Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave

PJM Interconnection
December 23, 2013

Contents

1 Executive Summary

Several days of unusual, extremely hot weather in September 2013 in the Midwest and Mid-Atlantic states led to emergency conditions in the PJM Interconnection service area. In order to avoid more serious impacts, PJM had to direct transmission owners to implement controlled outages in a few contained areas for limited time periods. Controlled outages such as these are a last resort to prevent uncontrolled blackouts over larger areas that could affect many more people. During this period, temperatures were up to 20 degrees above normal, and demand for electricity reached an all-time high for September in parts of PJM's footprint. At the same time, some generation and transmission facilities were scheduled to be out of service for routine maintenance because lighter electricity demand usually is experienced during the month.

In September 2013, a PJM team initiated a detailed, technical analysis of the events of September 9 through September 11 including the controlled outages (called a load shed in industry terms) and other events involving synchronized reserves and load management. The purpose of the analysis, which is detailed in this report, was to gain and present to stakeholders a comprehensive understanding of the events and the actions taken by PJM and its members and to use that understanding to improve training, tools, procedures and processes. PJM also has conducted a compliance analysis and will share the results of that analysis with NERC, the North American Electric Reliability Corporation, and Reliability*First*.

This report is presented in two sections covering operational events and market impacts associated with the events and subsequent actions to maintain an adequate power supply. The analysis builds on PJM's "Initial Analysis of Operational Events during the September 2013 Heat Wave," issued September 23, 2013[i], which provided a preliminary overview of the system conditions, operations and key events that occurred between September 9 and September 11, 2013.

The markets section of this report explains that the primary impacts to markets during the period were higher prices driven by the deployment of large amounts of demand response, which set the wholesale price of electricity in the American Transmission Systems, Inc., or ATSI, pricing zone in Northern Ohio. A secondary effect of the higher prices was a reduction in funding for Financial Transmission Rights.

The events examined in this report include:

- A controlled outage on September 9 occurred in southern Michigan at American Electric Power's Pigeon River Substation, affecting 1,066 customers for 24 minutes (referred to in the report as Pigeon River 1). The controlled outage was necessary because power lines were out of service and unseasonably high loads on the local 69-kilovolt system – below the level that PJM monitors and controls – put the greater area around the substation at risk of an uncontrolled, cascading outage. A September 10 controlled outage occurred in the same southern Michigan area as the September 9 outage, at American Electric Power's Pigeon River Substation affecting 1,072 customers for about eight and a half hours (referred to in the report as Pigeon River 2). Because of continued line outages and even higher loads on the 69-kV system, the greater area around the substation was again at risk of an uncontrolled cascading outage, which led to the need for the second controlled outage.

- A controlled outage September 10 near Warren, Ohio, at FirstEnergy's Tod substation that affected about 4,500 customers for one and a half hours (referred to in the report as FE Tod). Unplanned as well as planned equipment outages and high loads because of the extreme heat put the greater area around the substation at risk of an uncontrolled cascading outage resulting in the need for the controlled outage.
- A September 10 controlled outage near Erie, Pa., around Penelec's Erie South substation that affected approximately 35,000 customers for up to 6 hours and 13 minutes (referred to in the report as Penelec Erie South). The unplanned loss of two generating units and a transmission line, coupled with a planned transmission line outage, created a risk of uncontrolled cascading outages in the area.
- A controlled outage in Fort Wayne, Ind., September 10, that affected 3,331 customers for about one hour (referred to in the report as AEP Summit). With planned transmission outages, higher than normal power flows resulting from the hot weather put the local area at risk of uncontrolled cascading outages.
- A less-than-expected response on September 10 to PJM's call for reserve resources. (To fill an unforeseeable, sudden need for power, PJM carries at all times additional resources on the system, known as Synchronous Reserves, which can be deployed almost instantly.)
- A call for demand response in the ATSI territory on September 10 because of high loads and a transmission constraint in the area south of Canton, Ohio that resulted in a 695-megawatt reduction in demand for electricity. (Under demand response, retail customers volunteer and are paid to reduce their electricity use when requested.)
- A call for demand response in much of PJM's service area on September 11 in preparation for another day of unseasonably high use of electricity that resulted in a 5,791 MW reduction in electricity demand, the largest amount of demand response PJM has ever received.
- Curtailment of 100 MW of firm transactions to New York (a level 5 Transmission Loading Relief procedure) on September 11 because of an overload on a New Jersey transmission line.

This analysis of the September 2013 operational events, conducted by PJM staff, confirms findings in PJM's preliminary report that the actions taken during the events were appropriate and it identifies some areas for improvement. The actions by PJM and its members were effective in preventing larger events that could have affected many more customers over a significantly larger area.

Still, many lessons learned through the assessment of the events of September 9 through September 11 will enhance PJM operations and PJM intends to work through the PJM stakeholder process to address them. The report lists recommendations related to system modeling, PJM and member dispatcher training, technology changes, process improvements, notifications and communication protocols. They include:

- Review how and when to telemeter and computer-model the system
- Review facility limits on equipment on the border of neighboring systems
- Review the approach for representing known generation that does not participate in PJM markets (behind-the-meter generation) and is not dispatched by PJM
- Review how communications tools are used during controlled outages

- Review market rules for Synchronized Reserves to determine if they provide sufficient incentives to obtain synchronized reserves needed in real time
- Review the current mechanism to confirm the amount of reserve generation available to identify methods to improving the quality of data being reported
- Review demand response to improve operational flexibility to include shorter lead time; subzonal calls, calls outside of emergencies and shorter minimum run times
- Provide dispatchers with better visibility of the location and amount of load relief from demand response

In summary, the intense, prolonged heat wave of September 9-11, 2013, caused PJM to take necessary emergency actions to preserve the overall reliability of the grid and to minimize the number of customers affected by system conditions. The five controlled outages were in response to local grid conditions which, if unaddressed, could have resulted in widespread, uncontrolled outages affecting many more people. PJM recognizes that any time electricity is interrupted consumers experience inconvenience and hardship. For that reason, implementing controlled outages is an extremely rare event and is always the action of last resort for grid operators. In the case of the September 9-11 heat wave, the prospect of more extensive interruptions required decisive action. The outage events totaled 154 MW of demand compared to the near-record September demand of more than 145,000 megawatts of electricity that week on the PJM grid.

PJM and its members are learning from these events and will use the insights to improve operations in the future.

2 Introduction

On September 23, 2013, PJM published its initial report entitled ‘Initial Analysis of the Operational Events that occurred during the September 2013 Heat Wave[1]. The initial report presented an overview of the grid conditions and actions taken by PJM and others to minimize the impact on electricity customers during unseasonably hot weather in the PJM Interconnection service area September 9 through September 11, 2013. On September 2013, PJM formed an operational event analysis team to conduct a more detailed assessment of PJM’s and PJM members’ responses from September 9 through September 11. This report presents the results of that initiative.

The *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave* report provides a thorough examination of the events including a detailed description of the PJM regional transmission organization’s system conditions, operations, and key events that occurred during the September heat wave when temperatures across the PJM footprint were well above average for the month of September. See Figure 1 for the temperatures across the RTO September 9 – 11.

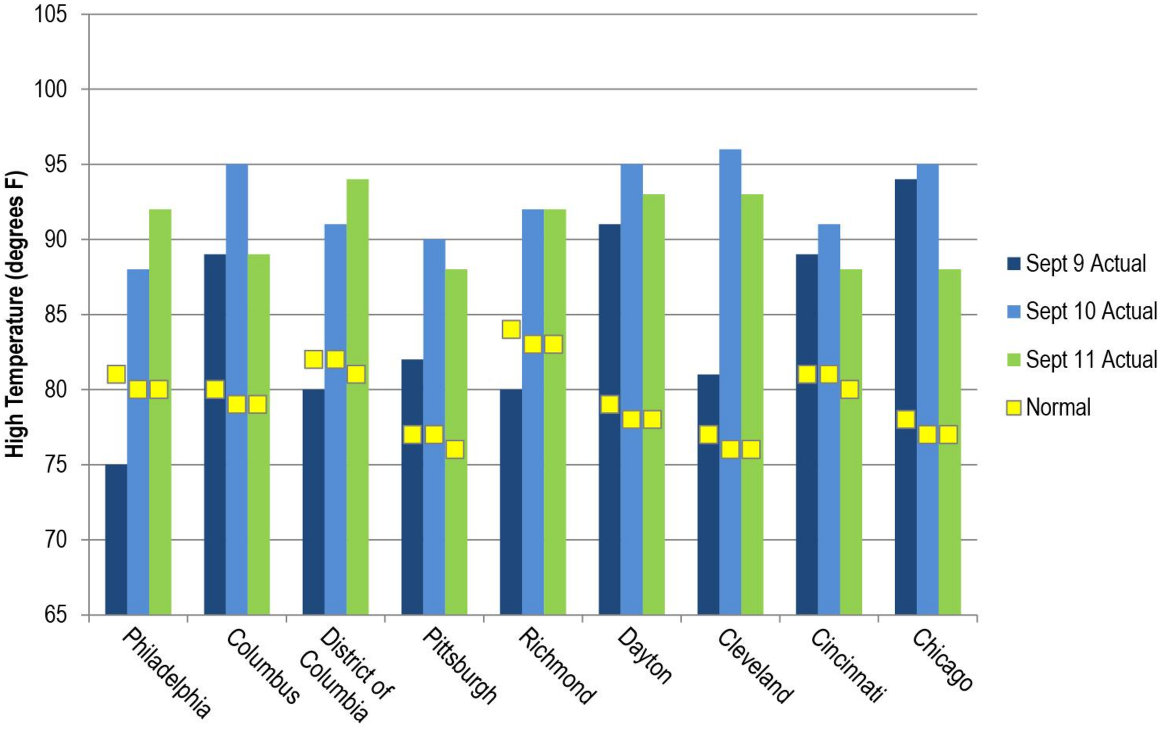

Figure 1. **RTO Temperatures**

Leveraging the information collected during the initial analysis, the purpose of the detailed assessment was to conduct a deeper dive into the operational events and contributing factors as well as conduct a review of the actions taken by PJM and its members. The assessments focus on the operational activities leading up to the events,

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[1] http://www.pjm.com/~/media/documents/reports/20130923-initial-analysis-of-operational-events-during-the-september-2013-heat-wave.ashx

activities throughout the events and subsequent activities while returning to normal operations. Recommendations with respect to the processes, procedures and tools were also identified. PJM also has conducted a compliance analysis and will share the results of that analysis with NERC and Reliability*First*.

The analysis includes the following operational events that occurred between September 9 and September 11, 2013:

- Two American Electric Power, or AEP, Pigeon River load shed events in southern Michigan: one event on September 9, which impacted 3.1 MW / 1,066 customers and a second event on September 10, which initially involved 5 megawatts of load followed by an additional 3 MW event impacting a total of 1,072 customers.
- A 16-MW load shed event at First Energy's Tod substation near Warren, OH on September 10 that impacted approximately 4,500 customers.
- A 105-MW First Energy load shed event around Penelec's Erie South substation near Erie, PA on September 10 that impacted approximately 35,000 customers. The load was shed in increments of 70 MW and an additional 35 MW.
- A 25-MW AEP Summit load shed event in Ft. Wayne, IN on September 10 impacted 3,331 customers.
- A Synchronized Reserve event on September 10 and a PJM-initiated Shared Reserves event with the Northeast Power Coordinating Council.
- Two Demand Response, or DR, implementations on September 10 and September 11, resulting in demand reductions of 695 MW and 5,782 MW, respectively.

Table 1 summarizes the load shed events. A high-level time frame of when the key operational events occurred is shown in Figure 1 and a geographic display of the impacted areas can be seen in Figure 2.

	Name of Event	Date	Duration (Start & End)	Total Outage Time	Zone	Electrical Location	Geographic Location	# of Customers Impacted (aprox)	Total MWs
1	Pigeon River 1	9/9	16:17 - 16:31	14 min	AEP	Pigeon River Station 69 kv	Southern MI close to IN	1,066	3.1
2	Pigeon River 2	9/10	12:49 - 21:23	8 hr 34 min	AEP	Pigeon River Station 69 kv	Southern MI close to IN	670	5
			13:14 - 21:23	8 hr 09 min				400	3
3	FE Tod	9/10	15:07 - 16:42	1 hr 35 min	ATSI	Tod 138 kv	Near Warren, OH	4,554	16
4	Penelec Erie South	9/10	17:41 (9/10) - 00:02 (9/11)	6 hr 21 min	Penelec	Erie 115 kv	Erie (Northwestern PA)	24,500	70
			18:19 (9/10) - 00:02 (9/11)	5 hr 43 min				10,500	35
5	AEP Summit	9/10	19:13 - 20:16	1 hr 03 min	AEP	Summit 138 kv	Near Fort Wayne, IN	3,330	25
							9/9	**1,066**	**3.1**
							9/10	**43,954**	**154**

Table 1. Summary of Load Shed Events

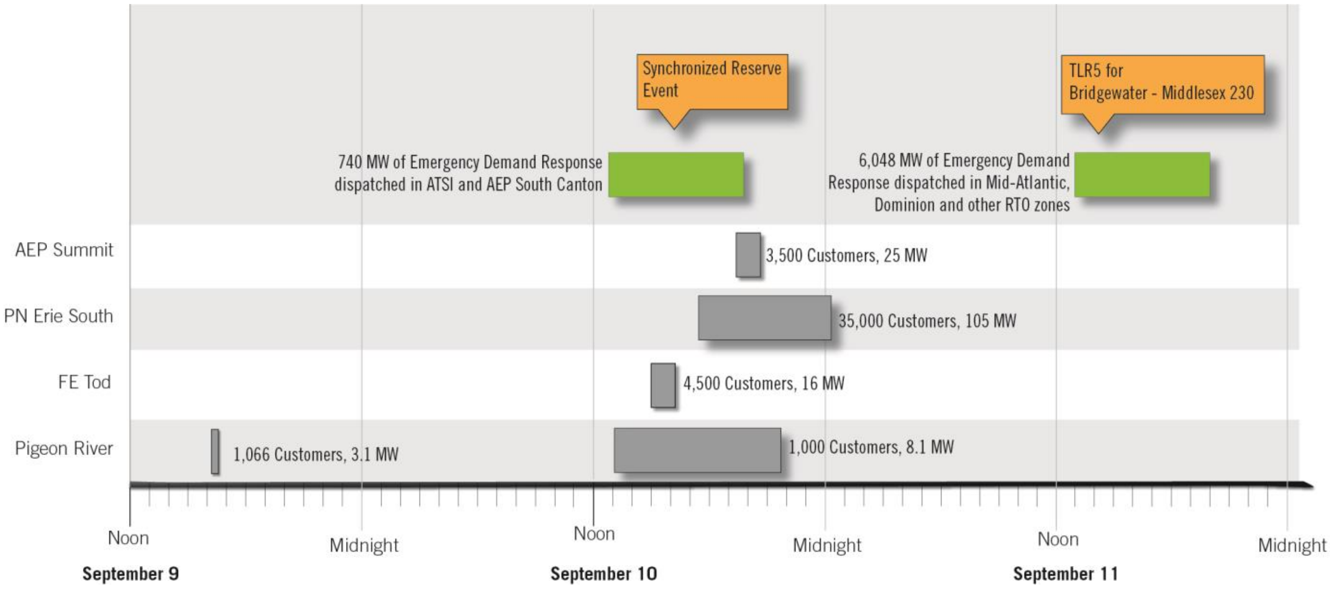

Figure 2. **Key Operations Events**

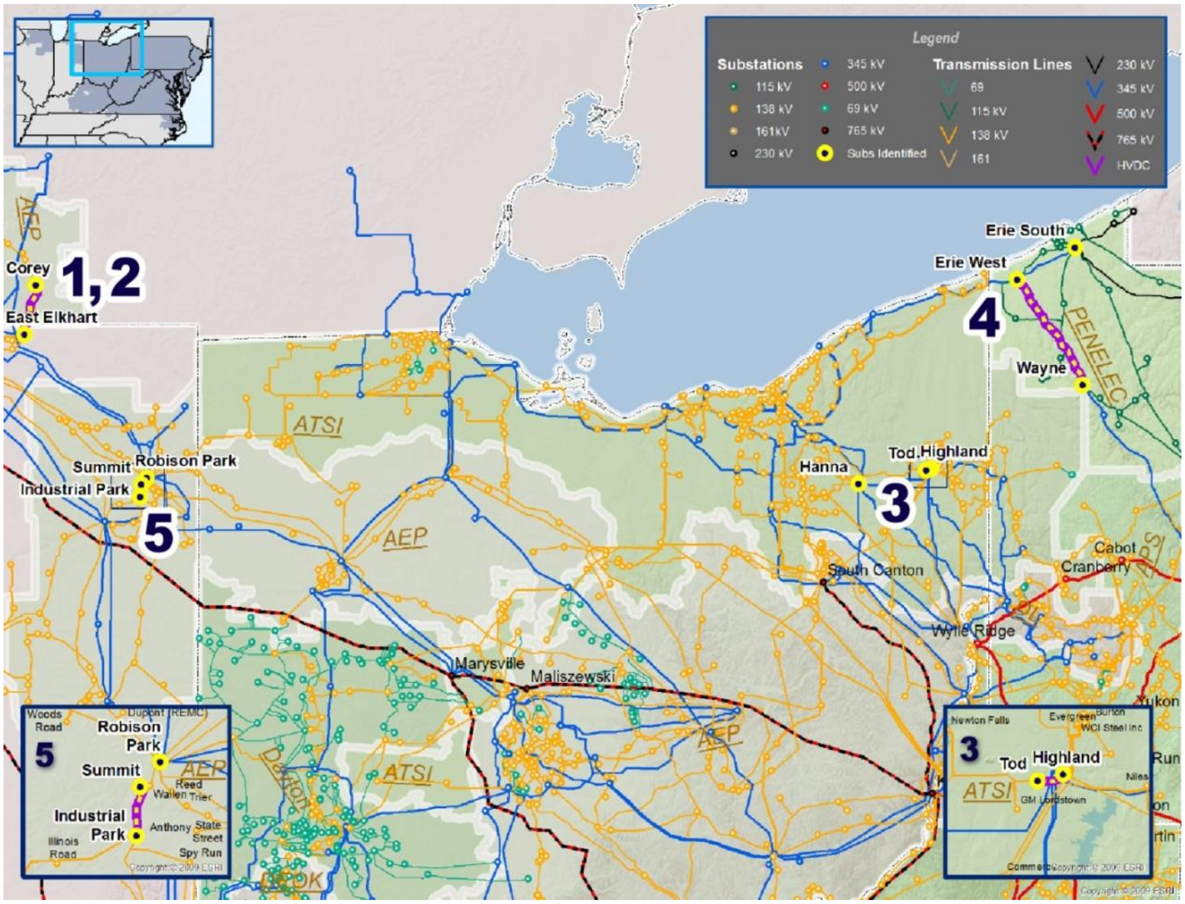

Figure 3. **Geographic Presentation of Load Shed Events**

This assessment will review each of the key operational events, detail the actions taken by PJM and its members, identify contributing factors, as well as provide an analysis of the operational actions and the transmission and generation in the areas impacted by the load shed events. In response to the many questions PJM received about the impact of generation retirements, PJM evaluated the impact of generation that retired in the areas of the load shed in the past year. PJM also reviewed the already planned upgrades projects included in PJM's Regional Expansion Transmission Plan, or RTEP, to determine if the upgrade projects could have reduced the amount of load shed. The results of this analysis are provided for each load shed event as well as summarized in the Generation Outage and Retirement Analysis Appendix B. Recommendations for each key operational event, including the Synchronized Reserve event and the Demand Response events, have been identified and are presented with each event as well as summarized in the Recommendation section of the report.

Each operational event is written so that it can be read independently of the rest of the report and still present the full detail and analysis of what happened, what contributed, and the resulting recommendations. As a result, there are some observations and recommendations that are repeated throughout the report. This was done intentionally considering the different audiences of this report and how it might be used.

In addition to the key operational events, PJM also conducted a review of PJM's load forecasting tools and methodology as well as PJM's communication protocols to determine what, if any, changes should be made to these processes. Specific recommendations have been identified for these and are also included in the Recommendation section as well.

In order to fully understand the impacts to PJM markets as well as operations, PJM also undertook a detailed examination of market outcomes that resulted from the operational events. PJM examined these outcomes in order to determine if there is a need to change processes going forward to more closely link operational decisions to market prices. The results of this analysis are presented in the Market section of the report.

PJM and its members are learning from these events and using the insights to improve operations going forward. The next steps for the 22 identified recommendations are discussed in the conclusion of the report.

3 Load Shed Event Assessments

Each load shed event has been analyzed to determine system and local conditions leading up to and during the event. Also analyzed were PJM and member actions taken during the event; transmission and generation outages active at the time of the event; the potential impact of new upgrades already planned for by PJM in these areas; and the potential impact of local generation that had recently retired. Based on the analysis, observations are made and recommendations developed to address the potential mitigation of the event.

3.1 Pigeon River 1 Load Shed Event (September 9, 2013)

Load shed event, Pigeon River 1, occurred on Monday, September 9, at 1607 in the Pigeon River substation area in the AEP zone in Southern Michigan close to the Indiana border. The amount of load shed was 3.1 MW, which affected approximately 1,066 customers for approximately 24 minutes from 1607 to 1631.

The following local and regional conditions existed prior to the Pigeon River 1 load shed event and contributed to its cause:

- Higher than normal September loads and flows on the 69-kV system between Lagrange, in the region served by Midcontinent Independent System Operator, or MISO, and Corey, in AEP's territory,
- An existing planned outage on the sub-transmission system of the Moore Park Tap-Industrial Park 69-kV line (AEP' line in the PJM region) ; and
- Previously unidentified relay trip set point on the LaGrange-Howe 69-kV line in the Northern Indiana Public Service Corp territory within the MISO region.

Figure 4 presents an overview diagram of the electric system in the Pigeon River 1 area.

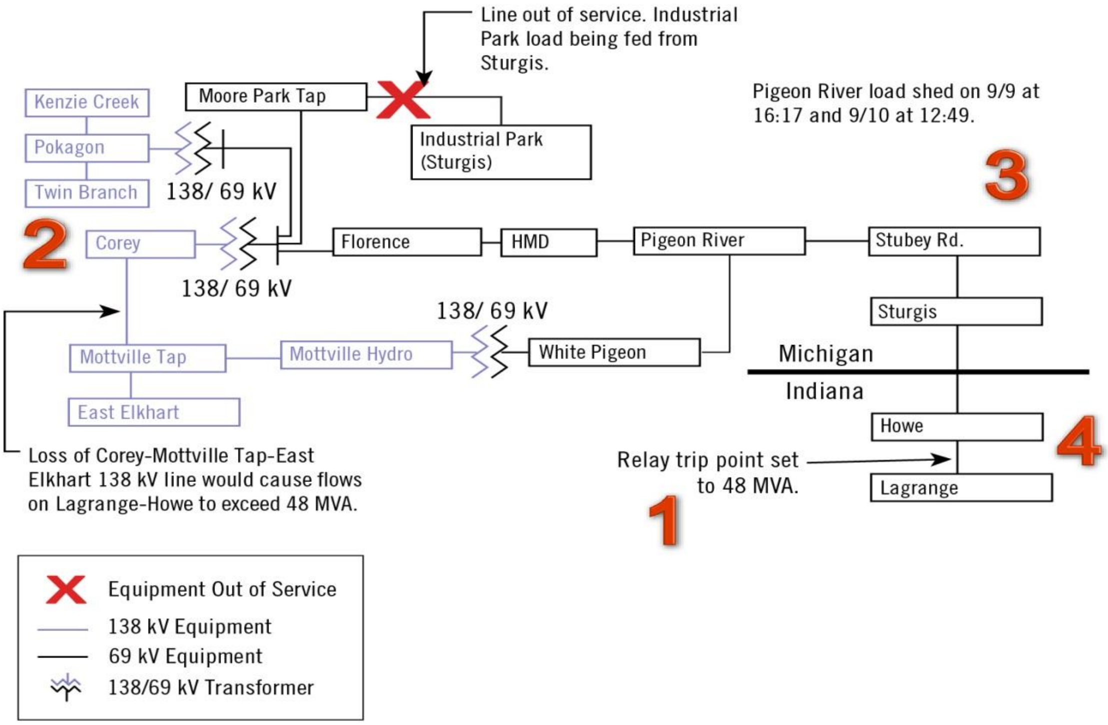

Figure 4. **Pigeon River Area**

The Pigeon River 69-kV system has three main feeds originating from Corey (AEP), Mottville (AEP), and Howe (NIPSCO). On September 9, 2013 load flows on the 69-kV system between Lagrange (MISO) and Corey (AEP) were increased due to significantly higher than normal temperatures in the Western Region of PJM. The existing planned outage of the Industrial Park 69-kV tap connecting the Moore Park-Moore Park Tap 69-kV (AEP) station contributed to the increased flows because this line was not available to transfer some of the flows through of the area (to pick up the additional loading). As part its Reliability Coordinator responsibilities to perform contingency or what-if analyses, PJM determined the most severe contingency in this area (load pocket) was the loss of the East Elkhart-Mottville Tap-Mottville-Corey 138-kV line (b) (#2 in the Figure 4). With the loss of this line, one of the sources to the 69-kV load pocket from Mottville would be lost, further increasing flows from Lagrange (NIPSCO) to serve the load pocket. PJM was monitoring this contingency in its Energy Management System, or EMS.

When PJM performed the contingency analysis, not all of the pre-existing and then-current conditions were included in the analysis. The Moore Park Tap-Industrial Park 69-kV line outage was not included. An existing relay limitation on the Lagrange-Howe (NIPSCO) section of the 69-kV line (#1 in the Figure 4) was also not included in the contingency analysis. (See the Transmission Analysis Section below for details). The impact of the relay limitation, when considered under the existing real-time conditions, meant that if the most severe contingency occurred in real-time (i.e. East Elkhart-Mottville Tap-Mottville-Corey 138-kV line were to trip), the Lagrange-Howe 69-kV would automatically relay out of service.

When PJM modeled the double contingency—loss of both the East Elkhart-Mottville Tap-Mottville-Corey 138-kV (AEP) line and the Lagrange-Howe (NIPSCO) 69-kV line and associated relay, there would have been only one source from Corey to feed the entire 69-kV load pocket. As a result, the voltage in the area would have dipped to 113-kV. The remaining feed was not capable of supporting the area post-contingency, and there would not have been sufficient time to perform a post-contingency load shed, because the line overload and potential voltage collapse would have occurred instantaneously after the relay action.

PJM and AEP operators began immediately coordinating to determine any actions that could be taken to prevent the potential post-contingency collapse, including looking for acceptable switching options, transferring load out of the area without shedding it, and starting any available generation. MISO informed PJM of a switching solution (closing a normally open 69-kV switch at Howe station, establishing a second 69-kV feed into the area). PJM requested MISO to contact NIPSCO to have the Howe switch closed. This switch does not have remote System Control and Data Acquisition, or SCADA, control, so a switchman would need to be sent to the station to manually perform the switching. MISO told PJM it would take approximately 45 minutes for a switchman to get to Howe station.

In order to avoid post-contingency voltage collapse and potential equipment damage, PJM performed the Post-Contingency Load Dump Limit Exceedance Analysis[2]. The analysis indicated a potential cascading event, which could lead to widespread outages throughout the electrical system, and directed AEP to pre-contingency load shed[3]. While PJM is responsible for issuing the emergency procedure directive to shed load, it is the transmission owner who determines what load to curtail, based on factors such as Supervisory control, knowledge of critical load and internal procedures. AEP chose the Pigeon River load in Michigan, because it had the greatest likelihood to alleviate the constraint (38.5 percent distribution factor) and had SCADA control. See Table 2 below for the load shed alternatives considered during the event.

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[2] PJM Manual 13: Emergency Operations, Section 5.4.1: Post-Contingency Load Dump Limit Analysis

[3] PJM's cascading (N-5) outage analysis showed the potential for a cascading event. This is a state where it is difficult to estimate the amount of load at risk (Manual 13, 5.4.1 Post-Contingency Load Dump Limit Exceedance Analysis).

Zone	Name	DFAX (% helps to relief constraint)	Total Station Load	Notes
NIPS	HOWE LOAD	78.7%	6	This is a NIPSCO station and not available to be shed prior to shedding PJM load as indicated by the PJM/MISO JOA
AEP	STURGIS LOAD	66.4%	42	There was no option to shed only a portion of the Sturgis load. All load would have had to be shed. While shedding 42 MW of load would have alleviated the overload, PJM only needed a few megawatts of relief. In an effort to minimize the overall impacts to customers the load at Sturgis was not shed.
AEP	STUBYRO A T1	61.4%	4	There was no SCADA, or remote control available to shed this load. A switchman would need to have been dispatched to the field to manually drop this load.
AEP	WHITEPIG T1	38.5%	3	There was no SCADA, or remote control available to shed this load. A switchman would need to have been dispatched to the field to manually drop this load.
AEP	PIGEONRI T1	38.5%	7	Based up SCADA control, distribution factor impact, load at the station and the overall relief needed for the constraint, the Pigeon River load was selected to be shed.

Table 2. Load Shed Alternatives

Based on a thorough assessment of the contingency analysis results, established operating procedures, and the estimated time for the switchman to get to the Howe station to perform the switching options, and with no other switching options available, PJM directed AEP to shed 4 MW of load in the Pigeon River area at 1538.

At 1543, AEP called the PJM Reliability Engineer to gain a better understanding of the load shed directive[4]. AEP's analysis did not agree with the potential for a thermal cascade. The PJM Reliability Engineer informed AEP the potential cascade could escalate to the 138-kV system. After further discussion, AEP recommended opening the Corey 'G' 69-kV circuit breaker; explaining this switching would eliminate the need for load shed. Because this was at the 69-kV level, PJM had not modeled that circuit breaker; however, PJM studied and agreed to trying the switching option and requested AEP to open the Corey 'G' 69-kV circuit breaker.

At 1603, AEP called the PJM Reliability Engineer and stated the switching option was not a viable solution, because it caused other issues on the AEP system. The load shed directive then remained the only option. AEP informed PJM that load was being shed at Pigeon River as per the PJM direction. At 1617, AEP informed PJM that 3.1 MW of load was shed at Pigeon River (#3 in Figure 4). PJM observed the area loads decrease and analysis showed the 3.1 MW of load was sufficient to alleviate the potential cascading issue. At 1623, the Howe station switching was performed (closing the normally open switch) enabling AEP to restore all load at 1631(#4 in Figure 4).

3.1.1 Observations and Analysis

Transmission Analysis

A contributing factor resulting in the Pigeon River Load Shed events was the planned outage of the Industrial Park 69-kV tap connecting the Moore Park-Moore Park Tap 69-kV (AEP) station to the load fed from Sturgis. PJM was not

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[4] Statement based on recorded phone conversations between PJM and AEP.

aware of this outage until the post-event analysis performed with AEP. The Moore Park Tap-Industrial Park 69-kV line was not modeled in the PJM, because it is below the 100-kV level, and the outage was not reported to PJM. Outages below the 100-kV level are not required to be reported to PJM under existing PJM rules.

If the outage had been modeled, PJM's outage analysis studies would have identified that removing the facility from service would increase loading on the Lagrange-Howe portion of the Lagrange-Sturgis 69-kV line on a post-contingency basis. The planned outage was to rebuild the 69-kV line. Since the line was under repair and not in a condition to be quickly restored to service, even if PJM was aware of the outage and its impacts, the planned outage could not have been recalled to avoid shedding load.

Generation Analysis

Generation outage analysis was also performed to determine if there was any generation in the area that could have been recalled from an outage to help alleviate the load shed event. Table 3 shows the amount of MW relief provided by generators that were either fully or partially outaged during the event. Shown is the portion of outaged MW that could have been available, disregarding startup times, and the MW that would have been available within an hour. The percent relief provided describes, in percentage of the total, MW that were shed, how much relief would have been provided within an hour.

		MW Relief Provided by raising generations given certain conditions:				
Event	Total MW Shed	All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
AEP Pigeon River 1 (Sept 9)	3.1	0.027	0.027	0.013	**0.013**	0.42%

Table 3. Outaged Generation MW Relief for Pigeon River Area

The analysis indicates recalling all of the planned and unplanned generation outages would not have provided significant relief to the 3 MW AEP Pigeon River 1 load shed event (less than 1 percent affect).

A study was also performed to understand the impact of retired generation, with a retirement date after September 1, 2012 until the event occurred, to determine if the retired generation would have impacted the load shed event. Based upon the generation outage analysis, having all retired generation available would have provided 0.01 MW relief to the 8-MW AEP Pigeon River 2. See Appendix B: Generation Outage and Retirement Analysis for the detailed analysis.

Operations Analysis

On September 9, 2013 at 1414, MISO notified PJM that NIPSCO had alerted MISO there was a relay limitation on the Lagrange-Howe (NIPSCO) section of the 69-kV line. If the East Elkhart-Mottville Tap-Mottville-Corey 138-kV line were to trip, the Lagrange-Howe 69-kV line would automatically relay out of service. Although there was a standing operating guide which had been jointly developed for the area (2013-T-078-E- EAST ELKHART-COUNTY ROAD 4 138-kV AEP), the guide did not identify the relay limit or the need for pre-contingency load shed. The operating guide was reviewed and accepted by PJM, MISO, NIPSCO and AEP with the intent to take post-contingency load shed actions. This guide was available for operators in all four control rooms.

PJM, as the Reliability Coordinator for the AEP transmission system, issued the load shed directive based on real-time contingency analysis results, established operating procedures, and NERC standards, which are developed to ensure the reliability of the bulk electric system. PJM's operating procedures dictate that load should be shed pre-contingency in order to avoid potential post-contingency voltage collapse and equipment damage. At times, a pre-contingency load shed is required to prevent a wide-area disturbance, such as the Midwest / Northeast Outage on August 14, 2003, or the more recent Southwest Outage, on September 11, 2011. MISO and PJM, as the Reliability Coordinators, collaborated in real-time to identify potential solutions to prevent the violation of a relay trip limit of a sub-bulk electric system transmission facility (Lagrange-Howe 69-kV line). AEP delayed implementing the load shed directive to suggest a switching option and PJM took the time to study the switching rather than reinforce the load shed directive with AEP.

Communications Analysis

A communications review of the load shed event was conducted to evaluate the communications that took place both internal to PJM, as well as with the PJM stakeholders (member companies, state and regulatory agencies, etc.)

The localized load shed event was performed by PJM Dispatch and AEP. The communications process for localized events is to communicate to the local TO, AEP, who is responsible for sending out any local notifications. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the AEP zone. The review of the recordings also indicates three-part communication, as required by NERC Reliability Standard COM-002, was used by both PJM and AEP. PJM Dispatch did not record any emergency procedures related to the localized load shed event nor the load shed directive in the Emergency Procedures application.

Post event interviews with Dispatch staff indicated an unawareness of a category in the Emergency Procedures application for a "Local Load Relief Action" largely because it had rarely if ever been used prior to September 9th. This wording does not correspond with PJM's "Post Contingency Local Load Relief Action"; therefore, Dispatchers logged the event as a generic transmission event in Smart Logs. As a result, those parties who depended on the Emergency Procedures application for notification were not notified of the load shed events

Additionally, various internal PJM departments were not notified of the events in a timely manner. During emergency operations, PJM Dispatch uses an informal process whereby the Shift Supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to Department of Energy, Federal Energy Regulatory Commission, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

See the Communications Review section for the detailed analysis.

Demand Response Analysis

PJM did not call for Emergency Mandatory Load Management Reductions for the Pigeon River event. This did not occur partly due to the highly localized issues experienced in the Corey area, but also due to the lack of a predefined subzone (that would have enabled PJM to be more surgical with the use of demand response). PJM could have called DR across the entire zone, with the expectation of seeing some value in the local area, but the lack of ability to be precise with the DR resources led PJM to explore other options in addressing the issues. Post-event analysis results highlight the following reasons why DR was not called:

- The lack of a pre-defined sub-zone in the Corey area
- The realized relief from load management reductions would be beyond the 30 minutes within which PJM must respond to a post-contingency voltage collapse based on the cascading analysis.

In the post-event analysis, PJM Demand Response Operations staff compiled a list of zip codes impacted by the Pigeon River load shed event and determined there were no registered DR resources in the area. (All demand response resources are listed by zip code in the PJM application tool eLRS). Demand response, therefore, would not have prevented the load shed events in the Pigeon River area from occurring essentially because there were no demand resources registered in that area. See the Demand Response Events for more detailed information on the analysis.

RTEP Upgrades

PJM also analyzed the impact of planned upgrades and recent generation retirements on the Pigeon River area.

The following two RTEP upgrades are planned for the AEP Pigeon River Region:

- Rebuild the Pokagon - Corey 69-kV line as a double circuit 138-kV line with one side at 69-kV and the other side as an express circuit between Pokagon and Corey stations[5]
- String a second 138-kV circuit on the open tower position between Twin Branch and East Elkhart[6]

The Pokagon – Corey 69-kV line rebuild will help reinforce the Pigeon River area. Had it been in place in September 2013, it may have helped to prevent the load shed event by reducing flows on the Lagrange-Howe line which would keep the flows below the identified relay trip setting. PJM is working with the Transmission Owner to fast-track the Pokagon-Corey 138-kV project, which is currently scheduled for June 2017, through the RTEP process.

The second 138-kV circuit on the open tower position between Twin Branch and East Elkhart will also make the system more robust to support increased load and flows.

Recommendations

The following recommendations resulted from the assessment of the AEP Pigeon River load shed events:

- Review PJM's overall approach to how and when to model and telemeter with a focus on the sub-transmission system
- Update model and telemetry in Pigeon River area

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[5] RTEP Baseline ID: b2257

[6] RTEP Baseline ID: b0840

- Update Pigeon River Operating Guide with Lagrange-Howe relay limit and pre-contingency load shed procedure
- Review facility limits on bordering equipment with MISO with a focus on pre and post-contingency load shed operations
- Review Manual 01 directive language with PJM and TO Dispatchers at the 2014 Dispatcher Seminar
- Review the Cascading Analysis procedure to include automation tools to trend the potential N-5 contingencies
- Review, enhance, and train Dispatchers on the use of PJM's Emergency Procedures application tool during load shed events
- Review load management market rules to improve DR operational flexibility through the PJM stakeholder process to include shorter lead times; subzonal calls, calls outside emergencies, and shorter minimum run times
- Improve the flexibility of subzonal demand response by proactively defining DR subzones across PJM footprint and/or mapping DR resources to nearest substation
- Provide the Dispatchers with better visibility of the location and amount (MW) of relief from DR
- Review the processes for conducting weather and load forecasting.
- Update the PJM - MISO - NIPSCO-AEP Operations guide

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

3.2 Pigeon River 2 Load Shed Event (September 10, 2013)

A second load shed event, Pigeon River 2, occurred on Tuesday, September 10, at hour 1249 in the same location, the Pigeon River substation area in the AEP zone. The amount of load shed was 8 MW in total, in increments of 5 MW at 1249 and an additional 3 MW at 1314. Approximately 1,070 customers were affected until 2123.

