Texas Reliability Entity, Inc.
Event Analysis

Event:
October 8, 2014
Lower Rio Grande Valley Load Shed
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Executive Summary

On October 8, 2014 at 15:51, three (3) units at the North Edinburg Generating Station tripped causing the loss of 660 Megawatts (MW) of generation in the Lower Rio Grande Valley (Valley) area. These trips, combined with the existing planned generation outages and the high load due to the high temperatures in the area, created a condition where System Operating Limits (SOLs) were exceeded. System operators constantly monitor the status of the electric grid and take steps to maintain system reliability if unexpected failures or outages, referred to as "contingencies", occur to system components, such as generators and transmission lines. In order to prevent voltage instability or undervoltage load shed if another next contingency occurred, manual load shed actions were initiated to reduce the transmission system load levels below the SOLs. Although the Valley area has Under Voltage Load Shedding (UVLS) relays in place to prevent voltage instability, the system operators took manual control actions immediately to shed load instead of waiting for the next contingency to initiate these relays. This decision had the added benefit of keeping the UVLS system intact and available to respond to protect the system in case additional contingencies occurred. Electric Reliability Council of Texas, Inc. (ERCOT), acting as the Balancing Authority (BA) and Reliability Coordinator (RC) for the ERCOT Region, worked with other Transmission Operators (TOPs) to initiate mitigation actions to shed firm load. A peak of 200 MW of firm load was instructed to be shed until generation could be brought back on-line, but 725 MW of firm load was actually shed.

The event of October 8, 2014 represented a known case of a large load pocket with geographically-restricted generation availability as well as a Generic Transmission Constraint (GTC), called the Valley Import GTC, which limits the amount of power that can be imported into the Valley area from other geographic areas of ERCOT. Contingencies in the Valley area are well known and pre-planned mitigation measures are in place when extreme contingencies occur. The October 8, 2014 event was similar to the Valley area event on February 3, 2011 when the Frontera generation plant tripped while the North Edinburg plant was on a scheduled outage, which precipitated firm load shed of 400 MW in the Valley area.

This report provides: (1) an overview of the event; (2) background on system conditions just prior to the event; (3) the detailed sequence of events; (4) an analysis of the causal and contributing factors for concerns that arose in this event; and (5) recommendations for follow-up action. Long-term strategies for introducing more generation or transmission solutions for the known challenges in the Valley area are outside the scope of this report.

Observations and conclusions pertaining to the period of October 8, 2014 are:
(1) Combined cycle generation contingencies used in Real-Time Contingency Analysis and outage coordination: Prior to the event, the loss of the entire North Edinburg generation plant was not considered as a credible single contingency in Real-time
Contingency Analysis (RTCA) or State Estimator. This was based on information provided by the generator owner related to the design of the plant. However, during the event, North Edinburg combustion turbines G1 and G2 were lost after the loss of the G3 steam turbine unit. The plant owner indicated that the loss of the G1 and G2 units following the loss of the G3 steam turbine was not by design, i.e., that the plant was designed to keep the combustion turbines on-line during a full steam turbine generator load rejection. The combustion turbine control logic in place during the event triggered the combustion turbines to completely unload when transition/cooling steam was 30% below required for more than five seconds. This logic was reviewed by plant engineers and the Original Equipment Manufacturer (OEM), and it has been updated such that combustion turbines will not completely unload in similar conditions, but rather they will run back at a slower rate until steam flow is recovered.

(2) Operator actions: After the loss of the North Edinburg generation plant, ERCOT operators had one base-case and multiple post-contingency thermal overload conditions to mitigate. The possible courses of action were reviewed, up to and including the decision to shed firm load, and were consistent with the ERCOT Protocols, Operating Guides, and ERCOT desk procedures. An operator error was noted with American Electric Power (AEP) during the event. Upon receiving the load shed instruction from ERCOT, AEP operators selected an incorrect load shed cycle button on their Energy Management System (EMS), which ultimately led to shedding 680 MW of load, rather than the 134 MW of load instructed by ERCOT. The impact of this action was that more than 150,000 customers unnecessarily lost power for approximately 10 minutes, voltages in the immediate area momentarily spiked above normal operating ranges, and system frequency momentarily peaked at 60.13 Hz. AEP has since removed the load shed cycle button from its EMS.

(3) Generation outage scheduling: Another large generation plant and the Railroad DC tie were on outages when the North Edinburg unit trips occurred. This had the effect of limiting the availability of local sources of both real and reactive power in an area with already limited resources. In addition, the additional generation plant and DC tie outages occurred when the Valley area was experiencing higher than normal load for a shoulder month. The load in the Valley reached a peak of 2067 MW on the day of this event which approached the all-time summer peak of 2241 MW set for the area in 2010.

(4) Valley area mitigation plans: Because of the transmission and generation limitations in the Valley area, mitigation plans were created for the Valley area prior to this load shed event. One of the mitigation plans called for load to be shed after losing either of the two 345 kV transmission lines that imports power into the Valley area. The other mitigation plan called for load to be shed after losing the largest Valley generation facility, North Edinburg. These mitigation plans provided the basis for the load shed actions taken by ERCOT and Transmission Operators. In addition, due to the La Palma – Rio Hondo 345 kV line outage which was in progress at the time of the event, a Temporary Outage Action Plan (TOAP) was in place in the Valley area for the loss of the La Palma – Rio Hondo 138 kV circuit.

(5) Generic Transmission Limit (GTL) and System Operating Limits (SOLs): The Valley Import GTC is made up of multiple transmission lines which as a group have an
associated limit called a GTL. ERCOT managed the flows on the transmission lines that form the Valley Import GTC well, because no base-case or post-contingency exceedances of the associated GTL were noted during the event. However, following the loss of the North Edinburg units and prior to the load shed, there was one base-case and other post-contingency thermal SOL exceedances for up to one hour on other transmission lines in the Valley area. In some cases, the post-contingency calculated flows were as high as 176% of the emergency rating and 15-minute rating of the transmission line. After the load shed, post-contingency SOL exceedances up to 120% were noted until approximately 17:53, or approximately two hours after the start of the event. It was noted that ERCOT staff considered ordering more than 200 MW of load shed, but ultimately decided to limit it to 200 MW. This amount of load shed was determined to be sufficient to result in a situation in which additional load shed could be ordered, if necessary, so that cascading outages would not occur.

(6) Protection system performance: Disturbance monitor records do not show any type of fault or disturbance prior to the trip of North Edinburg G3. The plant owner investigated the cause of the North Edinburg G3 transformer trip and determined that the cause of the G3 transformer trip was due to operation of one of the mechanical pressure relief devices on the transformer. The pressure relief device operated due to a defective bladder bag on the transformer, which allowed oil to leak from the conservator into the air cell.

(7) Long-term transmission plan for Valley area: The anticipated completion date for the Cross Valley project, which will add additional transmission capacity into the area, is in 2016. Until this project is completed, the Valley area remains at risk for similar load shed events. ERCOT has an understanding with Frontera to commit a portion of the plant generation capacity for the ERCOT region until 2016. In addition, there are multiple wind and gas units that have generation interconnect agreements in place, or are under review for a full interconnect study by request of the developers. The projected commercial operation dates as specified by the resource developers are from June 2015 to June of 2017.

(8) Communications: With two mitigation plans and one TOAP in place at the time of the event, Texas RE noted some minor confusion and questions on several voice recordings on the part of Transmission Operators regarding which plan was being executed.

Recommendations pertaining to the period of October 8, 2014 are:

(1) ERCOT should review the contingency definitions not only for the North Edinburg plant, but other combined cycle plants as well, to determine if the credible single contingency definitions used in RTCA and State Estimator are correct.

(2) ERCOT should review its generation outage approval process, especially for areas such as the Valley with geographically-restricted generation.
   a. Consideration should be given for combined cycle units to only allow one gas turbine outage at a time, rather than the entire train, and to minimize the amount of time that an entire plant is off-line.
   b. Consideration should be given for areas that have limited resources and are expected to experience relatively high loads during shoulder months.
(3) ERCOT should review the method used to determine the amount of load to shed during this event in light of the fact that several post-contingency SOL exceedances up to 120% remained for up to an hour after the load shed was implemented.

(4) ERCOT should work with affected Transmission and Generation Entities to develop a comprehensive plan for the Valley area to accommodate the Cross Valley project construction, planned generation outages, and ongoing maintenance while minimizing the load shed risk to the area until the completion of the Cross Valley project in 2016.

(5) ERCOT and Transmission Operators should work together to ensure the utmost clarity when giving and receiving instructions related to the Valley mitigation plans. ERCOT should review all communications procedures and policies related to transmission emergencies with appropriate entities for possible improvements. ERCOT Operators should place special emphasis when giving verbal dispatch instructions to ensure that the directive is clear and understandable.

(6) Additional training and sharing of lessons learned from the load shed may be warranted due to the AEP operator error during the implementation of the load shed.

I. Event Overview

On October 8, 2014 at approximately 15:50, the loss of a combined cycle generation plant combined with other scheduled generation outages, caused one base-case and multiple post-contingency overloads in the Lower Rio Grande Valley (Valley) area.

There are multiple independent power producers (IPPs) located in the Valley area with a capacity of more than 2385 MW. American Electric Power Texas Central Company (AEP), BPUB, Sharyland Utilities (Sharyland), and South Texas Electric Corporative (STEC) are Transmission Owners (TOs) and Transmission Operators (TOPs) in the Valley serving load to customers on the AEP, Magic Valley Electric Cooperative (MVEC), BPUB, and Sharyland distribution systems.

On October 8, 2014, the Valley load reached a peak of 2067 MW which was a relatively high load for a shoulder month. The all-time winter peak is 2734 MW which occurred February 2011, and the all-time summer peak is 2241 MW which occurred in 2010.

