FINAL REPORT ON THE

AUGUST 18, 2004 DCS EVENT

ERCOT COMPLIANCE

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EXECUTIVE SUMMARY

On August 18, 2004, at 9:59:20, ERCOT experienced a NERC Disturbance Control Standard (DCS) event. This standard measures the ability of a control area to recover from significant frequency disturbances. Qualifying DCS events are initiated by loss of generation totaling between 80% and 100% of the largest single contingency, and frequency must recover within 15 minutes. In ERCOT, the largest single contingency is a loss of one unit at the South Texas Project Plant, whose capability is 1250 MW.

The initiating event occurred at the Valley substation, where personnel were not aware of changes made earlier to a breaker wiring scheme. The crew's testing arrangements did not fully isolate part of the substation protective relaying. When the crew closed the breaker for testing, the entire 345 kV bus tripped, as well as a 138/345 kV autotransformer. Several cycles later, a Special Protection Scheme (SPS) activated due to conditions that were sensed at the 138 kV end of the tripped autotransformer. The bus trip caused two blocks of generation to trip, while the SPS operation caused another remote block to go offline. In total, 1115 MW of generation tripped and the ERCOT frequency dropped to 59.77 Hz.

ERCOT was in the middle of ramping between intervals at the hour ending 10:00, while a large schedule change was in progress at the time of the event. Even though load was increasing, a large amount of down balancing energy was deployed because the QSEs' scheduled more generation than the forecast. Up Regulation and Responsive Reserve energy deployed immediately after the event began.

Faulty SCADA data hindered operations at ERCOT. ERCOT was initially unaware of the full extent of the unit trips, since one block of generation telemetered bad data—after the 345 kV bus trip—for nearly one hour.

Various other problems compounded the effects of the three above including other smaller unit trips, poor governor performance, QSE failures to understand and meet ERCOT Protocol Standards, as well as meeting ramp rates stated in QSE Resource Plans. Twelve QSEs were asked to explain their Schedule Control Error (SCE) performance.

Items for follow up are included at the end of the report. Internal discussion of the event and QSE responses brought forward many issues that must be looked into further including: manual dispatching of responsive reserves, increasing the percentage deployment of generator responsive reserve and adjusting the frequency bias and control algorithm.

I. DESCRIPTION OF EVENT

A. Overview

On August 18, 2004 at 9:59 AM, a TXU Electric Delivery (TXUED) maintenance crew was in the process of performing routine maintenance on Valley switchyard breaker 4036. A work scope had been prepared ahead of time and the maintenance crew was working according to the outlined procedures. Changes made to breaker 4036's relay wiring scheme in the field by TXU Energy were not represented on any of TXUED's schematics located at the station.

At the moment the crew personnel closed breaker 4036, the Valley 345 kV bus and 345/138 kV autotransformer tripped and locked out, ultimately resulting in the loss of 1115 MW from the ERCOT grid.

B. Event Details

TXU Energy's changes to breaker 4036 were such that a follower relay was connected in parallel across a fault detector that activates breaker 4036. The crew from TXUED was unaware of the changes, thus when the breaker was closed, the breaker failure scheme operated. The backup bus timer on the 345 kV bus activated and timed out, thus tripping the entire 345 kV bus and the Valley SES 138/345 kV autotransformer. Breaker 4036 did not trip because remote tripping had been disabled[1].

With the 345 kV bus off line, lines from Valley to Farmersville, Paris, Anna, and Kiowa substations were de-energized from the Valley end.

One of QSE 22's plants feeds directly into the Valley 345 kV bus; this bus is the only connection the plant has into the ERCOT grid (the plant can also feed into SPP). The plant was producing 650 MW when it tripped off line at 9:59:28, thus 650 MW of generation was instantly removed from the ERCOT system.

In addition to the QSE 22 unit trip, SCADA data from the QSE failed to report that the three units tripped. Bad telemetry data was sent for nearly one hour until the data was corrected. The telemetered value of the plant's generation remained at the last good value, and this caused ERCOT operators not to fully realize the extent of generation that tripped at 9:59:20.

[1]TXU Electric Delivery's Event Investigation Report, see Appendix A.

Paris SPS #4 detected an overload condition on the 138 kV line due to the loss of the 345 kV bus and autotransformer at Valley. This operation caused three units—totaling 466 MW—from QSE 8 to go offline; one unit tripped every fifteen second to relieve loading on the 138 kV bus.

The Valley 138/345 kV autotransformer was in a tripped state for nearly 30 minutes, from 9:59:37 to 10:28:57. The Valley 345 kV bus was de-energized for nearly 9 minutes, 9:59:51 to 10:08:49.

C. Special Protection Scheme (SPS) Operation

The Valley bus and autotransformer trip created an overload condition on the 138 kV transmission line from Paris to Valley Switch. The Paris SPS was activated to relieve this overload condition: breakers CB_7310 and CB_7290 were opened and one block of generation (3 units) from QSE 8 tripped off line. The total generation lost at the plant was 466 MW, thus relieving the overload condition.

Appendix B details what the SPS measures, at what level it takes action and the steps it takes to relieve overloading conditions on the measured transmissions lines. The SPS had been in operation since 2000 and had no mis-operations before the August 18, 2004 event.

It should be emphasized that the SPS operated as it was designed to do as a result of an overload on the 138 kV line.

D. Unit Trip Conclusion

Though related by a common root cause, the unit trips on August 18, 2004 were not preventable by any action on the part of the QSEs or ERCOT. The root cause here was breaker maintenance at a switchyard that did not take into account design modifications made in the field.

QSE 22's units had no other bus to send power into ERCOT and were forced to trip. The Paris SPS detected an overload on the Paris line and sent trip signals to one block of QSE 8's units. All protection schemes on the Valley bus and at the various PGCs operated correctly.

In regards to TXU Energy's involvement in the event, a more stringent process should be in place to make modifications in the field. The equipment panels' design and testing procedures could also have provided for better isolation of the breaker in test. Further review of other substations, switchyards or other transmission facilities to discover out-of-date schematic diagrams has begun.

II. SYSTEM RESPONSE TO GENERATION LOSS

ERCOT originally stated that 1420 MW of generation tripped during the event[2]. According to NERC Policy 1.B, reportable events are those greater than or equal to 80% of the most severe single contingency loss in the control area[3]. At 1420 MW the event would be beyond 100% of the severest single contingency—loss of one of the 1250 MW units at South Texas Project—and thus not reportable to NERC. However, subsequent review during preparation of the quarterly Regional DCS report, as well as the event disturbance report, showed that generation loss was less than the largest single contingency, and thus reportable to NERC.

Frequency recovery began as expected with deployment of ancillary services. Approximately 10 minutes into the event, frequency recovery stalled for 6 minutes. The stall was apparently due to a combination of factors including, a large load increase of 900 MW, and a large amount of down balancing in progress at the beginning of the event.

If there had been no large load increase as ERCOT was recovering system frequency—all other factors being the same—the overall recovery time back to 60 Hz would have been several minutes shorter and within the required DCS standard. See Figure 1, note points where frequency stalled and recovered to 60 Hz.

This conclusion is supported by ERCOT's recovery on August 19, 2004—an unrelated DCS event on the next day. The August 19th event had a similar loss of generation, but did not have comparable schedule and load issues.

