Virtual Regional Dispatch

Concept, Evaluation, and Proposal

May 19, 2003

I. Introduction

This proposal facilitates efforts to increase the efficiency of the electric system dispatch across control areas. It enables the ISOs to achieve an interchange that is very similar to that which would result if the two systems were operated as a single market, with a single dispatch. In the proposed approach, each ISO would consider the bids and offers in their respective markets when optimizing the interface energy flow by establishing price equality , enabling load in the combined region to be served more efficiently.

The goal of FERC's Regional Transmission Organization (RTO) and its Wholesale Power Market Platform policies is to improve the reliability and efficiency of the electric power system. To assure efficiency, operators within each market now dispatch resources with minimum costs to satisfy load within their control area, while maintaining system security and reliability. Thus, each market individually meets the FERC's goals of reliability and market efficiency.

Additional gains in efficiency could be achieved with larger physical markets. However, combining markets is a complex technical, regulatory, and political undertaking. The Virtual Regional Dispatch (VRD) Proposal would enable adjacent control areas to realize many of the benefits of a larger market, while minimizing the technical, legal and political barriers. It directly addresses many of the seams issues between New York and New England, essentially eliminating them by increasing the size of the whole cloth.

II. Efficiency Gains of Coordinated Dispatch

This report addresses the efficiency gains possible by correcting market imperfections related to system operation. These shortcomings currently prevent the market from achieving optimum efficiency in real-time through trading between the control areas.

The efficiency gains of VRD are likely to be significant. According to the NYISO's Market Advisor in his annual report on the state of the NYISO market in 2002 (see Appendix D), substantial savings could accrue from greater dispatch coordination between the control areas. The unrealized production cost savings between the New York and the New England markets is on the order of tens of millions of dollars each year.

At interfaces where the proposed approach is employed, the ISOs will adjust the amount of energy interchanged within the hour in response to unforeseen, as well as to expected, events. Thus, Market Participants engaging in energy transactions between control areas will have more certainty that price differentials between control areas will be minimized.

III. Problem Statement

A. Arbitrage opportunities in real-time

Price convergence occurs when the energy prices at the border are equal, net of transmission fees and ancillary service charges. Price divergence at times when the interchanges are not constrained indicates unrealized arbitrage opportunities.

Market Participants are able to take advantage of most arbitrage opportunities arising in the day-ahead market. In real-time, it has proven difficult for control areas to achieve price equalization by relying only on transactions scheduled by Market Participants. Uncertainty, imperfect information, and offer submittal lead times limit the ability of Participants to capitalize on real-time arbitrage opportunities. Normal real-time market behavior, as well as unpredictable events, causes day-ahead supply schedules and real-time demand to diverge. Forced outages, load forecast errors, deviations from generators' start-up and shut-down schedules, and intra-hour economic commitment/de-commitment of fast start resources or dispatchable loads conspire to cause prices to remain divergent at the border. Thus, it can be very challenging to predict real-time price differences at control area boundaries, even just an hour ahead. This failure of real-time arbitrage gives rise to market inefficiencies that could be remedied if Market Participants and/or the ISOs were to trade energy in such a way as to reduce or eliminate the price differences.

Several factors impede the ability to optimize the interchange. Among the limitations are the lead times required for Participant transactions, insufficient incentives for Participants to utilize the full capability of the interfaces, and lack of coordinated market responses. The current market structure for bidding real-time transactions makes it very risky for Market Participants to respond to inter-market price divergence caused by short-term variables. Appendix A of this paper discusses these impediments in more detail.

B. Empirical evidence

Price divergence at the border, in the absence of congestion, is a fundamental market imperfection resulting from the separate dispatch of neighboring control areas. That is, inefficiencies, or seams, will arise at interfaces where dispatch is not coordinated across markets, and New York and New England are no exception.

Based upon information contained in his *2002 Annual State of the New York Markets Report* (excerpts in Appendix D), the market advisor to the NYISO recommends that NYISO and ISO-NE develop a real-time interchange management protocol similar to that contained in this proposal. He supports this recommendation with empirical evidence demonstrating that the current real-time process is not satisfactorily arbitraging the price differences between the NYISO and its neighboring markets.

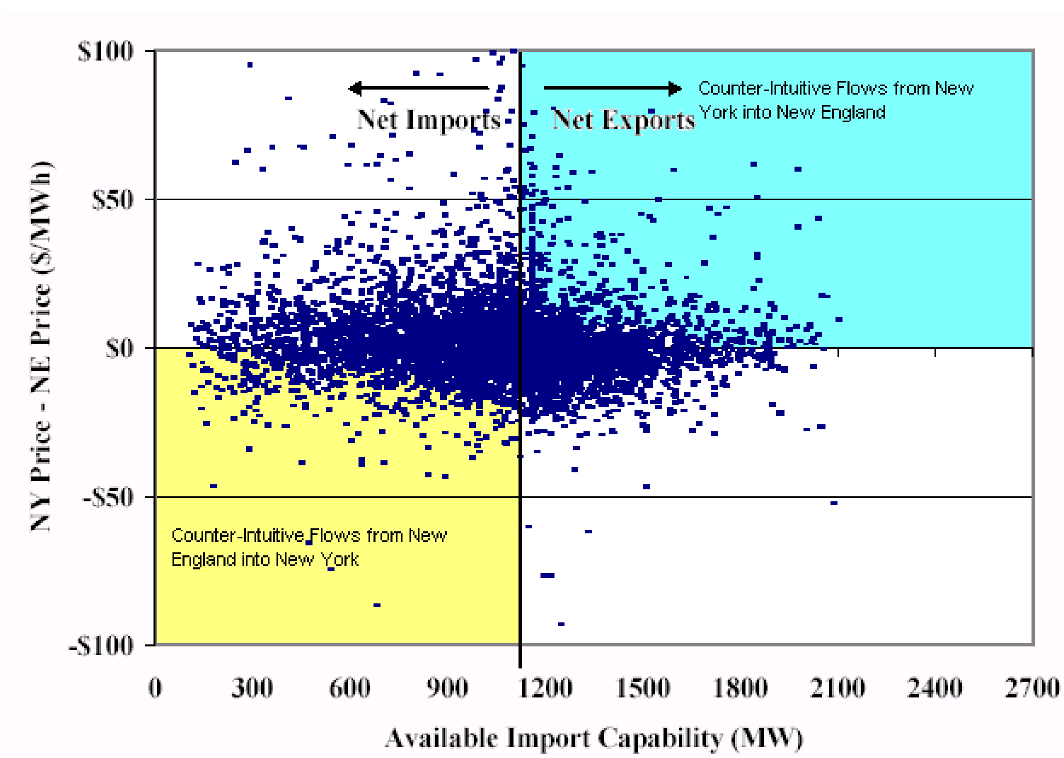
1. Counter-Intuitive Flows

If markets are operating efficiently, price differences between neighboring control areas ought to be close to zero when constraints that restrict the flow of energy are not binding. To the extent that price differences exist, electricity should flow from the lower priced control area to the higher priced control area. Market Participants would act quickly to arbitrage large price differences. However, energy flows between New York and New England do not always follow this pattern.