The Valley area is supported almost entirely by two 345 kV transmission lines from the Corpus Christi area and by three 138 kV transmission lines. The transmission map for the Valley area is shown in Figure 1.
ERCOT manages the Valley area transmission with a Generic Transmission Constraint (GTC), called the Valley Import Constraint. The Valley Import Constraint protects the Valley from issues due to the loss of one of the 345 kV lines – Ajo to Rio Hondo along the coast or Lon Hill to North Edinburg farther inland. At high Valley import levels, loss of one of the 345 kV lines could cause thermal overloads of the remaining 138 kV lines, voltage stability issues, or phase angle stability issues for generation in the Valley. During normal system conditions, the power flow into the Valley from other geographic areas of ERCOT is constrained to the hourly GTLs that are posted on the ERCOT Market Information System (MIS). These are conservative operations limits based upon day-ahead studies from thermal and voltage stability analysis. Additional detail on the Valley Import Constraint can be found in Section IV.

For the purposes of this report, the event began when the North Edinburg G3 steam turbine tripped offline on October 8, 2014 at 15:50:32, loaded at 244 MW. North Edinburg G1 ran back from 209 MW and tripped offline one minute later at 15:51:32, loaded at 204 MW. North Edinburg G2 ran back from 208 MW and tripped at 15:51:36, loaded at 204 MW. The sum of generation lost was 661 MW within one minute. This comprised approximately 38% of the generation capacity in the Valley at that time. System frequency dropped to 59.864 Hz and recovered within six minutes.
Two other generation plants in the Valley area, Duke CC1 (also known as Hidalgo) and Silas Ray Unit 5, were on scheduled outages on October 8, 2014. When the three (3) North Edinburg generation units tripped, the import level increased to 1395 MW at its peak, which approached, but did not exceed the Valley Import GTL for the operating hour. The 345 kV bus voltages at North Edinburg dropped momentarily to 335 kV (0.97 per unit).

Immediately following the loss of the North Edinburg plant, ERCOT system assessment tools indicated multiple post-contingency overloads if another contingency were to occur. At 16:19, a base-case overload on one 138 kV line also appeared. After studying multiple options, ERCOT reached the decision that the only option available was to shed 200 MW of firm load to relieve the base-case overload as well as post-contingency overloads.

ERCOT had previously developed two mitigation plans with AEP, STEC, and BPUB which predetermined the load allocation of any necessary manual load shed actions for the Valley import contingency loss of one of the 345 kV transmission lines, or for the loss of the North Edinburg generation plant. ERCOT had also developed a TOAP for the planned outage of the Rio Hondo – La Palma 345 kV line due to possible overloads if additional 138 kV line contingencies were to occur.

ERCOT Operators used the mitigation steps of the Valley mitigation plans and instructed AEP, STEC and BPUB to shed their share of 200 MW of load at 16:51. AEP, STEC and BPUB completed their share of the load shed by 17:04.

During the load shed period, approximately 216,000 separate customers were affected. Some customers had their service interrupted twice. The peak firm load shed during the rolling blackouts was approximately 725 MW.

<table>
<thead>
<tr>
<th>Entity</th>
<th>Customers Affected</th>
<th>Obligation</th>
<th>Firm Load Shed</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>191,344</td>
<td>66%</td>
<td>677.9 MW maximum</td>
</tr>
<tr>
<td>BPUB</td>
<td>12,738</td>
<td>13%</td>
<td>37.6 MW maximum</td>
</tr>
<tr>
<td>STEC</td>
<td>12,276</td>
<td>20%</td>
<td>40.4 MW maximum</td>
</tr>
</tbody>
</table>

Table 1: Customer Impact from Firm Load Shed

An automatic undervoltage load shed (UVLS) scheme is in place for the Valley area. During the period following the loss of the North Edinburg generation at 15:51 until the area was stabilized at approximately 19:15, if either of the 345 kV transmission lines into the Valley had been lost or if another major generation facility in the Valley had tripped, the UVLS scheme could possibly have activated to help prevent uncontrolled loss of load and outages in the Valley area.

The event met the criteria for Department of Energy (DOE) OE-417 reporting and North American Electric Reliability Corporation (NERC) Event Reporting under NERC
Reliability Standard EOP-004-2 due to the shedding of firm load of 100 MW and the public appeals to reduce the use of electricity for purpose of maintaining the continuity of the electric power system. The event met the definition of a Category 2f reportable event under NERC’s Event Analysis process for unintended loss of 300 MW or more of firm load for more than 15 minutes.

II. Initial System Conditions Prior to Event

*Initial system conditions just before the event at October 8, 2014 15:00 were:*  

<table>
<thead>
<tr>
<th>Active Forecast Pk HR Demand:</th>
<th>55,488 MW @ 1700 HR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual load at time of North Edinburg trip:</td>
<td>54,346 MW @ 15:51</td>
</tr>
<tr>
<td>Available Generation for Pk HR Demand:</td>
<td>57,249 MW @ 1700 HR</td>
</tr>
<tr>
<td>Load Shed Risk:</td>
<td>Low @ 1500 HR</td>
</tr>
<tr>
<td>Valley Net Generation:</td>
<td>1332 MW @ 1500 HR</td>
</tr>
<tr>
<td>Railroad DC Tie Flows:</td>
<td>0 MW @ 1500 HR</td>
</tr>
<tr>
<td>Valley Area System Load:</td>
<td>2020 MW @ 1500 HR</td>
</tr>
</tbody>
</table>

*Weather in the major cities around the ERCOT Region just before the event:*

<table>
<thead>
<tr>
<th>City</th>
<th>Temp (F), High/Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austin</td>
<td>92/68</td>
</tr>
<tr>
<td>Brownsville</td>
<td>89/74</td>
</tr>
<tr>
<td>Corpus Christi</td>
<td>90/72</td>
</tr>
<tr>
<td>Dallas</td>
<td>91/74</td>
</tr>
<tr>
<td>Houston</td>
<td>87/70</td>
</tr>
<tr>
<td>Midland/Odessa</td>
<td>92/64</td>
</tr>
<tr>
<td>San Antonio</td>
<td>94/75</td>
</tr>
</tbody>
</table>

III. Sequence of Events for October 4-9, 2014

**October 4, 2014**

- Railroad DC Tie has forced outage starting at midnight until Saturday October 11, 2014 (per ERCOT Operations Message posted on www.ercot.com)

**October 6, 2014**

- 15:00 North Edinburg CC1 planned outage completed

**October 7, 2014**
• 23:57  Duke CC1 maintenance outage begins due to vibration issues
• Railroad DC Tie outage cancelled at 07:20:29 (per ERCOT Operations Message)

October 8, 2014

• 05:06  North Edinburg plant operator requests and receives approval from AEP for low load reactive testing at North Edinburg
• 09:30  North Edinburg plant operator completes low load reactive testing at North Edinburg
• 09:50  North Edinburg plant operator requests and receives approval from AEP for Power System Stabilizer (PSS) testing at North Edinburg
• 12:30  North Edinburg plant operator requests and receives approval from AEP for HSL load reactive testing at North Edinburg
• 14:45  AEP contacts North Edinburg plant operator to request them stop reactive testing at North Edinburg at 15:00
• 15:50  North Edinburg G3 trips (244 MW)
• 15:51  North Edinburg G1 trips (205 MW) and G2 trips (208 MW)
• 15:54  Valley Interface flow temporarily reaches 1395 MW
• 15:56:30  ERCOT frequency recovers to 60 Hz following trip of North Edinburg units
• 15:57  ERCOT activates DLONOR58_S104A constraint for the double circuit loss of the Lon Hill – Orange Grove 138kV / North Edinburg 345kV line due to post contingency overload of Rio Hondo – MV Burns 138 kV line at 166% of its two hour rating.  Wind units in Valley back down.
• 16:00  ERCOT releases SLA_RIO8 constraint to allow additional wind generation in the Valley
• 16:01  ERCOT instructs QSE to increase bus voltage at a Valley area generation resource to 143.5 kV
• 16:04  ERCOT instructs QSE to increase bus voltage at a Valley area generation resource to 143 kV-143.5 kV
• 16:07 ERCOT instructs QSE to take units off test status and move all units to HSL and give maximum voltage support

• 16:07 ERCOT releases DLO NR58_S104A constraint to maximize wind output and allow additional reactive support

• 16:08 ERCOT issues Emergency Transmission Notice due to forced outages in the lower Rio Grande Valley

• 16:09 ERCOT Hot-line call to Transmission Operators to issue a Transmission Emergency for the Rio Grande Valley due to loss of generation. Possible deployment of Load Resources, curtailment of DC-Tie exports to CFE, request for emergency energy and Valley area load shed

• 16:14 ERCOT reviews mitigation plan steps with STEC

• 16:16 ERCOT Hot-line call to QSEs to notify them that ERCOT has declared a transmission emergency due to low voltage in the Rio Grande Valley

• 16:19 Rio Hondo – MV Burns 138 kV line exceeds continuous rating

• 16:23 ERCOT reviews mitigation plan steps with AEP

• 16:39 ERCOT is notified by Sharyland that Railroad DC tie can be put back into service. Sharyland begins to prepare DC tie for service.

