# RTC-RTD Convergence Study

A Report by the
New York Independent System Operator

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# Table of Contents

# List of Figures

## Purpose

In a well-functioning, competitive wholesale energy market, price convergence between Day-Ahead (DA) and Real-Time (RT) markets is important to support efficient resource commitment and dispatch. Price convergence is demonstrated when the difference between DA and RT prices is minimized, providing an indicator of the efficiency of the underlying RTO/ISO energy market.

Real-time pricing in the competitive wholesale energy market administered by the New York Independent System Operator (NYISO) is developed using separate real-time commitment (RTC) and real-time dispatch (RTD) algorithms. Efficient real-time pricing is dependent on tight coordination of these two algorithms. One way to measure the efficiency of the RTC and RTD algorithms is to measure the price convergence between these algorithms.

Price convergence is frequently reviewed and analyzed by the NYISO's Market Monitoring Unit (MMU) Potomac Economics.[1] The MMU's 2016 State of the Market (SOM) includes a recommendation to evaluate modeling inconsistencies between the RTC and RTD to identify variations that drive real time price volatility. The purpose of this paper is to identify the primary causes of systemic divergence between the RTC and RTD prices through data analysis and, based on the results, to provide recommendations that can be implemented to improve price convergence between the RTC and RTD. This paper is focused on analyzing conditions, factors and drivers that cause price divergences between the RTC and RTD, and determining which drivers are systematic (frequently occurring) and significant. This paper also reviews recent market design enhancements that have improved RTC-RTD price convergence and future planned projects that are expected to further improve RTC-RTD price convergence.

## Background of NYISO Market Systems

Today, the NYISO administers and settles DA and RT energy markets. Both markets have the same objective—to minimize production cost, subject to constraints driven by the physical characteristics of supply, load and the transmission system. The DA market establishes physical supply (including unit commitment), virtual transaction, external transaction and price sensitive load schedules in order to meet load. It also establishes operating reserve and regulation service requirements. The unit commitment decision for each hour established by the DA market is passed to the RT market system. Because RT prices are set based on RT market and systems conditions, RT

[1] See Potomac Economics State of the Market Analysis

prices often times vary from DA prices due to changes in operation, different resource availability, different real-time offers, and variations in actual load from the load that was predicted DA. A degree of price volatility is expected in the RT market.

The RT market system includes two separate programs, RTC and RTD, which are each described below. The RTD prices often times vary from the RTC prices due to changes in operation, availability of resources, and variations in actual load from the load that was predicted by the RTC. Permitting volatility to be reflected in RT locational based marginal prices (LBMPs) provides appropriate price signals when the RTD is responding to system conditions and events that the RTC did not anticipate. Price differences also occur because the RTC and RTD programs have different optimization horizons, as each program serves a different purpose. The other factor that differs between the two programs is that the RTC evaluates and schedules external transactions (hourly and intra-hourly), while the RTD sees external transactions as fixed injections or withdrawals.

### Real-Time Commitment (RTC)

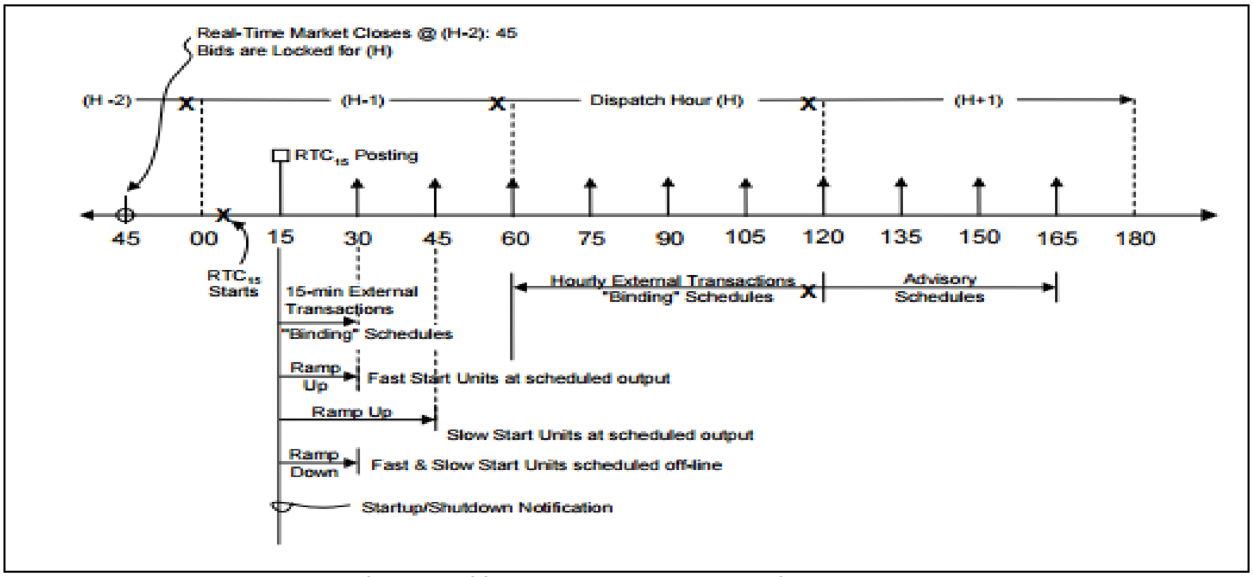
The RTC runs every fifteen minutes and looks ahead two-and-a-half-hours while simultaneously co-optimizing energy, operating reserves and regulation service on a least production cost basis over its optimization horizon. The RTC honors DA commitments for internal generators and is responsible for making unit commitment decisions for 10- and 30-minute quick start units. It also determines schedules for hourly and intra-hourly external transactions.

Unit commitment and economic dispatch are modeled and solved in the RTC using mixed-integer programming (MIP) and linear programming (LP) respectively. The solution from MIP establishes unit commitments for quick start units and the solution from LP establishes schedules and prices. Economic dispatch is run in two steps, the "physical dispatch" which is used to determine the schedules and the "ideal dispatch" which is used to establish LBMPs and ancillary service prices.

The RTC model conducts a look-ahead evaluation across a two-and-a-half-hour time horizon, posting results every fifteen minutes. The RTC begins its run thirty minutes prior to the actual operating period for which prices and schedules are established. Each RTC run contains a designation indicating the time at which results are posted, "$RTC_{00}$", "$RTC_{15}$", "$RTC_{30}$", and "$RTC_{45}$". The posting of results for each RTC run occurs fifteen minutes before the actual operating period.

The $RTC_{15}$ produces unit commitment instructions for periods beginning fifteen minutes (for 10-minute quick start units and variably scheduled external transactions) and thirty minutes (for 30-minute quick start units) after its scheduled posting time and produces advisory schedules for the remainder of the optimization period. The $RTC_{15}$ also establishes external transaction schedules for hourly external transactions. Figure 1 illustrates the $RTC_{15}$ timeline.

**Figure 1: Real-Time Commitment Timeline**



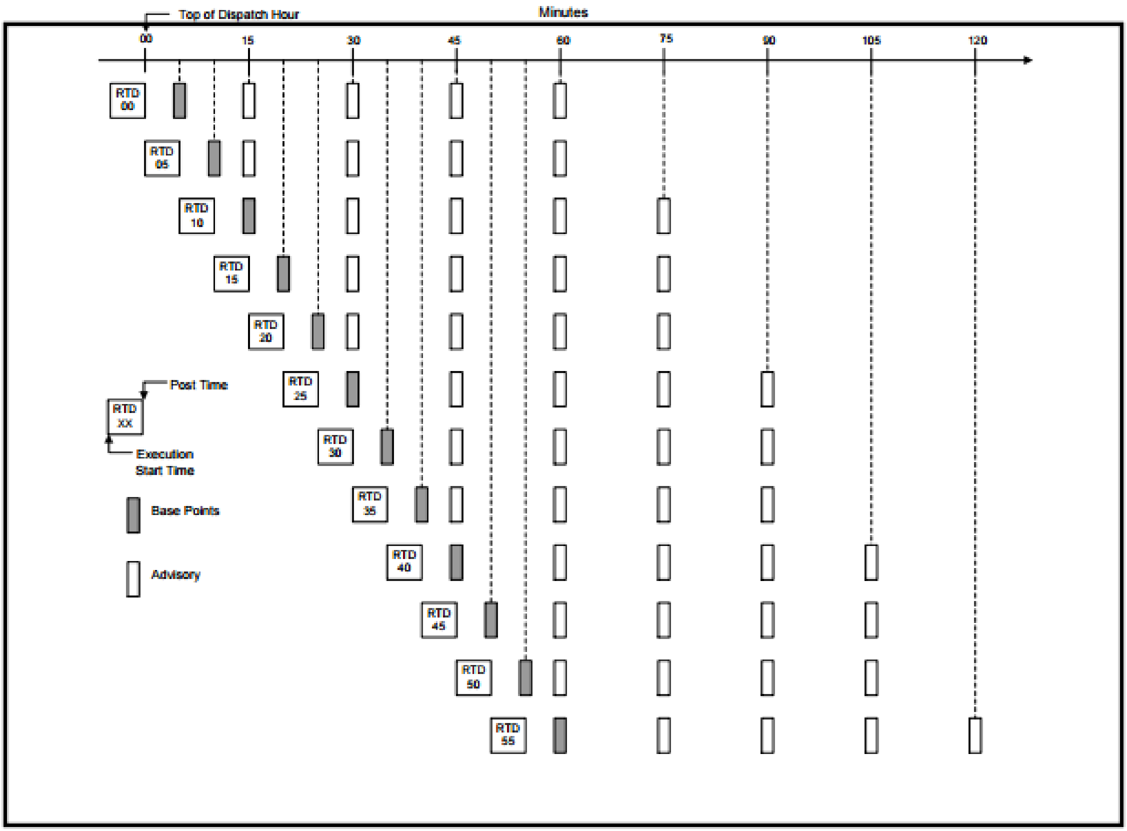

Source: NYISO Transmission and Dispatching Operations Manual

## Real-Time Dispatch (RTD)

The RTD runs nominally every five minutes dispatching units, sending base point signals to internal suppliers, and calculating real-time market LBMPs and clearing prices for operating reserves and regulation service. The RTD uses the unit commitment decisions, offers and external transaction schedules from the RTC. The RTD simultaneously co-optimizes energy, operating reserves and regulation service on a least production cost basis over its optimization horizon of roughly one hour.

The RTD uses LP to dispatch resources and develop a least production cost solution. Using the same algorithm as the RTC, economic dispatch is run in two steps, the “physical dispatch” which is used to determine the schedules and the “ideal dispatch” which is used to establish energy, operating reserve, and regulation service prices. The real-time market is settled on the LBMP’s from the RTD’s ideal dispatch pass. Each RTD’s five minute run produces binding schedules for the next five minutes and advisory schedules for the remaining four fifteen-minute periods of its optimization period. Figure 2 illustrates the timeline of RTD runs for one hour.

Figure 2: Real-Time Dispatch Timeline



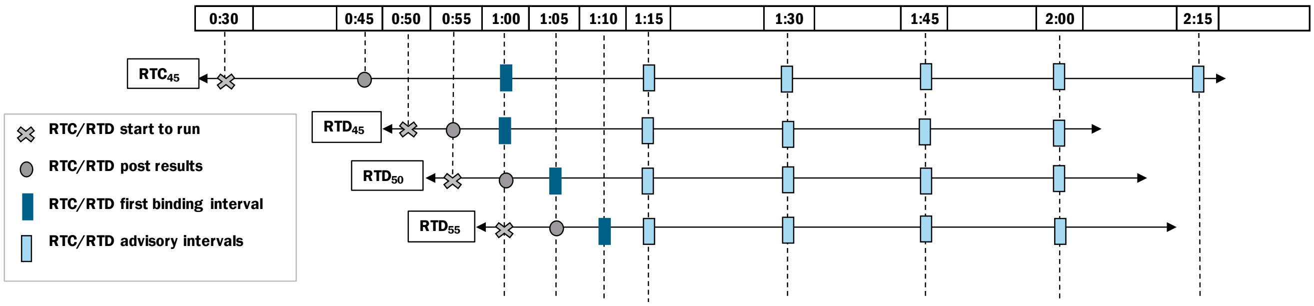

Source: NYISO RTD Formulation Document

### Coordinating RTC and RTD

The RTC and RTD generally have the same information regarding the solution set available. However, forecasts of load and wind, interchange schedules, phase angle regulator (PAR) flows, generator performance, and system topology can change, sometimes considerably, between the two programs.

Both programs produce LBMPs; however, the real-time market is settled using the RTD LBMPs. Each program evaluates system inputs on a different optimization horizon. The RTC runs every fifteen minutes and the RTD runs nominally every five minutes, so one RTC interval generally corresponds to three RTD intervals. The RTC initializes thirty minutes prior to the actual operating period, whereas the first RTD corresponding to that RTC initializes ten minutes prior to the actual operating period. Figure 3 illustrates the timing and coordination between RTC and RTD.

**Figure 3: RTC-RTD Timeline**




There is an inherent latency attributed to the timing of the two real time evaluation programs in which the RTC program is initiated using expected system conditions developed thirty minutes prior to actual market operation, while the RTD initiates using more up-to-date system conditions. Therefore, the RTD may be required to adjust to address changes that occurred after the RTC initiated.

In these instances, the RTD prices can deviate from the RTC price. Deviation between the RTC and RTD prices is appropriate for such events. Unexpected events that may justify RTC-RTD price deviations include transaction cuts, generator trips, and line outages.

Example 1 illustrates an instance of an unexpected system event during which price divergence between the RTC and RTD was observed.

**Example 1**: For the quarter hour period that spans 13:15 to 13:30, RTC starts to run at 12:45 and results are posted at 13:00. The three corresponding RTD intervals that line up with this quarter hour period are 13:20, 13:25 and 13:30. These RTDs start to run at 13:10, 13:15 and 13:20 respectively.

If an unexpected system event, such as a line or generator trip or transaction cut, occurs after RTC initiated but before RTD initiates for an interval, then RTC's solution will not incorporate the unexpected event, but RTD will. In this circumstance RTD would respond to the event and the effect of the event would be reflected in the posted RTD price.

**Figure 4: RTC and RTD Price Path During an Unexpected System Event**

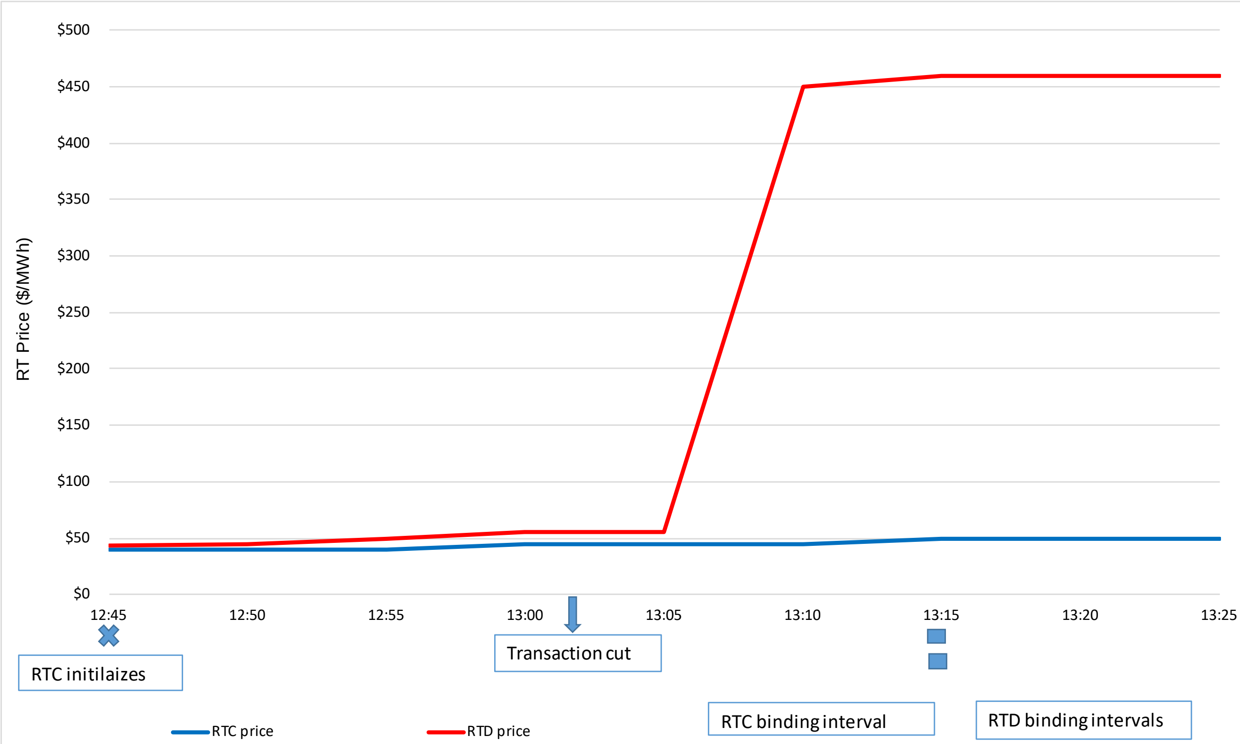


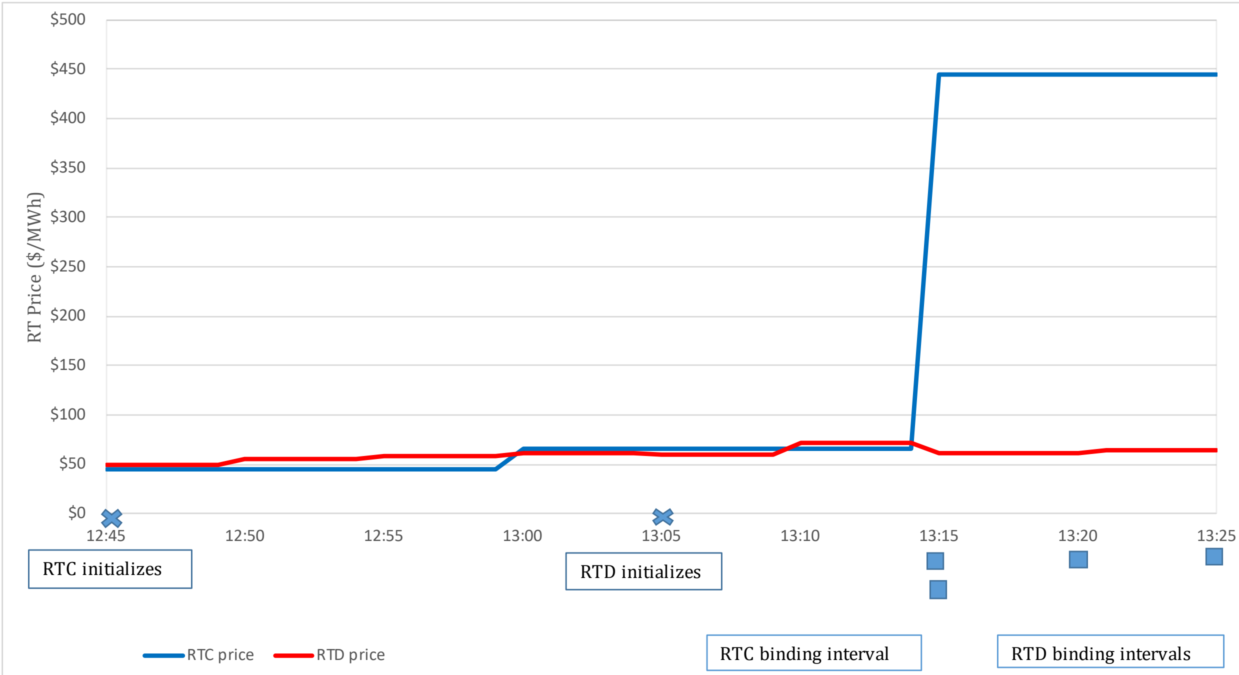

Figure 4 illustrates Example 1 described above. In Figure 4 RTD prices are higher than RTC prices due to an unexpected system event that occurred after RTC initiated but before RTD initiated for the 13:10, 13:15 and 13:20 time steps. Therefore, RTD is able to incorporate the unexpected event into the prices it develops.

There are also scenarios when RTC price can be higeher than RTD price. Example 2 illustrates one such secenario that was observed.

**Example 2**: For the quarter hour period that spans 13:15 to 13:30, RTC starts to run at 12:45 and results are posted at 13:00. The three corresponding RTD intervals that line up with this quarter hour period are 13:20, 13:25 and 13:30. These RTDs start to run at 13:10, 13:15 and 13:20 respectively.

If an unexpected generator or line trip occurs just prior to initializing the RTC and the issue is resolved within twenty minutes, then the RTD runs that are evaluating the same RTC operating period will have additional committed supply that is no longer needed but running to fulfill its minimum run time. This situation would result in the RTD having lower LBMPs than the RTC. Figure 5 illustrates Example 2 described above.

**Figure 5: RTC and RTD Pricing Path During a Reserve Shortage Event**




There could possibly be other scenarios when RTC prices are higher than RTD prices due to differences in the look-ahead timeframes over which each program optimizes, or differences between the RTC and RTD forecasted loads, or changes to external transaction schedules that occur following the initiation of RTC but prior to the initiation of RTD.

## Potomac Economics State of the Market Analysis

Potomac Economics is the NYISO's external Market Monitoring Unit (MMU). The MMU monitors the NYISO administered markets to identify conduct of Market Participants and/or market rules that may compromise the effectiveness of the market or may not produce appropriate or correct market outcomes. The MMU also issues quarterly and annual "State of the Market Reports" (SOM) that assess the performance of the NYISO's markets. As part of its annual SOM, Potomac Economics recommends proposed changes to the NYISO's market rules. In its SOM for 2016 the MMU recommended that the NYISO adjust the look-ahead evaluations RTD and RTC perform to make them more consistent with the timing of ramping to accommodate external transactions and gas turbine commitment.[2]

The MMU performed an analysis to determine the primary sources of real-time price spikes at locations across the NYCA where constraints frequently arise. The MMU's analysis examined real-time price volatility between five-minute RTD intervals. The analysis considered transmission constraint price spikes that occur when there is a shadow price that exceeds $150/MWh and that has increased by at least 100 percent from the previous interval. The analysis also addressed power balance constraint price spikes, which occur when the reference bus price exceeds $100/MWh and has increased by at least 100 percent from the previous interval. The price spikes the MMU studied only affected 5% of the RTD intervals in 2016. The MMU's analysis revealed that resources scheduled by the RTC , including external interchange schedules and gas turbine shutdowns, drove a significant portion of the real-time price spikes that occurred in 2016. The results are captured in Figure 6 below.

[2] 2016 SOM report page 83.

Figure 6: Potomac Economic Analysis of Real-Time Price Volatility

| | Power Balance | West Zone 230kV Lines | Central East | Dunwoodie - Shore Rd 345kV | Intra-Long Island Constraints |
|---|---|---|---|---|---|
| **Average Transfer Limit** | **n/a** | **711** | **1721** | **800** | **277** |
| **Number of Price Spikes** | **363** | **1101** | **242** | **318** | **965** |
| **Average Constraint Shadow Price** | **235** | **1239** | **352** | **373** | **464** |
| **Source of Increased Constraint Cost:** | **(%)** | **(%)** | **(%)** | **(%)** | **(%)** |
| **Scheduled By RTC/RTD** | **63%** | **6%** | **33%** | **66%** | **29%** |
| External Interchange | 32% | 6% | 14% | 37% | 7% |
| RTC Shutdown Resource | 24% | 0% | 11% | 24% | 14% |
| Self Scheduled Shutdown/Dispatch | 6% | 0% | 8% | 5% | 7% |
| **Flow Change from Non-Modeled Factors** | **5%** | **78%** | **50%** | **16%** | **64%** |
| Loop Flows & Other Non-Market | 1% | 50% | 18% | 10% | 21% |
| Niagara Generator Distribution | 0% | 11% | 0% | 0% | 0% |
| Fixed Schedule PARs (excl. Ramapo) | 0% | 11% | 22% | 4% | 43% |
| Ramapo PARs | 0% | 6% | 9% | 0% | 0% |
| Redispatch for Other Constraint (OOM) | 4% | 0% | 1% | 3% | 0% |
| **Load/Wind/Generator Derates** | **33%** | **17%** | **18%** | **18%** | **7%** |

Source: State of the Market Report 2016

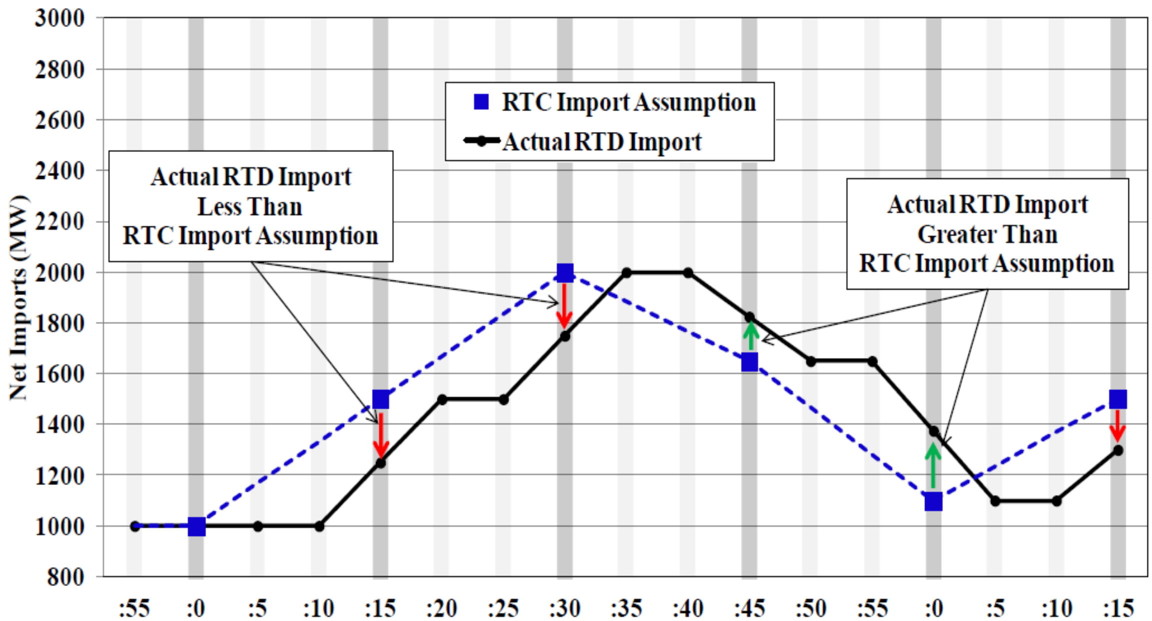
## Desired Net Interchange

The MMU also explored drivers of price divergence at the borders between New York and adjacent market area. Efficient external interface scheduling is important for several reasons; it allows access to external resources which can lower the cost of serving load in New York and lowers the cost of meeting reliability standards because neighboring systems can provide additional power in an emergency. Therefore, it is very important to achieve efficient transaction scheduling between New York and adjacent control areas. Convergence of prices between New York and the adjacent control areas is an indicator of efficient interface scheduling. Conversely, a pattern of price divergence between neighboring markets may indicate that transactions are not being scheduled efficiently.

External Transaction scheduling creates inconsistencies because the expected duration of the ramping periods differs between the RTC and RTD for external interchange schedules. Figure 7 below illustrates the ramp profiles assumed by the RTC and RTD for external transactions.

The RTC assumes external transactions start to ramp-in fifteen-minutes before the start of a quarter-hour interval and ramp up to their schedules by the beginning of the relevant quarter hour interval, while the RTD assumes that the external transactions start to ramp five minutes before the beginning of the quarter-hour interval and continue to ramp-in through the first five minutes of the interval. In other words, the RTD assumes the ramp occurs five minutes later than the RTC. The different ramp profiles lead to inconsistencies between the RTC and RTD that could contribute to differences between the RTC price forecast and actual five-minute RTD clearing prices.

**Figure 7: Potomac Economics Illustration of External Transaction Ramp Profiles**




Source: State of the Market Report 2016

# NYISO’s Study Analysis and Explanation of Results

### Study Approach

The goal of this study is to identify systematic divergences and extreme divergences (defined as 10 times the standard deviation of the entire dataset for each zone) between the RTC and RTD, and to develop an understanding of the frequency and significance of their occurrence. Price divergences between the two programs could be caused by a multitude of different factors. To better comprehend the contribution of different drivers of RTC-RTD price divergence, the NYISO performed a series of analyses, beginning with an LBMP analysis. This analysis served as the basis to narrow down the factors causing LBMP divergence. This section reviews the analytical methods the NYISO used to investigate and identify drivers of RTC-RTD price deviations.

An LBMP analysis was conducted to identify the magnitude and frequency of price divergences between the RTC and RTD. To further investigate the divergence patterns, the data is segmented by time-of-day to understand if the divergences that occur at certain times of the day are more pronounced due to specific drivers. The time-of-day analysis was further segmented to include extreme price divergences to understand the impact that higher magnitude price divergences had on the overall divergence patterns.

Following the time-of-day analysis, correlations between price divergences and various factors that could possibly drive RTC-RTD divergences were studied on a seasonal basis for three zones (West, NYC and Long Island).

### Quantifying the Frequency and Magnitude of Price Divergences

This analysis reviewed the frequency and magnitude of price divergence between the RTC and RTD. NYCA[3] price divergences were studied and the results are presented and discussed (see Figure 8). Additionally, the divergences in different zones such as West, N.Y.C and Long Island, and the PJAC interface (or PJM Keystone proxy bus) are also studied and the associated histograms are included in the appendix. A tabular summary of results is shown below (see Figure 9). The study was performed using data covering the period from July 2016 to June 2017. The prices used were taken from the RTC and RTD ideal dispatches.

