California ISO Issue Paper

Reserve Shortage Pricing Design

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Reserve Shortage Pricing Design

Prepared for Discussion at Stakeholder Meeting on June 6, 2007

1 Introduction

This paper identifies the major design issues to be addressed to achieve a systematic shortage pricing mechanism to send efficient reserve and energy price signals under shortage conditions. This paper also presents a survey of shortage pricing mechanisms implemented by other ISO/RTOs (Appendix A). Section 2 covers background information including a summary of the direction provided by the Federal Energy Regulatory Commission (FERC) on shortage pricing, the CAISO Ancillary Service requirements and reserve pricing mechanism under MRTU, emergency operation triggers, as well as the Reserve Demand Curve approach taken by other ISO/RTOs. Section 3 discusses the design issues that need to be addressed in future stakeholder meetings.

2 Background

2.1 FERC Order

Under MRTU Release 1, the CAISO has proposed a limited scarcity pricing mechanism that raises bids to the bid cap when there are insufficient energy bids in real time while no contingency events have occurred. In the July and September 2005 Orders, the Commission accepted, in concept, the CAISO's initial limited scarcity proposal, but has directed the CAISO to develop a more extensive reserve shortage scarcity pricing approach with a later release of MRTU. In its September 2006 MRTU Order, FERC ordered a more comprehensive reserve shortage scarcity pricing mechanism to be implemented within 12 months of the implementation of MRTU Release 1. In its April 2007 MRTU Order, FERC further emphasized these requirements and stated that "the concept of scarcity pricing involves a systematic procedure to ensure that prices can rise during periods of genuine scarcity".[1] The requirements are:

1) Prices should rise when energy and reserves are short in both the day-ahead and real-time markets whether or not there is a transmission or generation outage.[2]

2) The Commission has also directed the CAISO to "develop a reserve shortage scarcity pricing mechanism that applies administratively-determined graduated prices to various levels of reserve shortage". The Order also states that "In the event that a shortage occurs, prices should reflect the economic value of the reserves necessary to resolve the shortage. Thus, the prices for both reserves and energy in California should increase automatically as the severity of the shortage increases."[3]

[1] April 2007 FERC MRTU Order, 119 FERC ¶ 61,706.

[2] September 2006 FERC MRTU Order, 116 FERC ¶ 61,274 at P1077.

[3] September 2006 FERC MRTU Order, 116 FERC ¶ 61,274 at P1079.

2.2 Reserve Procurement & Pricing under MRTU

2.2.1 Reserve Procurement

Regulation (Regulation Up and Regulation Down) and Operating Reserves (Spinning and Non-Spinning Reserve) are procured in the Day-Ahead market and incrementally as needed in Hour Ahead Scheduling Process (HASP) and Real-Time.

Procurement targets for Regulation and Operating Reserves are shown in the following table.

Regulation Reserve Target	A percentage of Hourly CAISO Demand Forecast (excluding Exports) used as guide to determine a MW level needed for satisfactory Automatic Generation Control (AGC) performance
Operating Reserve Target	Max(5% of Demand met by hydro resources + 7% of the Demand met by thermal resources, the Single Largest Contingency)
Operating Reserve Requirements	At least 50% of the Operating Reserves must be met by Spinning; No more than 50% of the Operating Reserves may be met by Imports of AS; AS Import from a single tie <= 25% of total system-wide AS requirements.

Ancillary services will be procured using Ancillary Service Regions including the System Region and the Expanded Region (i.e., the System Region and the intertie scheduling points with adjacent Control Areas). The CAISO may also identify Sub-Regions within the System Region. Minimum and maximum limits on the amount of Ancillary Services to be obtained within the Expanded System Region, the System Region, and any Sub-Regions may be established. (MRTU Tariff Section 8.3.3.)

2.2.2 Reserve Pricing

Energy-Reserve Co-Optimization

Under MRTU, Energy and reserves will be priced simultaneously through energy-reserve co-optimization. Both Energy and reserve prices will reflect the opportunity cost of not providing the other product.

Ancillary Service Marginal Price (Reserve Market Clearing Prices)

Reserve Market Clearing Prices, or Ancillary Service Marginal Prices, for each reserve product at each resource location are determined by the sum of the constraint Shadow Prices of each zone where the resources are located. The Shadow Prices are produced as a result of the Energy-reserve co-optimization.

2.2.3 Contingency Only Reserves

Under MRTU Release 1, a portion of the Spinning and Non-Spinning reserves procured in the Day-Ahead market and all from Real-Time are Contingency Only. In case of Energy supply shortage but not Contingency some of the Contingency reserves have to be dispatched to meet the Load. The energy bids of the dispatched Contingency Only reserves will be set to the energy bid caps.[4] This provides some means of scarcity pricing under MRTU Release 1.