• 16:40 ERCOT reviews mitigation plan steps with BPUB

• 16:48 Sharyland advised that CFE has agreed to supply 50 MW of emergency power into ERCOT

• 16:47-16:49 ERCOT issues instructions to AEP, BPUB, and STEC for firm load shed of 200 MW per Valley mitigation plan

• 16:53 Rio Hondo – MV Burns 138 kV line flow reduced below continuous rating

• 16:55 ERCOT issues Operations Message for load shed in Valley

• 17:18 50 MW of emergency power procured across Railroad DC tie

• 17:21 North Edinburg G1 returns on-line at reduced output

• 17:55 ERCOT instructs AEP to open CBs 2070 & 2075 at Weslaco SS to sectionalize Rio Hondo – MV Burns 138 kV line
17:58-18:00 ERCOT issues instructions to AEP, BPUB, and STEC to restore their share of 100 MW of load

18:07 AEP re-energizes Azteca – South Edinburg 138 kV line (Outage recalled by ERCOT)

18:09 BPUB reports that they have restored their share of 100 MW (14.5 MW)

18:10 90 MW of emergency power procured across Railroad DC tie

18:16 STEC reports that they have restored their share of 100 MW (18.7 MW)

18:15-18:17 ERCOT issues instructions to AEP, BPUB, and STEC to restore the remaining 100 MW of load

18:21 BPUB reports that they have restored their share of 100 MW (13 MW)

18:23 AEP reports that they have restored their share of 200 MW (134 MW)

18:29 STEC reports that they have restored their share of 100 MW (43.1 MW)

19:12 ERCOT Hot-line call to TOs to cancel Transmission Emergency for the Rio Grande Valley

19:15 Emergency power across Railroad DC tie ramped down to 0 MW

19:20 ERCOT Hot-line call to QSEs to cancel Transmission Emergency for the Rio Grande Valley

19:40 AEP re-energizes Laureles – Port Isabel 138 kV line (Outage recalled by ERCOT)

20:41 Duke GT2 on-line

22:49 Duke ST1 on-line

October 9, 2014

01:54 Duke GT1 on-line

06:33 Ajo – Rio Hondo 345 kV line trips

06:45 ERCOT contacts Sharyland to request emergency assistance from CFE across the Railroad DC tie
- 06:49 ERCOT contacts Silas 6, 9, and 10 to determine on-line status. Estimated time 45 minutes

- 06:49 ERCOT contacts North Edinburg plant operator for status of North Edinburg GT2 on-line. Estimated time 2 hours

- 06:49 ERCOT Hot-line call to TOs to issue Transmission Emergency for the Rio Grande Valley

- 06:54 ERCOT Hot-line call to QSEs to issue Transmission Emergency for the Rio Grande Valley

- 06:55 ERCOT instructs QSE to take Valley area generation units to HSL

- 07:39 ERCOT instructs QSE for Valley area generation units to come on-line

- 09:16 Ajo – Rio Hondo 345 kV line back in service

- 09:39 ERCOT advises Sharyland to cancel emergency assistance from CFE across the Railroad DC tie

- 09:42 ERCOT Hot-line call to TOs to cancel Transmission Emergency for the Rio Grande Valley

- 09:44 ERCOT Hot-line call to QSEs to cancel Transmission Emergency for the Rio Grande Valley
Overview – 10/8/2014 15:50
Pre North Edinburg Trip

Overview – 10/8/2014 15:55
Post North Edinburg Trip
Overview – 10/8/2014 16:50
Pre Load Shed

<table>
<thead>
<tr>
<th>#</th>
<th>Plant</th>
<th>Flow (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Frontera</td>
<td>484</td>
</tr>
<tr>
<td>2</td>
<td>North Edin</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>Duke</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>Silas Ray</td>
<td>97</td>
</tr>
<tr>
<td>5</td>
<td>Los Vientos</td>
<td>216</td>
</tr>
<tr>
<td>6</td>
<td>Redfish</td>
<td>167</td>
</tr>
<tr>
<td>7</td>
<td>Railroad DC Tie</td>
<td>0</td>
</tr>
</tbody>
</table>

Valley Interface

Overview – 10/8/2014 17:00
Post Load Shed

<table>
<thead>
<tr>
<th>#</th>
<th>Plant</th>
<th>Flow (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Frontera</td>
<td>484</td>
</tr>
<tr>
<td>2</td>
<td>North Edin</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>Duke</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>Silas Ray</td>
<td>97</td>
</tr>
<tr>
<td>5</td>
<td>Los Vientos</td>
<td>225</td>
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<tr>
<td>6</td>
<td>Redfish</td>
<td>159</td>
</tr>
<tr>
<td>7</td>
<td>Railroad DC Tie</td>
<td>0</td>
</tr>
</tbody>
</table>

Valley Interface
Overview – 10/8/2014 18:00
Recovery In Progress

Overview – 10/8/2014 19:00
Recovery Complete

Figure 2: Event Timeline – October 8, 2014
IV. Analysis of Event

A. Generation Analysis

The Valley area is supported by approximately 2386 MW (Fall seasonal maximum MW rating) of local generation. The following table details the resource capacity data for the generation located in the Valley.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Seasonal (Fall) Max MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frontera G1</td>
<td>170</td>
</tr>
<tr>
<td>Frontera G2</td>
<td>170</td>
</tr>
<tr>
<td>Frontera G3</td>
<td>184</td>
</tr>
<tr>
<td>Duke (Hidalgo) GT1</td>
<td>145</td>
</tr>
<tr>
<td>Duke (Hidalgo) GT2</td>
<td>145</td>
</tr>
<tr>
<td>Duke (Hidalgo) ST1</td>
<td>173</td>
</tr>
<tr>
<td>North Edinburg G1</td>
<td>212.5</td>
</tr>
<tr>
<td>North Edinburg G2</td>
<td>212.5</td>
</tr>
<tr>
<td>North Edinburg G3</td>
<td>254.9</td>
</tr>
<tr>
<td>Silas Ray 10</td>
<td>46</td>
</tr>
<tr>
<td>Silas Ray 5</td>
<td>10</td>
</tr>
<tr>
<td>Silas Ray 6</td>
<td>20</td>
</tr>
<tr>
<td>Silas Ray 9</td>
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<tr>
<td>Los Vientos LV1A</td>
<td>200.1</td>
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<tr>
<td>Los Vientos LV1B</td>
<td>201.6</td>
</tr>
<tr>
<td>Redfish MV1A</td>
<td>99.8</td>
</tr>
<tr>
<td>Redfish MV1B</td>
<td>103.5</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>2385.9</td>
</tr>
</tbody>
</table>

Table 2: Lower Rio Grande Valley Generation Resources

The following table lists planned generation outages in the Valley area immediately prior to or during this event. Approximately 473 MW of seasonal capacity was unavailable due to these planned outages prior to the trip of the North Edinburg unit.

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Outage Time</th>
<th>Restore Time</th>
<th>Cause</th>
</tr>
</thead>
<tbody>
<tr>
<td>Silas Ray unit 5</td>
<td>7/1/2014 23:56</td>
<td>12/31/2014</td>
<td>Mothballed</td>
</tr>
<tr>
<td>Duke GT1</td>
<td>10/7/2014 23:56</td>
<td>10/9/2014 01:52</td>
<td>Maintenance outage</td>
</tr>
<tr>
<td>Duke ST1</td>
<td>10/7/2014 23:56</td>
<td>10/9/2014 01:52</td>
<td>Maintenance outage</td>
</tr>
</tbody>
</table>

Table 3: Lower Rio Grande Valley Scheduled Generation Outages, October 8, 2014

The North Edinburg generation plant is a combined cycle plant with two combustion turbines (G1 and G2) and a steam turbine (G3). The North Edinburg generation plant had completed at maintenance outage on October 6, 2014, two days prior to the event.
On the next day, October 7, 2014, a maintenance outage was started on the Duke generation plant. ERCOT had requested that the Duke outage be postponed; however, ERCOT ultimately accepted the Duke plant outage due to concerns conveyed by the plant owner regarding dynamics issues with the G1 gas turbine and vibration issues with the G2 gas turbine. ERCOT performed an additional outage study on October 7, 2014 with 55,000 MW of ERCOT load, including consideration of all North Edinburg units out of service as a contingency. No issues were identified.

On the morning of October 8, the plant owner was conducting reactive testing and power system stabilizer testing at North Edinburg. At 12:30, the plant owner requested and received approval from AEP for High Sustained Limit (HSL) load reactive testing at North Edinburg. At 14:45, AEP contacted the plant owner and requested that they stop reactive testing at North Edinburg at 15:00 due to system conditions.

The BPUB Silas Ray Power Plant was conducting an emissions verification for air quality control (RATA) test on units 6 & 9 that was cut short in order to bring the units to their maximum output to respond to the emergency.

The following graph shows the Valley Area demand and generation in relation to the Valley Import flow. As previously stated, the Valley Import flows approached, but did not exceed the Valley Import GTL during the period of the event. The trips of the North Edinburg generation units caused the Valley Import flow to reach a maximum value of 1395 MW for four minutes from 15:53 to 15:56, versus the GTL value of 1395 MW during the 1500 clock hour.
The North Edinburg G3 steam turbine tripped offline on October 8, 2014 at 15:50:32 due to the operation of the 86 lockout relay on the generator step-up (GSU) T3 circuit breaker CB5030. One of the two mechanical pressure relief devices on the GSU also operated. The unit was loaded at 244 MW. Disturbance monitoring data provided by AEP did not indicate any system disturbance prior to the unit trip. North Edinburg G1 ran back from 209 MW and tripped offline one minute later at 15:51:32, loaded at 204 MW. North Edinburg G2 ran back from 208 MW and tripped at 15:51:36, loaded at 204 MW. The sum of generation lost was 661 MW within one minute. The G1 and G2 units unloaded due to loss of steam flow for transition cooling.

The plant owner restarted and synchronized the North Edinburg G1 unit 17:24 at a reduced output of 115 MW versus a seasonal rating of 212.5 MW due to the unavailability of the steam turbine (G3). The plant owner restarted and synchronized the G3 unit on October 9, 2014 at 09:05 at a reduced output of 115 MW versus a seasonal rating of 212.5 MW due to the unavailability of the steam turbine (G3).

The plant owner completed electrical testing on the GSU T3. Oil samples were pulled and sent in for analysis. The relay protection system was reviewed by Engineering and no issues were found. None of the transformer tests showed any internal fault and there was no improper protective relay operation. The plant owner removed the mechanical...
pressure relief device that operated for further testing. A replacement mechanical pressure relief device was installed on 10/9/2014. Laboratory testing was completed on 10/21/14 and the pressure relief device operated satisfactorily. Upon completion of the testing, the plant owner released the GSU T3 for energizing and the transformer was placed back in service on 10/11/14 at 04:30. The plant owner restarted and synchronized the G3 unit on October 11, 2014 at 07:40.