[2] 1420 MW was entered into supervisor log, see Appendix D, log ID 140028
[3] North American Electric Reliability Council, Policy 1 - Generation Control and Performance, Section 2.4

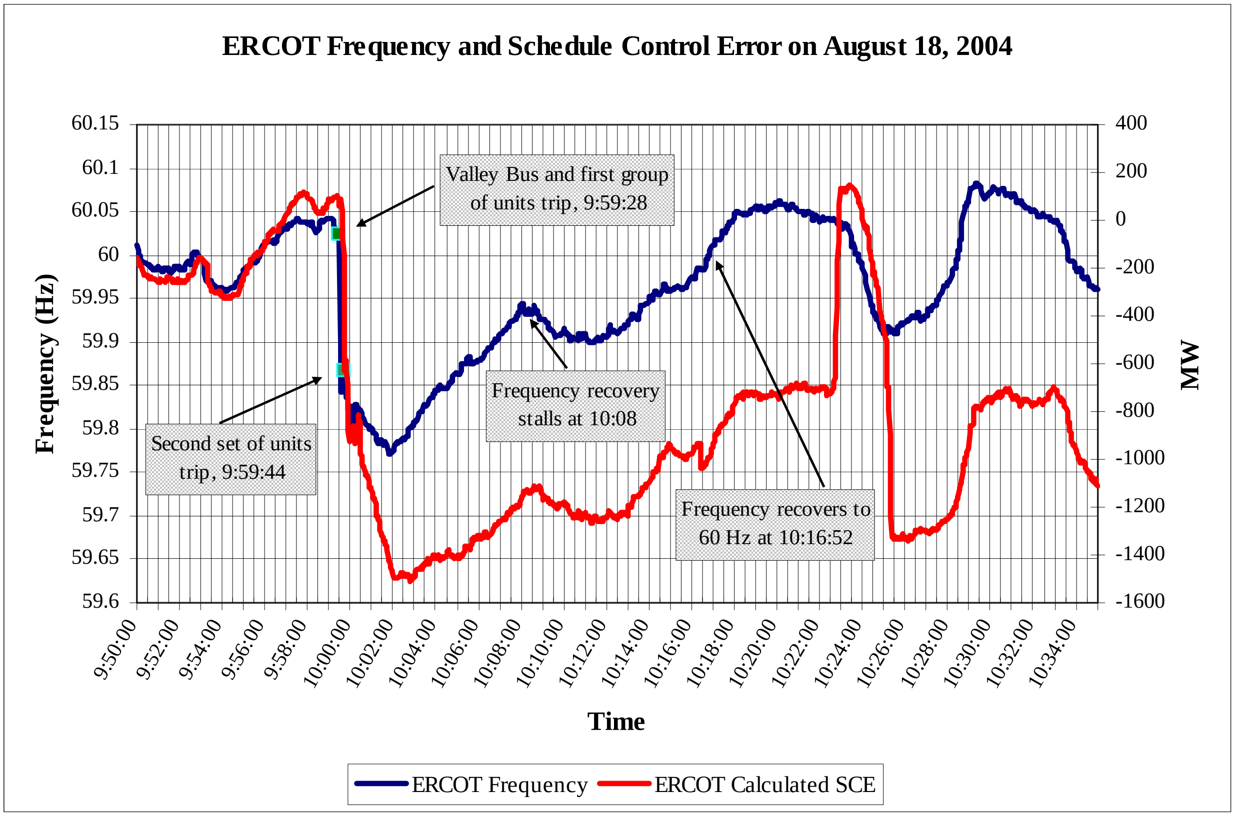

Figure 1: ERCOT Frequency and SCE on August 18, 2004

A. Overview of Conditions on August 18, 2004

Wednesday, August 18, 2004 was a typical summer day. The high across Texas was in the low 90's to upper 80's. ERCOT experienced a load high of 50,969 MW at 15:45.

Load Forecasts

See Table 1. For the interval ending 10:00, forecast load was 38302 MW, for the interval ending 10:15, 39308 MW—a net increase of 1006 MW.

Table 1: Load forecast and actual load on August 18, 2004

Interval Ending	Scheduled Generation	Load Forecast	Actual Load
9:00	35367	35701	35912
9:15	36788	36597	36683
9:30	37012	37176	37396
9:45	37284	37779	38039
10:00	37537	38302	39149
10:15	40430	39308	40458
10:30	40605	40045	41164
10:45	40831	40462	41835
11:00	41018	42724	42003

Base Schedules

QSEs scheduled an increase of 2746 MW between IE 10:00 and 10:15—see Table 2. Frequency just prior to the disturbance was high, 60.043 Hz at 9:58:50.

It is common for most QSEs to schedule the same MW value for all intervals in an hour, though some legitimately have static schedules for the hour. For the hour ending 11:00, only 4 out of the 30 QSEs provided different schedule values for each interval in the hour.

Table 2: QSE energy schedules for August 18, 2004

QSE	Energy Schedule IE 10:00	Energy Schedule IE 10:15	Energy Schedule IE 10:30	Energy Schedule IE 10:45	Energy Schedule IE 11:00
14	25	40	83	225	400
28	7799	8106	8171	8253	8330
1	590	745	745	745	745
27	8400	8500	8600	8700	8800
30	1555	1665	1665	1665	1665
9	1014	1093	1093	1093	1093
19	664	655	655	655	655
23	275	275	275	275	275
29	1505	1550	1550	1550	1550
4	295	276	276	276	276
11	163	163	163	163	163
31	4275	4681	4681	4681	4681
10	1487	1577	1577	1577	1577
26	314	348	348	348	348
5	272	412	412	412	412
21	600	600	600	600	600
34	585	825	825	825	825
22	690	1075	1075	1075	1075
32	725	803	803	803	803
7	488	488	488	488	488
13	165	165	165	165	165

QSE	Energy Schedule IE 10:00	Energy Schedule IE 10:15	Energy Schedule IE 10:30	Energy Schedule IE 10:45	Energy Schedule IE 11:00
16	662	662	662	662	662
17	201	207	217	226	236
15	361	356	356	356	356
8	2134	2400	2400	2400	2400
12	23	23	23	23	23
35	225	225	225	225	225
25	225	225	225	225	225
2	1446	1769	1769	1769	1769
33	0	0	0	0	0
ERCOT Total	**37163**	**39909**	**40127**	**40460**	**40822**

Balancing

ERCOT was balancing resources up and down throughout the morning. Balancing deployments for IE 10:00 were 464 MW up. For IE 10:15, balancing deployments were -1429 MW down; the net change between intervals was -1893 MW down. For Settlement Interval Ending 10:30, ERCOT's Net Balancing Deployment was 1006 MW down, which was up 423 MW from the previous interval.

Balancing instructions inform the participating QSEs the amount of energy to increase or decrease for the upcoming interval. QSEs are expected to use a 10-minute ramp to achieve the balancing award.

B. ERCOT Deployments during the Event

Balancing

As the disturbance occurred at 9:59:20, down balanced QSEs were already 4 minutes into their ramp and were instructed to keep down balancing for the next 5 to 6 minutes, see Figure 2. If ERCOT was not in a down balancing situation when the event occurred, it is likely recovery would have been achieved much sooner, since the units would not have had to overcome their downward inertia. See Table 3.