Counter-intuitive net interchange occurs when a) New York is a net exporter when NYISO prices exceed ISO-NE prices or b) New York is a net importer when NYISO prices are lower than the relevant LMP in ISO-NE. Figure 1 shows price differentials between New England and New York for unconstrained hours in 2002, from the perspective of the New York control area. When the price difference is positive, energy should flow from New England to New York, and vice versa when the price difference is negative. Counter-intuitive flows lie in the upper right and lower left quadrants of Figure 1. (Adapted from the NYISO Market Advisor's *2002 Annual Report*.) Since the counter-intuitive flows occur in both directions, the benefits from VRD will accrue to both control areas.

If one of the control areas is approaching a capacity shortage, VRD interchange scheduling can delay or avoid capacity deficiencies and scarcity pricing in the area with the impending shortage of supply. New England and New York are currently effectuating improvements to their pricing mechanisms that will more accurately reflect scarcity conditions in the price of energy. VRD would be implemented in a manner consistent with scarcity pricing rules, and emerging operating procedures and practices.

Figure 1: Price Differentials between New York and New England
Real-Time Prices vs. Hour-Ahead Schedules: Unconstrained Hours 2002



IV. Proposed Solution

A. Overview

The intent of this proposal is to resolve an important seams issue, providing financial benefits to both markets. The economic and secure dispatch of the control areas will not be affected.

The proposed changes to real-time transactions enable the ISOs to adjust actual energy exchanges periodically, based on residual price disparities. As a result, Market Participants would be able to execute transactions between control areas with less risk of exposure to the consequences of price separation between the markets.

Currently, ISO-NE and NYISO schedule energy flows between the control areas based solely on transactions submitted by Market Participants. Under this proposal, the ISOs would determine energy exchanges to maintain price equality more effectively, improving the efficiency of both markets. Market Participant transactions would become financial in nature, much like the internal bilateral contracts that now exist in each market.

This proposal would lead to a more efficient dispatch of resources, without physically combining the ISOs. Supply with the lowest cost offers in both control areas would be dispatched to satisfy their joint demand. When this objective is fully achieved, prices at the market interfaces will be equalized, except when transmission congestion is present.[1]

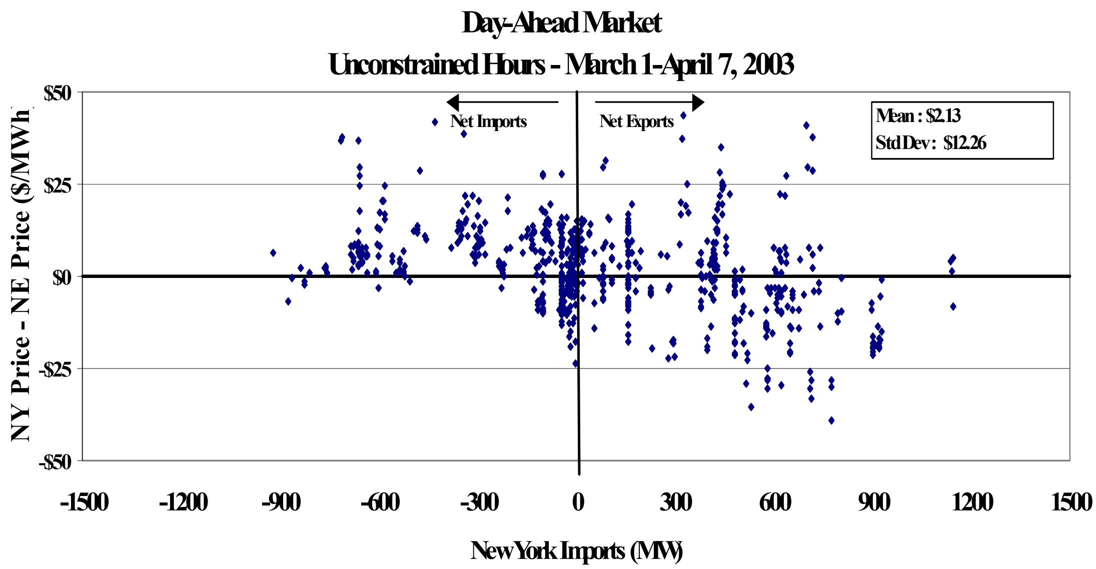
B. Day-Ahead Market

The market provides financial incentives for Market Participants to deliver on the obligations that they assume in the day-ahead market. Thus, transactions scheduled in each ISO's day-ahead market are a key component of VRD.

Greater convergence between interface prices in the real-time market should induce better arbitrage in the day-ahead market, and encourage Market Participants to schedule transactions in the day-ahead market. Figure 2 compares price differences in the day-ahead markets between New York and New England, after ISO-NE's implementation of SMD. It appears that the move to SMD has not alleviated the problem of counter-intuitive power flows, and that prices have not been converging in the day-ahead market. Once VRD is in place, real-time prices between the ISOs should move closer together, with power more often flowing in the expected direction, in both the real-time and day-ahead markets.

[1] "Prices" in this context include charges for through and out transportation charges, and ancillary services consideration.

Figure 2: Day-Ahead Market, Post-SMD



This proposal does not entail changes to the day-ahead markets, retaining the arbitrage opportunities available today. ISO-NE and NYISO will continue to run completely separate day-ahead markets that support the ability of their Market Participants to schedule fixed and price sensitive transactions between the two ISOs.