The plant owner completed an investigation into the cause of the GSU T3 trip. The GSU T3 was operating within normal parameters after reactive testing when one of two 10-PSI mechanical Pressure Relief Devices (PRD) operated. The operation of PRD caused 86B3B lockout relay to operate, sending a trip to G3 steam turbine generator. Transformer internal oil samples were pulled and series of transformer tests were performed. The testing included: overall insulation power factor, excitation, turns ratio, winding resistance, core megger, sweep frequency response analysis, and leakage reactance. All test results were acceptable and comparable to previous test results performed in April 2014. The liquid screen, Karl Fisher titration, and the dissolved gas-in-oil analysis results were all acceptable. The test results confirmed no windings or core faults caused the PRD to operate. The PRD was removed from the transformer, tested several times, and operated at or near design pressure of 10 PSI for each test. The transformer oil preservation system breathes through the air cell bladder. To confirm the overall condition of the oil preservation system, the integrity of the bladder was checked. A physical inspection was performed by opening the bleeder access at the top of the conservator and swabbing the inside of the air cell with a blunt dowel stick. There was 3-4 inches of oil visible on the stick. This confirmed that the air cell (bladder) had failed allowing oil to enter the inside of the air cell.

The plant owner also indicated that the loss of the G1 and G2 units was not by design and it conducted an analysis of the G1 and G2 control logic. The plant owner indicated that the plant was designed to keep the combustion turbines on-line during a full steam turbine generator load rejection. The combustion turbine control logic in place during the event triggered the combustion turbines to completely unload when transition/cooling steam was 30% below required for more than five seconds. This logic was reviewed by plant controls engineers and the OEM, and it has been updated such that combustion turbines will not completely unload in similar conditions, but rather they will run back at a slower rate until steam flow is recovered.

Impact of Wind Generation
A total of four wind plants at two sites (Los Vientos LV1A, Los Vientos LV1B, Redfish MV1A, and Redfish MV1B) are connected to the 138 kV transmission system in the Rio Hondo area. These four wind plants have a nameplate capacity of 605 MW.

Wind curtailments: The Valley wind plants were curtailed prior to the event due to the activation of the La Palma – Rio Hondo constraint (SLA_RIO8_RIOHND_ERIOHND) in SCED. This constraint was activated due to congestion from post-contingency overloads in the 138 kV system from the La Palma – Rio Hondo 345 kV planned outage. ERCOT de-activated the La Palma – Rio Hondo constraint at 16:00 so that
local wind generation would not be curtailed. This allowed Wind Generation in the Valley to be maximized, providing a large amount of voltage stability margin/reactive support. At 16:07, the Lon Hill – Orange Grove 138 kV/North Edinburg 345 kV double circuit constraint (DLONOR5_S104A) was also deactivated as it was causing the local wind units in the Valley to back down. Following the load shed, the DLONOR5_S104A constraint was activated at 17:02 to manage the post-contingency overload of the Rio Hondo – Burns 138 kV line. This had the effect of curtailing the local Valley wind generation. At 18:10, the DLONOR5_S104A constraint was released and, at 18:15, the SLA_RIO8_RIOHND_ERIOHND constraint was activated to manage post-contingency overloads on the Rio Hondo – East Rio Hondo 138 kV line. This had the effect of additional curtailment of the local Valley wind generation.

Observations and Conclusions from Generation Analysis
A large generating unit and a DC Tie in the Valley were scheduled out of service during a shoulder month period when a relatively high load was experienced. These planned outages, combined with the trip of the North Edinburg unit precipitated the need for firm load shed. ERCOT initially looked at postponing the Duke generation plant outage, but ultimately approved it due to concerns conveyed by the plant owner regarding dynamics and vibration issues with the gas turbines.

There are several generation plant additions planned for the Valley area prior to 2017 as well as one generation reconfiguration. ERCOT has an understanding with Frontera to commit a portion of the plant generation capacity until 2016 for the ERCOT region. In addition, there are multiple wind and gas units that have generation interconnect
agreements in place, or are under review for a full interconnect study by request of the developers. The projected commercial operation dates as specified by the resource developers are from June 2015 to June of 2017. Generation availability will continue to be an issue for the foreseeable future until additional generation is built and the Cross Valley transmission project is completed.

Corrective Actions Taken
The following actions are in progress or have already been taken to address the problems noted during the event:

- ERCOT temporarily updated the standard contingency list to include the loss of the entire North Edinburg combined cycle plant. This will remain in effect until such time that ERCOT has information from the plant owner as to why the entire train tripped, and if actions were implemented to avoid such an event in the future.
- The plant owner and the OEM reviewed the G1 and G2 control logic and it has been updated such that combustion turbines will not completely unload in similar conditions, but rather they will run back at a slower rate until steam flow is recovered.

**B. Transmission Analysis**

Several transmission lines were out of service during the event as indicated in the following table. The transmission line outages were not considered a contributing cause to the Valley load shed event. However, the North Edinburg 345 kV Bus #2 outage did increase the risk to the system since the loss of the Lon Hill – North Edinburg 345 kV line would also cause the loss of the North Edinburg – Rio Hondo 345 kV line due to the bus outage.

The La Palma – Rio Hondo 345 kV line outage required the development of a TOAP for the east Valley area, due to the long restoration time for the La Palma – Rio Hondo 345 kV outage. This TOAP contained a load shed option if multiple contingencies were to occur, i.e. the contingency loss of the La Palma – Rio Hondo 138 line combined with a outage or trip of Silas Ray generation (an N-2 situation). The TOAP called for targeted load shed at the Rio Hondo, Central Avenue, Coffee Port, Hwy 511, and Haine Drive substations.

<table>
<thead>
<tr>
<th>Equipment Name</th>
<th>Out Time</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 La Palma - Rio Hondo 345kV line</td>
<td>1/22/2014</td>
<td>New equipment energization</td>
</tr>
<tr>
<td>2a La Palma - MV Ranger 138 kV line</td>
<td>9/10/2014</td>
<td>New equipment energization</td>
</tr>
<tr>
<td>2b MV Ranger - Wesmer 138 kV line</td>
<td>9/10/2014</td>
<td>New equipment energization</td>
</tr>
<tr>
<td>3a Garza - MighowTP 138 kV line</td>
<td>10/1/2014</td>
<td>New equipment energization</td>
</tr>
<tr>
<td>3b Bates - MighowTP 138 kV line</td>
<td>10/1/2014</td>
<td>New equipment energization</td>
</tr>
<tr>
<td>4 Falfurias 69 kV SVC</td>
<td>8/29/2014</td>
<td>Replace damaged equipment</td>
</tr>
</tbody>
</table>
Table 4: Transmission Elements Out-Of-Service: Oct 8, 2014

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
<th>Date</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Frontera - Sharyland 138 kV line</td>
<td>10/3/2014</td>
<td>Retirement of old equipment</td>
</tr>
<tr>
<td>6</td>
<td>Azteca – S.E. Edinburg 138 kV line</td>
<td>10/6/2014</td>
<td>Line maintenance</td>
</tr>
<tr>
<td>7</td>
<td>Laureles MVEC – Port Isabel 138 kV</td>
<td>10/6/2014</td>
<td>Line maintenance</td>
</tr>
<tr>
<td>8</td>
<td>North Edinburg 345 kV Bus #2</td>
<td>09/02/2014</td>
<td>Station upgrade</td>
</tr>
<tr>
<td>9</td>
<td>Railroad DC Tie</td>
<td>10/3/2014</td>
<td>Planned outage</td>
</tr>
</tbody>
</table>

North Edinburg substation activities prior to the event

AEP reported the following activities in the North Edinburg substation prior to the North Edinburg generation unit trips. These activities had no direct impact on the cause of the unit trips.

- Protection and Control technicians were working in 345 kV DICM (Drop in Control Modules) updating the Protection & Control Information System (PCIS) database for the 345 kV equipment associated with the station upgrade (No actual work on relays)
- Contractors in 138 kV yard digging ditches for conduit install for the 138/69 kV transformer station service upgrade
- AEP Transmission Field Service technicians in 69 kV yard testing new PTs on the ground (Not Energized)

Rio Hondo to MV Burns 138 kV line overload

ERCOT has the following ratings for the Rio Hondo – MV Burns 138KV line:

- 121 MVA Normal/Continuous
- 174 MVA Emergency/2-Hour
- 174 MVA Load Shed/15-Minute

The real-time loading on Rio Hondo – Burns 138 kV line hit its continuous rating at 16:18, and remained above the continuous rating from 16:24 until 16:52, or approximately 31 minutes. The maximum load during the period was 125.5 MVA, or 103.7% of the continuous rating.

---

1 This line is not dynamically rated.
Figure 5: Rio Hondo – MV Burns 138 kV Line Loading

Valley area voltages
Voltage momentarily dropped to 0.97 per unit at 15:52 on the 345 kV system and 0.95 per unit on the 138 kV system at some locations in the Valley area. During the execution of the load shed, 345 kV voltages peaked as high as 1.07 per unit and 138 kV voltages peaked as high as 1.08 per unit. The following figures trend several 138kV and 345kV bus voltages in the Valley area from 14:00 to 21:00 on October 8, 2014.

The wind plants in the Valley were instructed by ERCOT to provide reactive power for voltage support. This reactive support was essential in maintaining voltage stability in the area during the event.
Figure 6: Rio Grande Valley Bus Voltages October 8, 2014
During the event, two of transmission line outages were withdrawn by ERCOT as shown in the following table:

<table>
<thead>
<tr>
<th>Type</th>
<th>From</th>
<th>To</th>
<th>Actual Start</th>
<th>Plan End</th>
<th>Time Withdrawn</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>Azteca</td>
<td>SE Edinburg</td>
<td>10/6 10:15</td>
<td>10/10 16:00</td>
<td>10/8 17:19</td>
</tr>
<tr>
<td>Planned</td>
<td>Laureles</td>
<td>Port Isabel</td>
<td>10/6 8:18</td>
<td>10/10 16:00</td>
<td>10/8 17:20</td>
</tr>
</tbody>
</table>

Observations and Conclusions from Transmission Analysis
Multiple transmission elements were out of service at the time of the event. The most significant of these were the La Palma – Rio Hondo 345 kV line and the North Edinburg 345 kV Bus #2 outage. These outages, while not a contributing factor to the event, had the effect of increasing the risk to the system.

