Federal Energy Regulatory Commission Technical Conference on
Local Market Power Mitigation and Reliability Must-run Issues

Many Possible Solutions: But It's All Price Discrimination if the Broader Market Structure is Flawed

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My name is Abram W. Klein and I am Director of Northeast Trading for Edison Mission Marketing and Trading (EMMT), the marketing and trading arm for Edison Mission Energy (EME), an Edison International Company. EMMT specializes in the marketing and trading of U.S. electricity, associated fuels and emission allowances, transmission congestion contracts, tailored long-term power sales and long-term fuel purchases employing forward and option structures, and asset-backed transactions supported by EME's U.S. merchant generation portfolio. EME merchant capacity now stands at over 12,600 megawatts. I am responsible for managing EME's trading and asset positions in the Northeast, including approximately 1,900 megawatts located in PJM and NYISO markets.

Prior to joining EMMT, I was a principal at Putnam, Hayes & Bartlett and its successor companies, PHB Hagler Bailly and PA Consulting Group. During seven years as a consultant I worked on electricity restructuring, market design, asset valuation and market power issues. As a consultant, I worked on and helped to develop the New York City local market power mitigation measures that were accepted by FERC as part of Con Edison's divestiture of in-City generation assets. I have testified before the Commission in the NYISO Automatic Mitigation Procedure docket and in the docket addressing ISO-NE's Market Mitigation Thresholds. I have also given presentations on electricity market issues at numerous industry conferences.

Summary of Comments

As observed in the FERC Standard Market Design NOPR, the challenge of establishing efficient pricing in transmission constrained locations where there may be few alternative supply options is among the more tricky market design problems in competitive electricity markets. Over the next two days at this technical conference, there will be numerous ideas and alternatives regarding local market power mitigation and pricing for must-run generation – many of them will be good ideas. My comments will not address specific market design proposals for load pockets. Rather, I'm going to focus on two areas that are essential for the Commission to consider in solving the RMR issue.

- First, it is critical to address market structure issues around local market power in the context of the overall market design and market performance. Indeed, for the Commission to look at the local market power problem in isolation, without taking account of the broader market design, would be a mistake, and, I might add, inconsistent with the framework provided in the SMD NOPR. From this perspective, a large percentage of the revenue inadequacy of RMR units is due to market structure flaws in the broader energy and reserve adequacy markets. PJM should be required to follow NYISO's lead and put in place scarcity and reserve shortage pricing in the energy market, and redesign its flawed capacity market.

- Second, local market power mitigation should be limited to local areas. The concept of a "load pocket" is meaningless if the ISO's Market Monitoring Unit is given and uses the unrestricted authority to cost cap wide swaths of supply resources based on the existence of virtually any transmission constraint and without consideration to the specific competitive conditions downstream of the constraint.

First, Fix the Broader Market Design, Which Is Flawed

During 2000-2002, each of the Northeast ISOs experienced very tight reserve margins on an annual basis and a clear need for new entry. In 2001 and 2002, each of the Northeast ISOs experienced extreme weather conditions during the summer, leading to multiple days with real scarcity events, and many more high demand days. Under these circumstances, spot energy prices in a workably competitive market should have been above – and perhaps significantly above – the levelized cost of entry.[1] Yet, actual spot prices were well below the cost of entry.[2] Prices were below the cost of entry due to market design flaws in the Northeast ISOs that suppressed energy and installed reserve prices.

- In the energy market, the culprits are a lack of efficient scarcity pricing and inadequate reserve pricing during peak periods[3] as well as pricing rules that require significant side payments to marginal generators in the form of uplift payments during normal demand hours.[4]

1 Prices would be expected to be above the cost of entry for two reasons. First, levelized entry cost assumes that a unit recovers exactly its cost of entry in each year. But the entrant would not expect to recover the average capital cost in all years – some future years may have a supply glut resulting in prices below the cost of entry. Second, not only was entry needed in 2002 and 2003, but demand was extreme. If the market structure leads to prices that fail to compensate a new entrant when demand is extreme and capacity is tight, the market structure is surely inadequate in the long term when demand is normal, entry has occurred and the market is in balance.