The local and regional conditions from the previous operating day remained:

- Higher than normal September loads and flows on the 69-kV system between Lagrange (MISO) and Corey (AEP).
- An existing planned outage on the sub-transmission system of the Moore Park Tap-Industrial Park 69-kV line (AEP in PJM) ; and
- A relay trip set point on the LaGrange-Howe (NIPSCO in MISO) 69-kV line (now modeled in the PJM EMS as a result of the previous day's events)
- Howe 69-kV station switching option still employed (as a result of the previous day's events), providing an additional feed into the area

The differentiating factor between Monday, September 9 and Tuesday, September 10 was the load. AEP load was forecasted to increase by 1,200 MW on September 10, but in actuality AEP's load increased by 2,200 MW. AEP's day-ahead analysis for September 10, 2013 did not show overloads on Lagrange – Howe.

The additional feed into the area provided by the Howe 69-kV switching option was not sufficient for the higher load levels. As a result, the September 9 operating condition reoccurred in which the next contingency (the potential tripping of the Corey-Mottville Tap-East Elkhart 138-kV line and the Lagrange-Sturgis 69-kV line because of post-contingency flows above the relay trip point on Lagrange – Howe 69-kV line) would not allow sufficient time to perform a controlled post-contingency load shed. PJM saw the constraint was trending at approximately 1030 on September 10. The post-contingency flow on Lagrange – Howe was trending close to the 47-MVA relay set point by 1220. In response, at 1249 on September 10 PJM directed AEP to shed 5 MW of load, pre-contingency to prevent a possible cascading event. Pigeon River remained the remotely controllable location with the greatest impact to alleviate the constraint. The 5 MW amount of load shed was not sufficient to alleviate the constraint, however, and PJM directed AEP to shed an additional 3 MW of load at 1314.

During the load shed event, PJM and AEP continued to assess other switching options, but based on analysis, these other options would have caused actual low voltages and actual thermal overloads. Emergency Demand Response was also not employed for the same reasons as the previous operating day. As a result, the load shed directives remained in effect until 2123 when the actual load started to reduce. The duration of the load shed was driven by the high temperatures as compared to Monday, September 9.

3.2.1 Observations and Analysis

Transmission Analysis

Day-Ahead studies performed by the PJM Reliability Engineers, on Monday, September 9, for the operating day Tuesday, September 10, took into consideration the operational parameters identified during the day such as the relay trip set point on the LaGrange-Howe (NIPSCO in MISO) 69-kV and the Howe 69-kV switching option. The outage of the Moore Park Tap-Industrial Park 69-kV radial line (AEP facility within PJM) and its associated impacts to the local loading was not included in this day-ahead analysis because this line out is not in the PJM model, is not a reportable facility to PJM (it's a radial path) and therefore the outage was not known to PJM until after both load shed events when the detailed post operational review took place.

The results of the Day-Ahead studies indicated the post-contingent flow on Lagrange-Howe would not violate the relay trip setting[7]. In other words, there would not be the need to shed load. With the actual load coming in higher than forecasted, however, (1,000 MW higher than what was studied) the additional feed provided by the Howe 69-kV station switching into the area was not sufficient to meet the increased load. In addition the base case used for September 10 studies was based on the most recent similar load day, which was August 30. The 69-kV outage started around September 5. So the impacts of that outage and the distribution level load shift it caused were not captured in the September 10 case.

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[7] Day Ahead studies did not show the need for shedding load, therefore local substation staffing was not considered.

Generation Analysis

Table 4 shows the amount of MW relief provided by generators that were either fully or partially outaged during the event. Shown is the portion of outaged MW that could have been available, disregarding startup times, and the MW that would have been available within an hour. The percent relief provided describes in percentage of the total MW that were shed, how much relief would have been provided within an hour.

		MW relief provided by raising generations given certain conditions:				
Event	**Total MW Shed**	All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
AEP Pigeon River 2 (Sept 10)	8	0.027	0.027	0.013	**0.013**	0.16%

Table 4. Outaged Generation MW Relief for Pigeon River Area

Similar to the Pigeon River 1 load shed event the previous day, based upon the generation outage analysis, recalling all of the planned and unplanned generation outages would have provided 0.01 MW relief to the 8-MW AEP Pigeon River 2 load shed event. See Appendix B: Generation Outage and Retirement Analysis section for the detailed analysis.

Operations, Demand Response, RTEP Upgrades Analysis

The Operations analysis, Demand Response analysis, and RTEP upgrades analysis are the same for the Pigeon River 2 load shed events as they were for the Pigeon River 1 load shed event the previous day. One additional observation for the second day, particularly given the length of time customers were out of service, was that rotating load shed was not utilized. PJM and AEP could have utilized rotating load sheds to spread the impact around to different customers during the lengthy outage. While this approach may have resulted in more total customers out of service, it would have reduced the inconvenience of the customers who were without power.

Communications Analysis

A review of the load shed event was conducted to evaluate the communications that took place both internal to PJM, as well as with the PJM stakeholders (member companies, state and regulatory agencies, etc.)

PJM System Operations conducts System Operations Subcommittee Transmission (SOS-T) conference calls on an as-needed basis during emergency operations events or hot weather alert days. The purpose of these conference calls is to discuss and share information regarding emergency operations events that can adversely impact the bulk electric system. On September 10, the decision was made that though temperatures were higher than normal, there were no forecasted events that would adversely impact the bulk electric system. As a result the decision was made by operations management that an SOS-T conference call was not necessary.

The localized load shed event was performed by PJM Dispatch and AEP. The communications process for localized events is to communicate to the local transmission owner, AEP, who is responsible for sending out any local notifications to any impacted parties. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the AEP zone. The review of the recordings also indicates three-part communication, as required by NERC Reliability Standard COM-002, was used by both PJM and AEP. PJM Dispatch did post the issuance of the localized emergency procedures in the Emergency Procedures application. PJM Dispatch did not post the actual load shed directive in the Emergency Procedures application.

Post-event interviews with Dispatch staff indicated that dispatch staff was unaware of the category in the Emergency Procedures application for a “Local Load Relief Action” largely because it had rarely if ever been used prior to September 9. This wording does not correspond with PJM’s “Post Contingency Local Load Relief Action” and as a result this issue was logged in Smart Logs, an internal PJM logging application, as a generic transmission event. As a result, those parties who depended on the Emergency Procedures application for notification were not notified of the load shed events

Additionally, various internal PJM departments were not notified of the events in a timely manner. As a result, the external communications initiated by these departments were delayed. During emergency operations, PJM Dispatch utilizes an informal process whereby the Shift Supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to DOE, FERC, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

See the Communications Review section for the detailed analysis.

Recommendations

The recommendations identified for the Pigeon River 1 load shed event are applicable for the Pigeon River 2 load shed event as well.

3.2.2 Pigeon River Conditions (September 11, 2013)

No load was shed in the Pigeon River area on Wednesday, September 11, 2013. Figure 5 presents the AEP actual and forecast loads for the three days.

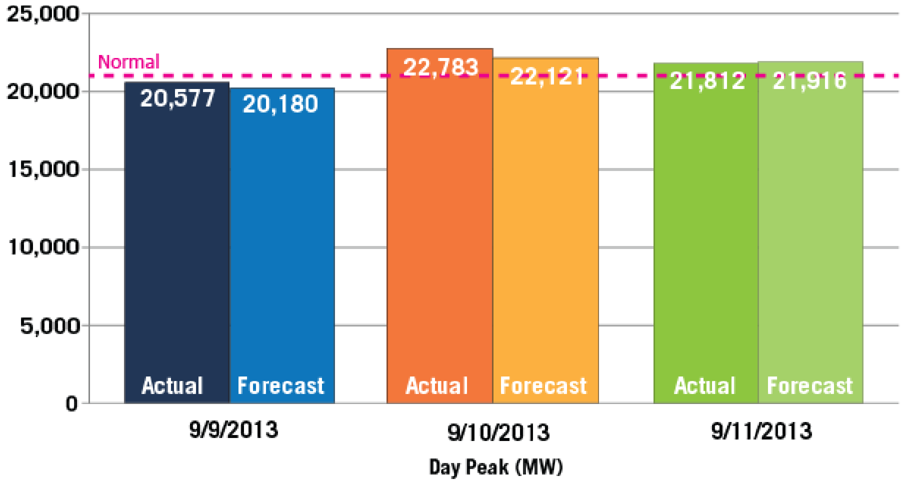

Figure 5. **AEP Loads September 9 to September 11**

The reason for no load being shed was the identification a 6-MW behind-the-meter generator within the city of Sturgis (Municipality of Sturgis, MI). In preparation for Wednesday, September 11, AEP personnel, while reviewing system one-line diagrams, identified a 6-MW behind-the-meter generator within the city of Sturgis.

The AEP local Transmission and Distribution Center (Indiana Michigan Power) informed Sturgis there was a PJM system emergency and of the possibility they may be required to reduce load. The city of Sturgis started the 6-MW generator which produced an output of approximately 5.4 MW. The City of Sturgis also called for Voluntary Customer Load Curtailment from some of their large industrial customers. (The voluntary curtailment was initiated by the City of Sturgis.) Approximately 2 MW of relief was achieved due to the curtailment. There was approximately 8 MW of relief in the Sturgis area from the combined effects of the behind-the-meter generator and the voluntary curtailment.

PJM and AEP do not have the Sturgis generator specifically modeled in their respective energy management systems, but do have loads modeled. Figure 6 presents a chart showing the Sturgis Load. The chart shows the impact to the load of the behind-the-meter generator coming on line as well as the impact from the voluntary load curtailment.

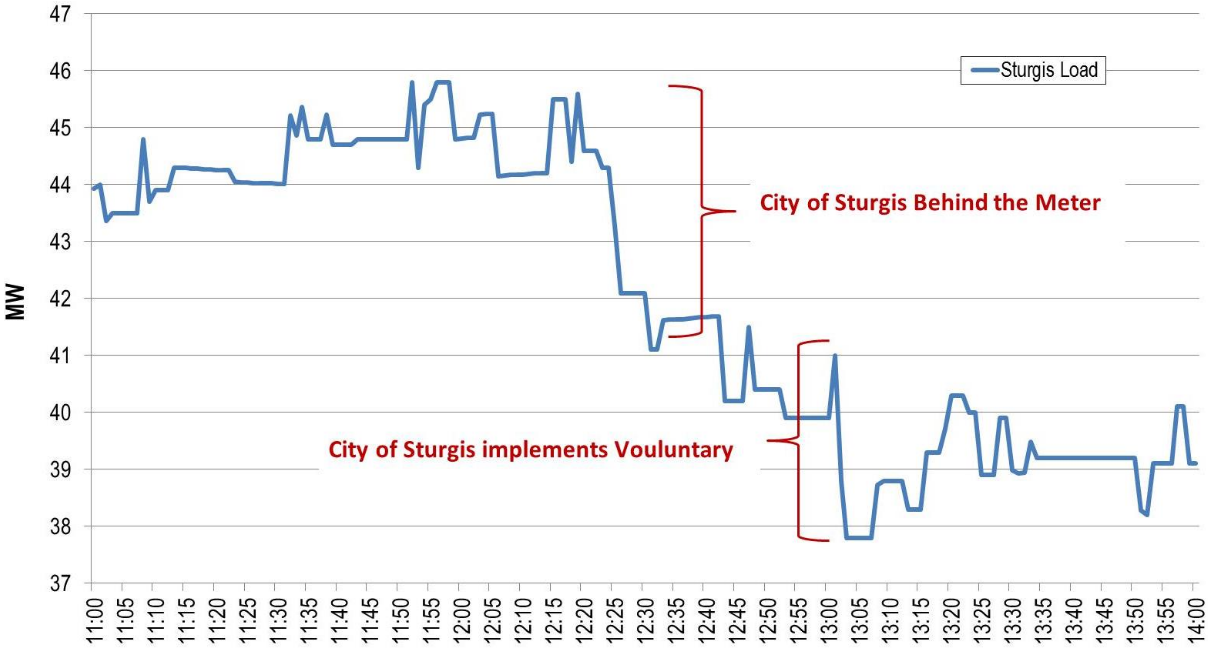

Figure 6. **Sturgis Load PI Chart**

Observations

The Sturgis unit has a large (67 percent) effect on the post contingent flow on the LaGrange – Howe portion of the Lagrange-Sturgis 69-kV line and together with the relief from the VCLC action initiated by the City of Sturgis, eliminated the need for pre-contingency load shed on Wednesday, September 11, in the Pigeon River area.

Post-event analysis showed Sturgis qualified as a 'Non-Retail' behind-the-meter generator. Non-Retail behind-the-meter generator is behind the meter generation used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load in the event of a power outage. Sturgis, by contract, does NOT use this generation for peak shaving, which means the unit does not run during the summer peak periods to reduce the Sturgis demand.

Behind-the-meter generation is not currently a resource available to PJM Dispatch, so PJM has no visibility of the generator, how it is used, or its operating parameters. There may also be contractual limitations that exist that may not allow it to be used for PJM's purposes.

Recommendations

Based on what PJM learned from the September 11, 2013 operating day in the Pigeon River area, specifically, the identification and impact of the Sturgis behind-the-meter generation as well as the Voluntary Customer Load Curtailment, the following recommendations have been identified:

- Establish and document PJM's approach, working with the States and Transmission Owners, for collecting information about Behind the Meter generation
- Review PJM's approach for representing behind-the-meter generation and operating criteria to dispatchers and incorporation with related emergency procedures

- PJM to work with transmission owners and the states to review existing modeling and telemetry, based on the issues experienced during the events of September 9-11.

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

3.3 Tod Load Shed Event (September 10, 2013)

The Tod load shed occurred on Tuesday, September 10, at 1507 in the ATSI zone. This load shed event occurred near Warren, Oh, at the Tod 138 kV substation. The amount of load shed was approximately 16 MW which affected approximately 4,500 customers from 1507 to 1642 (1 hour 35 minutes).

The following local and regional conditions existed prior to the FirstEnergy Tod load shed event and contributed to its cause:

- A forced outage on September 5 of a 138 kV switch at the nearby Hanna substation; this set up the loss of both Hanna transformers as a single contingency;
- An unplanned loss of the South Canton #1 345/138 kV transformer and the remaining 345 kV bus at the South Canton substation (on September 9), which contributed to high post-contingency flows on Highland to Tod by removing a feed into the affected area;
- FirstEnergy loads that were 3,000 MW higher, and AEP loads that were 1,200 MW higher than on September 9, 2013.; and 1,000 MW higher than those studied day ahead.; and
- A scheduled outage on the South Canton #2 345 kV bus, which also included the S. Canton #3 765/345 kV and #4 345/138 kV transformers.

Figure 7 presents a high-level electric system diagram of the FE (ATSI) Tod area.

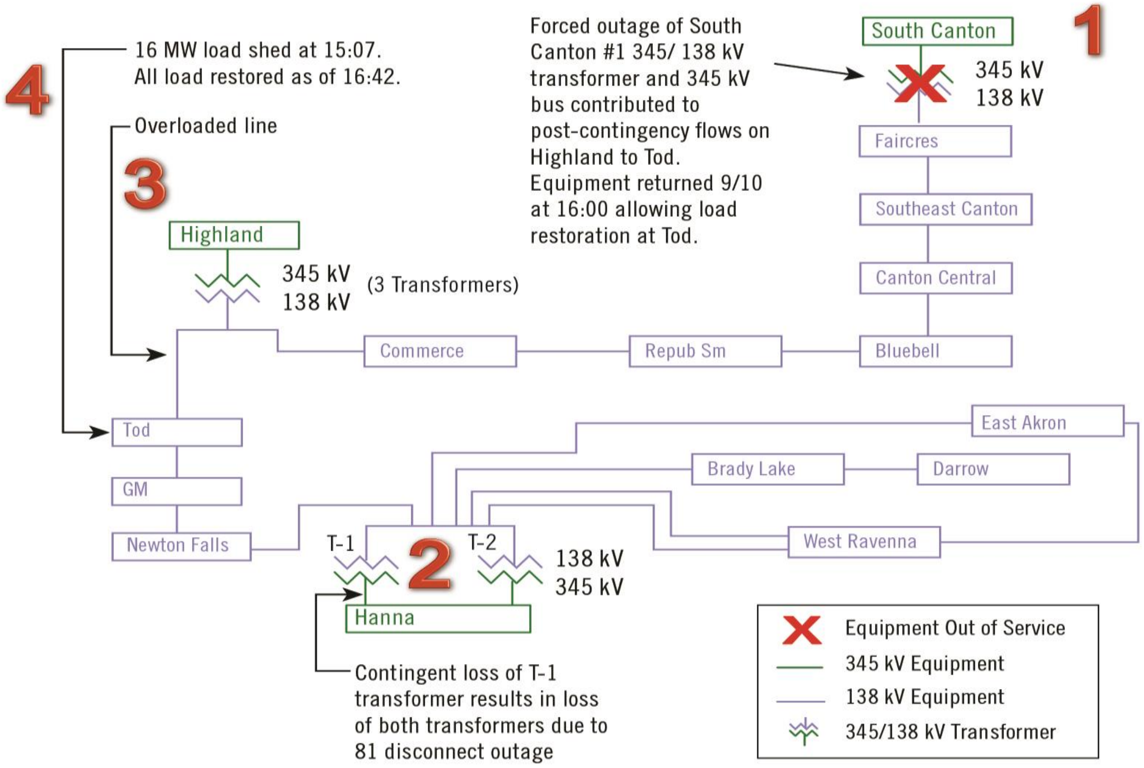

Figure 7. **FE (ATSI) Tod Area**

At 1849 on Monday, September 9, sudden pressure relays (which typically measure the oil/gas pressures of the transformer and activate at predetermined set points) were triggered on the South Canton #1 345/138 kV transformer tripping the equipment (#1 in Figure 7). There was a breaker failure relay misoperation (also known as an over reach) that also occurred at the station, which resulted in the loss of four 345 kV lines at South Canton. Two of the four 345 kV lines were restored at 0834 on Tuesday, September 10 (South Canton – Star and South Canton – Southeast Canton 345 kv lines).

PJM and ATSI determined that following a contingency (loss of the Hanna #1 345/138 kV transformer, #2 in Figure 7) flows on the Highland-Tod 138 kV line (#3 in Figure 7) would exceed thermal limits. PJM issued a Post Contingency Local Load Relief Warning at 1146 on Tuesday, September 10, to develop a load shed plan with ATSI. The Post Contingency Local Load Relief Warning alerts ATSI that, if directed by PJM, it would need to shed load in the Highland-Tod area within five minutes if the Hanna transformer were to trip.

At 1350, PJM prepared for the increased loads in ATSI by calling all available (683 MW) Long Lead Time Emergency Mandatory Load Management in the ATSI zone. PJM also issued a call for all available (115 MW) Long Lead Emergency Load Management in the South Canton subzone. The South Canton subzone was chosen, due to the large number of contingencies occurring in this area. At 1350, PJM issued a Maximum Emergency Generation Alert for the ATSI zone.

At approximately 1447, the post-contingency flow on the Highland-Tod 138 kV line was projected to exceed 115 percent of the load dump rating in the event of the loss of the Hanna #1 345/138 kV transformer. This triggered the PJM dispatchers to perform the Post-Contingency Load Dump Limit Exceedance Analysis. The analysis indicated a potential cascading event, which could lead to widespread outages throughout the electrical system. To avoid the potential cascading outage, at 1501, PJM directed ATSI to shed 16 MW of load in Tod station area (#4 in Figure 7). ATSI shed the load around 1507 and was able to restore the load at 1628 after the South Canton #1 transformer returned to service at 1600. All load was restored at 1642.

3.3.1 Observations and Analysis

Transmission Analysis

The emergency outage of the Hanna 138 kV disconnect on September 5 created a situation whereby a single fault would outage both 345/138 kV transformers at Hanna. This was the key event that triggered the load shed event. The outage of the Hanna 138 kV disconnect set up the loss of both Hanna transformers as a single contingency.

The planned outage of the South Canton 765/345 KV transformer was approved to be out of service from September 3, 2013 to Oct. 4, 2013. This particular outage was identified in the 2012 RTEP plan and was identified as a result of the retirement of New Castle units 3, 4 and 5 and diesels A and B. The outage was evaluated in PJM's short- term transmission outage analysis process from Aug. 27, 2013 to Aug. 29, 2013, as well as PJM's one-month out and six-month out analyses for September. Because of operating concerns experienced in this area on the peak summer day, July 18, PJM conducted additional analysis for this outage using the July 18 peak load and expected worst case generation outage scenarios for September, and after seeing no issues approved the outage. The outage was underway to replace equipment and, therefore, was unable to be recalled. As part of the post-event analysis, it was determined this outage contributed to less than 1 MW of the load shed event.

The unplanned loss of the South Canton #1 345/138 kV transformer and the remaining 345 kV bus at the South Canton substation (on September 9) was studied by PJM on September 9 in preparation for the September 10 operational day. The study did show there would be an increase in flows on the Highland-Tod contingency by approximately 2 MVA (0.6 percent). AEP planned to restore all facilities on Monday evening, September 9. Two of the lines were restored Monday night, and two remained out of service into Tuesday.

Day-ahead studies performed by PJM showed thermal issues in the FirstEnergy (ATSI) Tod area, but did not reveal any issues which would have warranted pre-contingency load shed. The forecasted loads used in the studies, however, were less than the actual loads encountered on September 10, 2013. Both AEP and FirstEnergy actual loads were 1,000 MW higher than those studied day ahead.

There were two 138 kV lines opened in the area for control of other area constraints that contributed to the increased loading on the Highland-Tod contingency. On September 10 at 1041, the Dale-West Canton 138 kV line was opened at Canton for Northeast Canton-Wagenhal loss of South Canton-Torrey 138 kV line; this contributed approximately 7 MVA (2.2 percent) to the Highland-Tod contingency. Restoring this line would have placed the Northeast Canton-Wagenhal contingency over the load dump rating, but less than 115 percent of this rating. (Close in the Dale-West Canton 138 kV line which would have improved the post-contingency solution by approximately 7 MVA (2.2 percent).)

On September 10 at 1348, the South Akron-Clay 138 kV line was opened at South Akron for an actual overload on East Akron-Gilchrist 138 kV line; this contributed approximately 3 MVA (0.9 percent) to the Highland-Tod contingency. Restoring this line would have caused the East Akron-Gilchrist 138 kV line for the loss of Hanna-Juniper 345 kV line contingency to be over the load dump rating, but less than the 115 percent of the load dump rating. (Close in the South Akron-Clay 138 kV line which would have improved the post-contingency solution by approximately 3 MVA (0.9 percent). Having both 138 kV lines (South Akron-Clay and Dale-West Canton) closed may have improved the post-contingency solution by approximately 16 MVA (4.9 percent).

Generation Analysis

An analysis was done on the available generation as well. There was one local diesel unit and a local combustion turbine that could have been used to control the constraint. No other generation had greater than a 2 percent effect on this contingency.

The diesel was a 5 percent raise help for the constraint, but it was bid in as available for maximum emergency only, due to environmental issues, with a 1 hour 15 minute start. Starting this unit would have helped the contingency by 0.75 MVA. PJM Dispatch did not see this unit as an option in the Dispatch Management Tool (DMT) because units bid in as maximum emergency do not show up in the list of available generation in the PJM DMT.

The combustion turbine was a 3.5 percent lower help on this contingency. The CT was online at 21 MW. Taking this unit off would have helped the contingency by 1 MVA, however the CT was committed to help control a constraint in the ATSI zone. Taking the unit off would have prevented it from protecting that wider area.

To summarize the additional analysis from the additional transmission and generation sections, there may have been some combination of the following which would have reduced the 16 MW of load shed, potentially prevented the load shed, or allowed it to be restored faster:

- Either not opening, or closing in the South Akron-Clay 138 kV line. This would have improved the post-contingency solution by approximately 7 MVA or even prevented the load shed
- Closing in the Dale-West Canton 138 kV line. This would have improved the post-contingency solution by approximately 3 MVA
- Running the diesel unit which was a 5 percent raise help for the constraint, but it was bid in as available for maximum emergency only due to environmental issues with a 1 hour, 15 minute start. Starting this unit would have helped the contingency by 0.75 MVA.
- Reducing the combustion turbine, which was a 3.5 percent lower help on this contingency, and was online at 21 MW. Taking this unit off would have helped the contingency by 1 MVA.

Generation outage analysis was also performed to determine if there was any outaged generation in the area that could have been recalled to alleviate the load shed event. Table 5 shows the amount of MW relief provided by generators that were either fully or partially outaged during the event. Shown is the portion of outaged MW that could have been available, disregarding startup times, and the MW that would have been available within an hour. The percent relief provided describes in percentages of the total MW that were shed, how much relief would have been provided within an hour.

Event	Total MW Shed	MW relief provided by raising generations given certain conditions:				
		All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
FE (ATSI) Tod	16	1.4478	0.357	1.3764	**0.0504**	0.32%

Table 5. Outaged Generation MW Relief for FE (ATSI) Tod Area

Based upon the generation outage analysis, recalling all of the planned and unplanned generation outages would have provided 0.05 MW relief to the 16 MW FirstEnergy (ATSI) Tod 1 load shed event. See the Appendix B: Generation Outage and Retirement Analysis section for the detailed analysis.

A study was also performed to understand the impact of retired generation with a retirement date after September 1, 2012, until the event occurred to determine if the retired generation would have impacted the load shed event.

The following five generating units have retired since September 1, 2012:

- Bay Shore 2
- Bay Shore 3
- Bay Shore 4
- Eastlake 4
- Eastlake 5

Based upon the generation outage analysis, having all retired generation available would have provided approximately 12.55 MW of relief to the FirstEnergy (ATSI) Tod 16 MW load shed event. This would not have eliminated the need for load shed, but the amount may have been reduced by 75 percent.

Unit	Capacity	Transmission Zone	Actual Deactivation Date	Impact Tod (MW)
Bay Shore 2	138	ATSI	9/1/2012	0
Bay Shore 3	142	ATSI	9/1/2012	0
Bay Shore 4	215	ATSI	9/1/2012	0
Eastlake 4	240	ATSI	9/1/2012	3.6
Eastlake 5	597	ATSI	9/1/2012	8.955
			Total Relief (MW)	**12.555**

Table 6. Retired Generation Impacts

Demand Response Analysis

Due to regional conditions like the increasing loads and some identified issues near Cleveland, OH, PJM issued Long Lead Time Emergency Load Management Reduction at 1350 for the AEP South Canton subzone and the entire ATSI zone for a total reduction of approximately 740 MW.

After completing a post-contingency flow analysis at 1447, PJM discovered the potential of a cascading outage due to the loss of the Hanna #1 345/138 kV transformer. Once this contingency was identified, PJM needed to respond within 30 minutes.[8] The demand response (DR) that had been requested earlier, in response to the regional conditions, was expected to be fully curtailed by 1550, beyond the 30 minute window PJM had to respond to the contingency.[9]

Post-event analysis showed there was approximately 3 MW of DR in the zip codes impacted by the FirstEnergy (ATSI) Tod load shed. Escalating the response time of the DR curtailment could have helped provide some faster relief, but would not have completely eliminated the need for the load shed event. See **Error! Reference source not found.** section for more information.

RTEP Upgrades

There are no RTEP upgrades planned in the Tod area which would have helped in mitigating or preventing the load shed event.

Communications

A communications review of the load shed event was conducted to evaluate the communications that took place both internal to PJM, as well as with the PJM stakeholders (member companies, state and regulatory agencies, etc.)

PJM System Operations conducts System Operations Subcommittee Transmission conference calls on an as needed basis during emergency operations events or hot weather alert days. The purpose of these conference calls is to discuss and share information regarding emergency operations events that can adversely impact the BES. On September 10, the decision was made that though temperatures were higher than normal there were no forecasted events that would adversely impact the BES. As a result the decision was made by operations management that an SOS-T conference call was not necessary.

The localized load shed event was performed by PJM Dispatch and ATSI at Tod. The communications process for localized events is to communicate to the local TO, ATSI, who is responsible for sending out any local notifications. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the ATSI zone. The review of the recordings also indicates three-part communication, as required by NERC Reliability Standard COM-002, was used by both PJM and ATSI. PJM Dispatch did record the issuance of the localized emergency procedures in the Emergency Procedures application. PJM Dispatch did not, however, log the actual load shed directive in the Emergency Procedures application.

Post event interviews with Dispatch staff indicated that Dispatch staff was unaware of the category in the Emergency Procedures application for a “Local Load Relief Action” largely because it had rarely, if ever, been used prior to

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[8] PJM Manual 03, Exhibit 1; as well as NERC TOP-004-2 Rv

[9] Post-event analysis showed approximately 3 MW of DR resources in the zip codes impacted by the load shed events

September 9. This wording does not correspond with PJM's "Post Contingency Local Load Relief Action" and, as a result, this issue was logged in Smart Logs, an internal PJM logging application, as a generic transmission event. As a result, those parties who depended on the Emergency Procedures application for notification were not notified of the load shed events

Additionally, various internal PJM departments were not notified of the events in a timely manner, including the State Government Policy, Member Relations, Federal Government Affairs, and Corporate Communications departments. As a result, the external communications initiated by these departments were delayed. During emergency operations, PJM Dispatch utilizes an informal process whereby the shift supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to DOE, FERC, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

See the Communications Review section for the detailed analysis.

Recommendations

The following recommendations resulted from the assessment of the FirstEnergy (ATSI) Tod load shed event:

- Provide reinforcement training for operators on contingency management (contingency trending, PCLLRW, load shed, etc.) in the control room simulator. Use this training to look for EMS enhancements for managing constraints
- Review the Cascading Analysis procedure to include automation tools to trend potential contingencies
- Review, enhance, and train dispatchers on the use of Emergency Procedures application tool during load shed events
- Review PJM's overall approach to how and when to model and telemeter with a focus on the sub-transmission system
- Provide Dispatch with better visibility of the location and amount (MW) of relief from DR
- Review the processes for conducting weather and load forecasting for extreme unseasonal conditions

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

3.4 Erie South Load Shed Event (September 10, 2013)

Erie South load shed occurred on Tuesday, September 10, at 1749 in the PJM Mid-Atlantic Zone (FirstEnergy Penelec). The load shed event occurred near Erie, Pa. The amount of load shed was 105 MW in total, shed in increments of 70 MW at 1749 and an additional 35 MW at 1822. Approximately 35,000 customers were affected during the event. FirstEnergy began restoring customer load at 2301 with all load restored by 0002 on September 11.

The local and regional conditions prior to the Penelec Erie South load shed event that contributed to the cause were:

- A scheduled and approved outage of the Geneva – Wayne 115 kV line;
- An unplanned loss of #1 Hydro unit (218 MW) on September 9;

- An unplanned loss of a #2 Hydro unit (203 MW) on September 10; and
- The unplanned loss of the Erie West-Ashtabula-Perry 345 kV line.

Figure 8 presents an overview diagram of the Erie South area.

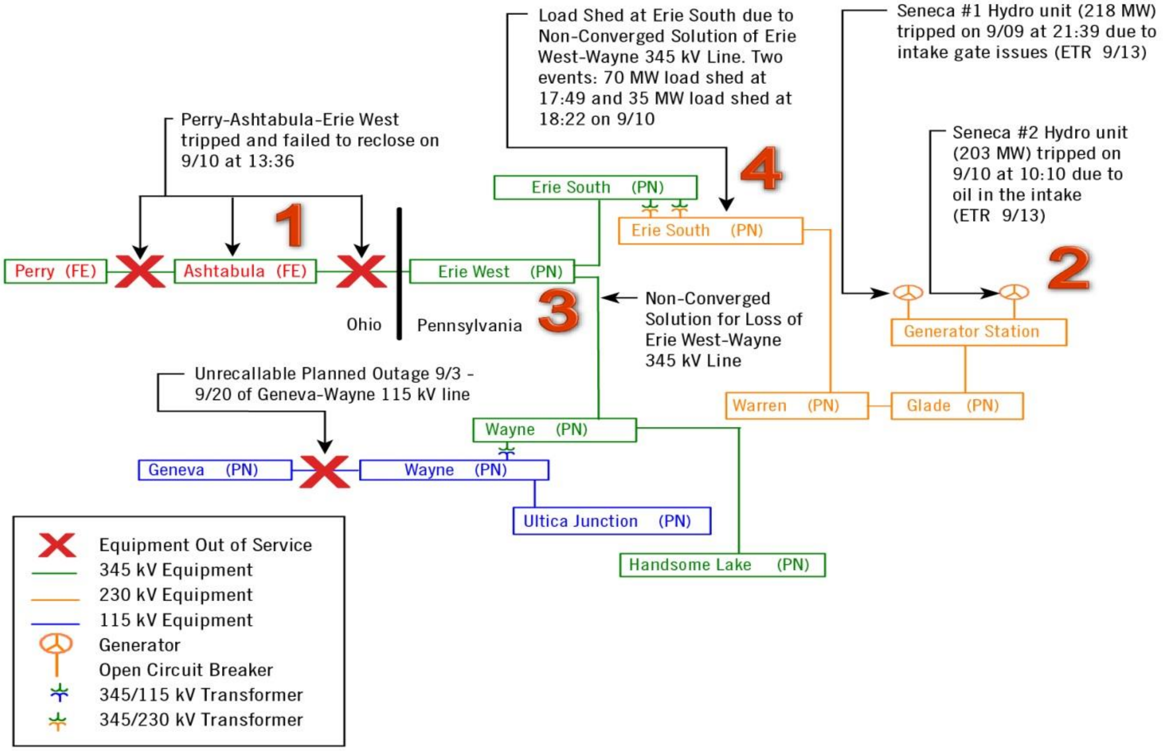

Figure 8. **FE (Penelec) Erie South Area**

On September 10 at 1336 the Erie West-Ashtabula-Perry 345 kV (#1 in the Figure 8) line tripped out of service in the Erie South area of Pennsylvania. FirstEnergy attempted to restore the line at 1345 but was not able to bring the line back because of a conductor on the ground. At 1402, FirstEnergy indicated to PJM that FirstEnergy observed several no-solve contingencies in its EMS. PJM did not observe the non-converge in its EMS, but worked with FirstEnergy to evaluate available options.

Upon observing the no-solve contingencies, FirstEnergy requested PJM call on specific generation to help alleviate those contingencies (no-solve contingencies are referred to as “non-converges”). The specific generators requested had become unexpectedly unavailable at 1405 (#2 in Figure 8). PJM worked with FirstEnergy to identify and implement possible solutions to the non-converges including lowering output of some units, bringing other units on-line, and switching options. At 1647, upon FirstEnergy’s request, PJM specifically studied the contingency – loss of Erie West-Wayne 345 kV line – in PJM's power flow analysis package(#3 in Figure 3). At 1659, PJM's power flow did not solve for this contingency; in other words, PJM’s EMS indicated a non-converge for this contingency resulting in a potential voltage collapse situation.

At 1702, based on its analysis of system conditions including a planned outage of the Geneva - Wayne 115 kV, the lack of generation in the local area, and the unplanned outage of the Erie West-Ashtabula-Perry 345 kV, FirstEnergy indicated they could not find any solutions to mitigate this non-converge (indicating potential voltage collapse) other than shedding load. The PJM dispatcher continued to investigate solutions to alleviate the operating emergency and issued the load shed directive at 1739.

PJM directed FirstEnergy to shed 70 MW of load in the Erie South area of Penelec. Additional analysis was performed, and showed the non-converge still existed and that additional load shed was required to alleviate the potential cascading outage (#4 in Figure 4). At 1819, PJM directed FirstEnergy to shed an additional 35 MW of load. All load was returned to service by 0002 Wednesday, September 11, when the overall system load reduced due to the time of day and lower temperatures.

3.4.1 Observations and Analysis

Operations Analysis

PJM and its member companies have adopted a conservative approach to address situations where a difference between a PJM member's "view" of the BES differs from PJM's "view". PJM Manual 3: Transmission Operations, Section 1.3: Transmission Operating Guidelines[10] states "If a difference exists between PJM and Transmission Owner Security Analysis results, PJM will operate to the most conservative results until the difference can be rationalized." While in general, this requirement refers to operating limits; the solutions of the two EMS systems could have also represented a "more conservative result." In this situation, the PJM dispatcher agreed with FirstEnergy's analysis at 1659, when PJM's study identified the contingency FirstEnergy indicated was a non-converge and shedding load was the only available option. However, it took PJM approximately 40 minutes (1659 – 1739) to direct FirstEnergy to shed load.

While PJM worked with FirstEnergy to take multiple operating actions throughout the day to try to address the constraints in a manner that would have avoided load shed, load shed ultimately was needed to maintain system reliability. PJM directed load shed at 1739. While the FirstEnergy (Penelec) Erie South load shed event could not be avoided, PJM should have directed the load shed earlier based on real-time analysis and internal procedures.

Transmission Analysis

An additional feed in the area, the Geneva-Wayne 115 kV line, was out of service for a planned outage from September 3 to September 20. The outage was to replace relays and the substation conductor and could not be recalled during the time of the load shed event on September 10. Had the Geneva-Wayne outage been able to be restored, it would have reduced the amount of load shed.

When the outage was evaluated in the short term outage process on August 27 to August 29, as well as the one month out and six month out analyses for September, no issues were identified. The studies performed do not look at five simultaneous contingencies (Geneva-Wayne 115 kV, Erie West-Ashtabula-Perry 345 kV, Seneca 1, Seneca 2, and Erie West-Wayne 345 kV) as was the case for the Erie South event. Any operational issues caused by the outage would not have been able to be identified beforehand.

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[10] PJM Manual 3: Transmission Operations, Section 1.3: Transmission Operating Guidelines

Generation Analysis

Both local hydro units, requested by FirstEnergy once the Erie West-Wayne 345 kV tripped, were scheduled to run at full output in the day-ahead market for September 10. One (218 MW) of the units tripped at 2139 on September 9 due to intake gate issues, and the second unit (203 MW) tripped at 1010 on September 10 due to oil in the intake. These were forced outages and not expected to return to service until September 13.

