests can be conducted without considering imports or the STL. This is likely to be of use primarily to very small sellers in control areas, who easily pass the screens without the need to consider imported capacity of any kind — and provided these small sellers don't own or control the import capability itself or large shares of import supplies.

[10] This may be true even if the market share is greater than 20 percent but the market is unconcentrated. See ¶ 111.

[11] This does not apply to RTOs that do not act as single Control Area (MISO and SPP at present), but it will be interesting to see the point at which the traditional Control Area boundary is no longer the most effective default in such cases (see ¶¶ 186-188).

[12] Demand-side resources are obliquely incorporated, at least in principle, in measurements of demand, and are briefly discussed in the Order.

Appendix A
Simplified Examples of New FERC Market-Based Rate Tests

Pivotal Supplier Analysis: An Applicant passes the test if the applicant's uncommitted capacity is less than the net uncommitted supply.

Example 1: Market A has an annual peak load of 4,000 MW and the average daily peak in the annual peak month is 3,000 MW. The short-term demand for wholesale power (or wholesale load) as defined by FERC for Market A is 1,000 MW (4,000-3,000). The Applicant owns and controls 5,000 MW,[1] and the uncommitted supply of competing suppliers,[2] which includes those inside Market A and first-tier suppliers, is *1,000 MW*. Applicant's uncommitted capacity is 2,000 MW (5,000-3,000), yielding total uncommitted supply in Market A of 3,000 MW. The net uncommitted supply, therefore, is 2,000 MW, which is the total uncommitted supply minus the wholesale load (3,000-1,000). *Result:* Applicant fails the test.

Example 2: Load conditions in Market A and Applicant's generation are the same as those described in Example 1, but the uncommitted supply from competing suppliers is now 1,001 MW. The net uncommitted capacity is 2,001 MW, yielding one MW more than Applicant's uncommitted capacity. *Result:* Applicant passes the test.

Example 3: Load conditions in Market A and the uncommitted capacity of competing suppliers are the same as those described in Example 2. Applicant's total capacity is now 6,000 MW. Applicant's uncommitted capacity becomes 3,000 MW (6,000-3,000), and the net uncommitted capacity increases to 3,001 MW, yielding one MW more than Applicant's uncommitted capacity. *Result:* Applicant passes the test.

In sum, as long as the competing supply is sufficient to meet Wholesale Load, Applicant passes the pivotal supplier test:

[1] This capacity is not adjusted for planned generation outages as FERC does not expect that the planned outages will be scheduled on the annual peak day. See 2004 MBR Order at ¶ 97.

[2] The amount of uncommitted capacity of a competing supplier is defined as its capacity (including capacity and net long-term purchases/sales) minus its average daily peak load and operating reserves commitments. The sum of uncommitted capacity of all identified competing suppliers should be limited to the simultaneous import limit of Market A.

Table 1
Pivotal Supplier Analysis Examples

	Peak Load (MW)	Avg Daily Peak Load (MW)	Wholesale Load (MW)	Total Capacity (MW)	Uncommitted Capacity (MW)
Example 1					
Applicant	4000	3000	1000	5000	2000
Competing Suppliers					1000
Total Supply					3000
Net Uncommitted Capacity					2000
Test Result					Fail
Example 2					
Applicant	4000	3000	1000	5000	2000
Competing Suppliers					1001
Total Supply					3001
Net Uncommitted Capacity					2001
Test Result					Pass
Example 3					
Applicant	4000	3000	1000	6000	3000
Competing Suppliers					1001
Total Supply					4001
Net Uncommitted Capacity					3001
Test Result					Pass

Market Share Analysis: The test is passed if the Applicant has less than 20 percent market share of the total uncommitted capacity under the minimum daily peak load conditions in the peak month of each of the four seasons.

Suppliers A, C, D, and E are first-tier utilities in Market A, and Supplier B is located inside the market. Table 2 lists each supplier's uncommitted capacity.[3] Total uncommitted capacity of the first-tier utilities is 3,150 MW but they can only import 1,500 MW into Market A due to the simultaneous transfer limit. While the uncommitted capacity of Supplier B remains at 1000 MW, the uncommitted capacity of A, C, D, and E are reduced according to their *pro rata* share of transmission,[4] *i.e.*, 500, 143, 357, and 500 MW respectively. Thus, the market shares of Suppliers A, B, C, D, and E are 20, 40, 6, 14, and 20 respectively. In our example, only Suppliers C and D would pass the market share test. Suppliers A, B, and E would either have to mitigate or conduct a DPT analysis.

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3 In this analysis capacity is adjusted by seasonal planned outages.

4 Shares based on share of supply, *e.g.*, Supplier A's share would be (1050/3,150)*1,500 = 500 MW.

Table 2
Uncommitted Capacity
Market Share Analysis Example

Supplier	Uncommitted Capacity (MW) Pro rata Method		Share (%)
	Before	After	
A	1050	500	20
B	1000	1000	40
C	300	143	6
D	750	357	14
E	1050	500	20
Total	4150	2500	100

Delivered Price Test Analysis

Suppose 5 percent over market price in Summer-peak period[5] of Market A is $100/MWh and potential suppliers are the same as those in our market share analysis example. The DPT model would calculate market shares of potential suppliers in Market A along with the HHI based on each supplier's economic cost of delivering power in Market A. Column [1] of Table 3 lists the amount of available economic capacity that each supplier can deliver to Market A. But since STL in Market A is 1,500 MW and the total potentially-available economic capacity from outside Market A is 2,050 MW, the transmission capacity must be allocated to Suppliers A, C, D, and E. Columns [3] and [4] present the shares and HHI results when the transmission capacity is allocated based on *pro rata*.[6] In this example, Supplier E passes the test as its share is below 20 percent threshold and the HHI is 2287, which is less than 2500.[7]

Table 3
Delivered Price Test Analysis

Supplier	Available Economic Capacity (MW) Pro rata Method		Share (%)	Share2
	Before	After		
	[1]	[2]	[3]	[4]
A	750	549	25	622
B	700	700	32	1012
C	300	220	10	100
D	500	366	17	277
E	500	366	17	277
Total	2750	2200	100	2287

5 The Commission requires an applicant who chooses to conduct the DPT analysis to perform a total of 10 periods.

6 Shares based on share of supply, *e.g.*, Supplier A's share would be (750/2,050)*1,500 = 549 MW.

7 Other transmission allocation approaches can be used and may be more appropriate.