POTOMAC ECONOMICS

GENERATION DISPATCH DEVIATIONS AND MARKET PERFORMANCE

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I. Introduction

It is common in electricity market for the output of a generator to not precisely match the dispatch instruction produced by the market software in any given interval, which we refer to in this report as generation dispatch deviations. In particular, we refer to generators producing less than the dispatch instructions as “dragging” and producing more than the dispatch instruction as “over-production”. Because the SCD model generally assumes that generators will be responding to dispatch signals, over-production and dragging results in a need to utilize regulation to balance load and can cause area control error (“ACE”) when regulation is not fully effective at resolving the imbalance.

When deviations are persistent, they can cause the physical production from the generator to differ significantly from the optimal economic output level for the unit. This occurs because the physical dispatch is calculated based on the actual current output level of each generating unit. Hence, an inframarginal generator will be instructed to increase its output by no more than its ramp rate from its current output level. This dispatch level is referred to as a “non-accumulated base point”.

However, the pricing software assumes that in each interval, the resources followed the instructions from the prior interval in determining each unit’s base point and calculating prices. We refer to this base point as the “economic base point”. Over many intervals, therefore, persistent generation deviations can cause the actual output to deviate substantially from the economic base point for the unit. We refer to this difference as the “economic deviation”. Due to data limitations, we were not able to analyze the economic deviations in this report. Instead, we focus primarily on generation deviations. Since economic deviations are caused by the physical generation deviations, we believe many of the conclusions drawn in this report would apply to both types of deviations.

In the Spring and Summer 2002, persistent dragging concerns were first raised that related primarily to gas turbines (“GT”). It was noted that certain GTs were consistently dragging due to reductions in capability due to high ambient temperatures during the summer. This problem was solved by having SCD automatically detect dragging and account for the temperature effects by reducing the dispatch signal to the generator. Deployment of the solution occurred in June of 2003. It operates by setting the physical schedule for the GT to its actual output when its output exceeds 70% of the unit’s capacity. However, the gas turbine “fix” does not address dragging or over-production by other types of generators.

Physical generation deviations can result from a number of factors, including:

- Physical limitations such as ambient temperature impacts, temporary equipment problems, or emissions considerations can prevent a generating unit from responding at its normal ramp rate or cause a delay in response to ramp signals.
- Some suppliers seek to avoid volatile dispatch movements be not responding to rapid changes in the dispatch signal.
- Suppliers that fail to derate a unit whose capability has decreased may persistently operate at a rate lower than the dispatch signal from SCD.

The NYISO has been educating generators about the impacts of persistent dragging and what they can do to minimize it. They are also working directly with several units that historical analysis and operations experience suggest are substantial contributors to net generation deviations. The NYISO previously had penalties to deter deviations. These rules were relaxed in order to avoid disincentives for units to be on-dispatch.

The NYISO has begun a dispatch design issue assessment that includes the issue of dragging. The NYISO asked Potomac Economics, Ltd., as the Independent Market Advisor, to evaluate generation deviations and determine the significance of this issue. The following sections of this report provide our evaluation of persistent physical dragging and over-production by resources in New York, defined as the difference between a unit’s actual output and its physical base point. Such deviations can affect prices causing the real-time market to clear higher or lower in the supply stack than would be the case if the model recognized that a resource was not going to adhere to the dispatch signal (with the difference being resolved with regulation deployments or reflected in the ACE in the five minute timeframe).

In addition, generation deviations can affect market prices due to the difference between the physical dispatch and the pricing dispatch (i.e., the economic deviation). Because data regarding each resource's economic base point was unavailable, we were not able quantify the deviations from the economic base points nor has an effective mechanism for uniquely identifying among units being dispatched, those which are failing to follow basepoints as instructed and those that are being dispatched off of their ideal basepoint in order to compensate for dragging or overproducing units. However, we qualitatively discuss a number of issues and potential improvements related to current physical dispatch and real-time pricing framework in Section III.

II. Generation Deviations in New York

A. Generation Deviations and Prices

Generators in the New York markets have claimed that persistent dragging by steam units can distort prices, create uplift and cause operational problems. It has been claimed that in periods where generators are dragging, the dispatch software will direct other units to operate at higher levels out of merit (including committing gas turbines) to make up for the physical generation deviations. This is not true because the SCD dispatch assumes that generators will respond to the dispatch instruction.[1] Therefore, if an operator commits a gas turbine to compensate for a generator that is dragging, the SCD dispatch will reduce the output of other generators by the output of the GT in future intervals. Nevertheless, dragging can have significant effects on the market outcomes.

Issues related to generation deviations center on the reaction of SCD and other elements of the system to the deviations. SCD will assume in each interval that the resource will respond to the dispatch signal. This dispatch signal recognizes the current output of the unit and is constrained by the ramp rate of the resource. When the unit fails to comply, the system runs a deficit

1 This can be true for the economic deviations, however, which can cause other units to increase or decrease output apparently out-of-merit to compensate for the economic deviation.

(surplus) in that interval relative to the desired dispatch quantity. In subsequent intervals, SCD will continue to assume the unit will move toward its economic dispatch point at the unit's ramp rate. This deficit (surplus) can, therefore, continue indefinitely until the unit finally responds or its prices change such that its economic dispatch point moves toward its actual output.

To compensate for the deviation, the NYISO will deploy regulation resources to maintain the balance between supply and demand. To the extent that regulation is not effective and an imbalance occurs, it will be evidenced in ACE. When ACE is sustained, operators will call a reserve pickup to attempt to bring the system back into temporary balance.

Price is affected by the deviation because, had the dispatch software recognized the deviation when it solved, the software would have dispatched other generation and the price would be determined by the generating resources that were truly marginal. In the case of dragging for example, resetting the dragging unit's dispatch point to its actual output would cause additional blocks of generation to clear and raise the price. Over-production would have the opposite effect on prices. The impact of generation deviations on prices will be related to both the extent of dragging and the tightness of the market (i.e., the slope of the supply curve). Large quantities of dragging during high load periods will tend to have the greatest impact. With over-production, the impact will be both on potential price and the opportunity costs incurred by regulation units that must reduce output.