2.3 Emergency Operation Triggers

<u>System Reserve Deficiency</u>

When system reserve requirements and load exceed available resources on a system-wide basis, the CAISO may declare a System Reserve Deficiency and issue a Stage 1 Emergency, a Stage 2 Emergency, or a Stage 3 Emergency.

Stage 1 Emergency – Operating Reserves deplete or are anticipated to drop below WECC Minimum Operating Reliability Criteria (MORC);

Stage 2 Emergency - Reserves deplete or are anticipated to drop below 5% of Load responsibility and cannot be restored;

Stage 3 Emergency - Spinning Reserve portion of the Operating Reserves deplete or are anticipated to drop below the MORC Requirement and cannot be restored.

<u>Regional Reserve Deficiency</u>

When regional reserve requirements and load exceed available resources and congestion restricts the movement of resources into a specific region, the CAISO may declare a Regional Reserve Deficiency. If regional procurement of AS reserve requirements is deficient to meet area requirements, the CAISO may issue a Stage 1 Emergency, a Stage 2 Emergency, or a Stage 3 Emergency.

Stage 1 Emergency – Regional Operating Reserves deplete or are anticipated to drop below WECC Minimum Operating Reliability Criteria (MORC) and cannot be restored, and anticipated congestion will not allow for movement of reserves into a specific region;

Stage 2 Emergency – Regional Operating Reserves deplete or are anticipated to drop below 5% of Load responsibility and cannot be restored;

Stage 3 Emergency - Spinning Reserve portion of the Operating Reserves deplete or are anticipated to drop below the MORC Requirement and cannot be restored.

[4] Suppliers will be paid the original bid price if a shortage is the result of a contingency.

2.4 Reserve Demand Curve Approach for Shortage Pricing by Other ISOs

Both the NYISO and ISO-NE have adopted a Reserve Demand Curve approach. The Reserve Demand Curve defines shadow prices (or penalty prices) for different reserve products under shortage conditions at both system and zonal level. The key features of this approach include the following.

1) Pre-defined shadow prices for reserves under shortage conditions.

Both the NYISO and ISO-NE co-optimize the energy dispatch and reserve procurement. The co-optimization problem minimizes system cost subject to energy balance constraints, system and local reserve requirements, and other constraints. Under physical shortage conditions when energy and reserve supply fall short of load plus reserve requirements, the co-optimization problem will have infeasible solutions (absent of operator actions). To prevent infeasible solutions, reserve shadow prices under shortage conditions are pre-defined to reflect the operator's estimate of the value of an additional 1 MW of reserve for reliable system operation. As such, reserve shortage shadow prices are pre-defined as the cost of virtual (hypothetical) reserves that could be deployed to relieve the shortage condition. These shadow values are set to be consistent with the actions normally taken by operators under reserve shortage conditions, and should generally exceed the relevant reserve bid caps.

2) Both system-wide and locational shortage pricing.

The Reserve Market Clearing Prices (RMCP) are calculated based on the shadow prices of system and local constraints. Specifically, RMCP for each reserve product is the sum of the shadow prices of the corresponding reserve constraints. Under shortage conditions, the shadow prices for each reserve constraint is determined by a pre-defined Reserve Demand Curve, and as such, the RMCP will be the sum of the shortage shadow prices of the binding constraints.

3) Product cascading.

Products are cascaded so that higher quality reserves are set at a higher value than lower quality reserves. This applies to both the economic and scarcity prices of the cascaded products.

4) Energy prices reflecting cost of reserves under shortage conditions.

Energy prices automatically reflect cost of reserves under shortage conditions resulting from energy-reserve co-optimization. By applying the Reserve Demand Curve, energy-reserve co-optimization ensures that energy prices will also automatically reflect the value of the reserves under shortage conditions.

The major differences between the Reserve Demand Curve specification by the NYISO and the ISO-NE are the following:

Reserve Demand Curve	NYISO	ISO-NE
Products	Operating Reserve Only 1) 10-Min Spinning 2) 10-Min Non-Spinning 3) 30-Min Operating Reserve	Both Operating Reserve and Regulation Operating Reserve 1) 10-Min Spinning 2) 10-Min Non-Synchronized 3) 30-Min Reserve Regulation
Real-Time / Day-Ahead	Real-Time Only	Both Real-Time and Day-Ahead

In PJM, the price in the scarcity pricing region is set equal to the highest offer price to supply either energy or reserves in real time subject to the overall offer cap of $1000/MWh. In the 2006 State of the Market Report, the Market Monitoring Unit of PJM studied market results in summer 2006 and found that the current scarcity pricing design was inadequate to send correct price signals under scarcity conditions, and provided a recommendation to refine the design by introducing stages of scarcity pricing and locational pricing rules.

More details are discussed in Appendix A.

3 Reserve Shortage Pricing Design Issues

The following sections list several of the design questions that will need to be answered in the design process.