Generation outage analysis was also performed to determine if there was any generation in the area that could have been recalled from their planned outage to mitigate the contingency and avoid the need for load shed. Table 7 shows the amount of MW relief provided by generators that were either fully or partially outaged during the event. Shown is the portion of outaged MW that could have been available, disregarding startup times, and the MW that would have been available within an hour. The percent relief provided describes in percentage of the total MW that were shed, how much relief would have been provided within an hour.

		MW relief provided by raising generations given certain conditions:				
Event	**Total MW Shed**	All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
FE (Penelec) Erie	105	3.3603	2.0703	0.434	**0.056**	0.05%

Table 7. Outaged Generation MW Relief for FE (Penelec) Erie Area

Based upon the generation outage analysis, recalling all of the planned and unplanned generation outages[11] would have provided 0.056 MW relief to the 105 MW FirstEnergy (Penelec) load shed event. None of those units are in the Erie load pocket.

Analysis was also done on recent unit retirements to determine if any of those units had an impact on this load shed event. The conclusion of the analysis indicates there were no unit retirements in recent years that would have had an impact.

See the Appendix B: Generation Outage and Retirement Analysis section for the detailed analysis.

Demand Response Analysis

Due to the outages in the Erie South area, the operational challenges already described, and the need to respond quickly to the contingency, demand response was not considered by PJM Dispatch. Specifically, the lack of detailed knowledge about DR resource locations within the electric system, and the 2-hour notification time required were the reasons Dispatch did not call upon DR to address the transmission constraints in real time.

The post event analysis, determined there were approximately 31 MW of emergency load management resources within the impacted zip codes for the FirstEnergy Erie South load pocket that could have provided some relief to the

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[11] Seneca units were not part of this analysis since they were considered part of the event. However, if they were running at full output (421 MW for units #1 and #2), it would have eliminated the post-contingency overload.

area, if either the entire Penelec zonal long lead time load management had been called, or if an Erie South subzone had defined prior to the operating day, or there was a shorter DR notification time. Depending on the exact locations of the resources this may have helped reduce the size of the load shed or the duration in some areas, but would not have completely eliminated the need.

Had PJM called the entire Penelec zonal long lead time load management upon learning about the non-converges in the FirstEnergy model, there would have been sufficient time for the resources to curtail (there were 265 MW of DR in the entire Penelec zone). The post event analysis, determined that approximately 31 MW of this would have been effective and depending on the exact locations of the resources this may have helped reduce the size of the load shed or the duration in some areas, but would not have completely eliminated the need.

RTEP Upgrades

There are no RTEP upgrades planned in the Erie South area which would have helped in mitigating or preventing the load shed event.

Communications

A communications review of the load shed event was conducted to evaluate the communications that took place both internal to PJM, as well as with the PJM stakeholders (member companies, state and regulatory agencies, etc.)

PJM System Operations conducts System Operations Subcommittee Transmission (SOS-T) conference calls on an as needed basis during emergency operations events or hot weather alert days. The purpose of these conference calls is to discuss and share information regarding emergency operations events that can adversely impact the BES. On September 10, the decision was made that, although temperatures were higher than normal, there were no forecasted events that would adversely impact the BES. As a result the decision was made by operations management that an SOS-T conference call was not necessary.

The localized load shed event was performed by PJM Dispatch and FirstEnergy (Penelec) at Erie South. The communications process for localized events is to communicate to the local TO, FirstEnergy (Penelec), who is responsible for sending out any local notifications to any impacted parties. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the FirstEnergy (Penelec) zone. The review of the recordings also indicates three-part communication, as required by NERC Reliability Standard COM-002, was used by both PJM and FirstEnergy (Penelec). PJM Dispatch did record the issuance of the localized emergency procedures in the Emergency Procedures application. PJM Dispatch did not, however, log the actual load shed directive in the Emergency Procedures application.

Post event interviews with Dispatch staff indicated that Dispatch staff was unaware of the category in the Emergency Procedures application for a “Local Load Relief Action” largely because it had rarely, if ever, been used prior to September 9. This wording does not correspond with PJM’s “Post Contingency Local Load Relief Action” and as a result this issue was logged in Smart Logs, an internal PJM logging application, as a generic transmission event. As a result, those parties who depended on the Emergency Procedures application for notification were not notified of the load shed events

Additionally, various internal PJM departments were not notified of the events in a timely manner, including the State Government Policy, Member Relations, Federal Government Affairs, and Corporate Communications departments.

As a result, the external communications initiated by these departments were delayed. During emergency operations, PJM Dispatch utilizes an informal process whereby the Shift Supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to DOE, FERC, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

See the Communications Review section for the detailed analysis.

Recommendations

The following recommendations resulted from the assessment of FirstEnergy (Penelec) Erie South load shed event:

- Review, enhance, and train dispatchers on the use of Emergency Procedures application tool during load shed events
- Review load management rules to improve operational flexibility through the PJM stakeholder process to include shorter lead times, subzonal calls, calls outside of emergencies, and shorter minimum run times
- Improve the flexibility of subzonal demand response by proactively defining DR subzones across PJM footprint and better mapping of DR resources to nearest substation
- Provide Dispatchers better visibility of the location and amount (MW) of relief from DR
- Review PJM EMS non-converge procedures and EMS tools to present non-converge situations to PJM operators to include troubleshooting processes

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

3.5 Summit Load Shed Event (September 10, 2013)

The load shed event in AEP Summit area occurred on Tuesday, September 10, at 1913 in Fort Wayne, IN, around the Industrial-Summit 138 kV line. A total of 25 MW of load was shed that impacted approximately 3,500 customers from 1913 to 2016 (approximately 1 hour 3 minutes).

The local and regional conditions prior to the AEP Summit load shed event that contributed to the cause were:

- Planned and approved outages of the Allen-Lincoln 138 kV line and the Lincoln 138 kV bus (bus work to add new disconnects at Lincoln);
- Facility ratings on Summit-Industrial 138 kV line that were all the same. (The normal rating (24 hours), emergency (four hours), and maximum (15 minute) limit all had a facility rating of 251 MVA);
- High loads in the AEP and ATSI zones; and
- Long-lead times for generation in the area.
- A modeling difference between PJM and AEP, which resulted in a 20 MVA discrepancy between PJM and AEP's solution

Figure 9 shows an overview of the electric system in the AEP Summit area.

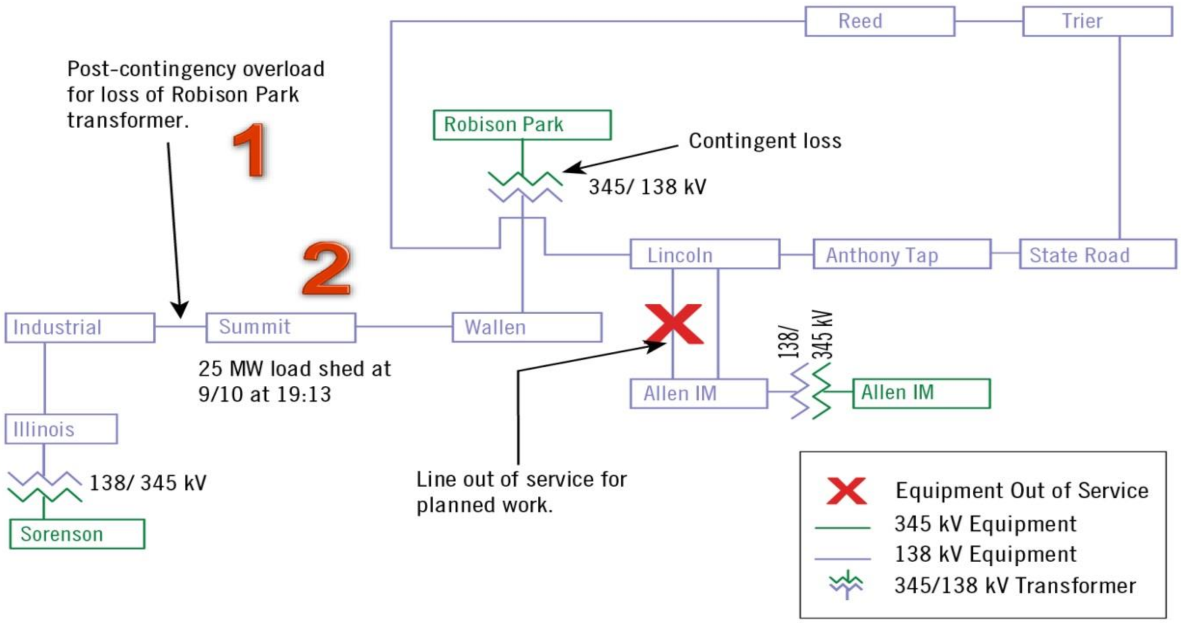

Figure 9. **AEP Summit Area**

Unseasonable hot weather (95 degrees in Fort Wayne) contributed to higher loads in the AEP and FirstEnergy ATSI zones. The Lincoln 138 kV bus and Lincoln-Allen 138 kV line were out of service for scheduled work starting September 7. These outages were known to be contributing to higher flows in the area. The Day-Ahead Contingency analysis showed overload issues on the Industrial-Summit 138 kV line for the loss of the Robison Park T5 345/138 kV transformer, but the overloads were at 86 percent of the Emergency limit. AEP's day-ahead analysis for September 10, 2013, did not show overloads on Industrial – Summit (#2 in Figure 9). PJM was monitoring the post-contingency load flow in the area.

As load increased (post-contingency flow on the Industrial-Summit 138 kV line exceeded the Emergency limit) PJM issued a Post Contingency Local Load Relief (PCLLRW) at 1146. The purpose of the PCLLRW was to alert AEP that it would need to shed load in the Summit area within five minutes if the Robison Park T5 345/138 kV transformer (#1 in Figure 9) were to trip. AEP developed plans identifying the load to shed and ensured that plan was in place and ready to be executed, as stated in M-13 section 5.4.

As loads continued to increase in the area, the simulated post-contingency flows on the Industrial-Summit 138 kV line also increased. At 1850, the AEP operator notified PJM that AEP's post contingency analysis was showing the flow on the Industrial-Summit 138 kV line for the loss of Robison Park T5 345/138 kV transformer to be 20 MVA higher than PJM's post contingency analysis.

PJM and AEP agreed to operate to the most conservative analysis, which was AEP's 20 MVA higher solution. With the additional 20 MVA of post-contingency flow, the flow on Industrial-Summit 138 kV line exceeded 115 percent of the Load Dump limit of the line. According to PJM Manual 13[12], a Post-Contingency Load Dump Limit Exceedance Analysis was performed, which identified a potential cascading event in the event.

At the higher flows, the Exceedance Analysis indicated that, should the Robison Park transformer trip, the transmission system voltage in the area would have collapsed immediately. The plan to shed load after the contingency occurred was no longer a viable option and action needed to be taken pre-contingency to avoid a potential cascading collapse.

At 1913, PJM directed AEP to shed 25 MW in the Summit area. The Summit load was chosen because it had the most impact in relieving the transmission constraint (61.3 percent effect). All customer load was returned to service by 2016 when the overall system load reduced due to the time of day and lower temperatures.

3.5.1 Observations and Analysis

Operation Analysis

The Industrial-Summit 138 kV line is a monitored priority 2 (MP 2) facility, or a facility which is above the 100 kV NERC Bulk Electric System (BES) level, but not turned over to PJM for control and calculation in the PJM congestion management process (LMP). Generation is only used to control an MP 2 contingency if the post-contingency flow is greater than the emergency rating and the transmission owner (AEP) accepts responsibility for the associated costs.

For this reason, generation was not re-dispatched to control the post-contingency flows on the Industrial-Summit 138 kV line when they were at 86 percent of the emergency rating. It was not until the post-contingent flows exceeded the emergency rating that PJM took action, which was to issue the Post Contingency Local Load Relief Warning (PCLLRW). If the Industrial-Summit 138 kV line were a Monitored Market Priority 1 (MP1) facility, PJM's generation commitment model would have committed additional generation in the day ahead analysis (likely the local combustion turbines), which may have eliminated the need for the load shed.

Transmission Analysis

There was a planned outage which removed Allen - Lincoln 138 kV line from September 7 to September 28 to replace bus disconnects. This outage was studied on September 4 and 5 as part of the short term transmission outage analysis. AEP and PJM analysis show that post-contingency flows on the Industrial-Summit 138 kV line are lower with the Allen-Lincoln 138 kV #1 line in service. The Summit load shed was impacted by the 138 kV line work, however the outage was un-recallable due to the nature of the work that was in progress.

On September 5, when the outage was approved, high loads were not forecasted, which lowered the post-contingency flows. A modeling issue was also discovered where PJM incorrectly modeled a 138 kV series device at Industrial that was not actually in the field. PJM's model included a pseudo-series device, which was added to the model in order to map available telemetry from AEP. A pseudo device is normally included in the PJM model with a zero impedance, so it does not affect the State Estimator solution. A non-zero impedance value was mistakenly added to the series device, which resulted in a 20 MVA solution difference between PJM and AEP's state estimator solutions. PJM State Estimator (SE) values were 20 MVA less than the real-time actual values. PJM correctly

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[12] PJM Manual 13: Emergency Operations, Section 5.4.1

compensated for the modeling difference in real-time by triggering the cascading outage analysis at a lower threshold based on AEP's analysis.

Due to the non-zero impedance on the pseudo-series device and lower than actual forecasted loads, day-ahead analysis indicated the constraint was 86 percent of the load dump rating on the MP2 Industrial-Summit 138 kV line, therefore PJM did not commit any controlling generation. The day-ahead analysis was erroneous because of the issues noted above. These problems led to PJM not committing any controlling generation. If PJM could have recalled the Allen-Lincoln 138 kV and/or committed the controlling generation, the load shed event may have been reduced or potentially eliminated.

Another observation was the normal, emergency, and load dump ratings on the Industrial-Summit 138 kV line were the same. PJM Manual 3A states that "Load Dump ratings are expected, but not required, to be higher than Emergency Ratings". The reason for having different ratings is to give the dispatcher time to trend and validate the flows as well as take action to reduce the flows on the line. The impact of all the ratings being the same is there is no time for the dispatcher to perform anything but the most extreme action that must be taken once the load dump rating is reached. In this case, it was to issue the PCLLRW and ultimately shed load.

Generation Analysis

Post event analysis looked at generators that had not been called upon during the event. The review specifically looked at combustion turbines in the area, which have a combined output of about 395 MW. These units were offline during the load shed event. These units were not committed in the day ahead analysis, in part, because PJM's EMS model was incorrect, resulting in flows that were within acceptable operating limits (86 percent of load dump rating). Had the Industrial-Summit line been an MP1 facility, the EMS error would have been inconsequential, as PJM would have either committed the combustion turbines in the day-ahead, or asked them to get onto turning gear (which reduces their start up time from 6-13 hours down to 1 hour). The analysis identified that if these generating units had been synchronized to the grid, the load shed in the Summit area may have been prevented.

Generation outage analysis was also performed to determine if there was any generation in the area that could have been recalled from an outage to alleviate the load shed event. Table 8 shows the amount of MW relief provided by generators that were either fully or partially outaged during the event. Shown is the portion of outaged MW that could have been available, disregarding startup times, and the MW that would have been available within an hour. The percent relief provided describes in percentage of the total MW that were shed, how much relief would have been provided within an hour.

		MW Relief Provided by raising generations given certain conditions:				
Event	**Total MW Shed**	All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
AEP Summit	25	7.8334	2.4176	0.9768	**0.396**	1.58%

Table 8. Outaged Generation MW Relief for AEP Summit Area

Based upon the generation outage analysis, recalling all of the planned and unplanned generation outages would have provided 0.39 MW of relief to the 25 MW AEP Summit load shed event.

A study was also performed to understand the impact of retired generation with a retirement date after September 1, 2012, until the event occurred to determine if the retired generation would have impacted the load shed event.

The following five generating units have retired since September 1, 2012:

- Bay Shore 2
- Bay Shore 3
- Bay Shore 4
- Eastlake 4
- Eastlake 5

Based upon the generation outage analysis, having all retired generation available and running would have provided approximately 12.15 MW of relief to the AEP Summit load shed event (Table 9) which resulted in 25 MW of load shed.

Unit	Capacity	Transmission Zone	Actual Deactivation Date	Impact Summit (MW)
Bay Shore 2	138	ATSI	9/1/2012	2.622
Bay Shore 3	142	ATSI	9/1/2012	2.698
Bay Shore 4	215	ATSI	9/1/2012	4.085
Eastlake 4	240	ATSI	9/1/2012	0.96
Eastlake 5	597	ATSI	9/1/2012	1.791
			TOTAL Relief (MW)	**12.156**

Table 9. Retired Generation Impacts on AEP Summit Area

3.5.2 Demand Response Analysis

PJM and AEP observed potential overloads on the Summit-Industrial 138 kV line at 1146 for the loss of the Robison Park T5 transformer and issued the PCLLRW. Demand Response was not called at this time because of the MP2 facility designation noted above as well as the lack of granularity and visibility into the impact of calling DR. PJM's only option would have been to call the entire AEP zone (1,500 MW) with no data to show it would be helpful in alleviating the Summit-Industrial 138 kV potential overload.

PJM discovered AEP's power flow analysis was solving 20 MVA higher than PJM's analysis at 1850. With the additional 20 MVA of post contingency flow, the flow on Industrial-Summit 138 kV line exceeded 115 percent of the Load Dump limit of the line, a contingency that needed to be addressed within 30 minutes.

Emergency load management was not considered an option because it requires a two-hour notification time and is not obligated to respond beyond 2000 (two hour response would have been 2050 which is beyond the 2000 window for requesting DR and beyond the 30-minute requirement PJM had to respond).

Had PJM known if DR resources would have been effective for controlling the potential overload and had the ability to call those specific DR resources at 11:46, when it observed the potential overload on the Summit-Industrial 138 kV line, there would have been sufficient time for the resources to fully curtail by the time of the potential contingency. The post-event analysis revealed the presence of 11 MW of registered DR in the area. Because the Summit-Industrial 138 kV line was an MP2 facility, or non-market line, AEP would have had to agree to pay for the DR resources instead of issuing a PCLLRW with little assurance that the DR would have helped the constraint.

These DR resources may have helped reduce the magnitude of the load shed, though not have completely eliminated the need to shed the 25 MW load. It is difficult to determine exactly how much impact the DR would have had on the final load shed, because the location of these resources (on the electric system) is unknown. Load curtailment on the wrong side of a transmission constraint can create higher flows, which can further exacerbate an already constrained line.

RTEP Upgrades

The following four RTEP upgrades are planned for AEP Summit region:

1. Perform a sag study on the Lincoln - Robison Park 138 kV line[13].[14] This upgrade could increase the current rating from 167 MVA Robison Park - Lincoln 138 kV line to 244 MVA.
2. Replace the risers at Lincoln 138 kV bus. This upgrade could increase both the Summer Normal and Summer Emergency ratings improve to 268 MVA (on the Lincoln-Allen 138 kV line)[15]
3. Replace the breaker at Lincoln 138 kV bus. This upgrade could increase the Summer Emergency rating to 251 MVA (on the Anthony-Lincoln 138 kV line) [16]
4. Perform a sag study of the Industrial Park - Summit 138 kV line[17]. This study could increase the rating at Industrial Park - Summit 138 kV line, potentially improving the situation by changing the normal, emergency, and load dump ratings which would allow time for Dispatcher to trend constraints and use control actions prior to load shed.

Communication Analysis

A communications review of the load shed event was conducted to evaluate the communications that took place both internal to PJM, as well as with the PJM stakeholders (member companies, state and regulatory agencies, etc.)

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[13] RTEP Baseline id: b1878

14 A test to determine transmission line characteristics which will determine the three different sets of line ratings (Normal, Emergency, Load Dump).

[15] RTEP Baseline id: b1439

[16] RTEP Baseline id: b1440

[17] RTEP Baseline id: b1736

PJM System Operations conducts System Operations Subcommittee Transmission (SOS-T) conference calls on an as needed basis during emergency operations events or hot weather alert days. The purpose of these conference calls is to discuss and share information regarding emergency operations events that can adversely impact the BES. On September 10th, the decision was made that though temperatures were higher than normal there were no forecasted events that would adversely impact the BES. As a result the decision was made by operations management that an SOS-T conference call was not necessary.

The localized load shed event was performed by PJM Dispatch and AEP at Summit. The communications process for localized events is to communicate to the local TO, AEP, who is responsible for sending out any local notifications to any impacted parties. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the AEP zone. The review of the recordings also indicates three-part communication, as required by NERC Reliability Standard COM-002, was used by both PJM and AEP. PJM Dispatch did record the issuance of the localized emergency procedures in the Emergency Procedures application. PJM Dispatch did not, however, log the actual load shed directive in the Emergency Procedures application.

Post event interviews with Dispatch staff indicated that dispatch staff was unaware of the category in the Emergency Procedures application for a “Local Load Relief Action” largely because it had rarely if ever been used prior to September 9. This wording does not correspond with PJM’s “Post Contingency Local Load Relief Action” and as a result this issue was logged in Smart Logs, an internal PJM logging application, as a generic transmission event. As a result, those parties who depended on the Emergency Procedures application for notification were not notified of the load shed events

Additionally, various internal PJM departments were not notified of the events in a timely manner, including the State Government Policy, Member Relations, Federal Government Affairs, and Corporate Communications departments. As a result, the external communications initiated by these departments were delayed. During emergency operations, PJM Dispatch utilizes an informal process whereby the shift supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to DOE, FERC, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

See the Communications Review section for the detailed analysis.

Recommendations

The following recommendations resulted from the assessment of the AEP Summit load shed event:

- Review PJM’s overall approach to how and when to model and telemeter with a focus on the sub-transmission system
- Update model (series device) in AEP Summit area. (This is tentatively scheduled for January 2014.)
- Review the Cascading Analysis procedure to include automation tools to trend potential contingencies
- Review, enhance, and train dispatchers on the use of PJM’s Emergency Procedures application tool during load shed events

- Review load management market rules to improve operational flexibility through the PJM stakeholder process to include shorter lead times; subzonal calls, calls outside emergencies, and shorter minimum run times
- Improve the flexibility of subzonal demand response by proactively defining DR subzones across PJM footprint and/or mapping DR resources to nearest substation
- Provide the dispatchers with better visibility of the location and amount (megawatts) of relief from DR

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

Other Operational Assessments

In addition to the load shed events of September 9 and September 10, there were other operational events that PJM included in the post-event analysis. Specifically, the Synchronized Reserve event on September 10 and the DR events on September 10 and 11 were analyzed. There was also a Transmission Loading Relief 5 that occurred between PJM and the NYISO on September 11. The results of these assessments follow in the next two sections.

4 Other Events

4.1 Synchronized Reserve Event (September 10, 2013)

To account for unforeseeable system events, such as unplanned outages, PJM carries reserves on the system, known as Synchronous Reserves, to maintain the generation needed to balance load. PJM is required to carry sufficient synchronized reserves on the system to handle the largest contingency on the system at that time. Going into the operating day on Tuesday, September 10, PJM was required to carry 1,322 MW of synchronized reserves. PJM's tools indicated that PJM had approximately 1,655 MW of Synchronized Reserves available.

PJM had reserves available to meet the requirement for the week including the three operating days reviewed (see Figure 10). Figure 11 shows hourly synchronized reserves requirement and hourly synchronized reserves PJM had available on September 10, 2013.

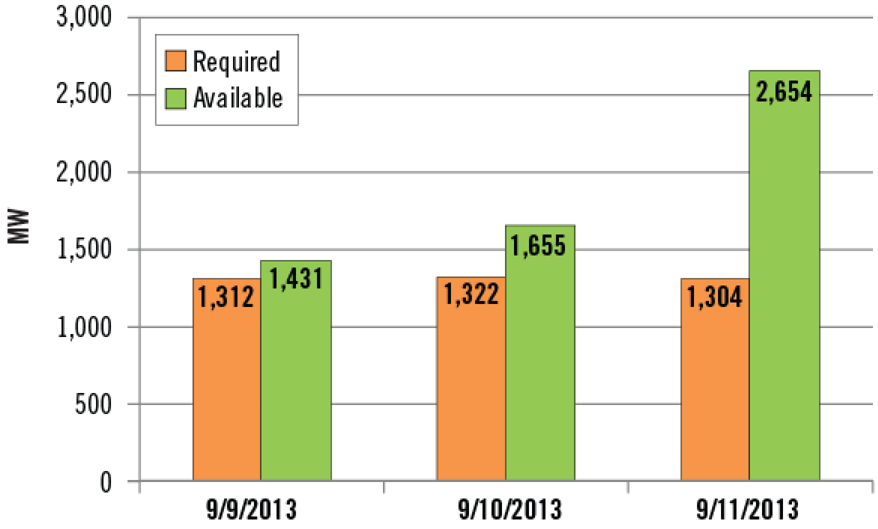

Figure 10. **Synchronized Reserves**

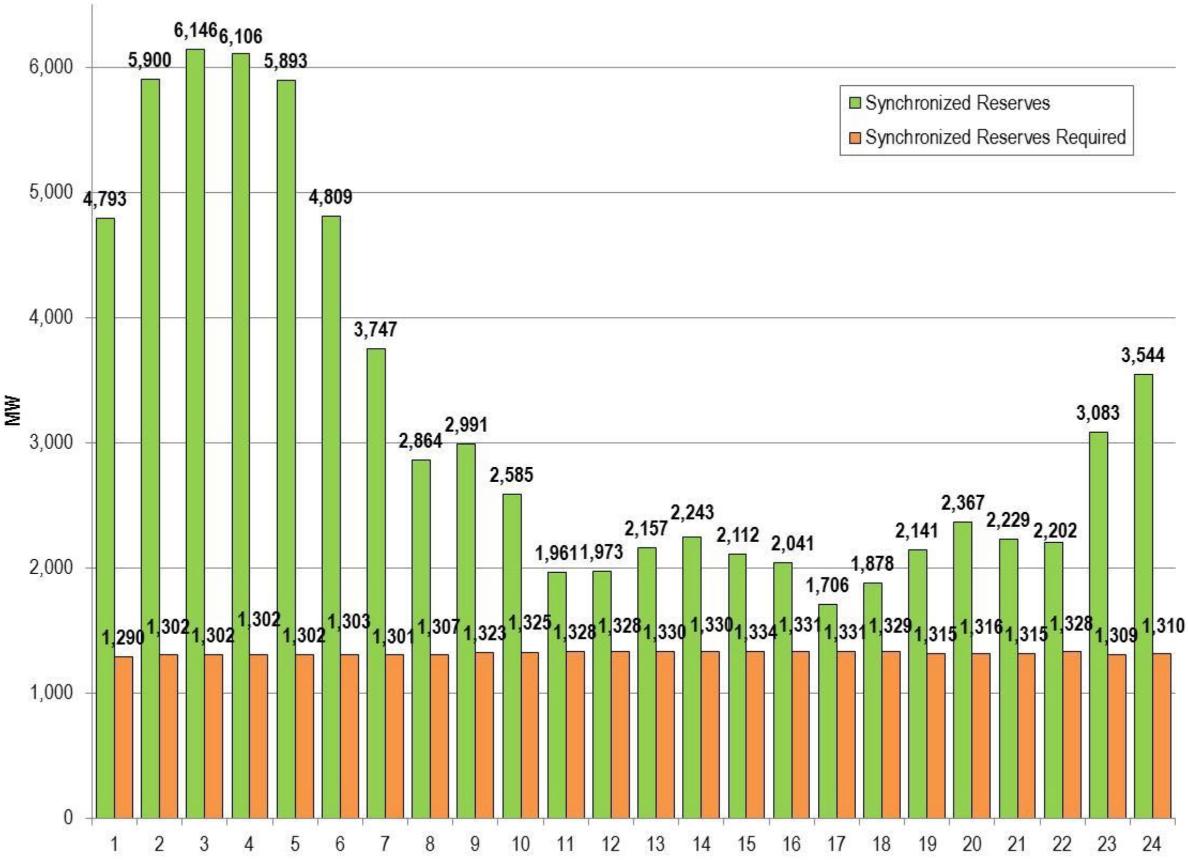

Figure 11. **Synchronized Reserves Hourly**

PJM Area Control Error – Is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts (which reflects generation in relation to load). Area Control Error is a value that defines how well the PJM balancing area is meeting its obligation.

At 1548 on September 10, 2013, PJM requested all synchronized resources in the RFC zone (PJM RTO less Dominion zone) to deploy 100 percent of available reserves to help PJM recover from a low ACE (approximately -1,600 MW). The response provided was significantly less than expected (1,655 MW). As a result, PJM kept the signal to the synchronized units at a full raise, asking generators to provide all available power. The event lasted an hour and six minutes.

This response is very unusual as historically synchronized reserve events typically last for no more than 10 minutes, because generation tends to significantly over-respond. At 1553, PJM activated shared reserves from Northeast Power Coordinating Council for 10 minutes to assist in recovering PJM’s low ACE.

Figure 12 below shows an overview of the synchronized reserve event.

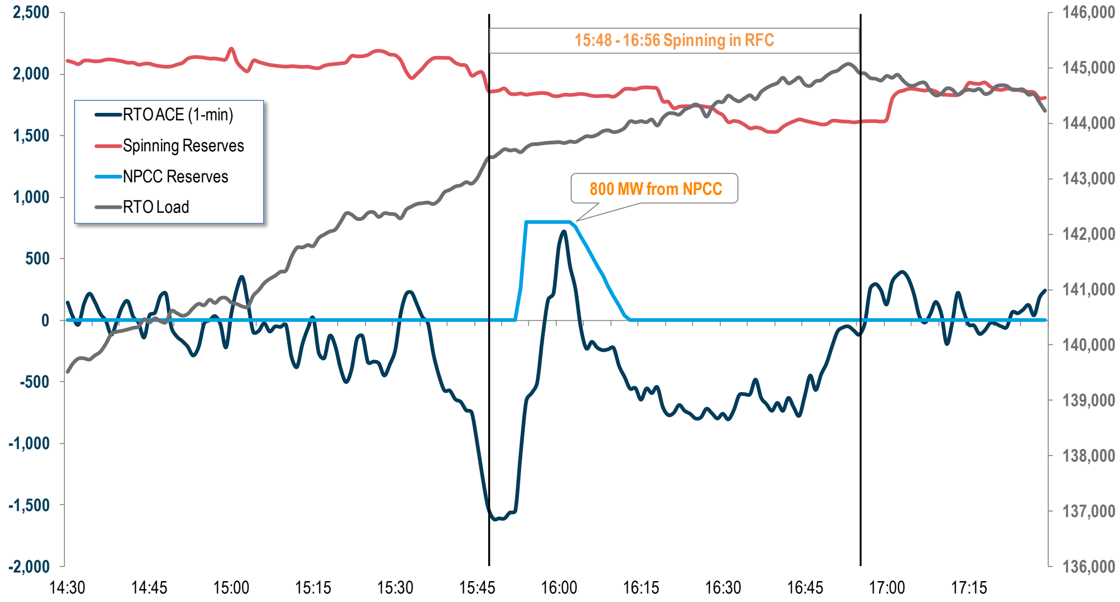

Figure 12. **September 10 Synchronized Reserve Event**

The shared reserves from NPCC and additional generation called on by PJM prior to the synchronized reserve event helped PJM recover the ACE from approximately -1600 MW to +800 MW. PJM's net generation increased by approximately 1,150 MW from 1545 to 1601. Because PJM recovered the ACE and no longer needed the shared reserves, at 1603 PJM terminated shared reserves with NPCC. However, after PJM terminated shared reserves with NPCC, PJM's ACE dropped to approximately -600 MW. To restrict further decline in ACE, PJM maintained the signal for synchronized reserves.

Figure 13 below shows the aggregate generation response from different types of generating resources in one-minute intervals from the start of the synchronized reserve event to 15 minutes into the event.

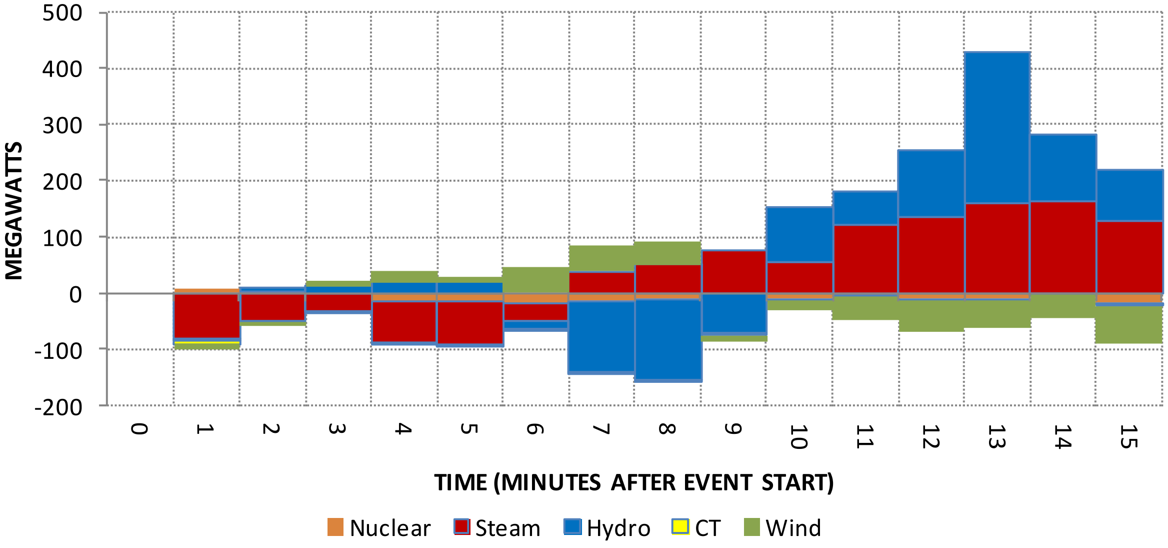

Figure 13. **Synchronized Reserve Event Generation Response**

A positive response indicates that those units increased their outputs while a negative response indicates that those units decreased their outputs during the event. In any given one-minute interval the total generation response is the sum of positive generation response less the negative generation response. Although the synchronized reserve event lasted for more than an hour, PJM did not observe generation response greater than approximately 400 MW. Generation response within the first 10 minutes of initiating the synchronized reserves was approximately 200 MW compared to the available 1,655 MW of synchronized reserves.

4.1.1 Maintaining Sufficient Reserves

PJM uses several tools to ensure sufficient reserves are maintained throughout the operating day. These include the Instantaneous Reserve Check, an EMS application called Reserve Monitor, Security Constrained Economic Dispatch, and the Ancillary Service Optimizer , a tool that performs the joint optimization function of energy, reserves and regulation.

The IRC provides a snapshot of the reserves available to PJM at any given time. PJM strategically requests an IRC during an operating day as described in PJM Manual 12: Balancing Operations, Section 4.4.1: Monitoring Reserves to get an indication of actual reserves available at that point in time. When PJM requests an IRC, generation owning companies within PJM report the synchronized reserves available from their units to PJM. Thus, an IRC at strategic points during the day helps PJM dispatchers establish benchmarks between actual and estimated reserves.

The Reserve Monitor is an EMS application that runs continuously and provides PJM dispatchers the amount of reserves (synchronized, primary, and contingency) available, as well as the reserve requirements in different reserve zones of PJM.

SCED conducts an economic analysis taking into account various constraints on the system in real time and dispatches generation accordingly. SCED runs every five minutes and conducts a 15-minute look-ahead and dispatches units so that they can be at the required output levels in the next 15 minutes.

ASO works in conjunction with SCED to make commitments for ancillary services, which include Synchronized Reserve, Non-Synchronized Reserve, and Regulation. ASO maintains sufficient reserves to meet the PJM reserve requirements (PJM Manual 13: Emergency Operations, Section 2.2: Reserve Requirements[18]). Sufficient synchronized reserves are maintained through two types of reserves – Tier 1 and Tier 2 reserves. Detailed information on Tier 1 and Tier 2 reserves is provided in Appendix B, Section B.8 Activating Synchronized Reserves & Reserves Sharing.

4.1.2 Observations and Findings

Instantaneous Reserve Check (IRC)

A review of the available reserves shown by the IRC at 1431 on September 10, 2013 and the Reserve Monitor indicates that there is a difference in the amount of actual synchronized reserves shown by the IRC and the Reserve Monitor; though both indicated sufficient synchronized reserves.

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[18] PJM Manual 13: Emergency Operations, Section 2.2: Reserve Requirements

Reserve	IRC Results for RTO Total (MW) (Provided by GOs)	Reserve Monitor for RTO Total (MW) (Calculated by PJM EMS)
Primary Reserve Requirement[18]	2000	1998
Primary Reserve	4907	3581
Synchronized Reserve Requirement[18]	1350	1332
Synchronized Reserve Available	3906	2102

Table 10. IRC and Reserve Monitor Reserve Requirements and Reported Values

Similar differences in the available synchronized reserves indicated by the IRC and the Reserve Monitor were observed on September 11, 2013. This appears to be a more general issue on any operating day in that IRC results do not match actual system conditions indicated by the Reserve Monitor. Interviews with subject matter experts, operating personnel and training personnel identified the following potential causes:

- Some of the GOs in PJM do not respond to a PJM IRC request. The IRC report identifies the GOs that do not respond to an IRC request.
- Some of the GOs who respond to a PJM IRC request may provide stale or unreliable data.
- Although PJM requires GOs to promptly respond to an IRC there appears to be a delay in some GOs responding to the IRC. For example, on September 10, 2013 PJM requested an IRC at 1431 and posted the results at 1500.

A combination of the observations listed above resulted in an inaccurate IRC, indicating that PJM had higher available synchronized reserves than what was actually available in real-time on September 10, 2013.