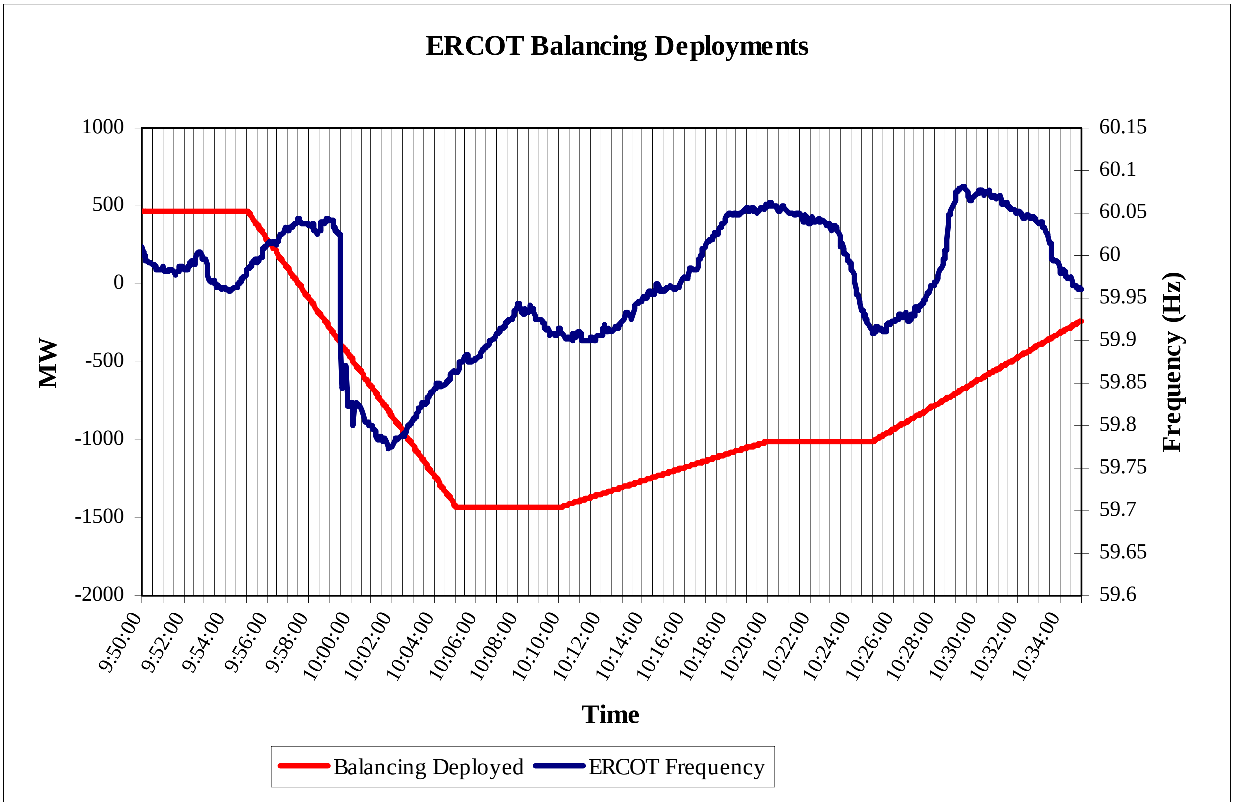

Figure 2: Balancing deployments on August 18, 2004

Table 3: Balancing energy deployments on August 18, 2004

QSE	BES Deployed IE 10:00	BES Deployed IE 10:15	BES Deployed IE 10:30
30	0	1	1
19	0	-205	0
29	77	0	0
4	100	100	100
11	-39	-39	-39
31	26	-111	14
26	0	-10	-10
21	40	-160	-164
34	-100	-176	-151
22	-35	-201	-125
32	5	-258	-114
7	25	-75	-51
8	141	40	-60
25	70	0	10
2	38	-31	-81
13	0	-13	0
15	35	-14	-19
28	-12	-312	-354
1	1	1	1
27	92	34	36
ERCOT Total	**464**	**-1429**	**-1006**

Thus at 9:55, ERCOT had issued instructions to many QSEs to balance down, even though load was increasing. When the event occurred—almost halfway through the ten minute ramp window—several QSEs were decreasing generation vigorously to support these down balancing deployments. This large amount of down balancing was in response to the QSEs raising their fleet generation to meet their expected obligations for the hour.

Regulation

With the QSEs ramping up to meet schedules, ERCOT frequency was above 60 Hz near 9:56. Down regulation is deployed at 60.036 Hz, thus ERCOT was sending down regulation instructions just as the DCS event began, see Figure 3. When the first of the units tripped at 9:59:30, ERCOT recalled 55 MW of down regulation and started deploying up regulation at a rate of 108 MW/minute. Up Regulation reached its available limit at 10:09:02 with 930 MW.

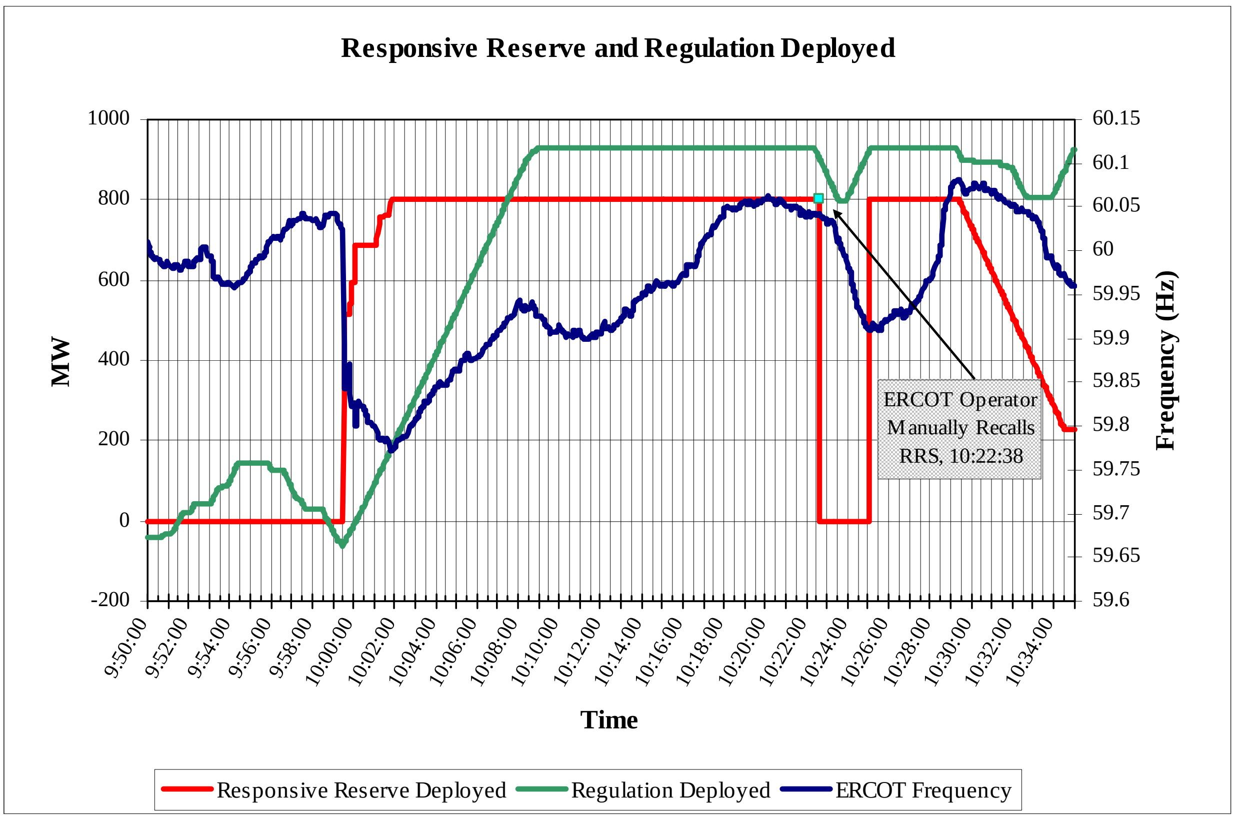

Figure 3: Responsive reserve and regulation deployed on August 18, 2004

Table 4: Down Regulation deployments on August 18, 2004

QSE	Down Regulation Award HE 10:00	Down Regulation Award HE 11:00
27	201	191
28	122	162
2	136	136
10	130	100
31	50	50
29	35	35
30	30	30
11	24	24
26	7	7
17	5	5
ERCOT Total	**740**	**740**

Table 5: Up Regulation deployments on August 18, 2004

QSE	Up Regulation Award HE 10:00	Up Regulation Award HE 11:00
27	240	240
28	192	226
10	163	137
2	135	128
31	61	61
29	40	40
30	30	30
11	25	25
25	0	25
1	0	10
26	9	8
21	35	0
ERCOT Total	**930**	**930**

RRS

2,300 MW of Responsive Reserve is procured continuously by ERCOT. ERCOT allows for up to 50% of the total to be provided from Loads Acting as Resources (LaaR) with the remainder provided by generators. Upon decay of frequency to 59.91 Hz, ERCOT's control system automatically requested immediate deployment of ERCOT's generator-based Responsive Reserve as shown in Figure 3. This reached a maximum level of 801.27 MW. ERCOT had the capability to deploy 1,293 MW of generator-based Responsive Reserve.