3.1 Products

Products

What Ancillary Service products should be included in the shortage pricing? Should shortage pricing apply to both Regulation and Operating Reserves or Operating Reserves only? If Regulation is included, is it necessary to include Regulation Down? One consideration is that given that the ISO can de-commit units (to allow AGC capable units to be scheduled above their Minimum Regulation Limit), it may not be necessary to price Regulation Down for shortage conditions. The same argument may apply to Operating versus Spinning or Non-Spinning reserves individually; while scarcity pricing for Operating Reserves is pertinent, it may not be necessary to price Spinning or Non-Spinning reserve scarcity separately since the operator can always commit a resource, thus converting one to the other.

Reserve Constraints and Product Cascading

The question is whether Ancillary Service products should be priced separately or combined together. Put it differently, how to define the reserve constraints to meet requirements for different types of reserves? Should the constraints be cascaded based on the value of the reserves? More specifically, should the Ancillary Service "soft constraints" (administrative prices associated with procuring less than the relevant Ancillary Service MW target) be (a) identical to; (b) a subset of, or (c) different from the Ancillary Service "hard constraints"? For example, would it suffice to provide demand curves (scarcity prices) for just Regulation Up and Upward Ancillary Service (the sum of Regulation UP, Spinning, and Non-Spinning)?

Since the Ancillary Service price is the sum of shadow prices of cascaded service type (Regulation, Spinning, and Non-Spinning) and cascaded regional constraints (AS Region, System Region, etc.), the various demand curves must be designed such that the sum of the resulting hard and soft constraint shadow prices do not exceed the Value of Loss of Firm Load.[5]

3.2 Reserve Demand Curve Values

How to determine the demand curve values? Should the values be cascading such that higher quality reserves are set at higher values than lower quality reserves? One consideration is that the shadow values (or penalty prices) of the reserve under shortage should not result in prices below the relevant bid caps.

3.3 Locational Requirements

Is it necessary to design the shortage pricing on a locational (zonal) level, or system-wide shortage pricing is sufficient?

3.4 Other Design Issues

1. Is it necessary to design a shortage demand curve for energy? Given a Reserve Demand Curve, will energy prices reflect shortage conditions under the energy-reserve co-optimization?

2. Given that FERC has stated that "Prices should rise to reflect the increased need for reserves and energy, whether or not the shortage arises in conjunction with a generation or transmission outage, in both day-ahead and real-time markets" (FERC MRTU Order September 21, 2006), is it necessary to design reserve shortage pricing for the Day-Ahead market, or is a Real-Time Reserve Demand Curve sufficient? Is a Day-ahead Must Offer requirement for AS a pre-requisite for Day-ahead AS scarcity pricing?

3. Opportunity Cost Compensation

There are several aspects to this issue:

1) As discussed in the previous sections, the co-optimization of energy and reserves will allow both energy and reserve prices to reflect the opportunity cost of not providing the other product, which will eliminate the need for separate opportunity cost payment.

[5] For example, for Midwest ISO, the latter is $3,500/MWh.

2) Economic Reserve Shortage

Economic reserve shortage refers to the situation when the re-dispatch cost to procure reserves exceeds the shortage price of the reserves. This situation could arise when the energy price is very high. Under this situation, reserve prices without shortage pricing could be much higher than the reserve prices being capped by the shortage pricing. As such, reserve constraint will rather go soft than procuring additional reserve from physical supplies.

For example, consider the case where the LMP = $2500/MWh (this can happen even if all Energy bids are below the bid cap) and the marginal unit dispatched to provide reserve has an energy bid of $30/MWh, and an AS bid of $50.

Without shortage pricing:

Reserve market-clearing price = marginal unit AS bid + lost energy opportunity cost

= $50 + ($2500 - $30) = $2520

Under shortage pricing:

Assume that the reserve market-clearing price being capped by shortage prices is $1500. In this case, should the unit be compensated for the $1020 difference?

4. Interaction between Shortage Pricing and Other Institutional Features of the Market

Shortage pricing design will also need to take into account of the interaction between shortage pricing mechanism and other institutional features of the market including must offer obligation, dispatch of out-of-market units, convergence bidding and capacity market. For example, under MRTU Tariff, RA resources must offer into the Day-Ahead Energy market but not the Ancillary Service market. It is possible for the recourses to withhold capacity from the Day-Ahead AS market and offer into the Real-Time AS market. That could artificially cause scarcity in Day-Ahead but not in Real-Time and provide opportunity for market manipulation. Another scenario is that out-of-market units may be dispatched under shortage conditions, in this case, the reserve market-clearing price may not reflect the actual shortage condition.