Tier 1 Synchronous Reserves Calculation

Tier 1 Synchronized Reserves are designed to provide initial response (within 10 minutes) to capacity or transmission- related emergencies. The current market structure provides incentives to generators in the PJM footprint to provide available synchronized reserves when PJM calls for a synchronized reserve event. However, the current Tier 1 calculation[19] appears to be incorrect and indicate may have indicated higher synchronized reserves than the synchronized reserves that were available in real-time on September 10, 2013. Interviews with SMEs and operating personnel and a review of current Tier 1 calculation revealed the following:

- Some generating units in PJM have their spin maximum greater than emergency maximum, which generally should not be the case. Some generation owners assumed that PJM’s Tier 1 calculation automatically accounted for this by selecting the lower of spin maximum and emergency maximum. However, Tier 1 calculations on September 10, 2013 did not account for this. This resulted in a higher Tier 1 value than Tier 1 reserves that existed in real-time on September 10, 2013.
- Not all generating units have different values for their respective emergency maximum, spin maximum, and economic maximum limits. Also, most units do not respond to a synchronized reserve event if they are already at their economic maximum. An analysis of the 42 most recent synchronized reserve events in PJM

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[19] Sample Tier 1 calculation provided in Appendix B, Section B8: Activating Synchronized Reserves & Reserves Sharing

indicated that approximately four percent of the units outperformed their respective economic maximum limits. This indicates that current Tier 1 reserve calculation is including generation response that is not obtainable. Additionally, depending on the type of the generating unit, there can be limitations in increasing the unit's output to attain spin maximum or emergency maximum limits. For example, run-of-river hydro units may not respond, since a certain water-level has to be maintained for various reasons. Other units may have to add duct burners, fuel guns, etc. to provide the additional generation response during a synchronized reserve. On September 10, 2013, the Tier 1 reserve calculation did not account for these limitations.

- Security Constrained Economic Dispatch automatically dispatches generation economically, accounting for any transmission constraints on the system at any given time. To control for transmission constraints, SCED reduces the output of a generating unit on the sending end of the constraint and increases the output of a generating unit on the receiving end of the transmission constraint. This implies that generating units on the sending end of the constraint cannot increase their output to avoid aggravating the transmission constraint that's being controlled. On September 10, 2013, SCED calculated available Tier 1 reserves from some units on the sending end of the transmission constraints, although those units could not increase their output. Thus the Tier 1 estimates on September 10, 2013 included synchronized reserves that were unobtainable because some units were dispatched down to control for a transmission constraint and could not respond to the synchronized reserve signal to dispatch up or increase their output.
- There can be instances where system conditions change so rapidly that PJM dispatchers may have to take action within the five minutes SCED runs and provides a suitable solution for the next 15-minute look ahead. In such instances PJM dispatchers manually dispatch generation and log it as “Manual Dispatch” in the Dispatch Management Tool so that SCED no longer economically dispatches those units. On September 10, 2013 PJM manually dispatched some generating units to decrease output levels to control for transmission constraints on the system. However, those manually dispatched units were not logged as “Manual Dispatch” in DMT. This resulted in SCED economically dispatching these units to a higher output as well as including them in Tier 1 calculation.
- PJM calculates Tier 1 reserves based on the ramp rates generators provide to PJM. Ramp rates are how many megawatts units can produced in a period of time. Although there are ways to measure the response (Degree of Generator Performance) of generating units to PJM signals, the current Tier 1 reserve calculation does not take into account whether generating units can attain the claimed ramp rates.

Signals to Generators

Generators in PJM respond to SCED signals. SCED economically dispatches generation based on available generation and transmission resources, load patterns, and unit characteristics (e.g. start time). When PJM initiates a synchronized reserve event in one of the PJM synchronized reserve zones, all available synchronized resources in that zone are to respond. SCED, however, still dispatches generation economically. This may result in PJM sending conflicting signals to some generators – PJM asking the units to increase their output in response to a synchronized reserve event and SCED economically dispatching the units potentially differently.

On September 10, 2013, during the synchronized reserve event generators in PJM received signals from PJM market applications (SCED and ASO) to reduce outputs of certain units to meet the reserve requirements, while PJM Operations called for a synchronized reserve event in the RFC zone requesting all generating units in this zone to increase their outputs. Additionally, PJM also manually dispatched some units to control for localized transmission constraints on the system, which may have also conflicted with the full raise synchronous reserve signal.

Reliability First Corporation (RFC) Only Spin

The RFC zone includes all generating units in PJM RTO except for the Dominion Virginia Power (DVP) units. The synchronized reserve event was only called in the RFC zone of PJM, not the entire RTO. This was because the available Tier 1 reserves in the RFC zone appeared to be sufficient to recover from a low ACE. Based on the data at the time PJM called the event, PJM believed calling for reserves from the entire RTO would have resulted in over-generation, driving the frequency higher and potentially causing high voltage issues.

In the post-event analysis, it was determined that had PJM extended the synchronized reserve event to the entire RTO, including DVP, PJM might have procured an additional 362 MW of generation response from Dominion zone.

Potentially Inaccurate Generator Data

Another contributing factor to the low generation response to the synchronized reserve event is the potential for inaccurate generator data. There are usually temperature restrictions on the output levels of generating units. On an unseasonably hot day, such as, September 10, 2013, the generating units may have to make certain changes to their configurations to attain their respective spin maximum or emergency maximum. If the GOs could not have achieved the claimed spin maximum, economic maximum or emergency maximum levels, the GOs should have updated the restricted limits through PJM eMKT application, thus informing PJM of their reduced generating capability. This would have enabled PJM to more accurately estimate the available Tier 1 reserves possibly by procure Tier 2 reserves, if necessary.

Currently, PJM does not perform a verification of the generator data that the GOs report to PJM, i.e., PJM does not verify whether the spin maximum, economic maximum, and emergency maximum limits that the GOs report to PJM are accurate and attainable. PJM should also conduct an analysis of the historic performance of individual units to gauge how the units will perform on a given day.

Recommendations

The detailed analysis of the synchronized reserve event resulted in the following recommendations:

- Review the current IRC mechanism to retire or improve; and identify methods of improving the quality of data being reported by GOs. Reinforce training to generation owners stressing the importance of accurate responses to IRCs.
- Review and modify Tier 1 reserve calculations to more accurately reflect the actual available reserves from synchronized generating units with consideration to the following:
- Review current business rules and market structure for Tier 1 Synchronized Reserves to determine if the construct provides sufficient incentives to obtain synchronized reserves needed in real time. (See the Markets section of the paper for more details)
- Investigate how to remove the conflicting signals being sent to generators by SCED and ASO during synchronous reserve events.

- Consider implementing a process for generator data performance validation (ecomax, emergency max, spin max, etc.)
- Review and improve the current methods of providing the dispatchers with an accurate presentation of the available reserves on the system at any given time both at an aggregate level and unit-specific.

4.2 Demand Response Events

Across PJM's footprint, there were 7,712 MW of demand response resources available for use from September 9 – 11. As can be seen in Figure 14, there were no DR resources called on Monday. Demand response was not able to be called for the localized issues experienced in the Corey area because PJM did not have a pre-defined subzone that covered the Corey/Pigeon River area. The only DR option available to PJM would have been to call DR across the entire zone, with the hopes of seeing some impact in the local area. This lack of precision in the use and impact of DR resources led PJM to explore other options to address the constraints in the Corey area.

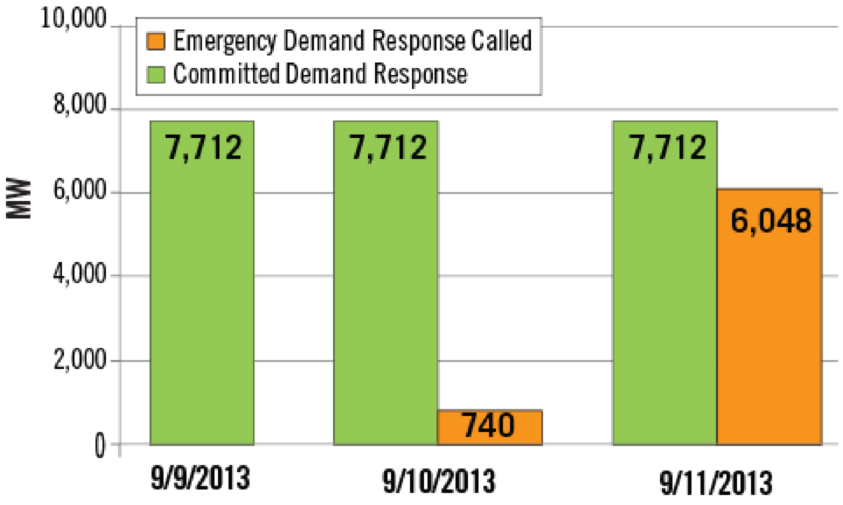


Figure 14. **Demand response resources (available vs. called)**

Demand response was used on September 10 to address transmission constraints and general concerns in the Cleveland area (ATSI zone and AEP-South Canton subzone) and on September 11 for a higher load forecast and in response to the capacity performance experienced on September 10.

As a result of unseasonably warm temperatures for mid-September, PJM load forecasts were off by between 4,000 and 5,000 MW from the actual loads experienced. Because of this error in the load forecast, emergency load response was needed September 10 and 11 to address transmission constraints and a generator response. Unfortunately, DR was not a viable alternative in all of the load shed events due to limitations in the lead time for calling on DR, the lack of defined subzones in the impacted areas and the restrictive time window for using DR.

4.2.1 *Demand Response Event (September 10, 2013)*

During the operating day, September 10, PJM encountered a transmission constraint in the South Canton area. As loads increased, at 1350, PJM issued a long lead time emergency mandatory load management reduction for the ATSI zone (683 MW) with an expected activation time of 1550 (Figure 15). At 1445 the request was expanded to include the long lead load management resources in the South Canton subzone (115 MW). Subzonal calls for load response are not mandatory in 2013, so PJM was expecting approximately 50 percent of the total 115 MW (~57 MW) of relief.

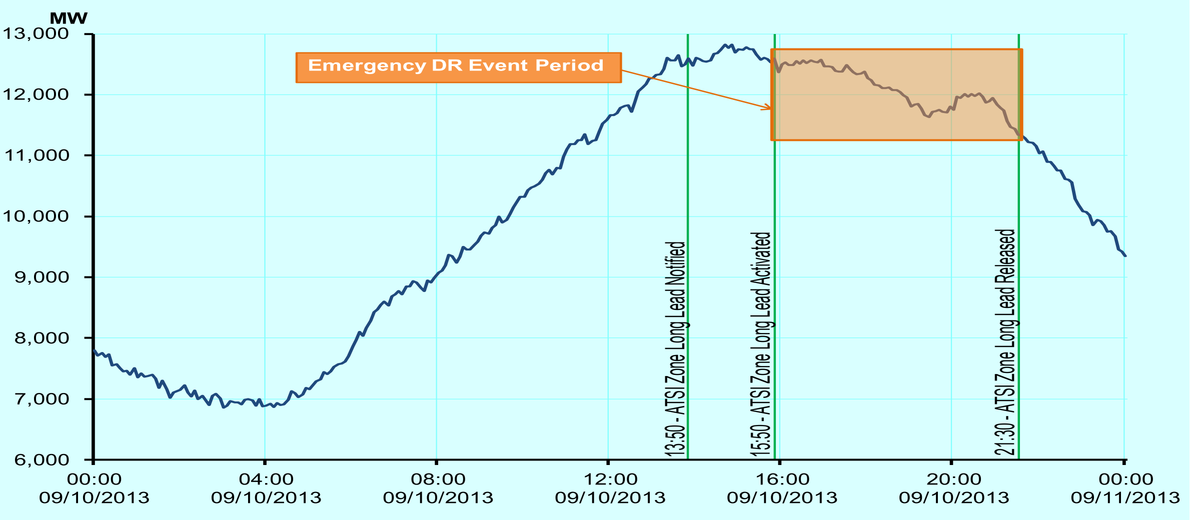
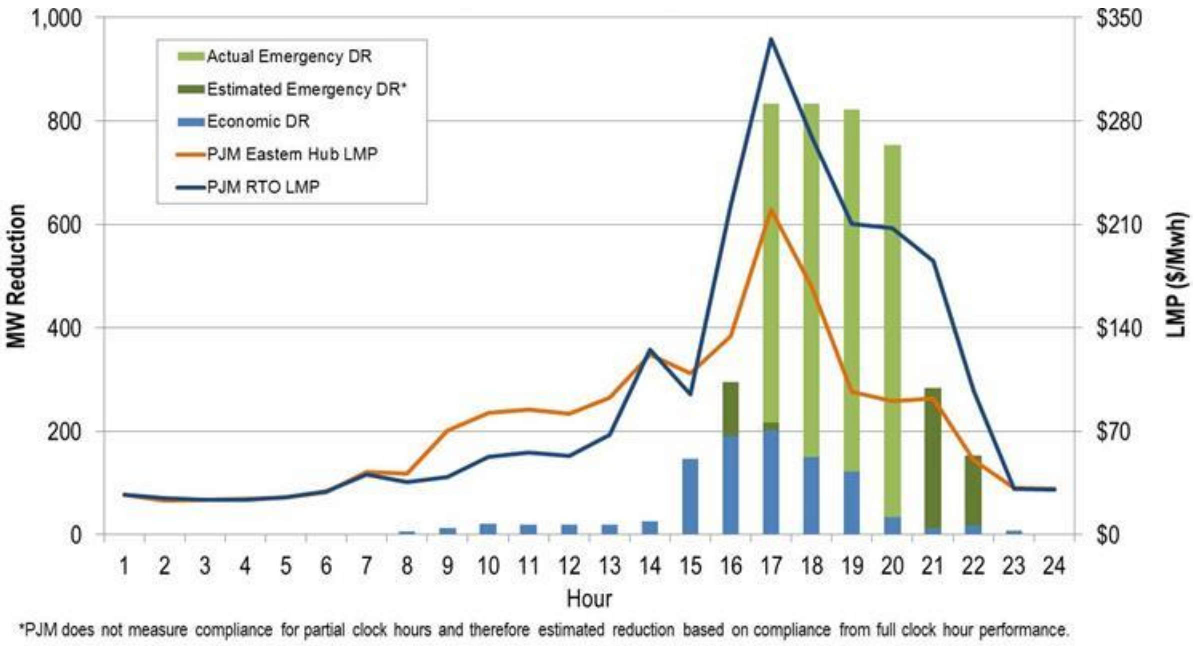


Figure 15. **September 10 load curve with long lead emergency load management event**

Based on compliance data filed by curtailment service providers, 695 MW responded (out of the 740 MW called) in both ATSI and the South Canton subzone. Additionally, there was some economic demand response on the system at the time (these resources will respond to high LMP prices rather than waiting on PJM to call for emergency load management). See Figure 16 for a graph showing both emergency and economic load management response by hour on September 10.



*PJM does not measure compliance for partial clock hours and therefore estimated reduction based on compliance from full clock hour performance.

Figure 16. **Estimated demand response (emergency and economic) in PJM on September 10, 2013**

4.2.2 Demand Response Event (September 11, 2013)

With a load forecast expected to exceed 148,000 MW, in preparation for Wednesday, September 11, on Tuesday September 10, PJM issued a Hot Weather Alert and Maximum Emergency Generation Alert for the entire RTO. Based on the forecasted loads, operating experience with transmission contingencies, available generation, and synchronized reserves response from the previous operating day, on September 11, PJM proactively implemented emergency load management for much of the RTO footprint for a total of 6,048 MW of reduction. The demand response resources began to affect the system at 1330 and were released starting at 1700 (Figure 17). By 2000 all emergency demand response had been cancelled as well as all maximum emergency generation alerts.

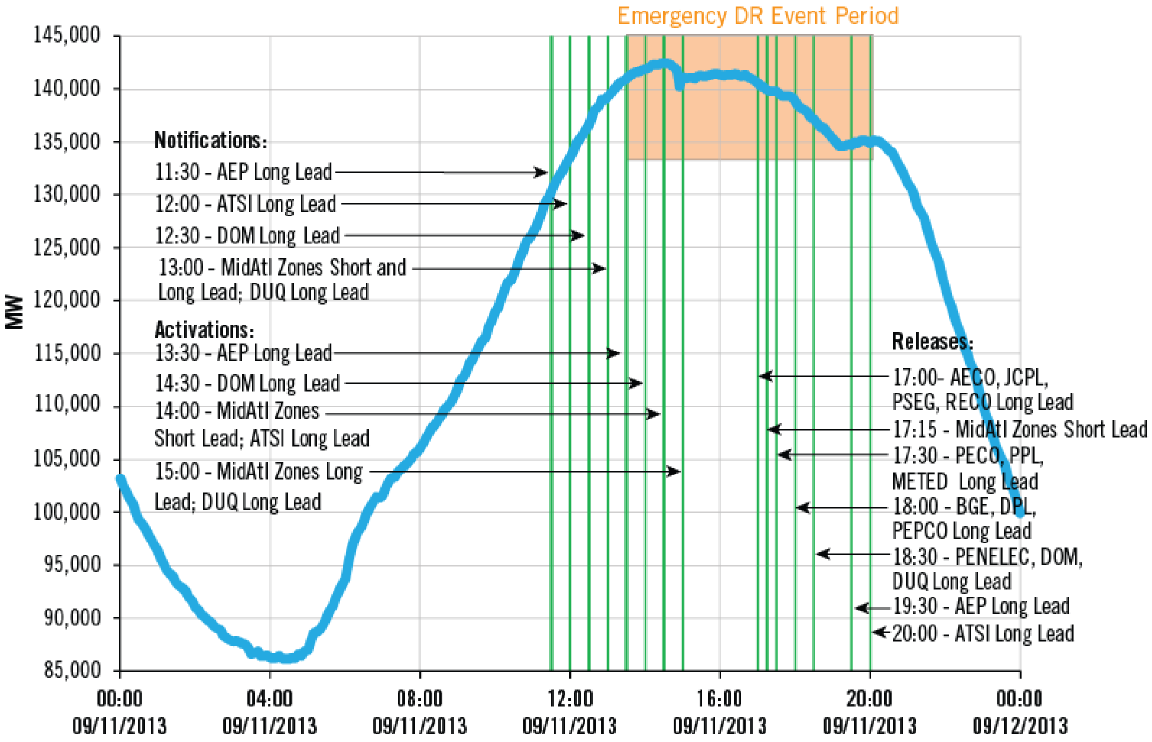


Figure 17. **September 11 Emergency DR Event**

Based on data filed by curtailment service providers[20] for the September 11 event, 5,782 MW of demand response responded to PJM's call. Additionally, there was some economic demand response on the system at the. See Figure 18 for a graph showing both emergency and economic load management response by hour on September 11.

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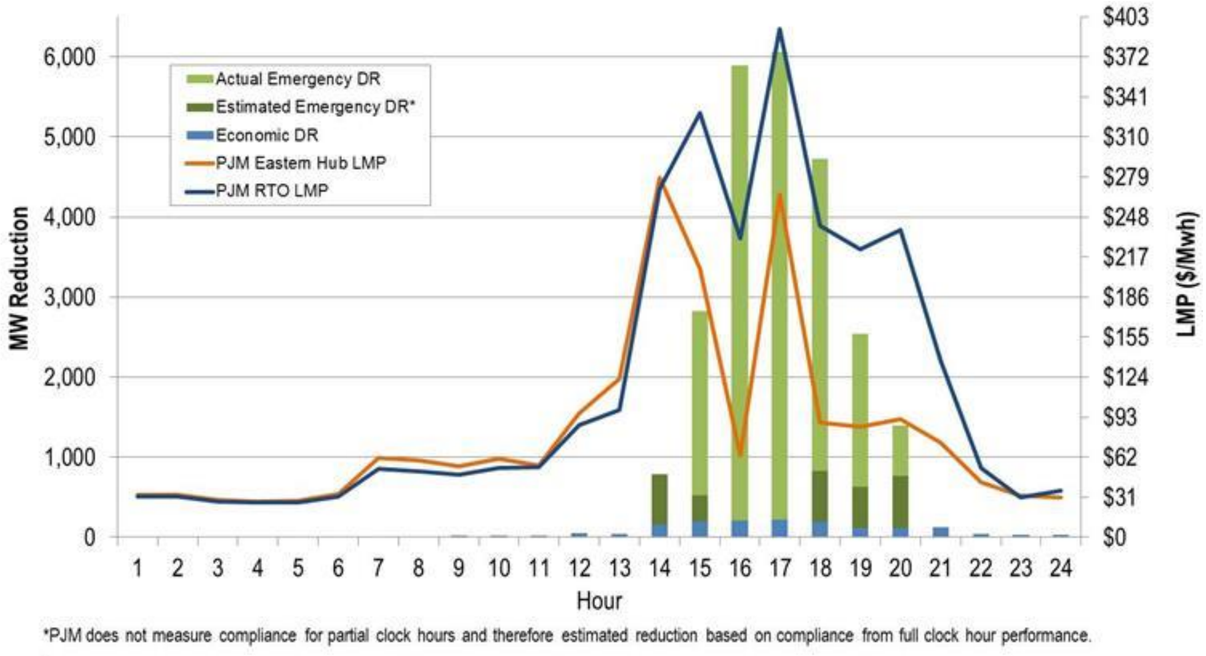
[20] Data provided via PJM's eLRS application.



*PJM does not measure compliance for partial clock hours and therefore estimated reduction based on compliance from full clock hour performance.

Figure 18. **Estimated Demand Response on September 11**

Observations

As part of the post event analysis, PJM's reviewed the registered DR resources and their locations by zip code in the areas affected by the load shed events. Table 11 shows the amount of long lead and short lead time DR available.

	Long Lead MW	Short Lead MW
AEP Pigeon River	0	0
FE (ATSI) Tod	3	0
FE (Penelec) Erie South	31	0
Penelec zone	265	0
AEP Summit	11	0

Table 11. Theoretical MW Relief from Long and Short Lead DR

Based on the data compiled in Table 11, long lead DR could have helped reduce the magnitude of some of the load shed events, but not entirely eliminated them. There are two specific problems with using DR to resolve transmission constraints: the lack of a specific location for the resources and the long lead time required by the resources to activate. First, while curtailment service providers provide specific location for its demand response resources (e.g. street address), this information is not mapped electrically to the nearest substation. When using these resources for transmission constraints, it is important for the dispatchers to know precisely where the curtailment will occur so that they can better understand the impact on the observed constraint. Too many DR resources on the wrong side of a constraint can make a constraint worse. Second, the long lead time of most of the DR resources does not lend itself well to addressing transmission constraints which often need controlling actions within 30 minutes. Long lead DR resources need a two-hour lead time. Short lead DR resources need a one- hour lead time.

Another challenge with using demand response resources is the limited amount of hours these resources can be called upon and required to respond. Under the current market rules for limited DR capacity resources, demand response resources are only obligated to respond to PJM's call for curtailment between the hours of 1200 and 2000. Response outside of that time window is voluntary.

For capacity emergencies, when PJM determines there is an insufficient amount of reserves available[21] a 1-2 hour lead time does not present a challenge. These lead times did present a problem for the transmission constraints, however, observed on September 10 events at Erie South and Summit. The operating window (1200 to 2000) also restricted the use of demand response. Post event analysis results indicate the use of DR could have helped reduce the scope of the load shed events.

Another limitation of demand response resources that proved challenging in September was the non-mandatory response allowed for subzonal load reductions and the limitation of defining subzones prior to the operating day. Currently there are only *seven* subzones defined (AEP Canton, ATSI Cleveland, Dominion Norfolk, APS East, MetEd East, Penelec East and PPL East). All of these were created proactively and strategically, based on where PJM Operations thought issues would likely occur. Starting in 2014, curtailment service providers are obligated to respond to subzone DR calls as long as PJM has published the zip code definition of subzones "the day before[22]" a demand response call is placed for a given subzone. This requires that PJM be able to predict where potential problems could occur so that they can define and publish the subzones in time for Curtailment Service Providers to prepare their resources.

Using demand response for transmission constraints is still a manual and imprecise process because of the lack of electrical location information about these resources. Unlike traditional generation resources, demand response resources are not modeled to specific substations in PJM's energy management system. In order to use DR to control a transmission constraint, the constrained area of the system needs to be identified prior to the operating day; Curtail Service Provider resources need to be mapped by zip code to the constraint or nearest substation, the impact of the DR on the constraint needs to be estimated, potentially a new a subzone defined, and all of this information communicated with CSPs for voluntary participation. For this reason and the concern that the curtailment may worsen an already constrained line or facility, dispatchers are hesitant to call upon DR for transmission constraints.

PJM's Capacity Senior Task Force has developed and Market Reliability Committee and Member Committee approved, business rule changes for demand response resources including reducing the lead time to 30 minutes. These changes will be filed with the FERC in December 2013.

Recommendations

The following recommendations resulted from the assessment of the Demand Response events:

- Review load management market rules to improve operational flexibility through the PJM stakeholder process to include shorter lead times; subzonal calls, calls outside emergencies, and shorter minimum run times
- Improve the flexibility of subzonal demand response by proactively defining DR subzones across PJM footprint and/or mapping DR resources to nearest substation

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[21] PJM Manual 13: Emergency Operations, Section 2 Capacity Emergencies

[22] PJM Manual 18: PJM Capacity Market, Section 8.5 Load Management Event Compliance

- Provide the dispatchers with better visibility of the location and amount (MW) of relief from DR

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

4.3 Additional Emergency Procedure (September 11, 2013)

An additional emergency procedure was called on September 11 that was not directly related to the load shed events but was mentioned in the *Initial Analysis of Operational Events during the September 2013 Heat Wave Report* and has been discussed along with the other operational events. This section briefly explains the event to put it in context with the rest of the week's activities. The event was a Transmission Loading Relief (TLR) 5 on the Neptune DC tie with New York ISO (NYISO).

PJM issued the TLR5 at 1830 after coordinating with New York ISO. The TLR 5 cut 100 MW of firm transactions on the Neptune DC tie to New York for an actual overload on the Bridgewater-Middlesex line. The TLR5 event was not related to the other events that occurred in the Midwest. The primary cause of the TLR5 was high load and no generation in the local area (combustion turbines in the area were taken out of service by Superstorm Sandy and have not been restored to operational order). The transactions on the Neptune DC tie to New York were restored at 2200.

5 Load Forecast Analysis

As has been noted throughout the report, temperatures the week of September 9 were unseasonably high. The post event analysis team also look at the load forecast tools and processes for a more detailed analysis of performance and areas for improvement. This next section details the results of the analysis.

Temperatures across the PJM footprint were forecasted to increase during the week of September 9, and be well above average for the month of September (Figure 19). In preparation for the warmer weather, on Sunday, September 8, PJM issued a Hot Weather Alert for the ComEd zone, followed on Monday by a Hot Weather Alert for the Western Region of PJM (Illinois, Indiana, Michigan, Ohio, West Virginia, and Kentucky) and on Tuesday for the entire RTO.

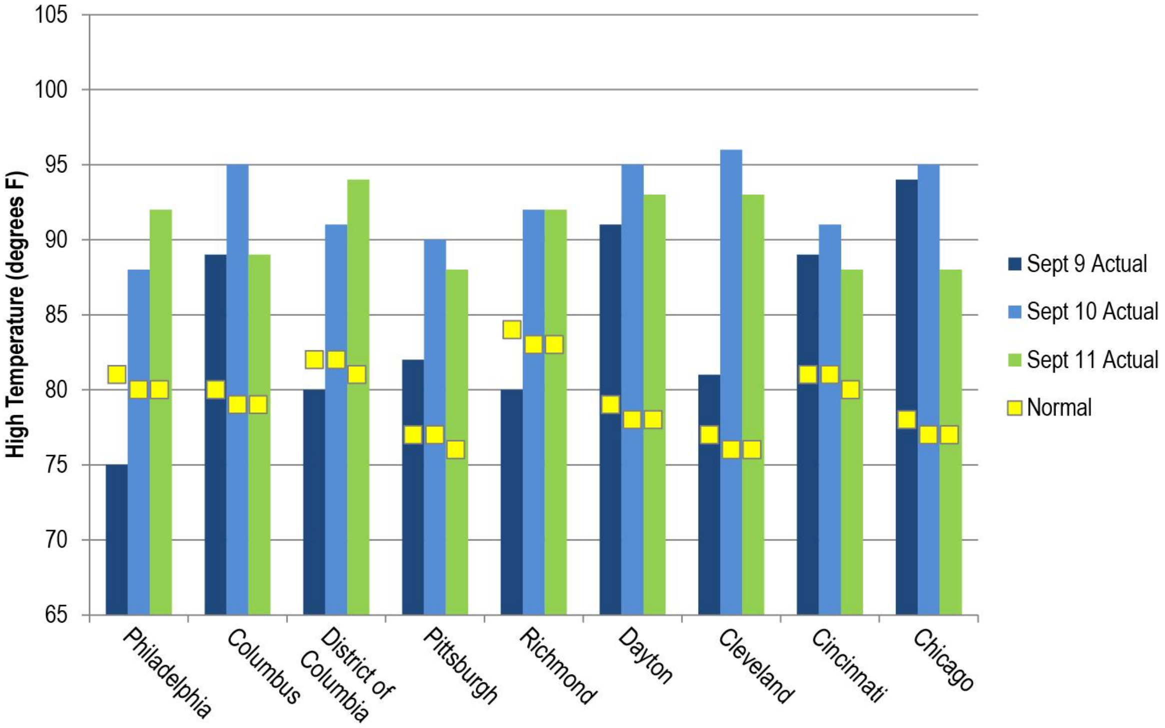

Figure 19. **RTO Temperatures**

The PJM RTO "unrestricted"[23] peak load on Monday, September 9 was 119,116 megawatts; the peak loads were 144,295 MW on Tuesday, September 10, and 146,443 MW on Wednesday, September 11. Figure 20 shows historic September peaks for the PJM RTO; and Figure 21 shows historic September peaks for the PJM RTO by zone.

Wednesday, September 11 was the highest September peak load day ever recorded in the PJM footprint, and it occurred later in the month than previous September peak days.

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[23] These actuals are "unrestricted." Unrestricted means that reductions to the overall load provided by demand side response on each day have been added back in to the total load number. This provides a picture of what the peak load would have been without the load reductions.

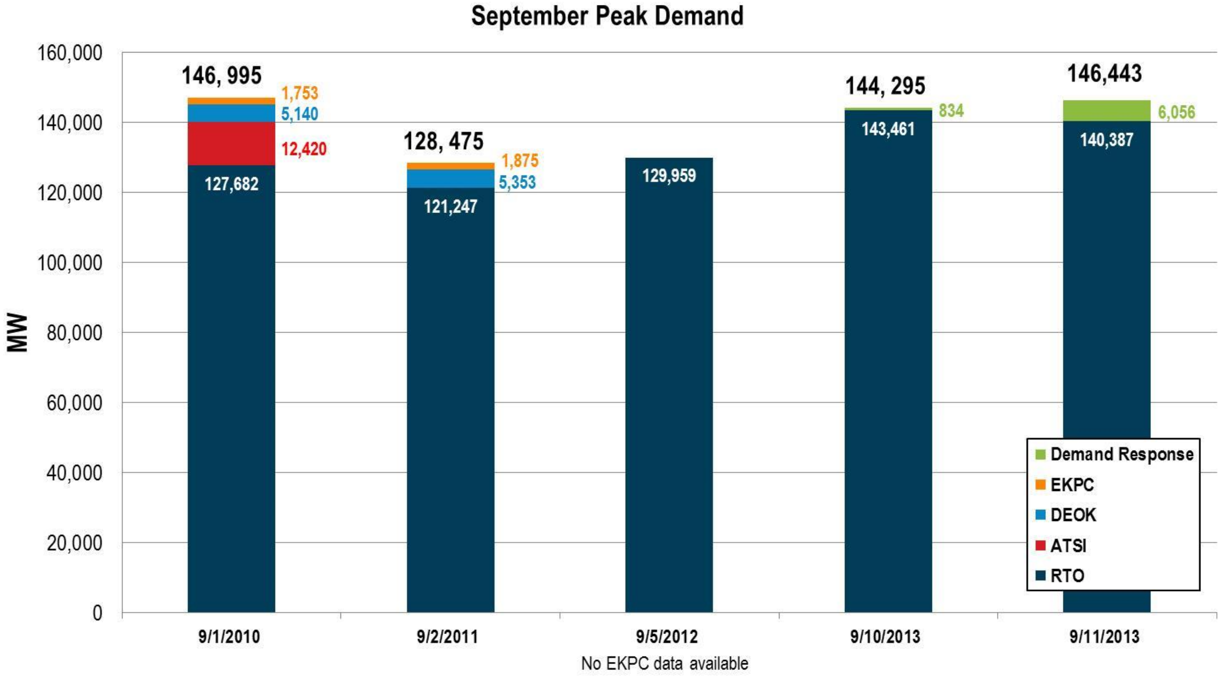


Figure 20. **RTO Actual Loads**

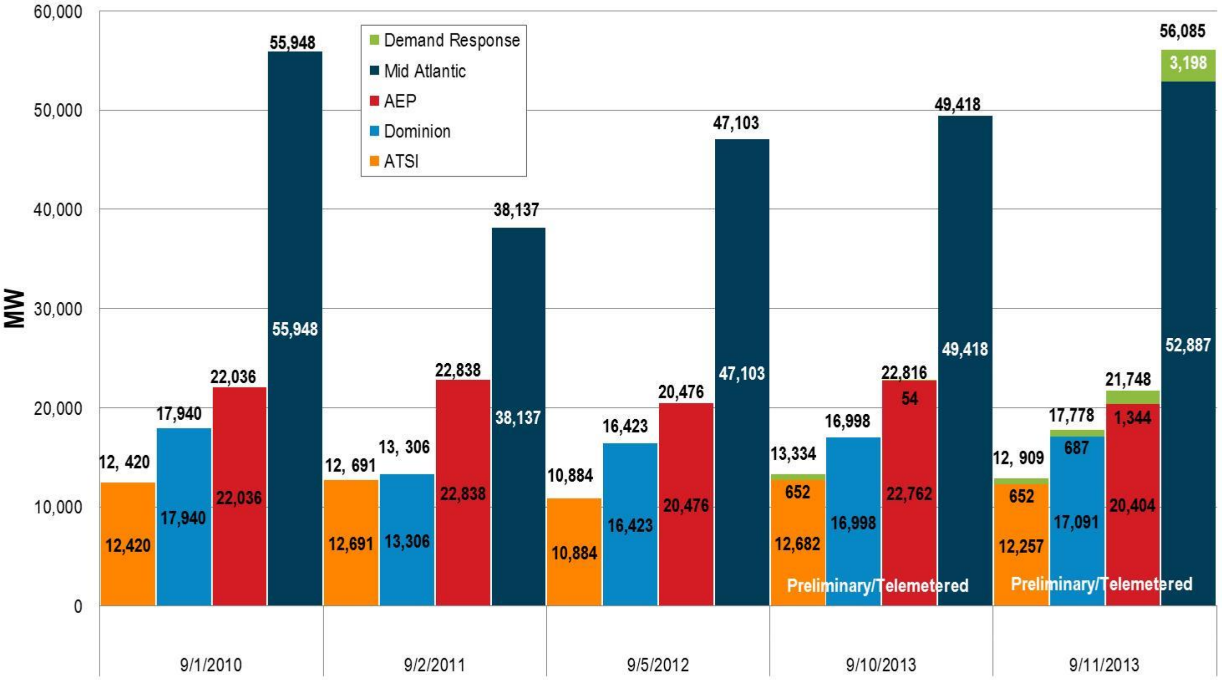
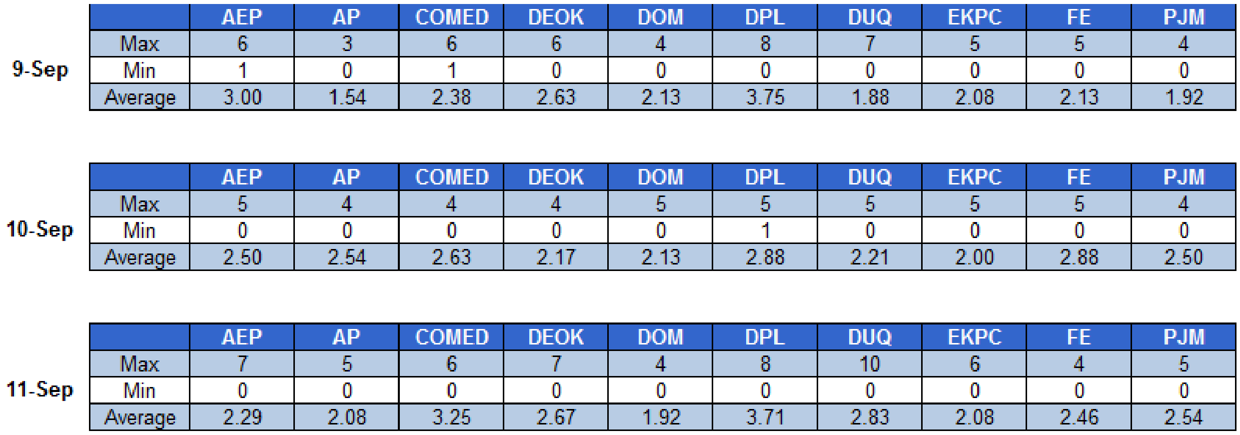


Figure 21. **Historic September Peaks by Transmission Zone**

5.1 Temperature Impact

For the period of observation, September 9 through September 11, the actual observed temperatures were compared to the forecasts from 1200 (noon) the day before – those that were used for day-ahead analysis and market planning. Table 12 provides the maximum, minimum and average hourly temperature error, in degrees, for each zone during the period of September 9 through September 11. Graphs of the temperature error for each zone over the course of each day are available in Appendix D, Figures 32-34. Analysis shows the actual temperatures were hotter than forecasted temperatures through the morning hours and again in the mid-afternoon, especially on Monday and Tuesday. In some hours over the course of these three days, the temperature forecast was off by as much as ten degrees. As the main variable in the load forecast model, the downward bias of the temperature forecast would cause the load forecast model to underestimate the expected amount of load. That being said, the average error in the temperature forecast for each zone for each day was, in most cases, less than three degrees. This indicates that, for most hours of the day, the temperature forecast error was actually much lower. For a more detailed numeric break down, see Table 35 in Appendix D.



		AEP	AP	COMED	DEOK	DOM	DPL	DUQ	EKPC	FE	PJM
9-Sep	Max	6	3	6	6	4	8	7	5	5	4
	Min	1	0	1	0	0	0	0	0	0	0
	Average	3.00	1.54	2.38	2.63	2.13	3.75	1.88	2.08	2.13	1.92

		AEP	AP	COMED	DEOK	DOM	DPL	DUQ	EKPC	FE	PJM
10-Sep	Max	5	4	4	4	5	5	5	5	5	4
	Min	0	0	0	0	0	1	0	0	0	0
	Average	2.50	2.54	2.63	2.17	2.13	2.88	2.21	2.00	2.88	2.50

		AEP	AP	COMED	DEOK	DOM	DPL	DUQ	EKPC	FE	PJM
11-Sep	Max	7	5	6	7	4	8	10	6	4	5
	Min	0	0	0	0	0	0	0	0	0	0
	Average	2.29	2.08	3.25	2.67	1.92	3.71	2.83	2.08	2.46	2.54

Table 12. Hourly Temperature Forecast Error (in degrees)

Temperature forecast error negatively impacts the load forecast model because temperature is one of the main inputs into forecasting the load. Large errors in the temperature forecast data that is fed into the load forecast model, or “Neural Net,” often lead to large errors in the model output, making it subsequently more difficult for the PJM dispatcher – master coordinator to create an accurate load forecast.

