Texas Reliability Entity
Event Analysis

Event:
February 3-4, 2011
Lower Rio Grande Valley Load Shed
Category 2f.1 Event

Texas Reliability Entity
August 26, 2011

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Executive Summary

On February 3, 2011 between 21:37 and 22:00, three units at the Generating Station A tripped causing the loss of 486 Megawatts (MW) of generation in the Lower Rio Grande Valley (LRGV) area. These trips, combined with existing planned generation outages in the area, caused the Valley Import Limit for the LRGV area to be exceeded. In order to prevent uncontrolled loss of load and cascading outages, manual load shed actions were initiated to reduce the transmission import levels below the critical thermal limits. Although the LRGV area has an undervoltage protection system in place, the Transmission Operator (TOP) B took manual control to shed load and did not wait for the Under Voltage Load Shedding (UVLS) relays to operate. A peak of 459 MW of firm load was shed until generation could be brought back on-line. The Balancing Authority (BA) and Reliability Coordinator (RC), worked with other TOPs to initiate mitigation actions to shed firm load.

Observations and conclusions pertaining to the period of February 3-4, 2011 are:

(1) Long-term transmission plan for LRGV area: Transmission Planners should re-consider a previously proposed long-term transmission plan to provide additional import capabilities into the LRGV area.
(2) Generation outage scheduling: The BA and RC should assess and update the generation outage scheduling process for the LRGV area based on the limited availability of generation.
(3) Valley Import mitigation planning: Registered Entities must update the Valley Import mitigation plans to include generation and DC tie contingencies, until a long-term transmission upgrade is completed.
(4) Communications: Registered Entities should review all communications procedures and policies related to grid emergencies with appropriate media, and regulatory agencies.
(5) System Operating Limits (SOLs):
    (a) The RC must clearly identify SOLs and supporting documentation used to determine SOLs, especially SOLs that are based on a combination of multiple transmission elements rather than single elements.
    (b) The RC must review multi-element SOLs used in the Energy Management System applications, with emphasis on RTCA and State Estimator and associated System Operator actions.

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.

I. Event Overview

On February 3, 2011 at approximately 05:58, extreme low temperatures, combined with high loading conditions and scheduled generation outages, caused the LRGV area Valley Import Limit of 1100 MW to be exceeded and remain above the limit throughout the day.

There are three independent power producers (IPPs) located in the LRGV area with a capacity of more than 2200 MW. Transmission Operator B, Transmission Operator C, and Transmission Operator D are Transmission Owners in the LRGV serving load to customers on the distribution systems in the area.

On February 3, 2011, the LRGV area hit an all-time high winter peak load of 2734 MW. The previous winter peak was 2378 MW set in 2010. The all-time summer peak was 2241 MW also set in 2010.

The LRGV area is supported by two 345 kV transmission lines from the Corpus Christi area and by three 138 kV transmission lines.

The RC manages the LRGV area transmission with a System Operating Limit called the Valley Import Limit. The Valley Import Limit protects the lines in the Rio Grande Valley primarily from the loss of one of the 345 kV lines. At high Valley imports, loss of one of those lines could cause overloads of the remaining 138 kV lines. During normal system conditions, the Valley Import interface is constrained to approximately 1100 MW into the Valley. This is a conservative operations limit based upon studies indicating that thermal ratings on the Valley Import lines could be exceeded post-contingency with import exceeding approximately 1200 MW. Additional detail on the Valley Import Limit can be found in Section IV.c.

At 21:37 on February 3, 2011, Generation Station A Unit 2 tripped offline dropping 158 MW of generation in the LRGV area. The cause of the trip was the opening of the compressor bleed valve due to loss of plant instrument air due to freezing issues. Generation Station A Unit 1 tripped offline at 21:59, dropping 111 MW of generation, due to a low high-pressure (HP) drum level caused by loss of plant instrument air. Generation Station A Unit 3 subsequently tripped offline at 22:00 following the loss of the above units. The sum of generation lost was 486 MW within 23 minutes. System frequency was relatively unaffected by these unit trips.

Two other large generation plants in the LRGV area were on a scheduled maintenance outage when a cold front migrated through the Valley. The transmission import level into the LRGV exceeded the 1100 MW Valley Import Limit on February 3, 2011 at 05:58 and remained above this level for over 31.4 hours until February 4, 2011 at 13:20. When the three (3) Generation Station A generation units (total of 486 MW) tripped at approximately 22:00, the import level increased to 2077 MW at its peak, or 188.9% of the Valley Import Limit of 1100 MW. The 345 kV bus voltages at one substation also dropped to a low of 313 kV (0.91 per unit). At this point, if either one of the 345 kV transmission lines into the LRGV was lost, the automatic undervoltage load shed (UVLS) scheme for the LRGV probably would have activated to help prevent uncontrolled loss of load and cascading outages.