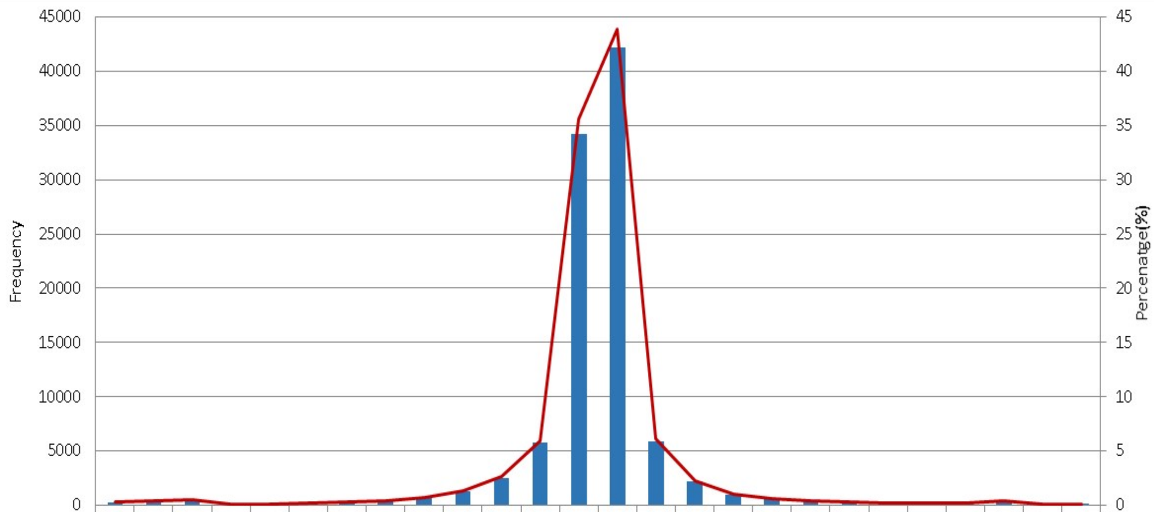
To understand the magnitude and frequency of the spread of price divergences between the RTC and RTD, histograms were utilized to observe if, on average, the RTC prices are higher than the RTD

[3] Throughout this report the NYCA price refers to the Marcy Bus price or Reference Price.

prices, or vice-versa.

Figure 8 shows a histogram of NYCA price divergences. This gives information on the percentage and frequency of price divergence between the RTC and RTD (RTC minus RTD) over all of the five-minute intervals in a year.

**Figure 8: Histogram Showing NYCA Price Divergences (RTC minus RTD) for a Year**




| | -570 to -200 | -200 to -100 | -100 to -50 | -50 to -45 | -45 to -40 | -40 to -35 | -35 to -30 | -30 to -25 | -25 to -20 | -20 to -15 | -15 to -10 | -10 to -5 | -5 to 0 | 0 to 5 | 5 to 10 | 10 to 15 | 15 to 20 | 20 to 25 | 25 to 30 | 30 to 35 | 35 to 40 | 40 to 45 | 45 to 50 | 50 to 100 | 100 to 200 | 200 to 570 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Percentage(%) | 0.2 | 0.4 | 0.5 | 0.1 | 0.1 | 0.2 | 0.3 | 0.4 | 0.7 | 1.3 | 2.5 | 5.7 | 34.2 | 42.2 | 5.9 | 2.2 | 0.9 | 0.6 | 0.4 | 0.3 | 0.2 | 0.2 | 0.1 | 0.4 | 0.1 | 0.0 |
| Frequency | 249 | 386 | 473 | 105 | 136 | 238 | 291 | 406 | 746 | 1335 | 2621 | 5965 | 3554 | 4387 | 6087 | 2239 | 972 | 615 | 407 | 290 | 218 | 159 | 148 | 398 | 60 | 50 |

In 76.4% of the time intervals, the price divergences are between $-5 and $5; 11.6% of the time the divergences are between $-10 and $-5 or between $5 and $10. Thus, 88% of the time the divergences are between -$10 and $10.

Between $10 and $100, and between -$100 and -$10, the percentage of intervals with positive divergences[4] are greater than the percentage of intervals with negative divergences,[5] by 0.21%. This trend of slightly more frequent positive divergences continues until the divergence exceeds $100/MWh or is less than -$100/MWh.

In general, all the zones follow a similar pattern as NYCA. Figure 9 summarizes the findings by

[4] "Positive" divergences occur when RTC prices are higher than RTD prices, including when RTC prices are less negative than RTD prices.

[5] "Negative" divergences occur when RTD prices are higher than RTC prices, including when RTD prices are less negative than RTC prices.

zones and locations that were analyzed.

**Figure 9: Summary of Histograms for Select NYCA Locations**

| RTC-RTD Price Divergence | $0 to $5 | -$5 to $0 | $5 to $10 | -$10 to -$5 | $10 to $100 | -$10 to -$100 | >$100 | >-$100 |
|---|---|---|---|---|---|---|---|---|
| Zone A (West) | 42.16% | 34.53% | 5.08% | 5.45% | 5.57% | 5.44% | 0.8% | 0.97% |
| Zone J (NYC) | 42.12 % | 31.14% | 7.71% | 6.1% | 5.7% | 6.15% | 0.12% | 0.96% |
| Zone K (Long Island) | 38.63% | 29.55% | 7.8% | 6.22% | 8.8% | 6.85% | 0.91% | 1.25% |
| PJAC (PJM Keystone) | 41.96% | 33.05% | 6.72% | 6.3% | 5.62% | 5.29% | 0.28% | 0.76% |
| NYCA | 42.18% | 34.17% | 5.85% | 5.73% | 5.24% | 6.11% | 0.11% | 0.61% |

Note: The histograms for each zone or location is shown in the appendix

### Time of Day Price Divergences

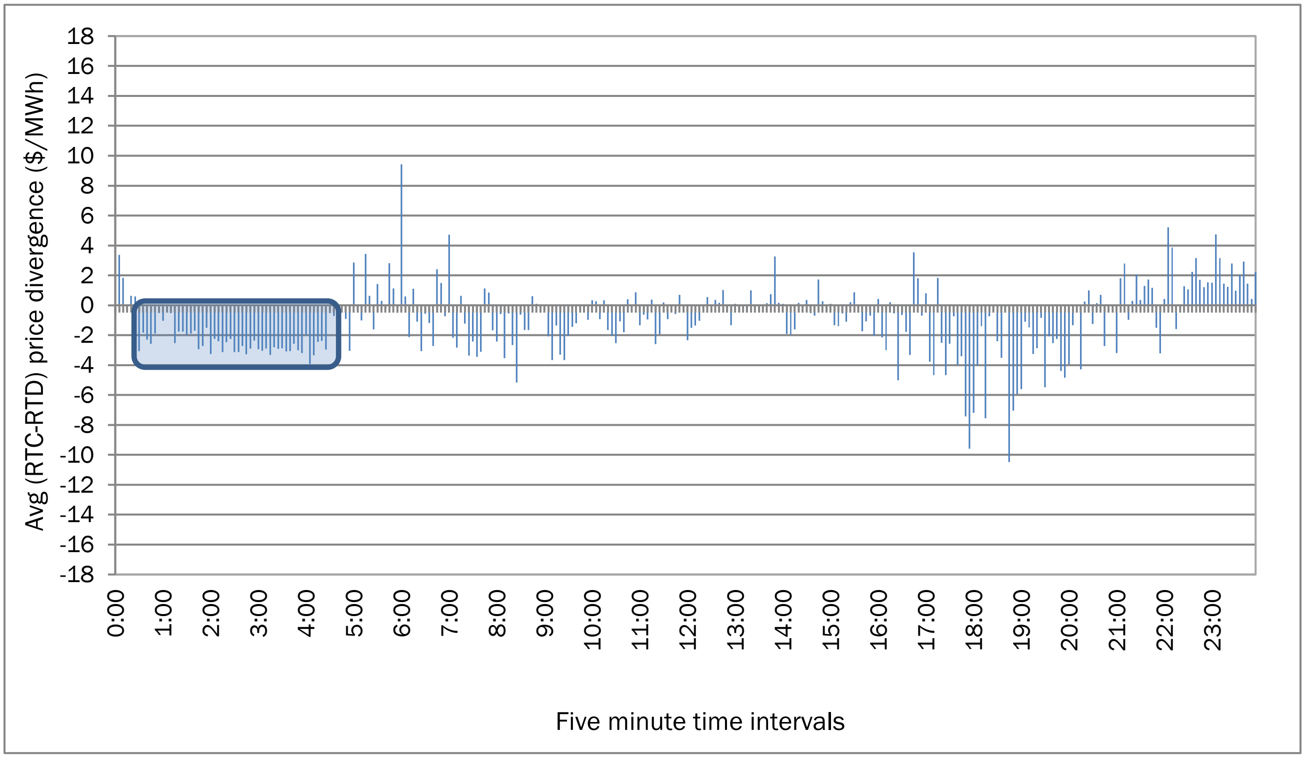
In this section, the price divergences between the RTC and RTD are studied at a time-of-day granularity. This helps narrow down the factors that could be causing price divergence between these two programs by identifying whether there are specific times of the day when RTC-RTD price divergences are more likely to occur.

This analysis encompasses an entire year of price data, on a five-minute basis, but does not include the extreme price divergences[6] between the RTC and RTD. Averages of the LBMP divergences are plotted against each five-minute interval of the day. For all the graphs shown below, the horizontal axis is each five minute interval of the day and the vertical axis is average of (RTC minus RTD) NYCA price divergence for each of these intervals over a year. Figure 10 shows the average NYCA price divergences.

Average price differences of relatively high magnitude are observed at the top of several hours towards the end of the day. This possibly occurs because large number of generators are all shutting off at the conclusion of their DA schedules at the top-of-the-hour. The other possible reason could be differences between how RTC and RTD model ramping of interchange.

[6] The next section includes extreme divergences between the RTC and RTD prices.

**Figure 10: Average LBMP divergence (RTC minus RTD) for a Year in NYCA**




The figure highlights a consistent pattern of negative price divergences (implying the RTD price was greater than the RTC price) between 12:30 a.m. and 4:30 a.m.

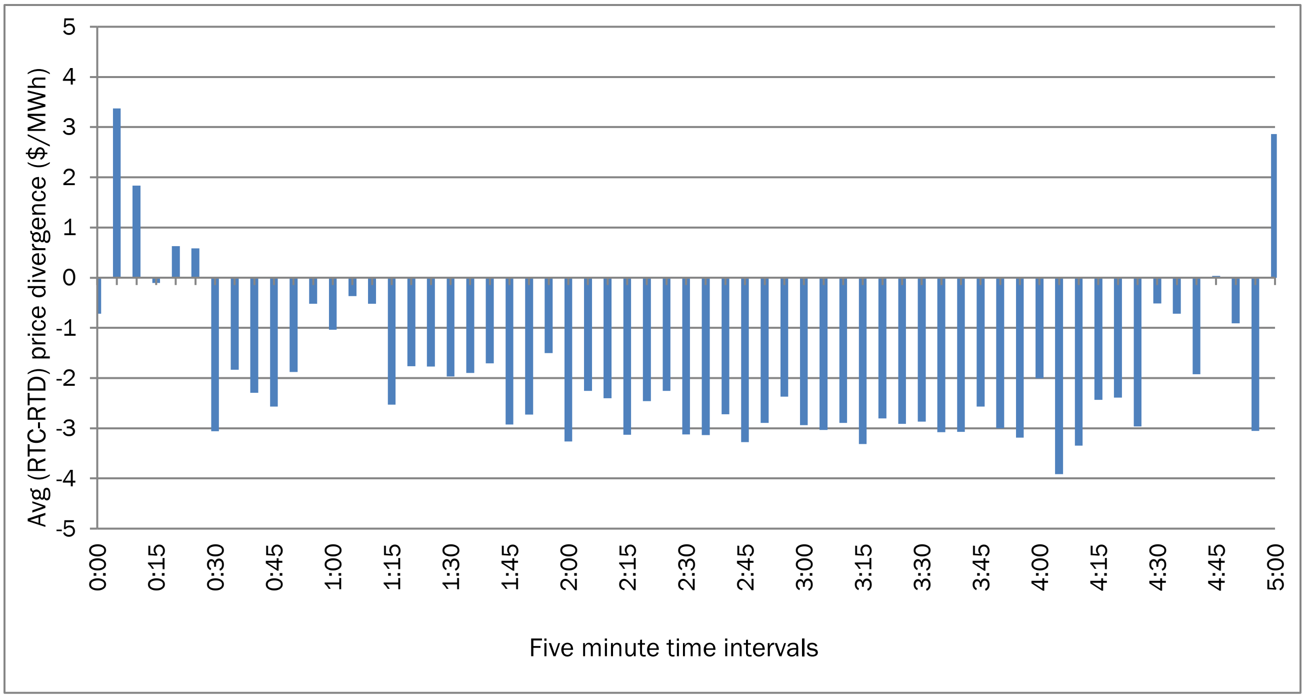
Figure 11 isolates the hours from the previous chart to the 12:00 a.m. to 5:00 a.m. timeframe. Because the data identified a consistent pattern, further analysis was performed to understand the driving factor of the negative divergences during these hours. On further investigation of these hours, a correlation was observed between an under-forecasting of LBMP's by RTC in the same hours that there was under-forecasting of load by RTC.[7]

## Time of Day Price Divergences including Extreme Price Divergences

In the previous section, price divergences excluding the extreme price divergences, in a year were plotted against five-minute intervals to understand the magnitude change between intervals.

[7] An improvement was made in June 2017 to better align the RTC load forecast with actual load.

**Figure 11: Average NYCA LBMP divergence between 12am and 5am**




In this section, we include all price divergences, including price divergences of extreme magnitude (10 times the standard deviation of the respective dataset), in all of the zones studied to understand if the larger magnitude price divergences are concentrated in certain times of day.

Shown below are the time-of-day charts for the West, NYC and Long Island zones respectively. In the Long Island zone, the average price divergences were significantly higher at certain times of the day. Long Island was compared to other zones to understand if a similar pattern occurred in any other zone. Comparing the same times (5 p.m. to 11 p.m.) for the three zones (West, NYC and Long Island) it is evident that the 10 p.m. price divergence is only observed on Long Island.

**Figure 12: Average NYC Zone LBMP Divergence Between 5 p.m. and 11 p.m.**

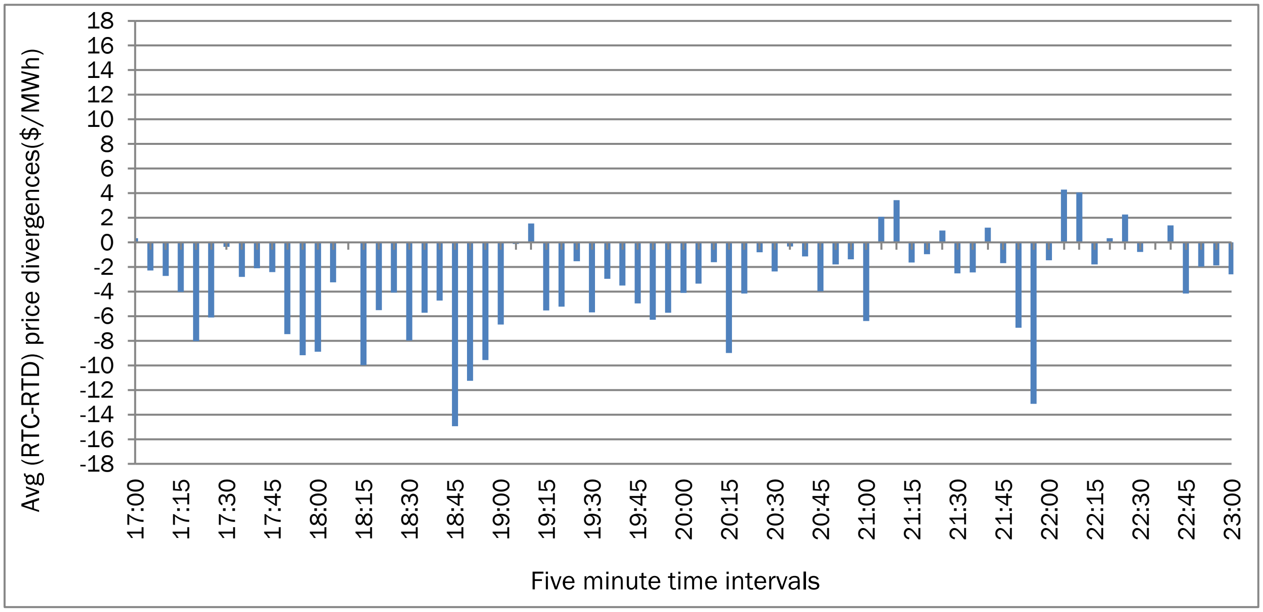



**Figure 13: Average West Zone LBMP Divergence Between 5 p.m. and 11 p.m.**

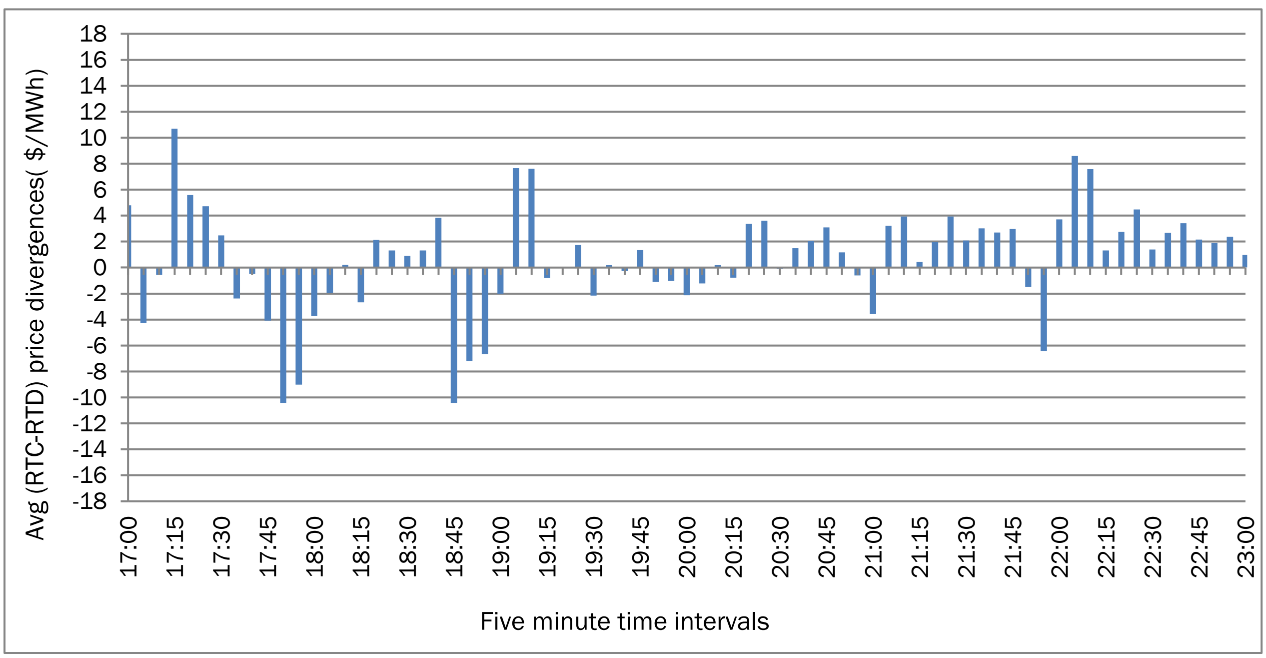
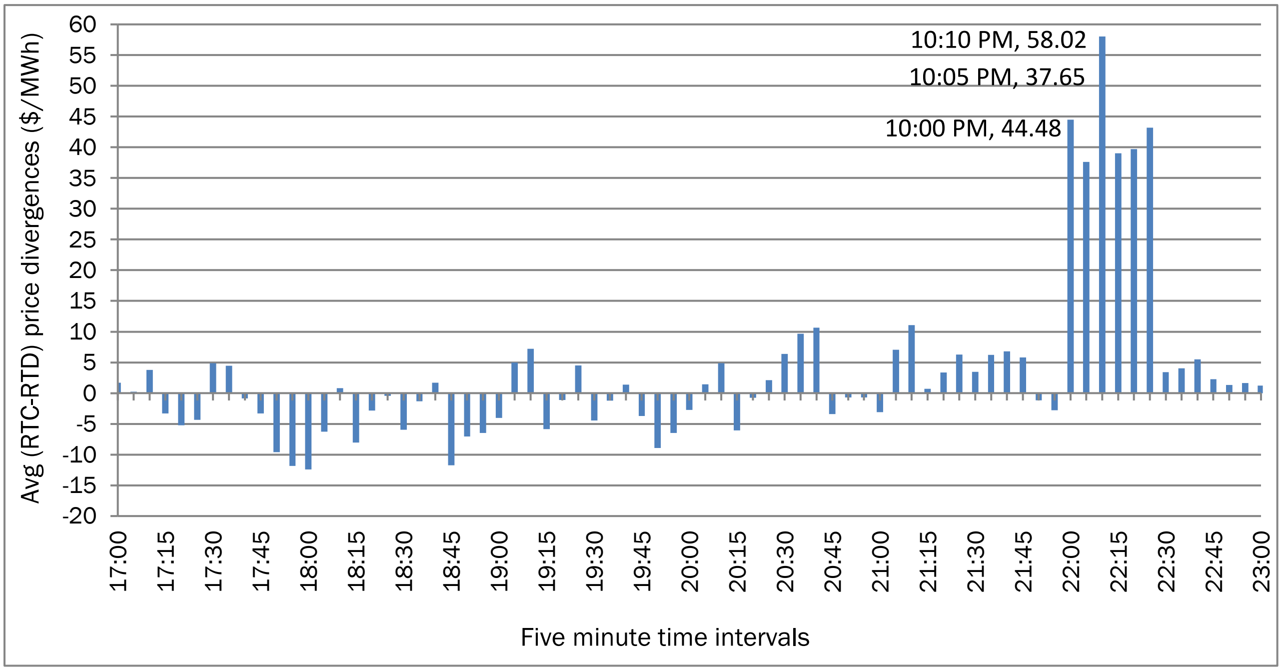


**Figure 14: Average Long Island Zone LBMP Divergence Between 5 p.m. and 11 p.m.**




This divergence could be caused by multiple factors. On further investigation[8] it was observed that the 901/903 PAR schedule changes that the NYISO receives from LIPA through telemetry occur at the same time as the price divergence is seen. Neither RTC nor RTD see the schedule change coming because they are provided to the NYISO as an instantaneous telemetry value. However, when the change occurs, RTD has a smaller window of time to react than RTC does. The data shows the resulting divergence can be significant and the 901/903 PAR schedule changes could be a significant factor in driving these divergences. The NYISO recommends that improvements to the RTC and RTD be made such that the software includes these schedule changes in advance of HB 22 as discussed in the Opportunities for Consideration and Recommendations sections below.

[8] Additional information regarding the analysis can also be found below in Case 3.

## Correlation Analysis

In this section, correlations between various possible drivers of price divergences between RTC and RTD, including the marginal cost of congestion component of the LBMP, load differences, Desired Net Interchange (DNI) differences and regulation capacity shortages, are discussed.

The correlation between the possible drivers and RTC-RTD price divergences is analyzed using scatter plots and by determining the correlation coefficient between the two datasets. Correlation coefficients are used because they indicate how strong a relationship is between two variables. They vary from -1 to 1. A correlation coefficient closer to 1 shows that the two datasets have a strong positive correlation, which implies that if one variable changes, the other variable also changes by a similar magnitude in the same direction. A correlation coefficient close to -1 indicates that the two datasets have a strong negative correlation, which implies that if the first variable changes, the second variable changes by a similar magnitude, but in the opposite direction.

In this study, correlation coefficients are used to understand how strongly RTC-RTD divergences are correlated to the various possible drivers mentioned above. For purposes of this study, a correlation coefficient greater than 0.7 or -0.7 is defined as a strong correlation, a correlation coefficient between (0.3 to 0.7) or between (-0.7 to -0.3) is defined as a moderate correlation and anything closer to zero than 0.3 or -0.3 is considered a weak correlation.

### Correlation between RTC-RTD Congestion and LBMP Differences

The purpose of this analysis is to determine whether there is a correlation between the difference in the marginal cost of congestion component of the RTC and RTD LBMPs, and the difference in the LBMPs between RTC and RTD. LBMPs are driven by two primary factors; the unconstrained cost of energy, known as the reference price, and the marginal cost of congestion due to NYCA transmission system limitations. By correlating the marginal cost of congestion component difference with the LBMP divergences, the impact transmission system congestion has on RTC-RTD price divergences can be observed. The following figure addressing Zone A, and the corresponding figures addressing other locations in the appendix, provide insight as to whether transmission congestion differences are a driver of LBMP divergence between RTC and RTD.

The data used in this analysis encompasses LBMPs for each 5-minute interval for the entire study period (July 2016 through June 2017). The RTD LBMP data for the PJM Keystone proxy bus and the PJM Linden VFT proxy bus uses the average LBMP data of the three corresponding RTD intervals.

The analysis revealed that there is high correlation between RTC-RTD price divergences and differences between the congestion component of the RTC LBMP and the RTD LBMP in West Zone (Zone A). Figure 15 showing results for Zone A, reveals that there is a correlation of 0.83 between the LBMP differences and the difference between the congestion components of the LBMP.

The analysis shows that in Zone A, 83% of the variability of price divergences is correlated with divergence between the congestion components of the RTC and RTD LBMPs. Based on this analysis, it is reasonable to conclude that differences in transmission congestion is a primary driver of RTC-RTD divergences in Zone A. Further study would be required to determine which variables have the most influence on Zone A transmission congestion.

The other locations that were studied are NYC (Zone J), the PJM Keystone proxy bus and the PJM Linden VFT proxy bus[9]. At the PJM Linden VFT proxy bus, a moderate correlation between the RTC and RTD transmission congestion differences and the RTC and RTD LBMP differences was observed while a weak correlation was seen at the other locations.

Currently, when the RTC or RTD prices a transmission constraint, the Transmission Shortage Cost curve is used when insufficient resources are available to solve the transmission violation. The Transmission Shortage Cost is applied to all transmission facilities that have a non-zero CRM[10] value. It is comprised of two steps; up to and including 5MW of additional transmission capacity is priced at $350/ MWh, an additional 15 MW of transmission capacity is priced at $1,175/ MWh. The final step of the Transmission Shortage Cost operates as a transmission constraint cost cap of $4,000/MWh[11].

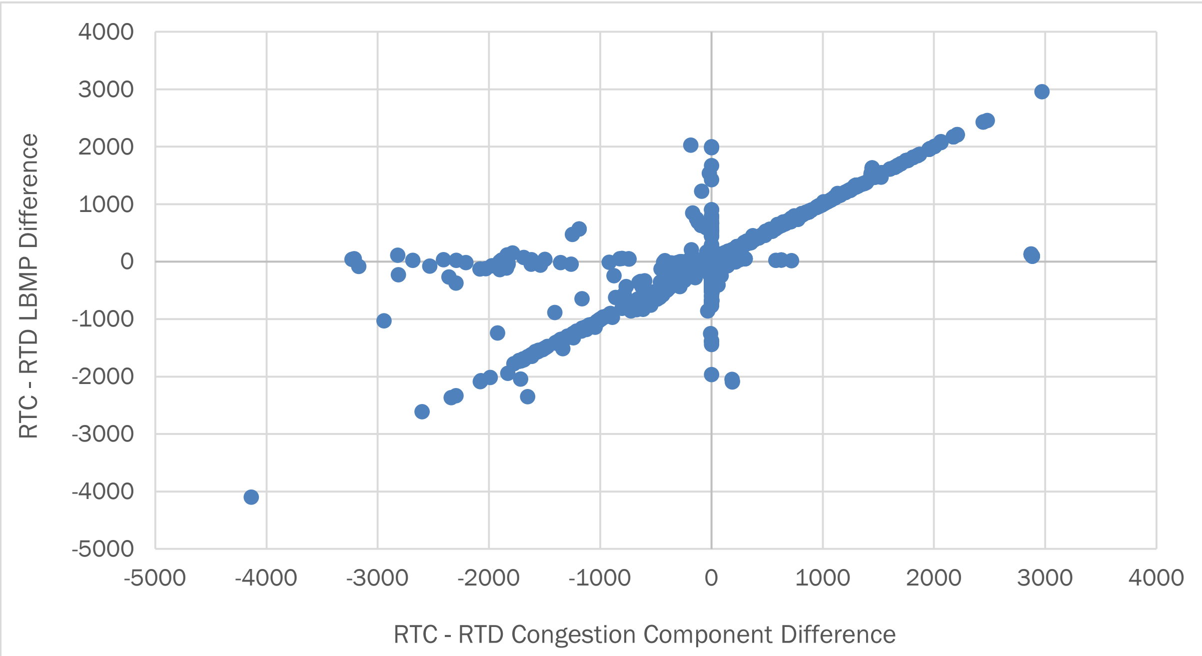
Transmission Shortage Cost curves with more graduated pricing steps could help minimize differences between the congestion components included in the RTC and RTD LBMPs. The congestion component could differ between RTC and RTD due to transmission constraints binding at different steps of the Transmission Shortage Cost curve. Constraint Specific Transmission Demand Curves could help to reduce price volatility in both the RTC and RTD that is associated with transmission shortage events.