C. VRD Interchange in Real-Time

The ISOs will physically schedule the interface to reach price convergence. Establishing the real-time transactions will be a two-step process, because the settlement interchange MWhs need to sum to the physical flow, while participant transactions are financial in nature. Market Participant transactions will first be scheduled, consistent with prices and procedures. If these transactions do not result in price convergence, the ISOs will schedule the residual quantity of energy needed to ensure that net transactions equal the physical flow by VRD interchange.

1. Market Participants and Financial Transactions

This proposal continues the current structure for Market Participants to enter real-time transactions between New York and New England. This proposal includes a new mechanism to enable participants to exploit near real-time arbitrage opportunities associated with residual price disparities. Transaction scheduling across interfaces gives rise to congestion. A process for collecting and allocating congestion revenues across areas needs to be developed. Additional details for participation in such short-term arbitrage remain to be worked out, and it is expected that these will be developed in collaboration with Market Participants over the summer of 2003. Hourly transactions would continue to be scheduled, although the timing of the check-out may be altered.

2. Virtual Real-Time Dispatch Process

a) Relationship between Day-Ahead Market Transactions and Real-Time Transactions under Virtual Regional Dispatch.

Forced outages, load forecast errors, generator deviations from startup and shutdown schedules, and intra-hour economic commitment/decommitment of fast start resources or dispatchable loads collectively can cause difficult- to-predict real-time deviations from the day-ahead schedule. In turn, these deviations are responsible for much of real-time price divergence at control area boundaries.

b) Real-Time Implementation of VRD.

The key element of the proposal is the adjustment of interchange schedules by the ISOs in real-time, to enable lower cost supply that is available in one ISO to serve the load in the other ISO. This dispatch adjustment must be done carefully to assure that the basic benefits of economic dispatch within the individual ISOs are not lost. The treatment of the interchange for reliability purposes, and the calculation of operating reserves in each region also must be addressed.

Frequent schedule corrections are required to adjust to intra-hour price divergence. This proposal calls for a 15-minute interchange schedule evaluation. This interval captures most of the potential market efficiency and is consistent with the 15-minute scheduling time-frame that will be deployed with Real-Time Scheduling under New York's SMD 2.0.

Conceptually, it is clear that supply in the lower cost ISO would increase, while at the same time, the output in the more expensive ISO would decline. The quarter-hour process calls for evaluating the price differential between the participating markets at their designated proxy locations, and adjusting the desired net interchange in a manner that equalizes prices at the border.

The control area with the lower LMP would incrementally increase exports to the area with the higher LMP. Iterations would continue every 15 minutes until price equality is achieved, to the extent possible. The following steps delineate the proposed scheduling process:

1. At 15-minute intervals, the ISOs will compare prices. If prices have not converged, the interchange schedule will be adjusted, increasing the flow of energy from the lower priced control area to the higher priced area. Provisions the size and period of adjustment are to be established and modified based upon operational experience.

2. Corrections indicated by the 15-minute evaluation will be ramped into the interchange net schedule over a 10-minute period.

3. VRD interchanges will require NERC tags.

4. At any point in time, the VRD MWs will equal the physical schedule, minus the net interchange scheduled by Participants.

Moving from a 15-minute cycle to a 5-minute cycle could conceivably result in additional market efficiency. However, such frequent schedule adjustments would require greater automation, and it is desirable to gauge the success of a 15-minute cycle before considering a shorter evaluation period.

D. Pricing Locations

The New York and New England ISOs each need a location at which to settle external transactions, and achieve near-convergence of prices. To schedule energy flows efficiently requires prices that are representative of marginal costs of delivery at the control area interface. Furthermore, price equalization by the ISOs must take place at the same point where Participants trade energy in the day-ahead and real-time markets. The locations should represent the marginal cost of modifying interchange schedules, and the resulting locational prices must be consistent with the pricing of internal, day-ahead and Participant-arranged real-time transactions within each respective market. The current proxy busses may or may not serve this purpose.

Effectively, the proxy busses establish a common point of evaluation at the New England/New York interface. Each of these locations appropriately distributes energy on the free-flowing AC tie lines connecting the markets. Importantly, neither control area's model of the other includes congestion or losses. Therefore, congestion and losses from the borders to the proxy buses are not included in the price calculations for these proxy locations.

The ISOs will research the effectiveness of the proxy bus locations, to determine a suitable location for calculating interchange reference prices. Data from the period following ISO-NE's implementation of SMD will be analyzed.

E. Settlement of VRD Interchanges

This proposal builds upon the current market design for settlement. Market Participant hour-ahead transactions scheduled under VRD will be priced and settled in the same manner as external transactions are settled today in each market.

A separate settlement apparatus will be developed to enable load in the importing area to pay generation in the exporting area, should participant transactions fail to converge interface prices when the ISOs schedule a transaction. The development of the mechanism requires considerable analysis by the ISOs, in collaboration with their Participants. One possible settlements mechanism is outlined in the following example.

Assume ISO-arranged VRD power is flowing from New England into New York, then:

- The LMPs at all locations in both control areas will reflect this flow.

- Participants with load in New York will pay the LMPs in New York for all real-time spot market purchases.

- The revenue collected from New York load should be adequate to pay New York supply, and to transfer a payment to the New England real-time spot market at the New England price for the VRD energy received.

- Therefore, Revenues from the New York ISO settlement prices will be used to pay New England suppliers providing the VRD energy delivered to New York.

- If locational prices converge, the revenues from New York will precisely equal the Out-service transmission fee (if any), and the payment to the New England suppliers. Revenues and payments will balance in the New York market, as well as in the New England real-time market.

- If the New York locational price remains above the New England price, there will be residual revenue in the New York settlements. This case would occur if the interface is constrained, or if the interface is scheduled conservatively. A revenue shortfall would result if energy were inadvertently scheduled from the high cost control area to the low cost area. In either case, a mechanism is needed for distributing the revenue imbalance to Market Participants. This mechanism will be determined as part of a planned collaborative process between the ISOs and their market Participants, to take place during the detailed design phase of implementation. An example of the settlements process is illustrated in Appendix B.

F. Out-Service Tariff[2]

Interchanges scheduled between Control Areas are currently subject to an Out-Service tariff. Advocates for the elimination of seams between Control Areas have argued for the removal of these fees. This proposal can be implemented independently of any decision regarding Out-Service tariffs. If these fees are retained, then recipients would remain obligated to pay Out-Service fees, which would be applied to any interchange adjustments scheduled by the ISOs. The degree of price convergence would need to be limited to assure collection of the out-service revenues.