See Equation 1 for ERCOT's formula to deploy Responsive Reserve.

Table 6: Responsive reserve deployments on August 18, 2004

QSE	Generation RRS Award HE 10:00	Generation RRS Award HE 11:00
28	281	281
27	246	246
2	217	163
29	100	154
8	157	135
31	113	122
10	94	93
16	41	39
11	23	23
26	21	21
17	1	8
25	0	8
ERCOT Total	**1294**	**1293**

$$-10 \times Frequency\ Bias \times \left(Actual\ Frequency - RRS\ Recall\ Frequency\right) \times \left(\frac{RRS\ Request\,\%}{100}\right)$$

Equation 1: ERCOT's RRS deployment calculation

Equation 1 is implemented in ERCOT's EMMS system and is not listed in the ERCOT Guides or Protocols. The EMMS is set to deploy 67% of RRS, and this was done on August 18. At the time of this event, ERCOT's frequency bias was 604 MW/0.1 Hz and the RRS Recall Frequency was 59.97 Hz.

LaaR Response

Upon decay of frequency to 59.8 Hz, one block of LaaR from ERCOT's Responsive Reserve was automatically triggered by under-frequency relays; 172.11 MW of load was shed. If the frequency continued to decay down to 59.7 Hz, the remaining LaaR portion of ERCOT's Responsive Reserve totaling 847 MW would have responded to this event. ERCOT Operations has the authority to order the remaining portion of LaaR to trip and assist in accelerating recovery, but chose not to. Table 7 outlines which QSEs were awarded LaaR Responsive Reserve.

Table 7: LaaR RRS awards on August 18, 2004

QSE	LaaR RRS Award HE 10:00	LaaR RRS Award HE 11:00
15	671	672
27	160	160
31	97	97
16	69	69
26	9	9
ERCOT Total	**1006**	**1007**

C. ERCOT Operator Actions

VDIs

ERCOT operators were aware of the low frequency and dispatched Verbal Dispatch Instructions (VDIs) to QSE's 14 and 28 at 10:14 and 10:15, respectively. The two QSEs were asked to raise their fleet's generation by 150 MW for 45 minutes. These instructions are listed in ERCOT's frequency logs for August 18, 2004, see Appendix C. VDIs helped in the recovery, but were not issued quickly enough to meet the NERC standard.

RRS De-activation after Recovery

ERCOT deployed 801 MW of RRS from 10:01:50 to 10:22:36. The emergency assist limit, or the frequency at which RRS is automatically recalled when all available Up Regulation is deployed, is currently set at 60.08 Hz. At 10:22:36, an ERCOT operator manually recalled RRS at 60.04 Hz. The operator did this because he and an EMMS Production Support Specialist were unaware of the RRS limit, and both were worried frequency was going too high. With the RRS reset to zero, the frequency fell to 59.91 at 10:24:52; RRS was re-deployed at 10:25:02 with 801 MW. ERCOT frequency reached 60.08 Hz at 10:29:04 and RRS deployments began to automatically recall at 10:29:26. See Appendix C for log entry 140018, which details operator actions concerning RRS.

EECP

The Protocols suggest that ERCOT must declare an Emergency and initiate the Emergency Energy Curtailment Plan (EECP) if more than 33% of Responsive Reserve is deployed:

> *ERCOT deployment of Responsive Reserve Service Resources will be proportioned first between suppliers who provide RRS using Generation Resources until 33% of the total amount purchased by ERCOT is deployed. On depletion of the first 33%, ERCOT shall declare the EECP in effect and follow emergency provisions in Section 5, Dispatch*.[4]

ERCOT Operators did not declare EECP, even though the 33% threshold was exceeded. ERCOT did not address this Protocol requirement in its operator procedures. EECP by itself does not change deployments; manual actions that are essentially the same as VDIs are necessary. ERCOT management has indicated that it does not find the Protocol requirement to declare EECP for short events workable. ERCOT will propose revisions to the Protocols, along with developing internal procedures to support manually deploying additional RRS if warranted by system conditions. The Protocols also contain a provision to allow recall of balancing energy; in this event, it is not likely such recall would help. Recovery proceeded adequately even though

[4] ERCOT Protocols 6.7.3 (4)

ERCOT had deployed significant amounts of down balancing. By the time an operator would have recognized the stalled recovery, the ramp period for the next interval (IE 10:30) would already be in progress.

D. QSE Actions

QSEs 22 and 8, had unit trips during the first minute of the event. All of QSE 22's units were tripped off line, while QSE 8 still had one block that was not directly affected by the event.

QSEs 28 and 14 were given VDIs of 150 MW and responded accordingly. QSE 28 responded within 10 minutes, while QSE 14 took approximately 26 minutes to raise its fleet generation.

Capacity Lost, Not Reported to ERCOT

QSE 10 lost a unit at the start of the event due to drum levels. The unit was just starting up when the frequency dropped; the unit's governor response caused the steam stored in the drum to be depleted and steam could not be replenished quickly enough; the unit experienced runback and finally tripped off line—five minutes after the start of the event. QSE 10's unit was producing 53 MW at the time of the trip.

QSE 21 reported problems with one unit, and was not able to increase output due to problems experienced by a high pressure bypass valve operation. The unit was synchronized and eventually generation was increased, but not within the disturbance period.

In neither case do operator logs indicate that changes in unit status were reported to ERCOT during the disturbance period.

Governor Response

ERCOT Protocols require all units to have governors that are free to respond to frequency changes. A droop—or ratio of unit output response to frequency deviation—is required to be set at 5%. However, generator operating points and controls do not typically make this full response available. ERCOT's Performance Disturbance Compliance Working Group (PDCWG) has developed a methodology to assess QSE portfolio level response as part of its review of system disturbances. A sustained governor response shows that a QSE responded to the event with an adequate droop and carried that response over 30 seconds. Squelched performance means a QSE provided an initial response but did not maintain it. Low response indicates some response but marginal in comparison to the expected contribution. Negative response shows that the governors responded by lowering output instead of raising it, while no response indicates that governors are not in operation or blocked.

See Table 8. Governor response on August 18 shows that 15 QSEs had acceptable governor response (sustained), four of the QSEs had squelched performance, while 8 QSEs that had no or negative governor response.

Table 8: Governor response on August 18, 2004

	Governor Performance					
	Sustained	*Squelched*	*None*	*Negative*	*Low*	*N/A*
Qualified Scheduling Entity	10	19	4	21	11	33
	30	29	22	12	16	
	9	32	7			
	23	35	8			
	31		15			
	5		27			
	34					
	25					
	26					
	2					
	13					
	17					
	1					
	14					
	28					

The PDCWG analysis shows that performance at the B point[5] was acceptable, but failed to meet droop criteria at the B+30 point.