2 A summary of Northeast ISO market performance is attached as an Appendix to my comments.

3 According to the October 15, 2002 report of the NYISO market monitor: "the current pricing rules and operating procedures have hindered the market from setting efficient prices during shortage conditions. This problem is common to all of the operating wholesale energy markets."

4 For a potential solution to this problem see: "On Minimum-Uplift Pricing for Electricity Markets," William W. Hogan and Brendan J. Ring, March 19, 2003.
http://ksghome.harvard.edu/~.whogan.cbg.Ksg/minuplift_031903.pdf

- In addition, mandatory installed reserve requirements were translated into poorly designed reserve adequacy markets. Reserve adequacy requirements are needed because the market design mitigates energy prices below the level needed to recover fixed cost of investment. The markets were poorly designed to be overly short term in nature and subject to excessive volatility. A solution, consistent with the Commission's SMD, has been developed through an inter-regional working group – the Resource Adequacy Model Group.[5]

In New York, the response has been a set of initiatives and reforms in 2003 aimed at specifically addressing the identified flaws in the design of both energy and resource adequacy markets. In energy, shortage pricing has been introduced in energy and reserves. NYISO resource adequacy markets were improved by introducing a demand curve for installed reserves. There is still work to be done. Nevertheless, because the problem of compensating must run units in New York is addressed within the context of these broader market structure reforms, the overall market design is internally consistent. In general, price signals support new entry for the load pockets of New York City and Long Island.[6] Price signals are increasingly efficient for the rest of New York State as well.[7]

In PJM, the market structure is essentially the same today as it was during 2000-2002, and the design flaws in the energy and capacity markets persist. In this context, the "problem" of must-run units not recovering their going forward costs is fundamentally a broader market design problem. Dr. Bowring noted as much in his declaration in the docket that led to this technical conference:

> "The fundamental reason that cost capping became an issue for some generators in 2002 and 2003 is that overall market revenues from both energy and capacity markets declined in 2002 and, as a result, net revenues declined for all units in the market."[8]

In this context, a market structure "solution" which provides a separate payment stream to RMR units is equivalent to monopsony price discrimination by the ISO and compromises the ISO's independence. Implicitly, the ISO is making a choice to provide side-payments to certain units to counterbalance the systematic under-compensation of

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5 A forthcoming review of RAM Model by NERA will be completed soon.

6 Real entry signals in New York City have facilitated creative and efficiency enhancing projects. For instance, one very innovative project that looks to be going forward in New York City is a 2000 MW DC tie from upstate New York to the City.

7 New York still has extensive uplift payments made to marginal generating resources and its automated mitigation procedures may be triggered more than is desirable. Moreover, I do not believe automatic mitigation is warranted in the broader markets that are unconstrained, such as Western NY.

8 Declaration of Joseph E. Bowring, Manager, PJM Market Monitoring Unit, Docket No. EL03-

supply resources in the broader market. Over time, broader market prices will not signal the need for entry even when entry becomes necessary. Rather, the ISO potentially would be required to undertake an ever expanding list of RMR commitments. On this point the Commission's SMD NOPR is clear:

> "The challenge for market power mitigation on the supply side is to assure that it allows long-term competitive prices, which allows the opportunity to recover the fixed costs of the investment as well as the short-term variable costs of producing electricity."[9]

To accomplish the Commission's objective it is necessary that market design not only provide for efficient pricing for reliability must-run units inside transmission constrained load pockets, but also that, first and foremost, the market design support efficient pricing in the broader market. Efficient pricing means more than merely maintaining least-cost short-term operations and dispatch in the ISO spot market. Truly efficient prices facilitate longer-term contracting and competitive entry. RMR structures could undermine efficient long-term resources allocation signals if they are not implemented within the context of a solid overall market structure foundation in the broader electricity market. New York has shown that such issues can be addressed to good effect. There is no reason why PJM cannot do likewise and put in place scarcity and reserve shortage pricing, including, potentially, locational reserve pricing where appropriate in the energy market. There is also no reason that PJM should not reform its deeply flawed installed reserve market.