G. Technical Feasibility

The ISOs will continue to use a security-constrained, least-cost protocol to dispatch each control area and to schedule interchange. There will be no adverse impacts on the dispatch efficiency of the individual ISOs from adopting this proposal. All system reliability and security rules and processes will continue to be met.

[2] The proposal could work equally well if out service charges are eliminated.

Decisions regarding which transactions to schedule will be made outside of the real-time dispatch software, much like it is done today. Some changes in the preparation of information about the interchange used as input to the respective dispatch algorithms will be needed, and some changes to the settlements software itself probably will be required.

The current tools available to the operators, including observation of real-time price separation, existing indicative pricing tools, and communication between Control Areas, will need to be supplemented in order to implement this proposal. While the tools available to control room operators may not be sufficient, the procedures outlined here may be accomplishable with reasonable additional effort. In short, the software changes need not be extensive to support the initial implementation phase, as it is described in this paper.

This proposal does not affect the day-ahead market or the software used to run it, and is consistent with the 15-minute scheduling time-frame that will be deployed with Real-Time Scheduling under New York's SMD 2.0.

H. Treatment of capacity during shortage conditions

This proposal will reduce the potential for one control area to experience scarcity conditions when additional supply is available in the larger region. It provides a mechanism to assure that power will flow in a direction that is consistent with the real-time price signals of the participating control areas. If one ISO is approaching scarcity conditions, it may be possible to flow power to it, avoiding the scarcity situation. The exact protocol for scarcity conditions will be determined collaboratively between the ISOs and their Participants.

I. Opportunities for Collaboration

The following are key among the issues that remain to be resolved collaboratively between the ISOs and their Participants.

1. Day-ahead market settlements, and the relationship to real-time operation and settlements.
2. Allocation of congestion revenues.
3. Complete settlements logic of Participant and VRD Transactions.
4. Operational details including the detailed components of the interchange determination process.
5. Operation of the VRD process during scarcity pricing conditions.
6. VRD relationship to ICAP recall.

Appendix A. Factors affecting current real-time arbitrage efficiency

Current real-time interchange scheduling efficiency is limited by a number of factors. Several of these issues cannot be alleviated without substantive structural change of the kind being proposed in this paper. They are discussed below.

1. **Time Limitations on the Current Hourly Competitive Scheduling Process**

   In real-time, a competitive market response requires the following sequential activities:

   - The ISOs need to release indicative price information to inform the market of potential market opportunities.
   - The market needs sufficient time to evaluate and arrange for transactions.
   - Offers must be prepared and submitted to the two ISO's at least an hour or more in advance.
   - The ISOs need to invoke a competitive selection process, evaluate security concerns, and perform an advance check-out of contracts with the neighboring Control Area.
   - Hour-ahead processes may not recognize the same relative economics as the real-time markets when scheduling price sensitive imports and exports.
   - Notification of accepted transactions is required in some cases.

   It is also significant that the duration of an accepted contract must be at least as long as the scheduling cycle, which in today's market is one hour. However, particularly in peak conditions, price differences can arise and dissipate quickly, creating substantial uncertainty and risk for participants scheduling transactions between control areas.

   Allowing market participants to arrange short-term transactions on very short notice and/or for shorter periods could potentially improve market efficiency. However, as long as interchange levels are driven solely by participant transactions, an inter-area check-out process similar to that described above will be required. There is little likelihood that the direct market approach alone could approach the efficiency of a regional, or even a virtual regional, dispatch.

2. **Limited Incentives to Reach Full Market Efficiency**

   The market provides insufficient incentives to encourage Participants to utilize interchange opportunities fully, thus limiting the potential for improving market efficiency solely through Participant transactions. The following example explains the limitations. Suppose a Control Area in the north has a marginal price of $100/MWh at its southern border. The Control Area to its south has a marginal price of $80/MWh. If a 100 MW transaction were to be arranged from the south to the north, the southern price would rise to $90/MWh, and the northern price would drop to 90 $/MWh. A cooperative dispatch would schedule the 100 MW. Market Participants would not have the same incentives, because once the transaction is scheduled, the equality of prices at the border removes the transacting parties' opportunity to arbitrage. All arbitrage profit-making opportunities are eliminated when the LMPs are equalized. In the real-time spot market, traders gain only when they can sell energy at a higher price than they can purchase it. Consequently, a market participant solution alone lacks incentives to utilize interface capabilities fully.

3. **Un-coordinated Market Response.**

   Depending upon the method chosen, market responses could well be prone to over- or under- reaction. Using the example above, suppose that a marketer in the north perceives an opportunity to make money, and requests a purchase of 100 MW if the forecasted price is above $90/MWh in the north. At the same time, a marketer in the south submits a sell order if the price in the south is below $90/MWh. Since the economic evaluations are made independently, both transactions would be scheduled. The independent scheduling causes the market to be over-sold. Over-reaction in one scheduling period is likely to be followed by under-reaction in the next.

Appendix B: VRD Schedule Settlements Example

This example illustrates a possible settlement mechanism for a VRD interchange. In this example, the VRD interchange flows at a rate of 100 MWh/hr, from New England to New York. That is, the NYISO and ISO-NE have jointly decided that the sum of the Market Participants' transactions should be modified by 100 MW. The duration of the VRD transaction is 15 minutes. Therefore, even though the ISOs adjust the interchange schedule by 100 MW from what Market Participants would have established, only 25 MWh of energy is exchanged in the VRD transaction.

This example assumes that the real-time energy prices are constant during the hour. In fact, NY settlement prices change every five minutes, while the NE settlement price is an average for the hour. Implementation of VRD transactions will ultimately have to account for these settlement differences, but this example finesses those differences by assuming constant energy prices for the duration of the VRD interchange. Those prices are as follows:

<u>New York's view of the border with New England.</u> This is the price calculated by NY with the 100 VRD schedule in place. NY is willing to buy/sell energy at \$53 per MWh.	\$53
<u>New England's view of the border with New York.</u> This is the price calculated by NE with the VRD schedule in place. NE is willing to buy/sell energy at \$50 per MWh.	\$50

Prices in the example have not converged, in part to make the example interesting. Presumably, without the VRD transaction, the price difference between the two control areas would have been even larger than the \$3 of the example. Also, in the interest of simplification, it is assumed that there are no out-service charges.