[9] The additional analysis can be found in the Appendix.

[10] A Constraint Reliability Margin represents the value below the maximum physical limit on a transmission facility or Interface that is used by the NYISO's market software as the effective limit when evaluating for economic commitment and dispatch decisions in SCUC, RTC and RTD.

[11] NYISO Transmission and Dispatching Operations Manual page 116

**Figure 15: Scatter Plot of RTC minus RTD LBMP and Congestion Differences for Zone A**




### Seasonal Analysis of Correlation between Load Differences and Price divergence

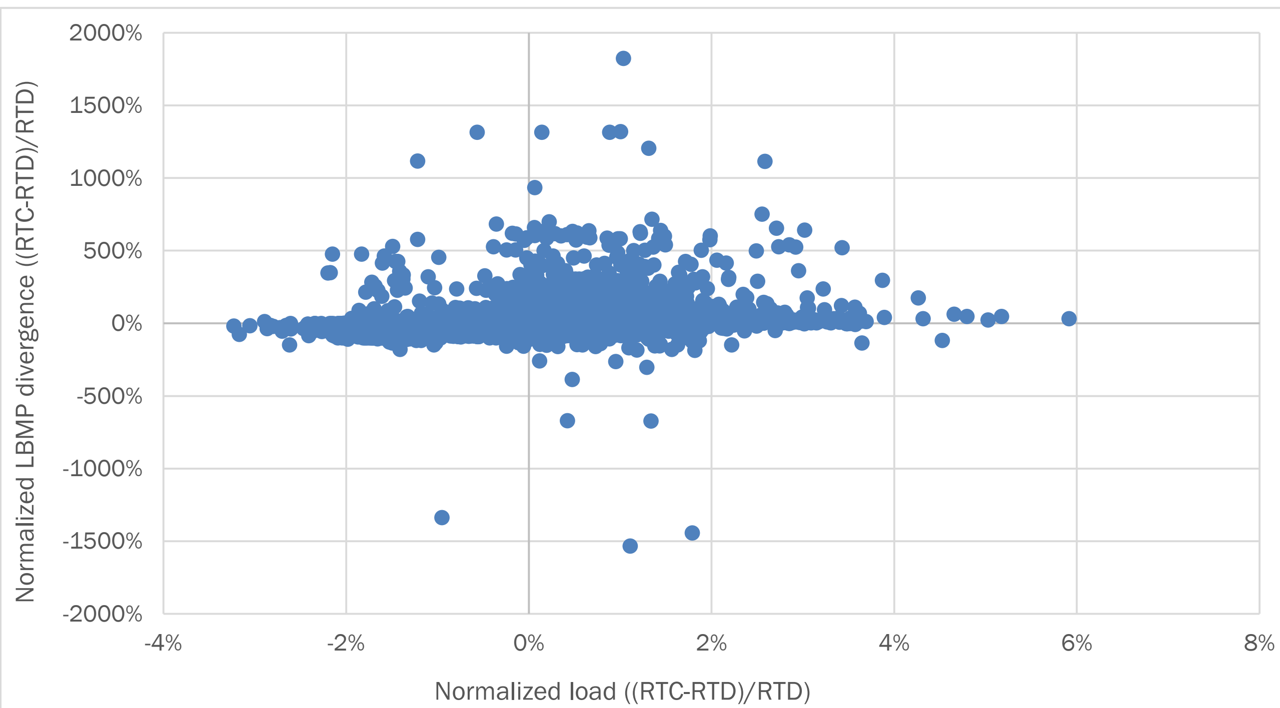
The RTC begins to run thirty minutes prior to the actual operating period, as discussed in the Real-Time Commitment (RTC) section above, and uses a forecast of the load for the operating period that exists at the time it begins to run. In other words, the RTC uses a load forecast for the operating period that was developed thirty minutes prior to the operating period. The first RTD that lines up with a particular RTC uses a load forecast for the operating period that was developed ten minutes prior to the operating period. The inherent timing latency between the RTC and RTD may cause them to use different load forecasts for the same operating period.

In this section, seasonal analysis was conducted for NYC (Zone J); comparing load changes between the RTC and RTD to price divergences between the RTC and RTD to investigate whether load differences were driving price divergence. The load differences were correlated to price divergence on a normalized basis to permit the two datasets to be compared on a percentage basis. The correlations were studied for New York City (Zone J) because the prices could possibly be more sensitive to small fluctuations in load due to load pockets and transmission constraints in this zone. Therefore, the LBMPs may be more sensitive to load fluctuations.

This analysis was done at a seasonal level because the load shape differs considerably between summer, winter and shoulder months. The data identified a weak correlation between load differences and RTC-RTD price divergence in all seasons. Of all the seasons, the highest correlation coefficient observed was in the fall months (September 2016 through November 2016) with a value of 0.27. This implies that there is a weak correlation between load differences and LBMP divergences in the fall months. A similar pattern is observed at other times of the year. Figure 16 below represents the scatter plot of the correlation between normalized load differences and normalized LBMP divergences in NYC (Zone J) for the fall months[12].

From this analysis, it may be gathered that load differences between RTC and RTD are not a significant driver of the RTC-RTD price divergences in NYC (Zone J), since there was not a moderate or strong correlation between the two datasets in any season. A statewide analysis may have yielded a different result, and could potentially be pursued in the future. The relationship between additional variables and load (such as transmission constraints) could also provide more insight into whether deviations in load between the RTC and RTD are correlated with price divergences under certain conditions.

**Figure 16: Scatter Plot of Normalized Load Differences and LBMP Divergences for Fall Months**




[12] Further analysis and supporting charts on other seasons can be found in the Appendix.

### Correlation between DNI and LBMP for NYCA

The RTC schedules external transactions assuming they reach their schedule at the top-of-each-quarter-hour. However, the net external transacation schedules, or DNI, actually move over a ten-minute period from five minutes before the top-of-the-quarter-hour to five minutes after, consistent with the NERC criterion. This inconsistency in the ramping of imports between RTC and RTD could possibly contribute to differences between RTC price forecast and actual five-minute RTD clearing prices[13].

In this section, net NYCA DNI differences between the RTC and RTD are correlated to five-minute NYCA price divergences. The intent is to observe if DNI changes from the RTC to RTD cause a corresponding price divergence. This was also one of the concerns raised by the MMU in its 2016 SOM report.[14]

Since the load shape may affect the DNI, the analysis was done on a seasonal basis. The analysis is also segmented by hours, to determine if there was a stronger correlation between the DNI differences and price divergence in certain hours.

The scatter plot in Figure 17 shows correlation between RTC-RTD DNI divergences and NYCA price divergences for the winter months (December 2016, January 2017 and February 2017) at five-minute intervals. The DNI difference was calculated by using the net change in the DNI across all 11 external proxy buses between the RTC and RTD, for each five-minute interval[15].

Figure 18 shows the correlation coefficients between DNI differences and price divergences, by hour. The correlation coefficient for each hour was calculated by rolling in the averages of LBMP divergences and DNI changes for all the five minute intervals in the hour (for example: the 12:00 a.m. correlation coefficient is calculated by correlating average price divergences and average DNI changes from 12:00 a.m. to 12:55 a.m.). Averaging prices and DNI changes across each hour could have masked local divergences that occurred at the fifteen-minute RTC intervals, but as some external proxies such as HQ Cedars and Cross-sound cable are still scheduled on an hourly basis, it was thought that an hourly average would provide a better overall perspective of macro trends.

There was a very weak correlation between the two datasets in all of the seasons studied. The

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[13] 2016 State of the Market Report, Page A-103

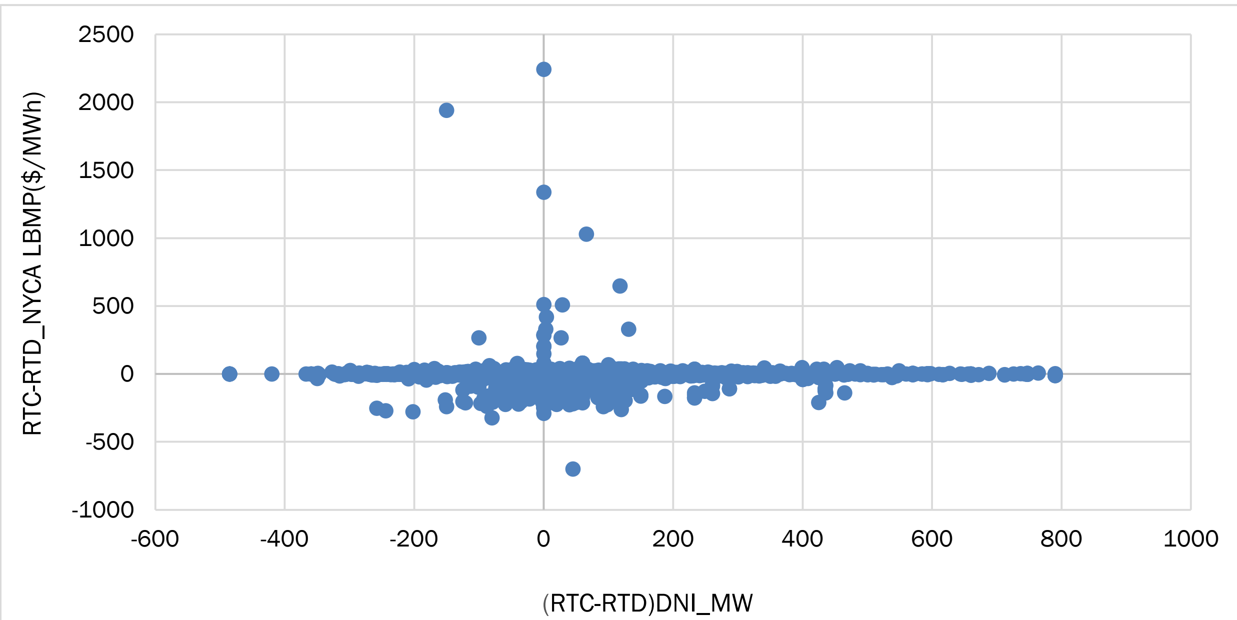
[14] See the Market Analysis above

[15] Further analysis and supporting charts for all other seasons can be found in the Appendix.

highest correlation was observed in the spring months. This analysis does not suggest that the DNI differences are a significant cause of price divergences between the RTC and RTD.

However, there was a stronger correlation between the DNI differences and LBMP divergence in hour 14 (for the summer, spring and winter months) and hour 21 (for the summer and fall months) than in other hours[16]. Further analysis would need to be conducted, to investigate the possible reasons for the DNI and LBMP divergences being strongly correlated in these hours. For example, if the same data were analyzed for correlations on a sub-hourly basis, it might be possible to determine whether specific RTC intervals contributed more to price divergences than others during those hours.

**Figure 17: Scatter Plot of Net DNI Difference and NYCA Price Divergences for Fall Months**

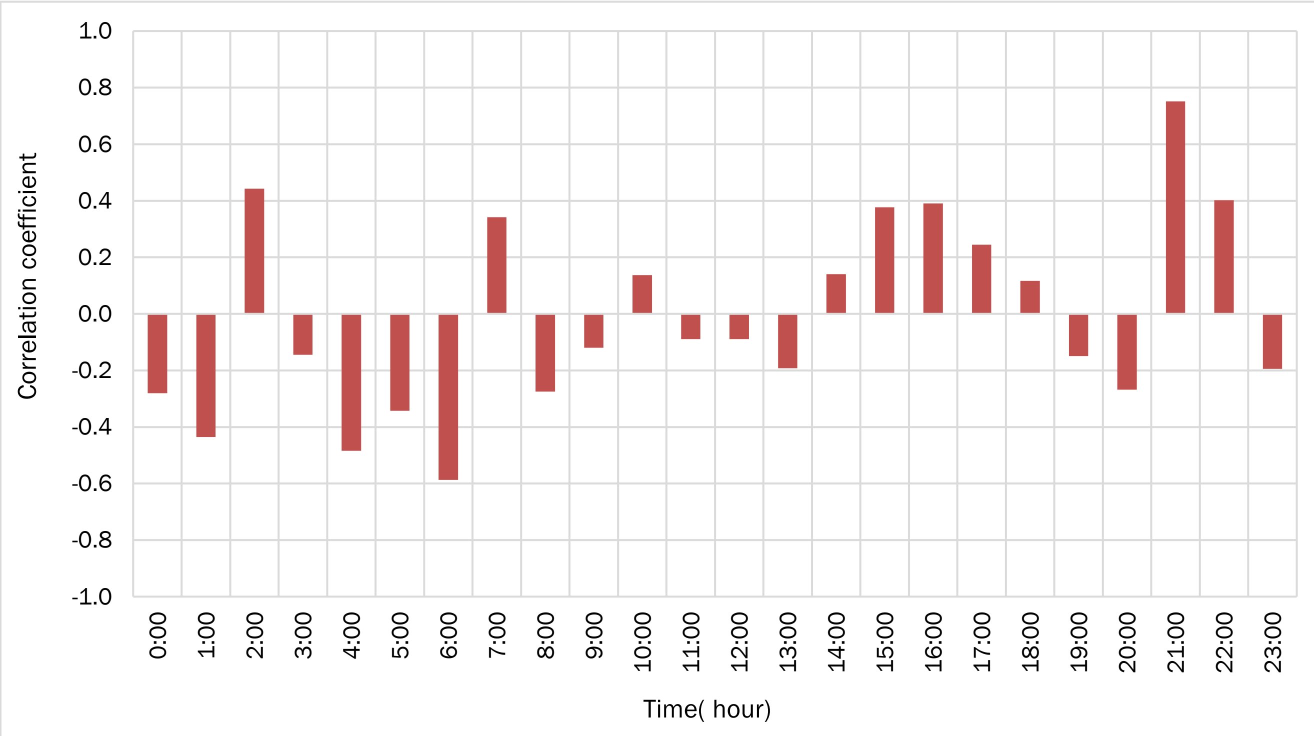



The correlation coefficient between the two datasets is -0.01 showing that the DNI difference and NYCA price divergences are not correlated in the fall months.

Figure 18 indicates that the hours exhibiting strong correlation between the two datasets is hour beginning 21. This shows that there is a moderate to weak correlation between DNI changes and LBMP difference in the fall months in all other hours.

[16] The additional figures illustrating these findings can be found in the Appendix.

**Figure 18: Correlation Coefficient for DNI Changes and NYCA Price Divergences for Fall Months**




## Analysis of Regulation Capacity Shortages

Shortage conditions arise when available resources are inadequate to meet energy and ancillary service needs of the system while honoring transmission security constraints. Shortages could be of operating reserves, regulation or transmission service. To efficiently reflect shortage conditions in real-time clearing prices, the NYISO currently uses demand curves during operating reserve and regulation shortages and Transmission Shortage Cost curves during transmission shortages.[17]

Regulation capacity shortages occur due to unexpected system events, or when there is not enough ramp available to the system. For example if a generator trips, RTD will forego regulation capacity to ensure the power balance is maintained until more resources can be brought online to make up for the loss in generating capacity. Additionally, when significant external transaction curtailments occur, RTD may not have sufficient internal resource ramp capability to meet the new interchange schedules. In this case, RTD may forego obtaining the desired quantity of regulation service to make up the shortage of ramp from available resources.

[17] NYISO Ancillary Services Manual page 6-39

From the NYISO's and MMU's analysis of the shortages[18], it was observed that regulation capacity shortages occurred most frequently of all the co-optimized ancillary service products. Analyzing the regulation capacity shortages over a year, it was observed that 8,639 total shortages occurred in the year studied.  Of that total, 6,510 regulation capacity shortages were only observed in the RTD, while 497 regulation capacity shortages were only observed in the RTC, and 1,632 regulation capacity shortages were observed in both the RTC and RTD. When a shortage is observed in both the RTC and RTD, both programs are likely to have the same information resulting in similar pricing outcomes. However, when a shortage occurs in only one of the two programs, the prices between the two programs will likely be different.

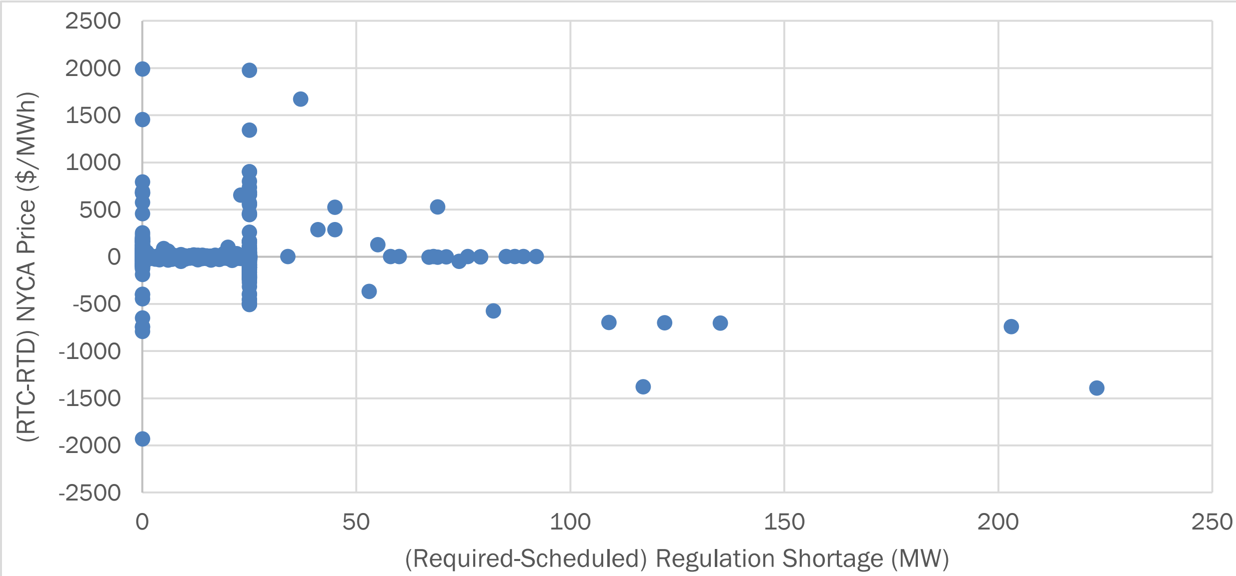
In this section, we first analyze the contribution of regulation shortages to price divergences between the RTC and RTD. This was accomplished by studying the correlations of the RTD-only regulation capacity shortage (MW) with the price divergences between the RTC and RTD to substantiate the possible effect of regulation shortages on price divergences between the RTC and RTD.

Figure 19 shows the scatter plot of correlation between the RTD-only regulation shortage and NYCA price divergence for the summer months[19]. It was observed that there was a weak to moderate correlation between the RTD-only regulation capacity shortages and RTC-RTD price divergences in all seasons, in the studied year.

[18] 2016 SOM report page A-132

[19] Charts for the other months are provided in the Appendix.

**Figure 19: Scatter Plot of Regulation Shortage and NYCA Price Divergence for Summer Months**




The correlation coefficient of -0.22 shows no correlation between LBMP divergences and RTD-only regulation shortage MW's in the summer months.

### Correlation between Regulation Shortages and DNI Differences

In this section, we analyze the correlation between changes in DNI from the RTC to RTD and the occurrence of Regulation Capacity shortages. This analysis was performed to address a concern that if the system is constrained at the same time there is a reduction in DNI from the RTC to RTD, then the NYISO would need to move internal resources from providing regulation to providing energy to make up for the missing interchange. The conversion of regulation providers to energy would cause a regulation capacity shortage, which could, in turn, cause price separation between the RTC and RTD.

Conversely, an increase in the RTD DNI above the amount anticipated by the RTC can result in regulation providers being dispatched to minimum generation to maintain the power balance which could also result in regulation shortages. This scenario was not analyzed as part of this study due to the very weak correlation observed in the analysis that was performed.

#### Example of Regulation Shortage caused by DNI Ramping.

On 12/1/16 for intervals 18:30 and 18:35, the NYISO experienced high RTD prices due to regulation capacity shortages that occurred in the RTD, but were not present in the RTC. Regulation, operating reserves and energy are simultaneously co-optimized, so regulation capacity shortage pricing affect the LBMP. On the day in question, higher prices were observed in the RTD than in the

RTC for all zones. For example, the RTD reference price at 18:30 was $130.31/MWh while the RTC reference price for the same time was just $36.85.

Comparison of RTC and RTD load and DNI on 12/1/16 at 18:30:

- RTC Load: 19,588 MW vs. RTD Load: 19,576 MW
- RTC DNI: 3,568 MW vs. RTD DNI: 3,462 MW

Net imports were 106 MW higher in the RTC than in the RTD. In the RTD, internal resources were shifted from providing regulation capacity to providing energy in order to meet load, which resulted in a shortage of regulation capacity. This shortage of regulation capacity resulted in regulation shortage pricing from the Regulation Service demand curve and higher LBMPs in the RTD. In this case, expected imports were temporarily higher in the RTC than in the RTD because of the way RTD ramps the DNI changes over two five-minute intervals.

To investigate further whether the DNI was responsible for systemic regulation capacity shortages, the count and average MW of the shortages are plotted by minutes. If the DNI changes cause regulation shortages, then the regulation shortages should be more pronounced or frequent at the quarter hour intervals (i.e. at 0:00, 0:15, 0:30 and 0:45). However, from Figure 20 and Figure 21 it is observed that the regulation shortages are prominent in minutes (0:05, 0:10, 0:20, 0:25, 0:35, 0:40, 0:50 and 0:55).

It appears that there is a pattern of regulation shortages on each quarter hour. The NYISO's investigation, to date, has not identified any definitive reasons for such a pattern. However, this pattern does not seem to indicate that changes in DNI are leading to more regulation shortages. Further investigation is necessary to determine any causation or potential reasons for the quarter hour pattern.

**Figure 20: RTD Regulation Shortages for the Summer and Winter Months**

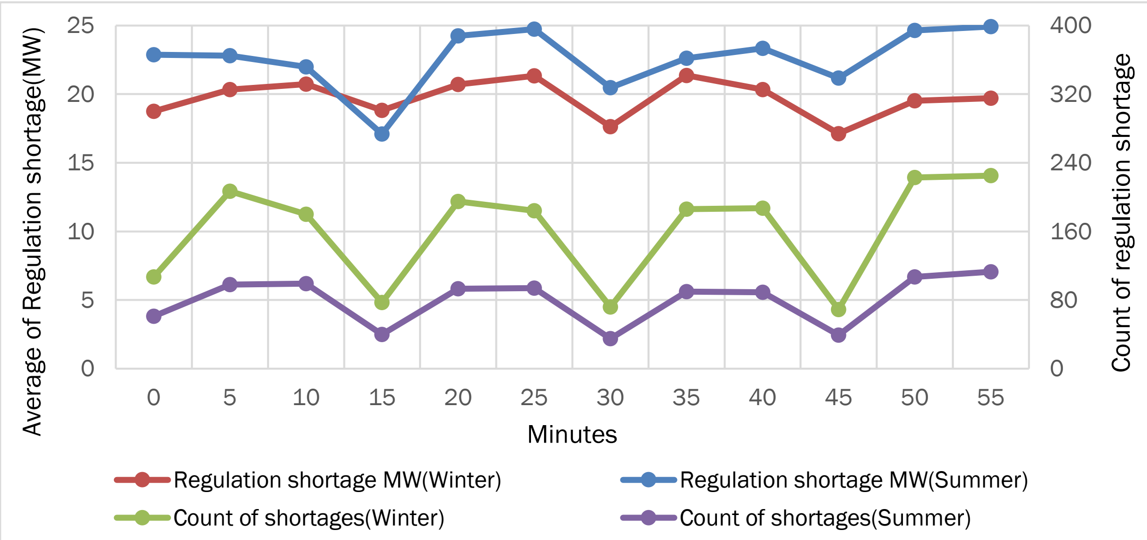
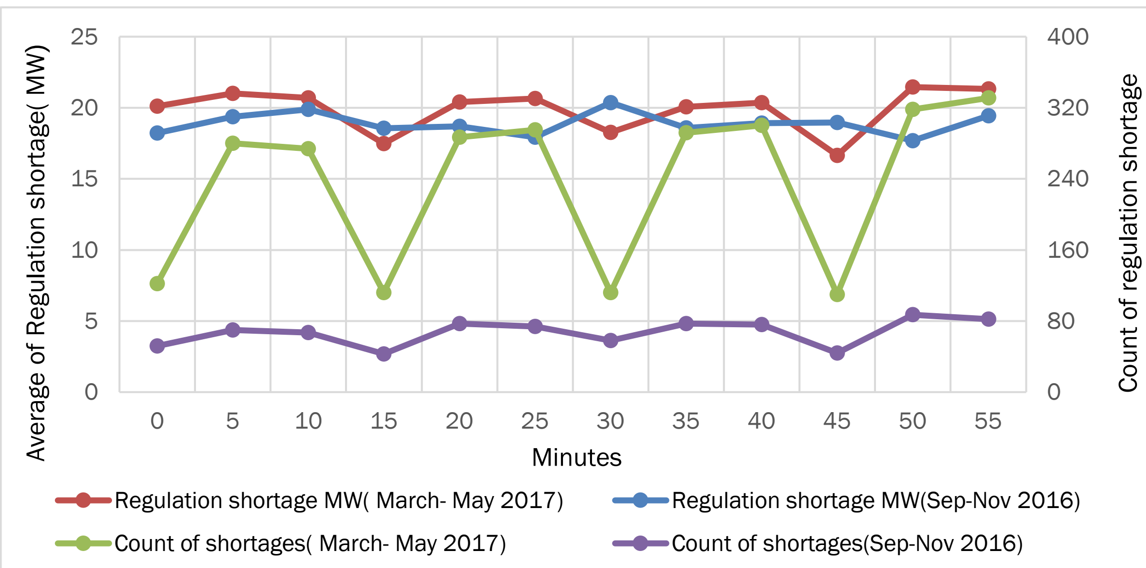


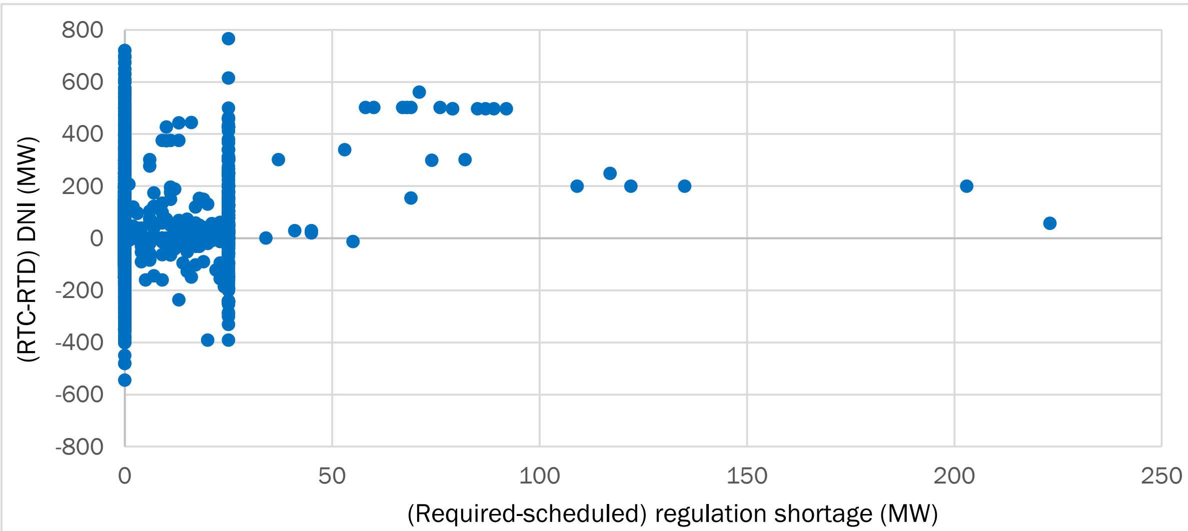

**Figure 21: RTD Regulation Shortages for the Shoulder Months**




The NYISO also analyzed the correlation between the DNI difference and RTD regulation shortages on a seasonal basis for the studied year. This analysis did not identify a significant correlation between changes in the DNI (RTC minus RTD) MW and the RTD regulation shortage MW in any of the seasons. However, in the summer months, it was observed that there is a weak correlation.