B. The Magnitude of the Issue

We examined a year of data, from May 2003 through April 2004 to determine the extent and timing of the generation deviations. We split the data into four groups, organized with respect to the peak demand experienced each day: 75 days with peak demand under 19,000 MW, 122 days between 19,000 MW and 21,000 MW, 87 days between 21,000 MW and 23,000 MW, and 78 days with peak demand greater than 23,000 MW (the days during the blackout in August were excluded).

We also split the data between steam generators, combined cycle units, hydroelectric and pump storage units which are dispatched, gas turbines (since all GTs are treated as if dispatched), and units on automatic generation control (AGC). We averaged interval data to obtain the average hourly deviations, since the issue relates to *persistent* deviations from dispatch instructions.

Extremely short-term fluctuations in deviations are expected in a well-functioning system and should not have a substantial impact on prices over the day.

In actual operation, these short-term deviations are inevitable. Units experience unexpected operational problems, dispatch commands to certain units may be delayed due to communication problems, and there may be short-term lags in response to dispatch commands for units that lack sophisticated communication equipment and operational controls. We would expect these "background" deviations to vary proportionally with (a) the number and capacity of units on line and (b) the speed with which the system is ramping. With regard to the ramping of the system, the deviations should be negatively correlated with the direction of the ramping, for example, if there are a number of units ramping at their maximum ramp rate, they are unlikely to raise production faster than ordered, but some are likely to raise output at a slower rate than dispatched.

Given that the committed capacity of units on AGC, dispatchable steam units, hydroelectric units, and GTs normally varies between 4,000 and 10,000 MW, a 1% fluctuation in either direction would suggest a range of 40-100 MW of gross deviations, with an expected net deviation from dispatch substantially less since the positive and negative deviations all cancel one another. Off-dispatch units do not cause generation deviations because the SCD assumes that their actual output is their desired generation level, even when their actual output is significantly different than their hourly schedule.

Deviations by Load Level

The tables below show the frequency of the net deviations and gross deviations over the year studied. These tables indicate the frequency of the deviations by load level and magnitude of the deviations.

Frequency of Net Deviations of Various Magnitudes

Net Deviation	< -100 MW	< -50 MW	-50 to 50 MW	> 50 MW	> 100 MW
Total Hours	177	1206	5769	1306	211
Hours with Load > 20,000 MW	80	452	1331	286	60
Hours Δ Load > 500 MW	131	680	1101	125	29
Hours Δ Load < -500 MW	18	97	1213	689	127

Frequency of Gross Negative Deviations of Various Magnitudes

Gross Deviation	< -250 MW	-200 to -249 MW	-150 to -199 MW	- 100 to -149 MW	> -100 MW
Total Hours	18	98	576	2588	5399
Hours with Load > 20,000 MW	10	74	343	960	822
Hours Δ Load > 500 MW	10	70	321	904	761
Hours Δ Load < -500 MW	5	14	100	543	1482

Frequency of Gross Positive Deviations of Various Magnitudes

Gross Deviation	> 250 MW	200 to 249 MW	150 to 199 MW	100 to 149 MW	100 MW <
Total Hours	32	99	591	2648	5309
Hours with Load > 20,000 MW	15	0	354	792	1048
Hours Δ Load > 500 mW	11	3	128	499	1425
Hours Δ Load < -500 mW	14	45	289	982	814

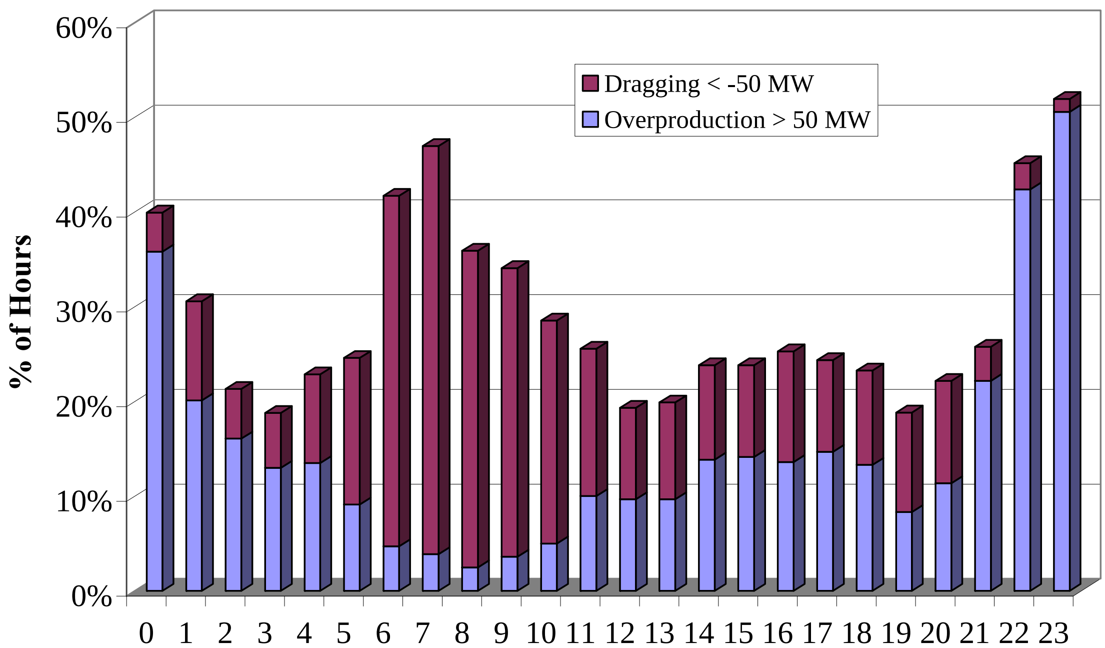
The conditions triggering negative deviations seem to be hours with rapid ramping-up of units, with a similar trend noted for over-production during periods when units were being ramped downward rapidly. Because many units fluctuate between over-production and under-production, large net deviations in either directions are relatively rare occurrences, with less than four hundred hours where net generation differed by more than 100 MW from the dispatch target (out of 15-20,000 MW of total generation).