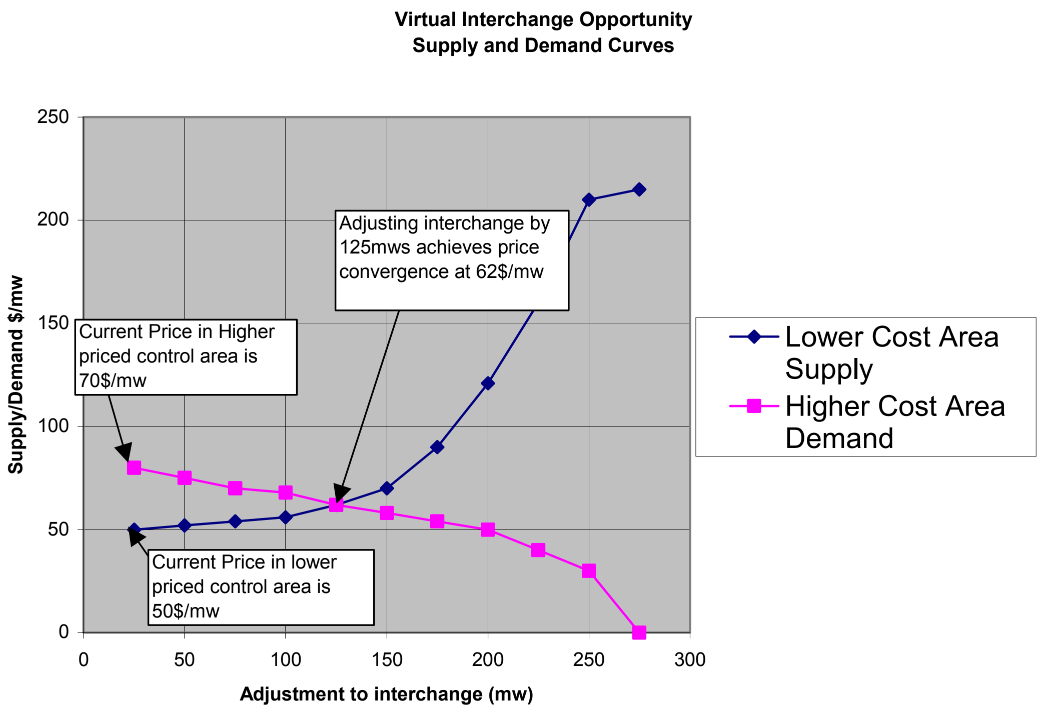
The revenue collected by the New England market (the "selling" control area) from the New York market (the "purchasing" control area) is adequate to pay New England generators and, to the extent that prices do not converge, there will be a revenue surplus to be distributed, as determined collaboratively by NYISO and ISO-NE and their Participants. That surplus is \$75 in this example. Had prices converged exactly there would be no revenue surplus.

New England		New York	
<u>NE Energy Market (generator)</u> • Sells 25 MWH to NE market at a rate of (100 MWH/H) for $50.00/MWH	$1,250		
<u>NEPOOL Market Settlements</u> • **<u>Buys 25 MWH from the NE Energy Market for $50.00/MWH</u>** • **<u>Sells 25 MWH to NY market for $53/MWH</u>** • **<u>Revenue surplus from the VRD schedule. Distribution to be decided.</u>**	($1,250) **<u>$1,325</u>** **<u>$75</u>**	<u>NY Market Settlements</u> • Buys 25 MWH from NE Market for $53/MWH • Sells 25 MWH to the NY Energy Market for $100/MWH • Revenue surplus from the VRD schedule	($1,325) **<u>$1,325</u>** **<u>$0</u>**
		<u>NY Energy Market (load)</u> • Buys 25 MWH from NY market for $53 /MWH	($1325)

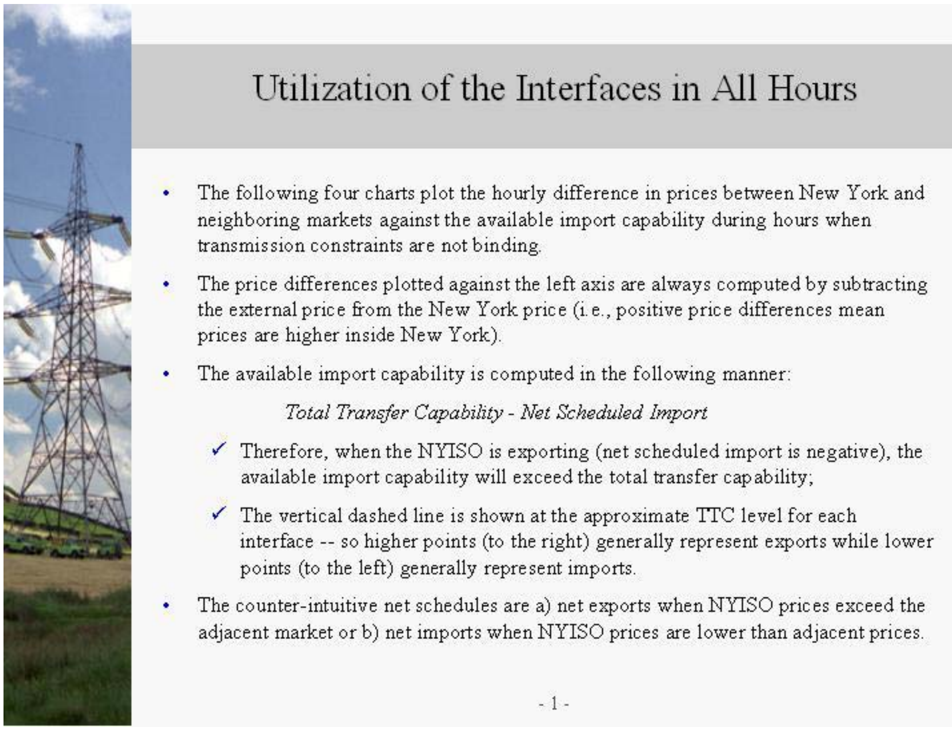
Appendix C: Using Demand/Supply Curves to Determine Interchange Adjustments