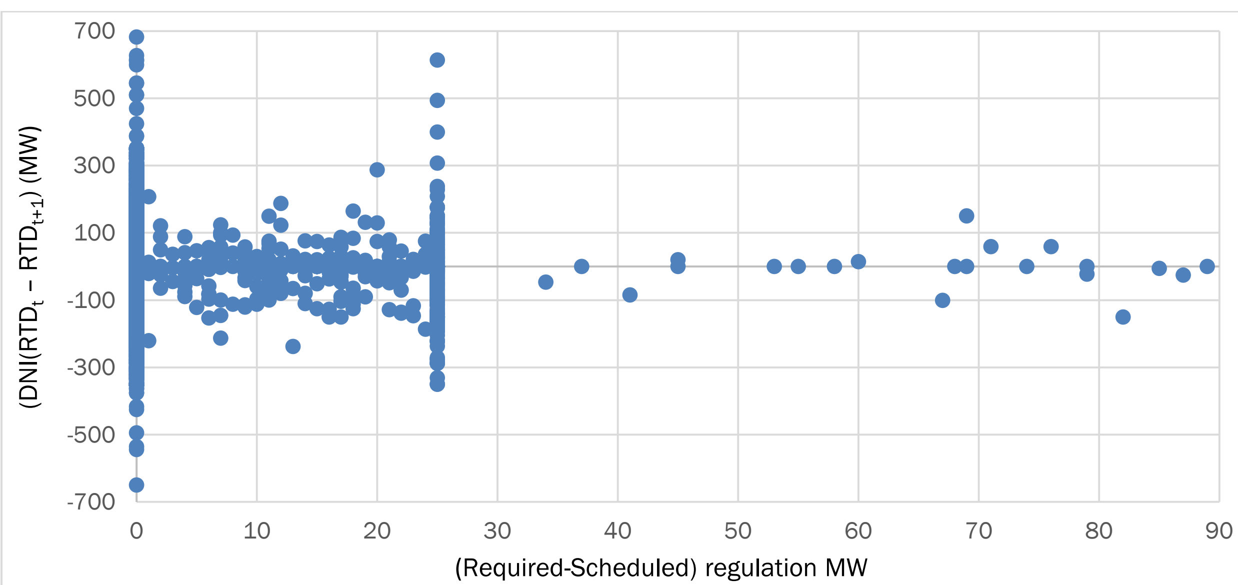
This analysis is segmented by seasons and, for each season, two scatter plots are shown. Figure 22 presents the DNI differences (RTC minus RTD) vs the RTD regulation shortage MW for the summer months. This was plotted by taking the difference between the RTC and RTD MW for each five-minute interval for each three month season and plotting a scatter plot against the RTD regulation capacity shortage MW (requirement minus schedule). Figure 23 shows the DNI differences in two consecutive RTD intervals against the RTD regulation shortage MWs[20].

**Figure 22: Scatter Plot of Net DNI Difference and RTD Regulation Shortage MW for Summer Months**




The correlation coefficient is 0.1 implying there is a weak correlation between the DNI differences and the RTD regulation shortages in the summer months.

**Figure 23: Scatter Plot of Net RTD DNI ($RTD_t$ - $RTD_{t+1}$) and RTD Regulation Shortage for Summer Months**




[20] Charts for other seasons and supporting analysis are provided in the Appendix.

The correlation coefficient is -0.02 between RTD DNI deltas and the RTD regulation shortages for summer months, indicating no correlation.

The NYISO does not recommend investigating the impacts of DNI on price divergences between RTC and RTD as the study did not observe DNI to be a significant driver of the price divergences or regulation shortages.

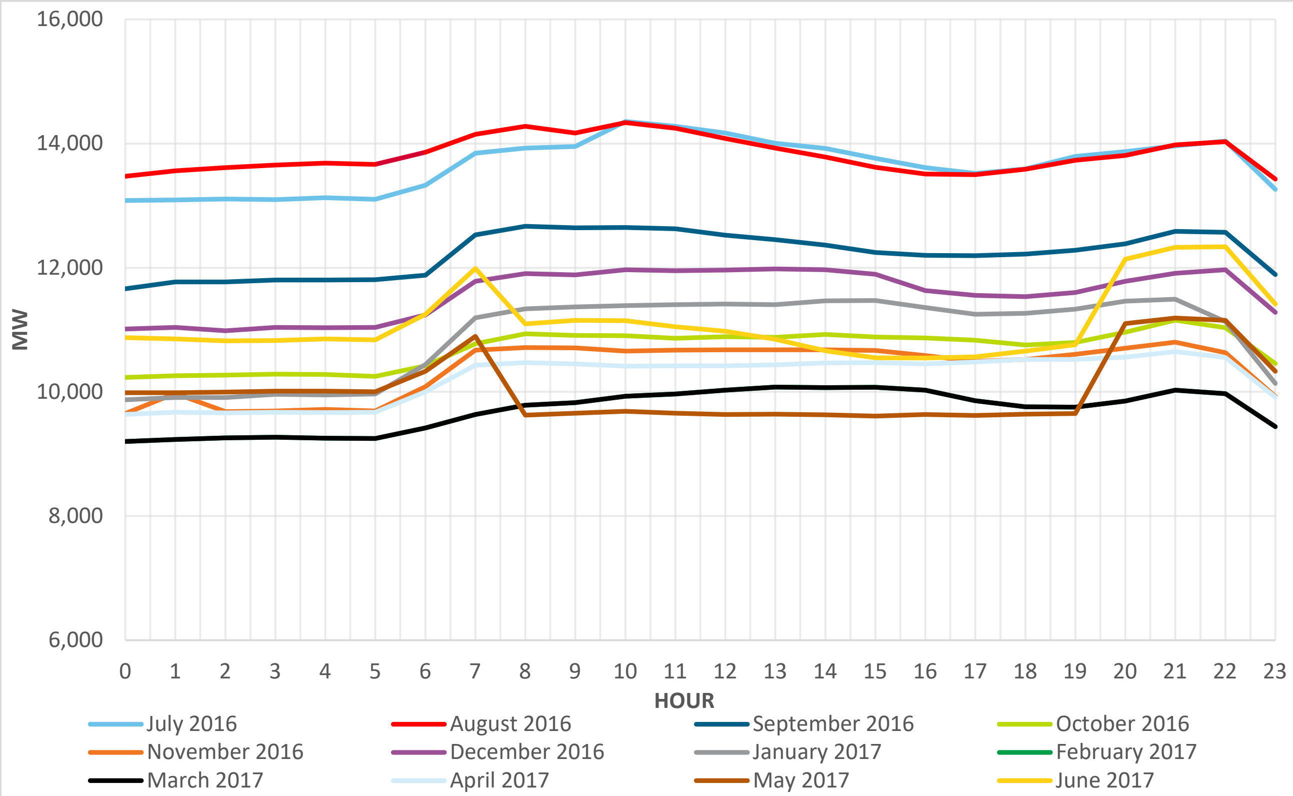
### System-Wide Dispatch Range Analysis

An analysis was performed on generator offers in order to better understand the average amount of system-wide dispatch range that was available to the RT market system. Having a sufficient amount of dispatch range available to the system allows the RTM market to make more economic and efficient commitment and dispatch decisions. In instances where RTC does not have enough available ramping capability to meet system requirement, it may lead to more costly commitment decisions and if RTD doesn't have a sufficient amount of dispatchable units to meet system needs, it could result in more price volatility as more expensive units are dispatched to meet reliability requirements in the RTM.

In this analysis, dispatchable generators represent all units that are not using the bid mode of "self-committed fixed." Self-committed fixed bids were removed from the analysis, as these units are not considered dispatchable. The dispatch range used was each unit's submitted hourly real-time normal Upper Operating Limit (UOL) minus its Minimum Generation (MinGen) value, with the exception of "self-committed flex" units. The MinGen value used for self-committed flexible units was either the highest of (i) the highest four fifteen-minute self-scheduled MW values , and (ii) the unit's submitted MinGen value. The analysis used RT bids submitted into the RTM for evaluation. The study period included data from July 2016 through June 2017, segmented by month and by season.

Figure 24 below illustrates the average hourly dispatchable MWs available to the real-time system for each month in the study period. The hourly system-wide dispatch range represents the average of the hourly sum of all generator's dispatch range values with real-time market offers. The analysis revealed that July and August had the highest system-wide hourly dispatch range. The rest of the months in the data range remained relatively consistent. In general, generators bid in a manner that was consistent with the system requirement patterns, following early morning and late evening load shape. May and June 2017 patterns are due to planned daily resource maintenance.

**Figure 24: Average Hourly Dispatch Range (July 2016 through June 2017)**




The following section reviews charts that compare the maximum average change in hourly time-weighted/integrated real-time load to the average hourly dispatch range by season. The analysis provides insight into whether the system has sufficient available dispatch range to meet fluctuations in real-time load. The analysis reveals that the available dispatch was always greater than the maximum average change in load. Based on the analysis we conclude that in the RTM there was, on average, sufficient dispatch range available to the system to cover changes in load throughout the day.

The analysis was segmented by season, with the summer representing July 2016, August 2016 and June 2017. The fall season represents September 2016, October 2016 and November 2016. The winter season represents December 2016, January 2017 and February 2017. The spring season represents March 2017, April 2017 and May 2017. The fall, winter and spring analyses can be found in the appendix.

For the seasonal analyses, the seasonal average dispatchable MW value represents the hourly average dispatchable MW range for the season in the study period. The seasonal average real-time load value represents the hourly average hourly integrated load values for the study period. The maximum average change in load represents the delta between the highest and lowest load point from the average real-time load seasonal value.

**Figure 25: Average Hourly Dispatchable MW and Actual Real-Time Load – Summer**

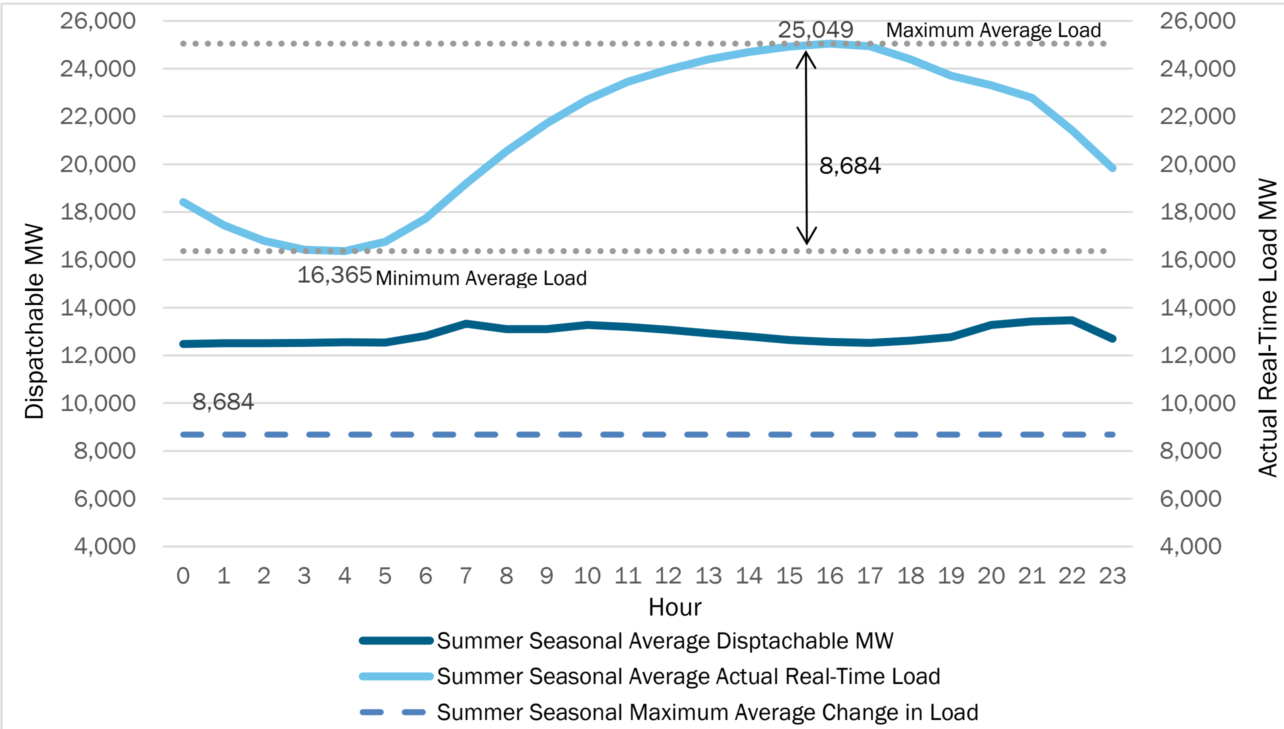



Figure 25 above compares the summer seasonal average hourly dispatch range to the like-season average hourly actual time-weighted integrated real-time load and to the maximum change in load (8,684 MW). The figure shows that the seasonal maximum average change in load was consistently less than the average seasonal dispatchable MW range. From these results, the NYISO concludes that there was, on average, sufficient dispatch range to meet the changes in load requirements that occurred over the course of the day for the seasonal period. Each seasonal period was analyzed. The analyses are included in the appendix.

## Case Specific Analysis:

This section reviews three specific instances of RTC-RTD price deviations that were recognized by NYISO market participants.

### Case 1

On August 11, 2016, for the RTC interval 14:45, RTC forecasted prices in excess of $2,000 at all internal NYCA zones, but due to an import constraint, forecasted a price at the PJM Keystone proxy bus of $950. The RTD prices for all internal NYCA zones for the same time period were in the +$200 to +$600 range, while the RTD price at the PJM Keystone proxy bus was approximately -$1,100. In this case, the divergence between the RTC and RTD LBMPs was a result of the latency in timing between the RTC and RTD.

High LBMPs forecasted in RTC were due to 10-minute reserve shortages, with the reserve demand curve setting these prices. When the RTD timeframe came around at 14:45-15:00, load was slightly different than had been forecasted in the RTC time horizon. The RTD was able to schedule less energy on some internal resources, freeing up 10-minute reserves on those resources. This eliminated the reserve shortages and resulted in RTD LBMPs in the $200-$600 range. Furthermore, the pricing rules for external proxy buses dictate that the external congestion associated with the RTC evaluation be carried forward into the RTD proxy bus price, which is why the RTD PJM Keystone proxy bus price remained approximately $1,300 lower that the prices at the rest of the internal NYCA zones, just as it had been in RTC.

The higher load that was expected at the time RTC initiated for the 14:45-15:00 interval is precisely why the RTC was forecasting more than $2,000 LBMPs statewide, while the RTD LBMPs came in between $200-$600 because the RTD was initiated using load data that was twenty minutes more current than the load data RTC relied on for the same time period.

**Case 2**

a) On June 13, 2017, across a period of 35 minutes in HB 22 and HB 23, several RTD LBMPs were set at negative $150/MWh and lower at the PJM Linden VFT proxy bus, while the RTC LBMPs for the same time period and location were above $0/MWh.

b) On June 15, 2017 during HB 12, two RTD LBMPs were set at negative $3,100/MWh at the PJM Linden VFT proxy bus, while the RTC LBMPs for the same time period and location were above $0/MWh.

For both examples, flows over the Goethals PAR were higher in the RTD timeframe than the flows that were anticipated by the RTC. Small changes in power flows can make a big difference in a small electrical area like Staten Island as there may be few flexible resources available for the RTD to back down while RTC could modify external transaction schedules on the Linden VFT Scheduled Line and, in this case, the transmission constraints had high constraint costs set by the Transmission Shortage Cost.

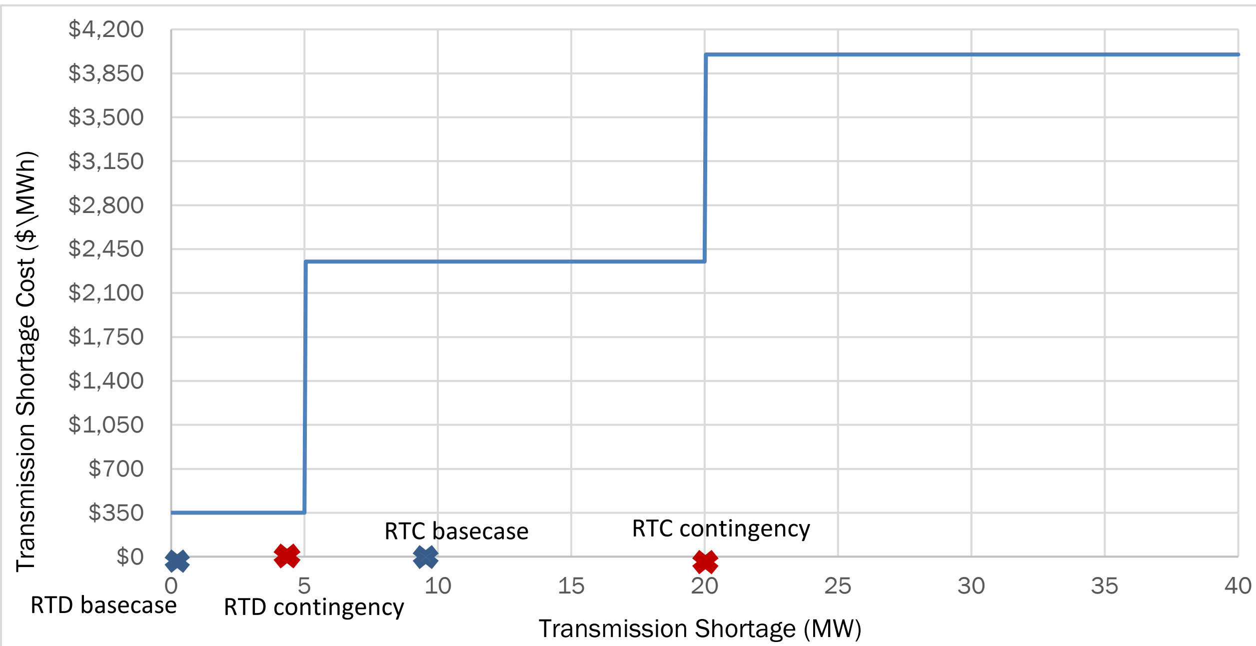
**Case 3**

On July 5, 2016 at 21:30, RTC forecasted a $4,743/MWh LBMP for Long Island. However, the

RTD LBMP for Long Island was only $800/MWh at 21:30.

This case was studied in detail to understand the driver for this $3,943/MWh price separation between the RTC and RTD. Analysis determined that the RTC and RTD prices were each set by the Transmission Shortage Cost[21]. The reason for using the Transmission Shortage Cost was that both the base case "Dunwodie-Shore_Rd 345" and the contingency case "Dunwodie- Shored_RTD 345 with Neptune HVDC tie line trip" constraints were violated at different shortage cost steps between the RTC and RTD ideal passes. Therefore, although both the RTC and RTD used the Transmission Shortage Costs to set the LBMP, they used different steps of the curve as shown in the figure below.

**Figure 26: Transmission Shortage Cost Representation**




In the RTC the "Dunwodie-Shore Rd 345" constraint was violated by 9.9MW and the "Dunwodie-Shore Rd_RTD 345 with Neptune HVDC tie line trip" constraint was violated by 19.8 MW. The contribution to the RTC price from this demand curve is $4,700 ($2,350 + $2,350 = $4,700). In RTD, the "Dunwodie-Shore Rd 345" constraint was violated by 0 MW, and the "Dunwodie- Shore Rd 345 with Neptune HVDC tie line trip" constraint was violated by 5 MW. Therefore, the contribution of this demand curve to the RTD price is $756 ($0 + $756 = $756).

The reason for flow difference on the Dunwodie- Shore Rd 345 constraint is that the RTD used off-line GT pricing to solve the overload on the constraint. In this particular case, there were two off-

[21] During this time the middle step of the Transmission Shortage Cost curve was $2,350/MWh.

line GT's that the RTD used in its ideal dispatch to reduce the flow on the constraint.

The NYISO was able to determine that the RTD used off-line GTs to solve the constraint by determining the shift factors of these two generators on the constraint and the resource schedules. Both the units had a shift factor of -1, which implies that they heavily affected the flow on the line. Because the two GTs were available to set the price in the RTD, this increased the flexibility of the system compared to the flexibility that was available to the RTC.

RTC does not utlize off-line GT pricing under the expectation that RTC should have committed the off-line GT's. However, in some situations, self scheduled generators which do not adhere to their submitted schedules could lead to differences between RTC's physical and ideal dispatch. In the RTC, the physical dispatch determines the schedules and commitments, while in the RTD physical dispatch determines the schedules. Also, the RTC's physical dispatch honors the day-ahead schedules of all non-quick start units. The ideal dispatch in both the RTC and RTD determines the prices.

In this particular scenario, there were self scheduled generators that were not following their submitted schedules. As RTC's physical dispatch honors the submitted schedule, RTC in its physical dispatch did not see the need to turn on the off-line GT's as it did not anticipate the self-scheduled generators not following their schedules. Therefore, the off-line GTs were not committed by the RTC.

However, the ideal dispatch of both the RTC and RTD consider the actual telemetry from all the units. Therefore, the difference caused by the self scheduled generators not following their submitted schedules was captured in the ideal dispatch of both RTC and RTD. To make up for the difference, both RTC and RTD ideal dispatch considered it economic to turn on the off-line GTs.

Currently, if the RTC does not commit the GTs in its physical dispatch, then the units are not available to set price in RTC's ideal dispatch. The RTD, on the other hand, has the capability to utilize an off-line GT if it is economic to do so in its ideal dispatch even if the unit is not committed by the RTC. By using off-line GT pricing, RTD was able to relieve the constraint. This is reflected by lower RTD prices, compared to RTC prices.

Similar results were observed on other days. For example, on July 31, 2016 at 21:30 the RTC price was $2,383.2/MWh and RTD price was $84.32/MWh, and on August 9, 2016 at 21:30 the RTC price was $2,388.69/MWh and RTD price was $91.64/MWh. In both of the identified intervals the price divergence between RTC and RTD was caused by off-line GT pricing being used in RTD but not in RTC, under circumstances similar to those described in Case 3.

The NYISO could consider revisiting the assumptions used in the physical and ideal dispatches of both the RTC and RTD. Better alignment between them coud help avoid some of the price divergences between these two programs. The NYISO could also consider using off-line GT pricing consistently in both the RTC and RTD by making an off-line GT available for RTC, to use in its ideal dispatch, even if the off-line GT was not committed in RTC's physical dispatch.

## Recent Initiatives Resulting in Improved RTC-RTD Coordination

This section highlights recent market design enhancements and modeling improvements, which have helped to improve RTC-RTD convergence. A single enhancement will not have a large effect on improving RTC-RTD convergence; however, over time the combined incremental effects will help to improve convergence.

#### ConEd PSEG Wheel Replacement

This project dealt with replacing a wheeling service between NYISO and PJM which modeled 1000 MW flowing from NYISO to PJM over JK interface and from PJM to NYISO over ABC interface. The wheel is replaced by optimized PAR flows over the ABC and JK interfaces to more effectively model NY-PJM AC interchange. This was implemented in May 2017.

#### Niagara Generation Modeling Improvements

This project included completing a modeling update that allows the Niagara Power Plant to be represented consistently in all components of the market software; security analysis, scheduling and pricing. This was implemented in May 2016. Potomac Economics reviewed the modeling improvement in the 2016 SOM report and found that the changes directly improved balancing congestion shortfalls.

#### Lake Erie loop flow modifications

A correlation exists between the severity of West Zone congestion and (a) the magnitude of unscheduled clockwise loop flow, and (b) sudden changes in loop flow interval-over-interval in the clockwise direction. Large price swings are typically coincident with RTD dispatch intervals where the amount of unscheduled clockwise loop flow experienced is significantly higher than the amount forecasted in the corresponding RTC commitment run. The NYISO capped the maximum value of loop flow used to initialize RTC. This prevents RTC from initializing with a difficult-to-achieve counter-clockwise loop flow value, reducing opportunity of RTD to be faced with constraints that can occur when the counter-clockwise loop flow RTC expected fails to materialize. A modification that NYISO implemented in June of 2016 assists in minimizing transient price spikes that drive differences between the RTC and RTD.

#### Hybrid GT Pricing Improvements

Modeling GTs as dispatchable in the pricing pass in the RTD, while continuing to exclude certain out-of-merit resources, provides greater consistency between the pricing methods used in the RTC and RTD. This change was implemented in Feb 2017 and ensures that both the RTC and RTD use the same supply curve, thereby reducing the price divergences between the RTC and RTD.

#### Initialization of Lake Success and Valley Stream PARs (901/903 lines)

The RTC and RTD now use the 901 and 903 PARs telemetered control schedule, rather than their telemetered actual flow, when initializing. The telemetered control schedule gives the MW value towards which the PARs are automatically adjusting. This change largely eliminates the effects of second-to-second volatility on generator commitments and improves the RTC-RTD assumption of where the PAR flows will be throughout the optimization window. This change results in a decrease in the price volatility caused by the Lake Success and Valley Stream PARs fixed schedules. This improvement was implemented in May 2016.

#### Graduated Transmission Demand curve

Reverting the second step of the graduated transmission shortage cost from $2350/MWh to $1175/MWh helped reduce the magnitude of RTC-RTD price divergence in instances when small changes in the violation of the transmission constraint in the RTC and RTD lead to significant LBMP divergences between the two programs. The stepped shortage-pricing curve was implemented in Feb 2017 with additional modifications to the curve and treatment of constraint relaxation implemented in June 2017.

#### Load Forecast Process Improvement

A correlation between consistent under forecasting of load by RTC and under forecasting of RTC prices was observed in the overnight hours in all zones. Load forecast process improvement were made to better align the RTC load forecast. This improvement was implemented in June 2017 and eliminated the price divergences between the RTC and RTD in the overnight hours.

# Conclusion

Overall, there is good convergence between the RTC and RTD prices. Where divergences between the RTC and RTD were observed, generally congestion pricing was found to be a significant contributor. Some of the congestion pricing could be explained by the differences in the flexibility of suppliers, like external interchange, between the RTC and RTD evaluations, but more detailed interval by interval analysis would be necessary to pinpoint every causality. The MMU's recommendations are provided below which complement their analysis above.

Given the nature of the observations from the analysis performed, the NYISO offers opportunities for consideration and a set of recommended actions later in this section.

## Potomac Economics Recommendations

The MMU performed an analysis to determine the primary sources of real-time price spikes at constrained locations across the NYCA. The MMU's analysis was based on real-time price volatility between five-minute RTD intervals. The price spikes observed only accounted for 5% of the RTD intervals. Potomac defined a transmission constraint price spike as a shadow price that exceeds $150/MWh and increases at least 100 percent from the previous interval. Price spikes at the power balance constraint were defined as a reference bus price that exceeds $100/MWh and increases at least 100 percent from the previous interval. The MMU's analysis indicated that resources scheduled by RTC, including external interchange and gas turbine shutdowns, drove the majority of real-time price spikes throughout the NYCA.

External Transaction scheduling creates inconsistencies, as the timing of the ramps are different for RTC-RTD evaluations of external interchange schedules. Based on the differences in the ramp assumptions the MMU recommends adjusting the timing of the look-ahead evaluations of the RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating interval :05, :20, :35, and :50 rather than :00, :15, :30, and :45.

Based on these observations and analysis the MMU offered the following recommendations:

- Add two near-tem look-ahead evaluation periods to RTC and RTD around the quarter hour;
- Adjust the timing of the look-ahead evaluations of RTC and RTD to be more consistent with the ramp cycle of external interchange;
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line;
- Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbine generators with the actual demonstrated performance; and

- Address inconsistencies between the ramp assumptions used in RTD's physical pass and RTD's pricing pass when units are ramping down.

## Opportunities for Consideration and Recommendations

This section highlights several opportunities for consideration that could further improve RTC-RTD coordination.

#### Constraint Specific Transmission Demand Curves (Recommended)

Currently, all transmission constraints utilize a common Transmission Shortage Cost curve. The congestion component of the LBMP is sensitive to divergences between the RTC and RTD. Small MW differences in the violation of a constraint can lead to significant LBMP divergences between the RTC and RTD.

This project would reassess the existing Transmission Shortage Cost construct. By providing the RTC and RTD more flexibility in its application of pricing transmission constraints there would be less extreme volatility in congestion prices between the RTC and RTC, thereby improving price convergence.

Options include developing a more gradual slope to the shortage cost curve used for pricing transmission constraints, and/or developing distinct curves for different types of constraints.

The NYISO recommends pursing changes to the Transmission Shortage Cost modeling that would improve real-time price formation.

#### 100+kV Constraint Modeling (Recommended)

Currently, the New York Transmission Owners (TOs) are responsible for operating the lower kV system. The NYISO helps the TOs manage the constraints through TO-requested resource commitments and certain operator actions. In instances where constraints are managed through Out-of-Merit[22] (OOM) actions, the market prices will not represent the true cost of maintaining system reliability.

Because OOM actions are immediately incorporated into the RTD, the RTD may have a different set of supply resources than the RTC for the same period, possibly leading to divergence between the RTC and RTD prices. Although such actions were not studied as part of this analysis, the NYISO believes they will positively influence RTC-RTD price convergence by better aligning scheduling and pricing in real-time.

[22] Out-of-Merit (OOM) is defined as: the designation of Resources committed and/or dispatched by the ISO at specified output limits for specified times to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch.

This project will create criteria for securing certain select 100+kV constraints within the NYISO market model.The NYISO recommends continuing to work on incorporating 100+kV transmission constraints into energy market pricing.

#### RTD Pricing Improvements for External Interfaces

Transactions at an external proxy buses are economically evaluated and scheduled in real-time only by the RTC, not by the RTD. The RTD does not re-evaluate external transaction schedules, but instead sees external transactions as fixed interchange. If the RTC-established external transaction schedules are sufficient to secure the constraint, the RTD will see an unconstrained solution.

Developing pricing logic that would carry the marginality of external transaction scheduling from the RTC to the RTD would result in both programs having similar solution sets to solve the constrained optimization problem. This would potentially minimize the price divergences between the two programs being caused by the way external transactions are treated currently.

The NYISO recommends completing other priorities before considering this modification.

#### 5-minute Interchange Scheduling

Transactions at an external proxy buses are economically evaluated and scheduled in real-time only by the RTC, not by the RTD. The RTD does not re-evaluate transaction schedules, but instead sees transactions as fixed interchange. This can reduce the flexibility the RTD has to deal with changes on the grid since the last RTC, and could potentially lead to price divergences between the RTC and RTD.

Incorporating 5-minute interchanges scheduling into the real-time market would provide the RTD with additional scheduling flexibility and remove some systemic differences between the RTC and RTD. Although 5-minute interchange scheduling may not be workable at all of the external NYCA interfaces, incorporating it at a few locations may also help improve price convergence between the RTC and RTD.

The NYISO recommends further evaluating the viability of such an improvement in the future.