Transmission Operator B had previously developed a mitigation plan with the RC, Transmission Operator C, and Transmission Operator D 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. The Transmission Operator B Transmission Operator used the mitigation steps of this plan, even though the specific generation loss contingency was not part of the mitigation plan. To reduce the import level, the Transmission Operator B Transmission Dispatch Center (TDC) dispatcher instructed Transmission Operator B Distribution Dispatch Center (DDC) dispatcher to shed 300 MW of load at approximately 22:06 and notified the RC about the load shed. At 22:19, the TDC dispatcher instructed the DDC dispatcher to stop load shedding since the import level had dropped to approximately 1750 MW. At 22:42, Transmission Operator B called the RC to request that Transmission Operator C and Transmission Operator D to shed their share of the load. This was requested so Transmission Operator B could restore Transmission Operator B load to the percentages previously agreed to as specified in the mitigation plan for the 345 kV line loss contingency. Transmission Operator C and Transmission Operator D completed their share of the load shed (~ 96.5 MW combined) by 22:53.

During the rolling blackout period, approximately 115,000 customers were affected, based on OE-417 report submission. The peak firm load shed during the rolling blackouts was 459 MW at 23:00 as shown in Table 1.

Entity	Customers Affected	Obligation	Firm Load Shed
Transmission Operator B	85,000	60%	345.7 MW maximum
Transmission Operator D	10,400	20%	61.4 MW maximum
Transmission Operator C	19,600	20%	53.7 MW maximum

Table 1: Customer Impact from Firm Load Shed

This event did not meet the criteria as a NERC Disturbance Control Standard (DCS) event since the loss of generation was below the 1083 MW threshold for the ERCOT Region. The event met the definition of a Category 2f.1 event (Load shedding resulting in a loss of load of 100 MW or greater as a result of manual load shedding) under NERC's Event Analysis procedure. The event met the criteria for OE-417 reporting due to load shedding of 100 MW or more implemented under emergency operational policy, public appeals to reduce the use of electricity for purpose of maintaining the continuity of the electric power system, and loss of electric service to more than 50,000 customers for one hour or more.

II. Initial System Conditions Prior to Event

Initial system conditions just before the event at February 3, 2011 18:00 were:

High Forecasted Pk HR Demand:	57,059 MW @ 2000 HR
Seasonal Pk:	56,830 MW
System Projected Pk HR Demand:	57,293 MW @ 2000 HR
System Generation for Pk HR Demand:	59,036 MW @ 2000 HR
Load Shed Risk:	Medium @ 0300 HR

Valley Net Scheduled Generation:	1020 MW
Valley DC Tie Flows:	0 MW
Valley Area System Load:	2680 MW

Weather in the major cities around the the RC Region just before the event:

City	Temp (F), High/Low	Conditions
Austin	27/17	Sunny
Brownsville	31/26	Sunny
Corpus Christi	30/21	Partly Cloudy
Dallas	22/15	Cloudy
Houston	36/26	Sunny
Midland/Odessa	35/9	Sunny
San Antonio	31/20	Sunny

III. Sequence of Events on February 3-4, 2011

February 3, 2011

- 04:15 Valley import constraint binding in Security Constrained Economic Dispatch (SCED)
- 05:58 Valley import flow exceeded 1100 MW operational import limit
- 06:42 Transmission Operator B, Transmission Operator C, and Transmission Operator D instructed to increase transmission voltages
- 07:02 DC ties curtailed due to transmission outages (150 MW)
- 17:35 RC issued a Transmission Watch due to forecasted weather condition
- 18:30 Valley area hits peak load of 2765 MW
- 21:37 Generation Station A Unit 2 tripped off-line with 158 MW

- 21:48 Generation Station A Unit 3 started to ramp back from 170 MW
- 21:48 Valley Import ramp up from ~ 1,600 MW to 2,077 MW over the next 16 minutes
- 21:53 Generation Station A Unit 1 started to ramp back from 158 MW
- 21:59 Generation Station A Unit 1 tripped off-line with 111 MW
- 22:00 Generation Station A Unit 3 tripped off-line with 47 MW
- 22:04 Valley import rose to 2057 MW; Voltage at 345 kV bus dropped to 313 kV or 0.0907 p.u.
- 22:06 Transmission Operator B notified the RC that it would shed approximately 300 MW of firm load
- 22:29 RC issued Transmission Emergency Notice due to forecasted weather condition
- 22:42 Transmission Operator C and Transmission Operator D instructed to drop their share of the firm load as described in the mitigation plan. The load ratio share to Transmission Operator B, Transmission Operator C, and Transmission Operator D was 60%, 20%, and 20%, respectively.
- 22:47 Valley Import return from ~ 2,077 MW to 1,600 MW range
- 22:48 Transmission Operator C reported approximately 53.7 MW of firm load shed at this time, affecting approximately 19,600 customers
- 22:53 Transmission Operator B reported 345.7 MW of load shed at this time, affecting 85,000 customers
- 22:53 Transmission Operator D reported approximately 42.8 MW of firm load shed at this time, affecting approximately 10,400 customers
- 23:35 Transmission Operator B restored 93.8 MW (approximately 251.9 MW of Transmission Operator B load remaining). Transmission Operator B requested the RC to have Transmission Operator D and Transmission Operator C to restore 10 MW each
- 23:41 Transmission Operator C restored 10 MW