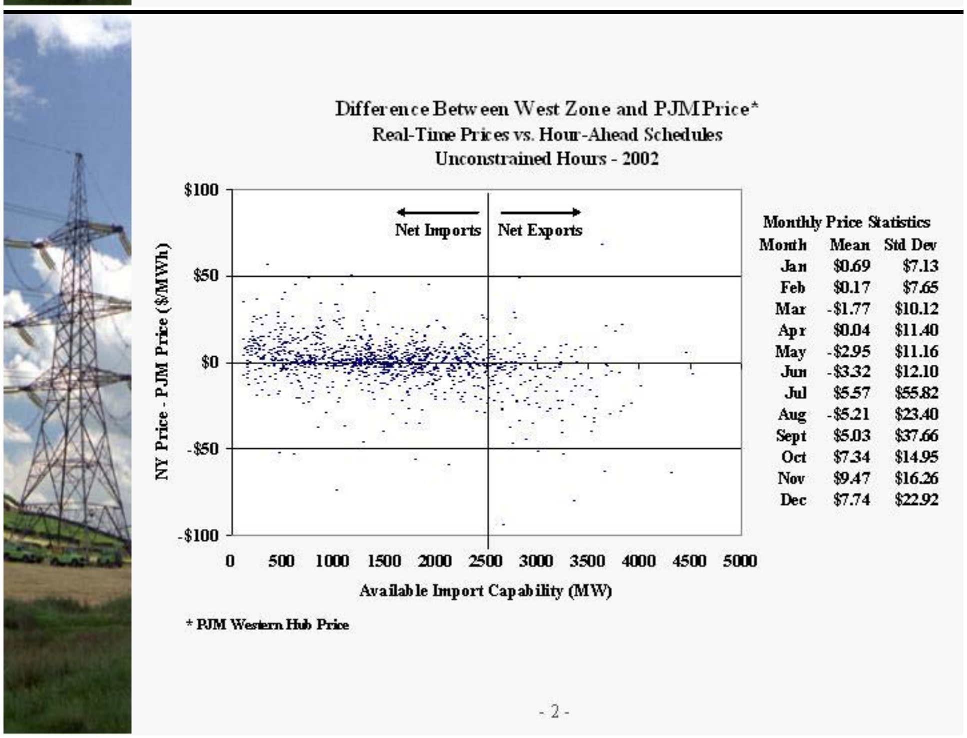
Initial implementation of VRD can be deployed with minimal software enhancements. Post-implementation software enhancements are envisioned that would select interchange schedule adjustments as follows.

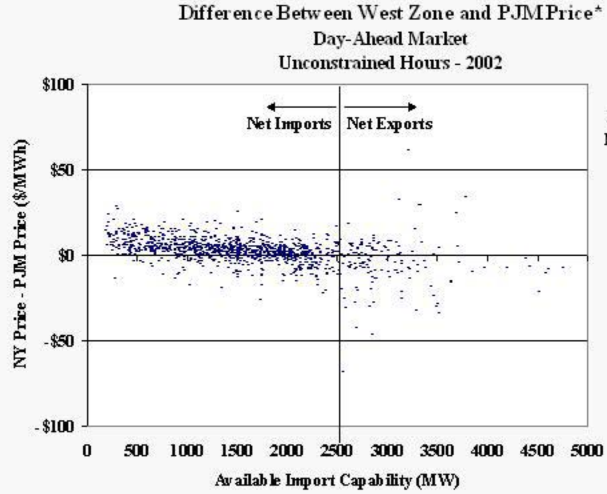
With the same software used to establish real-time locational prices, an automated process in the control area with the lower LMP would continuously update the cost schedule of delivering additional energy to the interchange (a supply curve). Similarly, the control area with higher prices would continuously produce demand curves estimating the value of increased imports. Additional automation would consider the demand curves, supply curves, and interface limits, and recommend the most efficient interchange schedule changes.