#### Treatment of Resource Ramping between Physical and Ideal Dispatch

The physical and ideal dispatch passes of both the RTC and RTD utilize different starting conditions and ramp strategies. This can create large differences between the physical schedule and ideal prices, as well as differences between the RTC and RTD schedules and prices.

The NYISO recommends further investigation of these differences before it can suggest any changes that should be considered.

#### Enhance RTD's Evaluation Window

Due to the structure of the RTD, there can be times when the look-ahead of the RTD is unaware that planned changes in external schedules and resource ramping are imminent. This is caused by look-ahead evaluation differences between the RTC and RTD that can lead to unnecessary RTD price volatility. The DNI analysis conducted in the study did not show this as a significant concern. Nevertheless, the NYISO recognizes that this is a structural difference between the two programs and therefore suggests this recommendation.

Incorporating five-minute time steps for the first twenty to thirty minutes of each RTD evaluation period would ensure that the RTD is aware of and positioning the system for these planned changes. This would reduce unnecessary price volatility due to the structure of the RTD look-ahead software.

The NYISO recommends completing other priorities before considering this modification.

#### Allow Flexible Shutdown of DAM Committed Generation

Today, the shutdown of day ahead committed generators must occur at the top of the hour due to the structure of the day ahead and balancing markets. This can lead to large changes in supply at the top of an hour and drive unnecessary price volatility between RTC and RTD.

This project would consider ways for RTD to vary the shutdown of generators from the top of the hour by a few minutes to reduce systemic shocks to the market algorithms when large amounts of generation is shutting down.

The NYISO recommends completing other priorities before considering this modification.

#### Lake Success and Valley Stream PAR schedule changes (Recommended)

The Lake Success and Valley Stream PARs are operated based on a long-standing transmission agreement between Con Ed and LIPA and typically change schedules twice a day. The PAR schedules increase flow to Con Edison at 10:00 a.m. and decrease flow to Con Edison at 10:00 p.m.

The NYISO recommends that improvements to the RTC and RTD be made such that the software includes these schedule changes in advance of HB 22. By making this improvement, it gives RTC and RTD a view of the schedule change in their respective forward-looking optimizations.

The NYISO recommends pursuing this change as quickly as possible.

#### Use of Offline GTs in RTC and RTD

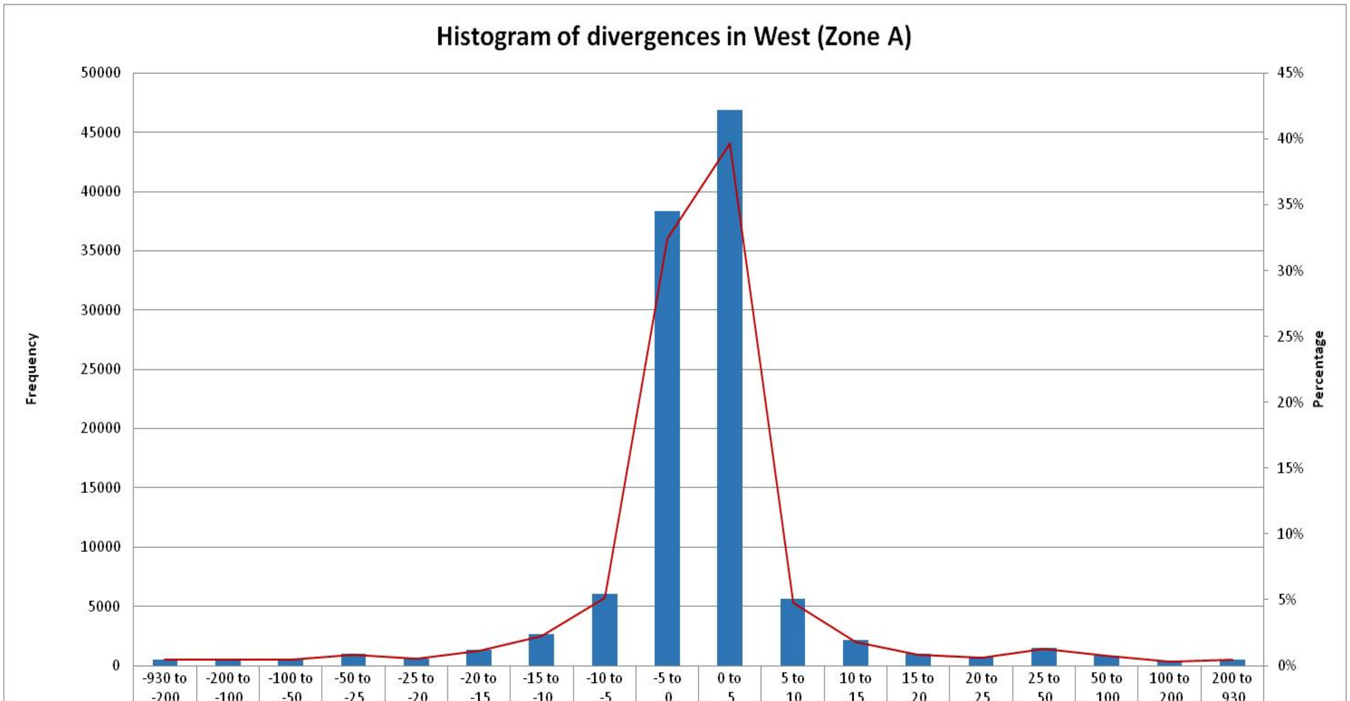
The NYISO could consider revisiting the assumptions used in the physical and ideal dispatches of both the RTC and RTD. Better alignment between them coud help avoid some of the price excursions between these two programs. In addition, the NYISO could also consider using off-line GT pricing consistently in both the RTC and RTD by making an off-line GT visible to the RTC, to use in its ideal dispatch, even if the off-line GT was not committed withing the RTC physical dispatch.

The NYISO recommends further investigating the treatment of off-line GT pricing in both RTC and RTD.

# Appendix

The appendix contains additional details supporting the RTC-RTD price convergence analysis.

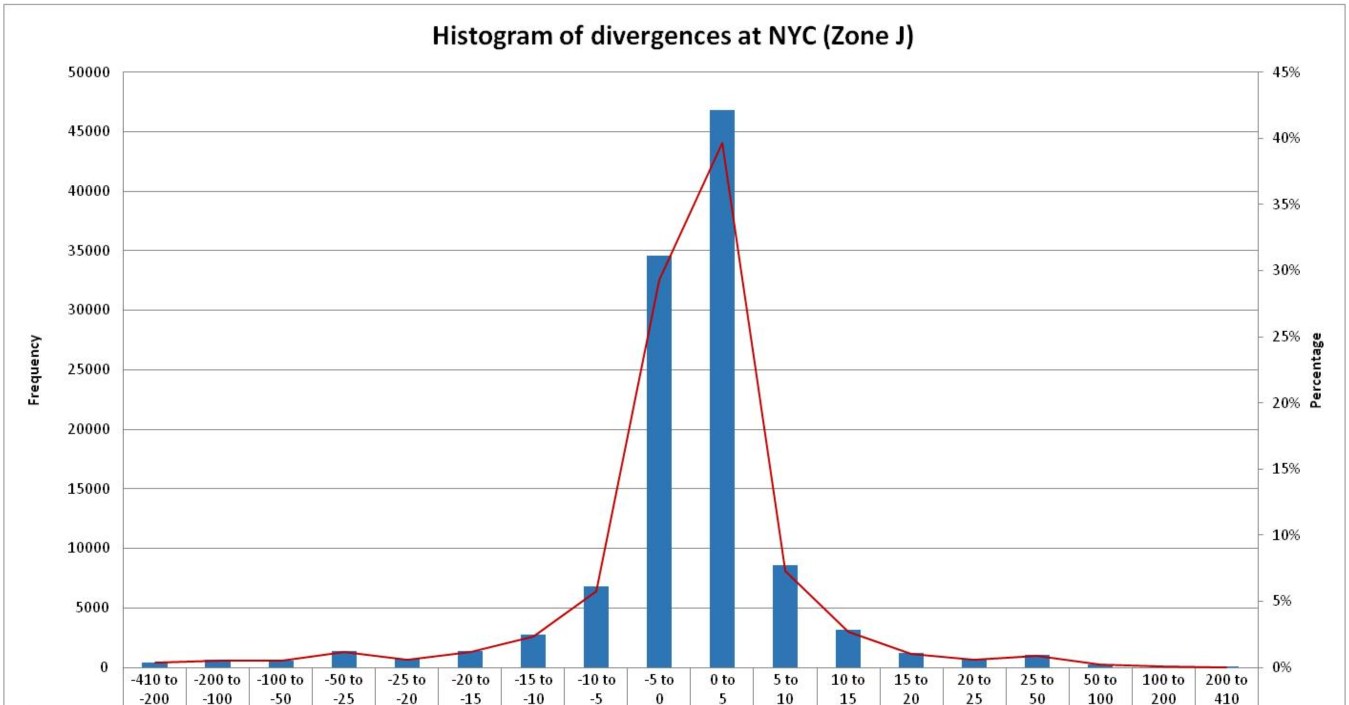
**Figure 27: Histogram for West Zone (Zone A)**




| | -930 to -200 | -200 to -100 | -100 to -50 | -50 to -25 | -25 to -20 | -20 to -15 | -15 to -10 | -10 to -5 | -5 to 0 | 0 to 5 | 5 to 10 | 10 to 15 | 15 to 20 | 20 to 25 | 25 to 50 | 50 to 100 | 100 to 200 | 200 to 930 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| percent | 0.47% | 0.50% | 0.49% | 0.88% | 0.53% | 1.17% | 2.37% | 5.45% | 34.53% | 42.16% | 5.08% | 1.92% | 0.91% | 0.64% | 1.34% | 0.76% | 0.34% | 0.46% |
| Frequency | 492 | 526 | 514 | 922 | 553 | 1220 | 2476 | 5689 | 36066 | 44044 | 5306 | 2005 | 948 | 671 | 1401 | 791 | 358 | 476 |

- In 76.69% of the time intervals the price divergences are between $-5 to $ 5 and 87.22% of the time intervals the divergences are between $-10 to $-10.
- Across the $5 to $20 and the -$20 to -$5 bins, negative divergences are greater than the positive divergences is 1.08%.
- Across the $20 to $100 and the -$100 to -$20 bins, the percentage of time divergences are positive is greater than the percentage of time divergences are negative by 0.84%.
- In summary, between -$100 and $100, the intervals with positive divergences are more frequent (by 6% of the time) than the intervals with negative divergences.The difference is driven by the $5 to $10 and the -$10 to -$5 bins.
- In addition, when divergence exceeds $100 or $-100, the negative divergence intervals are more frequent

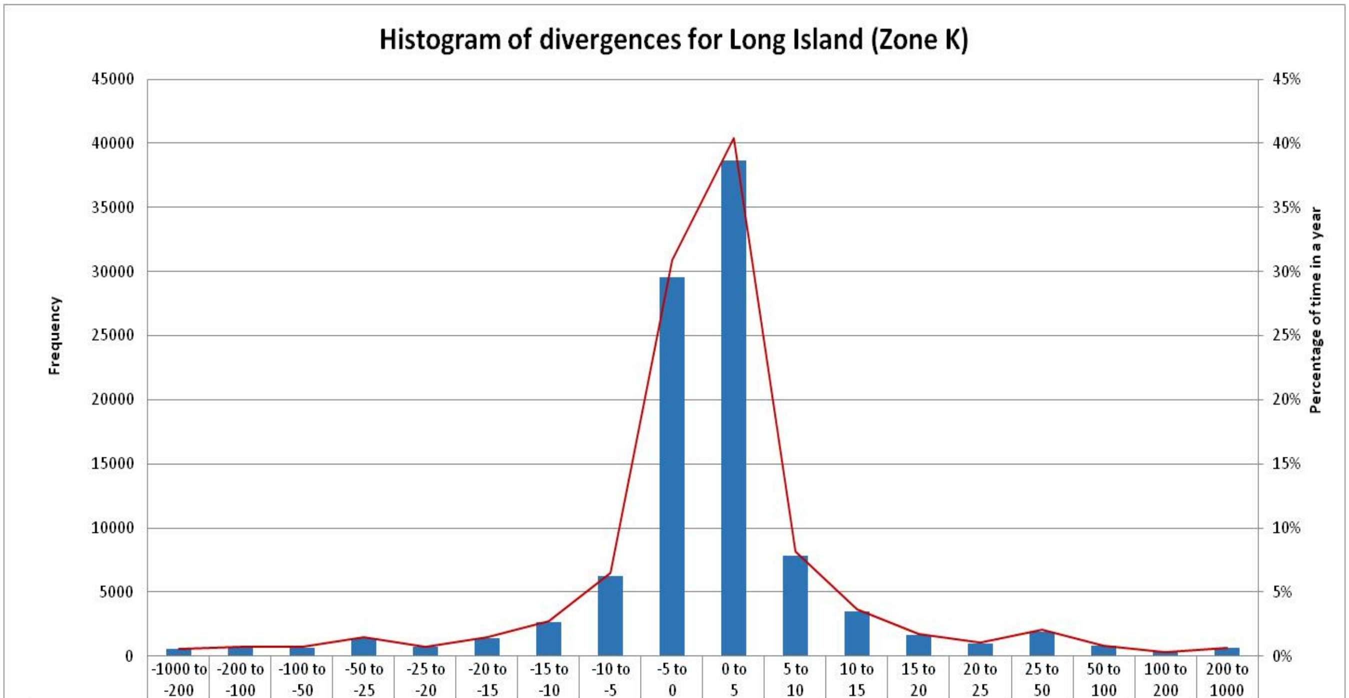
**Figure 28: Histogram for NYC zone (Zone J)**




| | -410 to -200 | -200 to -100 | -100 to -50 | -50 to -25 | -25 to -20 | -20 to -15 | -15 to -10 | -10 to -5 | -5 to 0 | 0 to 5 | 5 to 10 | 10 to 15 | 15 to 20 | 20 to 25 | 25 to 50 | 50 to 100 | 100 to 200 | 200 to 410 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| percent | 0.38% | 0.58% | 0.55% | 1.26% | 0.63% | 1.22% | 2.49% | 6.10% | 31.14% | 42.12% | 7.71% | 2.85% | 1.09% | 0.61% | 0.93% | 0.22% | 0.10% | 0.02% |
| freq | 398 | 607 | 572 | 1315 | 664 | 1274 | 2604 | 6383 | 32568 | 44046 | 8061 | 2982 | 1141 | 636 | 974 | 235 | 102 | 23 |

- In 73.26% of the time intervals, the price divergences are between \$-5 to \$ 5 and 87.07% of the time the divergences are between \$-10 to \$-10.
- Between \$5 to \$100, 13.41% of time the RTC LBMP is greater than the RTD LBMP
- The tail ends of the histogram (i.e.) between \$100 to \$410. 0.96 % of the time, the divergences are between -\$410 to -\$100. In contrast, the divergences between \$100 to \$410 is only 0.12% of time
- These positive divergence time intervals between -\$100 to \$100, are driven mostly by the higher divergences in the \$0 to \$10 bins. Considering bins beyond +/-\$10, generally, the negative divergences occur higher percentage of times compared to positive divergences.
- Between \$10 to \$410, the percentage of positive divergences are 5.82% and between -\$410 to -\$10 the percentage of negative divergences are 7.11%.

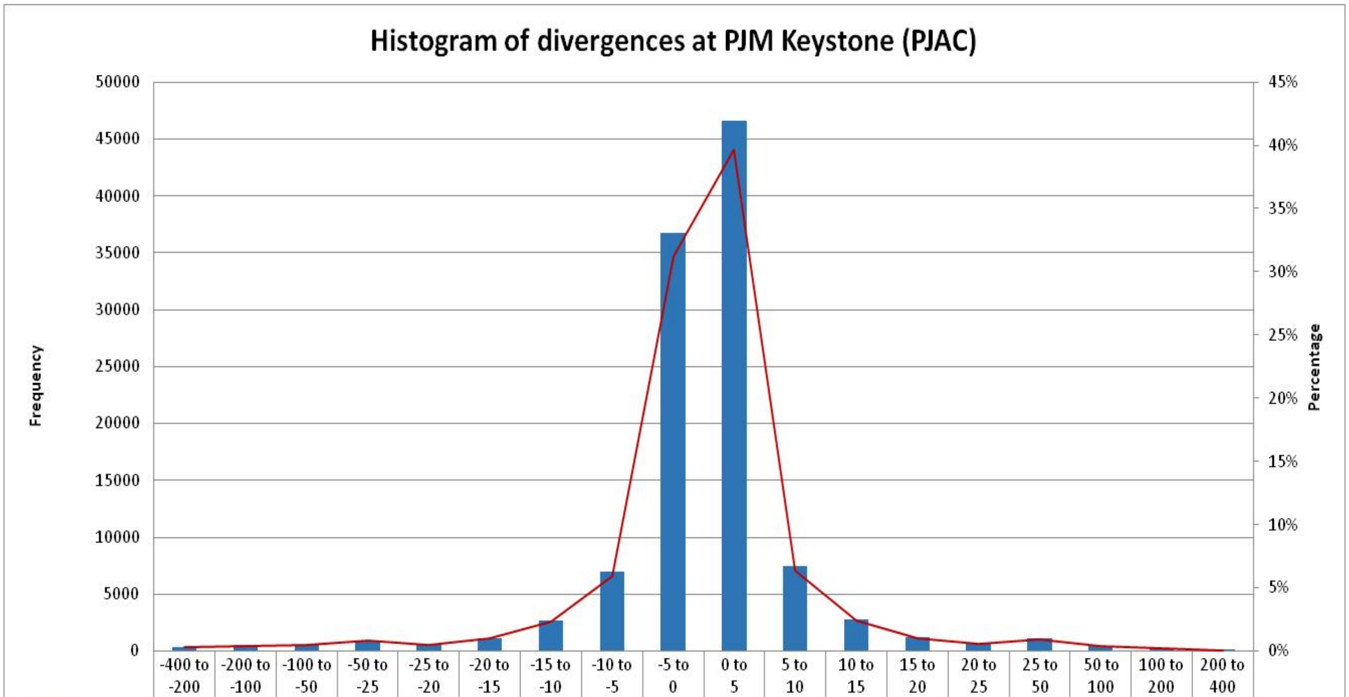
**Figure 29: Histogram for Long Island Zone (Zone K)**




| | -1000 to -200 | -200 to -100 | -100 to -50 | -50 to -25 | -25 to -20 | -20 to -15 | -15 to -10 | -10 to -5 | -5 to 0 | 0 to 5 | 5 to 10 | 10 to 15 | 15 to 20 | 20 to 25 | 25 to 50 | 50 to 100 | 100 to 200 | 200 to 1000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Percentage | 0.56% | 0.69% | 0.69% | 1.41% | 0.69% | 1.41% | 2.65% | 6.22% | 29.55% | 38.63% | 7.80% | 3.46% | 1.63% | 0.99% | 1.94% | 0.78% | 0.30% | 0.61% |
| Frequency | 588 | 720 | 721 | 1475 | 727 | 1480 | 2768 | 6505 | 30915 | 40424 | 8159 | 3619 | 1705 | 1036 | 2031 | 811 | 309 | 641 |

- In 68.18% of the time intervals, the price divergences are between $-5 to $ 5 and 82.2% of the time the divergences are between $-10 to $-10.
- Between $5 to $100, the percentage of time the divergences are positive is 16.6% and 13.07% of the time, the divergences are between -$100 to -$5.
- The positive divergences being higher in these bins can be mostly accounted to the $0 to $10 bins. The percentage of time the price divergences are between $10 to $100 is 8.8% and the percentage of time the divergences are between $-100 to -$10 is 6.85%.
- The tail ends of the spikes between $100 to $1000 and -$1000 to -$100 follow the same pattern as all other zones. The negative divergences intervals occur a higher percent of time (0.34%)

**Figure 30: Histogram for Proxy PJM Keystone**




| | -400 to -200 | -200 to -100 | -100 to -50 | -50 to -25 | -25 to -20 | -20 to -15 | -15 to -10 | -10 to -5 | -5 to 0 | 0 to 5 | 5 to 10 | 10 to 15 | 15 to 20 | 20 to 25 | 25 to 50 | 50 to 100 | 100 to 200 | 200 to 400 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| percentage | 0.30% | 0.46% | 0.48% | 0.85% | 0.47% | 1.04% | 2.45% | 6.30% | 33.05% | 41.96% | 6.72% | 2.54% | 1.11% | 0.58% | 0.97% | 0.42% | 0.19% | 0.09% |
| Frequency | 313 | 487 | 508 | 891 | 497 | 1089 | 2575 | 6617 | 34695 | 44047 | 7057 | 2668 | 1164 | 610 | 1016 | 443 | 198 | 97 |

- In 75.01% of the time intervals, the price divergences are between $-5 to $ 5 and 88.03% of the time the divergences are between $-10 to $-10.
- Between $5 to $100, the percentage of time the divergences are positive is 12.34% and 11.59% of the time, the divergences are between -$100 to -$5.
- The positive divergences being higher in these bins can be mostly accounted to the $0 to $10 bins.
- The percentage of time the price divergences are between $10 to $100 is 5.62% and the percentage of time the divergences are between $-100 to -$10 is 5.29%.
- In tail ends of the spikes between $100 to $400and -$400 to -$100 percentage of time the divergence is in the negative dollar bins is higher than the positive bins by 0.48%

**Figure 31: Average LBMP divergence over a year for PJM Keystone Proxy Bus**

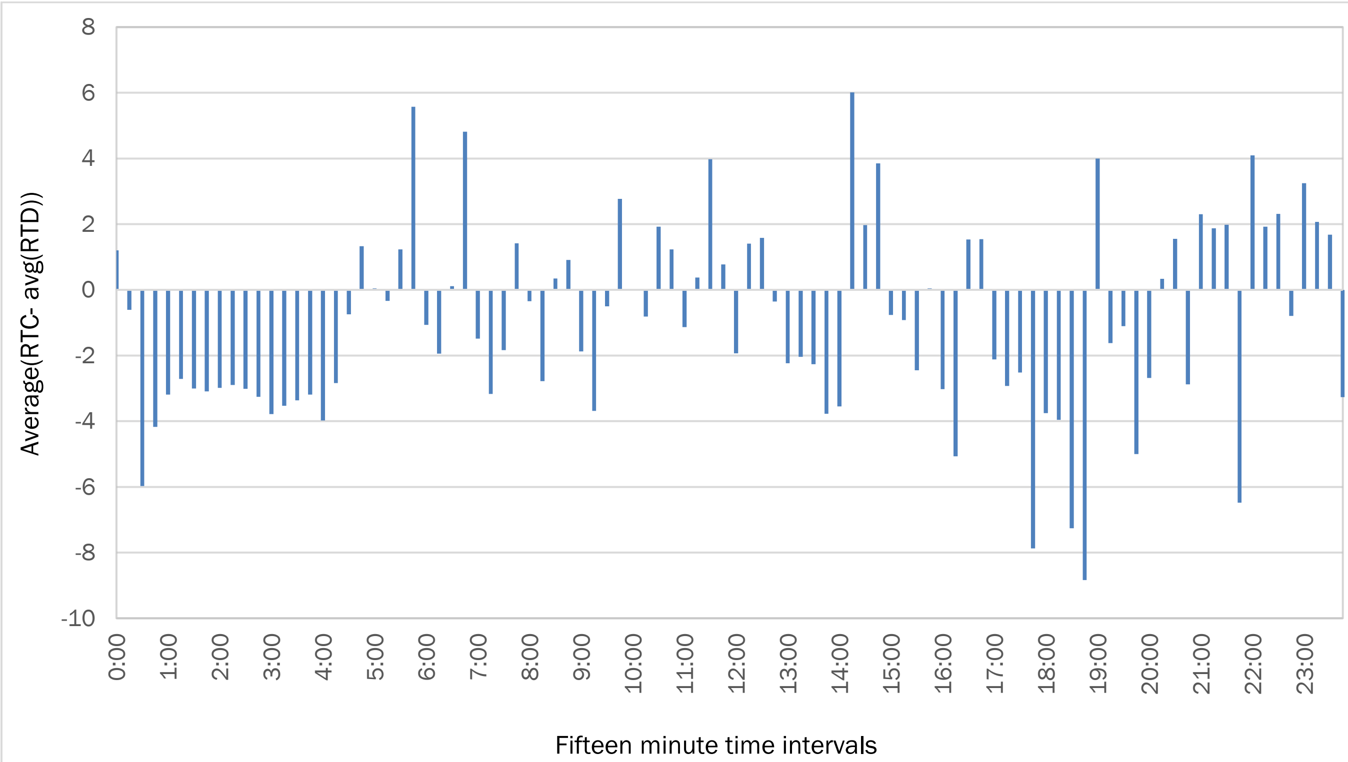



Figure 31 shows the average LBMP divergence between RTC and RTD at fifteen-minute intervals for a year at PJM Keystone proxy bus by time-of-day. This chart uses the RTC LBMP values at quarter hour intervals and the RTD LBMP values used are the average of three-five minute RTD LBMP's corresponding to a particular RTC. The LBMP divergence is then the averaged RTD LBMP value subtracted from the RTC LBMP value.

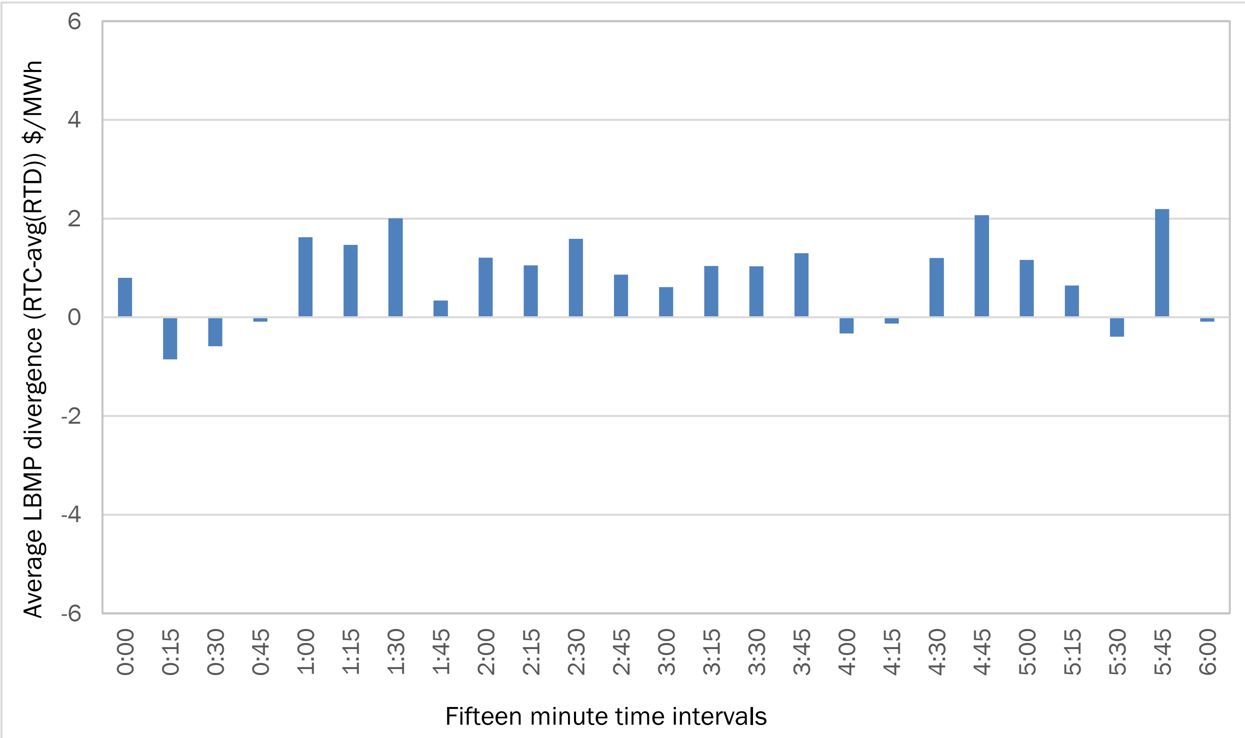
High magnitude of average price differences are observed in the evening hours specifically at 5:45pm, 6:45pm, 7:45pm, 8:45pm, 9:45pm, 10:45pm and 11:45pm. This phenomenon is not as prominent in internal zones during the same time-of-day.

This possibly occurs because large number of generators are shutting off as per their Day-ahead-market schedules at the top-of-the-hour. The other possible reason could be ramping of interchange in RTD that RTC does not have to deal with, thus causing price spikes in the last quarter of these hours.