Second, Limit Local Market Power Mitigation to Local Areas Where There is a Competitive Concern

As noted in the Declaration of Dr. Bowring, PJM rules governing the exercise of local market power were first filed with the Commission in 1997. Based on a 1996 study prior to the start of the PJM market by Frame and Joskow, these rules allow cost capping (to cost plus 10%) of supply resources whenever there is a transmission constraint other than one of the three reactive interfaces internal to PJM. All supply resources downstream of the transmission constraint are potentially cost capped. At the time the mitigation measures were developed, it was prudent to provide wide discretion in cost capping supply bids as there was absolutely no experience with a competitive energy market in PJM to that date.

However, since 1997, the PJM Market Monitoring Unit (MMU) has interpreted the rules governing the exercise of local market power to justify far broader cost capping authority than I believe was ever the intention of the Commission. Recently, for instance, the MMU has stated its intention to declare the entire Northern Illinois control area to be a

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9 Notice of Proposed Rulemaking: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design. July 31, 2002. (SMD NOPR), at 393.

load pocket under certain circumstances.[10] Moreover, within PJM, there have been instances during extreme summer peak conditions when several thousand MW of supply resources have been cost capped and when the ISO was taking out of merit actions; the combination of cost capping and out of merit actions by the ISO suppressed prices below competitive levels.

I do not believe it was ever the intention of the Commission that the Joskow/Frame study stand in perpetuity as an inflexible doctrine prescribing how to address local market power mitigation. Since 1997, we have over five years of market experience in PJM.[11] New generation has been built and other generation has been divested. New control areas have been added to the market. It makes sense to revisit the approach.

Local market power mitigation and cost capping should not be used by the market monitor to mitigate transmission constraints that are not truly local in nature. The Commission 1) may want to more narrowly delineate the authorization to apply local market power cost capping, 2) may want to review the use of cost capping by the MMU, and 3) may want to revisit the Frame/Joskow study to determine whether competitive conditions have changed. Furthermore, in my opinion, the use of the Commission's 1997 local market power authorization to declare an entire control area to be a load pocket represents an overly loose interpretation of the Commission's delegation of authority. Such an extensive broad mitigation policy should require the Commission's approval.

10 The entire 25000 MW control area of Northern Illinois would be cost capped under PJM local market power mitigation whenever the 500 MW contract path from PJM to Commonwealth Edison is subscribed toward Northern Illinois, regardless of whether there are any internal transmission constraints inside Northern Illinois or between Northern Illinois and surrounding control areas in MAPP, MAIN and ECAR.

11 And as discussed here, market performance suggests that PJM's prices have been too low.

Appendix A
Evidence of Northeast ISO Market Performance: 2000-2002

During 2000-2002, there was a clear need for new capacity in each of the Northeast ISO markets due to both very tight reserve margins and extreme weather conditions. NYISO has issued multiple "power alerts" on the continuing "statewide energy crisis." During August of 2001, NYISO also experience a shortfall in generation during the peak week which included a 1 in 15 year heat wave. Likewise, ISO-NE had mere 10% reserve margins in 2001 and 2 separate instances of generation shortages when OP-4 emergency procedures were activated. In 2002, while expected reserve margins in New England were higher than 2001, extreme weather and delays in the installation of new generation led to scarcity conditions on 6 days. PJM's capacity market was extremely tight in 2000 through early 2002 and the pool experienced several days of voltage reduction and load shedding (up to 2400 MW) during the August peak of 2001. In 2002 there were 3 events of load management curtailment in PJM.

Clearly entry was needed in 2000-2002 and, given extreme weather conditions, spot market prices should have above the cost of entry.