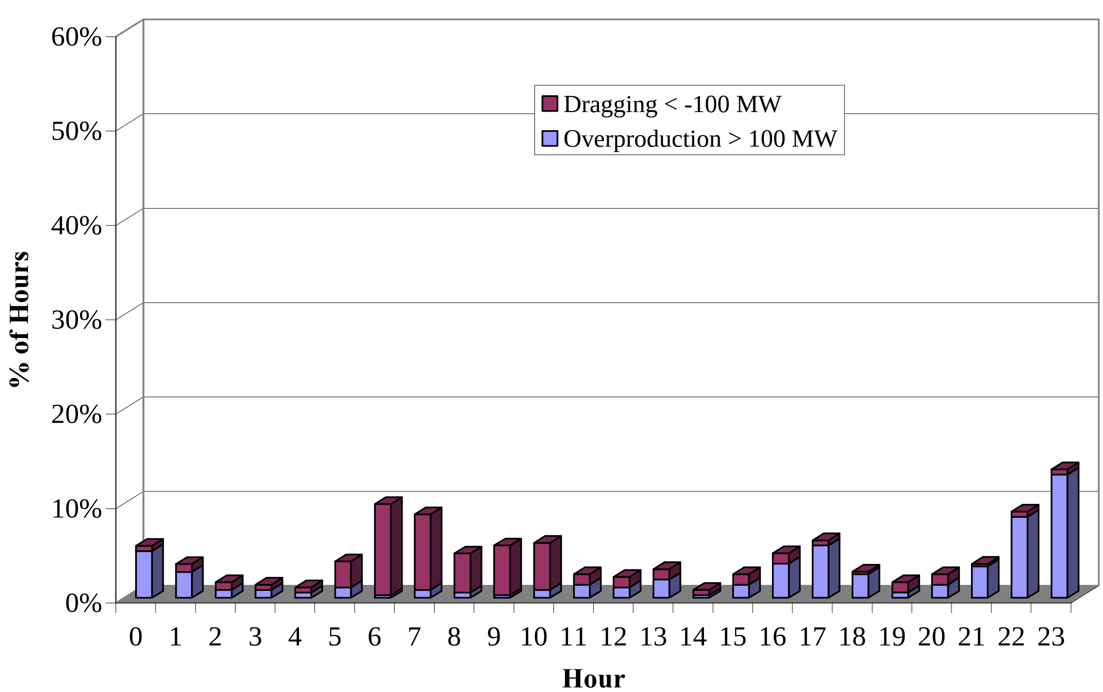
While net deviations of 50-100 MW above or below desired dispatch were fairly common, these would be expected to have only minor impacts on market prices, and such impacts could be considered acceptable as "workable efficiency," since the cost of eliminating small deviations from dispatch would probably outweigh any gains from increased efficiency. The sum of gross deviations from dispatch in either direction exceeded 250 MW for only 50 hours, and 200-250 MW on 197 hours (some of which experienced large deviations in both directions).

Deviations by Time of Day

To better understand the nature of the deviations, we next analyze when deviations occur. The following charts show the percent of hours with net deviations by hour of the day