In the morning hours, the price divergences between RTC and RTD observed during the study period could be attributed to the overnight load forecast problem as discussed above. However, the

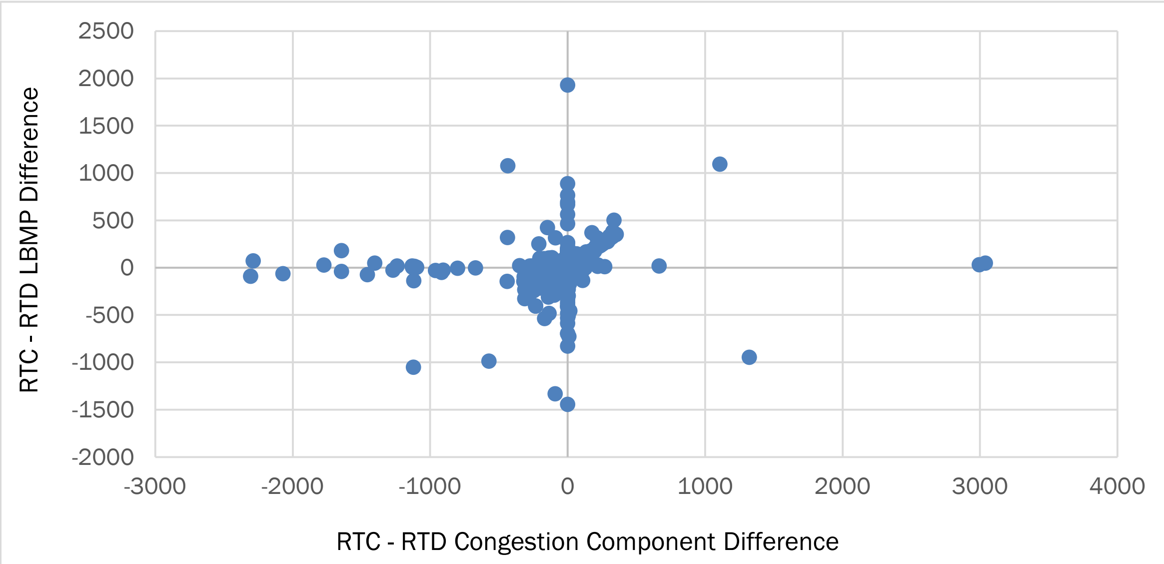
NYISO has since improved its process. This is demonstrated in the next figure. Figure 32 shows the LBMP divergences in the month of September 2017 for the PJM Keystone proxy bus.

**Figure 32: Average LBMP divergence for PJM Keystone Proxy Bus from Sep 2017 - Oct 2017**



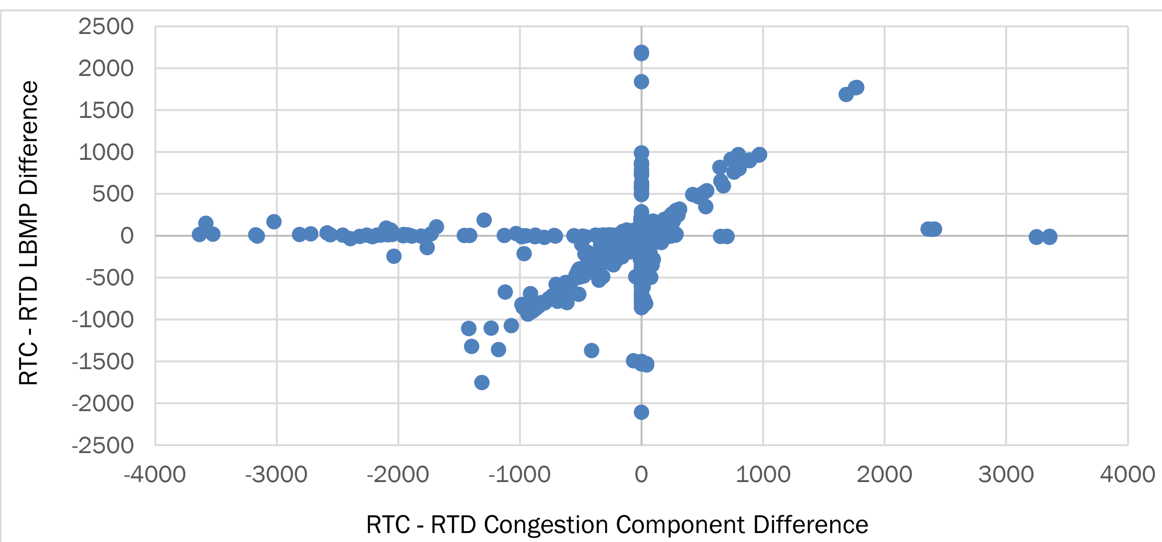

- Based on the analysis from more recent months in late 2017, the observed LBMP divergence in the morning hours (where RTC prices were consistently higher than RTD prices) has been addressed by the NYISO's implementation of operational process improvements.

**Figure 33: Scatter Plot of RTC minus RTD LBMP and Congestion Differences for Zone J**



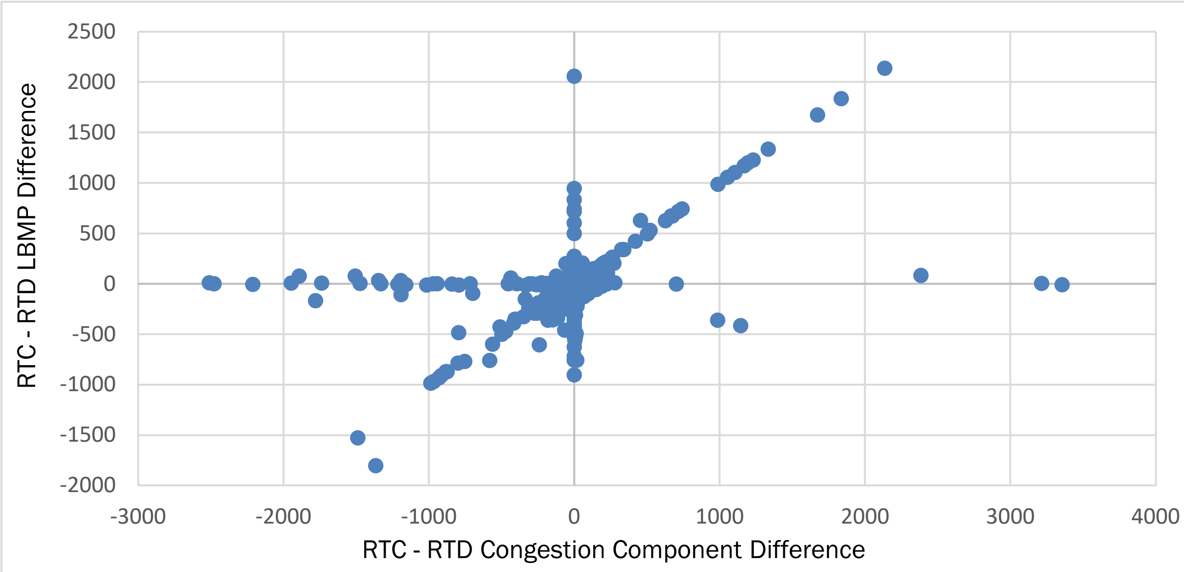

- This figure represents the correlation of the LBMP difference to the congestion component difference for Zone J.
- The data indicates that there is a weak relationship between the two variables, with a correlation coefficient of 0.30.
- Other factors could be causing LBMP price divergences in Zone J, such as load differences

**Figure 34: Scatter Plot of RTC-RTD LBMP and Congestion Differences for the Keystone Proxy Bus**



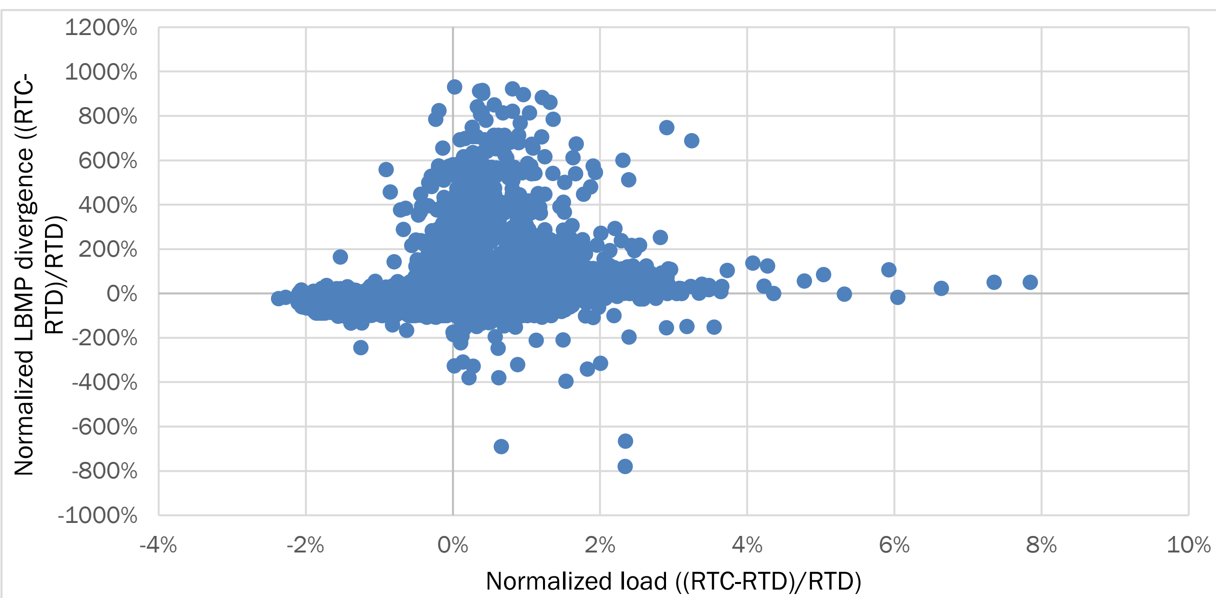

- Figure 34 represents the correlation of the LBMP difference to the congestion component difference for PJM Keystone proxy bus.
- The analysis reveals that there is a weak correlation between the two variables, with acorrelation coefficient of 0.16.

**Figure 35: Scatter Plot of RTC-RTD LBMP and Congestion Differences for the Linden VFT Proxy Bus**



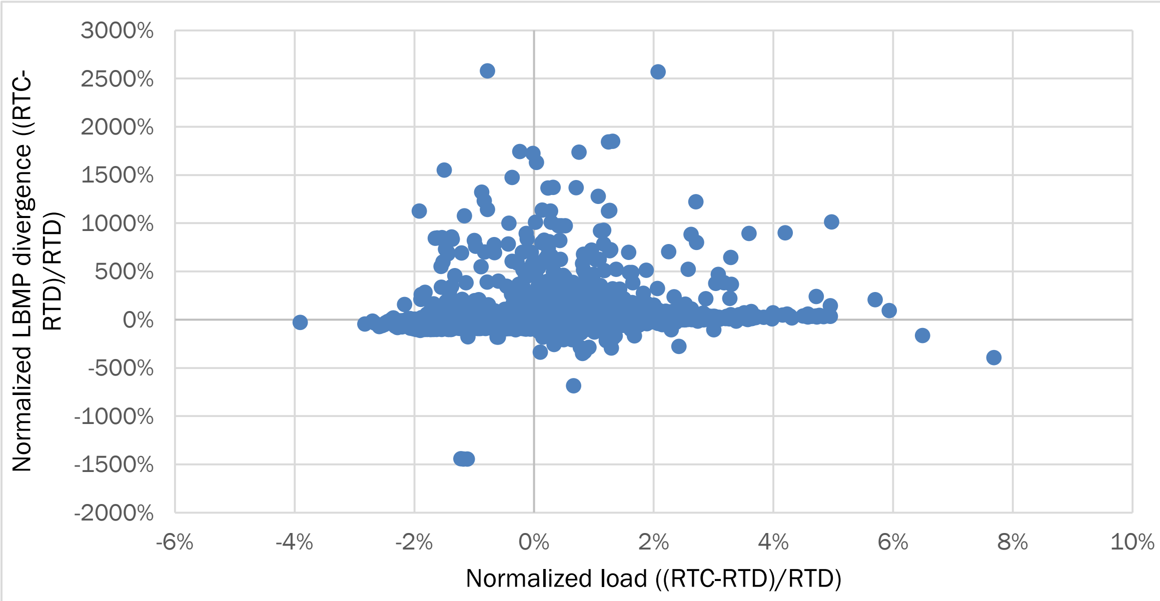

- Figure 35 represents the the LBMP difference to the congestion component difference for the Linden VFT Proxy Bus.
- The analysis reveals that there is a moderate correlation between the two variables, with a correlation coefficient of 0.46.

**Figure 36: Scatter Plot of Normalized Load Differences and LBMP Divergences for Summer Months**



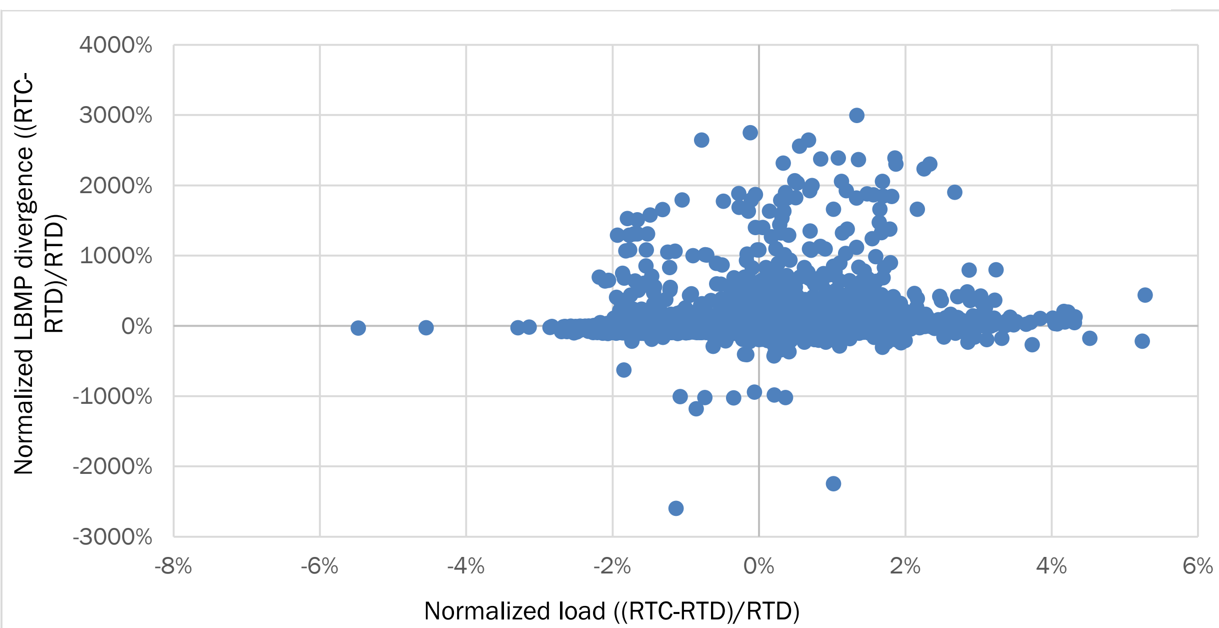

- The correlation coefficient between the two datasets is 0.2, indicating a weak correlation between normalized RTC-RTD load differences and normalized RTC-RTD LBMP divergences in the summer months

Figure 37: Scatter Plot of Normalized Load Differences and LBMP Divergences for Winter Months



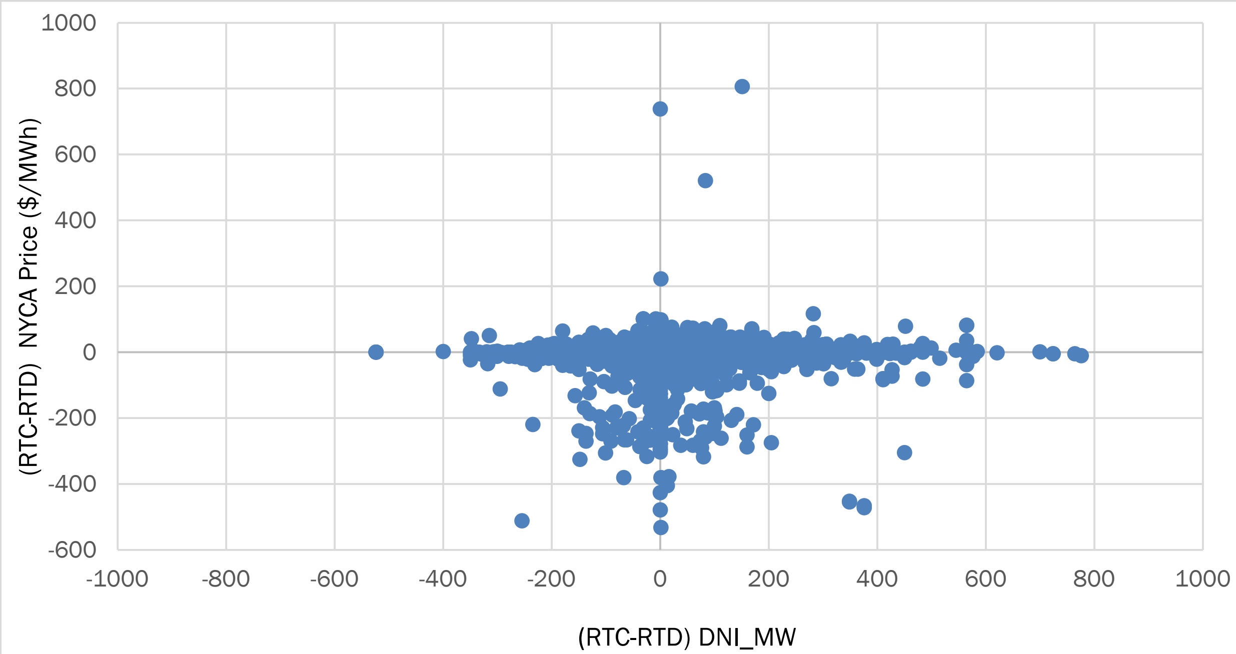

- The correlation coefficient between the two datasets is 0.17 for the winter months, indicating that the two datasets have a weak relationship.

Figure 38: Scatter Plot of Normalized Load Differences and LBMP Divergences for Spring Months



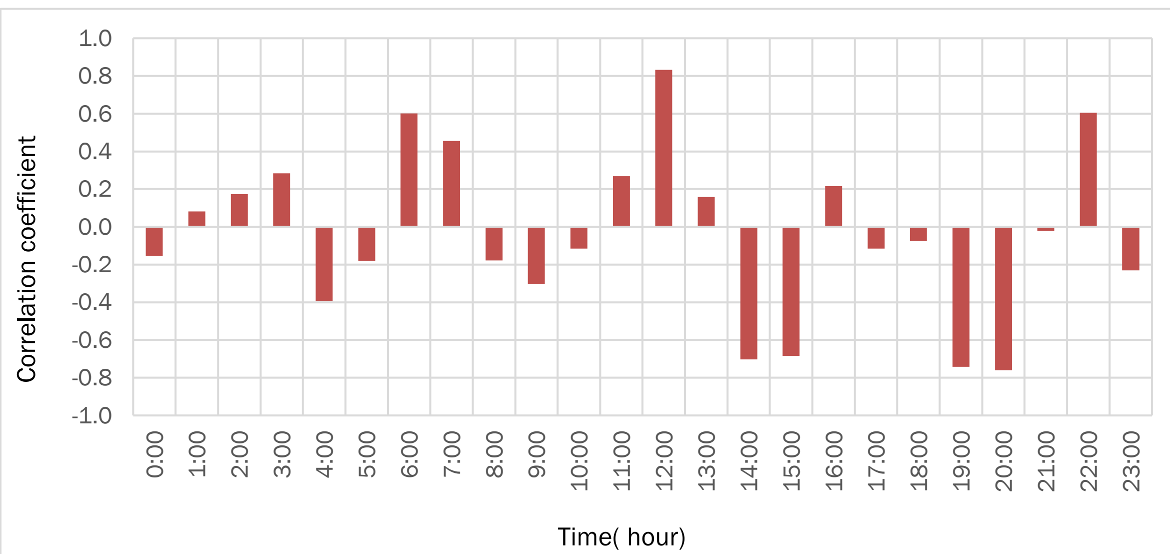

- The correlation coefficient is 0.15 between the RTC-RTD normalized load differences and normalized LBMP divergences for the spring months, indicating that the two datasets have a weak relationship.

**Figure 39: Scatter Plot of Net DNI Difference and NYCA Price Divergences for Winter Months**



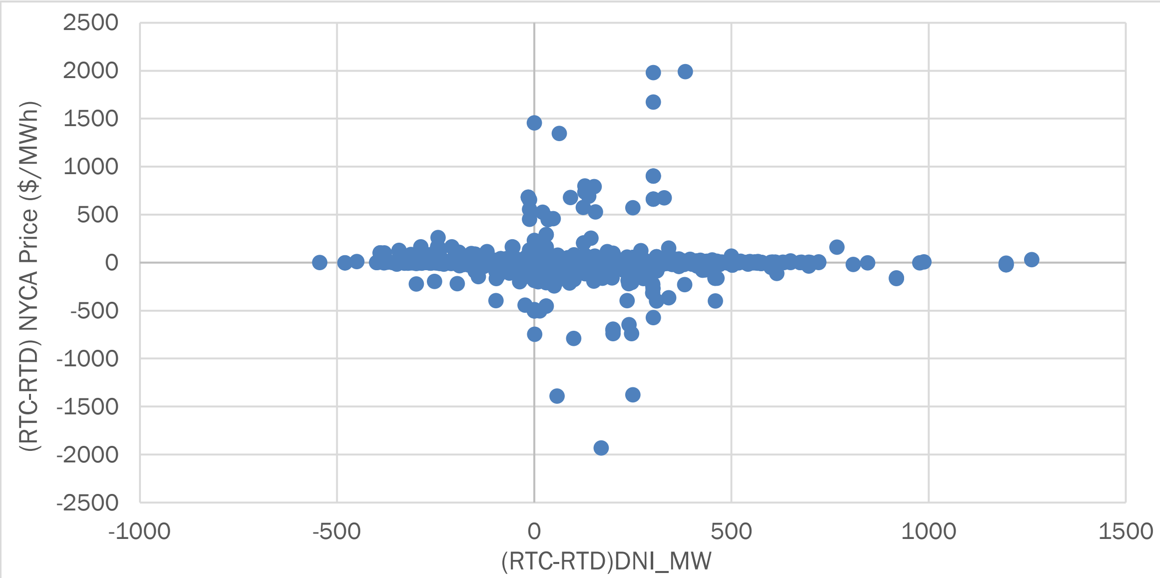

- The correlation coefficient is 0, implying there is no correlation between the DNI differences between RTC and RTD and NYCA LBMP price divergences in the winter months.

**Figure 40: Correlation Coefficient for Net DNI Changes and NYCA Price Divergences for Winter Months**



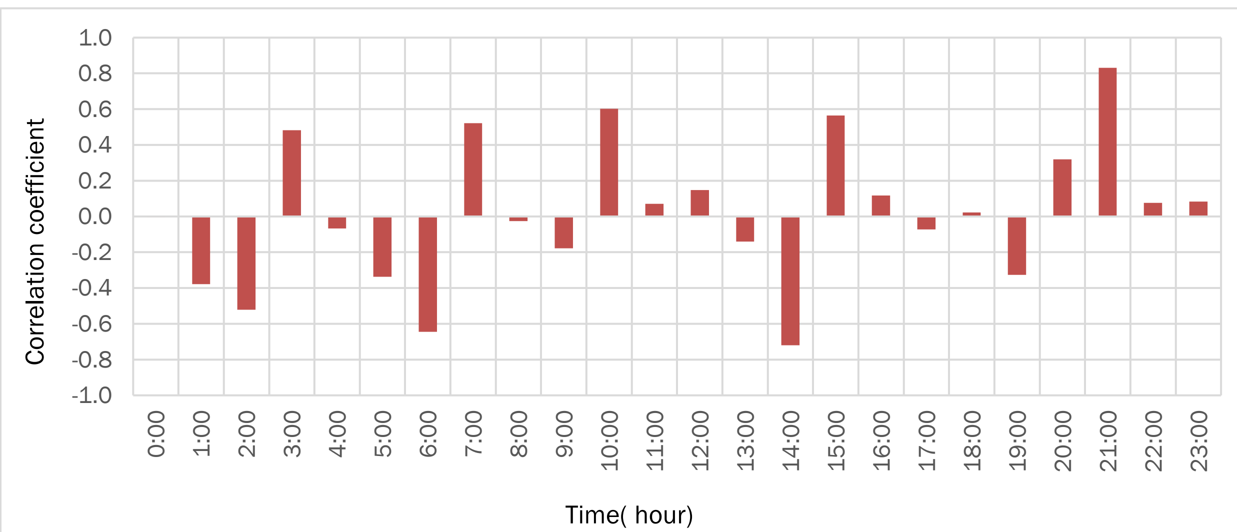

- The correlation coefficients of NYCA LBMP divergences and DNI changes by hour, for the three winter months (Dec 2016, Jan 2017 and Feb 2017).
- There is a strong correlation between the two datasets in the hours beginning 12, 14, 19 and 20. All other hours in the day show a weak correlation, or no correlation.

**Figure 41: Scatter Plot of Net DNI Difference and NYCA Price Divergences for Summer Months**




- The correlation coefficient is -0.01, indicating the datasets (DNI difference and LBMP difference) have no correlation.

**Figure 42: Correlation Coefficient for Net DNI Changes and NYCA Price Divergences for Summer Months**




- The above figure identifies a strong correlation between the two datasets in hours 6, 14,and 21. All the other hours in the day show a weak correlation or no correlation.
- The correlation coefficient is -0.02 between DNI differences and NYCA LBMP divergences for the spring months, indicating no correlation between the two datsets.

Figure 43: Scatter Plot of Net DNI Difference and NYCA LBMP Divergences for Spring Months

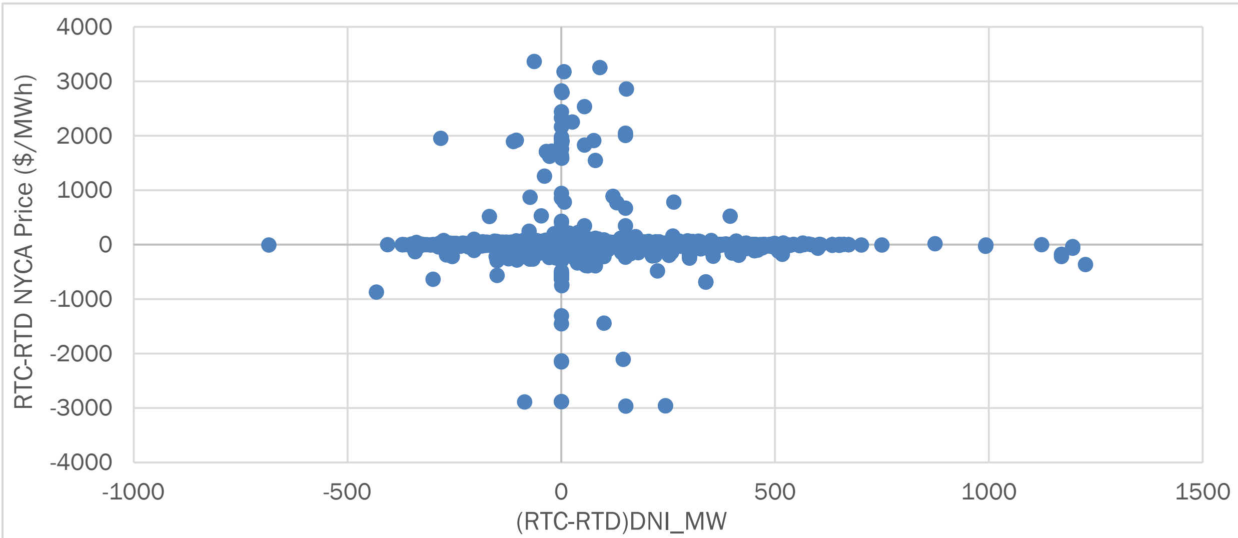
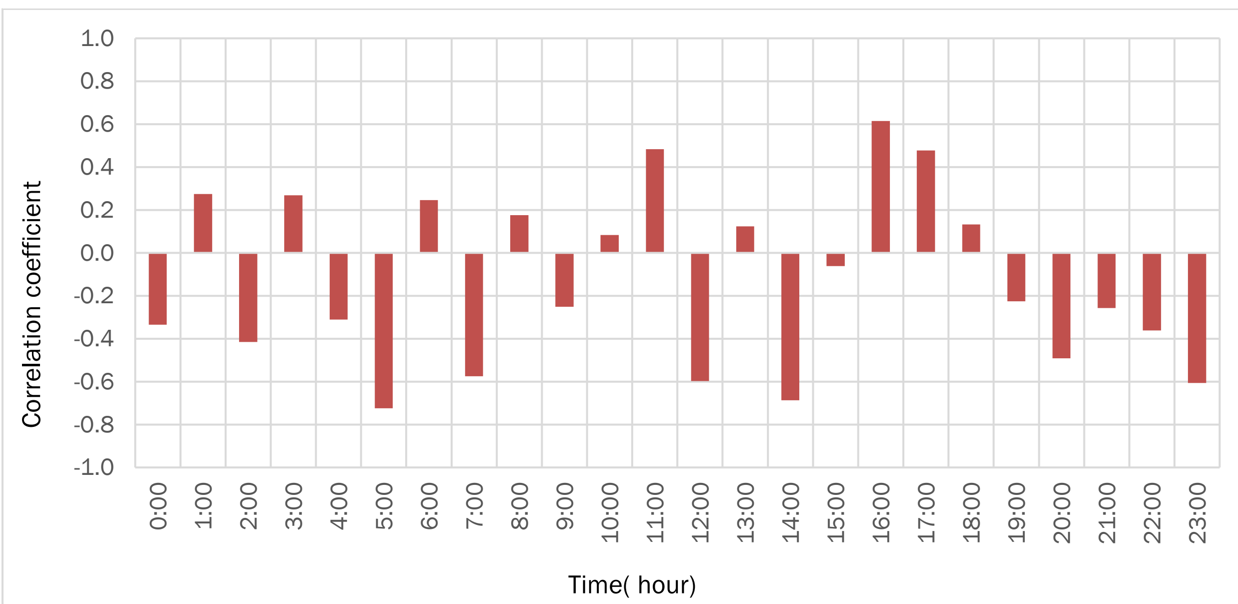



Figure 44: Correlation Coefficient for Net DNI changes and NYCA LBMP Divergences by Hour for Spring Months




- From the above figure, it can be seen that the hours exhibiting strong correlation between the two datasets are hours beginning 5, and 14 in the spring months.
- The correlation coefficient is only 0.03 showing close to zero correlation between them. This shows that there is not a significant correlation between DNI differences and regulation shortage MW in the fall months.