C. Load Shed Analysis

The ERCOT Operations Transmission and Security Desk Procedure, Section 4.2 contains the pre-planned system operator actions to take for congestion in the Rio Grande Valley.

There are two mitigation plans in effect in the Valley area; one for loss of either of the 345 kV lines into the Valley region and the other for the loss of the North Edinburg generation facility. Both mitigation plans call for the following possible post-contingency actions on the part of ERCOT:

1. Procure power across the DC ties
2. Increase generation
3. Shed load in 100 MW blocks according to the following ratios:
   - Direct AEP to shed 66 MW of firm load
   - Direct STEC to shed 20 MW of firm load from Magic Valley
   - Direct Public Utility of Brownsville to shed 13 MW of firm load
   - Direct Sharyland to shed 1 MW of firm load

The following table and chart summarizes the load-shed obligation and actions.

<table>
<thead>
<tr>
<th>Transmission Operator</th>
<th>Assigned % Shed</th>
<th>Assigned MW Shed</th>
<th>Actual MW Shed (Maximum)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>66</td>
<td>134</td>
<td>677.9</td>
</tr>
<tr>
<td>BPUB</td>
<td>13</td>
<td>26</td>
<td>37.6</td>
</tr>
<tr>
<td>STEC</td>
<td>20</td>
<td>40</td>
<td>40.4</td>
</tr>
<tr>
<td>Sharyland</td>
<td>1</td>
<td>2</td>
<td>No instruction given</td>
</tr>
</tbody>
</table>

The following chart shows the real-time performance of the load shed actions taken.
Issues noted during load shed

ERCOT instructed AEP to shed 134 MW across the Valley area. AEP Transmission Dispatch communicated the ERCOT directive to shed 134 MW to AEP Distribution Dispatch. AEP Distribution Dispatch input the 134 MW load amount into its automated computer feeder load shed program but then selected the cycle load shed button instead of the MW amount load shed control button. The first feeder was interrupted at 16:53. The cycle load shed program tried to go through the entire Valley load shed cycle and indicated a total load shed of about 590 MW. Nineteen feeders in this load shed cycle timed out due to a SCADA response recognition time limit, but did finally operate to shed load. The final calculation indicates a total load shed of 680 MW by AEP in the Valley. A significant part of the excess load shed was restored within about 10 minutes. However, because the program did not recognize the extra 19 feeders, the amount of load shed stayed above 134 MW throughout the rotation, until ERCOT released all load to be restored. The final feeder was restored at 18:55. One feeder had a breaker close control problem and was energized at 19:58. The total outage time for the load shed was 118 minutes.

AEP implemented an automated computer feeder load shed program as a result of the ERCOT 2011 load shed event in order to more timely complete load shed directives in future emergency load shed events. AEP Distribution dispatchers received training on how to use the program via a simulator, but this Valley event was the first time the
automated computer feeder load shed program was used in a real-time event. The load shed amount was communicated properly from AEP Transmission Dispatch to AEP Distribution Dispatch and that value was inserted into the load shed program properly. When it came time to execute the load shed, the dispatcher inadvertently selected the cycle load shed computer control button instead of the load shed MW amount control button and the program proceeded to try to interrupt all feeders for the Valley that were in the Valley load shed program cycle. Also, the automated computer feeder load shed program did not account for feeders that originally timed out but later tripped. Thus, the program did not have a complete count of load that had been shed.

AEP has disabled the cycle trip control feature by removing the control button from the control screens so all future trips can only be handled by an input set amount of MWs.

**Impact of load shed on generation fuel supplies**
AEP was contacted by Enterprise Products, indicating that one of their gas facilities was affected by the outage which caused problems for one of the Valley area generation facilities. AEP has removed this feeder from manual load shedding per ERCOT’s indication that it could affect the generation in the future. It will also not be part of UFLS/UVLS.

**Observations and Conclusions from Load Shed Analysis**
ERCOT instructed AEP, BPUB, and STEC to shed a combined 200 MW of firm load at 16:51. Due to AEP operator error, a peak of 725 MW was shed at 16:55 before settling to a level of approximately 310 MW at 17:06. The total load shed remained in a range between 266 MW and 316 MW until ERCOT ordered load restoration to begin at 17:59. This difference was due to the 19 feeders reported by AEP that their automated feeder load shed program did not account for. Additional training and sharing of lessons learned from the load shed may be warranted due to the AEP operator error that occurred during the implementation of the load shed.

**Corrective Actions Taken**
The following actions are in progress or have already been taken to address the problems noted during the event:
- AEP has removed the cycle load shed feature (button) on the automated system control screens so that a load shed can only be performed by the MW target control feature (button) of the program.
- AEP has removed one feeder from manual load shedding due to its effect on the generation gas fuel supply.

**D. Valley Area Under-Voltage Load Shed Program**

An automatic undervoltage load shed (UVLS) scheme is in service in the Valley to shed load to prevent uncontrolled loss of load and outages. The UVLS scheme has two setting levels; one level has a one-time delay setting that trips approximately 30% of the
load in two seconds at 75% or 85% voltage level depending on load location in the Valley. The second level has multiple time delay settings that trip load at 90% voltage.

During the period following the loss of the North Edinburg generation at 15:51 until the area was stabilized at approximately 19:15, if either of the 345 kV transmission lines into the Valley was lost, or if another major generation facility in the Valley tripped, analysis conducted by Texas RE indicates that the UVLS scheme would possibly have activated to help prevent uncontrolled loss of load and outages in the Valley area.

**E. Valley Import GTC**

The Valley Import GTC is composed of the following elements:

<table>
<thead>
<tr>
<th>Transmission Lines</th>
<th>Normal Limit MVA</th>
<th>2-hour Limit MVA</th>
<th>Emergency Limit MVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Edinburg - Lon Hill 345kV</td>
<td>1057</td>
<td>1195</td>
<td>1195</td>
</tr>
<tr>
<td>Ajo – Rio Hondo 345kV</td>
<td>1852 *</td>
<td>2379</td>
<td>2379</td>
</tr>
<tr>
<td>Raymond 2 – Yturria 138kV</td>
<td>216</td>
<td>216</td>
<td>216</td>
</tr>
<tr>
<td>North Edinburg - Rachal 138kV</td>
<td>211 *</td>
<td>239</td>
<td>239</td>
</tr>
<tr>
<td>Roma SW – Falcon SW 138kV</td>
<td>245 *</td>
<td>257</td>
<td>257</td>
</tr>
</tbody>
</table>

*NOTE: Line is dynamically rated.

GTCs are used in reliability and market analyses pursuant to ERCOT Nodal Protocol Section 3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits. GTLs associated with GTCs are posted on the Market Information System (MIS) Secure Area. All GTCs used in the Operations Horizon are interface constraints, where the GTL associated with each GTC is defined as the sum of flow on all of the elements within the GTC.

ERCOT manages the Valley area transmission with a GTC called the Valley Import GTC, which protects the lines in the Rio Grande Valley upon the contingency loss of one of the 345 kV lines – Ajo to Rio Hondo or Lon Hill to North Edinburg, or upon contingency loss of generation in the Valley area. A contingency loss of one of the 345 kV lines or generation during high load conditions could cause overloads, voltage instability, and outages in the Rio Grande Valley.

The following table provides the values of the GTLs association with the Valley Import GTC.

<table>
<thead>
<tr>
<th>Valley Import GTL</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations Limit</td>
<td>Varies: 1100-1500 MW</td>
</tr>
<tr>
<td>Operations Limit with One of the 345 kV Lines Out-of-Service</td>
<td>460 MW</td>
</tr>
</tbody>
</table>

*Table 6: Valley Import GTL Values*
The following graph shows the power flow into the Valley on October 8 and October 9 in relation to the Valley Import GTC. As previously stated, the GTL of the Valley Import GTC was reached but not exceeded during the period of the event. The trips of the North Edinburg generation units caused the power flow into the Valley to reach a maximum flow of 1395 MW for four minutes from 15:53 to 15:56 when the GTL of the Valley Import GTC was also 1395 MW.

The next morning 10/9/2014 at 06:33, the Ajo to Rio Hondo 345 kV line tripped due to a failed surge arrestor on the series capacitor. As noted on the preceding figure, the GTL of the Valley Import GTC was reduced to 460 MW per ERCOT mitigation plans until the line was restored at 09:16.

**Impact of Comisión Federal de Electricidad (CFE) DC ties**

Initially, imports through the Railroad tie from CFE were unavailable due to a forced outage of the Railroad tie. The Eagle Pass DC tie and Laredo Variable Frequency Transformer (VFT) were exporting power (~ 130 MW) throughout the event. The following sequence of events details communications and transactions related to the Railroad DC tie.