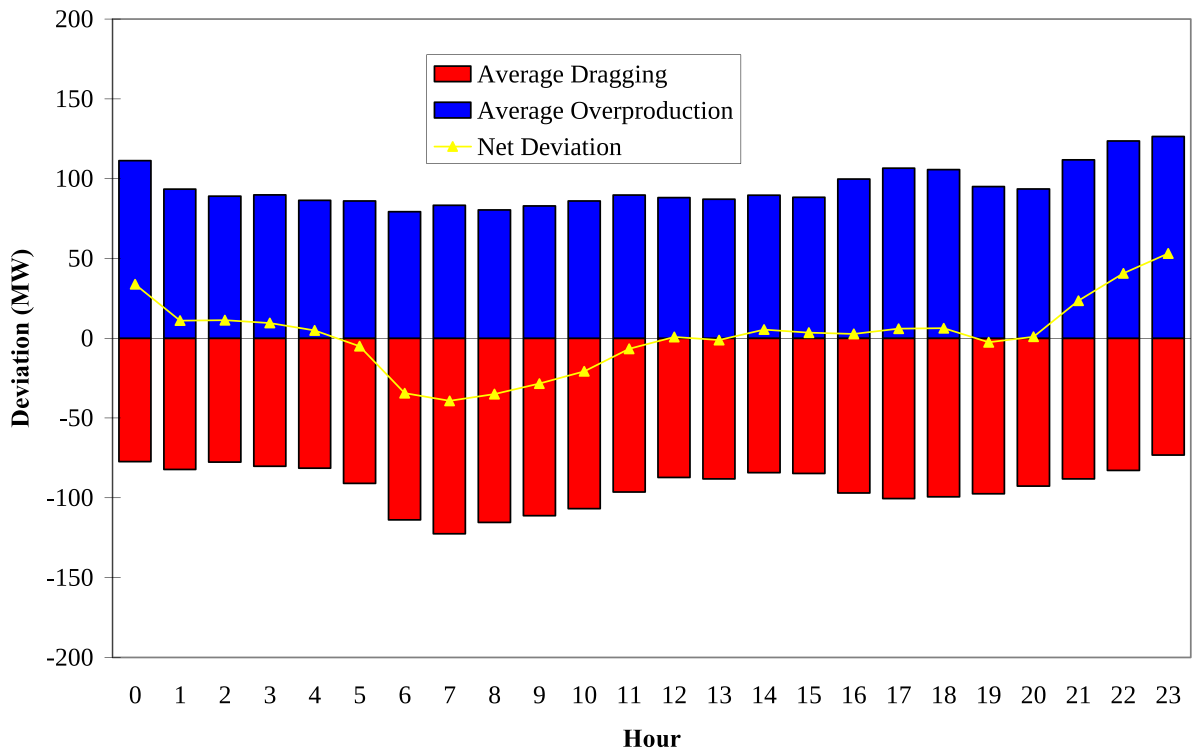
Net Deviation by Hour of Day

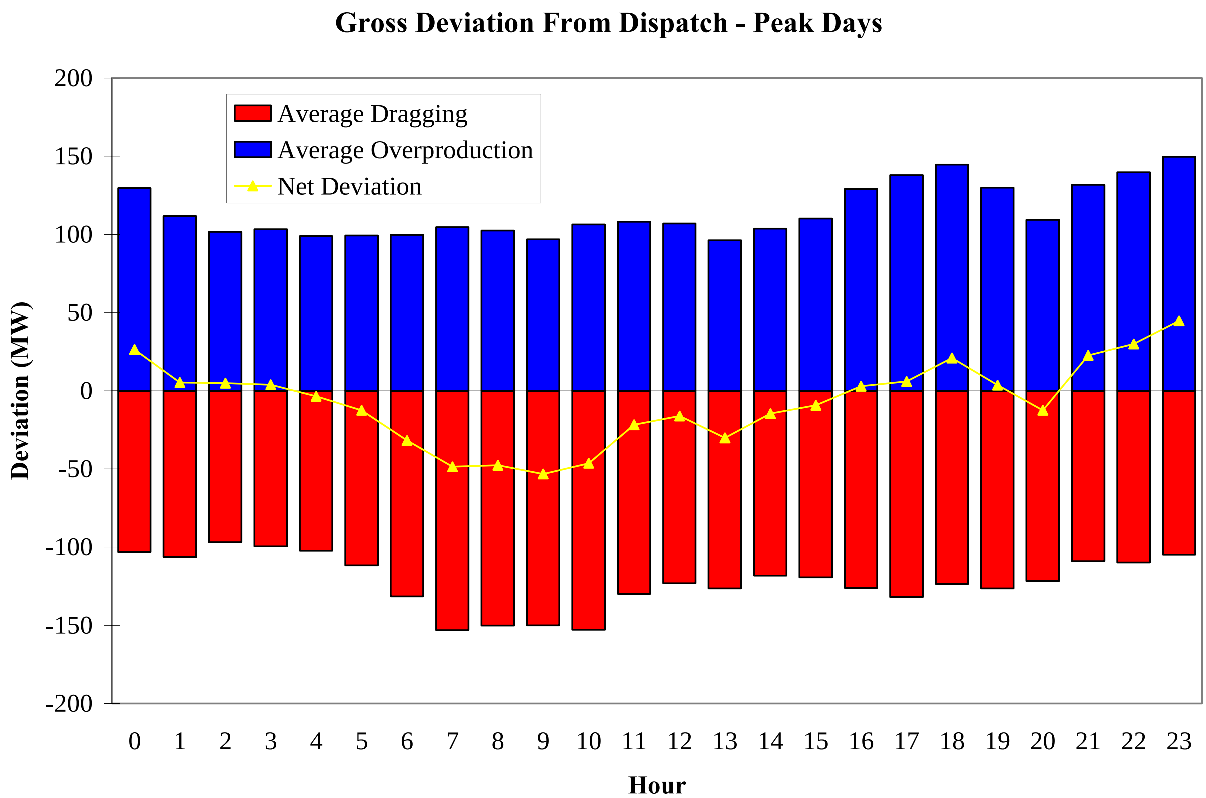




The hours with large net deviations from dispatch tend to be distributed in a systematic fashion. Hours with substantial net dragging were those associated with ramping up, including the hours from 5 AM to 11 AM. The hours with the largest over-production occurred in the late afternoon and just before midnight. However, during the days with the highest peak load (peak load > 20,000 MW), the peak dragging quantities were concentrated in the period from 8 AM to 11 AM, while the highest over-production hours were between 4 PM and 7 PM.

Gross Deviation From Dispatch - All Days





As predicted, both over-production and dragging increased on high load days in all hours. This suggests that one component of deviation from dispatch is simply related to the quantity of resources that are being dispatched, i.e., the higher the dispatch level, the greater the sum of deviations in each direction.

The increase in gross dragging on high load days is larger than the increase in over-production. This may reflect the fact that the generation units that are dispatched on high load days tend to be older, less efficient units that are less likely to respond to dispatch signals reliably.

Deviations by Type of Unit

The next analysis evaluates the generation deviations by type of unit. This analysis is important for understanding the causes of the deviations, which can be completely different for different types of units. The results of this analysis are presented in the following table.

Types of Generators Responsible for Generation Deviations

	Total Output (MWH)	Cumulative Over-production	Cumulative Dragging
All Dispatched Units*	67,939,003 (% of total)	933,383 (1.4%)	970,375 (1.4%)
All Fossil Fuel Dispatched Units	49,788,656	768,851 (1.5%)	630,042 (1.3%)
Steam Units	45,320,304	720,456 (1.6%)	552,550 (1.2%)
CC Units	1,809,432	40,412 (2.2%)	33,133 (1.8%)
Gas Turbines	2,658,919	7,982 (0.3%)	44,359 (1.6%)

* Includes hours when steam units were providing AGC.

This table shows that fossil-fired steam units are generally the primary source of dispatch deviations. The second largest source of generation deviations is is hydroelectric and pump storage units. Those that are dispatchable generally have very high ramp rates and provide a substantial amount of regulation.

The change in the treatment of gas turbines such that only a turbine that fails to generate up to 75% of its capacity will be counted as dragging has reduced their role in causing deviations from dispatch. Only one GT is large enough and operates often enough to provide a significant contribution to cumulative deviations, and it still doesn't rank among the top 30 fossil units in terms of deviations from dispatch. GTs as a group are a minor factor, though their effect is almost completely limited to dragging, since they tend to operate at full capacity when they do respond to dispatch signals. Combined cycle units are also a minor contributor, primarily because most prefer to self-schedule and are not dispatchable.

Deviations by Resource

Finally, we evaluated how widely distributed the deviations are among the individual generating resources to determine whether certain units exhibit unusually poor performance and account for a large share of the total generation deviations. These results of this analysis are presented in the following table.