Analysis of Optimal Dispatch of a New Entrant

I have calculated the annual margin from the Northeast ISO energy markets for a merchant combined cycle (CC) unit under the assumption that the unit is dispatched with perfect foresight of market prices and has no impact on the prices that it sees. Both assumptions are unrealistic and actual margins for the hypothetical CC would certainly be less. The model uses the actual historical DA market prices at NYISO's Hudson Valley "Zone G.,"[12] in eastern New York, the PECO (Philadelphia Electric) zone in PJM, and the single market clearing price for ISO-NE.

Table 1 below shows the energy and capacity margins earned for the hypothetical entrant CC along with the variable cost assumptions,[13] and capital cost. When compared with a levelized entry cost of $115/kw-yr calculated in Table 2, it is evident that spot prices are well below the cost of entry in each Northeast ISO in each year from 2000-2002.

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12 Zone G represents an eastern NY location that is both outside New York City, where the cost of entry is much higher, but also east of the key NYISO west to east congestion points. Zone G is also a hub used in over-the-counter markets for transacting forward contracts for eastern New York

13 These cost assumptions represent reasonably conservative estimates typically used in the industry.

Table 1

Summary of Ex-post Optimal Dispatch Model -- Performance of Entrant Combined Cycle Unit

Pool / Year	All-hours Average Price ($/MWh)	Average Revenue ($/MWh)	Average Cost ($/MWh)	Average Energy Margin ($/MWh)	Average Energy Margin ($/kw-yr)	Capacity Factor
ISO-NE						
2000	43.2	48.0	35.0	13.1	75.9	66%
2001	40.2	42.7	29.8	12.9	72.2	64%
2002	32.2	35.3	25.5	9.8	61.2	71%
NYISO Zone G DAM						
2000	44.8	49.9	35.1	14.8	78.3	60%
2001	41.9	43.4	29.4	14.0	79.6	65%
2002	35.0	37.5	26.4	11.1	73.6	75%
PJM PECO Zone						
2000	29.2	52.3	37.4	14.9	30.1	23%
2001	33.6	42.3	28.0	14.3	53.4	43%
2002	27.8	36.2	25.3	11.0	44.2	46%

Prices are ISO-NE ECPs, Zone G DAM, PECO Zone DAM

Cost assumptions for the hypothetical CC are as follows:
- Gas prices as quoted daily by *Gas Daily* for the Tennessee Zone 6 (NE), Transco Zone 6 (NY), Texas-Eastern M3 (PJM)
- 4 percent State Taxes and 10 cents LDC charge added to *Gas Daily* daily price.
- Full load average heat rate of 7100 btu/kw.
- 10% unit derating during Summer months.
- $60/MW per start start-up cost reflecting the both fuel cost and allocation of major maintenance.
- $1/MWh of VOM
- 5% forced outage rate.
- No fixed maintenance schedule (adding this would lower energy margins)

Table 2 below shows the assumptions I used in a pro forma financial model to calculate the annual return required by the hypothetical merchant CC in Eastern NY. The precise levelized cost will vary depending on the assumptions, and those used in Table 2 are generally conservative. For instance, a 50/50 debt/equity ratio reflects industry standards, but in light of the current difficult financial environment for electricity projects in the US, the actual debt level may be less, which would drive up the cost.

Table 2
Levelized Cost/Fixed Charge Rate Calculator for Merchant Plant
Input Assumptions and Levelized Cost