One of the responsibilities of the PJM dispatcher – master coordinator is to update the load forecast based on system conditions. In the figure below, the master coordinator’s day-ahead forecast from 1200 and 1600 are compared against the actual load to show the amount of Load forecast error for the period from September 9 through September 11. This shows that the earlier forecast (1200) has a higher error than the later forecasts (1800), and the error on Tuesday was higher than Wednesday.

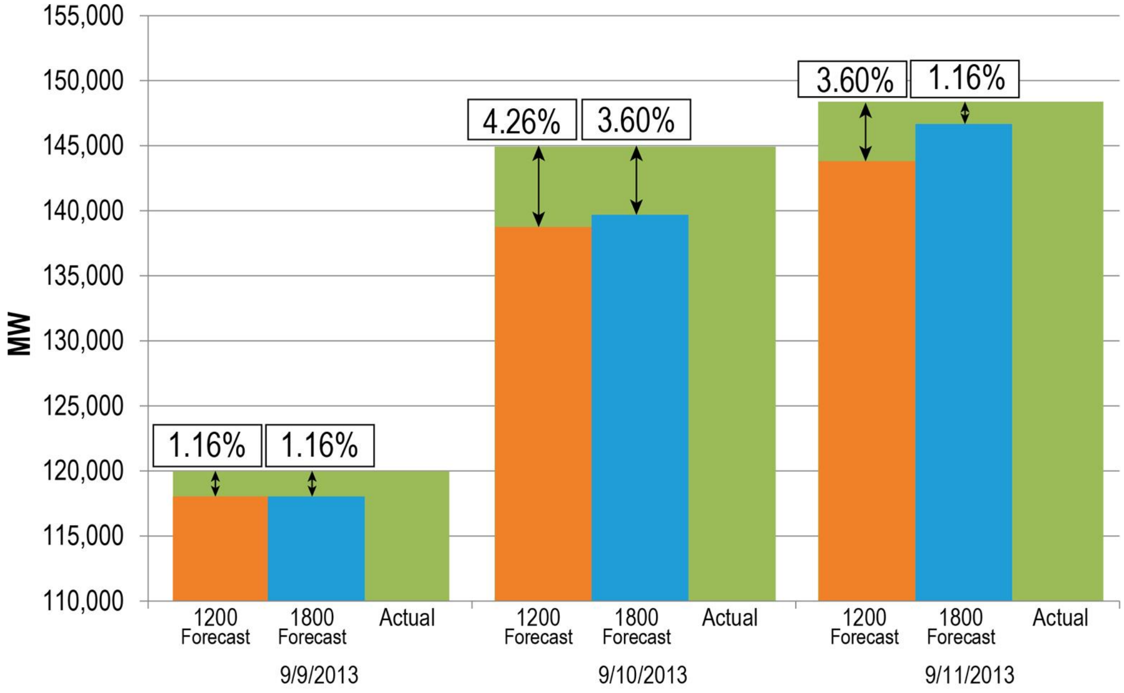


Figure 22. **Load Forecasts vs. Actual Loads (Percent Error)**

5.2 Observations

As part of PJM's daily performance review, the previous day's actual weather observations are fed into the Neural Net to create a "backcast" – what the model would have predicted with a perfect weather forecast. The backcast provides PJM forecasters with an indication of the model error independent of weather forecast error.

The Table 13 and Figure 22 above show that the model seemed to under-forecast throughout this period, most notably on September 10 (with the exception of COMED). For the AEP and FE zones, the model trended toward under-forecasting load throughout the entire period. The Neural Net output also trended low for PJM Mid-Atlantic on September 10 and 11.

The chart in Table 13 shows the absolute average, high and low hourly backcast error by day and by zone for the period of observation from September 9 to September 11. Positive values represent over-forecasting and negative values indicate the forecast was too low.

		Mid Atl	AEP	COMED	DOM	FE	AP	DUKE	DPL	DUQ	EKPC
9-Sep	Average	1.87	1.65	3.92	2.07	1.84	1.77	1.09	2.20	2.72	2.51
	High	4.24	1.21	1.49	0.56	1.04	3.53	1.47	3.58	1.06	6.55
	Low	-3.92	-4.92	-7.71	-5.66	-7.14	-2.80	-3.74	-3.96	-6.04	-6.59

		Mid Atl	AEP	COMED	DOM	FE	AP	DUKE	DPL	DUQ	EKPC
10-Sep	Average	1.93	2.62	4.45	1.31	2.30	1.31	2.34	2.95	2.63	3.14
	High	0.64	-0.02	8.67	1.20	0.22	1.79	-0.81	-0.09	0.95	6.08
	Low	-5.36	-4.72	-0.28	-2.78	-5.31	-2.84	-5.15	-5.06	-6.51	-1.24

		Mid Atl	AEP	COMED	DOM	FE	AP	DUKE	DPL	DUQ	EKPC
11-Sep	Average	3.93	2.10	2.57	2.38	3.44	1.61	1.81	1.58	1.92	2.77
	High	-1.45	3.62	9.33	1.26	-0.63	1.11	2.67	4.13	5.31	6.41
	Low	-9.02	-5.70	-0.74	-4.83	-7.38	-3.98	-4.64	-1.17	-2.79	-0.56

Table 13. Hourly Neural Net "Backcast" Load Error (in percent)

There were two sources of load forecast error during the period of September 9 to September 11: temperature forecast error and inherent load forecast model error. The temperature forecasts for these three days were off by as much as ten degrees in certain zones for certain hours. This will introduce error into the load forecast model, which relies heavily on temperature forecasts. In addition, weather input is weighted across larger zones:

- ATSI has temperature inputs composed of 20 percent Akron, OH; 25 percent Cleveland, OH; 25 percent Columbus, OH; and 10 percent Toledo, OH; and 20 percent Youngstown, OH., VA.
- AEP has temperature inputs composed of 55 percent Columbus, OH; 10 percent Charleston, WV; 25 percent Fort Wayne, IN; and 10 percent Roanoke, VA.

On days where temperature forecasts in portions of the zone are not tracking to the original forecast, it can impact the entire zone's load forecast as well because of the blending and weighting of temperatures across a large zone. Particularly in zones that span a large geographic area like AEP, weighting can contribute to the weather forecast accuracy.

However, even with actual weather observations input into the model, it appears there was a downward bias internal to the model on these days. This was caused in part by the reliance of the Neural Net on the previous day's temperature and load trends. The effect of persistence forecasting plays a large part in the error on the latter of consecutive but dissimilar days. Persistence forecasting creates a lag – when temperatures change significantly from one day to the next, it takes time for the Neural Net to catch up. Therefore the model inherently does not handle this first day of change well.

5.3 Summary and Recommendations

The load forecast error experienced on September 9 through 11 had two sources: temperature forecast error and the limitations inherent to the load forecast model used primarily in the creation of PJM's official load forecast. PJM was experiencing temperatures significantly above average for this time of year. Temperatures in parts of PJM were under-forecast over much of these three days, including during the peak hours. Because temperatures were so far above average for the month of September, the Neural Net also struggled to accurately forecast load. The model relies heavily on historic load measurements from past September days, and there would have been few, if any, good matches.

A model with perfect temperature forecasts and dynamic variable assumptions still has limitations. The load forecast model allows the temperature trends of previous days to influence the next day. This can create a lag, which it did during the week of September 9, when the temperature trend changed substantially. The load forecast model is also not designed to consider factors such as transmission constraints or demand response actions. PJM also does not forecast individual regions or local areas loads.

Based on this analysis, it appears that load forecast did not have a significant impact on the various load shed events. That being said, there are recommendations related to load forecasting in the Recommendations Section to include more conservative operations when there are significant day to day temperature changes; to address temperature weighting across larger zones; and to improve the visibility on very local load changes.

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

6 Communications Review

The communications review of the events that occurred on September 9 through September 11 evaluated the communications that took place both internal to PJM, as well as with PJM's stakeholders (member companies, state and regulatory agencies, etc.). The analysis evaluated the effectiveness of the communications that occurred against the following criteria to accomplish the following functions:

- PJM System Operators must transmit information and issue reliability directives via voice and electronic means to PJM Transmission Owners), Generation Owners and Energy Market participants and neighboring reliability entities (i.e. ,NYISO, MISO, TVA) to maintain the reliability of the bulk electric system (BES).
- PJM personnel must submit information in a timely fashion to the appropriate regulatory agencies (DOE, NERC) to comply with reliability standards.
- PJM must provide information in a timely fashion to federal and state authorities in order to enhance situational awareness for Emergency Management planning purposes.
- PJM personnel must share information internally in a timely fashion in order to maintain situational awareness and to ensure that all required notifications as listed above are performed.

PJM Manual 01: Control Center Requirements Section 4 Voice Communications defines the specificity of communications and the requirements for the issuance of reliability directives during emergency conditions that would occur between PJM's System Operators and TOs and GOs. Other communications that occur between PJM both internally and externally during emergency events for notification purposes are performed by PJM's Member Relations, Corporate Communications and State Government Policy departments. The level of communications that is required by PJM and its members is dependent upon the nature of the event (i.e., emergency vs. routine operations) and regulatory requirements.

Ensuring clear and precise communications is a challenge during normal operations periods and becomes more challenging during emergency events. This is due to the increased volume of information that is required to be communicated to all of PJM's stakeholders, both internal and external. A review of the voice recordings for the September load shed events indicates that even in a stressful environment PJM and TO System Operators used clear and concise communications during the hot weather events. This was appropriate and in compliance with

NERC Reliability Standard COM-002 and PJM Manual 01 Section 4.2.4 that require the use of Three Part Communications for all reliability directives. Three-Part Communications is defined as the sender transmitting a message, the receiver repeating back the message and the sender then verifying whether the message was repeated back correctly.

PJM System Operations also conducts System Operations Subcommittee Transmission conference calls on an as-needed basis during emergency operations events or hot weather alert days. The purpose of these conference calls is to discuss and share information regarding emergency operations events that can adversely impact the BES. On September 10, the decision was made that although temperatures were higher than normal, there were no forecasted events that would adversely impact the BES. As a result, the decision was made by operations management that an SOS-T conference call was not necessary. Because of the operational events on the 10th, the decision was made to hold conference calls on September 11. PJM disseminated operational information regarding the hot weather events of September 10 and September 11 via the SOS-T conference call. While most SOS-Transmission members agreed that the communications of the conference call were adequate, some conference call participants stated that they would have liked more detailed information provided for the operations issues being discussed.

The capacity-related procedures issued by PJM during the hot weather event included the activation of Synchronized Reserves, the issuance of Hot Weather Alerts, Maximum Emergency Generation Alerts, and the request for Emergency Demand Response. In accordance with PJM Manual 13: Emergency Operations[24], PJM Dispatch issued these procedures via the PJM All Call. Additional electronic notification of the issuance of emergency procedures was performed via PJM's Emergency Procedures application and the NERC Reliability Coordinator Information System.

The localized load shed events were performed by PJM Dispatch and the member TO. The communications for these localized events were not conducted via the PJM All-Call. Instead, PJM dispatchers spoke with the relevant TO, who in turn was responsible for sending out any necessary notifications to the potentially impacted local parties and other regulatory agencies. Review of event recordings indicate PJM did notify and direct pre-contingency load shed for the transmission issues in the AEP, ATSI, and Penelec zones. The review of the recordings also indicates that three-part communication, as required by NERC Reliability Standard COM-002, was used.

PJM Dispatch also records the issuance of these localized emergency procedures in the Emergency Procedures application. The Emergency Procedures Application is a tool used by PJM Dispatch to communicate Emergency Procedures to the subscribers of the tool. Anyone can subscribe to receive an automatic email notification every time a message is posted. As events occurred throughout the operating periods, the events were entered into the Emergency Procedures application and notifications were sent to application subscribers. The local load shed directives, however, were not logged in the Emergency Procedures application.

Additionally, various internal PJM departments were not notified of the events in a timely manner, including the State Government Policy, Member Relations, Federal Government Affairs, and Corporate Communications departments. As a result, the external communications initiated by these departments were delayed. During emergency operations, PJM Dispatch utilizes an informal process whereby the Shift Supervisor notifies PJM Operations management to activate the internal communications plan. Interviews with shift supervision confirmed Dispatch has no formal

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[24] PJM Manual 13: Emergency Operations

notification checklist to follow except for certain emergency procedures steps requiring specific notifications pursuant to DOE, FERC, NERC, or PJM Manual requirements. The emergency procedures implemented in the Pigeon River event were not procedures for which PJM manuals required specific internal notification.

6.1 Observations

Interviews with Dispatch staff indicated a lack of awareness of a category in the Emergency Procedures application for a “Local Load Relief Action”. This may be due to inconsistent event labeling in the Emergency Procedures application versus the descriptions in PJM Manuals 03 and 13. As a result, these issues were logged in Smart Logs as generic transmission events. As a result, those parties who depended on the Emergency Procedures application for notification were not notified.

Internal to PJM, some entities were not included in the notification process in a timely manner. This included PJM’s Member Relations, State Government Policy, Federal Government Affairs, and Corporate Communications departments. PJM Dispatch’s informal process is for the Shift Supervisor to notify PJM Operations management to activate the communications plan. Interviews with shift supervision confirmed Dispatch has no formal notification checklist to follow outside of regulatory and procedural requirements that are contained in NERC Reliability Standards or PJM Manuals.

The manual notification process employed by System Operations during the event resulted in information being delivered in an inconsistent manner. For example, some of PJM’s member companies receive information via email while some depend on electronic notification from PJM’s Emergency Procedures application. Interviews with PJM’s Member’s Relations, State Government Policy and Corporate Communications departments revealed PJM has formalized communications plans for crisis management and for other communications with federal and state agencies. These processes are department-specific and depend on PJM Dispatch management to inform them of an issue that would trigger such an external communication plan execution. The implementation of these plans was delayed as a result of the inconsistent and, in some instances untimely, communication from System Operations.

Interviews with the Master Dispatchers at both the Valley Forge and Milford control room locations revealed the volume of calls and the focus on individual zonal problems resulted in a situation where the one MD was unaware a non-converged solution existed and was being worked on by another MD. The shift supervisor and most of the other operators were aware of the non-converge, but some operators were not. One MD also indicated the analysis of the non-convergence situation was delayed due to the inability to interact with the Reliability Engineer and the volume of concurrent events. The large volume of operational events during the days in question also indicated that some operators stayed focused on their individual areas, limiting their awareness of the entire picture in the control room.

There were times that one of the MDs was unable to recognize visual cues over the videoconferencing system that another MD was heavily task-loaded. The large amount of call volume on the FirstEnergy MD resulted in a situation, in which the MD was devoting all attention to the FirstEnergy non-convergence. As a result, the MD did not have an understanding of the Valley Forge counterpart’s workload and did not request assistance. Interviews with both dispatchers confirmed each was unaware of what the other was doing due to the extreme volume of phone calls. In all cases, the shift supervisor was aware of the workload and assignments.

6.2 Recommendations

The following recommendations resulted from the assessment of the communications processes:

- Formalize PJM Dispatch communications processes with a focus on coordination between PJM departments and PJM stakeholders during operational emergencies. Provide training on the improvements
- Review, enhance, and train appropriate entities on communications responsibilities during localized load shed events
- Evaluate current control room staffing practices for system emergencies to ensure adequate and appropriate staffing
- Add filtering capability to the electronic notification tool to allow PJM stakeholders to choose the type of messages they receive

For a more detailed description of these recommendations see the Conclusions & Recommendations section.

7 Conclusions & Recommendations

The Operations assessment is based on the analysis completed by the PJM September Heat Wave Operational Analysis Team, which completed its assessment of the actions PJM took in its role as the RTO, Reliability Coordinator, Transmission Operator, and Balancing Authority, focusing on the operational activities leading up to the events, activities throughout the events on September 9 through September 11, and subsequent activities while returning to normal operations. PJM member actions during the operational events were also reviewed.

As described throughout the report, PJM's actions during the operational events were effective in preventing larger cascading events. Based on the load, generation, and transmission conditions encountered from September 9 to 11, in general PJM and its members followed PJM operating practices and protocols to minimize the outage impacts on consumers. The targeted outages prevented more extensive outages from occurring and allowed PJM to maintain the overall reliability of the grid.

That being said, there is always room for improvement and to learn from experiences. The load shed event and other operational area assessment resulted in 22 recommendations related to system modeling, special operating procedures, PJM and Member Dispatcher training, business rule changes, technology enhancements, process changes notifications and communication protocols. Some of these recommendations have either already been implemented (for example, updates to the Pigeon River Operating Guide); some are already well under way (for example, Demand Response operational rules changes developed through the PJM Capacity Senior Task Force and included in a forthcoming FERC filing), and some are newly identified, such as changes to the way PJM identifies Behind the Meter resources.

PJM and its members are committed to preserving the reliability of PJM-monitored Bulk Electric System facilities. Part of that commitment is to analyze system events or problems for the purpose of implementing corrective actions and sharing knowledge to improve operations at PJM and member companies. Some of recommendations identified in this report have already been completed, for example, the Pigeon River Operating Guide has been updated to include pre-contingency load shed procedures and Lagrange relay limit; and Tier 1 synchronous reserves calculations are being modified.

Some of the recommendations in this report are already well underway. Updates will be made to the PJM model curing the Winter Model build, specifically to improve the model and telemetry in the areas where the issues were experienced. Demand Response operational rules have been approved by the PJM Stakeholders via the Capacity Senior Task Force and associated tariff changes will be filed with the FERC in December 2013.

Within the next 90 days, PJM will develop an action plan to address all of the newly identified recommendations. PJM is confident that implementing the recommendations will enable PJM and its members to enhance PJM operations.

PJM will also share the results of its compliance analysis with NERC and Reliability*First*.

PJM has also received a number of inquiries from FERC Staff as to whether generation outages resulting from MATS compliance had an impact on driving the particular local conditions that gave rise to these load shed events. The report has analyzed this issue and found that the causes of these particular events was much more localized and transmission-based and cannot be attributed directly to generation outages or retirements resulting from MATS compliance.

Table 14 presents each recommendation, including an indication of the current status of the recommendation.

ID	Event Category	Recommendation	Type	Status
1.	Load Shed Events	Regarding PJM's approach to modeling and telemetry, the following actions should be taken: (1) Update PJM's documentation for modeling process and practices to include: a. Expectations of Transmission Owners' input to PJM modeling process b. The approach to implementing more modeling and telemetry across the transmission and sub-transmission system.	System Modeling	New
2.	Load Shed Events	Update PJM's model in the areas where issues were experienced during the events of September 9 -11, as needed: (1) Areas where PJM had modeling differences with the TO (2) Areas where PJM did not have real-time telemetry data	System Modeling	Under way (winter model build [mid-December] will have updates for Pigeon River and Summit)
3.	Load Shed Events	Update the Operating Guide for Pigeon River to include the Lagrange-Howe relay limit and pre-contingency load shed procedure.	Operation Guide Update	Complete
4.	Load Shed Events	Review facility limits with neighboring companies with a focus on the following pre- and post-contingency information: (1) The Load Dump limit as xx% of the 'Relay Limit'. (2) Transmission Owners calculate a Load Dump rating consistent with Transmission & Substation Subcommittee guide to allow separation between LTE and LD rating, permitting operational flexibility and enhanced monitoring.	System Modeling	Under way
5.	Load Shed Events	Review Manual 01 directive language with the PJM and TO Dispatchers at the 2014 Dispatcher Seminar. Work with individual TOs to reinforce language (as needed).	PJM & Member Dispatcher Training	Standing item at dispatch seminar
6.	Load Shed Events	Develop automation for the cascading outage analysis procedure to include tools to trend the potential cascading contingencies.	Technology	Currently under way with the SOS (as of Nov. 2013). Automation release is due in 2014.

ID	Event Category	Recommendation	Type	Status
7.	Load Shed Events	Establish and document PJM's approach for representing known Behind the Meter generation and the related operating criteria for Dispatchers. Working with the States and the TOs, the following should be included in the approach document: (1) TO responsibilities to determine 2 megawatt BtM and above in their zone (2) Definition of BtM responsibilities with consideration to size of unit, location, ramp rate, etc. (3) Representation by transmission zone and subzone (4) Visual representation of BtM generation criteria and relevant operating criteria (state limitations, etc.) (5) Better incorporation of BtM generation into emergency operations, to include Supplemental Status Report and emergency procedures actions as appropriate	Process Change or Addition Technology	New
8.	Load Shed Events	Review how Emergency Procedures application tool is used in local load shed events and develop solutions to address the following topics: (1) Develop process language for logging local load shed events (2) Develop training to reinforce process and tool (3) Ensure contacts lists are updated and stakeholder are enrolled properly	PJM & Member Dispatcher Training Communication & Notification Protocols	Tool adjustment should be finished. Process and training are new.
9.	Load Shed Events	Review PJM EMS non-converge procedures and EMS tools to present non-converge situations to PJM operators to include troubleshooting processes	Process Change or Addition	New
10.	Synchronized Reserve Event	Review and modify Tier 1 reserve calculations to more accurately reflect the available reserves from synchronized generating units with consideration to the following: (1) All Units used in the Tier 1 estimate should be capped to the lesser of Eco Max or Spin Max. (2) Remove appropriate hydro and combined cycle units from Tier 1 estimates with the exception of combined cycle units that have Spin Max < Eco Max. (3) Remove appropriate units on manual dispatch instruction from Tier 1 calculation. (4) Develop a process to incorporate the Degree of Generator Performance modifier into the Tier 1 calculation to more accurately reflect unit performance under high load conditions.	Market Construct Processes Change or Addition PJM & Member Dispatcher Training	(1) End of year (2013) (2) Completed (3) End of year (2013) (4) End of year (2013)

ID	Event Category	Recommendation	Type	Status
		(5) Remove appropriate generating units that are utilized for transmission constraint control in Tier 1 calculation. (6) Implement a formalized process of communicating to the Generation Owners when their units are dispatched for transmission constraint control. (7) Review whether generating units providing regulation service impact Tier 1 calculation and modify Tier 1 calculation accordingly.		
11.	Synchronized Reserve Event	Review the current Instantaneous Reserve Check mechanism for improvements or possible retirement; and identify methods of improving the quality of data being reported by GOs. Reinforce training to generation owners stressing the importance of accurate responses to IRCs.	Processes Change or Addition PJM & Member Dispatcher Training	In-progress (this is an active discussion)
12.	Synchronized Reserve Event	Improve the current methods of providing the dispatchers with an accurate presentation of the available reserves on the system at any given time both at an aggregate level and unit-specific.	Technology	Options are being discussed.
13.	Demand Response Event	Implement, through the stakeholder process to improve Demand Response operational flexibility to include shorter lead time; subzonal calls, calls outside of emergencies, and shorter minimum run times.	Market Construct	Approved by MC. Will be filed to FERC late 2013 / early 2014.
14.	Demand Response Event	To improve the reliability of using DR for transmission constraints, PJM, in conjunction with Members, should (1) Define more subzones proactively across the PJM footprint (2) Map DR resources to nearest substation	Market Construct	New
15.	Demand Response Event	Develop tools to aid the dispatchers in visualization of the location and MW relief from DR.	Technology	New
16.	Communication & Notification Protocols	Develop a comprehensive document that contains PJM's crisis communications policies in order to enhance coordination within PJM as well as with PJM stakeholders (states and others) and provide training on the process and any improvements.	Communication & Notification Protocols	In-progress (no end date defined)
17.	Communication & Notification Protocols	Adding filtering capability to the electronic notification tool to allow PJM staff and stakeholders to determine the applicability of messages they receive.	Technology Communication & Notification Protocols	In-progress

ID	Event Category	Recommendation	Type	Status
18.	Load Forecast Analysis	Implement the following changes to PJM's hot and cold weather alerts processes: (1) At least 3-days ahead of a load increase day, issue hot weather alerts based on temps, load and capacity margin, using different triggers based on transmission zone and different trigger based on (2) Review the current process of handling notification of load forecast errors (3) Apply percent error margin to the Neural Net for Reliability Engineer Studies and for new Forward Generation Commitment Tool. (4) Create documentation and training that better explains to the Master Coordinators what information to look at when these days are forecasted.	Process Change or Addition	New
19.	Load Forecast Analysis	Review the processes for conducting weather and load forecasting. Consider the following: (1) Sampling and weighting of weather data throughout the RTO footprint (2) Methods of developing load forecasts on a sub zonal basis	Process Change or Addition	New
20.	Synchronized Reserves	Develop and implement a process for validating generator performance data (ecomax, emergency max, spin max, etc.)	Process Change or Addition	New
21.	Generation Analysis	Improve the generation sorting functionality in Dispatcher Management Tool. Available and max emergency units should be included on the normal sort. Max Emergency units should be flagged for easy identification.	Process Change or Addition	New
22.	Load Shed Events	Provide reinforcement training for operators on contingency management (contingency trending, PCLLRW, load shed, etc.) in the control room simulator. Use this training to look for EMS enhancements for managing constraints.	Training	New

Table 14. Recommendations

8 Markets Impacts During September 2013 Heat Wave

8.1 Background

In order to fully understand the impacts to PJM markets as well as operations, PJM also undertook a detailed examination of market outcomes in conjunction with the operational events previously described. PJM examined those outcomes in order to determine if there is a need to change processes going forward in order to more closely link operational choices to market prices.

Specifically, the hot weather operational analysis review centers on the load-shedding events that occurred between September 9 and September 11, 2013 as well as the synchronized reserve and demand response events. In addition to those events, the Markets Analysis Team reviewed the following focus areas:

- Market Outcomes
- Interchange Impacts
- Revenue Adequacy
- Future Enhancements

8.1.1 Approach

To achieve the purpose and to address the scope of work, PJM established a team of subject matter experts to review the market events between September 9 and September 11.

The team collectively performed the following activities:

- Collected markets data related to the hot weather event
- Analyzed the markets outcomes that were impacted by operational events
- Identified recommendations with respect to what should be changed or further reviewed
- Prepared and vetted the report summarizing the market outcomes

8.1.2 Markets Report Content

In conjunction with the operational section, the markets section of the report includes the following areas:

- **Market Outcomes** – Daily summary of the market outcomes for the hot weather event.
- **Impacts of Interchange** – Summary of the impact of the interchange during the hot weather event and comparison to the hot weather event in July 2013.
- **FTR Revenue Adequacy** - Detailed examination of market modeling and impact of the operational events on real time prices that ultimately impacted financial transmission rights underfunding.
- **Pricing Operator Actions** – Summary of the impacts of decisions made in real time and the outcome on market results.

- **Other Market Assessments** – Summary of the impacts to market outcomes due to the Synchronized Reserve event on September 10 and the Demand Response events on September 10 and 11.

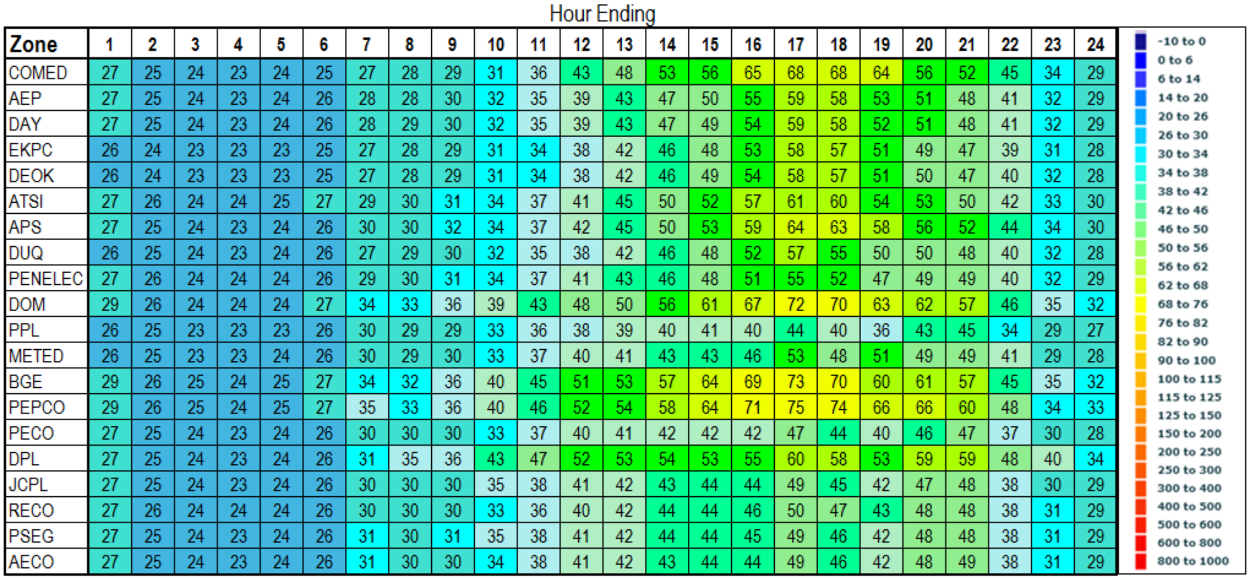
8.2 Market Outcomes

This section reviews the market outcomes during the hot weather event of September 2013. It examines specific events and determines if the operational events impacted market outcomes. The hot weather event began on September 9, 2013; therefore for completeness, the analysis begins with examination of Day-Ahead Market runs executed on Sunday, September 8, 2013. While September 9 did not have significant impacts, it will be evaluated and detailed in order to use as a reference for the other market outcomes on September 10 and 11.

8.2.1 Sunday, September 8, 2013

In preparation for the warmer weather PJM issued a Hot Weather Alert on Sunday, September 8, for the following day, Monday, September 9, in the Commonwealth Edison zone. As shown below in the figure and table, the Day-Ahead Market results for Monday, September 9, were as expected with a few exceptions. The western zones in PJM (COMED, AEP, DAY, EKPC, DEOK, ATSI and APS) cleared with higher than average Locational Marginal Prices during the afternoon peak (hours ending 15-18). Some of the zones closer to the eastern coast within the PJM footprint (BGE, PEPCO) and in the south (DOM) were also cleared higher than average LMPs. The load forecast for the peak RTO load was predicting a peak value of 118,000 MW initially and was updated to approximately 119,000 MW at 0400 that morning. To put that in perspective, this represents a fairly significant load for the September. timeframe considering that September 1 is the beginning of maintenance season when generators take outages to perform scheduled maintenance. Typically this level of load would not be expected to impact the overall RTO from an operational or market standpoint; however, there may be some localized issues that could cause congestion.

The figure below illustrates the LMP in the Day-Ahead Market results for September 9. The zones are listed down the left-hand column shown in a general west-to-east order across the PJM footprint. The color coding is the same color scheme as the PJM LMP contour map (shown on the figure to the right). The numbers within the graph represent the hourly integrated LMP for that hour rounded to the nearest integer value.



Hour Ending

Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	27	25	24	23	24	25	27	28	29	31	36	43	48	53	56	65	68	68	64	56	52	45	34	29
AEP	27	25	24	23	24	26	28	28	30	32	35	39	43	47	50	55	59	58	53	51	48	41	32	29
DAY	27	25	24	23	24	26	28	29	30	32	35	39	43	47	49	54	59	58	52	51	48	41	32	29
EKPC	26	24	23	23	23	25	27	28	29	31	34	38	42	46	48	53	58	57	51	49	47	39	31	28
DEOK	26	24	23	23	23	25	27	28	29	31	34	38	42	46	49	54	58	57	51	50	47	40	32	28
ATSI	27	26	24	24	25	27	29	30	31	34	37	41	45	50	52	57	61	60	54	53	50	42	33	30
APS	27	25	24	23	24	26	30	30	32	34	37	42	45	50	53	59	64	63	58	56	52	44	34	30
DUQ	26	25	24	23	24	26	27	29	30	32	35	38	42	46	48	52	57	55	50	50	48	40	32	28
PENELEC	27	26	24	24	24	26	29	30	31	34	37	41	43	46	48	51	55	52	47	49	49	40	32	29
DOM	29	26	24	24	24	27	34	33	36	39	43	48	50	56	61	67	72	70	63	62	57	46	35	32
PPL	26	25	23	23	23	26	30	29	29	33	36	38	39	40	41	40	44	40	36	43	45	34	29	27
METED	26	25	23	23	24	26	30	29	30	33	37	40	41	43	43	46	53	48	51	49	49	41	29	28
BGE	29	26	25	24	25	27	34	32	36	40	45	51	53	57	64	69	73	70	60	61	57	45	35	32
PEPCO	29	26	25	24	25	27	35	33	36	40	46	52	54	58	64	71	75	74	66	66	60	48	34	33
PECO	27	25	24	23	24	26	30	30	30	33	37	40	41	42	42	42	47	44	40	46	47	37	30	28
DPL	27	25	24	23	24	26	31	35	36	43	47	52	53	54	53	55	60	58	53	59	59	48	40	34
JCPL	27	25	24	23	24	26	30	30	30	35	38	41	42	43	44	44	49	45	42	47	48	38	30	29
RECO	27	26	24	24	24	26	30	30	30	33	36	40	42	44	44	46	50	47	43	48	48	38	31	29
PSEG	27	25	24	23	24	26	31	30	31	35	38	41	42	44	44	45	49	46	42	48	48	38	31	29
AECO	27	25	24	23	24	26	31	30	30	34	38	41	42	43	44	44	49	46	42	48	49	38	31	29

Figure 23. **September 9, 2013: Day-Ahead Energy Market Zonal LMP**

Metric	Value ($/MWh)
RTO Daily Average	$38.29
RTO On Peak LMP Average (HE 6-23)	$39.94
RTO Off Peak LMP Average (HE 24-5)	$34.98
Zonal Max LMP	$75.41 in PEPCO
Zonal Min LMP	$22.61 in EKPC

Table 15. September 9, 2013: Day-Ahead Energy Market Summary

8.2.2 Day-Ahead Market Outcomes

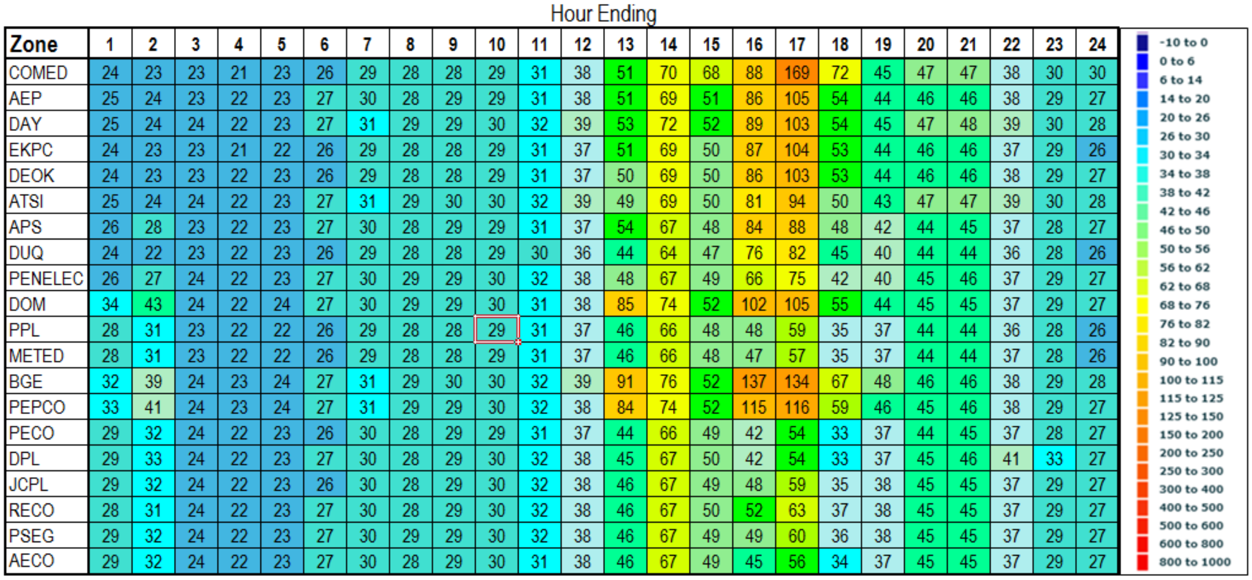
The highest zonal LMP in the Day-Ahead Market for the first day of the hot weather event, September 9, was $75.41 in the PEPCO zone at hour ending 1600. The average Day-Ahead Market LMP for the entire RTO was $38.29. The RTO on-peak (Hour Ending 06 to Hour Ending 23) LMP average was slightly higher at $39.94 while the off-peak (Hour Ending 24 to Hour Ending 05) LMP average was $34.98. The RTO daily average was just above the 70th percentile based on a one-year average for the overall RTO LMP.

8.2.3 Monday September 9, 2013

With warmer temperatures continuing to be forecasted, PJM updated the peak RTO load forecast from 118,000 MW to 119,000 MW and issued a Hot Weather Alert for the Western Region of PJM (which includes Illinois, Indiana, Michigan, Ohio, West Virginia, and Kentucky) for the following day, Tuesday, September 10. At 1607, PJM directed AEP to shed 3.1 MW of load in the Pigeon River area due to load reliability concerns as discussed in more detail in the operations section of this report. At 1845, the South Canton #1 transformer 345/138 kV relays activated, which switched out four 345 kV lines, contributing to the FirstEnergy (ATSI) Tod load shed event that occurred on Tuesday, September 10.

8.2.4 Real-Time Market Outcomes

On September 9, there were some differences when comparing the Day-Ahead and Real-Time results. Real-Time Energy Market prices were typically higher than those observed in the Day-Ahead Energy Market; however, the pattern of higher prices was consistent with the Day-Ahead Energy Market prices. The highest real-time LMP was $169.28 in the COMED zone for hour ending 1700, which was higher than the Day-Ahead Market results by $101. The average Real-Time Market LMP for the entire RTO was $39.78. The RTO on-peak (Hour Ending 06 to Hour Ending 23) LMP average was slightly higher at $46.70 while the off-peak (Hour Ending 24 to Hour Ending 05) LMP average was $25.93. The RTO average LMP was just below the 80th percentile based on a one-year average.