Share of Deviation Due to Units with Largest Deviations

	5 Units with Largest Deviations	5 Steam Units with Largest Deviations	10 Steam Units with Largest Deviations
Dragging Results			
Net Deviation < -50 MW			
% Gross Negative Deviation	33.8	23.5	37.0
% Net Negative Deviation	67.1	46.7	73.3
Net Deviation < -100 MW			
% Gross Negative Deviation	35.8	28.0	41.2
% Net Negative Deviation	58.3	45.7	68.1
Net Deviation < -50 MW And Load > 20,000 MW			
% Gross Negative Deviation	31.7	25.7	39.7
% Net Negative Deviation	67.8	55.0	84.8
Over-Production Results			
Net Deviation > 50 MW			
% Gross Positive Deviation	27.3	22.1	38.0
% Net Positive Deviation	52.8	42.7	73.4
Net Deviation > 100 MW			
% Gross Positive Deviation	30.3	23.2	38.7
% Net Positive Deviation	47.7	36.5	61.0
Net Deviation > 50 MW And Load > 20,000 MW			
% Gross Positive Deviation	32.0	27.2	44.9
% Net Positive Deviation	74.5	63.2	104.4

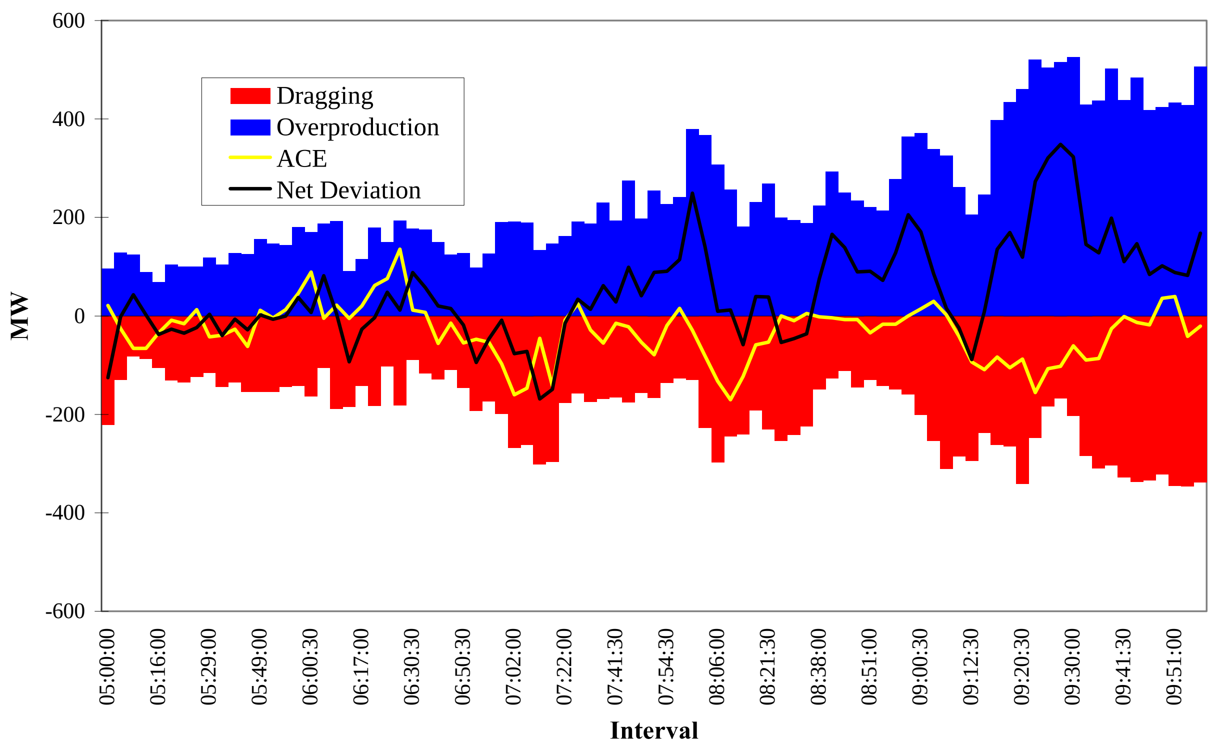
This table shows that the steam units with the largest deviations account for a significant portion of gross dragging and over-production. For example, the 10 steam units with the largest deviations over the year represent approximately 40 percent of the gross deviations under all of the conditions shown. As a percent of the net deviations, these units account for 60 percent to more than 100 percent of the deviations. When load is the highest and prices are most sensitive to deviations, the table shows that the top 10 steam units account for 85 of the net deviations when the system is dragging by more than 50 MW and 104 percent of the net deviations when the system is overproducing by more than 50 MW. The corresponding statistics for the top 5 steam units range from 37 percent to 63 percent of the net deviations.

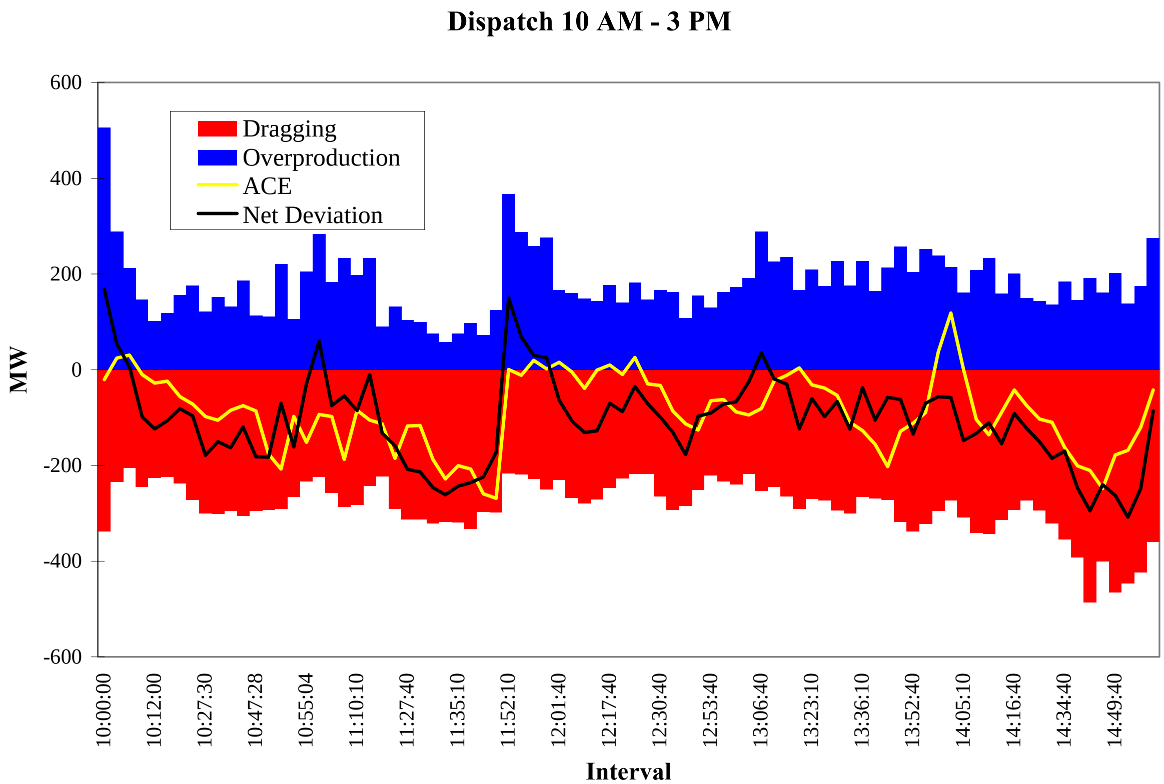
When other types of units are considered, the five units that exhibit the largest deviations over the year account for 58 to 68 percent of the net negative deviations (i.e., dragging amounts), and 48 to 75 percent of the net over-production. These results indicate that by focusing on a limited number of units, the NYISO may be able to substantially reduce the net generation deviations and associated effects on market prices.