- 23:47 Transmission Operator D restored 10 MW

- 23:48 Transmission Operator B requested the RC to have Transmission Operator D and Transmission Operator C to restore 10 MW each

<u>February 04, 2011</u>

- 00:02 Transmission Operator D restored 10 MW

- 00:15 Transmission Operator C restored 10 MW

- 00:18 Transmission Operator B restored 39.5 MW (approximately 212.4 MW of Transmission Operator B load remaining). RC requested Transmission Operator C and Transmission Operator D to restore 15 MW each

- 00:25 Transmission Operator C restored 15 MW

- 00:26 Transmission Operator D restored 15 MW

- 00:29 Transmission Operator B restored 55.3 MW (approximately 157.1 MW of Transmission Operator B load remaining). Transmission Operator B requested the RC to have Transmission Operator D and Transmission Operator C to restore remaining load.

- 00:33 Transmission Operator C restored its remaining 18 MW

- 00:41 Transmission Operator D restored 23 MW (approximately 1.2 MW of Transmission Operator D load remaining).

- 01:01 Generation Station A Unit Unit 1 returned back to service

- 01:33 Generation Station A Unit Unit 1 tripped off-line (during ramp-up)

- 03:04 Generation Station A Unit Unit 2 returned back to service

- 04:14 Generation Station A Unit Unit 3 returned back to service

- 04:35 Generation Station A Unit Unit 1 returned back to service

- 05:10 Media Appeal issued by the RC

- 12:32 RC Cancelled Transmission Emergency Notice

- 13:20 Valley import flow below 1100 MW operations import limit

- 13:54 RC Cancelled Transmission Watch
- 14:35 Transmission Operator D restored remaining 1.2 MW of load
- 23:28 Transmission Operator B completed the recovery by restoring the remaining load

IV. Analysis of Event

A. Generation Station A Unit Trips

Generation Station A Unit 2 tripped offline on February 3, 2011 at 21:37 due to high exhaust pressure. The cause of the trip was the opening of the compressor bleed valve due to loss of plant instrument air. The unit was loaded at 158 MW. At this time, Generation Station A Unit 1 started a run-back from a load level of 158 MW and Generation Station A Unit 3 started a run-back from a load level of 170 MW. Generation Station A Unit 1 tripped offline on February 3, 2011 at 21:59 due to a low high-pressure (HP) drum level caused by loss of plant instrument air. Generation Station A Unit 3 tripped offline on February 3, 2011 at 22:00 following the loss of the Unit 1 unit. The sum of generation lost was 486 MW within 23 minutes (nameplate rating of the combined cycle train is 529 MW).

Generation Station A restarted and synchronized the Unit 1 unit on February 4, 2011 at 01:01. However, the unit tripped again at 01:33 during ramp-up due to a gas control valve (GCV) out of position caused by a failed servo valve.

The Unit 2 unit was returned to service at 03:04. The Unit 3 unit was returned to service at 04:14. The Unit 1 unit was returned to service at 04:35.

Generation Station A identified the cause of the unit trips as due to the loss of plant instrument air. Plant air compressor drains began to freeze due to high winds, freezing rain and low temperatures. The plant instrument air pressure transmitter froze causing a shutdown of the plant air compressors. The loss of instrument air affected all plant air operated valves.

A temporary shelter was built using tarps to help reduce the wind and freezing rain effects on the compressor skid. Flood lights and extra insulation was added where needed to increase the temperature. These measures were completed just prior to the first restart on Unit 1 at 01:01 on February 4, 2011.

B. Transmission Operator B

Transmission Operator B experienced several transmission issues indicated in the following table during the event. The transmission line outages listed increased the risk to the system, but were not considered a contributing cause to the Valley load shed event.

During this period, a Static Synchronous Compensator tripped at 20:56, or approximately one hour 10 minutes prior to the load shed actions. The Static

Synchronous Compensator could have been used to help support the voltage in the area; however, it tripped offline due to the loss of its auxiliary power sources which are fed from a local distribution circuit. The loss of the Static Synchronous Compensator also increased the risk to the system, but was not a contributing cause to the Valley load shed event. The reliability of Static Synchronous Compensator auxiliary power is under review by Transmission Operator B in order to reduce future risk to the system.

C. Valley Import Transmission Limit

The Valley Import Limit is composed of the following BES elements:

Transmission Lines	Normal Limit MVA	2-hour Limit MVA	Emerg Limit MVA
345kV Line E	1011	1176	1176
345kV Line F	1011	1195	1195
138kV Line G	216	216	216
138kV Line H	211	239	239
138kV Line J	245	356	356

The RC manages the LRGV area transmission with a SOL called the Valley Import Limit, which protects the lines in the Rio Grande Valley upon the contingency loss of one of the 345 kV lines. A contingency loss of one of the 345 kV lines while exceeding the Valley Import Limit would cause overloads and cascading outages resulting in loss of load in the Rio Grande Valley. The following table provides additional details of the Valley Import limit.