Appendix A Shortage Pricing Design by Other ISOs

Appendix A Shortage Pricing Design by Other ISOs

1 Executive Summary

Shortage Pricing	ISO-NE	NYISO	PJM	MISO
Summary	Reserve Demand Curve Approach Results: • Locational reserve prices • Energy prices reflecting the cost of reserves under shortage conditions	Reserve Demand Curve Approach Results: • Locational reserve prices • Energy prices reflecting the cost of reserves under shortage conditions	Price in the scarcity pricing region is set equal to the highest offer price to supply either energy or reserves in real time subject to the overall offer cap of $1000/MWh.	Prices will be set at the highest accepted offer or $1000/MWh under shortage.
Effective Date	Late 2006	February 2005	January 2006	
Real-Time / Day-Ahead	Real-Time only	Both Real-Time & Day-Ahead	Real-Time only	Both Real-Time & Day-Ahead
Products	Operating Reserve Only 1) 10-Min Spinning 2) 10-Min Non-Spinning 3) 30-Min Operating Reserve	Both Operating Reserve and Regulation **Operating Reserve** 1) 10-Min Spinning 2) 10-Min Non-Synchronized 3) 30-Min Reserve **Regulation**		
System / Locational	System + Four Reserve Zones	• Locational for Operating Reserve - Three Reserve	Five regions subject to annual review	

		Zones • System-wide for Regulation		
Further Enhancements	Enhance real-time reserve pricing to capture out-of-merit dispatch costs.		In the 2006 State of the Market Report, the MMU of PJM studied market results in summer 2006 and found that current scarcity pricing design was inadequate to send correct price signals under scarcity conditions, and recommended to refine the design by introducing stages of scarcity pricing and locational pricing rules.	

2 ISO-NE

The ISO New England (ISO-NE) implemented Standard Market Design (SMD) in March 2003. Initially, there was not a separate market for Operating Reserve, and resources providing Operating Reserves relied on revenues from energy payments, Net Commitment Period Compensation Credits and Installed Capacity payments. These compensations were insufficient to provide efficient incentive especially to peaking resources that run infrequently and rarely receive energy payments. To address this issue, the ISO-NE implemented an interim Forward Reserve Market in January 2004 to provide economic incentive to resources that provide Operating Reserves during peak periods.[6]

In February 2006, the ISO-NE filed Phase II of the Ancillary Services Market (ASM Phase II) proposal to improve upon the existing Forward Reserve Market design.[7] ASM Phase II proposal was subsequently approved by FERC in May 2006. ASM Phase II proposed a locational component to the existing Forward Reserves Market and a Real-Time Reserve Market that co-optimizes the dispatch of energy and reserves.[8]

2.1 Locational Forward Reserve Market

Three Reserve Products & Four Reserve Zones

Operating reserve products include 10-Minute Spinning Reserve (TMSR), 10-Minute Non-Spinning Reserve (TMNSR), and 30-Minute Operating Reserve (TMOR), which is provided by resources not synchronized to the grid but can be converted to energy within 30 minutes or dispatchable demand resources that can reduce consumption within 30 minutes.[9]

There are currently four reserve zones in the ISO-NE, namely Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (RoS). The locational reserve requirements proposed by ASM Phase II will result in locational reserve prices based on the second-contingency requirements for the Reserve Zones.[10] (Under the interim Forward Reserve Market, resources procured to meet local second contingency requirements were compensated by uplift payments.)

[6] New England Power Pool and ISO New England, Inc., 105 FERC ¶ 61,204 (2003).

[7] Ancillary Service Market Phase I (ASM Phase I) was implemented in October 2005. The major components of ASM Phase I include enhancement to the Regulation Market, revised rules to allow submission of revised incremental energy offers during the re-offer period, provision to allow external transactions to set LMPs. (Ancillary Service Market Phase II Overview, ISO-NE, http://www.iso-ne.com/support/training/courses/p2_asm/asm_phase_ii.pdf).

[8] The third major component of ASM II is to allow demand-side participation in both energy and reserve markets.

[9] New England Power Pool and ISO New England Inc., 115 FERC ¶ 61,175 (2006).

[10] ISO New England Inc., 2006 Wholesale Markets Plan (2005), pp. 16.

System Reserve Requirements

Reserve Products	System Reserve Requirements
10-Minute Spinning Reserve (TMSR)	50% of the largest First Contingency in the system
Total 10-Minute Reserve (TMSR + TMNSR)	100% of the largest First Contingency in the system
Total 30-Minute Operating Reserve (TMSR + TMNSR + TMOR)	100% of the largest First Contingency in the system + 50% of the largest Second Contingency in the system

Local Reserve Requirements

Reserve Products	System Reserve Requirements
10-Minute Reserve Requirement	None
Total 30-Minute Operating Reserve (TMSR + TMNSR + TMOR)	100% of the largest **Second Contingency** in the Reserve Zone subject to the (N-1) import interface limit

2.2 Real-Time Reserves Pricing

Real-Time Hourly Reserves Pricing co-optimizes the dispatch of energy and reserves by including both regional and locational constraints. The Real-Time Reserves Clearing Prices will be determined by the cost of providing the next increment of reserves for each Reserve Zone. Under most circumstances, the Real-Time Reserves Clearing Prices will be zero reflecting low marginal cost of supplying reserves in real-time once sufficient reserves are committed.