RRS Compliance

According to Protocol 6.10.5.4, a QSE providing Responsive Reserve can have an SCE between 95% and 150% of the RRS at which they are deployed. QSE performance according to Protocol 6.10.5.4 is detailed in Tables 9 and 10. Four QSEs out of the 12 RRS providers passed the criteria at the 10-minute mark—the time when RRS has been fully deployed, while only two QSEs met the criteria at the 15-minute DCS point.

ERCOT cannot separate SCE contributions from different units or for different services from a QSE, therefore the RRS criteria is evaluated based on aggregate SCE for an entire portfolio considering all obligations (base schedule, balancing, ancillary services and governor response). The tables below indicate poor compliance with Protocol 6.10.5.4, due to this method.

[5] See ERCOT Protocols 5.8.2 for definitions of B and B+30 points.

Table 9: QSE compliance with ERCOT Protocol 6.10.5.4 - 10 minutes after full deployment

QSE	SCE	RRS Deployed	Lower Limit	Upper Limit	Comply?
10	-168.13	57.63	-2.88	28.82	NO
29	-25.43	95.43	-4.77	47.72	NO
11	-9.96	14.25	-0.71	7.13	NO
31	32.17	75.6	-3.78	37.8	YES
8	-552.99	83.66	-4.18	41.83	NO
25	1.39	4.96	-0.25	2.48	YES
26	4.91	13.01	-0.65	6.51	YES
2	7.62	101.01	-5.05	50.51	YES
16	-15.23	24.17	-1.21	12.08	NO
17	5.83	4.96	-0.25	2.48	NO
28	-35.37	174.14	-8.71	87.07	NO
27	18.28	152.45	-7.62	76.22	YES

Table 10: QSE compliance with ERCOT Protocol 6.10.5.4 - 15 minutes after start of event

QSE	SCE	RRS Deployed	Lower Limit	Upper Limit	Comply?
10	-196.35	57.63	-2.88	28.82	NO
29	-27.43	95.43	-4.77	47.72	NO
11	-12.52	14.25	-0.71	7.13	NO
31	-40.27	75.6	-3.78	37.8	NO
8	-583.66	83.66	-4.18	41.83	NO
25	2.61	4.96	-0.25	2.48	NO
26	7.49	13.01	-0.65	6.51	NO
2	11.25	101.01	-5.05	50.51	YES
16	-27.51	24.17	-1.21	12.08	NO
17	6.46	4.96	-0.25	2.48	NO
28	-46.15	174.14	-8.71	87.07	NO
27	33.39	152.45	-7.62	76.22	YES

III. Post-mortem Investigations

ERCOT Operations completed an analysis of the DCS event in early October 2004. See Appendix F for Operations' final report.

To learn more about what happened, and to determine what actions and which QSEs hurt recovery, ERCOT Compliance probed deeper and began an investigation into the event.

A. QSE Investigations

ERCOT's NERC Compliance group analyzed data from the DCS event to assess QSE performance. The Protocols do not define event specific criteria to QSEs, only the Responsive Reserve deployment criteria of Protocol 6.10.5.4 ties performance measurement to a single event. Two problems result from this measurement when considering impact on the DCS recovery. First, it indicates non-compliance when a QSE has over-generated, or when the SCE limits are very small. Second, it fails to include QSEs short on all obligations but not providing Responsive Reserve. Those companies short on their obligation—at the DCS measurement point (15 minutes after the start of the event)—intuitively, contributed to the event. Therefore for purposes of this investigation—after discussion with the Performance Disturbance Compliance Working Group—12 QSEs were selected because they had a negative SCE fifteen minutes after the event began or ten minutes after RRS was fully deployed. Some QSEs had very small SCE errors, but were contacted nevertheless to gain insight. Compliance further limited QSE selection to SCEs less than 95% of their obligation at 10 and 15 minutes. Various aspects of the QSE schedule, ramp rates, and ancillary service awards were reviewed and forwarded to the QSEs for comments.

Table 11: SCE for QSEs selected for investigation

QSE	Measure @ End of Event		Measure @ End of Responsive Deployment Period	
	15 Min SCE	15 Min % Obligation	10 Min SCE	10 Min % Obligation
10	-115.1	59%	-143.4	51%
8	-67.0	50%	-97.7	39%
21	-46.0	25%	-74.0	-21%
28	-35.4	93%	-46.1	91%
1	-30.2	70%	-30.6	69%
29	-25.4	79%	-27.4	77%
16	-15.2	55%	-27.5	36%
19	-14.5	68%	-13.9	86%
11	-10.0	70%	-12.5	62%
14	-3.8	91%	-9.4	77%
15	-2.1	93%	-4.6	85%
31	32.2	109%	-40.3	89%

QSE Responses

All selected QSEs responded within the given timeframe. Several responses indicate failure to communicate or understand the need for prompt increase of output during RRS deployments. Some QSEs blamed the plant for their poor performance while others stated the SCE errors were due to telemetry and related data issues. QSE responses are summarized in Table 12 below. QSEs with no responses listed provided no clear explanation or blamed the poor performance on plant operations.

Table 12: Summary of QSE responses to investigation letters

QSE	QSE Issue
10	Generator runback and trip due to governor response
21	Unit problems
11, 29, 31	Operator failure to maximize ramp rate for RRS deployments
19	Inability to control more tightly to setpoints for SCE under 3%
1, 28	Controls problems
8	Inability to meet all ramps due to time of event occurrence
8	Lack of communication regarding SPS operations
16	Computer problems masking SCE
15	Data latency; ERCOT fault in handling large amounts of data.
15 and 14	Protocol changes to fully utilize resources during DCS events.
14	Units in startup mode cannot respond to instructions immediately.
16	Clarification of Protocol 6.10.5.4.
28	SCE data that takes into account expected turbine governor response - not an ERCOT contracted item.
28	Bias setting issues - not contracted, not studied in disturbance report[6], but influences SCE score.
28	Use more LaaRs during frequency events.
28	Down balancing was not recalled by ERCOT during the event.
28	VDIs sent out too late to QSEs by ERCOT operators.

B. ERCOT Mitigation Issues

In the course of investigating the cause of the August 18, 2004 event, ERCOT staff developed several issues that should be looked into further to mitigate future frequency events. See Table 13.

[6] Refers to investigation letter sent to QSEs by ERCOT NERC Compliance and reports published by the PDCWG

Table 13: ERCOT Mitigation Issues

1. Explore raising the 33% threshold of initial Responsive Reserve deployment on generation and giving System Operators the authority to deploy the remaining generation resources after the initial amount is used.
2. Investigate raising the frequency threshold for deployment of Responsive Reserve above 59.91 Hz and the Emergency Assistance set point, where ramp rate limitations on deployment of Regulation Service – Up are eliminated, above 59.94 Hz.
3. Fully investigate response of generators supplying RRS during this event to determine if their response met requirements.
4. Evaluate whether all participants were supplying their obligated schedule amounts and ERCOT deployment requirements
5. Review how often the ERCOT frequency bias setting should be changed and whether the value in place during this event had a detrimental effect upon response actions.

Along with the issues brought to light by the QSEs, the ERCOT mitigation issues should be investigated further and implemented in Protocol Revision Requests (PRRs) or Operating Guide Revision Requests (OGRRs).

Issues 3 and 4 have been undertaken and the resulting investigation is detailed earlier in Section A.

IV. CONCLUSION

The size of the Eastern and Western Interconnects dwarf ERCOT in comparison. As a result, ERCOT does not enjoy the large amount of generators that produce system inertia during frequency events such as occurred on August 18, 2004. To compensate, ERCOT must have situational awareness at all times and hold the QSEs to their obligations and resource plans, regardless of the circumstances.

