Market Monitoring Unit

REPORT
TO
THE FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF STANDARDS, INDICES AND CRITERIA

Market Monitoring Unit
PJM Interconnection, L.L.C.

April 1, 2001

Introduction

On November 25, 1997, the Commission approved the comprehensive restructuring of the PJM marketplace, establishing PJM as an Independent System Operator ("ISO").[1] The Commission further authorized PJM to administer the PJM Power Exchange ("PJM PX").

In its order, the Commission found that the restructuring of PJM "will significantly alter the operation of the electric power market within PJM" and that, as a result, "it is important to monitor its implementation to assess undue discrimination and market operation" and to evaluate "how the pool and non-pool markets and transmission pricing arrangements are working." The Commission directed PJM to submit a proposed market monitoring plan that would allow PJM to monitor and report to the Commission on the potential to exercise market power within PJM. The Commission stated that the plan should evaluate the operation of both pool and bilateral markets to detect either design flaws or structural problems.[2]

On June 29, 1998, PJM filed a Market Monitoring Plan ("Plan") in compliance with the Commission's Order. The Plan was filed as an amendment to the PJM Tariff in order to ensure the PJM Board's independence in administering and revising the Plan.[3] By order issued March 10, 1999 the Commission accepted the Plan filed by PJM as part of the PJM Tariff to be effective April 1, 1999.[4] The Commission found that the ability of the Market Monitoring Unit ("MMU") to effectively and broadly monitor and investigate the PJM Market to be essential in view of its contemporaneous decision to approve market-based pricing authority on offers to sell energy into the PJM-PX.[5]

The March 10 Order requires the MMU to report to the Commission by April 1, 2001 on: (1) the MMU's assessment of the standards, indices and criteria by which it will evaluate data and information collected; (2) the MMU's evaluation of additional enforcement remedies, if any.[6]

This Report is filed pursuant to item (1) above in the Commission's March 10 Order.

PJM's Market Monitoring Plan

The Market Monitoring Plan establishes the MMU as a separate market monitoring unit of PJM with a broad range of monitoring responsibilities. Among other responsibilities, under the Plan, the MMU is to monitor the activities of participants in the PJM PX for the potential exercise of market power, monitor all bilateral and other electric power

---

1 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997) ("November 25 Order").

2 81 FERC at 62,282.

3 The Plan appears in the PJM Tariff at Original Sheet No. 184 through First Revised Sheet No. 190. Section references herein are to Sections of the Plan.

4 See PJM Interconnection, L.L.C., 86 FERC ¶ 61,247 (1999) ("March 10 Order").

5 Id. at 61,887 n.4 (citing Atlantic City Elec. Co., 86 FERC ¶ 61,248 (1999)).

6 The Commission also stated: "We direct the MMU to provide copies of its filing to the PJM board and state commissions by that time as well." 86 FERC ¶ 61,247 (1999).

transactions, and monitor participants for their compliance with the rules, standards, procedures, and practices of PJM.

The Market Monitoring Plan states, in Section VI.E., Market Monitoring Indices, that:

> "The Market Monitoring Unit shall develop, and shall refine on the basis of experience, indices or other standards to evaluate the information that it collects and maintains. Prior to using any such index or standard, the Market Monitoring Unit shall provide PJM Members, Authorized Government Agencies, and other interested parties an opportunity to comment on the appropriateness of such index or standard. Following such opportunity for comments, the decision to use any index or standard shall be solely that of the Market Monitoring Unit."

On June 28, 1999, the MMU published its Proposed Initial Market Indices and solicited comments from market participants and other interested parties. After reviewing the comments received, the MMU implemented its proposed indices. On January 17, 2000, the MMU published a proposal to implement an additional index related to the cost of acquiring spinning reserves from synchronous condensers. After reviewing the comments received, the MMU implemented this index.

It is the view of the MMU that the listed indices or standards provide information on the structure of PJM markets, on the behavior of individual PJM market participants, and on the outcomes from PJM markets, all of which is essential for the evaluation of the competitiveness of the PJM markets. The MMU uses the indices in its evaluations of the competitiveness of markets on a daily, weekly, monthly and annual basis. The MMU publishes several indices related to Locational Marginal Prices (LMP) including monthly LMP duration curves, the monthly frequency distribution of LMPs, and the monthly distribution of constrained LMPs.[7] The MMU publishes indices related to spinning reserves. The MMU also relies on the indices in its published market analyses including the State of the Market Report, the Report on Ancillary Services Markets, the Report on the Capacity Market for June 2000 and the FTR Auction Report. It is the view of the MMU that the published indices, as refined, are appropriate measures of the level of competition in the PJM markets and are also appropriate indicators of potential market power issues. The MMU has applied its published indices to the newly introduced day ahead energy market and regulation market, as reflected in the list below. The MMU will continue to refine the published indices as the PJM markets evolve and to add new indices as appropriate.

[7] The referenced MMU material may be found at pjm.com under the Market Monitoring Unit link.

The indices are listed below.