**Figure 45: Scatter Plot of Net DNI Difference and RTD Regulation Shortage MW for Fall Months**

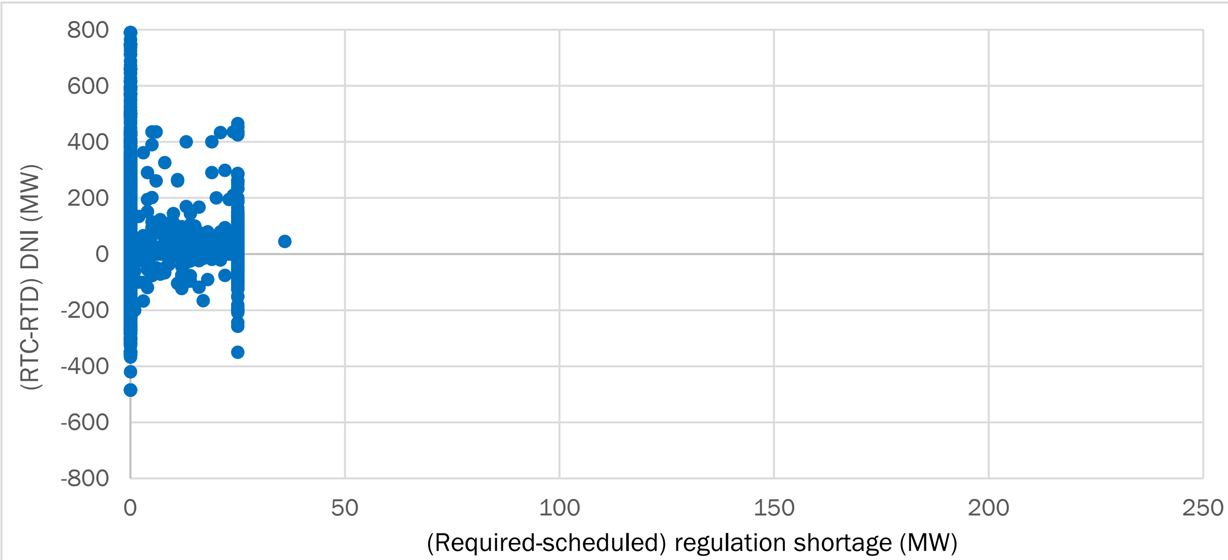
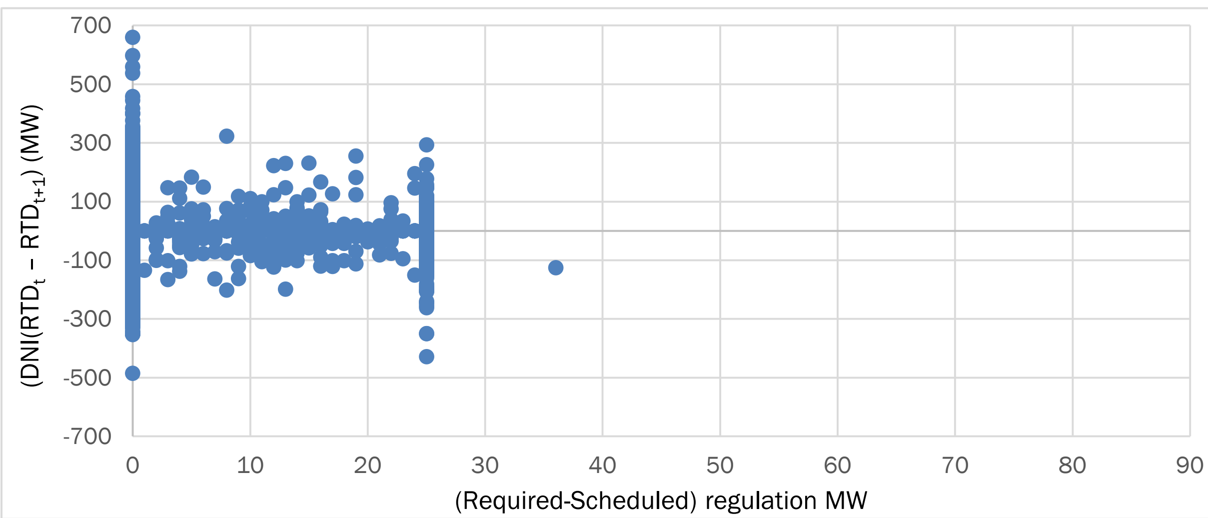
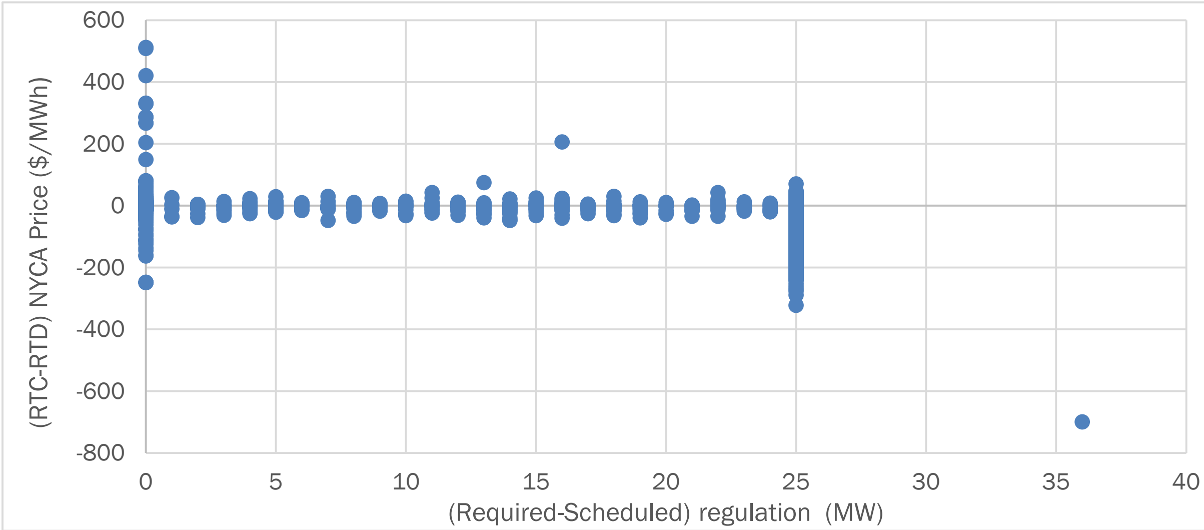



**Figure 46: Scatter Plot of Net RTD DNI delta ($RTD_t$ - $RTD_{t+1}$) MW and RTD Regulation Shortage MW for Fall Months**



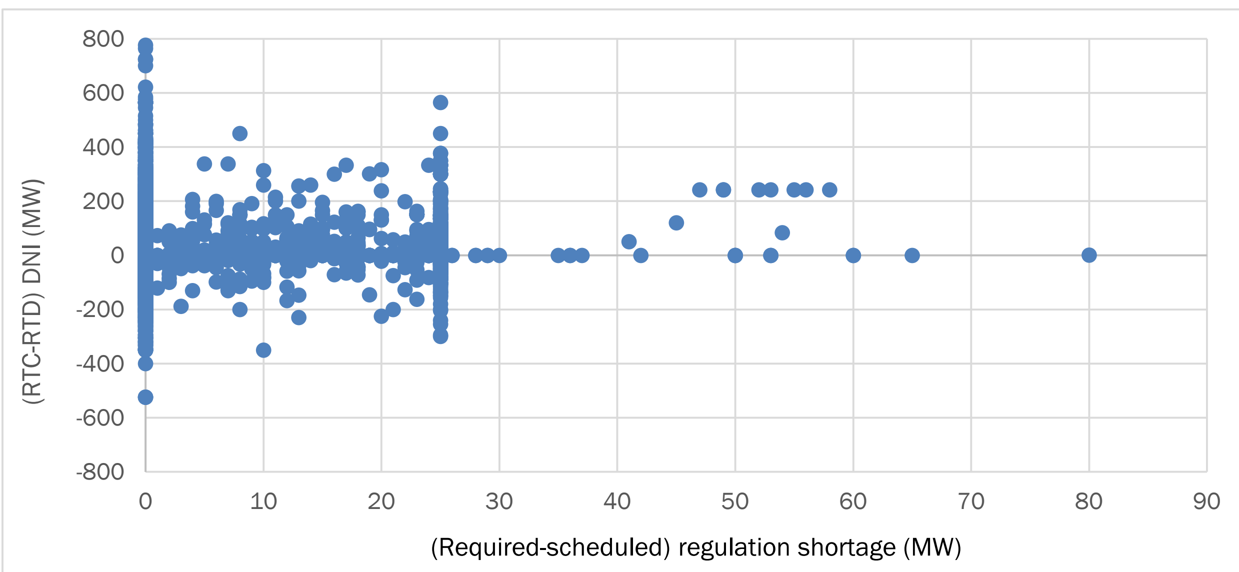

- The correlation coefficient is only 0.03 between RTD DNI deltas and regulation shortage MW is showing that there is no significant correlation.

Figure 47: Scatter Plot of RTD Regulation Shortage and NYCA Price Divergence for Fall Months



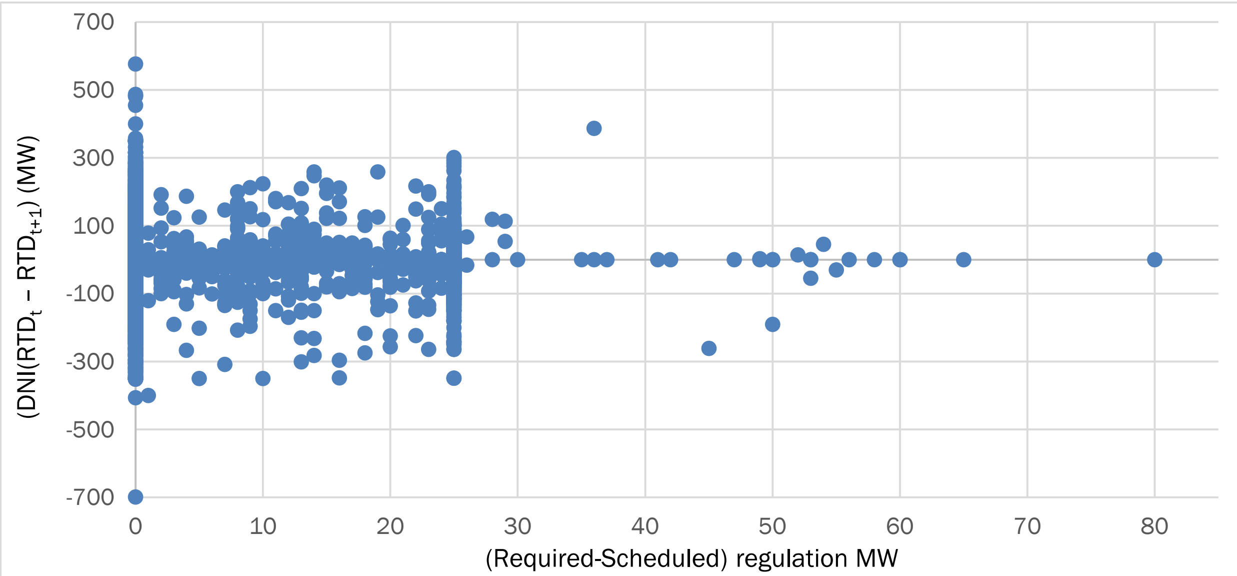

- The correlation coefficient is -0.47 showing weak correlation between RTD regulation shortages and LBMP divergences in NYCA in the fall months.

Figure 48: Scatter Plot of Net DNI Difference and RTD Regulation Shortage MW for Winter Months



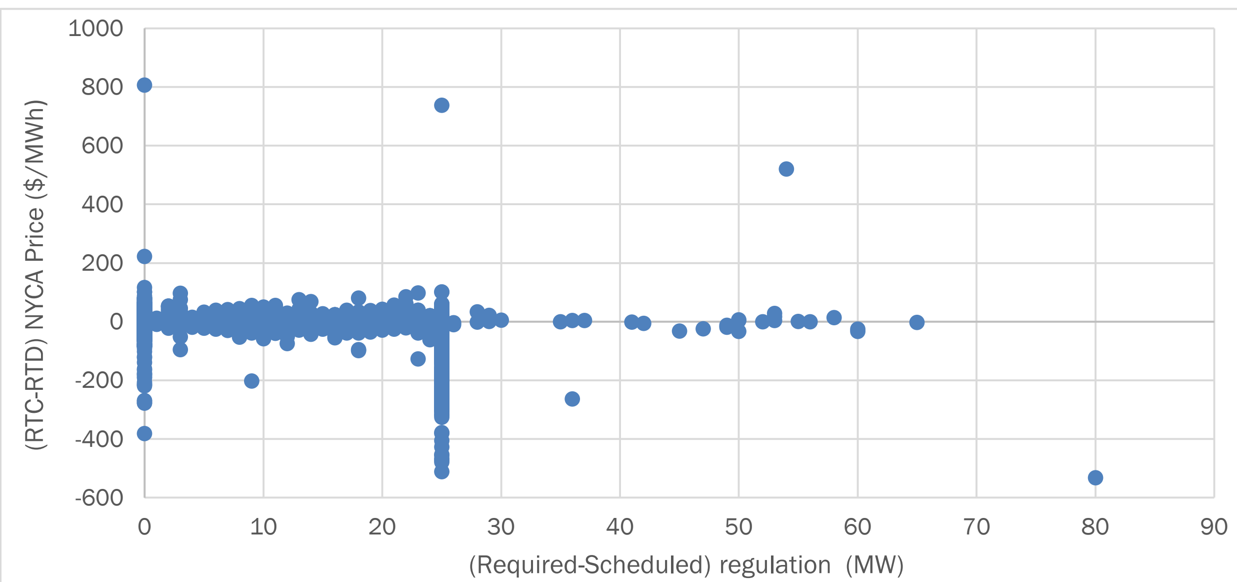

- The correlation coefficient is only 0.03 implying there is no correlation.

**Figure 49: Scatter Plot of Net RTD DNI delta ($RTD_t$ - $RTD_{t+1}$) MW and RTD Regulation Shortage MW for Winter Months**



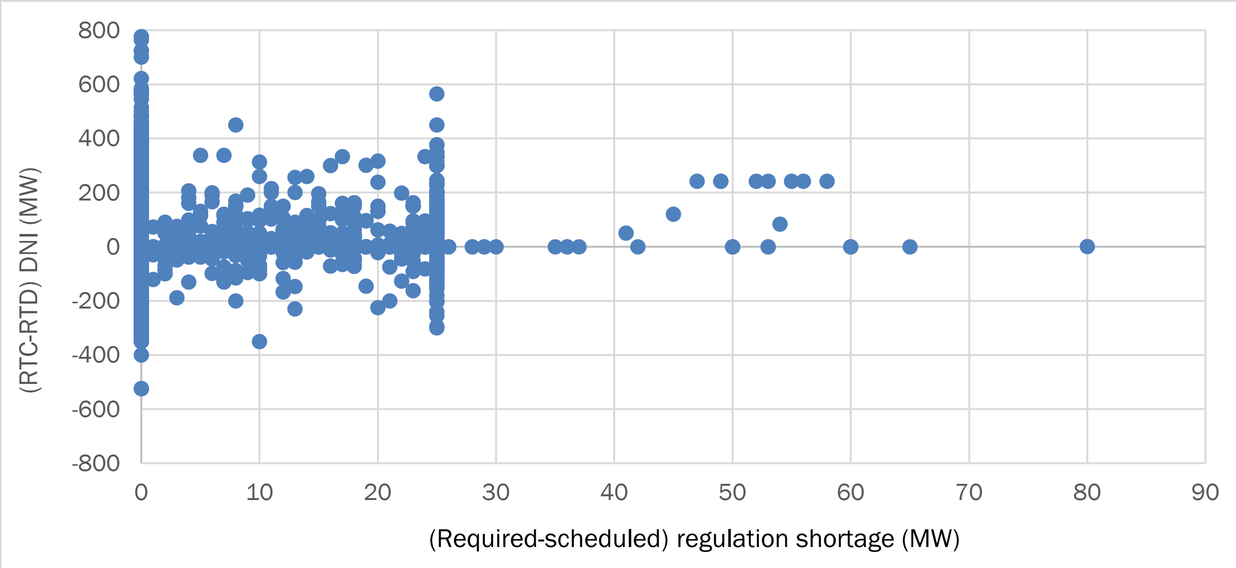

- The correlation coefficient is only -0.04 between RTD DNI deltas and RTD regulation shortages.

**Figure 50: Scatter Plot of RTD Regulation Shortage and NYCA Price Divergence for Winter Months**



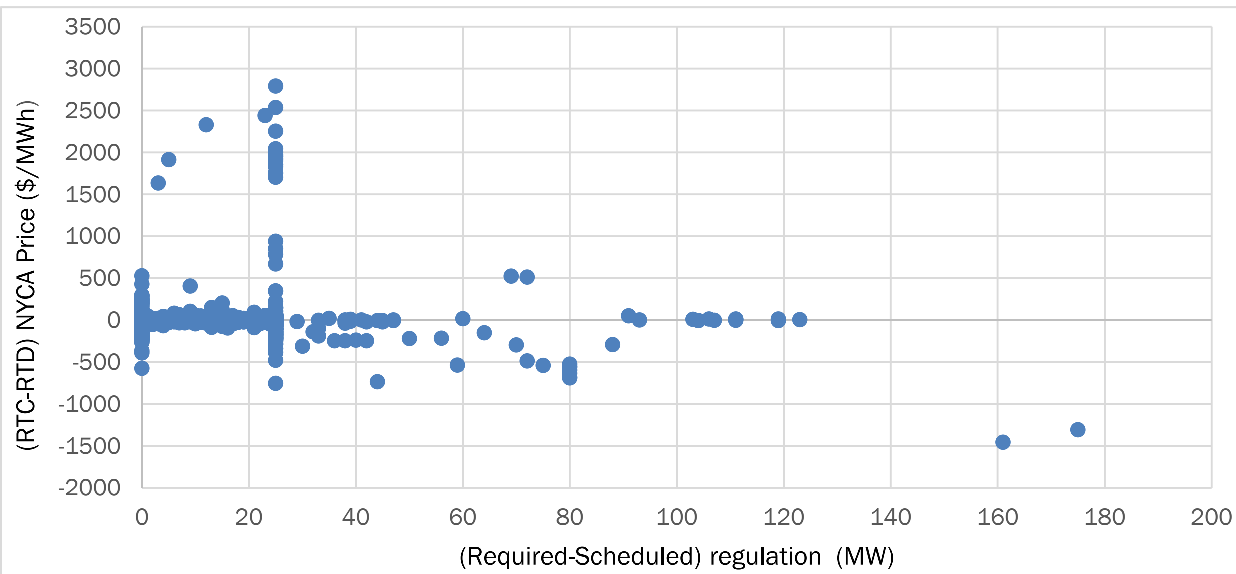

- The correlation coefficient is -0.29 showing there is no correlation between regulation shortages and LBMP divergences in the winter months.

**Figure 51: Scatter Plot of net DNI difference and RTD Regulation Shortage MW for spring months**



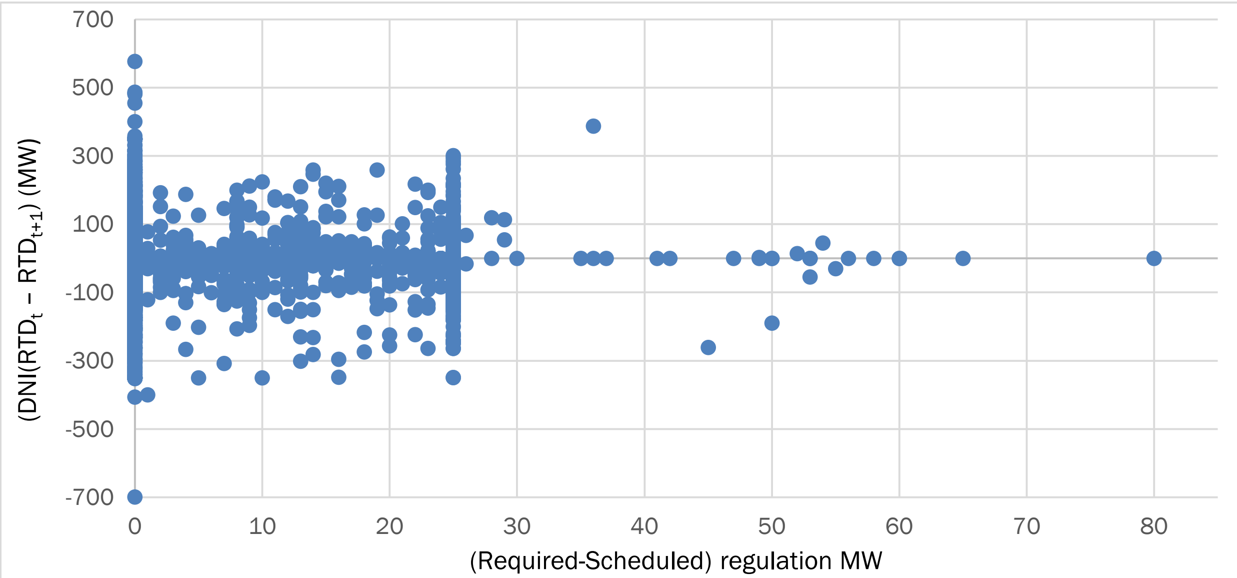

- The correlation coefficient is 0.03 showing no correlation.

**Figure 52: Scatter Plot of RTD Regulation Shortage and NYCA Price Divergence for Spring Months**




- The correlation coefficient is -0.05 ,showing no relationship between the two datasets.

**Figure 53: Scatter Plot of Net RTD DNI delta ($RTD_t$ - $RTD_{t+1}$) MW and RTD Regulation Shortage MW for Spring Months**




- The correlation coefficient is -0.01 between RTD DNI deltas and regulation shortages for spring months. This shows that there was no significant correlation between the two datasets in these months.

Figure 54: Average Hourly Dispatchable MW and Actual Real-Time Load – Fall

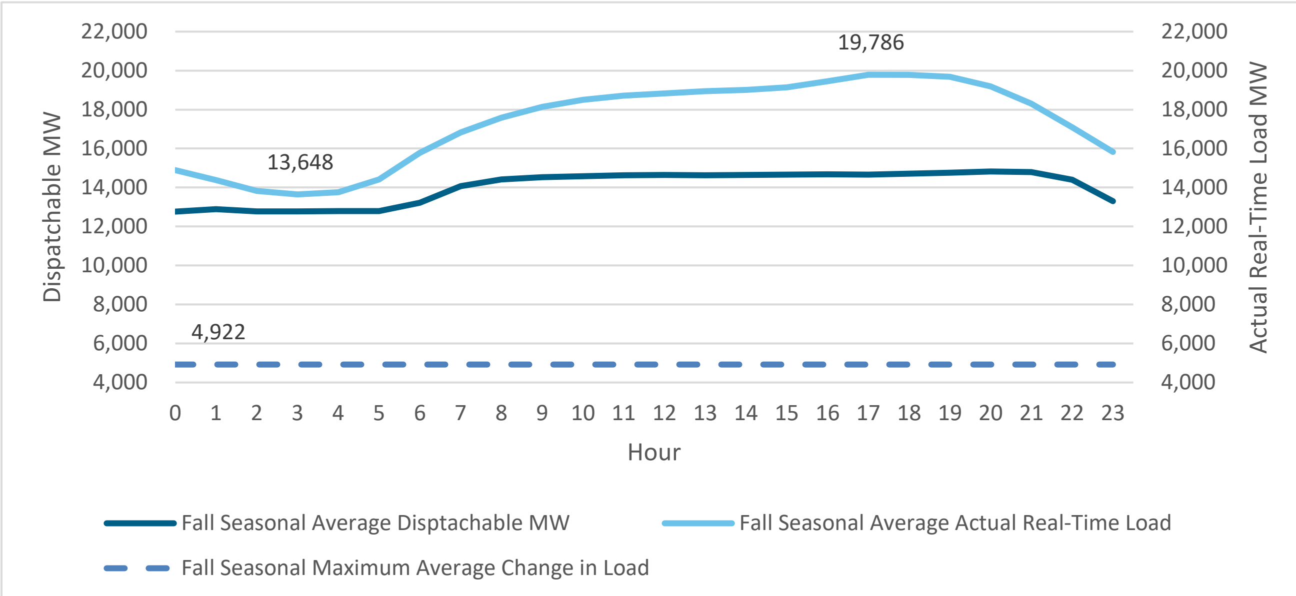



Figure 55: Average Hourly Dispatchable MW and Actual Real-Time Load- Winter

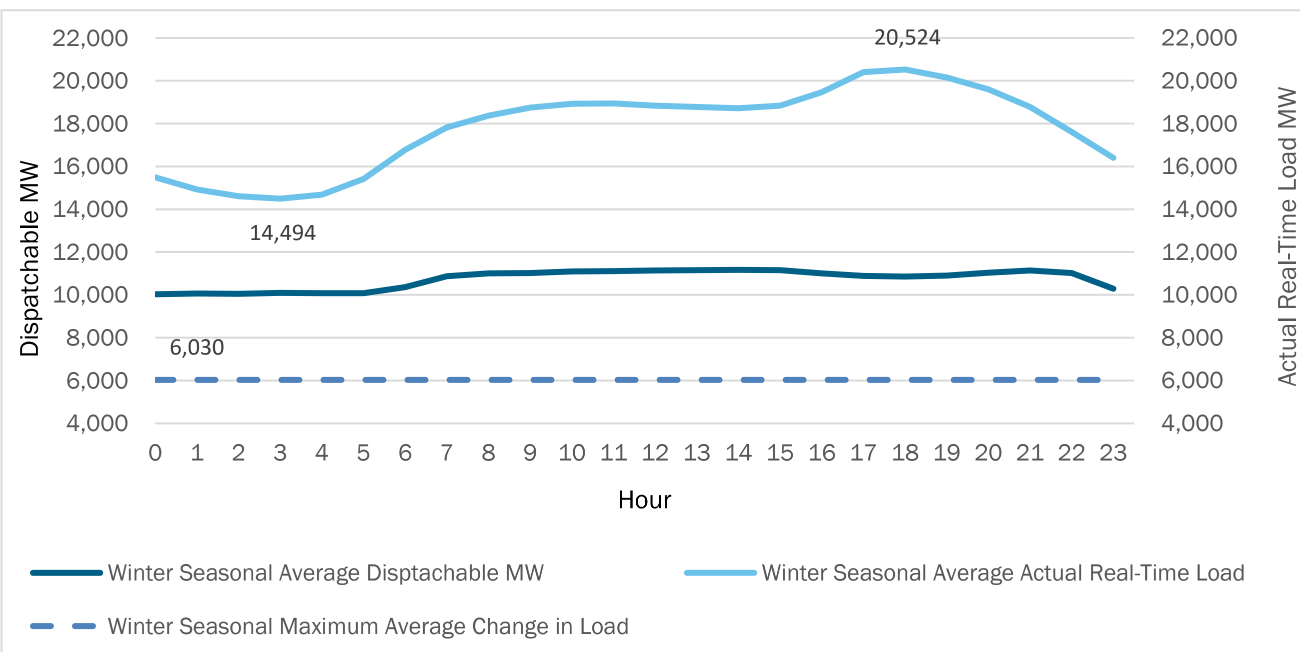
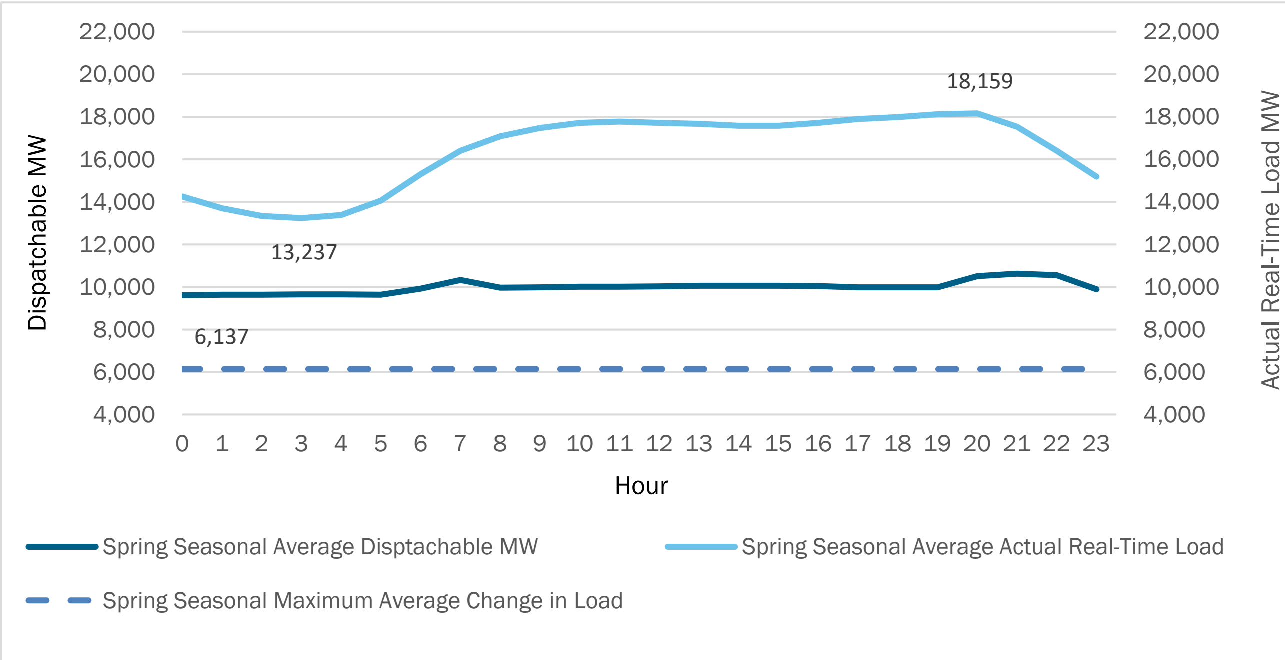


**Figure 56: Average Hourly Dispatchable MW and Actual Real-Time Load – Spring**




Figures 57 – 68 below illustrates the average hourly UOL MWs and MinGen MWs available to the real-time market system for each month in the study period. The MW values were calculated by summing all generator's UOL values and MinGen values by hour. The summed values were then averaged by hour to get the average hourly system-wide UOL and MinGen values for each month. In general, at HB 5 the average offered MWs increase and then begins to decrease at HB 20.