Appendix D: Data and Excerpts from Patton's Presentation to NYISO



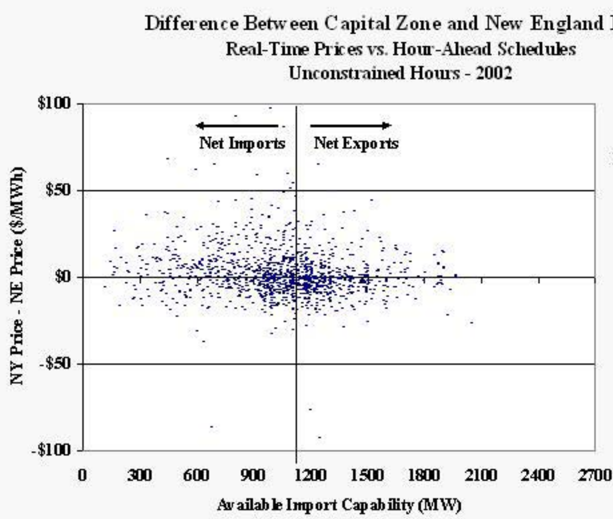




Monthly Price Statistics

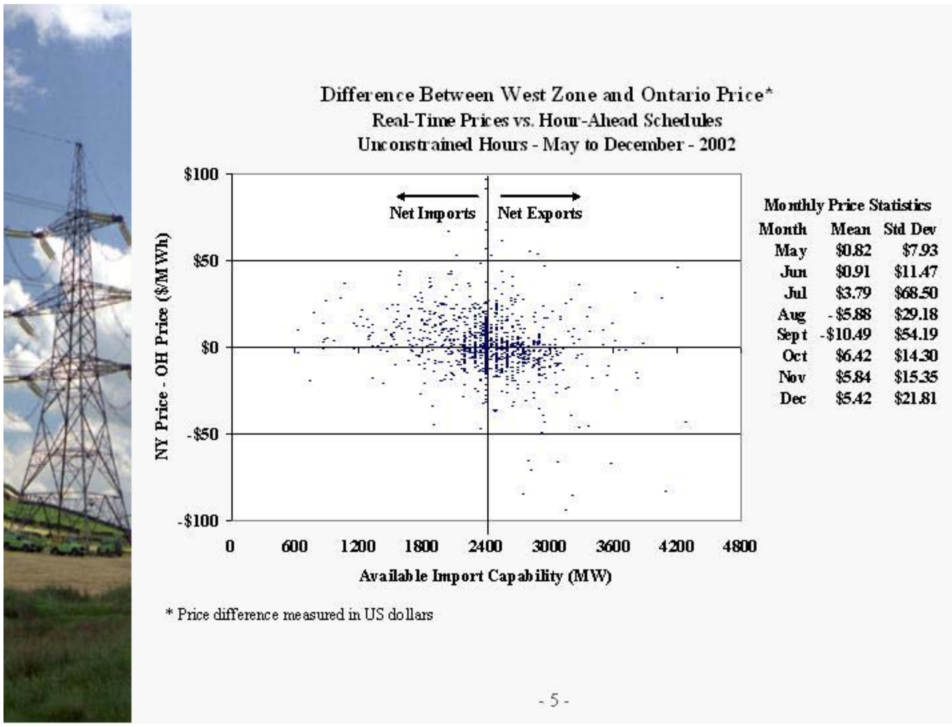
Month	Mean	Std Dev
Jan	$2.21	$3.56
Feb	$0.66	$3.71
Mar	$1.01	$5.39
Apr	$0.40	$9.99
May	-$1.46	$7.26
Jun	-$0.65	$7.76
Jul	$1.48	$11.57
Aug	$3.08	$13.61
Sept	$6.24	$8.18
Oct	$6.32	$7.48
Nov	$9.51	$6.09
Dec	$5.42	$8.77

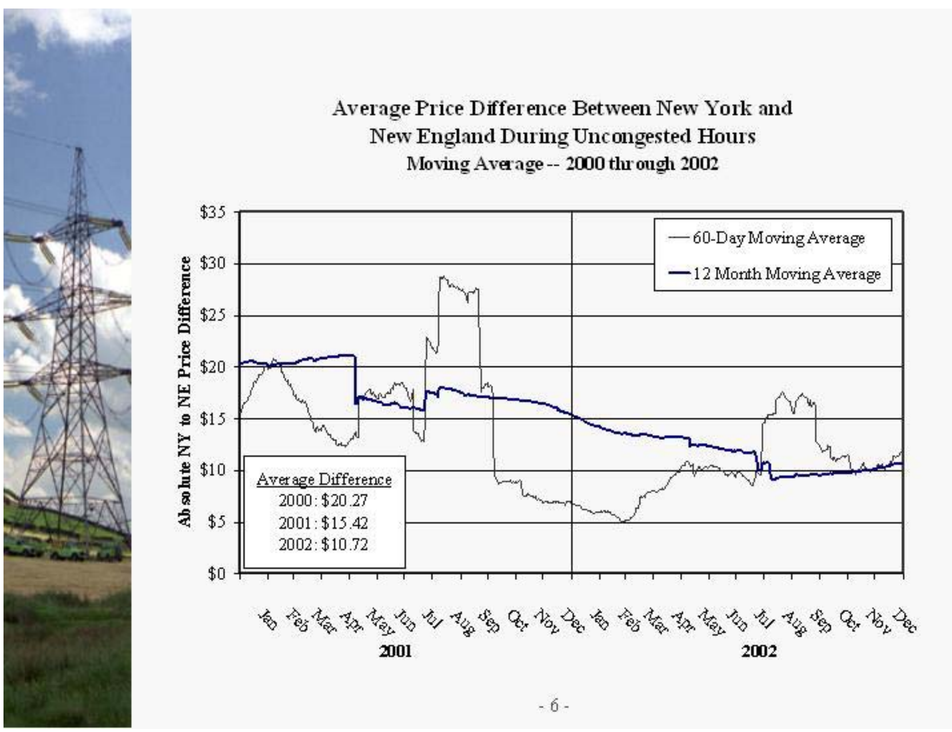
* PJM Western Hub Price

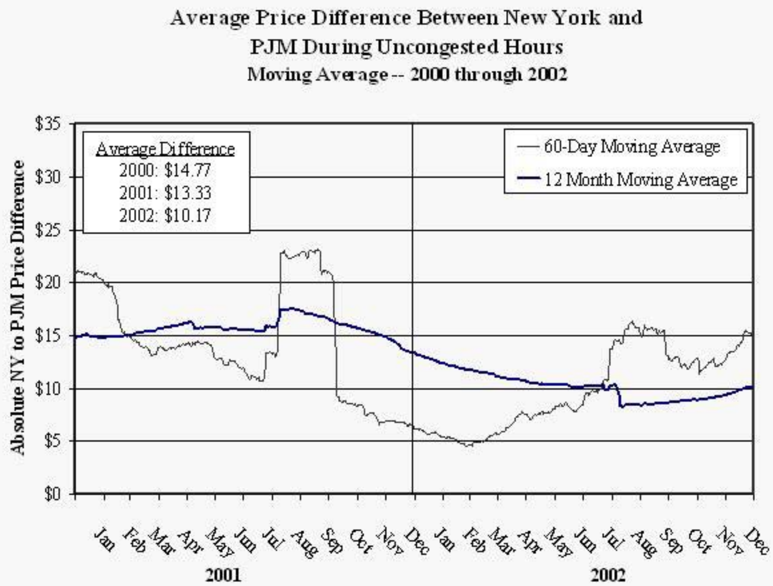


Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$0.51	$7.77
Feb	-$2.00	$7.80
Mar	$3.39	$18.74
Apr	$4.30	$13.29
May	$1.53	$16.20
Jun	-$1.04	$11.36
Jul	$10.59	$74.21
Aug	-$4.37	$32.61
Sept	-$0.13	$34.15
Oct	$3.57	$16.41
Nov	$4.36	$15.57
Dec	$3.96	$20.92


Difference Between West Zone and Ontario Price*
Real-Time Prices vs. Hour-Ahead Schedules
Unconstrained Hours - May to December - 2002
NY Price - OH Price ($/MWh)
$100
$50
$0
-$50
-$100
Net Imports
Net Exports
0
600
1200
1800
2400
3000
3600
4200
4800
Available Import Capability (MW)
Monthly Price Statistics
Month Mean Std Dev
May $0.82 $7.93
Jun $0.91 $11.47
Jul $3.79 $68.50
Aug -$5.88 $29.18
Sept -$10.49 $54.19
Oct $6.42 $14.30
Nov $5.84 $15.35
Dec $5.42 $21.81
* Price difference measured in US dollars
- 5 -