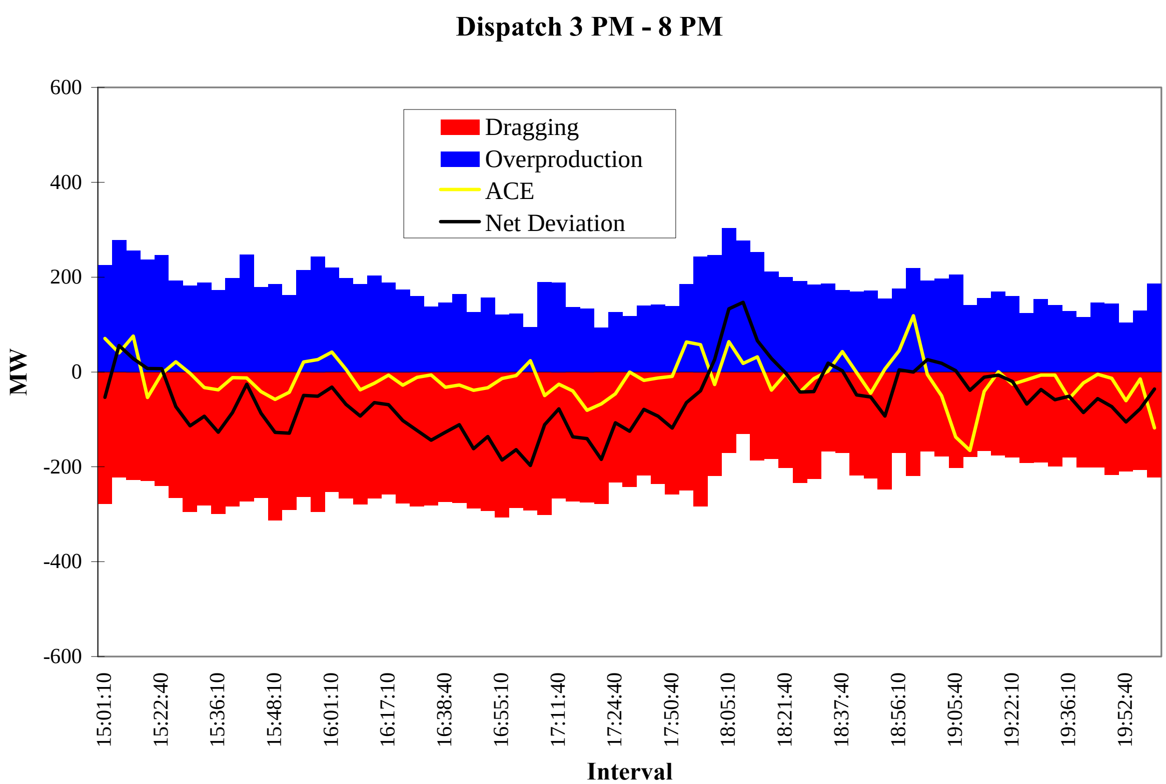
C. Case Study: August 21, 2003

To show how deviations occur on a specific high-load day, we examined the patterns of generation deviations on August 21, 2003. This day was among the highest load days during the summer 2003 (peak demand exceeded 28,000 MW) and was selected because it exhibited relatively high generation deviations. The following four figures show the gross over-production and dragging on an interval basis from 5 a.m. to Midnight. These figures also show the net deviation and ACE in each interval.

Dispatch: 5 AM to 10 AM




Dispatch 10 AM - 3 PM
Dragging
Overproduction
ACE
Net Deviation
MW
600
400
200
0
-200
-400
-600
10:00:00
10:12:00
10:27:30
10:47:28
10:55:04
11:10:10
11:27:40
11:35:10
11:52:10
12:01:40
12:17:40
12:30:40
12:53:40
13:06:40
13:23:10
13:36:10
13:52:40
14:05:10
14:16:40
14:34:40
14:49:40
Interval