**Figure 57: Average Hourly Dispatchable MWs in July 2016**

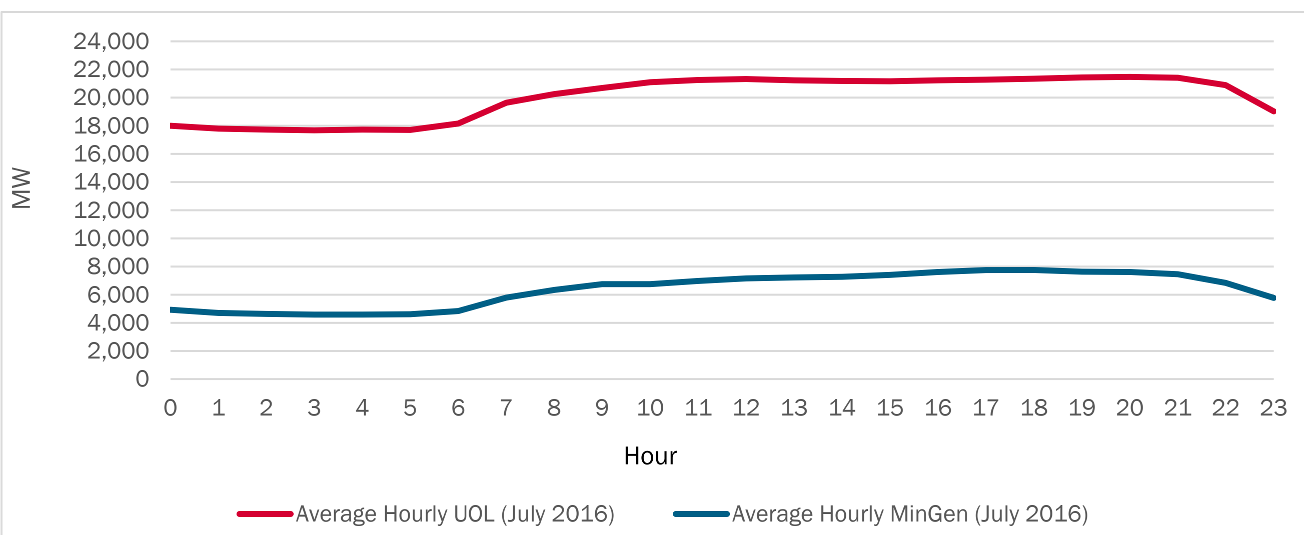


**Figure 58: Average Hourly Dispatchable MWs in August 2016**

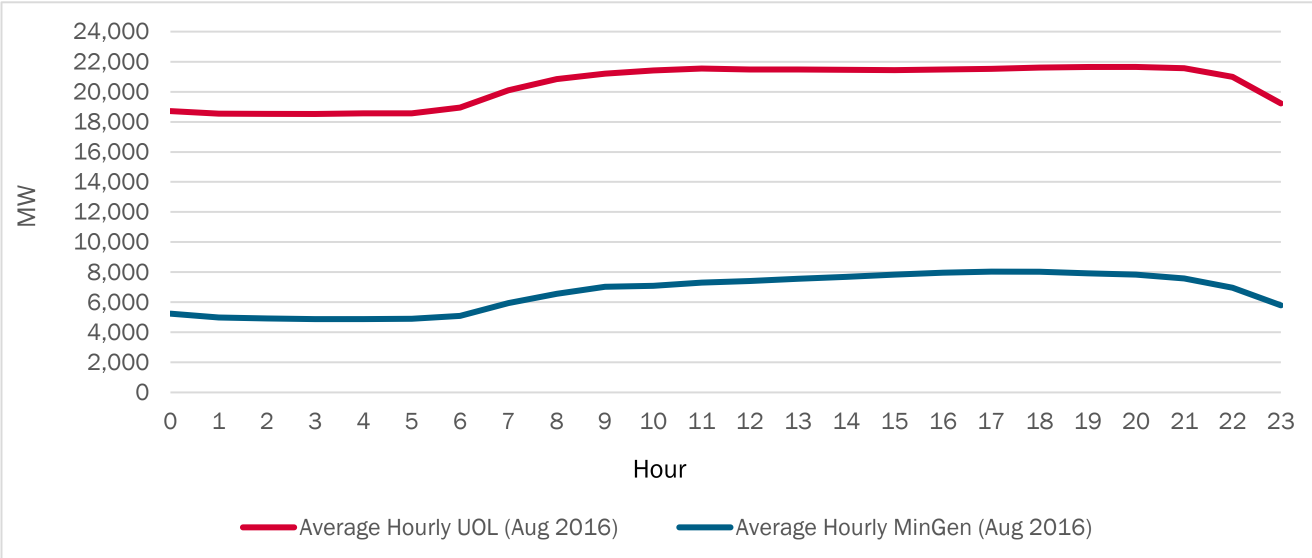



**Figure 59: Average Hourly Dispatchable MWs in September 2016**

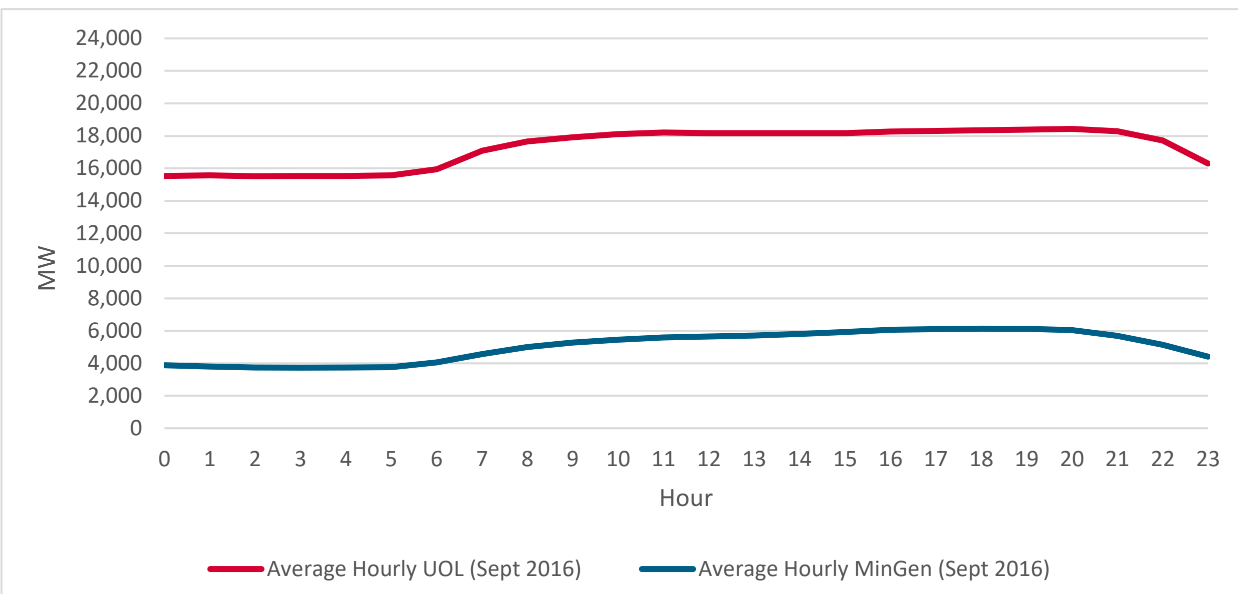


Figure 60: Average Hourly Dispatchable MWs in October 2016

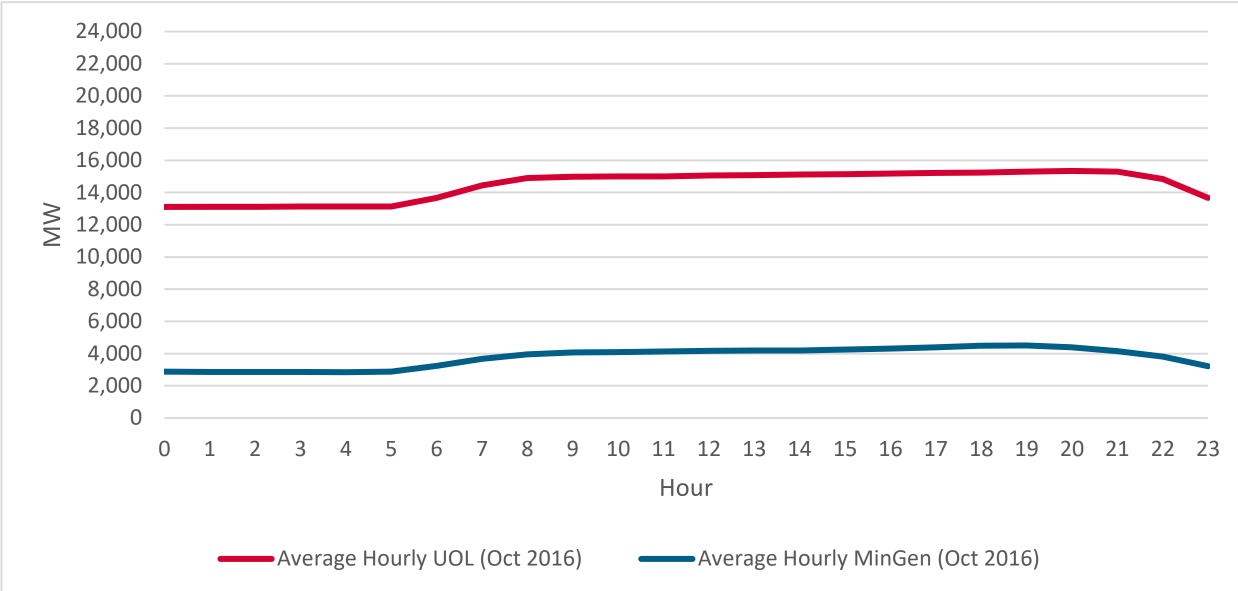



Figure 61: Average Hourly Dispatchable MWs in November 2016

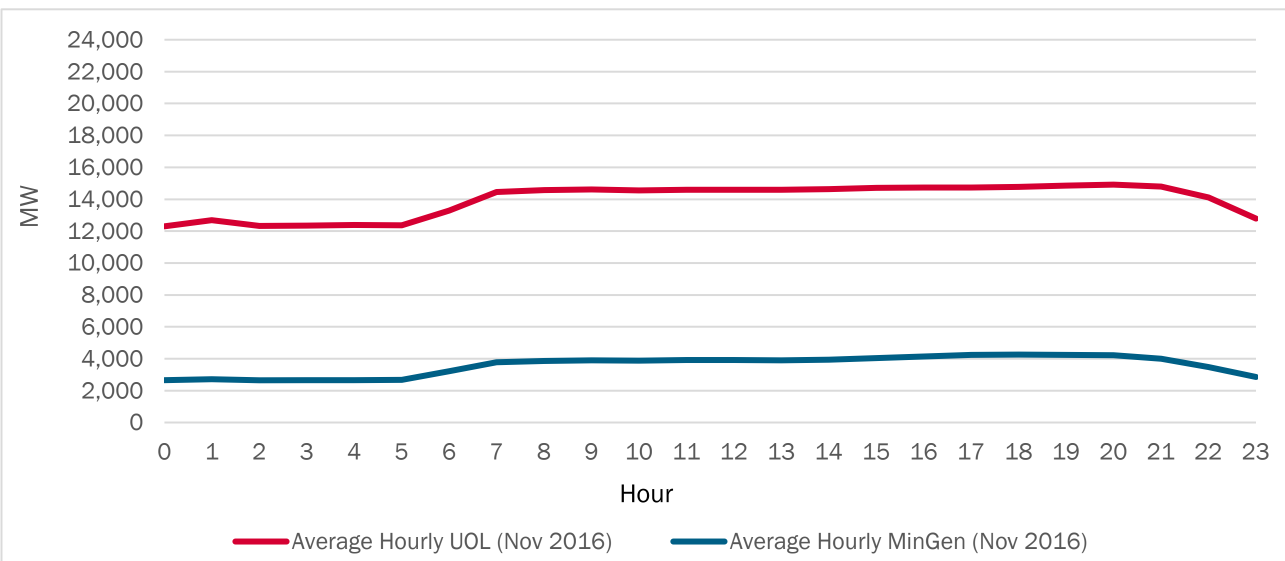


**Figure 62: Average Hourly Dispatchable MWs in December 2016**

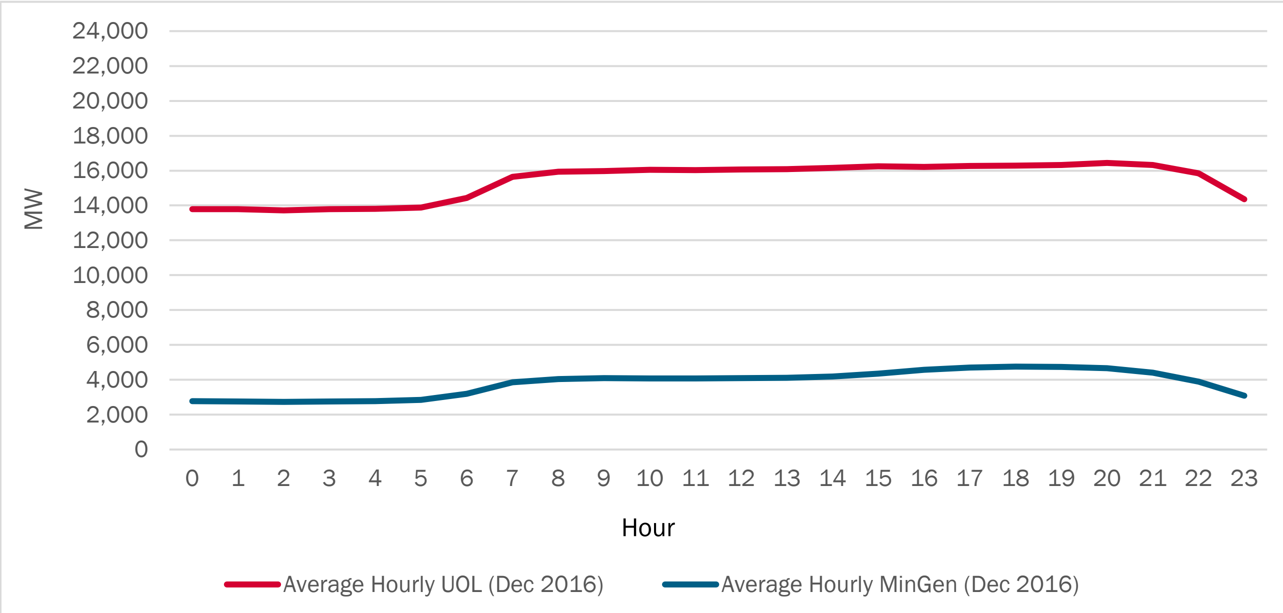



**Figure 63: Average Hourly Dispatchable MWs in January 2017**

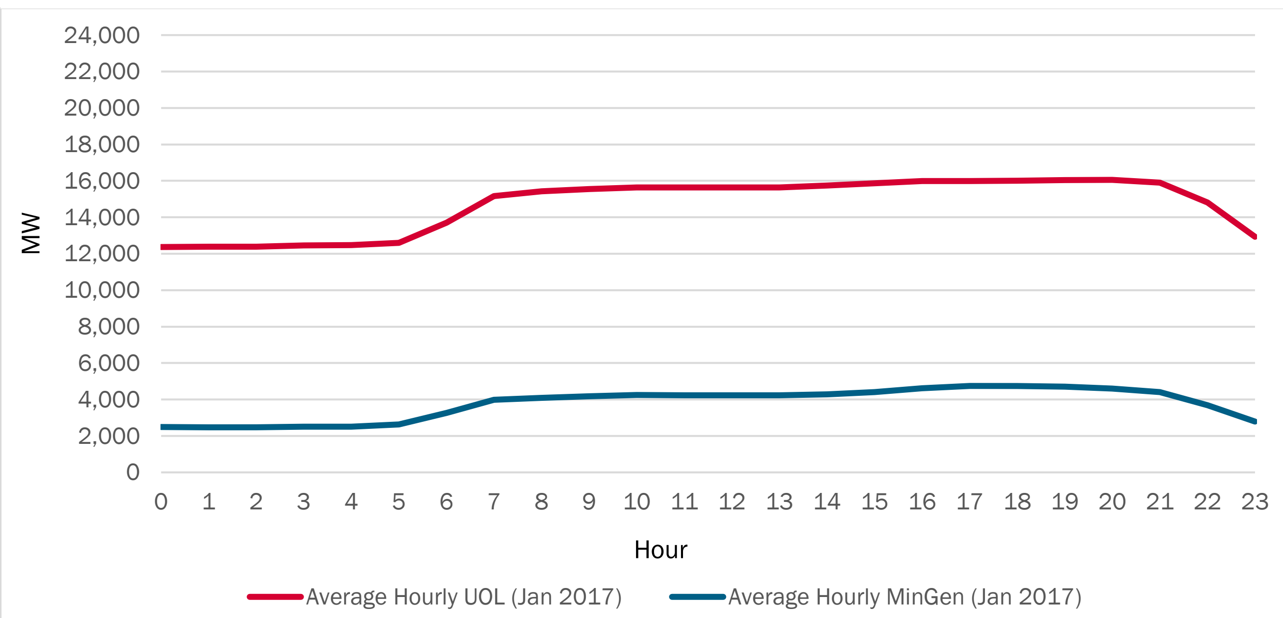


Figure 64: Average Hourly Dispatchable MWs in February 2017

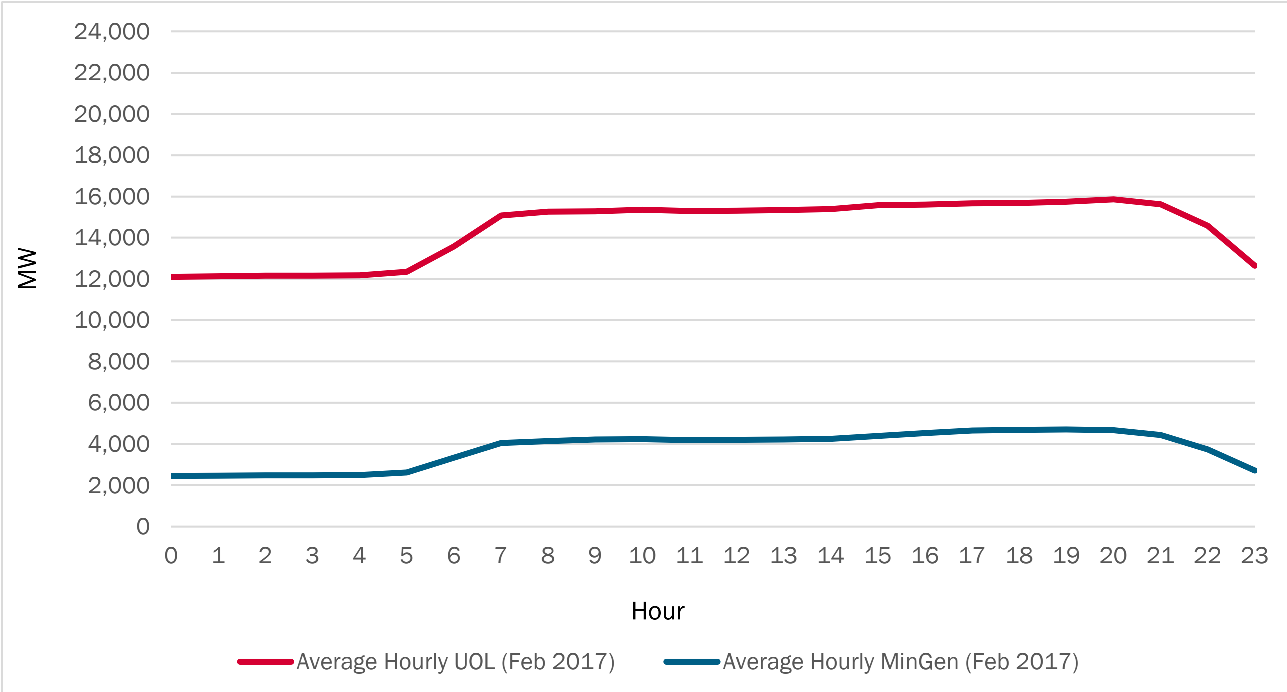



Figure 65: Average Hourly Dispatchable MWs in March 2017

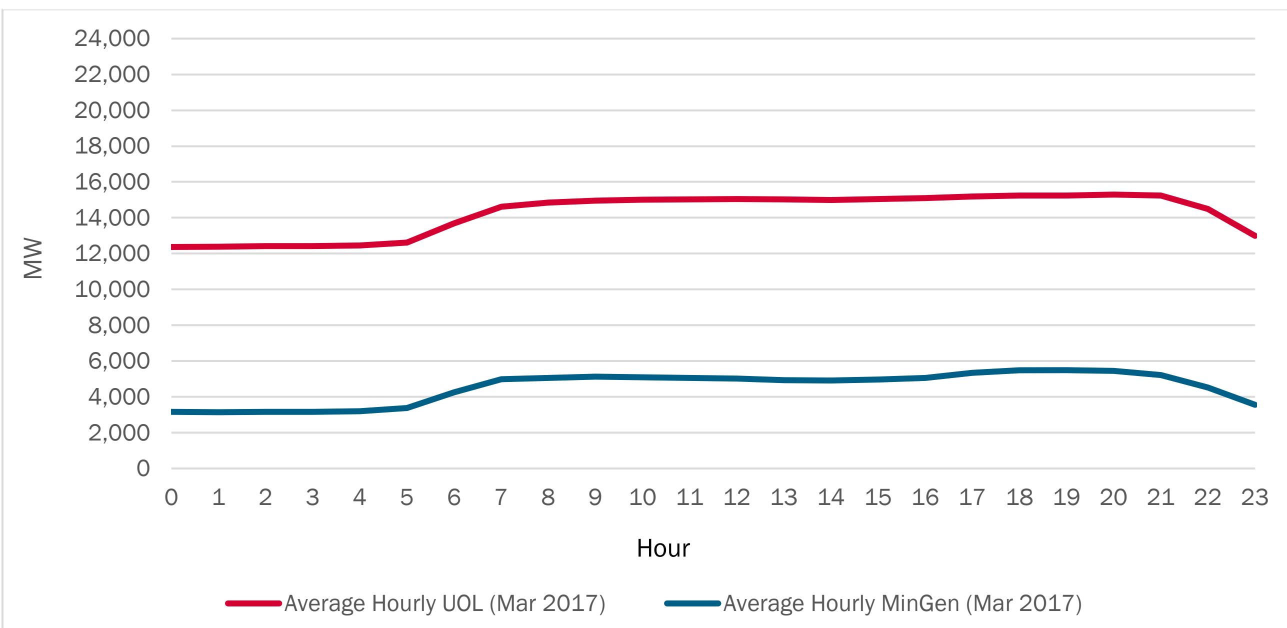


Figure 66: Average Hourly Dispatchable MWs in April 2017

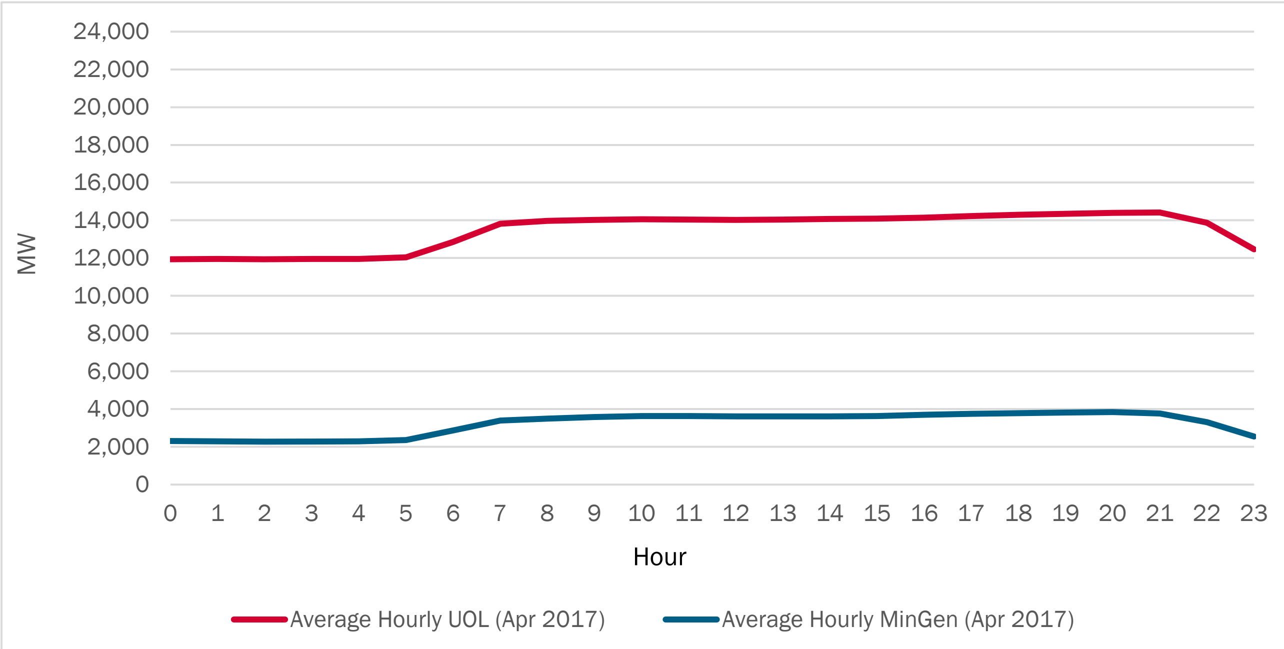



Figure 67: Average Hourly Dispatchable MWs in May 2017

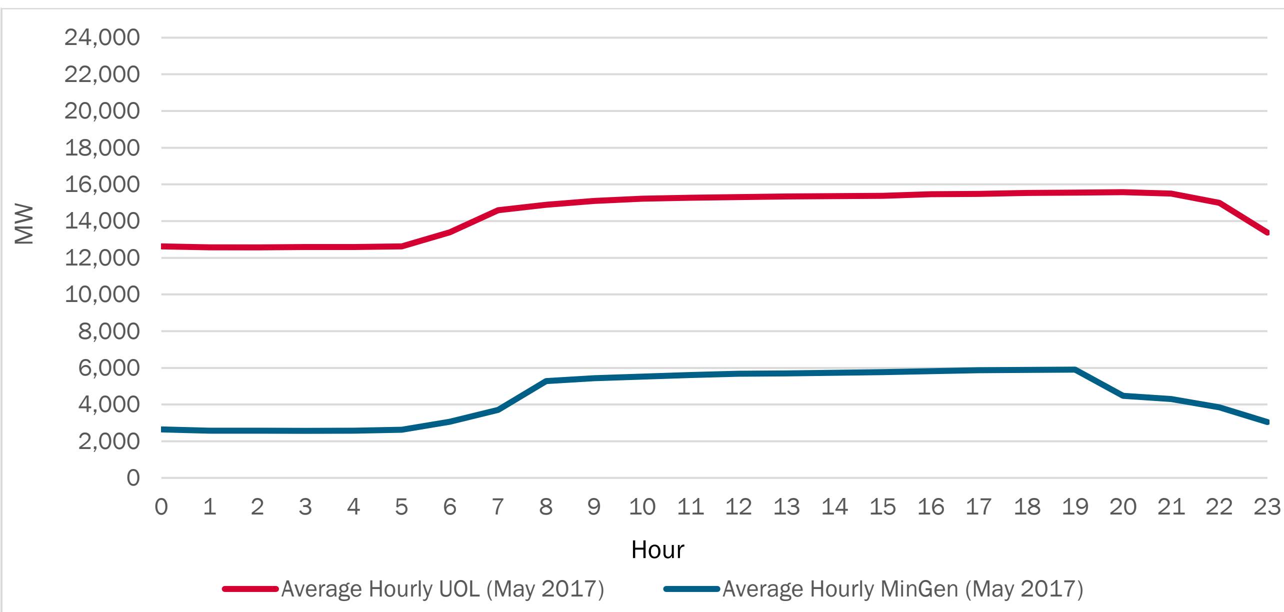


**Figure 68: Average Hourly Dispatchable MWs in June 2017**