Valley Transmission Import Limit	Value
Operations Limit	1100 MW
Single Contingency Thermal Limit	~ 1200 MW
One 345kV Circuit Out-of-Service	400 MW

Table 2: Valley Import Limit Values

During normal system conditions, the Valley Import interface is constrained to approximately 1100 MW into the LRGV. This is a conservative operations limit based upon studies indicating that (1) thermal ratings on the Valley Import lines could be exceeded post-contingency, and (2) voltage stability in the LRGV area could be compromised with import exceeding approximately 1200 MW.

On February 3, 2011, the transmission import level into the LRGV exceeded the 1100 MW Valley Import Limit at 05:58 and remained above this level for over 31.4 hours until February 4, 2011 at 13:20. The import level into the LRGV exceeded 1200 MW at 06:22 and remained above this level for over 30.5 hours until February 4, 2011 at 12:55.

An automatic undervoltage load shed (UVLS) scheme is in service in the LRGV to drop load to prevent uncontrolled loss of load and cascading outages. The UVLS has two setting levels; one level has a one-time delay setting that trips approximately 30% of the load in 2 seconds at 75% or 85% voltage level depending on load location in the LRGV. The second level has multiple time delay settings that trip load at 90% voltage

RC SOL Methodology

From the document, *System Operating Limit Methodology for the 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. System Operating Limits are based upon certain operating criteria. These include, 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 Energy Management System (EMS) Real-Time Contingency Analysis (RTCA) is utilized to determine SOLs. When RTCA indicates a facility rating exceedance post-contingency for an element for a given contingency, congestion management techniques are employed per the *RC Operations Transmission and Security Desk Procedure (Appendix 5)*. Once an RTCA potential post-contingency rating exceedance is confirmed as valid, the facility rating on the associated element becomes an SOL.

The RC 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) Potential IROLs will be investigated when the RTCA application indicates a thermal rating exceedance in excess of 125% of the SOL of the monitored facility rating (Emergency Rating).
(b) Potential IROLs will also be investigated for base case exceedance greater than 100% of the normal facility ratings.
(c) Potential IROLs will also be investigated when the Real-Time Contingency Analysis application indicates an under-voltage condition characterized by bus voltages of less than 90% across three or more related BES facilities or an over-voltage condition greater than 110% across three or more related BES facilities.

If an SOL exceedance identified is validated (i.e. no bad SCADA or model data, etc.), then an off-line study shall be performed for the contingency which identified the SOL exceedance. The element identified as having the SOL exceedance shall be opened, and the system response to the loss of this will be evaluated. If the results of this evaluation indicate cascading outages or voltage collapse which is not confined, then this SOL exceedance is considered to be an IROL.

Per the *System Operating Limit Methodology for the Operations Horizon*, in determining the system's response to a single Contingency, the following shall be acceptable:

(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) 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, e.g., load greater than studied. System reconfiguration through manual or automatic control or protection actions.

Per this procedure, a mitigation plan was developed between Transmission Operator B, the RC, Transmission Operator C, and Transmission Operator D which predetermined the load allocation of any necessary manual load shed actions for the Valley import contingency loss of one of the 345kV circuits.

Also according to the RC, the Valley Import level SOL would never be considered as a potential IROL since outages resulting from the Valley Import SOL contingencies would be localized to the LRGV and would not expose the entire ERCOT Region to instability, uncontrolled separation, or cascading outages. However, exceeding the Valley Import Limit can expose the LRGV to possible cascading outages and separation even with the UVLS protection in place.

The RTCA output shows the base case violations for February 3-4, 2011. The outputs shows that there were no instances of individual Valley import transmission elements being overloaded by more than 125% of its facility rating, which would necessitate its evaluation as a possible IROL. However, the RTCA does not monitor or report violations of the aggregate Valley Import Limit, as it is monitored differently than the discreet elements which constitute the Valley Import Limit. This may constitute a possible gap in the situation awareness tool for the System Operators.

<u>LRGV Area Generation</u>
The LRGV area is supported by local generation. There were multiple planned generation outages in the LRGV area during this event. Approximately 1004 MW of nameplate capacity (829 MW winter sustained rating) was unavailable due to these planned outages.

The scheduled outages left only Generation Station A, Generation Station K and Generation Station L available in the LRGV area, with approximately 1200 MW of remaining generation nameplate capacity (1045 MW winter sustained rating).

With an 1100 MW Valley Import Limit, and available LRGV generation of only 1045 MW (winter rating), the LRGV load was theoretically limited to 2145 MW, not including any import through the south DC ties. This indicates that the RC was not secure to meet its most severe single contingency (a status called “N minus one” or “n-1”). The RC was not n-1 compliant for the loss of one of the 345 kV lines at LRGV loads greater than 1445 MW and was not n-1 compliant for the worst case generator loss contingency at

LRGV loads greater than 1651 MW. As stated previously, on February 3, 2011, the LRGV area hit an all-time high winter peak load of 2734 MW. The previous winter peak was 2378 MW set in 2010.