Reserve Constraint Penalty Factors (RCPF)

In the case of reserve shortage, the prices will be set by Reserve Constraint Penalty Factors (RCPF) specified below. The RCPF values are determined to reflect the maximum price that will be paid to re-dispatch the system to create operating reserves. In the case of reserve shortage, shortage pricing will reflect the value of the reserves in both energy and reserve prices.[11]

Operating Reserve Constraint	RCPF
System 10-Minute Spinning Reserves (TMSR)	$50/MWh
System Total 10-Minute Reserves	$850/MWh
System Total 30-Minute Operating Reserves	$100/MWh
Local 30-Minute Operating Reserve	$50/MWh

[11] ISO New England Inc. Docket Nos., ER-06-613-000, February 6, 2006. (http://www.iso-ne.com/regulatory/ferc/filings/2006/feb/er06-__-000_2-6-06_asm_part1.pdf). ISO New England Inc., 2006 Wholesale Markets Plan (2005), pp. 17.

Application of RCPF

Under reserve shortage conditions, one or several of the system and local reserve constraints will be violated and the energy-reserve co-optimization problem will have infeasible solutions. RCPFs are created to prevent the infeasible solutions to the optimization problem. As such, RCPFs can be understood as virtual reserves that can be deployed at the cost pre-defined by the value of RCPFs.

	Operating Reserve Constraints
System TMSR Requirement	TMSR from all Resources + Virtual Reserve from TMSR RCFT Resource ≥ System TMSR Requirement
System Total 10-Minute Reserve Requirement	(TMSR+TMNSR) from all Resources + Virtual Reserve from Total 10-Min RCFT Resource ≥ System Total 10-Min Reserve Requirement
System Total 30-Minute Reserve Requirement	(TMSR+TMNSR+TMOR) from all Resources + Virtual Reserve from Total 30-Min RCFT Resource ≥ System Total 30-Min Reserve Requirement
Local 30-Minute Operating Reserve Requirement	Constraints for each Reserve Zone: 1) System reserves must meet the local reserve requirement (TMSR+TMNSR+TMOR) from all System Resources + Virtual Reserve from Local RCFT Resource ≥ Local Total 30-Min Reserve Requirement 2)Reserves in the Reserve Zone must meet its own local reserve requirement (TMSR+TMNSR+TMOR) from all Local Resources + Virtual Reserve from Local RCFT Resource ≥ Local Total 30-Min Reserve Requirement 3) Import Constraint - If one Reserve Zone is nested in another Reserve Zone, then the import from the parent zone must meet the reserve requirement in the child zone. (TMSR+TMNSR+TMOR) from Parent Zone Resources + Virtual Reserve from Local (Child Zone) RCFT Resource ≥ Local (Child Zone) Total 30-Min Reserve Requirement

Source: ISO New England Inc., Ancillary Service Market Phase II – Real-Time Energy Reserve Co-Optimization (2006). (http://www.iso-ne.com/support/training/courses/p2_asm/asm_energy_reserve_cooptimization.pdf).

Energy-Reserve Co-Optimization & Reserve Market Clearing Prices

The optimization problem minimizes the total cost subject to the following constraints,

- Energy Balance
- System Reserve Constraints

- Local Reserve Constraints
- Transmission Constraints
- Resource Level Constraints, etc.

The results are dispatch levels, LMPs, reserve designation, and Reserve Market Clearing Prices (RMCP).

The Reserve Market Clearing Prices (RMCP) are calculated based on the shadow prices of system and local constraints. Specifically, RMCP for each reserve product is the sum of the shadow prices of the corresponding reserve constraints. As discussed earlier, since the shadow prices for each reserve constraints is determined by pre-defined RCPF, the RMCP will be the sum of the RCPFs of the binding constraints. Based on the values of RCPFs, in practice, the maximum RMCP for 10-Minute Spinning Reserve in general will not exceed $1100, and the maximum RMCP for 10-Minute Non-Spinning Reserve will not exceed $1050, and the maximum RMCP for 30-Minute Operating Reserve will not exceed $200.[12]

In case of reserve shortage, the energy price will also rise reflecting the increase in re-dispatch cost.

Physical Reserve Shortage

Physical reserve shortage refers to the condition when the system does not have enough capacity to meet the total energy and reserve requirement.

Under physical reserve shortage, the energy prices will be inflated by the reserve price. The LMP solution to the energy-reserve co-optimization problem will implicitly include the value of the reserve, i.e, LMP = marginal unit's energy offer price + RMCP, reflecting the shadow price of the energy balance constraint. If system load increases by 1 MW, the increase in total cost is the marginal unit's energy bid plus the value of 1 MW forgone reserve.