16:09 - ERCOT declared a transmission emergency in the Rio Grande Valley; ERCOT advised Sharyland that it may require emergency power across the DC Ties and load shedding
16:39 – ERCOT notified by Sharyland that Railroad DC tie can be put back into service. Sharyland began to prepare DC tie for service
16:43 – ERCOT requested emergency transfer from Railroad HVDC Tie for 2-3 hours. The Tie was under a clearance but was released and put into service. CFE agreed to supply 50 MWs of power for the emergency
17:20 – Railroad HVDC Tie ramped to 50 MWs from CFE to ERCOT
18:03 – CFE advised that it could supply an additional 40 MWs of emergency power, 90 MW total
18:09 – Railroad HVDC Tie ramped from 50 MWs to 90 MWs
19:10 – ERCOT reported that energy condition in the Rio Grande Valley has improved and the energy emergency is being cancelled
19:10 – ERCOT requested that the DC Tie be ramped to 0 MWs at 1915
19:18 – Railroad HVDC Tie ramped to 0 MWs and offline

**Figure 9: DC Tie Imports**

**Observations and Conclusions from Valley GTL Analysis**
Following the loss of the North Edinburg units, ERCOT managed to keep the flows on the transmission lines that make up the Valley GTC within the GTL by increasing the remaining available generation in the Valley. No base-case or post-contingency exceedances of this GTL were noted during the event. ERCOT worked with Sharyland to successfully restore the Railroad DC tie and procure emergency power from CFE to assist in the restoration.
F. Operation Within System Operating Limits

From the document, ERCOT System Operating Limit Methodology for the Planning and Operations Horizon: An SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria including, but are not limited to:

- Facility Ratings (Applicable pre and post Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre and post Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre and post Contingency Voltage Stability)
- System Voltage Limits (Applicable pre and post Contingency Voltage Limits)

The Contingency Analysis package in the EMS RTCA is utilized to monitor SOLs. When RTCA indicates a post-contingency facility rating exceedance for an element for a given contingency, congestion management techniques are employed per the ERCOT Operations Transmission and Security Desk Procedure (Appendices 5 and 6). ERCOT also utilizes additional real-time tools such as Voltage Security Assessment Tool (VSAT) and Transient Security Assessment Tool (TSAT) to determine and monitor stability limits and stability SOLs. The above tools utilize credible single and multiple contingencies in the Operations horizon.

Additional SOLs may be identified in the Operations horizon if system performance results in any of the following:

a) Transient, dynamic instability (resulting in the loss of a generator due to the instability);
b) Voltage instability (resulting in uncontrolled voltage collapse);
c) Cascading or uncontrolled separation;
d) Voltage stability margin in the planning horizon is not sufficient to maintain post-transient voltage stability under the following two conditions for an ERCOT or TP-defined area:
   1) A 5% increase in Load above expected peak supplied from resources external to the ERCOT or TP-defined area and NERC Category A or B operating conditions; or
   2) A 2.5% increase in Load above expected peak supplied from resources external to the ERCOT or TP-defined area and NERC Category C operating conditions;
e) Post disturbance frequency outside the range from 59.4 Hz to 60.4 Hz; or
f) Manual system adjustments, such as system reconfiguration between contingencies in an N-1-1 Category C event, or load shedding are needed in order to prevent cascading or transient, dynamic, or voltage instability.

ERCOT reviews SOL exceedances in the Operations Horizon (Real-Time) to determine if they qualify as potential Interconnect Reliability Operating Limits (IROLs) based on the following criteria:
(a) Loss of load in the Cascading or voltage collapse, either through manual action or as a consequence of the event (including loss of load as a result of Under Voltage Load Shedding (UVLS)), is greater than six times 1% of the ERCOT Interconnection aggregate load level used in the study

(b) Trigger of automatic Under Frequency Load Shedding (UFLS)

(c) Observable inter-area oscillation with damping ratio less than 3%

Per the **ERCOT System Operating Limit Methodology for the Planning and Operations Horizon**, in the Operations horizon, the system’s response to a single Contingency may include the following:

(a) Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

(b) System reconfiguration through manual or automatic control or protection actions.

(c) Interruption of other network customers only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or if the real-time operating conditions are more adverse than anticipated in the corresponding studies.

At the time of the event, the loss of the entire North Edinburg combined cycle plant was not set up as a single contingency in either RTCA or State Estimator. According to the plant operator, ERCOT considered the North Edinburg combined cycle plant through the following contingency definitions:

- 1 GT/1 steamer (G1 and G3)
- 1 GT/1 steamer (G2 and G3) and
- The loss of each individual unit (G1, G2, or G3)

As a result, RTCA did not show a post-contingency overload condition in the Valley area for the loss of a portion of the North Edinburg generation plant. The plant operator also indicated that the loss of the G1 and G2 units following the loss of the G3 steam turbine was not by design.

Prior to the event, RTCA showed multiple post-contingency overloads for the following contingencies:

- Loss of La Palma – Rio Hondo 138 kV line (SLA_RIO8_RIOHND_ERIOHND) overloads the Rio Hondo – East Rio Hondo 138 kV line
- Loss of La Palma – Rio Hondo 138 kV line (SLA_RIO8_HARLNS_OLEAND1) overloads the Harlingen Switch – Oleander 138 kV line
- Loss of La Palma – Rio Hondo 138 kV line (SLA_RIO8_S105) overloads the East Rio Hondo - Central Ave 138 kV line

These contingencies were due to the concurrent planned outages for the Rio Hondo – La Palma 345 kV line and the Laureles – Port Isabel 138 kV line. A TOAP was created during outage coordination studies which called for targeted load shed at the Rio Hondo, Central Avenue, Coffee Port, Hwy 511, and Haine Drive substations upon the loss of the La Palma – Rio Hondo 138 kV line.
After the loss of the North Edinburg units and prior to the firm load shed, RTCA showed one base-case and multiple post-contingency overloads for the following contingencies:

- **Base-case** – Rio Hondo – MV Burns 138 kV line (max of 102% of normal rating)
- **Loss of double circuit Lon Hill – Orange Grove 138 kV and North Edinburg 345 kV lines (DLONOR58)** overloads the following lines:
  1. Rio Hondo – MV Burns 138 kV line (max of 176 % of emergency/15 minute rating)
  2. MV Burns – MV Heidelberg 138 kV line (max of 165 % of emergency/15 minute rating)
  3. MV Heidelberg – Weslaco Sub 138 kV line (max of 157 % of emergency/15 minute rating)
  4. Weslaco Sub – Weslaco Switch 138 kV line (max of 146 % of emergency/15 minute rating)
- **Loss of Lon Hill – North Edinburg 345 kV line (SNEDLON5)** overloads the following lines:
  1. Rio Hondo – MV Burns 138 kV line (max of 176 % of emergency/15 minute rating)
  2. MV Burns – MV Heidelberg 138 kV line (max of 164 % of emergency/15 minute rating)
  3. MV Heidelberg – Weslaco Sub 138 kV line (max of 157 % of emergency/15 minute rating)
  4. Weslaco Sub – Weslaco Switch 138 kV line (max of 146 % of emergency/15 minute rating)
- **Loss of Ajo – Rio Hondo 345 kV line (SAJORI25)** overloads the following lines:
  1. Lon Hill – North Edinburg 345 kV line (max of 100 % of emergency rating)
  2. Rio Hondo – Las Pulgas 138 kV line (max of 100 % of emergency rating)

Since several of the post-contingency thermal exceedances noted above exceeded 125% of the emergency rating of the circuits, this brought up concerns of N-1 cascading outages.

After the load shed, post-contingency SOL exceedances were noted until approximately 17:53, or approximately two hours after the start of the event. RTCA showed multiple post-contingency overloads for the following contingencies:

- **Loss of double circuit Lon Hill – Orange Grove 138 kV and North Edinburg 345 kV lines (DLONOR58)** overloads the following lines:
  1. Rio Hondo – MV Burns 138 kV line (max of 124 % of emergency/15 minute rating)
  2. MV Burns – MV Heidelberg 138 kV line (max of 122 % of emergency/15 minute rating)
  3. MV Heidelberg – Weslaco Sub 138 kV line (max of 118 % of emergency/15 minute rating)
  4. Weslaco Sub – Weslaco Switch 138 kV line (max of 115 % of emergency/15 minute rating)
- **Loss of Lon Hill – North Edinburg 345 kV line (SNEDLON5)** overloads the following lines:
i. Rio Hondo – MV Burns 138 kV line (max of 124 % of emergency/15 minute rating)
ii. MV Burns – MV Heidelberg 138 kV line (max of 122 % of emergency/15 minute rating)
iii. MV Heidelberg – Weslaco Sub 138 kV line (max of 118 % of emergency/15 minute rating)
iv. Weslaco Sub – Weslaco Switch 138 kV line (max of 115 % of emergency/15 minute rating)

At this point, since the post-contingency thermal exceedances were below the 125% of the emergency rating of the circuits, the concern of a possible cascading outages was reduced. If additional contingencies had occurred during this period of the event, then additional load shed may have been necessary.

ERCOT’s VSAT did not show any voltage security violations during the event.

![Figure 10: VSAT Output for October 8, 2014](image)

When comparing the RTCA results provided by ERCOT and AEP, several differences were noted in the base-case and post-contingency exceedances for several elements. AEP indicated that its RTCA models the Valley generation contingencies as both a single unit and as a train, where ERCOT reported that it does not consider the entire train as a single contingency. Differences were also noted in transmission element contingencies in the data provided.
Observations and Conclusions from System Operating Limit Analysis
Following the loss of the North Edinburg units, there was one base-case and multiple post-contingency thermal SOL exceedances as high as 176% of the emergency/15-minute ratings of the circuits for up to one hour before the firm load shed. If the loss of the Lon Hill – North Edinburg 345 kV line contingency had occurred during this period, studies conducted by Texas RE show possible activation of one or more stages of the Valley UVLS system.

After the load shed, post-contingency SOL exceedances of up to 124% of the emergency/15 minute ratings were noted until approximately 17:53, or approximately two hours after the start of the event.

There are two matters of concern related to the operation within SOLs.
1) The first matter of concern is the post-contingency loading of the Rio Hondo – MV Burns line between the loss of the North Edinburg units and the firm load shed. During this period, post-contingency overloads were noted up to 176% of the emergency/15 minute circuit rating. Since the emergency (2-hour) rating and 15-minute rating are the same, if one of the relevant contingencies had occurred during this period, ERCOT would have had less to 15 minutes to relieve the overload in order to avoid the SOL violation.