The following graphs show LRGV Area demand and generation in relation to the Valley Import Limit. As previously stated, the Valley Import Limit was exceeded from 05:58 on February 3, 2011 until 13:20 on February 4, 2011 due to the generation outages and high loads in the LRGV. The trips of the Generation Station A generation units from 21:37 to 22:00 caused the Valley import to reach a maximum flow of 2077 MW at 22:03. DC tie flows were unavailable due to transmission issues.

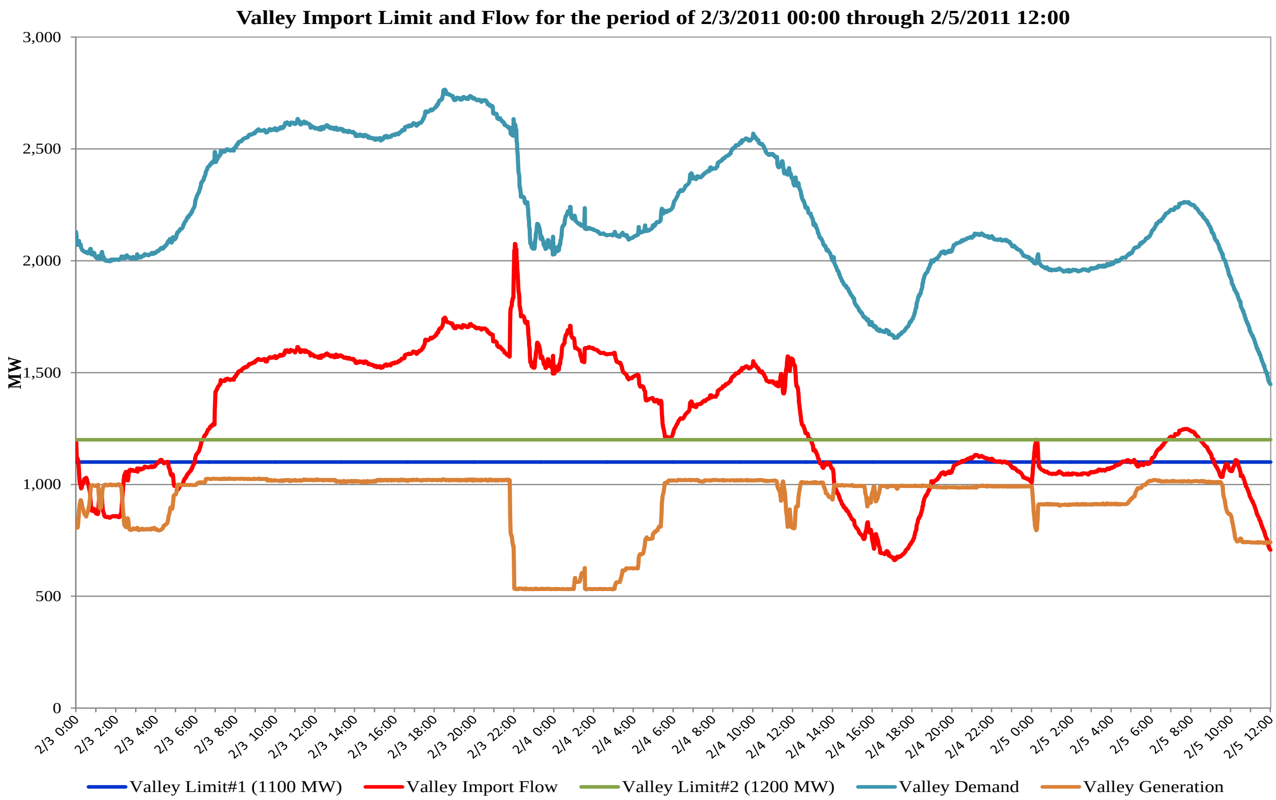

Figure 1: Valley Import Flow, Demand, and Generation

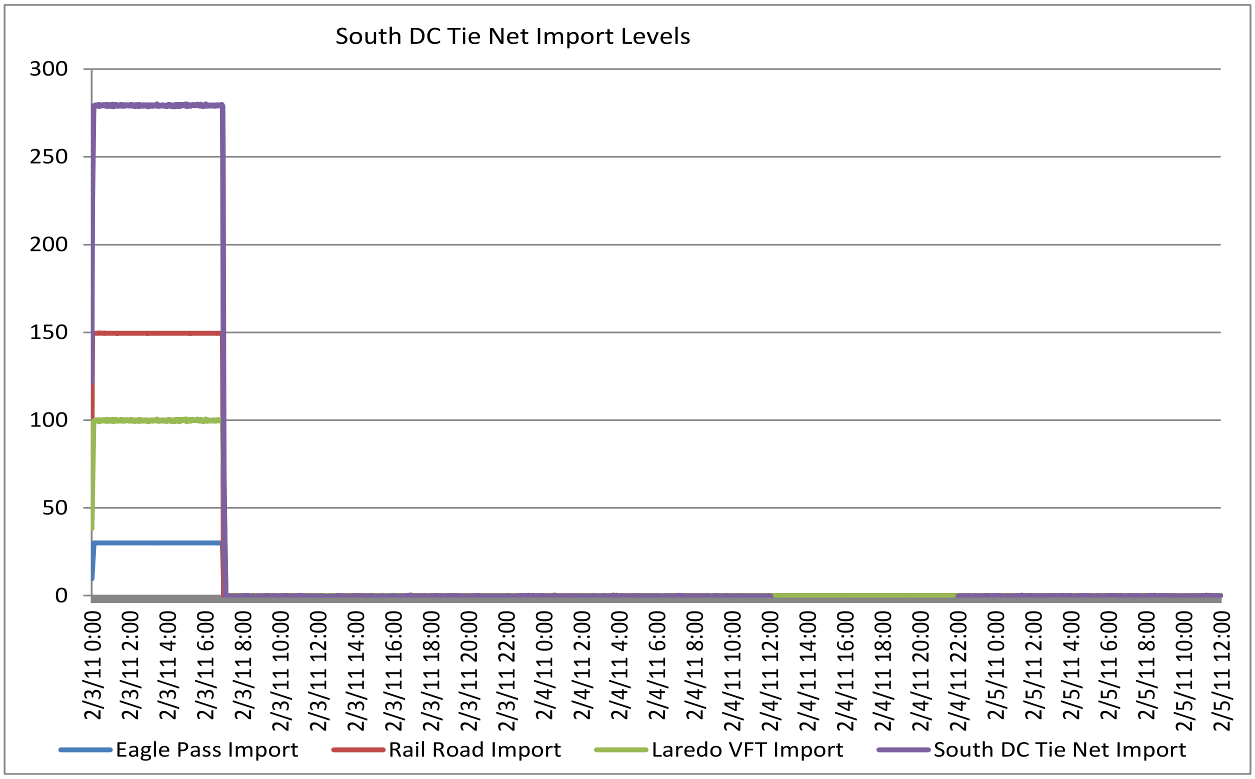

Figure 2: DC Tie Imports

From the time when the Valley Import Limit was initially exceeded (05:58) until the initial Generation Station A Unit trip (21:37), the RC did not issue any Verbal Dispatch Instructions (VDIs) or seek commitments for additional generation to come on-line through the Daily Reliability Unit Commitment (DRUC) and Hourly Reliability Unit Commitment (HRUC) process for February 3, 2011 to relieve the Valley Import Limit violation. A previous VDI and Hot-Line call (February 3, 2011 @ 08:45) was in-place instructing all Qualified Scheduling Entities (QSE's) to not take any generation off-line without contacting the RC through February 4, 2011 at 15:00.

D. Response Actions

From the document, *System Operations Procedure-Congestion Management Plans*, a mitigation plan is defined as an action plan that the RC and Transmission Owners (TOs) agree to execute post-contingency to reduce overloading on a given monitored element or elements to below the Normal/Continuous rating.

The mitigation plan in effect for a loss of either of the 345 kV lines into the LRGV region calls for two possible post-contingency actions on the part of the RC:

(1) Procure power across the DC tie

(2) Upon loss of either 345 kV line with additional generation unavailable, shed LRGV load in 100 MW blocks according to the following ratios until the Valley import is below 400 MW.