Economic (or Artificial) Reserve Shortage

Economic reserve shortage refers to the condition when the system re-dispatch cost to procure reserve exceeds the value of the RCPF. This situation could arise when the unit being dispatched up has a very high energy offer price. In this case, the reserve price is capped by the value of RCPF, but the energy prices will be inflated by the opportunity cost of providing reserve. The LMP solution to the energy reserve co-optimization problem will implicitly include the value of the reserve, i.e,

LMP = marginal unit's energy offer price + re-dispatch cost to procure additional 1 MW of reserve.

A 2-Generator Example:

Marginal unit's energy offer price (unit B) = $20/MWh

[12] These maximum RMCPs are based on the assumption that the system in practice has enough 30-minute reserve to meet any local requirement. (ISO New England Inc., Ancillary Service Market Phase II – Real-Time Energy Reserve Co-Optimization (2006), pp. 60, http://www.iso-ne.com/support/training/courses/p2_asm/asm_energy_reserve_cooptimization.pdf).

RMCP = RCPF = $50 (assume there is only one system reserve requirement)

Physical Reserve Shortage	Economic (Artificial) Reserve Shortage
Unit A Energy Bid = $25 Re-dispatch cost to procure additional 1 MW of reserve = $25 - $20 = $5 < RMCP RMCP = $50 LMP = $20 + RMCP = $20 + $50 = $70	Unit A Energy Bid = $75 Re-dispatch cost to procure additional 1 MW of reserve = $75 - $20 = $55 > RMCP RMCP = $50 LMP = $20 + $55 = $75

Source: ISO New England Inc., Ancillary Service Market Phase II – Real-Time Energy Reserve Co-Optimization (2006), pp. 101-117.

The reserve pricing methodology proposed by ISONE is consistent with the approach adopted by NYISO, and the proposed RCPFs are comparable to the maximum prices allowed under the reserve market demand curves in the NYISO and approved by FERC.[13]

2.3 Demand Participation

ASM Phase II also proposed to allow dispatchable load to bid directly into the energy and reserve markets.

2.4 Future Enhancements -- Improved Real-Time Reserve Pricing to Reflect Out-of-Merit Dispatch Costs

ISO-NE is currently exploring to enhance real-time reserve pricing to capture out-of-merit dispatch costs. An option being investigated is to set a local 30-minute reserve floor price based on the cost of the resources required to meet local reserve requirement. Both the local reserve price and the energy price will increase as a result of this design enhancement when resources are dispatched out of merit.[14]

3 NYISO

3.1 Real-Time Scheduling

The NYISO implemented Standard Market Design (SMD) 2.0 and Real-Time Scheduling (RTS) in February 2005, in which the prior reserve shortage scarcity pricing has been replaced by the reserve demand curve. Major market enhances under RTS include the following.

1) Energy reserve co-optimization in the real-time.

[13] New York Independent System Operator, Inc., Order Accepting Tariff Filing Subject to Modification, 106 FERC ¶ 61,111 at PP 44-45 (2004).

[14] ISO New England Inc., 2007 Wholesale Market Plan (2006), pp16.

Energy reserve co-optimization in the real-time market guarantees that "the clearing prices of energy, reserves, and regulation fully reflect the opportunity cost of not providing the other serves, eliminating the need for separate lost opportunity cost payments" (New York ISO 2005 State of the Market Report, pp. xv).

2) Reserve demand curves in the Day-Ahead and Real-Time Markets provide shortage pricing signals.[15]

Three Operating Reserve Products & Three Reserve Zones

Operating reserve products include 10-Minute Spinning Reserve, 10-Minute Non-Synchronized Reserve, and 30-Minute Reserve. Three reserve zones are Long Island, East of Central East (East), and West of Central East (West).

Reserve Requirements

	NYCA	Eastern New York	Long Island
10-Minute Spinning	600 MW	300 MW	60 MW
10-Minute Total Reserve	1200 MW	1000 MW	120 MW
30-Minute Reserve	1800 MW	1000 MW	270-540 MW

Source: NYISO, Introduction to Ancillary Services (2007), pp. 56.

3.2 Reserve Demand Curve for Shortage Pricing

Reserve Market Clearing Prices (RMCP) are calculated for both Day-Ahead and Real-Time Market. Operating reserve suppliers must submit bids in the Day-Ahead market. All dispatchable units submitting energy bids to the real-time market must submit $0 reserve bids.

Reserve market clearing prices are set on a **locational basis** using the shadow prices of the reserve constraints **in both the day-ahead and real-time markets**. RMCP for each reserve product is the sum of the shadow prices of relevant reserve constraints.