2) The second matter of concern is the amount of load shed when compared to the reduction in the post-contingency flows for the impacted 138 kV lines. ERCOT instructed 200 MW of load shed and ultimately achieved almost 300 MW, or 100 MW more than what was estimated to mitigate the SOL exceedances. It was noted that ERCOT staff considered ordering more than 200 MW of load shed, but ultimately decided to limit it to 200 MW. This amount of load shed was determined to be sufficient to result in a situation in which additional load shed could be ordered, if necessary, so that cascading outages would not occur.

Corrective Actions Taken
The following actions are in progress or have already been taken to address the problems noted during the event:

- ERCOT has updated the standard contingency list to include the loss of the entire North Edinburg combined cycle plant. This will remain in effect until such time that ERCOT has information from the plant owner as to why the entire train tripped, and if actions were implemented to avoid such an event in the future.

G. Operator Actions

Mitigation Planning
Per ERCOT Nodal Protocol 6.5.7.1.10(3)(i) Network Security Analysis Processor and Security Violation Alarm,

(e) If all other mechanisms have failed, ERCOT may authorize the expedited use of a Temporary Outage Action Plan (TOAP) or Mitigation Plan.
ERCOT Protocols define Mitigation Plans (MPs) as “A set of pre-defined actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A Mitigation Plan must be implementable and may include transmission switching and Load shedding. Mitigation Plans shall not be used to manage constraints in SCED by either activating them or deactivating them”. Per ERCOT Nodal Operating Guide 11.4(3), an approved Mitigation Plan may be executed immediately, post-contingency, by the transmission operator without instruction by ERCOT or shall be executed upon direction by ERCOT.

ERCOT Transmission and Security Desk Operating Procedure, Section 4.2 Transmission Congestion in the Rio Grande Valley, states

If:

- One of the following conditions exist without a generation solution:
  - Unsolved contingency
  - Post-contingency loss of a 345kV to the Valley overloads a 345kV
  - Post-contingency overload above 125%
  - Valley import is above 90%
  - Reliability margin is below 95;

Then ERCOT Operators will:

- Issue a Transmission Emergency Notice
  - Make Hotline call to TOs
  - Posting message on MIS Public
  - Notify Real-Time Desk to make Hotline call to QSEs
- Other possible actions include:
  - Request Resource Operator to deploy Load Resources in the Rio Grande Valley
  - Request DC Tie Operator to curtail any exports on the Railroad DC tie
  - Request emergency energy from the DC Tie Operator across the Railroad DC tie
  - Utilize existing Valley Import Mitigation plans

Following the trip of the North Edinburg generation units, ERCOT reviewed multiple options to relieve the base-case and post-contingency thermal exceedances discussed above. Also, several of the post-contingency thermal exceedances exceeded 125% of the emergency rating of the circuits, which brought up concerns of N-1 cascading outages. Ultimately, there was no generation or transmission solution available to relieve both the base-case and post-contingency overloads, leaving firm load shed as the only option available to relieve the SOL exceedances. ERCOT reviewed the Mitigation Plan load shed steps and levels with each of the Transmission Operators in the Valley and instructed the 200 MW of firm load shed at 16:49.

The shift engineer log entry for provides a detailed summary of the studies conducted.

Shift Engineer log entry for 10/08/14:
At 15:50:40, NEDIN_G3 tripped offline while carrying 248.0MW. Shortly afterward at 15:51:40, both NEDIN_G1 and NEDIN_G2 tripped offline while carrying 209.5MW and 208.4MW respectively. This brought in a thermal base-case violation on the 138kV line S104A from Rio Hondo (RIOHONDO) to Burns Sub (MV_BURNS) at 107.1%. In addition to the base-case violation, there was also a post contingency overload of up to 172.2% on the Rio Hondo (RIOHONDO) to Burns Sub (MV_BURNS) for the CTG ID DLONOR58. This post contingency overload brought up concerns of N-1 cascading outages and a potential IROL. The original snapshot of the event has been saved as SC_100814_NEDIN_RJM with a case timestamp of 15:52:28. Initial potential IROL studies indicated there would be cascading outages across the valley that would result in the loss of approximately 1850MW of load in the valley. System load at the time of the study was 46829MW. Using this snapshot, I conducted different studies to attempt to remedy the post contingency overload. I attempted splitting the overloaded element, raising online generation in the valley to the top (SILASRAY and FRONTERA at the time), importing energy across DC_ROAD, and shedding firm load according to MP_2014_04. Out of these potential solutions, only the firm load shed was able to relieve the post contingency overload to around 125% (threshold for potential IROL) and restore/maintain voltage stability in the valley area. Initially, only 100MW of firm load was shed in the study (11 @ MV_BURNS, 11 @ MV_HBRG4, 42 @ SE_EDINB, and 40 @ PHARR), resulting in a post contingency overload of 139.9% for CTG ID DLONOR58. A second block of 100MW was shed in the study (30 @ ELGATO, 40 @ MV_DOEDN, 15 @ N_ALAMO, and 22 @ MERETT), which resulted in a post contingency overload of 121.3% for CTG ID DLONOR58. At this time with these results, the operators and shift supervisor agreed upon requesting up to 200MW of firm load shed according to MP_2014_04. We had been notified that the scheduled DC_ROAD outage could be restored and they would be able to provide emergency energy across the tie. In addition to already shed load, I studied a 50MW import across the DC_ROAD tie. This resulted in a post contingency overload of up to 113.7% in the study for CTG ID DLONOR58 on the 138 kV line S104A. Approximately 50MW of emergency energy across the DC_ROAD tie was imported starting at 17:21. Additionally, NEDIN was able to recover NEDIN_G1 and provide up to 115MW of generation. Once the 200MW of firm load had been shed, DC_ROAD had a 50MW import across the tie, and NEDIN_G1 was generating, I began a study to split the 138kV line at WESLACO (CBs 2070 & 2075) to protect the overloaded element and allow the operators to constrain to the CTG ID SLA_RIO8 and clear the CTG DLONOR58. The study cleared the CTG DLONOR58 and resulted in no additional thermal or voltage ctgs and/or base-case violations. At this point, the operators and shift supervisor were in agreement to begin load restoration. All load had been recovered by 19:15.

Following completion of the 200 MW of firm load shed at approximately 17:10, RTCA still showed post-contingency thermal overloads for the double circuit contingency loss of the Lon Hill – Orange Grove 138 kV and North Edinburg 345 kV lines (DLONOR58) as well as the single circuit contingency loss of the Lon Hill – North Edinburg 345 kV line (SNEDLON5). These post-contingency overloads persisted until 17:53, or
approximately two hours after the loss of the North Edinburg units. However, the post-contingency overloads were all below the 125% threshold determined by ERCOT as qualifying for a potential IROL. At this point, if another contingency had occurred, ERCOT would most likely have shed additional firm load using the existing Valley mitigation plans.

Observations and Conclusions from Operator Action Analysis
After the loss of the North Edinburg generation plant, ERCOT operators had one base-case and multiple post-contingency thermal overload conditions to mitigate. The possible courses of action that were reviewed, up to and including the decision to shed firm load, were consistent with the ERCOT Protocols, Operating Guides, and ERCOT desk procedures. The steps taken in the recovery from this event were based upon pre-determined mitigation plans that were consistent with the ERCOT Protocols and Operating Guides. Not all remedial actions were performed in accordance with established procedures, as exemplified by the AEP load shed operator error, but, even with these issues, the risk to the system caused by the loss of the North Edinburg plant was mitigated.

H. Primary Frequency Response

The event began when the North Edinburg G3 steam turbine tripped offline on October 8, 2014 at 15:50:32, loaded at 244 MW. North Edinburg G1 ran back from 209 MW and tripped offline one minute later at 15:51:32, loaded at 204 MW. North Edinburg G2 ran back from 208 MW and tripped at 15:51:36, loaded at 204 MW. The sum of generation lost was 661 MW within one minute. ERCOT deployed approximately 600 MW of generation responsive reserve and 360 MW of up-regulation in response to the unit trip. System frequency dropped to 59.864 Hz and recovered within six minutes.

At 16:53, due to the AEP load shed action, system frequency momentarily peaked at 60.13 Hz and recovered within 5 minutes. The high frequency was arrested by governor action, with a significant contribution from wind generation governor response.

The following chart shows the system frequency over the course of the event and highlights areas where frequency response is a concern.
Figure 11: System Frequency 10/8 14:00-19:00

Figure 12: Regulation and Responsive Reserve Deployment after loss of North Edinburg
Generator governor response was analyzed by the ERCOT Performance, Disturbance, Compliance Working Group (PDCWG). The initial calculated system frequency response target, termed the “B” point, is 420 MW per 0.1 Hz established in ERCOT Nodal Protocol 8.5.2.1 - ERCOT Required Primary Frequency Response. The second calculated response point, termed “B+30”, denotes how well response is sustained 30 seconds after the event. The “B+30” target is also 420 MW per 0.1 Hz. The final response point measures the total response time for the system to return to 60 Hz or the pre-disturbance frequency. The target established by the NERC BAL-002 R4 standard is less than 15 minutes.

For the initial generation trip, system frequency response was 667 MW per 0.1 Hz at the “B” point and 687 MW per 0.1 Hz at the “B+30” point, both exceeding the target of 420 MW per 0.1 Hz. Also, the overall system recovery time was approximately six minutes, which exceeded the NERC target of less than 15 minutes.

The governor response to the high frequency event provided by wind generation units is shown in the figure below.

![Figure 13: Overall Wind Generation Governor Response to High Frequency](chart.png)
**I. Communications**

Per *ERCOT Nodal Protocol 6.5.9.3.4(2)*, ERCOT shall issue an Emergency Notice for one or both of the following reasons:

(a) ERCOT cannot maintain minimum reliability standards (for reasons including fuel shortages) during the Operating Period using every Resource practicably obtainable from the market; or

(b) Immediate action cannot be taken to avoid or relieve a Transmission Element operating above its Emergency Rating.