Hour Ending

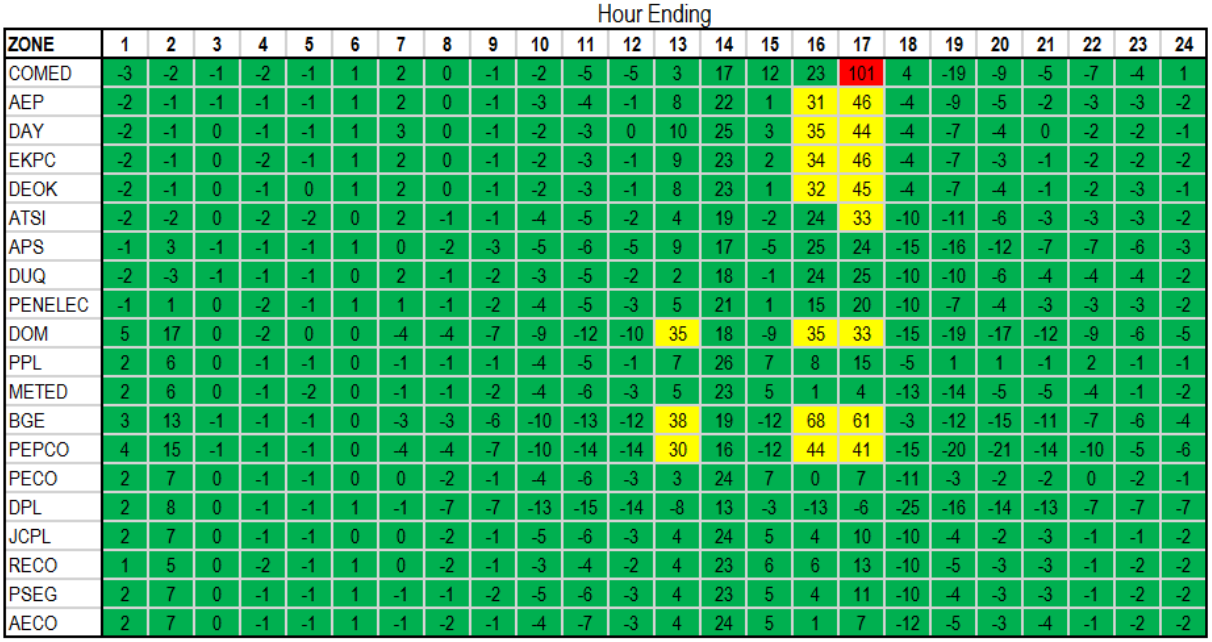
Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	24	23	23	21	23	26	29	28	28	29	31	38	51	70	68	88	169	72	45	47	47	38	30	30
AEP	25	24	23	22	23	27	30	28	29	29	31	38	51	69	51	86	105	54	44	46	46	38	29	27
DAY	25	24	24	22	23	27	31	29	29	30	32	39	53	72	52	89	103	54	45	47	48	39	30	28
EKPC	24	23	23	21	22	26	29	28	28	29	31	37	51	69	50	87	104	53	44	46	46	37	29	26
DEOK	24	23	23	22	23	26	29	28	28	29	31	37	50	69	50	86	103	53	44	46	46	38	29	27
ATSI	25	24	24	22	23	27	31	29	30	30	32	39	49	69	50	81	94	50	43	47	47	39	30	28
APS	26	28	23	22	23	27	30	28	29	29	31	37	54	67	48	84	88	48	42	44	45	37	28	27
DUQ	24	22	23	22	23	26	29	28	28	29	30	36	44	64	47	76	82	45	40	44	44	36	28	26
PENELEC	26	27	24	22	23	27	30	29	29	30	32	38	48	67	49	66	75	42	40	45	46	37	29	27
DOM	34	43	24	22	24	27	30	29	29	30	31	38	85	74	52	102	105	55	44	45	45	37	29	27
PPL	28	31	23	22	22	26	29	28	28	29	31	37	46	66	48	48	59	35	37	44	44	36	28	26
METED	28	31	23	22	22	26	29	28	28	29	31	37	46	66	48	47	57	35	37	44	44	37	28	26
BGE	32	39	24	23	24	27	31	29	30	30	32	39	91	76	52	137	134	67	48	46	46	38	29	28
PEPCO	33	41	24	23	24	27	31	29	29	30	32	38	84	74	52	115	116	59	46	45	46	38	29	27
PECO	29	32	24	22	23	26	30	28	29	29	31	37	44	66	49	42	54	33	37	44	45	37	28	27
DPL	29	33	24	22	23	27	30	28	29	30	32	38	45	67	50	42	54	33	37	45	46	41	33	27
JCPL	29	32	24	22	23	26	30	28	29	30	32	38	46	67	49	48	59	35	38	45	45	37	29	27
RECO	28	31	24	22	23	27	30	28	29	30	32	38	46	67	50	52	63	37	38	45	45	37	29	27
PSEG	29	32	24	22	23	27	30	29	29	30	32	38	46	67	49	49	60	36	38	45	45	37	29	27
AECO	29	32	24	22	23	27	30	28	29	30	31	38	46	67	49	45	56	34	37	45	45	37	29	27

Figure 24. **September 9, 2013: Real-Time Energy Market Zonal LMP**

Metric	Value ($/MWh)
RTO Daily Average	$39.78
RTO On Peak LMP Average (HE 6-23)	$46.70
RTO Off Peak LMP Average (HE 24-5)	$25.93
Zonal Max LMP	$169.28 in COMED
Zonal Min LMP	$21.48 in EKPC

Table 16. September 9, 2013: Real-Time Energy Market Summary

The first load shed event (Pigeon River 1) occurred between 1607 and 1642, which would equate to hour ending 17. As illustrated in the figure above, the AEP LMP in hour ending 1700 was $105. The LMP in the two hours surrounding that event were $86 and $54, respectively. However, the price decrease in that zone is probably not correlated to the specific load shed event given the small magnitude of the load reduced (3.1 MW) and the fact that the overall RTO LMP had a sharp decline from hour ending 17 to 18. This change in LMP along the same timeline does not necessarily correlate to the load shedding event, the load at that point had begun to decrease and systemwide LMP was decreasing across the RTO.



	Hour Ending																							
ZONE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
COMED	-3	-2	-1	-2	-1	1	2	0	-1	-2	-5	-5	3	17	12	23	101	4	-19	-9	-5	-7	-4	1
AEP	-2	-1	-1	-1	-1	1	2	0	-1	-3	-4	-1	8	22	1	31	46	-4	-9	-5	-2	-3	-3	-2
DAY	-2	-1	0	-1	-1	1	3	0	-1	-2	-3	0	10	25	3	35	44	-4	-7	-4	0	-2	-2	-1
EKPC	-2	-1	0	-2	-1	1	2	0	-1	-2	-3	-1	9	23	2	34	46	-4	-7	-3	-1	-2	-2	-2
DEOK	-2	-1	0	-1	0	1	2	0	-1	-2	-3	-1	8	23	1	32	45	-4	-7	-4	-1	-2	-3	-1
ATSI	-2	-2	0	-2	-2	0	2	-1	-1	-4	-5	-2	4	19	-2	24	33	-10	-11	-6	-3	-3	-3	-2
APS	-1	3	-1	-1	-1	1	0	-2	-3	-5	-6	-5	9	17	-5	25	24	-15	-16	-12	-7	-7	-6	-3
DUQ	-2	-3	-1	-1	-1	0	2	-1	-2	-3	-5	-2	2	18	-1	24	25	-10	-10	-6	-4	-4	-4	-2
PENELEC	-1	1	0	-2	-1	1	1	-1	-2	-4	-5	-3	5	21	1	15	20	-10	-7	-4	-3	-3	-3	-2
DOM	5	17	0	-2	0	0	-4	-4	-7	-9	-12	-10	35	18	-9	35	33	-15	-19	-17	-12	-9	-6	-5
PPL	2	6	0	-1	-1	0	-1	-1	-1	-4	-5	-1	7	26	7	8	15	-5	1	1	-1	2	-1	-1
METED	2	6	0	-1	-2	0	-1	-1	-2	-4	-6	-3	5	23	5	1	4	-13	-14	-5	-5	-4	-1	-2
BGE	3	13	-1	-1	-1	0	-3	-3	-6	-10	-13	-12	38	19	-12	68	61	-3	-12	-15	-11	-7	-6	-4
PEPCO	4	15	-1	-1	-1	0	-4	-4	-7	-10	-14	-14	30	16	-12	44	41	-15	-20	-21	-14	-10	-5	-6
PECO	2	7	0	-1	-1	0	0	-2	-1	-4	-6	-3	3	24	7	0	7	-11	-3	-2	-2	0	-2	-1
DPL	2	8	0	-1	-1	1	-1	-7	-7	-13	-15	-14	-8	13	-3	-13	-6	-25	-16	-14	-13	-7	-7	-7
JCPL	2	7	0	-1	-1	0	0	-2	-1	-5	-6	-3	4	24	5	4	10	-10	-4	-2	-3	-1	-1	-2
RECO	1	5	0	-2	-1	1	0	-2	-1	-3	-4	-2	4	23	6	6	13	-10	-5	-3	-3	-1	-2	-2
PSEG	2	7	0	-1	-1	1	-1	-1	-2	-5	-6	-3	4	23	5	4	11	-10	-4	-3	-3	-1	-2	-2
AECO	2	7	0	-1	-1	1	-1	-2	-1	-4	-7	-3	4	24	5	1	7	-12	-5	-3	-4	-1	-2	-2

Figure 25. **September 9, 2013: Market Convergence (Real-Time LMP minus Day-Ahead LMP)**

Financial Transmission Rights payout percentage was above 90 percent and Regulation and Reserve Market clearing prices were within normal expectations. For the month of September the average Regulation Market Clearing Price was $22/MWh. The average Regulation Market Clearing Price for September 9 was $19/MWh. For the month of September the average reserve market clearing prices were $0.39/MWh and $2.88/MWh for RTO and Mid Atlantic Dominion, respectively. On September 9, the average reserve market clearing prices the RTO and Mid Atlantic Dominion areas were $1.47/MWh and $2.49/MWh, respectively. Overall, market outcomes from the first day of the hot weather event were in line with a typical September day with the exception of a few higher prices during hours ending 16 and 17 in a few zones. As predicted on Sunday, when PJM issued a hot weather alert for COMED, that zone turned out to be the highest LMP on September 9 in real time.

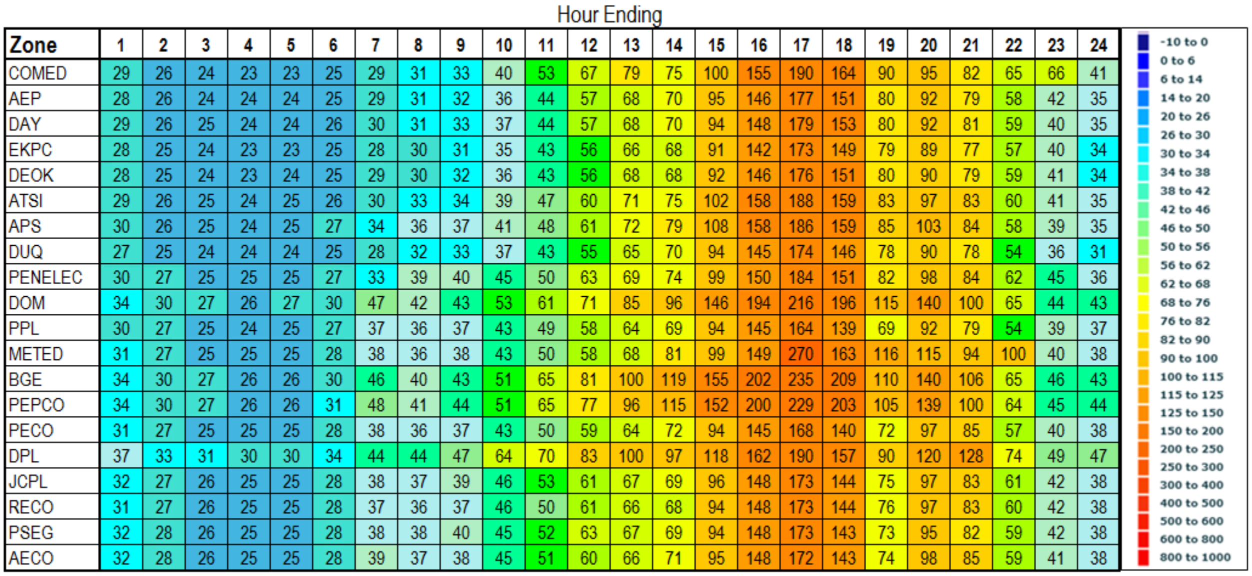
8.2.5 Tuesday, September 10, 2013

With continuing warmer weather forecast, PJM updated the peak RTO load forecast to 141,000 MW. PJM initiated several emergency procedures throughout the Operating Day, beginning with issuing a Hot Weather Alert for the entire RTO for Wednesday, September 11. PJM deployed Long Lead Time Emergency Demand Response for the FirstEnergy ATSI zone and AEP Canton sub-zone and issued Maximum Emergency Generation Actions in each area, but did not load maximum emergency generation capacity. PJM issued load shed directives to AEP (in the Pigeon River and Summit regions) and FirstEnergy (in the Tod area and Erie South area), as well as initiated a call for synchronized reserves and shared reserves with Northeast Power Coordinating Council. Finally, PJM issued a Maximum Emergency Generation Alert for the entire RTO for September 11. The timing and order of the emergency procedures on these days was impacted by the varying conditions in local areas in the western portion of the PJM system, in conjunction with the forecast accuracy for Tuesday, September 10.

8.2.6 Market Results for September 10, 2013

On the second day of the hot weather event, conditions were more extraordinary for September and the projection was very different from the first day. This is most likely driven by market participant expectations as well as the need to schedule additional combustion turbines in the Day-Ahead Market given the unavailability of typical steam that had begun to take planned outages, were already in wet layup[25] or were drained[26], causing a very long lead time.

On September 10, the Day-Ahead Market outcomes reflected the expectation that the most significant hot weather would be to the south and east (DOM, BGE, and PEPCO) with an overall high trend for the entire RTO. The load forecast for the day was predicted to be just above 140,000 MW.



	Hour Ending																							
Zone	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
COMED	29	26	24	23	23	25	29	31	33	40	53	67	79	75	100	155	190	164	90	95	82	65	66	41
AEP	28	26	24	24	24	25	29	31	32	36	44	57	68	70	95	146	177	151	80	92	79	58	42	35
DAY	29	26	25	24	24	26	30	31	33	37	44	57	68	70	94	148	179	153	80	92	81	59	40	35
EKPC	28	25	24	23	23	25	28	30	31	35	43	56	66	68	91	142	173	149	79	89	77	57	40	34
DEOK	28	25	24	23	24	25	29	30	32	36	43	56	68	68	92	146	176	151	80	90	79	59	41	34
ATSI	29	26	25	24	25	26	30	33	34	39	47	60	71	75	102	158	188	159	83	97	83	60	41	35
APS	30	26	25	24	25	27	34	36	37	41	48	61	72	79	108	158	186	159	85	103	84	58	39	35
DUQ	27	25	24	24	24	25	28	32	33	37	43	55	65	70	94	145	174	146	78	90	78	54	36	31
PENELEC	30	27	25	25	25	27	33	39	40	45	50	63	69	74	99	150	184	151	82	98	84	62	45	36
DOM	34	30	27	26	27	30	47	42	43	53	61	71	85	96	146	194	216	196	115	140	100	65	44	43
PPL	30	27	25	24	25	27	37	36	37	43	49	58	64	69	94	145	164	139	69	92	79	54	39	37
METED	31	27	25	25	25	28	38	36	38	43	50	58	68	81	99	149	270	163	116	115	94	100	40	38
BGE	34	30	27	26	26	30	46	40	43	51	65	81	100	119	155	202	235	209	110	140	106	65	46	43
PEPCO	34	30	27	26	26	31	48	41	44	51	65	77	96	115	152	200	229	203	105	139	100	64	45	44
PECO	31	27	25	25	25	28	38	36	37	43	50	59	64	72	94	145	168	140	72	97	85	57	40	38
DPL	37	33	31	30	30	34	44	44	47	64	70	83	100	97	118	162	190	157	90	120	128	74	49	47
JCPL	32	27	26	25	25	28	38	37	39	46	53	61	67	69	96	148	173	144	75	97	83	61	42	38
RECO	31	27	26	25	25	28	37	36	37	46	50	61	66	68	94	148	173	144	76	97	83	60	42	38
PSEG	32	28	26	25	25	28	38	38	40	45	52	63	67	69	94	148	173	143	73	95	82	59	42	38
AECO	32	28	26	25	25	28	39	37	38	45	51	60	66	71	95	148	172	143	74	98	85	59	41	38

Figure 26. **September 10, 2013: Day-Ahead Market Zonal LMP**

Metric	Value ($/MWh)
RTO Daily Average	$63.34
RTO On Peak LMP Average (HE 6-23)	$70.12
RTO Off Peak LMP Average (HE 24-5)	$49.78
Zonal Max LMP	$270.11 in METED
Zonal Min LMP	$22.80 in COMED

Table 17. September 10, 2013: Day-Ahead Energy Market Summary

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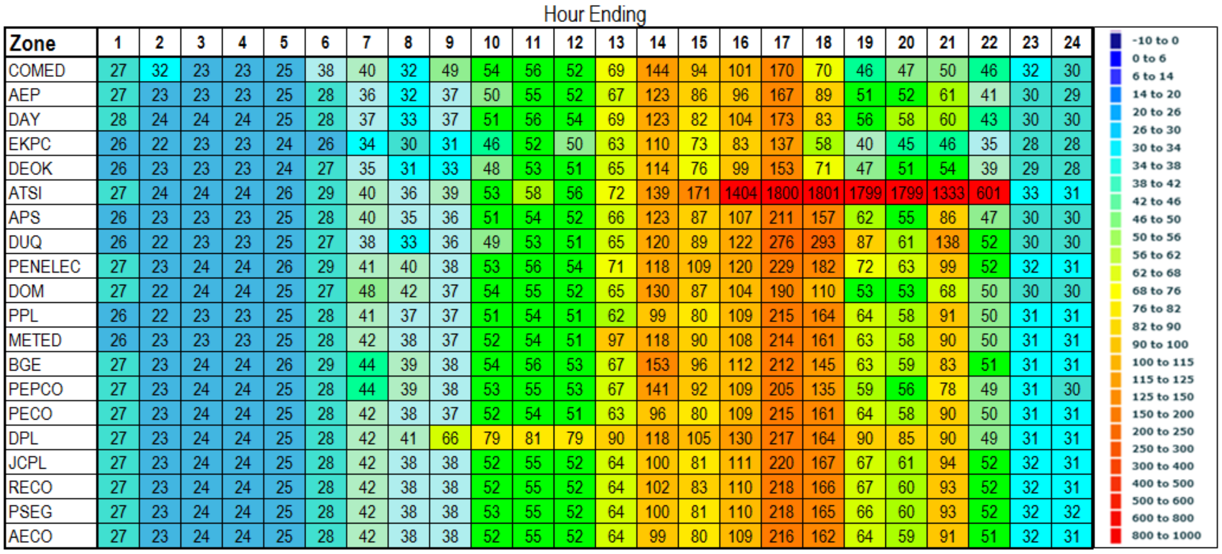
[25] Wet layup is a process where boilers are not at operating temperature and filled with water in order to minimize corrosion. It takes a longer period of time to get boilers to where they are making sufficient steam to provide generation to the grid.

[26] Drained refers to when boilers have all water removed and filled with an inert gas in order to minimize corrosion. Similar to wet layup returning the boiler to service takes a longer period of time.

The highest LMP in the Day-Ahead Energy Market was $270.11 in METED at 1700 with a daily RTO average of $63.34. The RTO on-peak LMP average was slightly higher at $70.12 while the off-peak LMP average was $49.78. The RTO daily average was in the extreme outlier range at the 100th percentile based on a one-year average. This illustrates that market participants were expecting even hotter conditions than the previous day, which drove the Day-Ahead Energy Market results as seen in the figure above.

On September 10, there were significant differences between the Real-Time and Day-Ahead Energy Market prices. Real-Time Market LMPs were higher as a result of higher loads in Real-Time as compared to Day-Ahead and increased congestion, specifically in the ATSI zone and surrounding areas of the footprint. The highest LMP in the Real-Time Market was $1,800 in the ATSI zone for several hours due to Demand Response setting price at approximately $1,800/MWh, its offer cap at the time.[27] When PJM deploys Emergency Demand Response in the ATSI zone, the ATSI Interface is activated. This occurs because PJM set up an ATSI interface[28] on July 17, 2013. This interface is used to set LMP when emergency load management is issued and is explained in more detail in the Demand Response section. As shown in the figure below, the convergence between the Day-Ahead and the Real-Time Energy Markets was fairly consistent throughout the day, with the exception of the ATSI zone and hours endings 14, 16 and 20. The daily average of all LMP was $63.28, on-peak at $81.78 and off-peak at $26.28, which was approximately at the 100th percentile based on a one-year rolling average.



Hour Ending

Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	27	32	23	23	25	38	40	32	49	54	56	52	69	144	94	101	170	70	46	47	50	46	32	30
AEP	27	23	23	23	25	28	36	32	37	50	55	52	67	123	86	96	167	89	51	52	61	41	30	29
DAY	28	24	24	24	25	28	37	33	37	51	56	54	69	123	82	104	173	83	56	58	60	43	30	30
EKPC	26	22	23	23	24	26	34	30	31	46	52	50	63	110	73	83	137	58	40	45	46	35	28	28
DEOK	26	23	23	23	24	27	35	31	33	48	53	51	65	114	76	99	153	71	47	51	54	39	29	28
ATSI	27	24	24	24	26	29	40	36	39	53	58	56	72	139	171	1404	1800	1801	1799	1799	1333	601	33	31
APS	26	23	23	23	25	28	40	35	36	51	54	52	66	123	87	107	211	157	62	55	86	47	30	30
DUQ	26	22	23	23	25	27	38	33	36	49	53	51	65	120	89	122	276	293	87	61	138	52	30	30
PENELEC	27	23	24	24	26	29	41	40	38	53	56	54	71	118	109	120	229	182	72	63	99	52	32	31
DOM	27	22	24	24	25	27	48	42	37	54	55	52	65	130	87	104	190	110	53	53	68	50	30	30
PPL	26	22	23	23	25	28	41	37	37	51	54	51	62	99	80	109	215	164	64	58	91	50	31	31
METED	26	23	23	23	25	28	42	38	37	52	54	51	97	118	90	108	214	161	63	58	90	50	31	31
BGE	27	23	24	24	26	29	44	39	38	54	56	53	67	153	96	112	212	145	63	59	83	51	31	31
PEPCO	27	23	24	24	25	28	44	39	38	53	55	53	67	141	92	109	205	135	59	56	78	49	31	30
PECO	27	23	24	24	25	28	42	38	37	52	54	51	63	96	80	109	215	161	64	58	90	50	31	31
DPL	27	23	24	24	25	28	42	41	66	79	81	79	90	118	105	130	217	164	90	85	90	49	31	31
JCPL	27	23	24	24	25	28	42	38	38	52	55	52	64	100	81	111	220	167	67	61	94	52	32	31
RECO	27	23	24	24	25	28	42	38	38	52	55	52	64	102	83	110	218	166	67	60	93	52	32	31
PSEG	27	23	24	24	25	28	42	38	38	53	55	52	64	100	81	110	218	165	66	60	93	52	32	32
AECO	27	23	24	24	25	28	42	38	38	52	55	52	64	99	80	109	216	162	64	59	91	51	32	31

Figure 27. **September 10, 2013: Real-Time Market Zonal LMPs**

Metric	Value ($/MWh)
RTO Daily Average	$63.28
RTO On Peak LMP Average (HE 6-23)	$81.78
RTO Off Peak LMP Average (HE 24-5)	$26.28

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[27] Shortage Pricing was implemented with an offer cap of $1000 (Generator Offer Cap) + two penalty factors. The penalty factors are $250, $400, $550, and $850 for year 1, 2, 3, and 4 respectively. This hot weather occurred in year two.

[28] The ATSI interface was created in order to set LMP when emergency mandatory load management is issued in the ATSI transmission zone.

Zonal Max LMP	$1800.79 in ATSI
Zonal Min LMP	$21.62 in EKPC

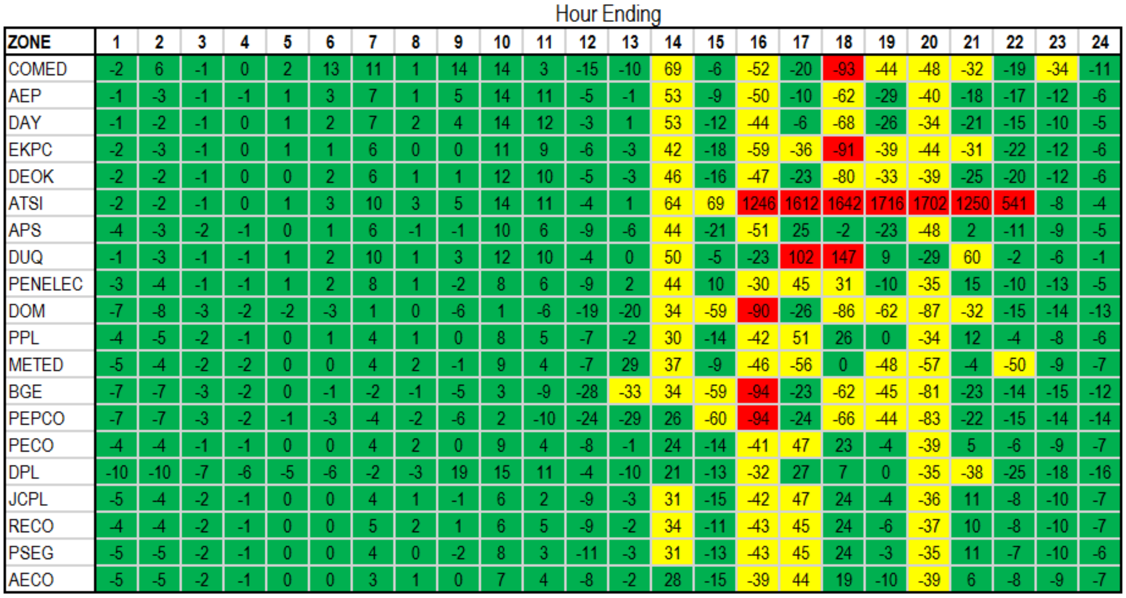
Table 18. September 10, 2013: Real-Time Energy Market Summary

September 10, showed a 59 percent increase from the previous day with respect to average RTO LMP. Other market outcomes were also impacted and deviated outside of nominal outcomes. FTR payout percentage was very low due to divergence between ATSI Day-Ahead and Real-Time Energy Market Outcomes. Revenue Adequacy and ATSI zone will be discussed in a later section of this report in more detail.

Reserve Market clearing prices were in line with expectations for September. However, Regulation prices were much higher than the previous day with an average Regulation Market Clearing Price (RMMCP) at $66.00/MWh. This was a 247-percent increase from the previous day.

The highest Reserve Market clearing price was $3.18/MWh for RTO and Mid-Atlantic Dominion Reserve Market areas. The average Reserve Market clearing prices for September 10 were $0.20/MWh and $0.20/MWh for RTO and Mid-Atlantic Dominion, respectively.

Regulation Market Clearing prices were high in some hours around the peak of the day. The highest price was $391/MWh during hour ending 1700. This was due to co-optimization of energy and regulation.

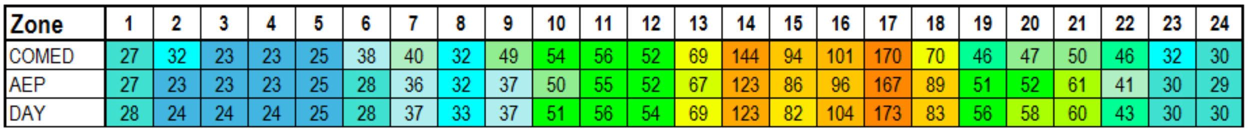


	Hour Ending																							
ZONE	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
COMED	-2	6	-1	0	2	13	11	1	14	14	3	-15	-10	69	-6	-52	-20	-93	-44	-48	-32	-19	-34	-11
AEP	-1	-3	-1	-1	1	3	7	1	5	14	11	-5	-1	53	-9	-50	-10	-62	-29	-40	-18	-17	-12	-6
DAY	-1	-2	-1	0	1	2	7	2	4	14	12	-3	1	53	-12	-44	-6	-68	-26	-34	-21	-15	-10	-5
EKPC	-2	-3	-1	0	1	1	6	0	0	11	9	-6	-3	42	-18	-59	-36	-91	-39	-44	-31	-22	-12	-6
DEOK	-2	-2	-1	0	0	2	6	1	1	12	10	-5	-3	46	-16	-47	-23	-80	-33	-39	-25	-20	-12	-6
ATSI	-2	-2	-1	0	1	3	10	3	5	14	11	-4	1	64	69	1246	1612	1642	1716	1702	1250	541	-8	-4
APS	-4	-3	-2	-1	0	1	6	-1	-1	10	6	-9	-6	44	-21	-51	25	-2	-23	-48	2	-11	-9	-5
DUQ	-1	-3	-1	-1	1	2	10	1	3	12	10	-4	0	50	-5	-23	102	147	9	-29	60	-2	-6	-1
PENELEC	-3	-4	-1	-1	1	2	8	1	-2	8	6	-9	2	44	10	-30	45	31	-10	-35	15	-10	-13	-5
DOM	-7	-8	-3	-2	-2	-3	1	0	-6	1	-6	-19	-20	34	-59	-90	-26	-86	-62	-87	-32	-15	-14	-13
PPL	-4	-5	-2	-1	0	1	4	1	0	8	5	-7	-2	30	-14	-42	51	26	0	-34	12	-4	-8	-6
METED	-5	-4	-2	-2	0	0	4	2	-1	9	4	-7	29	37	-9	-46	-56	0	-48	-57	-4	-50	-9	-7
BGE	-7	-7	-3	-2	0	-1	-2	-1	-5	3	-9	-28	-33	34	-59	-94	-23	-62	-45	-81	-23	-14	-15	-12
PEPCO	-7	-7	-3	-2	-1	-3	-4	-2	-6	2	-10	-24	-29	26	-60	-94	-24	-66	-44	-83	-22	-15	-14	-14
PECO	-4	-4	-1	-1	0	0	4	2	0	9	4	-8	-1	24	-14	-41	47	23	-4	-39	5	-6	-9	-7
DPL	-10	-10	-7	-6	-5	-6	-2	-3	19	15	11	-4	-10	21	-13	-32	27	7	0	-35	-38	-25	-18	-16
JCPL	-5	-4	-2	-1	0	0	4	1	-1	6	2	-9	-3	31	-15	-42	47	24	-4	-36	11	-8	-10	-7
RECO	-4	-4	-2	-1	0	0	5	2	1	6	5	-9	-2	34	-11	-43	45	24	-6	-37	10	-8	-10	-7
PSEG	-5	-5	-2	-1	0	0	4	0	-2	8	3	-11	-3	31	-13	-43	45	24	-3	-35	11	-7	-10	-6
AECO	-5	-5	-2	-1	0	0	3	1	0	7	4	-8	-2	28	-15	-39	44	19	-10	-39	6	-8	-9	-7

Figure 28. **September 10, 2013: Market Convergence (Real-Time LMP minus Day-Ahead LMP)**

8.3 Impacts to Market Outcomes from Load Shedding Events on September 10, 2013

On September 10, there were four different load shedding events as detailed in the operations section of the report. The first load shed event of September 10, the Pigeon River 2, occurred between 1249 and 2123 (HE13-HE22). This load was located in the AEP zone. Below are the Real-Time LMPs from that zone and also the neighboring COMED and DAY zones.

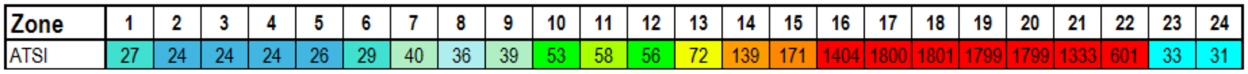


Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	27	32	23	23	25	38	40	32	49	54	56	52	69	144	94	101	170	70	46	47	50	46	32	30
AEP	27	23	23	23	25	28	36	32	37	50	55	52	67	123	86	96	167	89	51	52	61	41	30	29
DAY	28	24	24	24	25	28	37	33	37	51	56	54	69	123	82	104	173	83	56	58	60	43	30	30

Figure 29. **September 10, 2013: Real-Time Market AEP Zone LMP**

The magnitude of the load shed was 8 MW. In looking at that time frame in the figure above between the hours ending 13-22 for AEP, the LMP was not directly impacted by this small-magnitude load shed event. The AEP zonal LMP tracked with the zones experiencing the same system conditions in that geographic region.

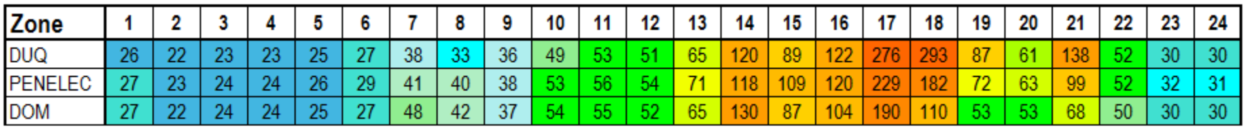
The second load shed event of September 10, the FE Tod, occurred between 1507 and 1642 (HE16-HE17) in the ATSI zone. The magnitude of the load shed was 16 MW total. Examining the figure below shows that emergency load management (demand response) was already setting price in the zone at that time. Therefore, it is unlikely this magnitude of load shed had any impact on prices.



Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ATSI	27	24	24	24	26	29	40	36	39	53	58	56	72	139	171	1404	1800	1801	1799	1799	1333	601	33	31

Figure 30. **September 10, 2013: Real-Time Market ATSI Zone LMP**

The third load shed event of September 10, the Penelec Erie South, occurred between 1739 and 0002 (HE18-HE1) of the following day. The magnitude of this load shed was 105 MW total. In examining the figure below showing the PENELEC zone and the neighboring DUQ and DOM zones, LMP was high in HE 1800, then fell sharply in HE 1900 and remained low until the next day.

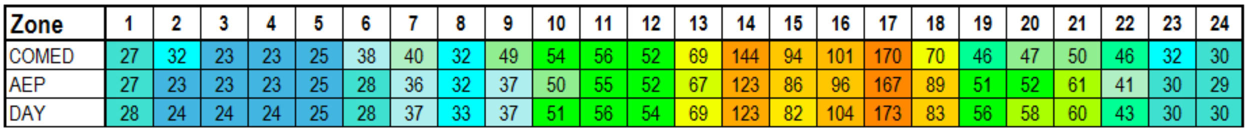


Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUQ	26	22	23	23	25	27	38	33	36	49	53	51	65	120	89	122	276	293	87	61	138	52	30	30
PENELEC	27	23	24	24	26	29	41	40	38	53	56	54	71	118	109	120	229	182	72	63	99	52	32	31
DOM	27	22	24	24	25	27	48	42	37	54	55	52	65	130	87	104	190	110	53	53	68	50	30	30

Figure 31. **September 10, 2013: Real-Time Market PENELEC Zone LMP**

This LMP pattern tracked with the other zones experiencing the same system conditions. Most likely the load shed did not have a direct impact on the price decrease that occurred at the same time.

The final load shed event of September 10 at AEP Summit occurred between 1913 and 2016 (HE20- HE21) in the AEP zone. The magnitude of the load shed was 25 MW total. In looking at the zonal LMP, there was minimal impact to the zonal prices in that zone. Below are the Real-Time LMPs from that zone and also the neighboring COMED and DAY zones.



Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	27	32	23	23	25	38	40	32	49	54	56	52	69	144	94	101	170	70	46	47	50	46	32	30
AEP	27	23	23	23	25	28	36	32	37	50	55	52	67	123	86	96	167	89	51	52	61	41	30	29
DAY	28	24	24	24	25	28	37	33	37	51	56	54	69	123	82	104	173	83	56	58	60	43	30	30

Figure 32. **September 10, 2013: Real-Time Market AEP Zone LMP**

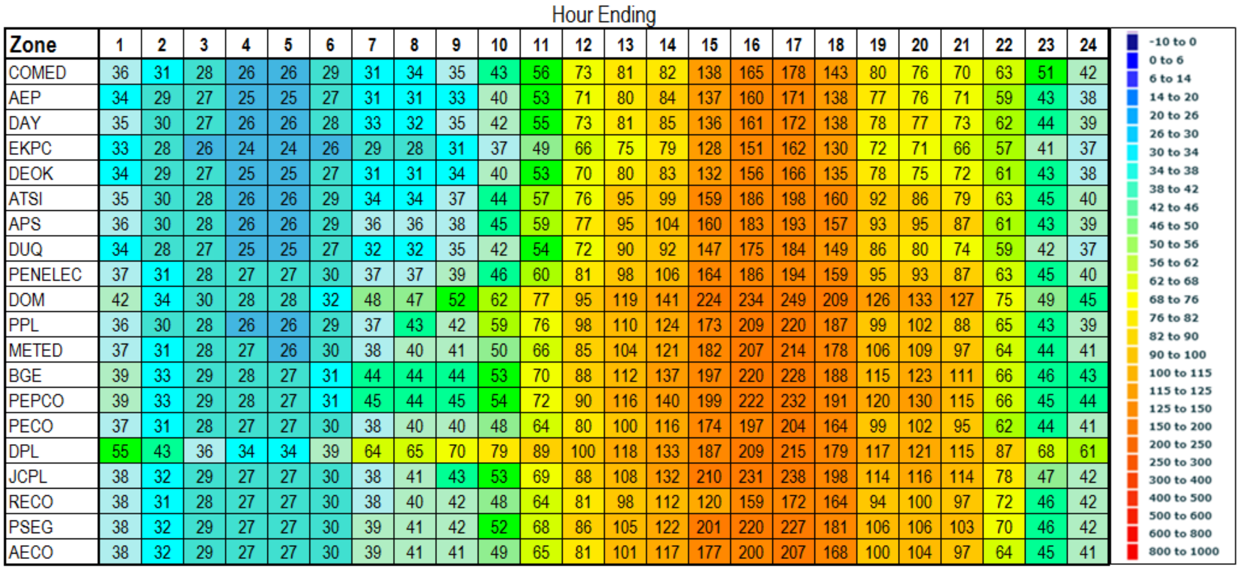
As discussed in the operations section and the executive summary related to the load shedding below the bulk electric system, the location of these load shed events and the magnitude of the reductions in load did not have significant impacts on market outcomes.