The reserve demand curve establishes "an economic value for reserves that will be reflected in energy prices at times when the energy market must bid scarce resources away from the reserve markets. Because reserves should generally be substituted to maintain the highest quality reserve, the total value of a specific reserve type will incorporate the demand curve values of lower quality reserves. The demand curve values have been set at levels that are consistent with the actions normally taken by the NYISO operators in reserve shortage conditions." (NYISO, 2004 State of The Market Report, 2005.)

[15] New York ISO 2005 State of the Market Report (2006).

Reserve Demand Curves – Shadow Prices of Reserves under Shortage

	NYCA	Eastern New York	Long Island
10-Minute Spinning	$500	$25	$25
10-Minute Total Reserve	$150	$500	$25
30-Minute Reserve	200MW @ $50 200MW @ $100 200MW @ $200	$25	$300

Source: NYISO, Introduction to Ancillary Services (2007), pp. 114.

Reserve Clearing Prices Under Shortage

	NYCA	Eastern New York	Long Island
10-Minute Spinning	**$850** = $500+$150+$200	**$1400** = $500+$25+ $150+$500 +$200+$25	**$1750** = $500+$25+$25 + $150+$500+$25 +$200+$25+$300
10-Minute Total Reserve	**$350** = $150+ $200	**$875** = 150+$500+200+$25	**$1200** =$150+$500+$25 +$200+$25+$300
30-Minute Reserve	**$200**	**$225** = $200 + $25	**$525** = $300 + $200 + $25

Source: NYISO, Introduction to Ancillary Services (2007), pp. 116.

Regulation Demand Curve for Shortage Pricing

There are only system-wide requirements for regulation. Regulation units must submit bids into both the Day-Ahead and the Real-Time Market.

Regulation	Demand Curve Value
Need > 25 MW to meet Target	$300/MW
Need < 25 MW to meet Target	$250/MW

Source: NYISO, Introduction to Ancillary Services (2007), pp. 139.

4 PJM

4.1 An Administrative Scarcity Pricing Mechanism

PJM filed a Settlement Agreement with the FERC in November 2005 establishing new scarcity pricing rules which was subsequently approved and made effective by FERC in January 2006.[16] Under scarcity conditions, offer capping of units in a scarcity pricing region will be removed, and the price in the entire scarcity pricing region will be set to the highest offer price among all units supplying either energy or reserves on a real-time dispatch basis.[17]

Scarcity Condition

1) PJM control area experiences a material shortage in the reserves that PJM maintains to meets NERC reliability standards, and
2) The shortage is likely to be sustained absent operator action.

Trigger

The trigger for scarcity pricing includes the following.

Emergency Messages	Description
Max Emergency Generation Loaded	The purpose is to increase generation above the normal economic limit. 1) Dispatch of online generators, which are partially designated as Maximum Emergency, into emergency output levels 2) Dispatch of online generators, which are entirely designated as Maximum Emergency, above their minimum load points 3) Dispatch of offline generators that have been designated to run only in emergency conditions.
Emergency voltage reduction	A request to reduce distribution level voltage by 5%.
Emergency energy purchases	This request is typically issued at the Max Emergency Generation emergency procedure step.
Manual load dump actions	The request to disconnect firm customer load.

Source: PJM, Docket Nos. EL03-236-006, EL04-121-000 (2005). 2006 State of the Market Report, Table 3-39, pp. 149.

[16] PJM Interconnection, L.L.C., Docket Nos. EL03-236-006, EL04-121-000 (2005).
PJM Interconnection, L.L.C., 114 FERC ¶ 61,076 (2006).
[17] The units in the scarcity pricing region are still subject to the overall offer cap of $1,000/MWh.

Scarcity Condition Termination

Scarcity conditions will be terminated when demand and reserves can be fully satisfied with generation that is not designated as Maximum Emergency.

Scarcity Pricing Region

Scarcity Pricing Regions are regions with potentials to be transmission import limited due to an Extra-High-Voltage 500kv or greater constraint. There are initially five established Scarcity Pricing Regions in PJM. PJM will review the definition of these regions on an annual basis and file changes with the Commission as required.

<u>Established Regions</u>

1) Entire market consistent of all transmission zones in PJM;
2) Bedington-Black Oak Region consisting all pricing nodes that have a positive 5% or greater positive power distribution factor (dfax)
3) The Eastern MAAC region consisting all pricing nodes that have a positive 5% or greater dfax relative to the Eastern Reactive Transfer constraint
4) Eastern Market Region consisting all pricing nodes that have a positive 5% or greater dfax relative to the Bedington-Black Oak and the Central Reactive Transfer constraints; and
5) The MAAC region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Western Reactive Transfer constraint.

<u>Annual Review</u>

Additional Pricing Regions must meet the following requirements:

1) consist of at least two entire transmission zones
2) consist of contiguous transmission zones and sub-zones
3) transmission import or transfer must be limited by EHV (500kv or greater) constrains; and
4) consist of pricing node that have a 5% or greater positive dfax relative to the constraints.