Given the abundance of spinning reserves and LaaR that ERCOT could have called upon, this event by itself cannot be considered a major breakdown in operations. This event is an opportunity to examine ERCOT's performance in a complex set of circumstances and increase preparedness for future events.

NERC requires control areas to purchase more Responsive Reserve capacity each time a DCS event occurs. The "penalty" amount required is proportional to the size and magnitude of all DCS events in a quarter. A DCS event also occurred the next day and the recovery to this event was much more prompt and was in compliance with the NERC standard. The NERC calculation looks at these two August events and determines how much of an adjustment to RRS should be made. A sample calculation is included in Appendix G.

Key areas for follow-up tracking and reporting:

1) ERCOT Operations procedural and Protocol issues that prepare it to manually deploy additional RRS when a recovery stalls, and train operators as needed
2) QSE action items listed in or developed from responses to ERCOT, especially related to controls adjustments, operator communication of status changes and operator awareness of responsive reserve performance expectation.
3) Transmission company actions identified to improve ability to isolate breaker testing
4) ERCOT frequency bias and impact of bias changes on automatic RRS deployments and recall, as well as other matters related to frequency control
5) QSE SCADA failure and corrective actions
6) Assessment of responsibility for future failure to meet NERC DCS standard, including possible changes to performance criteria
7) Review of QSE scheduling practices by interval vs. by hour and impact on ERCOT Operations

Certainly other items may merit additional follow-up, but these seem most related to the event and findings.

Appendix A – SPS Investigation by TXUED

Operation of Special Protection System

Event Date: 8/18/04Time: 09:59 AM
Location: Paris Switching station Dallas Region / Sulphur Springs District
Description of Event: As a result of the 345 kV bus at Valley Sw. being accidentally tripped by TXU Electric Delivery personnel doing maintenance on CB 4036 an overload condition occurred on Paris Sw. 138 kV circuit (CB 3535) to Valley Sw. The SPS at Paris correctly detected the condition and operated to reduce generation at [redacted] by activating the opening of CB 7310 and CB 7290.

Description of Investigation: TXU Electric Delivery crews were in the process of performing Routine Operator Maintenance on Valley SES Unit 3, 345kV generator breaker 4036 as part of the 2004 maintenance contract with TXU Energy. Procedures and a workscope had been prepared for the job and were being followed. When the crew closed breaker 4036 as part of the test procedure, the 345kV bus and the 345/138 kV auto transformer tripped and locked out.

The investigation discovered that as part of a TXU Energy design modification in 2003 an 'a' contact from an auxiliary contact follower relay was installed in parallel with the fault detector relay. The contact follower is controlled by an 'a' switch out of generator breaker 4036. This circuit is duplicated on TXU Electric Delivery print E-63399-018 sh. 007, but this drawing was not revised to reflect the circuit modification. With generator #3 being off line and the generator lockouts left in the tripped position the 'a' switch in breaker 4036 prevented the breaker failure timer from timing out. When the breaker was closed the 'a' switch closed completing the circuit that starts the 345kV Backup bus timer. The backup timer tripped the 345kV bus and autotransformer. Breaker 4036 did not automatically trip after it was closed because remote tripping had been disabled as required in the TXU Electric Delivery maintenance procedures. Following the tripping of the bus, CB 4036 was tripped manually to reset the scheme. The circuit design modification not being reflected in the 345 kV switchyard control building prints set the trap for field personnel.

Corrective Action: To prevent a recurrence of this event, test switches will be installed in breaker 4036 that will disable the trips, close, and disable the 'a' switch that picks up the contact follower relay in the control room. The test switches will be labeled 'Maintenance Test Switch' (pull when operator maintenance or diagnostic testing will be performed). This will be added to the TXU Electric Delivery maintenance procedures. In addition the duplicate circuit will also be removed form drawing E 63399-018 Sh. 7 so that there is only one drawing to refer to for specific information.

Pending Action: The change to the print is being handled through standard drawing correction procedures. Test switches are to be added and the test procedures are being rewritten to reflect the addition of the test switches. Before additional contract work is performed at other locations similar schemes will be reviewed.

Appendix B – SPS Information Provided by TXUED[1]

[1] TXUED referred to as Oncor throughout document

SPS#4 Paris Switch B

To accommodate the maximum possible generation production out of the [redacted], an SPS is required on an interim basis. The SPS hardware shall consist of two parts. The first part of the SPS is located at Paris Switching station, and was designed and installed by Oncor. This part of the SPS monitors the predetermined criteria for both the stability and thermal overload conditions, and provides a signal via redundant fiber optic cables provided by the Customer to activate the second part of the SPS. The second part of the SPS was designed by [redacted] and is located at the [redacted] interconnection facility and is designed to automatically reduce generation upon receiving a signal from Oncor.

The SPS consists of overcurrent relays to establish “two-out-of-three” relaying logic. These relays monitor the line currents on the 345 kV and 138 kV circuits to Valley Switch from Paris Switch, and are set to pickup at 1800 amperes and 900 amperes, respectively. A long relay operating time (5 seconds) is used for line reclosing coordination purposes. When an overload condition is detected, a trip signal is sent to [redacted]’s interconnection facility via redundant fiber optic communications channels. Upon receiving the trip signals, [redacted]’s SPS will automatically trip one generating unit and will proceed to trip two other units, one every fifteen seconds or until the trip signals are cleared. If the trip signals continue after tripping three units, Power will reduce its remaining generation through manual control until the trip signals are cleared.

The [redacted]’s part of the special protection system works as follows:
For line overloading conditions (i.e., above 550 MW) when a signal is first received from Oncor through the fiber optic communication system, unit GTG-3 is tripped immediately. Two Additional units will be tripped sequentially if the overloading condition persists. Fifteen seconds after the first trip STG-2 will be tripped and fifteen seconds after that GTG-4 will be tripped. If the overloading condition persists after the three units are tripped, further reduction will be accomplish via manual action.

Oncor provides two signals to operate two separate devices making the SPS more reliable. [redacted] uses the second set of signals to perform the same functions (i.e., trip the same generators) via different tripping devices.

Appendix C – ERCOT Frequency Control Log Book

August 18, 2004

Table 1: Frequency control log book for August 18, 2004

Log Id	Log Date	Time Start	Time End	Log Type	Log Comments
139972	8/18/2004	1:00	0:00	Compliance	Failed CPS1 with a 28. At 1209 out of up regulation relation did not return until about 0033. In the middle of this [redacted] began coming offline an hour early making the situation worse. Their SCE was -212mw at 0010 and didn't cross zero until 0033. [redacted] has a forced out on [redacted].
139979	8/18/2004	4:51	4:53	Misc.	Per [redacted] they have lost signal to [redacted]t. They expect this to clear up shortly...
140001	8/18/2004	9:20	0:00	Misc.	ERCOT data base load
140002	8/18/2004	9:34	0:00	Misc.	[redacted] data base load
140012	8/18/2004	9:59	10:16	Low Frequency	Freq spiked to 59.772 reset to 59.786 17min recovery due to trip of valley 345kv buss causing [redacted] steamer and block 2 trip
140015	8/18/2004	9:59	0:00	Unit Trip	[redacted] Block 2 tripped 500mw due to Valley 345kv bus trip. in Outage Scheduler to return 1200 today
140022	8/18/2004	10:00	0:00	CPS1 & CPS2	CPS1 score for 1000 is -476 due to trips Valley 345 bus [redacted] plant site and [redacted] block 2
140016	8/18/2004	10:14	11:01	Verbal dispatch	F08182004-01 [redacted] raise fleet generation 150mw to restore freq after 0959 disturbance
140017	8/18/2004	10:15	11:00	Verbal dispatch	F08182004-02 [redacted] raise fleet generation 150mw to restore freq after 0959 disturbance
140018	8/18/2004	10:23	0:00	RESPONSIVE RESERVE	Responsive Reserve deployed 801mw and was hung up trying to recall. After breif consultation with Arthur Boecker RRS was unrequested and the requested. this took deployment to zero and back to 801 and recalled without a problem.
140019	8/18/2004	10:41	0:00	RESPONSIVE RESERVE	Notified [redacted] to restore [redacted] pot lines after frequency disturbance at 0959