Dispatch 3 PM - 8 PM
Dragging
Overproduction
ACE
Net Deviation
MW
600
400
200
0
-200
-400
-600
15:01:10
15:22:40
15:36:10
15:48:10
16:01:10
16:17:10
16:38:40
16:55:10
17:11:40
17:24:40
17:50:40
18:05:10
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18:56:10
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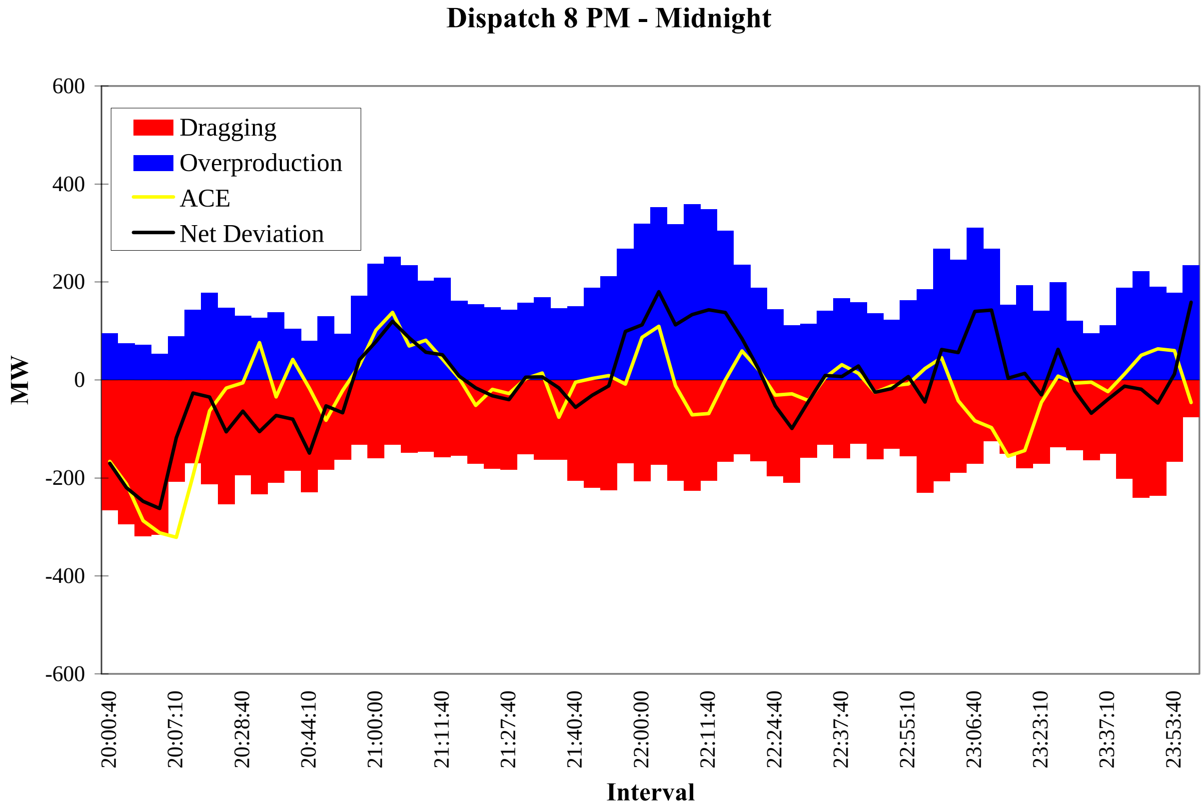
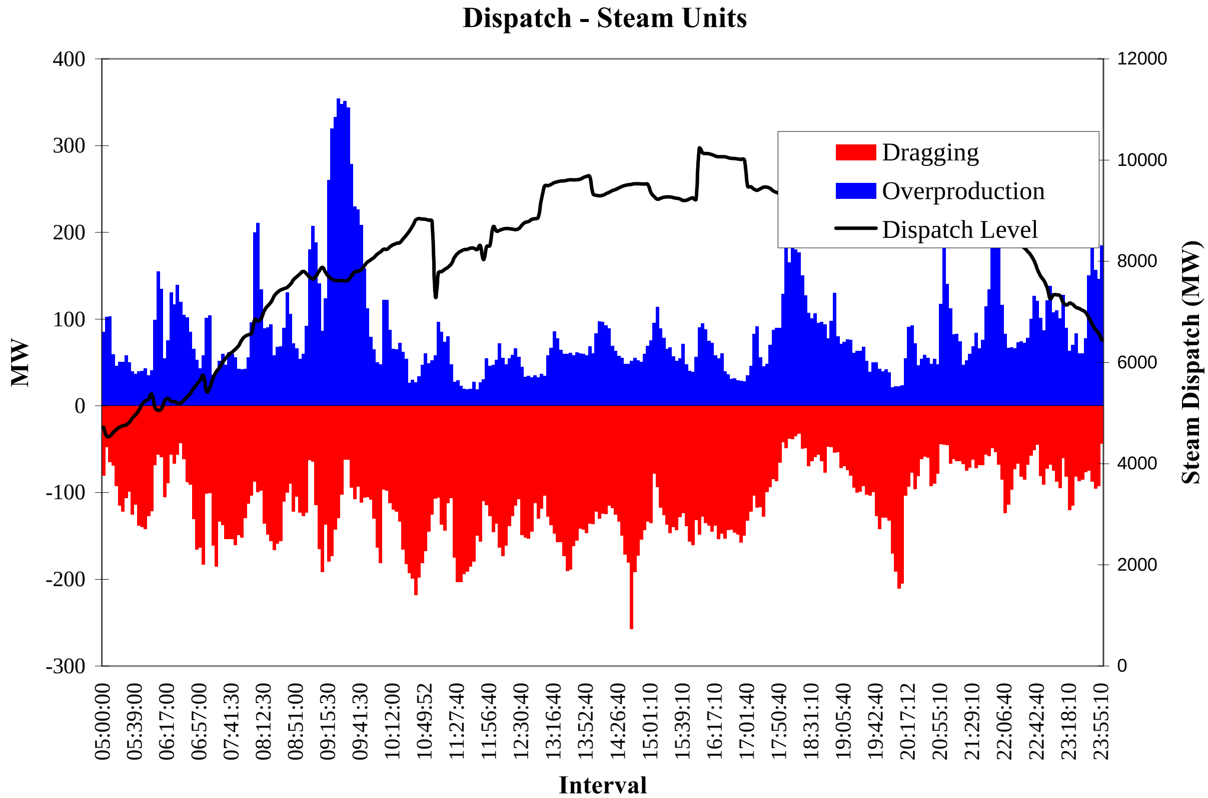
19:22:10
19:36:10
19:52:40
Interval



On this day, the net deviation was positive during the morning ramp hours in contrast to the average deviations over the entire year. For the remainder of the day, the net deviations generally ranged from -200 MW to 200 MW. During the peak afternoon hours from 1300 to 1700, the system was dragging in most intervals. The dragging peaked at almost -400 MW, which is large enough to have a significant effect on New York's energy prices. The fact that the system was dragging over such an extended period confirms that the NYISO has limited options currently for eliminating the dragging. This report recommends changes in the short-run and longer-run to addressing dragging and over-production when it persists.