Average Price Difference Between New York and
New England During Uncongested Hours
Moving Average -- 2000 through 2002
Absolute NY to NE Price Difference
$35
$30
$25
$20
$15
$10
$5
$0
60-Day Moving Average
12 Month Moving Average
Average Difference
2000: $20.27
2001: $15.42
2002: $10.72
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
2001
2002
- 6 -



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Tracking Changes in the Inter-ISO Seams

- **Estimated Production Cost Savings**
  - ✓ NY/PJM: $40 Million
  - ✓ NY/NE: $30 Million
- **The charts examine how fully the real-time prices between New York and other markets have been arbitraged by participants by calculating the potential production cost savings from full arbitrage.**
  - ✓ Both charts show a 12-month and 60-day rolling summation of the unrealized production cost savings between New York and an adjacent market. The 60-day summation has been scaled up to an annual basis.
  - ✓ Sharp movements in the rolling sums generally correspond to periods of price spikes in one of the markets, resulting in extremely large differences.
  - ✓ The annual unrealized production cost savings for 2000, 2001 and 2002 are equal to the 12 month rolling sum as of December 31 of each year.
- **Both charts indicate that significant improvements in the seams issues have been made over the past three years.**

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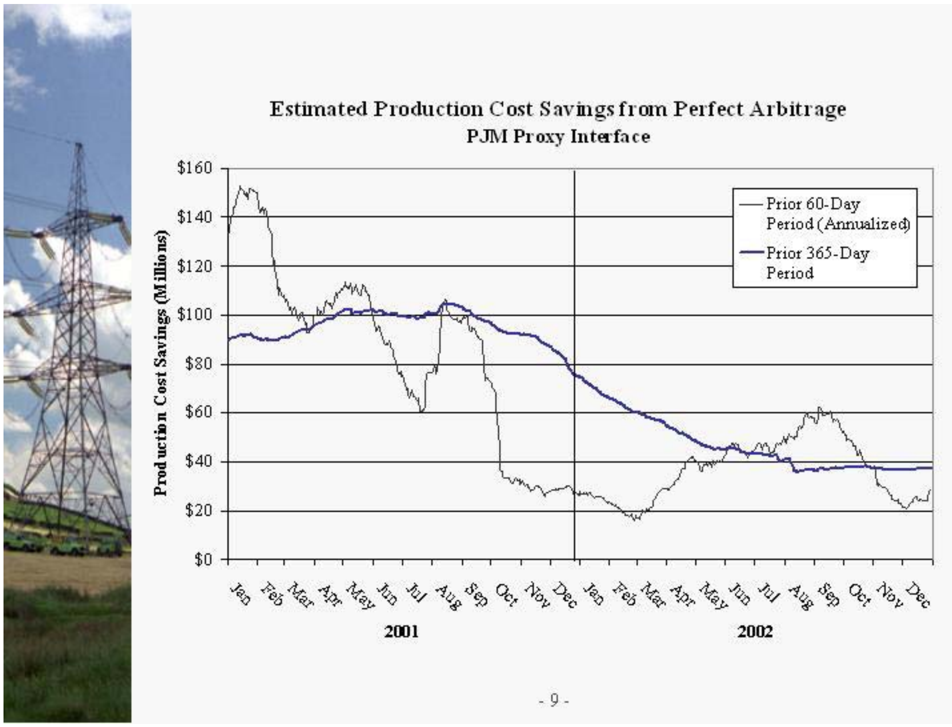
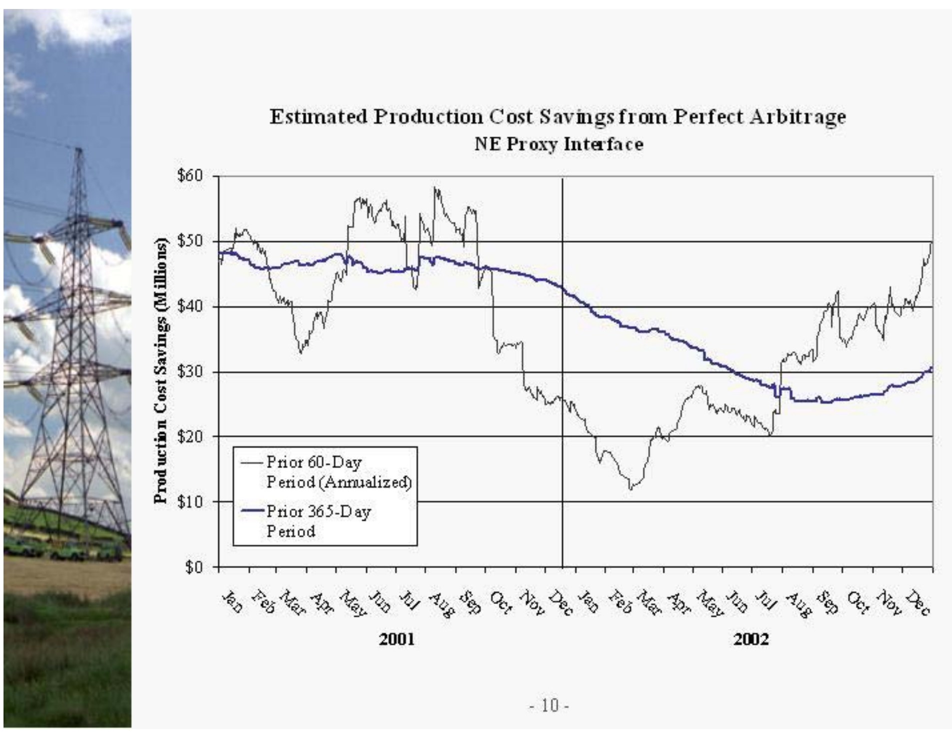

Estimated Production Cost Savings from Perfect Arbitrage
PJM Proxy Interface
Production Cost Savings (Millions)
$160
$140
$120
$100
$80
$60
$40
$20
$0
Prior 60-Day Period (Annualized)
Prior 365-Day Period
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
2001
2002
- 9 -


Estimated Production Cost Savings from Perfect Arbitrage
NE Proxy Interface
Production Cost Savings (Millions)
$60
$50
$40
$30
$20
$10
$0
Prior 60-Day Period (Annualized)
Prior 365-Day Period
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
2001
2002
- 10 -