   - Direct Transmission Operator B to shed 60 MW of firm load
   - Direct Transmission Operator C to shed 20 MW of firm load from Magic Valley
   - Direct Public Utility of Brownsville to shed 20 MW of firm load

The mitigation plan does not specifically list the loss of local LRGV generation as a possible contingency requiring manual load shedding. The mitigation plan also states that load should be shed until the Valley Import is below 400 MW. During the event on February 3-4, 2011, Transmission Operator B and the RC Transmission Operators did not follow the mitigation plan as explicitly stated, instead deciding to manually shed enough load to closely match the amount of generation lost, which in turn, reduced the Valley import to approximately 1600 MW. The following tables and chart summarizes the load-shed obligation and actions.

Transmission Operator	Assigned % Shed	Assigned MW Shed	Actual MW Shed (Maximum)
Transmission Operator B	60	156	345.7
Transmission Operator D	20	52	61.4
Transmission Operator C	20	52	53.7
TOTAL	100	260	459.5

Load Shed by each Entity and load restoration time:

Time	Transmission Operator D Net MW	Transmission Operator C Net MW	Transmission Operator B Net MW	Valley Total MW
22:06			3.2	3.2
22:10			71.6	71.6
22:13			148.5	148.5
22:16			192.6	192.6
22:19			232.1	232.1
22:40			260.9	260.9
22:43	12.4		312.5	324.9
22:47	36.3	53.7	315.2	405.2
22:53	42.8	53.7	345.7	442.2
23:50	61.4	53.7	252.9	368
0:01	42.5	33	279	354.5
0:23	35.6	18	178.2	231.8
0:34	24.2	0	140.4	164.6
0:41	1.2		129.1	130.3
14:35	0		67.3	67.3
14:55			65.4	65.4

15:43			61.8	61.8
16:15			59.3	59.3
16:28			55.5	55.5
16:51			50	50
19:21			44.5	44.5
20:20			41.5	41.5
21:35			29.9	29.9
22:10			22.2	22.2
22:58			13.1	13.1
23:04			4	4
23:28			0	0

Table 3: Manual Load Shed by Entity

The following chart shows the real-time performance of the load shed actions that were taken.