These figures also show that the ACE is correlated with the net deviations. This indicates that the deployment of regulation is not always effective in addressing generation deviations. If it was perfectly effective and the deviations were never larger than the quantity of regulation maintained, the ACE would be very close to zero. It is not perfectly effective, which causes the ACE to rise and fall as the generation deviations rise and fall.

The final analysis in this subsection shows the gross deviations on this day for on-dispatch steam units. This analysis is shown below in the following figure together with the total dispatch level for the steam units.



On this day, the steam units accounted from approximately half of the net dragging that occurred. Typically, the steam units account for a much higher share of the dragging. This figure also shows that as the dispatch level rises, the dragging quantities tend to exceed the over-production quantities. Based on our analysis of the largest contributors to the deviations, the net deviations on this day would, in fact, have been substantially eliminated by derating a limited number of the steam units that were dragging.

III. The Role of Physical and Economic Base points in New York

As described in the introduction, New York currently determines physical base points starting from the actual output of the resources while the economic base point is determined based on past base points for the resource even if they are not responding (i.e., accumulating base points). The result of this process is that a generator deviating for multiple intervals from the ISO's dispatch instructions will result in an increasingly large difference between the physical base point and economic base point for the unit (i.e., economic deviation). When this economic deviation base point becomes large and negative, the physical dispatch will increase the output of other generators to compensate that may not be economic at the prevailing price. Hence, these units would generally be paid bid production cost guarantee payments, which would be reflected in the real-time uplift costs.[2] In this case, the price is understated relative to the bids of the units that are actually on the margin. Likewise, generators that are over-producing relative to their economic base point will cause other generators to be ramped down and prices to be overstated.

Under the current system, the calculation of prices can be inconsistent with the physical base points sent to the generators. This is a contributor to real-time uplift and can inefficiently affect prices in New York. It is impossible prior to SMD to determine the significance of this issue. However, the data is available under SMD to measure the economic deviations and fully evaluate the issue. In addition, SMD will provide more information to generators regarding the likely dispatch path over future intervals, which should address one of the reasons why some generators did not always follow the SCD dispatch signal. I recommend such an evaluation be performed after the first six months of operation under SMD to evaluate the economic deviations.

In the long-run, prices and physical dispatch signals should be consistent to the maximum extent possible. However, the accumulating base points in the pricing model is important in determining when gas turbines should be eligible to set prices. However, it may be possible to modify the pricing model in a manner that preserve the hybrid pricing logic for the gas turbines, but increase the consistency of the pricing model with the non-accumulating base points in the physical dispatch.

Improving the consistency of the physical dispatch and pricing methodologies would also reduce real-time uplift costs by not dispatching certain generators economically out-of-merit (i.e., dispatching higher on their offer curves than the levels corresponding to the prevailing prices) in response to other generators producing below their economic base points.

2 These obligations are calculated over the 24 hours in the day so a unit that had earned revenues above its offer prices may not be held harmless for being dispatched above its economic level.

It is important to recognize that ex-post pricing would not solve this problem because it is inconsistent with the hybrid pricing methodology. Ex-post pricing is very similar to using non-accumulating base points for both physical dispatch and pricing. This approach was initially used by the New York ISO, but it does not accurately determine when GTs should set LBMPs. Using non-accumulating base points for pricing can cause gas turbines to appear needed and economic when they are not. This occurs when steam units and other lower-cost resources are ramped-down to make room for the dispatch of block-loaded gas turbines, causing them to operate well below their economic level. Because the steam units have limited capability to ramp up over the next 5 minute interval, the gas turbines can appear to be economic only because the rest of the economic output of the steam units is physically unavailable due to ramp rate restrictions. In addition, ex-post pricing makes other inefficient price adjustments relative to comparable ex-ante prices.

IV. Conclusions

Based on the analysis in this report, we conclude that generation deviations (from physical base points) are not a significant problem in most hours. Nevertheless, in some hours deviations can have a significant effect on the market outcomes, particularly under high load conditions when prices are more sensitive to the deviations. In evaluating and prioritizing the potential changes that could be made to limit the deviations and their associated price effects, we must balance the significance of this issue with the costs of the options to address it.

One important result that bears on this assessment is the fact that roughly two thirds of the net deviation could be eliminated by focusing on the 5 resources with the largest deviations on an annual basis. Hence, the deviations are concentrated in a relatively small number of generators. Because this is the case, we recommend in the short-term that the NYISO operators focus on the units that tend to deviate most on an annual basis and any other resources exhibiting substantial deviations in an hour. By focusing on this limited number of units, the operators can derate the units that are dragging significantly when the system is dragging on net, which will improve the SCD dispatch and resulting prices. Although implementing such an approach generally could reduce the capability available from online units that could otherwise be dispatched (and potentially reduce reliability), implementing this approach for a very limited number of units should not raise these concerns.

In the longer-term, we recommend that deviations be tracked by zone and the NYISO consider the feasibility of allowing the operators to make adjustments to the modeled load in the zone to compensate for the deviations and improve the control of the system. In other words, if the generators in New York City are dragging by 150 MW, the load in NYC could be increased in the next interval by 150 MW to cause the model to increase the output of the generation to compensate for the deviation and reduce the reliance on regulation. This approach should also reduce the ACE, regulation deployments, and the reliance of the operators on reserve pickups. This approach would need to be carefully evaluated to determine its impact on settlements, total market costs, and the incentives of the generators.

We also recommend that the NYISO should comprehensively review the incentives and penalties facing generators to evaluate whether the incentives to respond to the NYISO dispatch signals are adequate. For example, it may be reasonable for generators that are deviating to bear a share of the regulation costs since they are a primary reason that regulation is needed and deployed. However, such allocations tend to reduce the incentives for generators to remain on-dispatch. These considerations need to be carefully balanced to ensure that generators have adequate incentives to provide the flexibility the system needs by being on-dispatch, while following the NYISO's dispatch signals to the extent possible.

Finally, we believe it is important to evaluate the issues related to the economic deviations that are inherent in the current physical dispatch and pricing methodologies once we have accumulated the necessary data and experience under the SMD markets. As part of this evaluation, I recommend that the NYISO consider the feasibility and costs of alternative means for improving the consistency of the physical and economic base points. One alternative to consider is the use of non-accumulating base points in the pricing model for any generator that is not following the NYISO's dispatch instruction over multiple intervals.