*Nodal Protocol 6.5.9.3.4(4) and (5)* state, “(4) ERCOT is considered to be in an Emergency Condition whenever ERCOT Transmission Grid status is such that a violation of security criteria, as defined in the Operating Guides, presents the threat of uncontrolled separation or cascading Outages and/or large-scale service disruption to Load (other than Load being served from a radial transmission line) and/or overload of a Transmission Element, and no timely solution is obtainable through SCED or CMPs” and (5) If the Emergency Condition is the result of a transmission problem, ERCOT shall act immediately to return the ERCOT System to a reliable condition, including instructing Resources to change output, curtailing DC Tie Load and instructing TSPs or DSPs to drop Load.”

ERCOT *Transmission and Security Desk Operating Procedure, Section 4.2 Transmission Congestion in the Rio Grande Valley*, states

If:

- One of the following conditions exist without a generation solution:
  - Unsolved contingency
  - Post-contingency loss of a 345kV to the Valley overloads a 345kV
  - Post-contingency overload above 125%
  - Valley import is above 90%
  - Reliability margin is below 95;

Then ERCOT Operators will:

- Issue a Transmission Emergency Notice
  - Make Hotline call to TOs
  - Posting message on MIS Public
  - Notify Real-Time Desk to make Hotline call to QSEs

ERCOT and registered entities strived to maintain effective communications with transmission, distribution, and generating entities during the event through the use of Hot-line calls, email, and electronic messaging through ERCOT Operations Messages. The table below is a summary of the key communications between ERCOT, QSEs and TOs during the event.

<table>
<thead>
<tr>
<th>Time</th>
<th>Communication</th>
</tr>
</thead>
<tbody>
<tr>
<td>10/8 15:50</td>
<td>ERCOT advised of North Edinburg generation trip</td>
</tr>
<tr>
<td>16:08</td>
<td>ERCOT issues Emergency Transmission Notice due to forced outages in the lower Rio Grande Valley</td>
</tr>
<tr>
<td>16:09</td>
<td>ERCOT Hot-line call to Transmission Operators (TOs) to issue a Transmission Emergency for</td>
</tr>
</tbody>
</table>
the Rio Grande Valley due to Loss of Generation. Possible deployment of Load Resources, curtailment of DC-Tie exports to CFE, request for emergency energy and Valley area load shed

<table>
<thead>
<tr>
<th>Time</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>16:14</td>
<td>ERCOT reviews Valley mitigation plan with STEC operators</td>
</tr>
<tr>
<td>16:16</td>
<td>ERCOT Hot-line call to QSEs to notify them that ERCOT has declared a transmission emergency due to low voltage in the Rio Grande Valley</td>
</tr>
<tr>
<td>16:23</td>
<td>ERCOT reviews Valley mitigation plan with AEP operators</td>
</tr>
<tr>
<td>16:40</td>
<td>ERCOT reviews Valley mitigation plan with BPUB operators</td>
</tr>
<tr>
<td>16:51</td>
<td>ERCOT issues instructions for firm load shed of 200 MW per Valley mitigation plan</td>
</tr>
<tr>
<td>16:55</td>
<td>ERCOT issues market notice for load shed in Valley</td>
</tr>
<tr>
<td>17:25</td>
<td>BPUB issues press release notifying the media and public of the load shed event and of the need to conserve electricity</td>
</tr>
<tr>
<td>17:59</td>
<td>ERCOT issues instructions to AEP, BPUB, and STEC to restore their share of 100 MW of load</td>
</tr>
<tr>
<td>18:17</td>
<td>ERCOT issues instructions to AEP, BPUB, and STEC to restore the remaining 100 MW of load</td>
</tr>
<tr>
<td>19:12</td>
<td>ERCOT Hot-line call to TOs to cancel Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>19:20</td>
<td>ERCOT Hot-line call to QSEs to cancel Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>18:39</td>
<td>BPUB issues press release updating the media on the event and reiterating the need to conserve electricity</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Time</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>10/9 06:33</td>
<td>Ajo – Rio Hondo 345 kV line trips</td>
</tr>
<tr>
<td>06:49</td>
<td>ERCOT Hot-line call to TOs to issue Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>06:54</td>
<td>ERCOT Hot-line call to QSEs to issue Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>09:16</td>
<td>ERCOT Hot-line call to TOs to cancel Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>09:42</td>
<td>ERCOT Hot-line call to QSEs to cancel Transmission Emergency for the Rio Grande Valley</td>
</tr>
<tr>
<td>09:44</td>
<td>ERCOT Hot-line call to QSEs to cancel Transmission Emergency for the Rio Grande Valley</td>
</tr>
</tbody>
</table>

Observations and Conclusions from Communications Analysis
Overall communications appeared to work well during the event. The emergency notices issues and Hot-line calls followed established ERCOT procedures. Several areas of improvement were noted:

- With two mitigation plans and one TOAP in place at the time of the event, Texas RE noted some minor confusion and questions on several voice recordings on the part of Transmission Operators regarding which plan was being executed.
- ERCOT Operators should place special emphasis when giving verbal dispatch instructions to ensure that the directive is clear and understandable.

V. Conclusions and Recommendations
The management of operating limits and the steps taken in the recovery from this event were based upon pre-determined mitigation plans that were consistent with the ERCOT System Operating Limit (SOL) methodology, ERCOT Protocols and Operating Guides, and ERCOT desk procedures. There are several opportunities to review and improve the decision-making process regarding contingency definitions used in RTCA as well as the decision-making process for generation outage scheduling which may help prevent a similar event from occurring in the future.

Texas RE has reached the following conclusions and recommendations regarding the event of October 8, 2014:
1. Combined cycle generation contingencies used in Real-Time Contingency Analysis and outage coordination: Prior to the event, the loss of the entire North Edinburg generation plant was not considered as a credible single contingency in Real-time Contingency Analysis (RTCA) or State Estimator. This was based on information provided by the plant owner related to the design of the plant. ERCOT should review the contingency definitions not only for the North Edinburg plant, but other combined cycle plants as well, to determine if the credible single contingency definitions used in RTCA and State Estimator are correct.

2. Operator actions: After the loss of the North Edinburg generation plant, ERCOT operators had one base-case and multiple post-contingency thermal overload conditions to mitigate. The possible courses of action that were reviewed, up to and including the decision to shed firm load, were consistent with ERCOT Protocols, Operating Guides, and ERCOT desk procedures. An operator error was noted with AEP during the event. Upon receiving the load shed instruction from ERCOT, AEP operators selected an incorrect load shed cycle button on their Energy Management System (EMS), which ultimately led to shedding 680 MW of load, rather than the 134 MW of load instructed by ERCOT. The impact of this action was that more than 150,000 customers unnecessarily lost power for approximately 10 minutes, voltages in the immediate area momentarily spiked above normal operating ranges, and system frequency momentarily peaked a 60.13 Hz. AEP has since removed the load shed cycle button from their EMS. Additional training and sharing of lessons learned from the load shed may be warranted due to the AEP operator error during the implementation of the load shed.

3. Generation outage scheduling: Another large generation plant (Duke) and the Railroad DC tie were on outages when the North Edinburg unit trips occurred. This was similar to the Valley event on February 3, 2011 when the Frontera generation plant tripped while the North Edinburg plant was on a scheduled outage, causing firm load shed in the Valley. ERCOT should review its generation outage approval process, especially for areas such as the Valley with geographically-restricted generation. Consideration should be given for combined cycle units to only allow one gas turbine outage at a time, rather than the entire train, and to minimize the amount of time that an entire plant is off-line.

4. Valley Import mitigation planning: Existing Valley Import mitigation plans include load shed plans for the loss of a 345 kV circuit as well as the loss of the largest generation facility, North Edinburg. These plans provided the basis for the load shed actions taken by ERCOT and Transmission Operators. Due to the La Palma – Rio Hondo 345 kV line outage which was in progress at the time of the event, a TOAP was also in place in the east Valley for the loss of the La Palma – Rio Hondo 138 kV circuit. With two mitigation plans and one TOAP in place at the time of the event, Texas RE noted some minor confusion and questions on several voice recordings on the part of Transmission Operators regarding which plan was being executed. ERCOT and Transmission Operators should work together to ensure the utmost clarity when giving and receiving instructions related to these mitigation plans.

5. Generic Transmission Limits and System Operating Limits: ERCOT performed well in managing the flows on the transmission lines feeding the Valley area within the GTLs. No base-case or post-contingency exceedances of the Valley Import GTL
were noted during the event. Following the loss of the North Edinburg units and prior to the load shed, there were base-case and post-contingency System Operating Limit (SOL) exceedances for up to one hour. In some cases, the post-contingency calculated flows were as high as 176% of the emergency rating and 15-minute rating of the circuit. After the load shed, post-contingency SOL exceedances up to 120% were noted until approximately 17:53, or approximately two hours after the start of the event.

6. Protection system performance: Disturbance monitor records do not show any type of fault or disturbance prior to the trip of North Edinburg G3. The plant owner investigated the cause of the North Edinburg G3 transformer trip and determined that the cause of the G3 transformer trip was due to operation of one of the mechanical pressure relief devices on the transformer. The pressure relief device operated due to a defective bladder bag on the transformer, which allowed oil to leak from the conservator into the air cell.

7. Long-term transmission plan for Valley area: The anticipated completion date for the Cross Valley project is in 2016. Until this project is completed, the Valley area remains at risk for similar load shed events. ERCOT should work with affected Transmission and Generation Entities to develop a comprehensive plan for the Valley area to accommodate the Cross Valley project construction, planned generation outages, and ongoing maintenance while minimizing the load shed risk to the area. ERCOT has an understanding with Frontera to commit a portion of the plant generation capacity for the ERCOT region until 2016. In addition, there are multiple wind and gas units that have generation interconnect agreements in place, or are under review for a full interconnect study by request of the developers. The projected commercial operation dates as specified by the resource developers are from June 2015 to June of 2017.