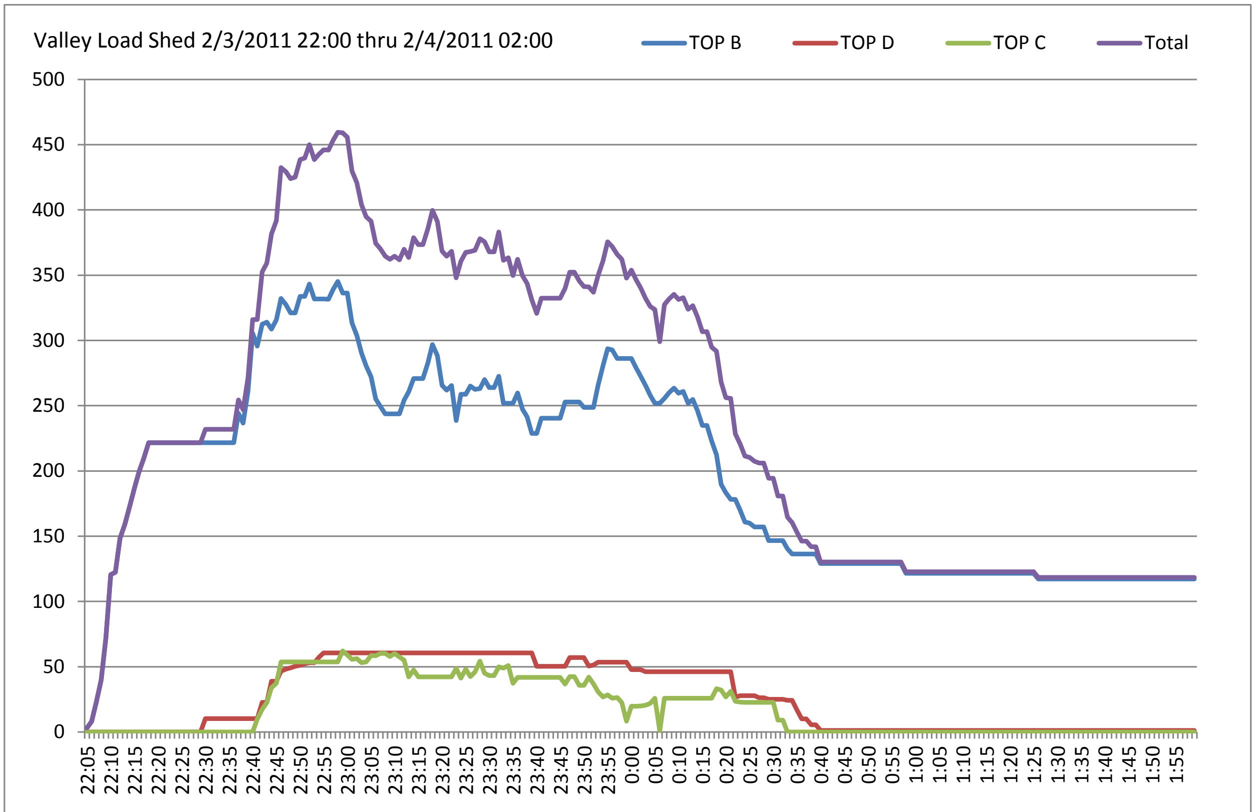

Figure 3: Real-time Manual Load Shed Performance

<u>LRGV Area voltages</u>

From approximately 21:56 to 22:15 on February 03, 2011, the ERCOT Region experienced low voltage conditions in the LRGV area. Voltage dropped below 0.91 p.u. in the area by 22:01.

The load shed actions taken by Transmission Operator B, Transmission Operator D, and Transmission Operator C temporarily resolved the voltage issues in the LRGV area and also reduced the Valley Import from a peak of 2077 MW to approximately 1600 MW until the Generation Station A generation units were restarted at approximately 03:04 on February 4, 2011.

Communications

The Valley Import Limit was exceeded at 05:58 on February 3, 2011 and remained above the limit throughout the day. the RC did not issue a Transmission Watch for the Valley area until 17:30, 11.5 hours later.

The trips of the Generation Station A generation units from 21:37 to 22:00 caused the Valley Import to reach a maximum flow of 2077 MW at 22:03. The RC did not issue a Transmission Emergency for the LRGV area until nearly 30 minutes later, at 22:29.