Economic Assumptions			**Notes:**
Inflation Rate	2.50%		
Project Assumptions			
Project Life	30	years	Must be 30 years or less
Project Size	520	MW	Annualized Capacity - does not affect Levelized Cost per kW
Capital Costs (installed - $2000)	700	$ / kW	Exclusive of IDC
Fixed O&M / A&G Costs ($2000)	10.5	$ / kW-year	
Project Construction (beginning of year)	2001		
Construction Duration	2	years	Must be 1, 2, or 3 years
In-Service Date (beginning of year)	2003		
Tax Assumptions			
Property Tax Rate	2.00%		Percent of capital cost (including IDC) paid in taxes per annum.
Federal Tax	35%		
State Tax	6%		
Blended Rate	38.90%		
Tax Depr Yrs	20	years	Must be 15 or 20 years
Financing Assumptions			
Perc. Financed with Debt	50%		
Perc. Financed with Equity	50%		
Return on Debt	9.10%		
Return on Equity	13.50%		
Debt Payback Period	20	years	In addition to construction period
Debt Payment Inflator	1.5%		Debt payments increase annually at this rate.
Technological Assumptions			
Heat Rate Decline per year	0.0%		
Real Capital Cost Decline per year	1.0%		
Unit Type	CC		Must be CC or CT
Heat Rate Decline Multiplier	1.75		Effect of a 1% change in heat rate on energy margin
Real Energy Margin Decline	1.0%		Rate at which a unit's real Energy Margin will decline over time due to lower capital costs and heat rates of newer un
Nominal Energy Margin Escalation Rate	1.5%		Energy Margin increases annually at this rate

Levelized Cost ($2000/kW)	**115.4**
FCR	**14.9903%**

This table shows that a merchant plant in the Northeast would need to earn approximately \$115/kw-yr *in each year* for 30 years to break even. The \$115/kw-yr does not account for two critical factors that make the estimate conservative. First, a new project faces significant risk that changes in technology or markets will reduce the competitiveness of the project in later years. As such, a new CC generally needs to enter in a market where entry is needed and prices are high so that it can make more than its annual average requirement in the early years of project life, as returns in later years are much less certain. Thus, a merchant CC really needs substantially more than \$115/kw-yr in the early years of the project. A related point is that there will certainly be years when prices are low due to weather or oversupply market conditions, given the cyclical nature of commodity markets. As a result, it is important that there be the opportunity to make much more than the annual requirement in an environment where loads are high or supply/demand conditions are tight. In PJM, market power mitigation measures and the broader market design, whether inside load pockets or not, prevent prices from rising above the average cost of entry in any year – for instance capacity prices are effectively capped at or below the cost of entry.

Finally, Table 3 shows the returns on a merchant CC project including capacity market payments. Even after including capacity market payments during the 2000-2002 period when reserve margins were tight, margins for a merchant entrant would have been below the cost of entry.

Table 3
Performance of Entrant Combined Cycle Unit; Energy and Capacity Payments

Pool / Year	Average Energy Margin (\$/kw-yr)	Capacity Payment (Historical Spot Data) \$/kw-yr	Capacity Payment (Current Forward Market \$/kw-yr)	Levelized Entry Cost (\$/kw-yr)	Levelized Return with Historical Capacity Price (\$/kw-yr)	Levelized Return with Forward Capacity Price (\$/kw-yr)
ISO-NE						
2000	75.9	-	8.4	115.0	(39.1)	(30.7)
2001	72.2	-	8.4	115.0	(42.8)	(34.4)
2002	61.2	-	8.4	115.0	(53.8)	(45.4)
NYISO Zone G DAM						
2000	78.3	11.1	15.0	115.0	(25.6)	(21.7)
2001	79.6	19.6	15.0	115.0	(15.9)	(20.4)
2002	73.6	19.8	15.0	115.0	(21.6)	(26.4)
PJM PECO Zone						
2000	30.1	22.3	7.3	115.0	(62.5)	(77.6)
2001	53.4	17.8	7.3	115.0	(43.8)	(54.3)
2002	44.2	0.1	7.3	115.0	(70.7)	(63.5)

Energy Margins from Optimal Dispatch Model

Capacity Spot Prices From ISO Web Sites of PJM, NYISO and ISO-NE
PJM capacity prices are daily clearing prices.
NYISO prices are Six-month Strip auctions
ISO-NE cancelled the spot auctions for capacity in 2000, and has not administered spot capacity market since then.
For the period, 2000-2001, capacity prices in ISO-NE were \$0, and no bilateral market existed.
Capacity Forward prices are based on OTC broker quotes for Calander Year 2003 on 11/5/02.