1. Summary statistics for PJM system by hour/day/week/month/year.
    a. PJM system prices and loads: day ahead and real time markets.
        i. Average PJM load weighted price;
        ii. Maximum PJM load weighted price;
        iii. Average PJM load;
        iv. Maximum PJM load;
        v. Correlations between PJM prices and loads.
    b. PJM congestion.
        i. Maximum hourly congestion costs;
        ii. Total congestion cost;
        iii. Number of active constraints.
    c. PJM volumes.
        i. Total MW bid;
        ii. Total MW self scheduled;
        iii. Total bilateral contract MW;
        iv. Hourly net imports and exports including all components.

2. Day ahead market
    a. Total hourly load
    b. Composition of load
        i. Fixed price bids
        ii. Price sensitive bids
        iii. Decrement bids
    c. Composition of supply offers
        i. Generation offers
        ii. Increment offers

3. Aggregate relationships between day ahead and real time markets
    a. Hourly aggregate LMP comparisons
    b. Hourly aggregate load comparisons
    c. Hourly aggregate congestion comparisons

4. Comparative prices and loads for PJM and surrounding power markets:
    a. Forward prices for each system by market term;
    b. Forward price spreads by market term;
    c. Real time prices as available;
    d. Real time price spreads;
    e. Loads for each system as available;
    f. Net imports/exports between PJM and each system.

5. Locational prices and loads.
    a. Bus locational marginal prices (LMPs);
    b. Aggregate LMPs;

c. Bus LMPs less the PJM average price;
d. Loads and generation by bus;
e. The distribution of LMP rankings for each bus by bus price and by bus load/generation;
f. Daily/weekly/monthly price-load comparisons:
   i. Maximum bus LMP by hour;
   ii. Minimum bus LMP by hour;
   iii. Average load LMP by zone, by aggregate load bus, for PJM;
   iv. Average generation LMP by zone, by aggregate load bus, for PJM;
   v. Load/injections by bus, by zone, by aggregate buses, for PJM.
g. Zonal LMPs
   i. Zonal daily LMP
   ii. Highest bus LMP within zone;
   iii. LMP ranking across zones.

6. Congestion by hour/day/week/month/year by bus/zone/bus aggregates.
   a. Total congestion costs for period;
   b. Peak congestion costs;
   c. Percent of time with congestion;
   d. Frequency of individual constraints;
   e. Frequency of must run price cap implementation;
   f. Frequency of constraints without must run price cap implementation.

7. Transmission congestion and FTR revenue adequacy

8. Congestion comparisons between day ahead and real time markets
   a. Total congestion costs for period;
   b. Peak congestion costs;
   c. Percent of time with congestion;
   d. Frequency of individual constraints;
   e. Frequency of must run price cap implementation;
   f. Frequency of constraints without must run price cap implementation.

9. Offers and dispatch.
   a. Unit offer/supply curves;
   b. Maximum economic offer;
   c. Minimum economic offer;
   d. Company aggregate offer/supply curves;
   e. Aggregate PJM supply curves;
   f. Comparisons of unit offer/supply curves to historical offer curves;
   g. Comparisons of company offer/supply curves to historical supply curves;
   h. Comparisons of aggregate PJM supply curves to historical supply curves;
   i. Deviations from requested dispatch, by unit;
   j. Ramp rates by unit, by time period, by company.
   k. Comparisons of ramp rates by unit type, by company.

l. Operational constraints on offers: start times; minimum run requirements; minimum down times; maximum starts.
m. Start up costs.

10. Comparisons between day ahead and real time offers

11. Relationship between offers and LMPs
    a. Identification of units which set price;
    b. Identification of fuel type of marginal units;
    c. Frequency of individual units setting price;
    d. Frequency of generation owners setting price.

12. Transmission contracts.
    a. Contract quantities;
    b. Service types;
    c. Contract paths.

13. Energy contracts.
    a. Contract quantities;
    b. Service types;
    c. Contract paths.

14. Regulation
    a. Available regulation
    b. Regulation offers
    c. Regulation price
    d. Aggregate regulation supply
    e. Regulation adequacy

15. Spinning.
    a. Condenser bids;
    b. Condenser costs;
    c. Condenser credits;
    d. Total condenser MWs;
    e. Total spinning requirements.

16. FTR Auction Market.
    a. Total market volume offered and cleared;
    b. Total market revenue;
    c. Average clearing price;
    d. Path specific revenue and volume;
    e. Source specific revenue and volume;
    f. Sink specific revenue and volume.

17. Available capacity
    a. Total capacity resources;

b. Total available capacity;
c. Outage status by unit;
d. Frequency of outages, by type, by unit, by time period;
e. Comparisons of outages across units;
f. Company summary outage frequency;
g. Comparisons of outages across companies;
h. Frequency of unit outages by time period, by demand conditions; by system/bus price.

18. Capacity market
    a. Company supply curves by time period of market;
    b. Company demand curves by time period of market;
    c. Supply/demand balance;
    d. Market prices for each market;
    e. Comparisons of offers to opportunity costs;
    f. Delisting of units by company;
    g. Capacity position by company.

19. Market structure by market
    a. Concentration ratios by hour;
    b. Incremental concentration ratios by hour;
    c. Concentration ratios by transmission defined markets within PJM;
    d. Concentration ratios by zone;
    e. Concentration ratios by interface.

20. Price-cost margins
    a. Unit specific price-cost margins;
        i. Compare unit offers to unit costs
    b. Company price-cost margins;
        i. Compare unit price-cost margins by company.
    c. Price-cost margins for marginal units
    d. Aggregate price-cost margins