8.3.1 Wednesday, September 11, 2013

Shortly after midnight, FirstEnergy restored all power to the Erie South region, ending the FirstEnergy (Penelec) Erie South load shed event from Tuesday, September 10. PJM initiated emergency procedures on this day beginning at 1130 by deploying Long Lead Time Emergency Demand Response in the AEP and ATSI zones, followed by issuing a reduction of non-critical plant load for the AEP and ATSI zones. PJM also deployed Long Lead Time Emergency Demand Response for the Dominion zone, the Mid-Atlantic region, and the Duquesne zone and Short Lead Time Emergency Demand Response for the Mid-Atlantic Region and Duquesne zone. Later in the day PJM issued Voltage Reduction Warnings for the AEP and ATSI zones. A TLR 5 was also issued for a transmission constraint, which cut 100 MW of firm transactions on the Neptune DC tie to New York ISO.

8.3.2 Market Outcomes September 11, 2013

On September 11, the third and final day of the hot weather event, conditions were even more out of the ordinary for September. The Day-Ahead Market results reflected the expectation that the most significant hot weather would be to the south (DOM) with an overall impact to all zones in the RTO from east to west. The load forecast for the day was predicted to be just above 149,000 MW. The highest LMP in the Day-Ahead Market was $249.24 in DOM at 1600 with a daily average of $69.69. The on-peak LMP average was slightly higher at $79.74 while the off-peak LMP average was $49.58. This was at the 100th percentile based on a one-year average LMP. This shows that market participants were expecting conditions similar to the previous day, which drove the Day-Ahead Market results shown below.



Hour Ending

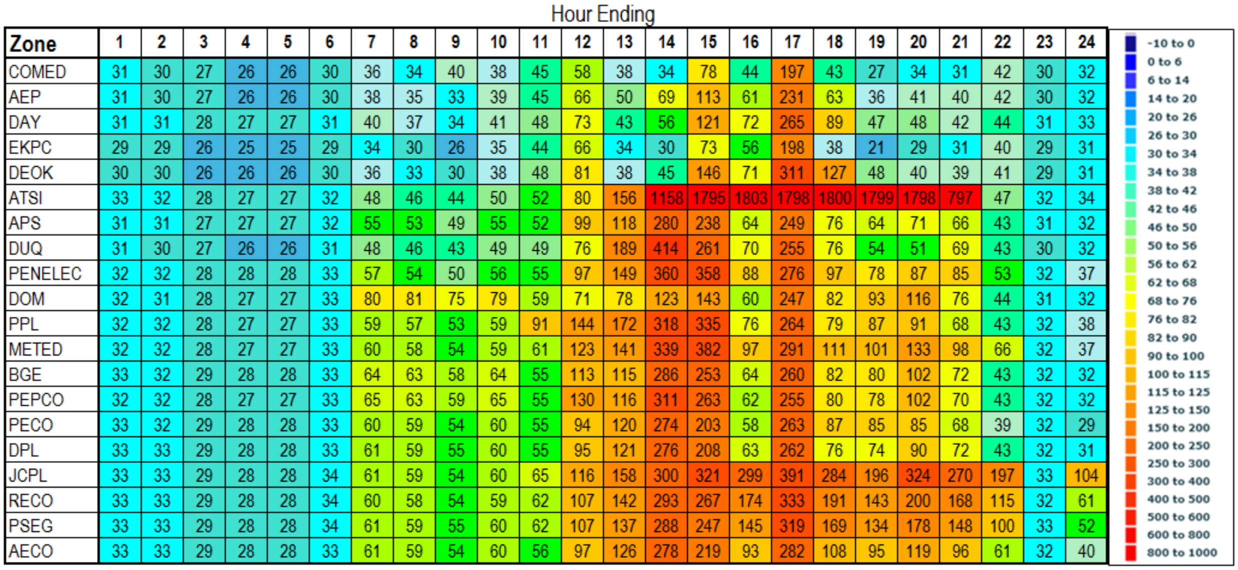
Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	36	31	28	26	26	29	31	34	35	43	56	73	81	82	138	165	178	143	80	76	70	63	51	42
AEP	34	29	27	25	25	27	31	31	33	40	53	71	80	84	137	160	171	138	77	76	71	59	43	38
DAY	35	30	27	26	26	28	33	32	35	42	55	73	81	85	136	161	172	138	78	77	73	62	44	39
EKPC	33	28	26	24	24	26	29	28	31	37	49	66	75	79	128	151	162	130	72	71	66	57	41	37
DEOK	34	29	27	25	25	27	31	31	34	40	53	70	80	83	132	156	166	135	78	75	72	61	43	38
ATSI	35	30	28	26	26	29	34	34	37	44	57	76	95	99	159	186	198	160	92	86	79	63	45	40
APS	36	30	28	26	26	29	36	36	38	45	59	77	95	104	160	183	193	157	93	95	87	61	43	39
DUQ	34	28	27	25	25	27	32	32	35	42	54	72	90	92	147	175	184	149	86	80	74	59	42	37
PENELEC	37	31	28	27	27	30	37	37	39	46	60	81	98	106	164	186	194	159	95	93	87	63	45	40
DOM	42	34	30	28	28	32	48	47	52	62	77	95	119	141	224	234	249	209	126	133	127	75	49	45
PPL	36	30	28	26	26	29	37	43	42	59	76	98	110	124	173	209	220	187	99	102	88	65	43	39
METED	37	31	28	27	26	30	38	40	41	50	66	85	104	121	182	207	214	178	106	109	97	64	44	41
BGE	39	33	29	28	27	31	44	44	44	53	70	88	112	137	197	220	228	188	115	123	111	66	46	43
PEPCO	39	33	29	28	27	31	45	44	45	54	72	90	116	140	199	222	232	191	120	130	115	66	45	44
PECO	37	31	28	27	27	30	38	40	40	48	64	80	100	116	174	197	204	164	99	102	95	62	44	41
DPL	55	43	36	34	34	39	64	65	70	79	89	100	118	133	187	209	215	179	117	121	115	87	68	61
JCPL	38	32	29	27	27	30	38	41	43	53	69	88	108	132	210	231	238	198	114	116	114	78	47	42
RECO	38	31	28	27	27	30	38	40	42	48	64	81	98	112	120	159	172	164	94	100	97	72	46	42
PSEG	38	32	29	27	27	30	39	41	42	52	68	86	105	122	201	220	227	181	106	106	103	70	46	42
AECO	38	32	29	27	27	30	39	41	41	49	65	81	101	117	177	200	207	168	100	104	97	64	45	41

Figure 33. **September 11, 2013: Day-Ahead Market Zonal LMPs**

Metric	Value ($/MWh)
RTO Daily Average	$69.69
RTO On Peak LMP Average (HE 6-23)	$79.74
RTO Off Peak LMP Average (HE 24-5)	$49.58
Zonal Max LMP	$249.24 in DOM
Zonal Min LMP	$23.82 in EKPC

Table 19. September 11, 2013: Day-Ahead Energy Market Summary

When September 11 arrived there were some fairly significant differences between the Real-Time and Day-Ahead Market as well as impacts from the interchange that were not seen on previous days. Real-Time Market prices were higher; however, the areas where higher loads were expected did track with the Day-Ahead Market prices.



Hour Ending

Zone	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	31	30	27	26	26	30	36	34	40	38	45	58	38	34	78	44	197	43	27	34	31	42	30	32
AEP	31	30	27	26	26	30	38	35	33	39	45	66	50	69	113	61	231	63	36	41	40	42	30	32
DAY	31	31	28	27	27	31	40	37	34	41	48	73	43	56	121	72	265	89	47	48	42	44	31	33
EKPC	29	29	26	25	25	29	34	30	26	35	44	66	34	30	73	56	198	38	21	29	31	40	29	31
DEOK	30	30	26	26	26	30	36	33	30	38	48	81	38	45	146	71	311	127	48	40	39	41	29	31
ATSI	33	32	28	27	27	32	48	46	44	50	52	80	156	1158	1795	1803	1798	1800	1799	1798	797	47	32	34
APS	31	31	27	27	27	32	55	53	49	55	52	99	118	280	238	64	249	76	64	71	66	43	31	32
DUQ	31	30	27	26	26	31	48	46	43	49	49	76	189	414	261	70	255	76	54	51	69	43	30	32
PENELEC	32	32	28	28	28	33	57	54	50	56	55	97	149	360	358	88	276	97	78	87	85	53	32	37
DOM	32	31	28	27	27	33	80	81	75	79	59	71	78	123	143	60	247	82	93	116	76	44	31	32
PPL	32	32	28	27	27	33	59	57	53	59	91	144	172	318	335	76	264	79	87	91	68	43	32	38
METED	32	32	28	27	27	33	60	58	54	59	61	123	141	339	382	97	291	111	101	133	98	66	32	37
BGE	33	32	29	28	28	33	64	63	58	64	55	113	115	286	253	64	260	82	80	102	72	43	32	32
PEPCO	32	32	28	27	27	33	65	63	59	65	55	130	116	311	263	62	255	80	78	102	70	43	32	32
PECO	33	32	29	28	28	33	60	59	54	60	55	94	120	274	203	58	263	87	85	85	68	39	32	29
DPL	33	33	29	28	28	33	61	59	55	60	55	95	121	276	208	63	262	76	74	90	72	43	32	31
JCPL	33	33	29	28	28	34	61	59	54	60	65	116	158	300	321	299	391	284	196	324	270	197	33	104
RECO	33	33	29	28	28	34	60	58	54	59	62	107	142	293	267	174	333	191	143	200	168	115	32	61
PSEG	33	33	29	28	28	34	61	59	55	60	62	107	137	288	247	145	319	169	134	178	148	100	33	52
AECO	33	33	29	28	28	33	61	59	54	60	56	97	126	278	219	93	282	108	95	119	96	61	32	40

Figure 34. September 11, 2013: Real-Time Market Zonal LMPs

Metric	Value ($/MWh)
RTO Daily Average	$76.75
RTO On Peak LMP Average (HE 6-23)	$99.41
RTO Off Peak LMP Average (HE 24-5)	$31.43
Zonal Max LMP	$1802.75 in ATSI
Zonal Min LMP	$21.09 in EKPC

Table 20. September 11, 2013: Real-Time Energy Market Summary

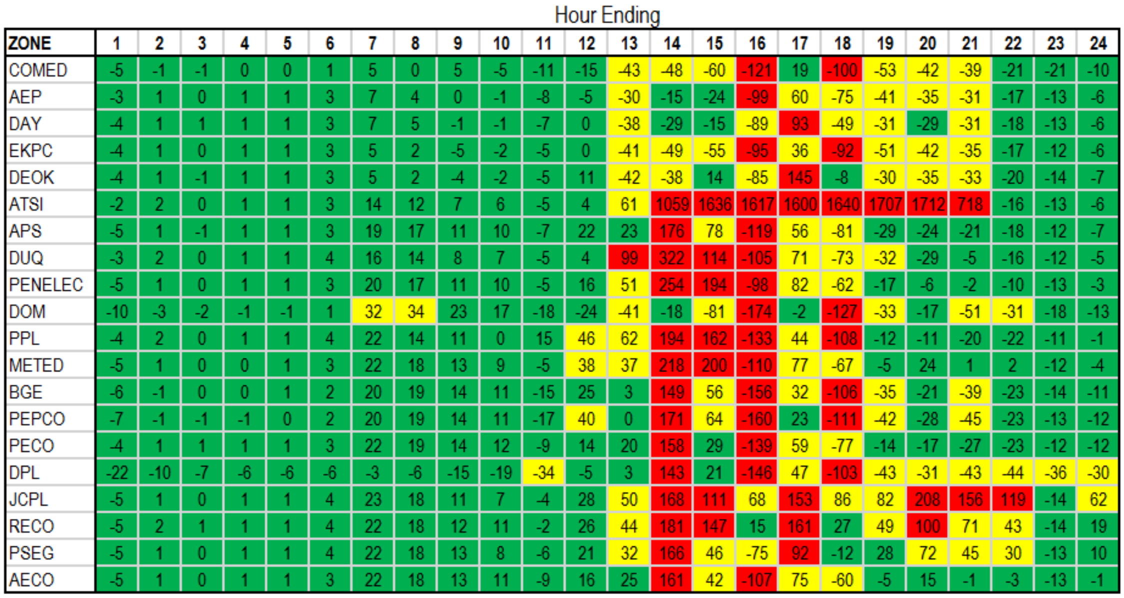
The highest LMP in the Real-Time Market was $1,800 in the ATSI zone for several hours due to Demand Response setting price. This occurs because PJM set up an ATSI interface[29] on July 17, 2013. This interface is used to set LMP when emergency load management is issued and is explain in more detail in the Demand Response section. Unlike the previous day, the convergence between the day-ahead and real-time results was significantly different. The variance ignoring the ATSI zone was between +$322 to -$174 and prices in 1600 were significantly depressed. The daily average of all LMPs was $76.75, on-peak at $99.41 and off-peak at $31.43 which is at the 100th percentile based on a rolling one-year average.

In comparison to September 9, September 11 showed a 93 percent increase with respect to average RTO LMP. Other market outcomes were also impacted and deviated outside of nominal outcomes. FTR payout percentage was again was very low due to divergence between ATSI Day-Ahead and Real-Time Energy Market Outcomes.

Reserve Market clearing prices were higher than the average with respect to the Mid-Atlantic Dominion area. However the RTO was within one standard deviation of the mean. Regulation prices were much higher than the previous day with an average Regulation Market Clearing Price (RMMCP) of $78.00/MWh. This was a 310 percent increase from September 9.

The highest Reserve Market Clearing Price were $210.07/MWh for Mid-Atlantic Dominion and $19.48/MWh RTO Reserve Market areas. The average Reserve Market clearing prices for September 11 were $1.03/MWh and $20.64/MWh for RTO and Mid-Atlantic Dominion, respectively.

Regulation Market Clearing Prices were high in some hours around the peak of the day. The highest price was $330/MWh during hour ending 1600, this was again due to co-optimization of energy and regulation.



Hour Ending

ZONE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
COMED	-5	-1	-1	0	0	1	5	0	5	-5	-11	-15	-43	-48	-60	-121	19	-100	-53	-42	-39	-21	-21	-10
AEP	-3	1	0	1	1	3	7	4	0	-1	-8	-5	-30	-15	-24	-99	60	-75	-41	-35	-31	-17	-13	-6
DAY	-4	1	1	1	1	3	7	5	-1	-1	-7	0	-38	-29	-15	-89	93	-49	-31	-29	-31	-18	-13	-6
EKPC	-4	1	0	1	1	3	5	2	-5	-2	-5	0	-41	-49	-55	-95	36	-92	-51	-42	-35	-17	-12	-6
DEOK	-4	1	-1	1	1	3	5	2	-4	-2	-5	11	-42	-38	14	-85	145	-8	-30	-35	-33	-20	-14	-7
ATSI	-2	2	0	1	1	3	14	12	7	6	-5	4	61	1059	1636	1617	1600	1640	1707	1712	718	-16	-13	-6
APS	-5	1	-1	1	1	3	19	17	11	10	-7	22	23	176	78	-119	56	-81	-29	-24	-21	-18	-12	-7
DUQ	-3	2	0	1	1	4	16	14	8	7	-5	4	99	322	114	-105	71	-73	-32	-29	-5	-16	-12	-5
PENELEC	-5	1	0	1	1	3	20	17	11	10	-5	16	51	254	194	-98	82	-62	-17	-6	-2	-10	-13	-3
DOM	-10	-3	-2	-1	-1	1	32	34	23	17	-18	-24	-41	-18	-81	-174	-2	-127	-33	-17	-51	-31	-18	-13
PPL	-4	2	0	1	1	4	22	14	11	0	15	46	62	194	162	-133	44	-108	-12	-11	-20	-22	-11	-1
METED	-5	1	0	0	1	3	22	18	13	9	-5	38	37	218	200	-110	77	-67	-5	24	1	2	-12	-4
BGE	-6	-1	0	0	1	2	20	19	14	11	-15	25	3	149	56	-156	32	-106	-35	-21	-39	-23	-14	-11
PEPCO	-7	-1	-1	-1	0	2	20	19	14	11	-17	40	0	171	64	-160	23	-111	-42	-28	-45	-23	-13	-12
PECO	-4	1	1	1	1	3	22	19	14	12	-9	14	20	158	29	-139	59	-77	-14	-17	-27	-23	-12	-12
DPL	-22	-10	-7	-6	-6	-6	-3	-6	-15	-19	-34	-5	3	143	21	-146	47	-103	-43	-31	-43	-44	-36	-30
JCPL	-5	1	0	1	1	4	23	18	11	7	-4	28	50	168	111	68	153	86	82	208	156	119	-14	62
RECO	-5	2	1	1	1	4	22	18	12	11	-2	26	44	181	147	15	161	27	49	100	71	43	-14	19
PSEG	-5	1	0	1	1	4	22	18	13	8	-6	21	32	166	46	-75	92	-12	28	72	45	30	-13	10
AECO	-5	1	0	1	1	3	22	18	13	11	-9	16	25	161	42	-107	75	-60	-5	15	-1	-3	-13	-1

Figure 35. **September 11, 2013: Market Convergence (Real-Time LMP minus Day-Ahead LMP)**

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[29] The ATSI interface was created in order to set LMP when emergency mandatory load management is issued in the ATSI transmission zone.

The figures above demonstrate an interesting pricing behavior from September 11 that was not present on September 10 – the depressed price in HE 16 during a very hot part of the day. This type of pricing pattern is usually caused by imports coming into PJM, which are price-takers and receive the cleared price at their interface. This behavior was clearly demonstrated by the events during the hot weather in July 2013, discussed in the Impacts of Interchange section of this report. However, on September 11 the import levels were about the same as the previous day. This particular price depression in real time was driven by calling a significant amount of demand response that was projected to be required given the load forecast. PJM's peak demand was expected to be around 149,000 MW but during the in-day ramp it appeared that it was going to be significantly higher by about 4,000 MW. The demand response was called based on an expectation of 153,000 MW peak load. Since PJM does not account for these MW as additional reserves[30], LMP is set by the marginal resource and Demand Response did not to set price when dispatched because this volume of demand response was not ultimately required in hindsight. This over deployment of demand response was primarily caused by the fact that nearly all Demand Response requires two-hour lead time and the PJM operators cannot predict real-time conditions two hours in advance. Thus PJM operators are conservative in making the call for Demand Response in order to ensure the reliability of the grid.[31] This amount of Demand Response called caused the lower prices during hour ending 16.

Three Day Market Outcome Trends

As seen in the table below, the shift in market outcomes was very significant. However it is in line with the weather conditions that were present during the hot weather in September 2013. Market outcomes are driven primarily by load, as load increases which it did, the LMP is expected to follow.

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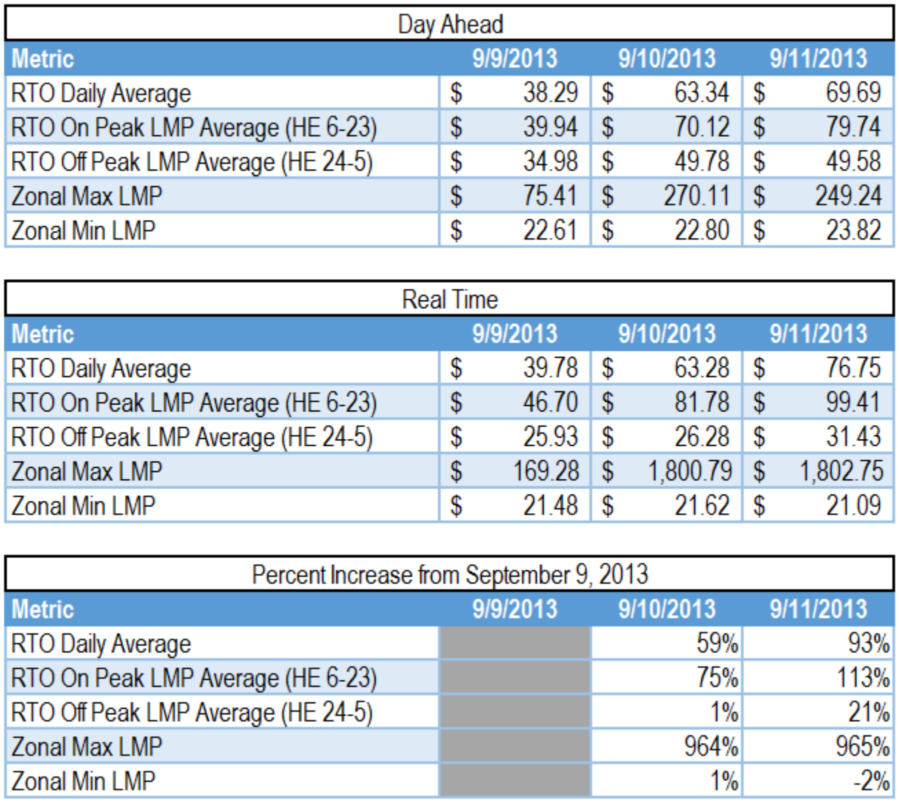
[30] PJM is currently working through stakeholder process at Nov. 21, 2013, Markets and Reliability Committee to determine what could be done to improve this process and have less impact on prices.

[31] PJM has discussed the operational difficulty caused by the two-hour lead time required by demand response offers and PJM will be submitting a filing with FERC to address this issue based on the outcome of the stakeholder process.



Day Ahead			
Metric	**9/9/2013**	**9/10/2013**	**9/11/2013**
RTO Daily Average	$ 38.29	$ 63.34	$ 69.69
RTO On Peak LMP Average (HE 6-23)	$ 39.94	$ 70.12	$ 79.74
RTO Off Peak LMP Average (HE 24-5)	$ 34.98	$ 49.78	$ 49.58
Zonal Max LMP	$ 75.41	$ 270.11	$ 249.24
Zonal Min LMP	$ 22.61	$ 22.80	$ 23.82

Real Time			
Metric	**9/9/2013**	**9/10/2013**	**9/11/2013**
RTO Daily Average	$ 39.78	$ 63.28	$ 76.75
RTO On Peak LMP Average (HE 6-23)	$ 46.70	$ 81.78	$ 99.41
RTO Off Peak LMP Average (HE 24-5)	$ 25.93	$ 26.28	$ 31.43
Zonal Max LMP	$ 169.28	$ 1,800.79	$ 1,802.75
Zonal Min LMP	$ 21.48	$ 21.62	$ 21.09

Percent Increase from September 9, 2013			
Metric	**9/9/2013**	**9/10/2013**	**9/11/2013**
RTO Daily Average		59%	93%
RTO On Peak LMP Average (HE 6-23)		75%	113%
RTO Off Peak LMP Average (HE 24-5)		1%	21%
Zonal Max LMP		964%	965%
Zonal Min LMP		1%	-2%

Table 21. Market Outcome Trends for September Hot Weather

The RTO daily average LMP saw a 59 percent increase and a 93 percent increase relative to the LMP on September 9. The September 9 daily average LMP was slightly above the 70th percentile based on a one-year average LMP.

8.4 Impacts of Interchange

As seen in July 2013, the imports on the interchange into PJM can have a significant impact on market outcomes. During the hot weather in July, PJM experienced a significant inflow of imports on the interchange RTO-wide. These imports were looking to take advantage of the high prices within the RTO at the time. The result was the increased imports drove prices down from $465 to $52 within an hour. Because this occurred in July, it is prudent to evaluate if the same impact was seen during the hot weather in September.

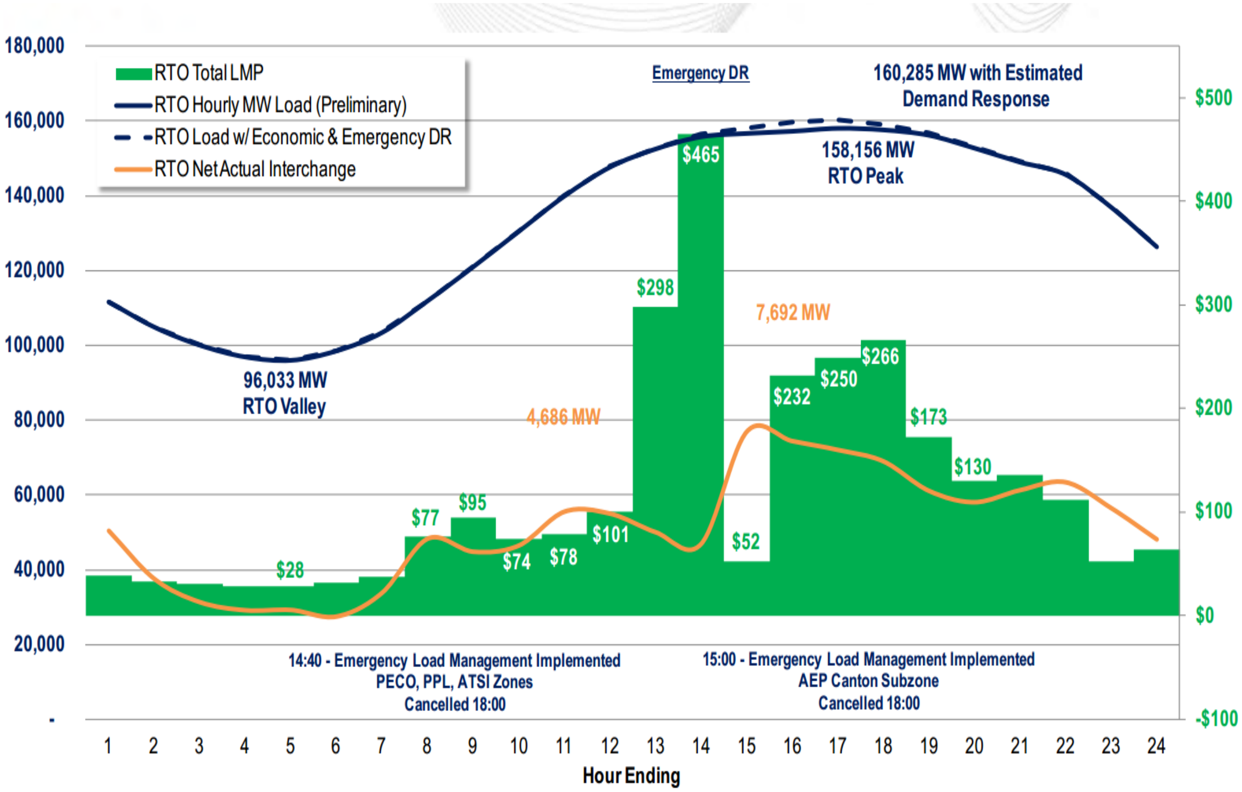


Figure 36. **July 18, 2013: RTO Load, LMP and Interchange**

In September 2013, the influence of interchange on market outcomes was examined to see if there was a similar effect to what occurred in July. As shown below, on September 9, the load was at about 120,000 MW and prices in real time did not get high except for hours ending 16 and 17.

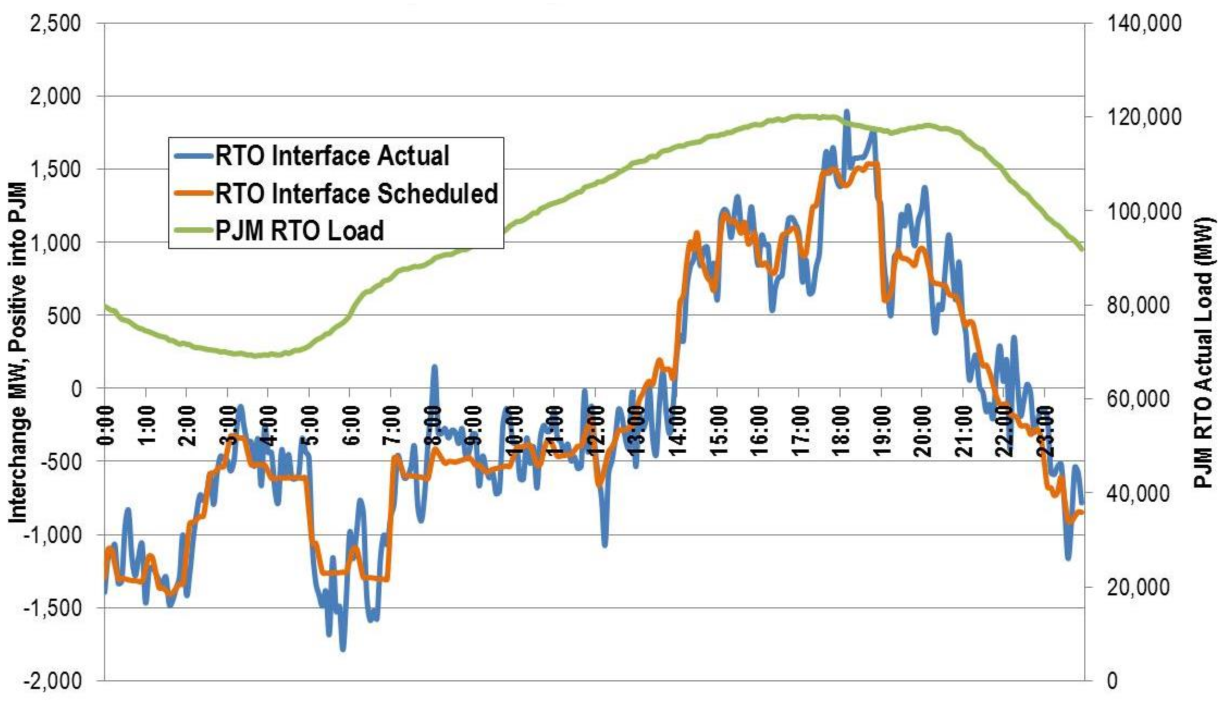


Figure 37. **September 9, 2013: Interchange and RTO**

PJM did not need or receive significant amounts of imports given the load shape and therefore did not see an impact to the real-time prices.

With higher than average load on September 10, prices followed the load and interchange increased during the day, but the imports did not have a substantial or abrupt impact on prices. The reason imports did not abruptly impact price was that the import MW flows followed the predicted pattern and were consistent with the scheduled level of MW. Since the interchange was predicted and was flowing before the system peak demand was reached, PJM operators were able to appropriately consider the interchange when determining the economic merit order of the internal generation dispatch, which allowed pricing to be consistent with operational decisions.

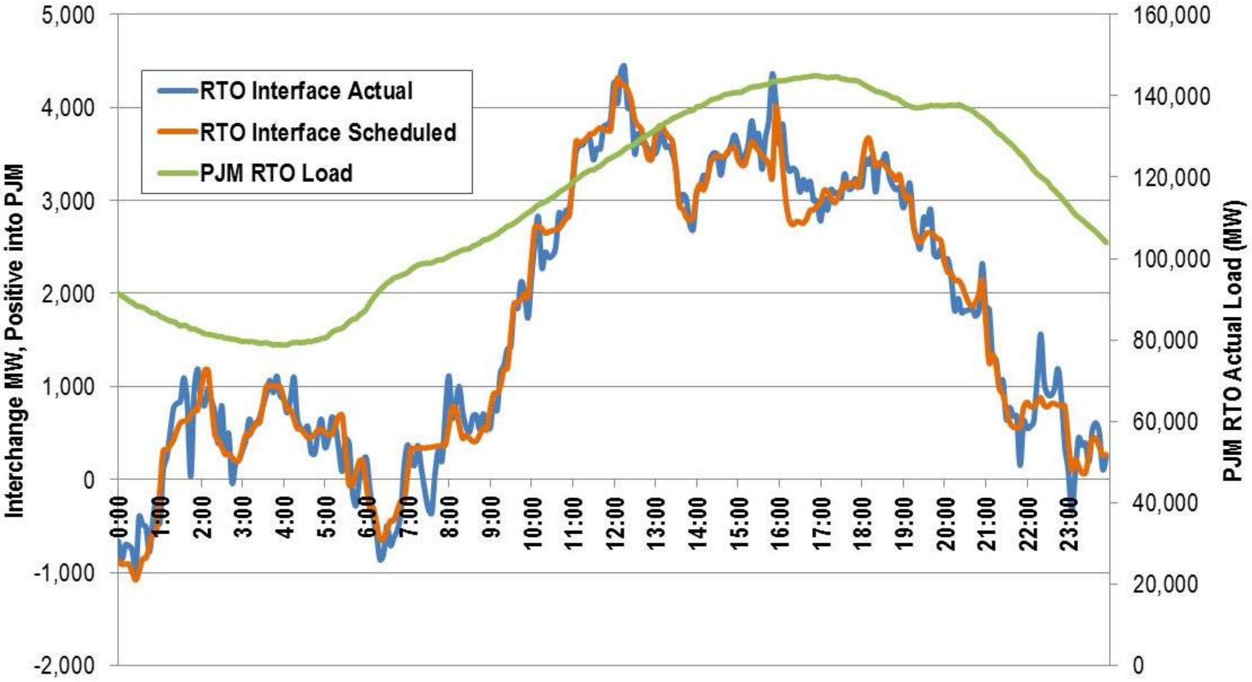


Figure 38. **September 10, 2013: Interchange and RTO**

However, on September 11, as shown in figure below, there were some interesting trends with the interchange. It appears that based on previous days' prices and projected load being higher than September 10, the imports on the interchange began to flow early in hopes of getting the higher prices that showed up the day before for those exchanges. Prices fell sharply around hour ending 13 and the interchange reduced and appeared to follow the lower price trends as would be expected. The sharp decrease in prices seen on September 11 were not caused by the interchange but rather were due to the amount of demand response that was called on to support the high load expectation, given the higher temperatures than the day before as well as the higher-than-expected projected load, as detailed in the operational report.

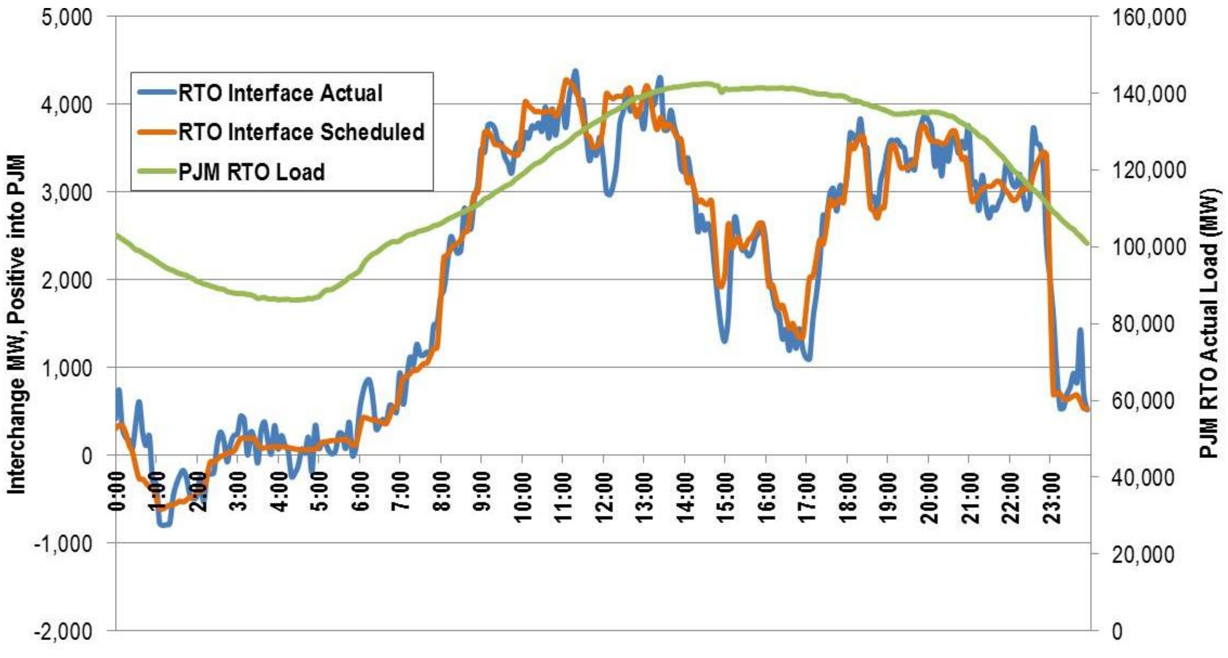


Figure 39. **September 11, 2013: Interchange and RTO Load**

8.5 Revenue Adequacy

An outcome that is of concern to PJM as well as stakeholders is the impact of seeing high prices in real time due to system conditions or operational decisions that cannot currently be modeled in the Day-Ahead Energy Market. This causes a condition where FTR underfunding can occur. During the September hot weather event, FTR underfunding on the ATSI Interface was due to having less flow on the facilities that make up that interface in real time than there was in the day-ahead model, as well as very high real-time congestion in the area. The use of Emergency Demand Response in real time to control flows into the ATSI zone was a significant contributor to this result. Controlling transmission constraints with Emergency Demand Response is very inefficient under today's market rules for several reasons.

- PJM does not model the discrete location of each demand response resource in its Energy Management System and, therefore, cannot accurately calculate the necessary distribution factors needed to determine how much demand response is needed to control a potential transmission overload.
- Even if PJM were able to determine the exact resources it needed to control an overload, compliance with the deployment of Emergency Demand Response was not mandatory during the summer of 2013 unless an entire zone is dispatched[32]. This leads the majority of deployments being at the zonal level even when that is not what is needed operationally.
- The zonal deployment of demand response will typically result in more relief than what actually is needed, therefore resulting in the over-controlling of transmission constraints in real time. Over-control in real time

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[32] Demand Response event compliance for sub-zonal events becomes mandatory under the current PJM Tariff beginning in the summer of 2014.

typically leads to lower flows than what was cleared in the Day-Ahead Market, which can lead to underfunding.

- The large majority of Demand Response offers require a two-hour lead time and have similar prices, which create operational discontinuities because large blocks of demand response have similar characteristics. The two- hour requirement makes it virtually impossible to accurately deploy demand response.

On September 11, the resulting real-time flows following the deployment of Emergency Demand Response in the ATSI Zone and the South Canton Sub-Zone were less than what was observed in the Day Ahead Market. This, in conjunction with significant real-time congestion due to the high offer prices of Emergency Demand Response, drove the FTR underfunding on that day.

As PJM has stated in prior FERC dockets, PJM believes it would be a beneficial market design change to allocate negative balancing congestion in a different manner that the current Tariff states, which is to FTR holders.

8.5.1 FTR Funding Impact

The hot weather in September had a significant impact on the revenue adequacy for the month. This was primarily driven by the large differences between the Day-Ahead Market price for the ATSI zone and the Real-Time Market price that was driven by calling emergency Demand Response resources to ensure reliability during the hot weather event. As shown below in the FTR Revenues vs. FTR Targets, September had a fairly large gap between the target and the revenue generated.