Log Id	Log Date	Time Start	Time End	Log Type	Log Comments
140013	8/18/2004	10:59	0:00	Unit Trip	All [redacted] generation tripped due to loss of Valley bus plant site is in the dark. Rupture disks were lifted on steamers with possible damage they are unsure if units were able to go to cool down mode. In outage scheduler to return midnight tonight
140026	8/18/2004	11:00	0:00	CPS1 & CPS2	CPS1 score for 1100 is 32 due to trips Valley 345 bus [redacted] plant site and [redacted] block 2
140031	8/18/2004	12:19	0:00	Hot Line Call	Notified all QSE's of transmission alert on post contingency overload on 69kv Nall-Briarcrest
140032	8/18/2004	13:21	0:00	SCE	[redacted] reports [redacted] Blk2 had trouble starting will come off line and try again
140036	8/18/2004	14:13	0:00	LAAR Deployment	[redacted] asked if they could close breakers to UFR after 1000 disturbance I gave them permission and asked them to notify ERCOT any time UFR operates
140038	8/18/2004	14:15	0:00	Hot Line Call	Notified all QSE's of transmission alert on post contingency overload on 138kv Asherton-W. Conoco
140039	8/18/2004	14:51	0:00	SCE	[redacted] block2 back on line
140050	8/18/2004	16:28	0:00	DC-N	[redacted]: notified [redacted] that the North should be at -119 and [redacted] had the tie at 22. [redacted] missed a PSE adjust on at tag that caused the mismatch. At 1639 [redacted] ramped the tie to -119.
140062	8/18/2004	18:27	0:00	SCE	[redacted]s SCE at -36mw due to cat 2 deployments. Unable to follow other deployments.
140065	8/18/2004	19:15	0:00	SCE	[redacted] SCE at -25mw. Per [redacted] Plant has taken an additional 25mw of generation for load for processing.

Log Id	Log Date	Time Start	Time End	Log Type	Log Comments
140066	8/18/2004	19:16	0:00	SCE	[redacted] SCE at -23mw. Per [redacted] their plant is slow coming up but QSE will contact them to speed their ramp up.
140080	8/18/2004	23:00	0:00	CPS1 & CPS2	Failed CPS1 for hour ending 2300 with a 94. Primary cause for failure was large movements by steel mill and also the usual large movements across the 2215 interval.

Appendix D – ERCOT Shift Supervisor Log Book

August 18, 2004

Table 1: Shift supervisor log book on August 18, 2004

Log Id	Log Date	Time Start	Time End	Log Book	Log Type	Log Comments
139991	8/18/2004	5:50	0:00	Supervisor	Unit Testing	Approved rata testing for [redacted] from 1100 - 2000 today and rata testing for [redacted] from 1100 - 2000 tomorrow.
140003	8/18/2004	9:38	0:00	Supervisor	Failover	Planned data base load is complete it was not sucessful and did another one at 10:50.
140021	8/18/2004	9:59	10:17	Supervisor	Abnormal Events	Valley Bus tripped which caused [redacted] and part of the [redacted] units to trip which was about 1 420 MW's. Frequency spiked to 59.722 and recovered at 10:17. ONCOR was doing maintenance at the station and suspect a relay malfunction.
140028	8/18/2004	12:06	0:00	Supervisor	MIS Posting	Posted the following message on the MIS per Leo: On 8/18/04 at 9:59 the Valley Bus tripped which caused approximately 1 420 MW's of generation to trip. Frequency spike to 59.772 and recovered at 10:17. The reason for the Bus trip is under investigation.
140088	8/18/2004	23:38	0:00	Supervisor	Abnormal Events	Cancelled MIS message 18082004124830 regarding VLSES bus outage per Lundy.

Appendix E –Performance Disturbance Compliance Working Group’s Disturbance Analysis

This appendix has been removed due to the confidentiality of the information.

Appendix F – ERCOT Operations Preliminary Report on August 18, 2004 DCS Event

Event

Wednesday, August 18th at 09:59:28, the 345 kV bus at Valley Station tripped. Routine maintenance was being performed on the Valley Unit 3 generator circuit breaker. After maintenance and with the disconnects open, the breaker was test tripped as part of the test procedure. This was determined to be the initiating cause of the bus trip. The 345/138 kV transformer was lost, along with the 345 kV lines from Valley to Farmersville, Paris, Anna, and Kiowa stations. The Kiowa - Valley 345 kV line is the only injection point for [redacted] generation and the six units at that station were lost carrying 650.6 MW.

The investigation discovered that as part of a TXU Energy (Generation Company) design modification in 2003, an auxiliary contact follower relay was installed in parallel with the fault detector relay. TXU Electric Delivery (Transmission Company) was not made aware of this modification. With the generator off-line, and the generator lock outs in the tripped position, the follower relay prevented the breaker failure timer from timing out. This started the 345 kV back-up bus timer which tripped the 345 bus and auto transformer.

The bus also resulted in loading the [redacted] – [redacted] 138 kV line to 917 Amps. When this line loading exceeds 900 Amps, a Special Protection Scheme is armed to automatically trip a unit at the [redacted] plant every 15 seconds until the overload is cleared. 464 MW were tripped by SPS action when [redacted] CT 21, 2, and CT 22 tripped (in that order).

As the last CT at [redacted] tripped carrying 145 MW, frequency dipped to just below 59.8 Hz. A portion of ERCOT Responsive Reserve provided by a Load acting as a Resource (LaaR) set to trip at 59.8 HZ actuated and 172 MW tripped off line, increasing the frequency to 59.83 Hz at 10:00:17. Over the next 90 seconds, frequency declined to a minimum of 59.775 Hz, gradually rose to 59.944 Hz at 10:08, relapsed to 59.90 Hz at 10:11, then recovered to 60 Hz at 10:16:46. Verbal Dispatch Instructions were sent to [redacted] at 10:14 and [redacted] at 10:15 to raise 150 MW of generation.

Through this event, 801 MW of Responsive Reserve were deployed by ERCOT. A total of 930 MW up Regulation was deployed and 49 MW of down Regulation was recalled. A total of 1,499 MW of procured Responsive Reserve remained on the system. Excess real-time Responsive Reserve on the system above and beyond the market procured obligation was greater than 3500 MW.

The disturbance on August 18th involved a loss of 1103.6 MW generation output from a total net capacity of units of 1420 MW. For comparison purposes, during a similar event on 8/19 at 11:16, 1247 MW was lost at a station. In that event, frequency dropped to 59.748 Hz. and was restored in 8 minutes 25 seconds. The event was very similar to the August 18th event in that multiple units, operated by the same QSE, were tripped in North Texas. It appears that the difference in response was largely due to a large schedule change that was occurring during the 10:15 interval on August 18th. The event of 8/19 did not encompass such a schedule change.

The failure to restore frequency to normal within 15 minutes appears to be related to insufficient provision of resources in response to ERCOT deployments and to the timing of deployment actions by ERCOT. There was excess capacity on line and excess reserve available on line. Carrying additional reserve, such as may result from assessment of a Contingency Reserve Adjustment (CRA) would not change the outcome of this event.

Schedule Change

Cumulative ERCOT schedule change over the 10:00 a.m. ramp period on August 18 was 2746 MW. While no individual QSE had a base power schedule change of over 400 MW, the total is a large value for any interval and changes of this magnitude are normally observed only at 06:00 and 22:00.