The RC did not issue a media appeal for energy conservation until 05:10 on February 4, 2011, seven (7) hours after the load shed event occurred.

V. Observations

The events of February 3-4, 2011 represented an extreme case due to record loads, lack of generation availability, as well as a geographically restrictive generation dispatch pattern. As such, the LRGV import paths were loaded well beyond any n-1 criteria necessitating the dependence upon automatic load shedding schemes and manual intervention. The following are either potential contributing factors to this event or are “Lessons Learned” that, while not contributing to the LRGV load shed event of February 3-4, 2011, describe potential process or equipment improvements that could help to address similar situations in the future and require further study.

Generation Availability

Multiple generating units were scheduled out of service in a possible transmission constrained area during this time period while a record level of load was experienced. If additional local generation had been available, record levels of imports and the need for manual load shedding potentially could have been avoided. However, it is unknown whether cold weather issues or fuel supply would still have negatively affected generation availability even if these units had not been on scheduled maintenance.

Transmission Planning

Although this was an extreme event, similar events could potentially be addressed through the planning process and the construction of additional import capability in the LRGV region. The area is dependent upon local generation and import through the DC ties to relieve possible transmission thermal constraints and voltage stability issues.

Considering that there is 2200 MW of local generation and a Valley Import Limit of 1100 MW and, with winter peak loads over 2700 MW, there is little flexibility in scheduling of generation or transmission maintenance outages. The RC may not necessarily have as much control over the timing of generator maintenance outages as it does with transmission outages. In addition, the need for transmission maintenance may not be known well in advance, since it is dependent upon the findings of routine inspections. When maintenance on the Valley Import transmission facilities must be scheduled, local generation in the LRGV area must be available to compensate for the reduction in transmission import capability.

Transmission Equipment

The Static Synchronous Compensator could have been used to assist with voltage support in the Brownsville area; however, it tripped offline due to the loss of its auxiliary power sources. The loss of the Static Synchronous Compensator increased the risk to the system but was not a contributing cause to the LRGV load shed event. However, it is unclear if the RC identified or established a new voltage stability limit when the Static Synchronous Compensator went out of service.

Transmission Operations

When the Valley Import Limit was exceeded, it appears that the RC and Transmission Operator B Transmission Operators chose to accept the risk of a contingency loss of one of the 345 kV circuits since there was an existing mitigation plan in place. With no additional LRGV generation or DC tie capacity available to reduce the import levels, the only options available to Transmission Operators were to reduce load and to rely on existing UVLS protection. However, the RC mitigation plan that was in place did not list or appear to consider, the loss of local generation as a possible contingency that would necessitate manual load shedding in the LRGV area.

Communication

Overall communication appeared to be very poor during this event. The RC did not issue a Transmission Watch for the LRGV area until 11.5 hours after the import limit was exceeded. The RC did not issue a Transmission Emergency for the LRGV area until 30 minutes after the final Generation Station A generation unit trip.

Finally, a media appeal for energy conservation in the LRGV area was not issued until 05:10 on February 4, 2011, seven (7) hours after the load shed event, rather than earlier on February 3, 2011 when the Valley Import was exceeded.

Registered Entity Corrective Actions Taken

Equipment owners have taken the following actions to address the problems noted:

- Transmission Operator B is reviewing the reliability of station auxiliary power for the Static Synchronous Compensator facility in order to reduce future risk to the system.

- A proposal has been submitted to build a new 345 kV line into the LRGV area from Laredo to mitigate the issues observed on February 3-4, 2011.
- Transmission Operator D identified log record-keeping as an area which it needs to improve, including:
  - Training on reportable content, and
  - Automation for accurate event capture.

VI. Conclusions and Recommendations

In general, the steps taken led to the recovery from this event. However, given the length of time that the LRGV system was being operated with increased risk, the magnitude of the event, and the necessity for accurate and timely communications, the RC and Transmission Operators could have handled the situation more effectively.

Texas RE has reached the following observations and conclusions regarding the events of February 3-4, 2011.

(1) Long-term transmission plan for LRGV area: Transmission Planners should re-consider a previously proposed long-term transmission plan to provide additional import capabilities into the LRGV area.

(2) Generation outage scheduling: The RC must assess and update the generation outage scheduling process for the LRGV area based on the limited availability of generation.

(3) Valley Import mitigation planning: Registered Entities must to update the Valley Import mitigation plans to include generation and DC tie contingencies, until a long-term transmission upgrade is completed.

(4) Communications: Registered Entities should review all communications procedures and policies related to grid emergencies with appropriate media, and regulatory agencies.

(6) System Operating Limits (SOLs):

  (a) The RC must clearly identify SOLs and supporting documentation used to determine SOLs, especially SOLs that are based on a combination of multiple transmission elements rather than single elements.

  (b) The RC should to review multi-element SOLs used in the Energy Management System applications, with emphasis on RTCA and State Estimator and associated System Operator actions.