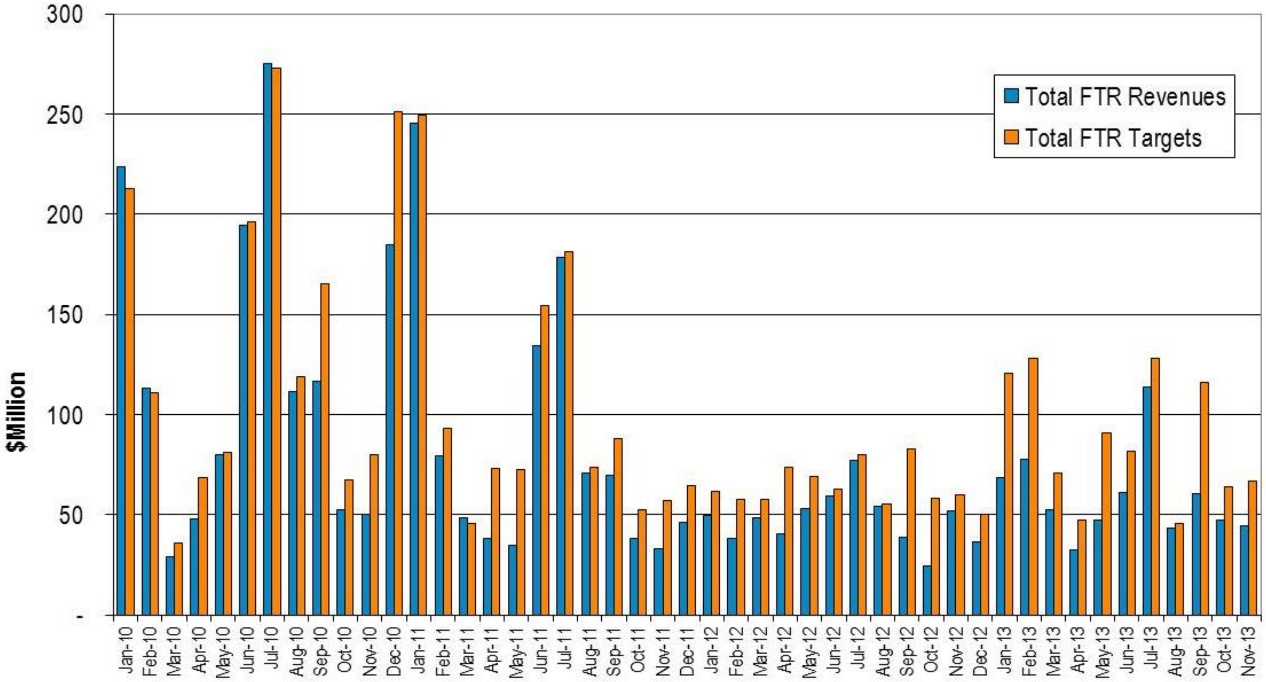

Figure 40. **FTR Revenues vs. FTR Target Allocation**

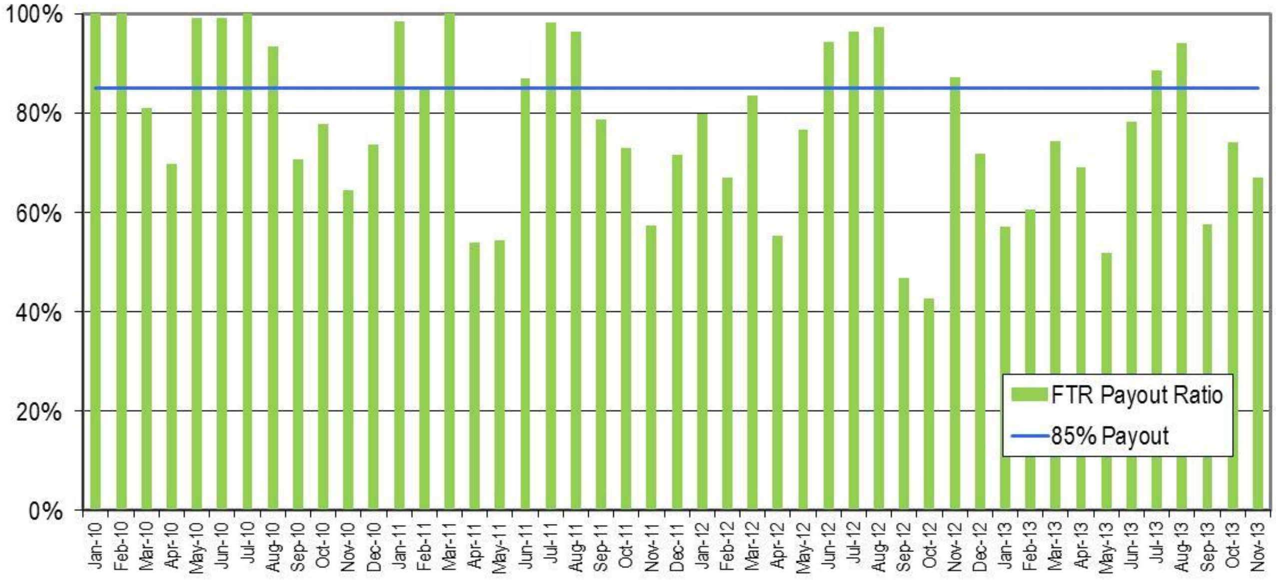

Figure 41. **PJM FTR Payout Ratio**

As shown above, September finished with a 58 percent FTR payout ratio with $56.3M of underfunding. September 10 and 11 had $29.3M of the FTR underfunding between them and reduced monthly FTR payout by 18 percent. This was a significant impact on the overall FTR payout. As shown in the figures above, September 2013 had a low payout percentage; however, other months also had a low payout percentage.

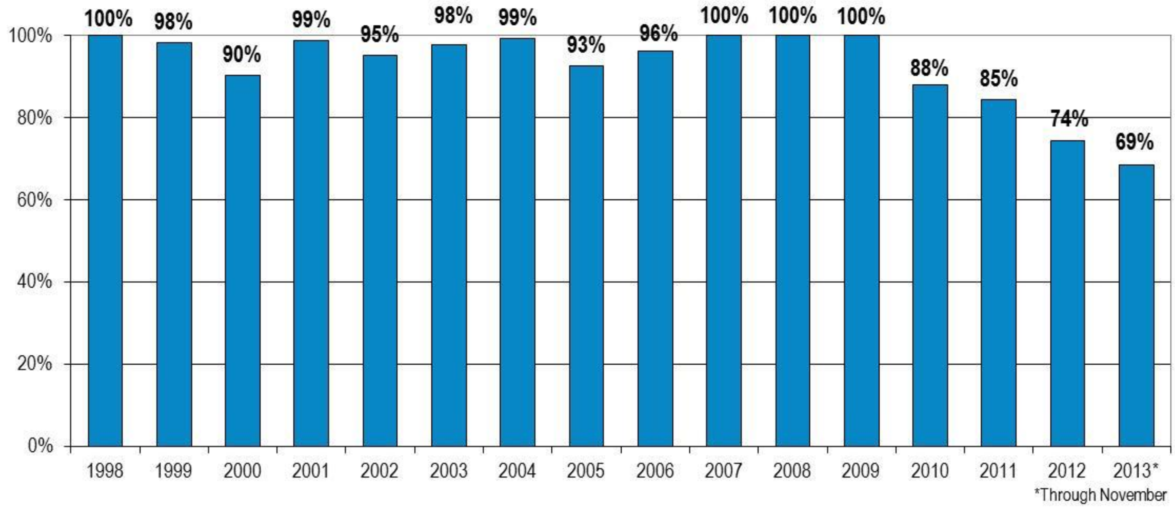

Figure 42. **PJM Calendar Year FTR Payout Ratio**

The ATSI Interface had $22.7M of underfunding, and reduced monthly FTR payout 20 percent. The ATSI interface had a significant impact on monthly payout that was amplified because it did not bind in the Day-Ahead Energy Market. Thus all of its $22.7M real-time congestion was incurred as negative balancing congestion, which typically leads to worse outcomes with respect to revenue adequacy. It also highlights the importance of day-ahead to real-time convergence in optimizing overall outcomes, as shown in the table below.

September 2013 FTR Underfunding Causal Assignment		
Underfunding ($M)	**Percent Underfunding**	**Cause**
-$56.3	**100%**	**Total**
-$22.7	40%	ATSI Interface
-$33.6	60%	Transmission outages
-$14.6	27%	• Maintenance
-$13.4	23%	• NERC sag-limit remediation
-$5.6	10%	• Construction

Table 22. September 2013 FTR Underfunding

There were about 20 additional constraints that were binding throughout each of the hot days. However, all of them had less of an effect on the overall FTR funding and monthly payout. The next 10 constraints altogether had $7.8M of underfunding and lowered monthly FTR payout 2.5 percent, which is a much less significant impact to the overall FTR payout. It should be noted that there were many constraints that finished with surpluses that offset some losses during this event. There are several key takeaways from this event with respect to FTR funding:

1. Emergency actions, like the deployment of Emergency Demand Response that only occur in real-time and are extremely expensive, can drive large occurrences of FTR underfunding due to the inability to discretely dispatch the needed quantity of the product to match Day-Ahead Market flows and the high price associated with the action.

2. Under the current market rules, FTR holders can be adversely impacted significantly by such emergency procedures taken to maintain system reliability when they have no impact to the Real-Time Market or system operations. PJM believes that this is a flaw in the market design that needs to be addressed.

8.5.2 Day-Ahead and Real-Time Operations

This section summarizes the FTR outcomes on a day-by-day basis. The event had an overall negative impact on FTR funding with the most significant impact occurring on the last two days of the event.

8.5.3 September 9, 2013

September 9, the first day of the hot weather event, had very little effect on the FTR outcomes on that day given that prices between day ahead and real time did not significantly diverge and the overall FTR funding for that day was above 90 percent. However, market outcomes were very different on the subsequent days.

8.5.4 September 10, 2013

September 10, the second day of the hot weather event, had $11.1M of underfunding, reducing monthly FTR payout 5 percent. The ATSI Interface bound over hours ending 16-22 causing the Real-Time Energy Market price in ATSI to reach $1,800/MWh. This price difference between Day-Ahead and Real-Time Energy Market directly led to $8.3M of underfunding. This reduced the monthly FTR payout 5 percent.

The hot weather had a significant effect on the system. During the time that ATSI was also a binding constraint, there were an additional eight constraints that bound during the same time frame in real-time and another 10 in Day-Ahead Market. However, all of them had secondary effects on FTR funding and monthly payout even when taken together. The most-significant of the secondary constraints was the Cherry Valley constraint with $0.45M of underfunding. The next 10 constraints with the largest impact together had $3.9M of underfunding among them and lowered monthly payout 1.4 percent. Many constraints finished with surpluses that offset losses.

There were some additional local, internal constraints within the ATSI zone when the ATSI interface bound, but none of these had a significant impact. The most significant constraint outside the ATSI Interface as far as restricting flows into Northern Ohio was Tidd-West Bellaire 345 kV. This constraint imposed an average of $33/MWh of congestion on ATSI zone, but that was relatively small in comparison to the ATSI Interface at $1,350/MWh.

8.5.5 September 11, 2013

September 11 had $18M of underfunding, reducing monthly FTR payout 10 percent. In addition, there was $1.5M of net negative congestion charged to balancing operating reserves. The ATSI interface bound over hours ending 14-21 and had $14.4M of underfunding, reducing monthly FTR payout 12 percent.

Six other constraints bound during the hours when ATSI Interface bound real-time, and another 18 in day-ahead. The most-significant of the secondary constraints was the Hawthorne-Hinchmans with $1.5M of underfunding that lowered monthly FTR payout 0.4 percent. The next 10 constraints together had $4.6M of underfunding among them and lowered monthly payout 0.8 percent.

There were some local, internal constraints inside the ATSI zone when the ATSI interface bound, but none had a substantial impact. The most significant constraint outside the ATSI Interface in terms of restricting flows into Northern Ohio was again the Tidd-West Bellaire, this time imposing an average of $100/MWh of congestion on the ATSI zone over HE 14-15, but that is minor compared to the ATSI Interface at $1,400/MWh.

Pricing of Operator Actions

As part of the review of the market results during the September heat wave and during other high-load events in 2013, PJM recognized that its market rules and pricing algorithms do not completely capture all actions being taken by its operators in the control room. The Shortage Pricing software implementation that went live on Oct. 1, 2012, helped to better tie together operator actions with market clearing prices, but it is evident that there is still opportunity to improve in this area.

PJM brought forward a problem statement at the Nov. 11, 2013, Markets and Reliability Committee Meeting to address this issue in addition to another issue around interchange volatility. This problem statement was approved and taken up by the Market Implementation Committee where it will be addressed via special sessions of that group. The stakeholder group addressing this issue will be tasked with finding better ways to incorporate operator actions into market clearing prices to ensure that the counter-intuitive price drops witnessed during emergency periods do not continue to occur. The group will also try to address the impact that interchange volatility has on the stability and certainty of market clearing prices and whether there are any improvements to be made in that area.

Other Market Assessments

In addition to the load shed events, additional assessments were conducted for the following events and processes:

- Synchronized Reserve Event of September 10
- Demand Response Events of September 10 and 11

The results of these assessments are presented here.

Synchronized Reserve Event (September 10, 2013)

Markets Implications from Synchronized Reserve Event

Given the response that PJM received during the spinning reserve event during the hot weather in September, as detailed in the operations section of the report, PJM has begun to look further into additional actions or controls that can be completed in order to avoid this type of situation in the future. As discussed in the details above, the event was very long in duration (not typical) and PJM received inaccurate estimates of Tier 1 synchronous reserves available. This event is analyzed in detail in the Operations section of this report. It is likely that the inaccurate, overstated Tier 1 estimates produced during this time period suppressed Primary and Synchronized Reserve Market Clearing prices in addition to LMPs.

As a result of the issues with this synchronized reserve event, PJM is reviewing the process for Tier 1 estimation as well as raising two issues in the stakeholder process. The findings from the above analysis recommend the following changes to Tier 1 estimation:

- Correct the tool that calculates Tier 1 reserves (Security Constrained Economic Dispatch) to use the lesser of Spin Maximum and Emergency Maximum in Tier 1 reserve calculation. A more conservative approach is to choose the lesser of Emergency Maximum, Spin Maximum, and Economic Maximum in the Tier 1 calculations.
- Conduct an assessment of historic synchronized reserve events to determine units that may be removed from Tier 1 reserve calculations based on the historical performance of those units.
- Remove generating units providing regulation service from the Tier 1 reserve calculations.
- Remove generating units that are on the sending end of a transmission constraint from the Tier 1 reserve calculations since increasing their output may aggravate the transmission constraint.
- Provide appropriate training to dispatchers to ensure manually dispatched units are properly flagged in Dispatch Management Tool so that Security Constrained Economic Dispatch does not include them in Tier 1 reserve calculations.
- Develop a consistent method of weighting the generator unit ramp rates based on past performance. This will ensure a more accurate prediction of generator ramp rates and thus a better input to the Tier 1 reserve calculation.
- Consider improving Security Constrained Economic Dispatch to recognize a synchronized reserve event so that SCED does not back down generating units during a synchronized reserve event.

PJM also plans to look at the following as another possible way to avoid this type of results in the future.

- Based on the minimum response provided during the Synchronized Reserve event, evaluate the current market structure for Tier 1 Synchronized Reserves to determine if the construct provides sufficient incentives to obtain Synchronized Reserves needed in real-time. Currently providing Tier 1 reserve is a voluntary decision by the generation owner. Higher bus prices alone may not be sufficient to move a generating unit to a higher output. For example, if the bus price is less than the marginal cost, the generating unit may not increase its output.

8.5.6 Market Outcome Implications of Demand Response Events in September

There are several drivers that influenced prices during the demand response events over the September 9-11 period. Currently, PJM Demand Response products are designated with a two-hour lead time. This requires operators to make a call early on that demand response will be needed and notify resources that will be required to help. Often the actual load is not as high as anticipated and the demand response reduction depresses the load further, putting downward pressure on price.

PJM is currently addressing the inflexibility of the demand response resources in the stakeholder process. PJM is discussing the lead time, reduction duration, and strike price for the emergency demand response events in the Capacity Senior Task Force. Specifically, to enhance the ability to use DR to control for transmission constraints, PJM will consider modifications to the load management programs such that PJM has the ability to request DR at a more granular level (i.e., nodal) and within a shorter time period (30 minutes).

There is also an item being discussed in the stakeholder process regarding the impact of deploying of Demand Response resources. When the Demand Response resources are deployed, they effectively add reserves to the system. The current reserve requirement, however, is not offset for these additional reserves, which tends to suppress the energy and reserve prices. This item is being addressed in the stakeholder process with the introduction of a problem statement. (The problem statement also addresses the interchange volatility issues discussed above.)

In addition, it may also be appropriate to increase the reserve requirement when there is low confidence in our estimates of available resources or when there are data quality issues. If the reserve requirement is not adjusted and the PJM operators believe there is a need to call on additional reserves, the operator action does not get reflected in prices. Adjusting the reserve requirement would align pricing with operator actions in order to both ensure reliability and price the market correctly for operator actions.

9 Appendices

9.1 Appendix A: Transmission Outage Analysis

Figure 43 shows a summary of the transmission outages for the PJM RTO for September 9 - 11, 2013. Outages are categorized as either planned, which are scheduled and studied prior to the equipment going out of service, or unplanned/forced, which can occur at any time as a result of equipment issues. The unplanned outages are noted below as forced outages and may have occurred prior to the operating day.

Over 80 transmission outages were cancelled or rescheduled for the period of September 9 to the 11.

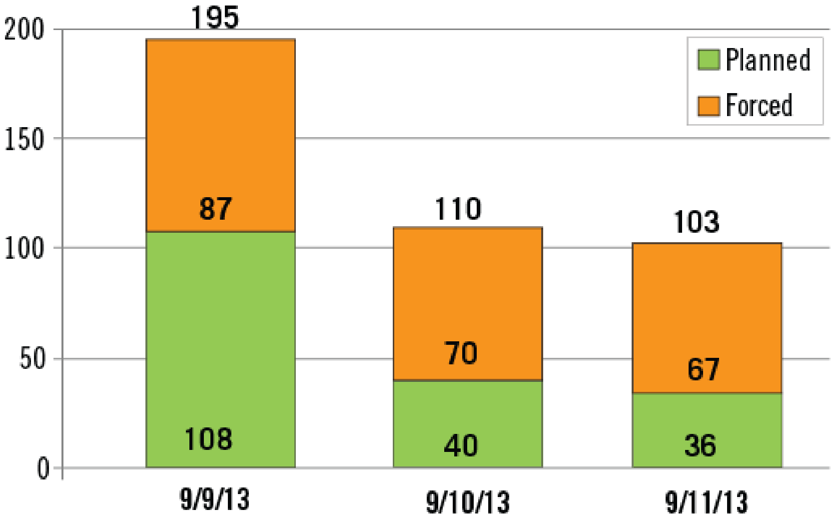

Figure 43. **Transmission Outages**

PJM's outage approval process depends on the load forecast. Improving the load forecast improve studies. The transmission outage process has demonstrated that, with accurate input data, future system conditions can be modeled accurately and can predict transmission issues caused by generator and transmission outages. The process of studying transmission outages starts at least six months prior to and continuing until the start of the outage. This process is comprehensive such that grid reliability is maintained during a single contingency, also referred to as an N-1 contingency, i.e. one event that takes one or more facilities out of service.

As part of PJM's technical analysis, the analysis team reviewed the reason for each of the transmission outages that were identified as contributing to the load-shed events to determine whether generator retirements resulting from compliance with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards, which limit emissions from power plants, was the reason for the transmission outage, which, then, may have affected the load shed events. Only the planned outage of the South Canton 765 kV/345 kV transformer and associated 345 kV bus was identified as a generator retirement driven outage. This outage was required to support an identified upgrade in the 2012 PJM Regional Expansion Transmission Plan (replace disconnect switch), which was needed prior to the retirement of the New Castle Units 3, 4 and 5 and diesels A and B. The post-event analysis determined that this outage contributed to less than 1 MW of the Tod area load shed event. Therefore, it can be concluded that the causes of these particular load shed events were more localized and transmission-based and cannot be attributed directly to generation or transmission outages or retirements resulting from MATS compliance.

9.2 Appendix B: Generation Outage and Retirement Analysis

Figure 44 shows a summary of the generation outages for the PJM RTO for September 9 - 11, 2013. Outages are categorized as either planned outages or maintenance outages, both of which are scheduled and studied prior to the equipment coming out of service, or unplanned outages (also known as forced outages), which can occur at any time as a result of equipment issues. The unplanned outages are noted in Figure 44 as Forced outages and may have occurred prior to the operating day. Outages listed as Planned in Figure 44 include both planned and maintenance outages.

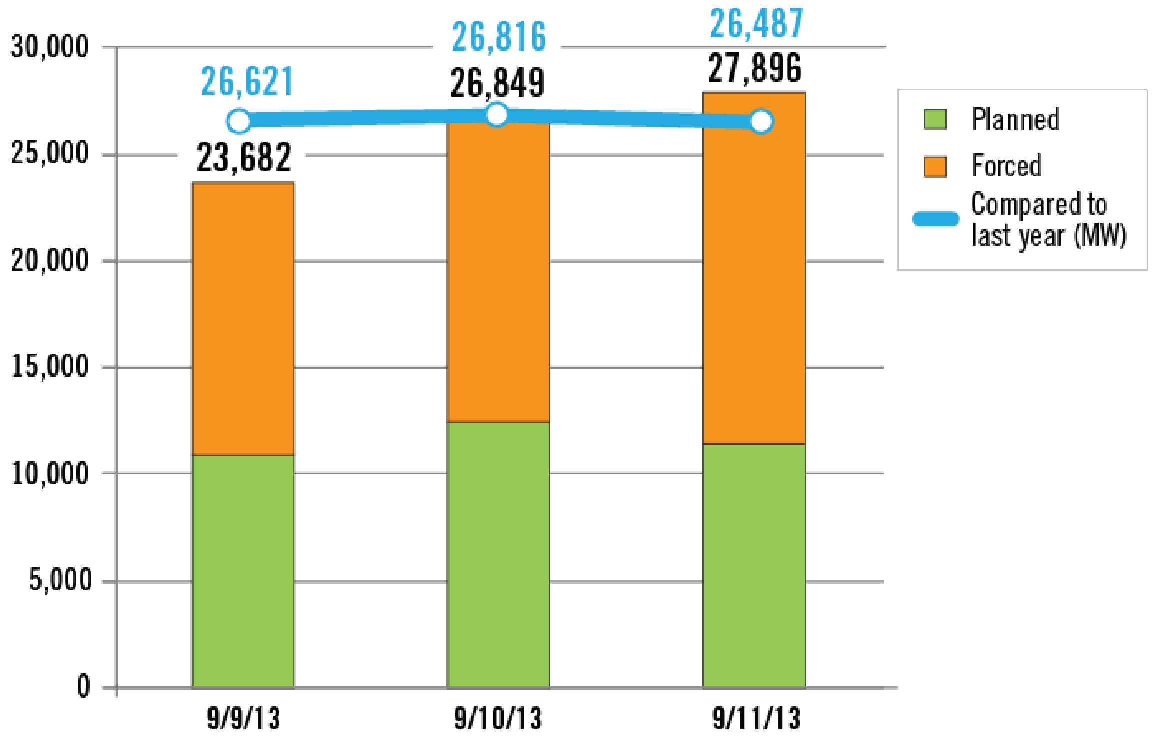

Figure 44. **Generation Outages**

A generator outage analysis was performed to determine the impact on the load shed areas if unavailable generation in the area had been available during the load shed events. To perform this study, a saved State Estimator case from the Energy Management System was loaded into study mode. A security analysis was then executed to determine the system constraints close to the time of the load shed events. The security analysis produced a list of post-contingency overloads that the PJM reliability engineers and master dispatchers evaluated in accordance with manuals M-03 and M-13. As other evaluations have concluded, reliability engineers and master dispatchers performed all studies as they were trained and in accordance with the manuals. Because they performed the studies correctly during real-time operations, this generator outage analysis examined only what, if any, effect the generating units out of service would have had on the load shed events if they had been available to Dispatch.

This study was performed twice: the first study determined the impact of all the generator outages (planned, maintenance and unplanned), and the second study determined the impact without the unplanned outages.

This generator outage analysis was performed by taking a list of generators that could be raised to help relieve the constraint and comparing it against those that were on an outage. The subset list of generators on outage that would have helped was then used to obtain the actual output at that time, maximum output of the unit, and the time it would take to dispatch the unit. The maximum minus the actual multiplied by the distribution factor ([max-actual]*dfax) was then used to determine the relief the unit would have had on the contingency. Table 23 shows the portion of megawatts on an outage that could have been available (disregarding startup times) and the megawatts that would have been available within an hour. The percent relief provided describes in percent of the total megawatts that were shed how much relief would have been provided within an hour.

Event	Total MW Shed	MW relief provided by raising generations given certain conditions:				
		All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
AEP Pigeon River 1 (Sept 9)	3.1	0.027	0.027	0.013	**0.013**	0.42%
AEP Pigeon River 2 (Sept 10)	8	0.027	0.027	0.013	**0.013**	0.16%
FE (ATSI) Tod	16	1.4478	0.357	1.4154	**0.0504**[33]	0.32%
FE (Penelec) Erie[34]	105	3.3603	2.0703	1.7954	**1.174**	1.12%
AEP Summit	25	7.8334	2.4176	4.615	**0.396**[35]	1.58%

Table 23. Summary of Generation on Outage MW Relief in Load Shedding Areas

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[33] 0.0504 MW of relief would be available in 1 hour and 2 minutes - this was considered part of the megawatts available within an hour.

[34] The study performed for the FirstEnergy (Penelec) Erie load shed event was performed differently due to the non-convergence. The identified planned and maintenance outage generation, which would have relieved the post-contingency constraint, was raised to its maximum output in the study. A power flow and security analysis was executed to see the post-contingency overload. An N-5 analysis would have been initiated due to the post contingency overload for the loss of the Erie West – Wayne 345 kV line. The case was still non-converging after the generation on outage was simulated to be online. The study shows that the generators on outage would not have alleviated the load shedding event.

[35] 0.357 MW of relief would have been available in 1 hour and 2 minutes - this was considered part of the megawatts available within an hour.

Table 24 presents the same data excluding the ambient air outage tickets since they limit the unit based on operating conditions:

Event	Total MW Shed	MW relief provided by raising generations given certain conditions:				
		All Outages - No timing requirements	All Outages Short Cold Start up Time (< 1 Hour)	Planned and Maintenance - No timing requirements	Planned and Maintenance - Short Cold Start up Time (< 1 Hour)	% of Relief provided
AEP Pigeon River 1 (Sept 9)	3.1	0.027	0.027	0.013	**0.013**	0.42%
AEP Pigeon River 2 (Sept 10)	8	0.027	0.027	0.013	**0.013**	0.16%
FE (ATSI) Tod	16	1.4478	0.357	1.3764	**0.0504**[27]	0.32%
FE (Penelec) Erie[28]	105	3.3603	2.0703	0.434	**0.056**	0.05%
AEP Summit	25	7.8334	2.4176	0.9768	**0.396**[29]	1.58%

Table 24. Generation on Outage Impact

From Table 23 and Table 24, if the planned and maintenance outage generation were available to Dispatch, it would have only minimally reduced the amount of the load shed, and it would not have prevented the event. The biggest percentage of help would have relieved Summit by 1.58 percent; however, given the generator's long start-up time, the event would have ended by the time the generator was available. The amount and location of all the generator outages (planned, maintenance and forced) were of little to no significance because the generators would not have alleviated the conditions which caused the load shedding events that occurred on September 9 or September 10.

Generators that were on unplanned outages should not be considered in this study since the generators were not available during the event

Recently Retired Generation

A study was performed to see the impact of retired generation with a retirement date after September 1, 2012, until the event occurred to determine if the retired generation would have impacted the load shed areas.

Table 25 presents the generators that retired after September 1, 2012, that would have impacted the load shedding events (if they had been running at full output).

Unit	Capacity	Transmission Zone	Actual Deactivation Date	Relief Pigeon (MW)	Relief Summit (MW)	Relief Tod (MW)
Bay Shore 2	138	ATSI	9/1/2012	0	2.622	0
Bay Shore 3	142	ATSI	9/1/2012	0	2.698	0
Bay Shore 4	215	ATSI	9/1/2012	0	4.085	0
Eastlake 4	240	ATSI	9/1/2012	0	0.96	3.6
Eastlake 5	597	ATSI	9/1/2012	0	1.791	8.955
			TOTAL Relief (MW)	**0**	**12.156**	**12.555**

Table 25. Retired Generation

The retired generation would have helped to alleviate the Summit and Tod load shedding areas. However, while it would have reduced the amount of load to shed, in both cases, the relief was not sufficient to eliminate the events.

Summary

The generation outage process has demonstrated that with, accurate input data, the future system conditions can be modeled accurately and can determine any overloads that need to be resolved prior to any outage. Generator owners typically want to submit planned or maintenance outage tickets, but there is always the possibility generator will need to submit a forced outage ticket.

The forced outage rate of a unit will affect the generator's capacity that it is able to be offered into the capacity market. With the input data provided for the generator studies, the results of the study are accurate and prepare the grid for an N-1 contingency event, i.e. one event that takes one or more facilities out of service. The study cannot predict which units will need to have a forced outage, but the N-1 contingency study is done to be proactive to protect system reliability. A pre-contingency load shed is always a possibility due to areas with little or no dispatchable generation, equipment failures and unseasonable weather. The cascading outage analysis was specifically added to support the decision of pre-contingency load shed in scenarios, where it formerly would not have been considered in order to prevent a cascading situation. This study will never be perfect since multiple real-time transmission and generation trips cannot be predicted. To improve the results of this study, would require better input data, which would mean more accurate forecasted data and assumptions of grid conditions.

PJM also has received a number of inquiries from the staff of the Federal Energy Regulatory Commission about whether generation outages resulting from compliance with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards had an impact on driving the particular local conditions that gave rise to these load shed events. The analysis shows these events were more localized and transmission-based and cannot be attributed directly to generation outages or retirements resulting from MATS compliance.

9.3 Appendix C: Approving and Scheduling Transmission Outages

In advance of an outage start date, PJM transmission owners are required to submit outage requests to PJM via eDART for all outages of reportable transmission facilities. PJM Manual 3: Transmission Operations, Section 4, Reportable Transmission Facility Outages[36], presents the PJM transmission outage submittal, coordination and approval process. PJM staff analyzes submitted outages to ensure outages do not violate PJM reliability criteria and market rules.

Beginning approximately six months and continuing to just prior to the start time of the scheduled transmission outage, PJM performs transmission outage peak studies, which include a thermal and AC voltage analysis for all transmission and generation outages included in the study period[37]. Among the many studies performed, PJM runs power flow and security analysis for any thermal, voltage, System Operating Limit, or Interconnection Reliability Operating Limit impacts arising from the outages and projected conditions. PJM resolves any identified issues by implementing non-cost operations (such as system reconfiguration) followed by adjusting generation. If outage conflicts still exist, PJM works with transmission owners to resolve the conflict, potentially denying the outage based on PJM market rules and reliability concerns.[38]

PJM's normal timeline for performing transmission outage peak studies are as follows, with each study increasing in accuracy in relation to real-time as variables reduce in volatility (such as online generation and emergency generation/transmission outages):

- **Six months and one month prior to outage start date –** The six and one month studies are used to identify high-level conflicting issues (i.e. simultaneous outages that cannot occur at the same time). Issues are noted on the respective eDART outage ticket. The results of these studies are preliminary in nature and subject to change due to uncertainties with long-range temperature forecasts, loads, topology and generation patterns.
- **Three days prior to outage start date –** The three-day-out study begins looking at the transmission and generation outages with more accurate load forecasts and system conditions. These studies are run as a precursor or filter towards the two-day-out approval process. This study details how each outage will affect transmission thermal and voltage constraints and the reactive interfaces. Any issues are noted on the outage eDART ticket. The transmission owners are notified for any potential issues affecting their scheduled transmission outages.
- **Two days prior to outage start date –** The two-day-out study process is again looking at transmission and generation outages with updated load forecast and system conditions. Transmission outage requests are officially approved, denied/canceled or rescheduled by 1400. Any issues are noted on the eDART ticket and on the daily transmission log.
- **One day prior to outage (called the "day-ahead study") –** Two studies are performed, and they both follow the same procedure as the two- and three-day-out studies. Again, any issues are noted on the eDART ticket and the daily transmission log.
    1. The first study (called Reliability Coordinator Analysis) is completed prior to 1200, so the approved transmission outages are used as an input to the Day-Ahead Market. The next-day reliability analysis ensures there a comprehensive operating plan is developed that meets all the reliability

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[36] PJM Manual 3: Transmission Operations, Section 4, Reportable Transmission Facility Outages

[37] PJM Manual 38: Attachment B: Transmission Reliability Analysis Procedure

[38] PJM Manual 38: Operations Planning Attachment B Transmission Reliability Analysis

requirements and provides for a level of certainty in facility availability. This analysis considers the latest available information regarding transmission and generation outages, and system topology. The daily transmission log is sent to all PJM transmission owners and neighboring reliability coordinators.[39] The PJM transmission owners and neighboring reliability coordinators work with PJM to coordinate transmission outages and establish mitigation strategies.

2. The second study (called 2 Pass or "2nd Pass") is performed after the Day-Ahead Market generation commitment has completed at approximately 1600. This study uses the actual generation committed by the Day-Ahead Market. It is mainly used to determine if additional out-of-merit generation is required for reliability. Any additional issues are noted on the eDART tickets and the daily transmission log. The daily transmission log is distributed to all PJM dispatchers to be used as a guide during the operating day.

- **30 minutes prior to an outage** – A study is performed 30 minutes prior to any transmission facility being removed from service.

Note: Studies beginning on a Monday are also looked at four days in advance, since a large number of outages begin on Mondays.

9.4 Appendix D: Approving and Scheduling Generation Outages

The beginning of September marks the start of the fall outage season. This is typically a lighter-load period; therefore, more generators and transmission facilities are taken out of service for routine maintenance. After a generator owner submits an outage ticket in eDART, PJM analyzes the impact of the outage on the RTO. PJM may have to direct the generation owner to make adjustments to the outage ticket as required for ensuring system reliability and compliance with market rules. Part of the generator analysis is to provide better outage coordination to avoid conflicting outages and align generator and transmission outages.

A generator submits an outage request in eDART when a generator needs to reduce its available output or to shut down. eDART allows transmission and generation owners to exchange operations and outage planning data. A generator ticket is automatically evaluated by the eDART application for approval or denial. Outage tickets may be submitted up to three years prior the start of the outage. As per PJM Manual 10, Pre-Scheduling Operations[40], section 2.1 states, PJM does not "schedule" when outages should take place. PJM Manual 38, Operation Planning, section 2.1 states, PJM staff are required to analyze submitted outages to ensure outages do not violate PJM reliability criteria and market rules. PJM's responsibility is only to accept or reject the request for outages, and PJM rejects the outage if a violation occurs while PJM members are responsible for determining the best time to schedule the outage.

When a generation ticket is submitted, it is automatically validated for timing requirements, black start violations, maintenance margin and reserve requirements. These requirements will be checked regardless of when the outage is submitted or the start date of the outage. The timing requirement checks to ensure it was submitted on time for the type of outage being requested, and the outage is not during the peak period maintenance. The peak period

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[39] PJM Manual 38: Operations Planning, Section 3 Next Day Reliability Analysis

[40] PJM Manual 10, Pre-Scheduling Operations

maintenance is defined as the weeks containing the 24th through 36th Wednesdays of the calendar year with each week beginning on a Monday (typically correlating to the summer period or, for the 2013 calendar year, June 9 until September 7). After it passes the timing requirements, eDART verifies that no more than one critical black start unit has a planned outage per station. The ticket is checked to ensure there is enough maintenance margin and reserve requirements are met after the unit is on an outage. The reserves requirements change in the winter due to generators not being able to start or respond as quickly due to the cold weather.

Outages are reviewed by the PJM Generation Department and reviewed by Reliability Engineering. Reliability engineers have a four-day outlook for outages starting on Monday and for every day there is a three-day, two-day, and day-ahead lookout to determine if there are major constraints on the system due to the submitted outages. If any constraints are found, the reliability engineers attempt to mitigate the problem prior to the outage starting. If a constraint cannot be resolved, they investigate cancelling outages or rescheduling them to a different time for better coordination and to maintain grid reliability.

There are three different types of generator outages:

1. **Planned Outage**: A planned outage must be submitted no later than 30 days prior to the start outage to be considered on time. PJM may withdrawal an approved planned outage, only if it violates reserve requirements or poses a challenge to the reliability of the RTO or transmission zone. The outage may be withdrawn as long as it is at least 24 hours in advance of the start of the outage.

2. **Maintenance Outage**: Maintenance outages must be submitted at least three days prior to the unit coming offline, but PJM may defer the outage to beyond the next weekend. During the peak period maintenance, a maintenance outage may only be nine days long, spanning at most five business days. Outside of the peak period maintenance, there are no limitations on the duration of the outage.

3. **Unplanned (Forced) Outage:** There are no submittal rules for forced outages since they typically are for emergencies. Even if PJM denies an outage, a unit can still take a forced outage. If generators have many forced outages, they will decrease the unit's capacity for the capacity market. Once a generator falls below the capacity the owner said it could supply, it will need to find another generator capable of supplying the additional megawatts and pay for the capacity to meet obligations.

Several areas need to be examined to understand a generation owner's perspective on outage scheduling. It takes a certain amount of time for a unit to start up and/or to ramp to an operating point as it is dispatched to raise or lower output. For example, a nuclear unit takes multiple days to go from a cold shutdown to full output. If an offline nuclear plant is needed in an hour and it is in cold shutdown, the unit will not able to produce the requested amount. Second, when larger units are preparing for planned outages, additional workers may be hired to assist during the outage. It is not cost effective for the generator owner to push the outage start date out while the additional labor is on site. Lastly, if PJM requests an outaged unit (fully or partially outaged) to startup or raise its output, it could potentially degrade plant equipment further. Operating the equipment to failure could force the unit to come offline and may cause more severe problems to the plant. Generator owners may not be willing to risk permanent equipment failure when it could have been fixed with maintenance instead of a full equipment replacement. Outages are necessary for plants to perform maintenance to the plant systems in order to repair, refurbish, replace or upgrade equipment so they are able to produce the power.

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[i] http://www.pjm.com/~/media/documents/reports/20130923-initial-analysis-of-operational-events-during-the-september-2013-heat-wave.ashx