Scarcity Pricing

When Scarcity Pricing is triggered in a Scarcity Pricing Region, the price in the entire region will be set equal to **the highest market-based offer price of all generating units** operating under PJM direction to supply **either energy or reserves on a real-time dispatch basis** subject to the overall $1000/MWh offer cap.

Opportunity Cost Compensation

If a generating unit in the scarcity pricing region is called up to reduce from its maximum output level for system or local transmission control during the scarcity pricing period, then this unit will be compensated for its opportunity cost, which is its MWh reduction times the difference between the scarcity price and the unit's offer price.

If a generating unit outside of a scarcity pricing region is called upon to relieve the transmission constraint in the scarcity pricing region, this unit will be paid the higher of the scarcity price for the region or the price it otherwise would have been paid. However, the unit's offer price shall not be used to set LMP or scarcity prices in the scarcity pricing region.

Scarcity Payments

Scarcity payments will be used to offset capacity payments.

4.2 2006 State of the Market Report - Recommendation to Refine the Scarcity Pricing Mechanism

In the 2006 State of the Market Report, the Market Monitoring Unit (MMU) of PJM analyzed scarcity situations by comparing demand and supply conditions in 2006, and made recommendations to refine the current scarcity pricing design. The report found that despite record high load very close to system generation capacity, prices remained relatively low and there were no official scarcity pricing events as defined in the PJM Tariff. Therefore, the MMU suggests the following modifications to enhance price signals,

1) Introducing stages of scarcity pricing;
2) Replacing the single scarcity pricing rule by locational signals.

The MMU identified hours in 2006 when demand, measured by load plus day-ahead operating reserve target, was close to or exceeded supply, and found that there were 70 hours of high load in summer 2006 among which 10 hours met the scarcity criteria. A high load event was defined as hourly load plus day-ahead operating reserve target greater than or equal to 90 percent of within-hour supply of non-emergency resources. A scarcity event was defined as hourly load plus day-ahead operating reserve target greater than or equal to total within-hour supply. [18]

5 MISO

MISO Tariff specifies the following shortage pricing rules.

382. Shortage conditions, defined as Maximum Generation Emergency conditions, trigger emergency procedures in both the Day-Ahead and the Real-Time Markets. A shortage in the Day-Ahead Market occurs when the sum of demand bids (including price sensitive demand) exports, and virtual bids cannot be satisfied with all available offers from generation, imports, and virtual supply, *i.e.*, the market cannot be cleared with existing bids and offers. A shortage in the Real-Time Market occurs when the real-time demand forecast cannot be satisfied with all available generation, self-schedules, and DRR offers.

[18] PJM, 2006 State of the Market Report, Section 3, pp141-150, (2007).
Within-hour supply was defined as economic (non-emergency) resources including “loaded generation, the lesser of the hourly available ramp or remaining non-emergency capacity of synchronized resources, the lesser of hourly available ramp or available non-emergency capacity of non-synchronized resources with less than a one-hour start-up time”, adjusted by outage information. (PJM, 2006 State of the Market Report, Section 3, pp142.)

383. A shortage condition in either market allows the Midwest ISO to consider additional supply sources (*e.g.*, offers from the emergency range of generation resources, DRRs available only for maximum generation emergencies, and emergency energy purchases) that are only available in these emergency conditions. It also may trigger a shortage pricing mechanism which administratively establishes the highest accepted offer at the $1,000 per megawatt-hour safety-net level. Emergency procedures are defined by similar sequential procedures followed in the Day-Ahead and Real-Time Markets in shortage conditions.

384. First, to clear **a day-ahead shortage**, supplies that can be provided from the high emergency range of on-line generation resources and DRRs will be scheduled, and their offer prices will be used to calculate LMPs. If the first step is not sufficient to balance the market, offers from off-line generation and DRRs available only for Maximum Generation Emergency conditions will be used to calculate LMPs. Third, as a final measure, shortage pricing may be triggered if the first two steps do not resolve the shortage. The Midwest ISO will proportionately reduce bids to achieve a supply/demand balance and **offers will be set at the highest offer of all on-line generation or $1,000 per megawatt-hour, whichever is greater**.

385. The Midwest ISO proposes a similar sequence of steps to deal with shortages in the Real-Time Market. First, supplies from the high emergency range of all on-line resources will be dispatched and used to calculate LMPs. Second, operating reserves may be used to provide energy which would trigger the shortage pricing mechanism. In this case, **segments of reserve capacity dispatched in merit would be offered at $1,000 per megawatt-hour and would be used to set LMPs**. Third, before resorting to load shedding, off-line generation available only for Maximum Generation Emergency conditions would be used to clear the market. Apart from these steps, the Midwest ISO may also make emergency energy purchases following a notification. In response to the notification, market participants and neighboring control area operators may submit offers for emergency energy which will be accepted on an economic basis. Emergency purchases, however, will not be used to determine LMPs.

References

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