Schedule Changes from IE 10:00 to IE 10:15 greater than 100 MW

[redacted]	+406
[redacted]	+385
[redacted]	+323
[redacted]	+307
[redacted]	+266
[redacted]	+240
[redacted]	+155
[redacted]	+140
[redacted]	+110
[redacted]	+100

Deployments

Responsive Deployments

801 MW of Responsive reserve was deployed along with the 172 MW of LaaR actuated on under frequency relay.

Regulation Deployments

Frequency and ERCOT SCE increased starting at 09:55, the beginning of the ramp period and continued to rise until the event at 09:59. Pre disturbance frequency was 60.042 Hz. Frequencies larger than +.036 Hz initiate Down Regulation to be deployed. Units providing Regulation Service are instructed to reduce generation. A rise in frequency is commonly observed during the initial minutes of a large schedule change when units ramp up faster than others are ramping down. At the time of the event ERCOT recalled the 55 MW of Down Regulation and 930 MW of available Up Regulation was deployed.

Balancing Deployments

As these QSE raised generation to meet their obligations a large amount of Down Balancing was deployed. Resources with requirements to provide the Down Balancing Energy to offset the schedule change are also instructed to ramp down.

Balancing Energy deployed for Interval Ending 10:00 =	464 MW
Balancing Energy deployed for Interval Ending 10:15 =	-1429 MW
Change in balancing energy =	1893 MW

The Down Balancing not only sends deployments to reduce generation during the first six minutes of this disturbance, it also adds latency to response of these units as their inertia is in the wrong direction. This adds an inherent delay in turning these units around and raising generation output to recover system frequency. Resource Entities required to provide Down Balance Energy but not Responsive Reserve were given instructions to lower generation significantly through the 10:00 ramp period. These same QSEs were then instructed to raise generation during the next ramp period. Two examples of QSEs providing Down Balancing are [redacted] and [redacted].

From 09:55 to 10:05 [redacted] had a -9 MW schedule change from 664 MW to 655 MW. They were instructed to reduce generation to 450 MW from 9:55 to 10:05. At 10:10 they were instructed to raise generation back to 655 MW. [redacted] attempted to follow the large schedule change. Generation from [redacted] approximately followed the deployments and was reduced to 460 MW by 10:11, then returned to their scheduled MW by 10:21.

[redacted] was following it's obligation of 735 MW at 09:55. Shortly after the disturbance [redacted] raised generation 30 MW in response and then followed Down Balancing instructions to reduce to 560 MW at 10:05. [redacted] closely followed their scheduled obligation when instructed at 10:10 and exceeded required generation output when Frequency declined during the recovery. Other QSEs were observed to have similar responses during the event.

Poor QSE Performance

[redacted] had an obligation to provide 93 MW of RRS for IE 10:15 and [redacted] was required to provide 135 MW over that interval. [redacted] lost three of the units involved in the initial event and [redacted] lost one unit during the recovery period. The unit had recently started and increased generation rapidly as frequency decayed. After this trip at 10:04, [redacted] was 200 MW short during the recovery period. [redacted] lost 452 MW on three units that tripped during the initial event. [redacted] SCE was initially -600, dropped to -636 and trended to -500 at the point of recovery. Some QSE performance indicated no governor response to the frequency excursion.

[redacted], [redacted] and [redacted] maintained a negative SCE through the first 10 minutes of the event. [redacted] SCE dropped to a -75 at 10:04 while [redacted] fluctuated between -50 and -100.

[redacted] and [redacted] were under -100 for the first four minutes of the disturbance. [redacted] SCE reached -160 MW at 10:01. [redacted] maintained an SCE between -65 and -27. [redacted] SCE hung around -50. [redacted] SCE -10 to -60.

Solutions and Lessons Learned

The large schedule change affected our DCS performance during this event. A great majority of ERCOT resources were ramping to the limits of their machines. Those moving up have little or no room to make up for loss of generation. The resources instructed to move down to balance generation and load may initially contribute to recovering frequency through generator action, but consistently continue to follow down instructions that were calculated prior to the generation loss. The frequency deviation component of the QSEs SCE will eventually deploy them up, but the generators can not immediately change direction, lengthening the time required to recover frequency significantly.

How well we execute a large schedule change also can contribute to poor DCS performance. ERCOT has consistently performed poorly during large schedule changes. ERCOT has observed and documented major frequency deviations during these periods when resources are ramped in a manner that deviates from expected performance.

Adequate reserve was procured and deployed to recover from this event within the DCS criteria. The effect of a 2746 MW schedule change arrested our ability to perform to DCS standards and should be considered as a contingency that occurred during the recovery period.

ERCOT currently carries a contingency reserve of nearly double that of the most severe contingency. More than half of the Responsive Reserve remained undeployed during this event. Other Reserve Sharing Groups of similar load to ERCOT carry contingency reserve equal to that of their larges unit. Adjusting the reserve number would not have affected how the system performed under the system conditions of this event.

Over half of the available Responsive Reserve that was not deployed was LaaR. Increasing the percentage of RRS carried by generation in relation to LaaR would have improved our performance without exposing the interconnection to the next contingency.
Deploying a higher percentage of the available RRS carried by generation may also have improved our performance for this event, provided a significant portion of the additional RRS requested was not deployed to resources already operating at their limits.. The amount of RRS from generation deployed is based on the Frequency Bias and the size of the frequency disturbance. Two-thirds of this value is currently deployed in our EMS.

Deploying a portion of the LaaR when it became apparent frequency may not recover within fifteen minutes would have rectified system conditions. Protocol Section 6.7.3 (4) describes how this should be accomplished by declaring EECP and directing all LaaR removed. PRR 307 describes how this may be automated when system changes are implemented. For this event only a portion of the LaaR should have been removed from service. With the recent increase in Responsive Reserve allowed to be provided by LaaR, Protocol language in Sections 5.6.7 and 6.7.3 may need to be updated to allow a more applicable portion of the LaaR to be dispatched and allow for a means to dispatch the Laar by declaring an Emergency Notice instead of proceeding to EECP.

Current Operator Procedures do not describe the steps to take to insure adequate Responsive Reserve is deployed to meet NERC requirements and should be modified to prevent prolonged recovery periods. The procedures should direct the operater to deploy a percentage of Laar after the initial RRS from generation has been deployed and it becomes apparent that frequency is not recovering in time to meet NERC criteria. The amount deployed will be based on frequency deviation and system bias. Deployement of additional Laar above this would serve to recover some of the RRS served through generaton but may not be necessary as NERC requirements allow for 90 minutes to recover Contingency Reserves .

Mitigation

Three types of Responsive Reserve Service (RRS) resources are available to ERCOT to resolve a low frequency disturbance.

- Responsive Reserve from fossil generation resources
- Responsive Reserve from Hydro units (Hydro Responsive)
- Responsive Reserve from Loads acting as Resources (LaaRs)

Responsive Reserve from generation resources responds to frequency disturbances via automatic governor response and subsequent control action (deployment of Responsive Reserve). Hydro Responsive and LaaRs respond automatically via underfrequency relays set at no lower than 59.8 Hz. At present, there are a few LaaRs set at 59.8 Hz and more LaaR and Hydro Responsive set at 59.7 Hz. Hydro Responsive and LaaRs can also be activated by operator action and respond very quickly; within a few seconds.

ERCOT Protocol 6.7.3 states that *ERCOT will deploy RRS using Generation Resources until 33% of the total amount purchased by ERCOT is deployed. On depletion of the first 33% ERCOT shall declare EECP in effect and follow emergency provisions in Protocol Section 5, Dispatch.*

The EECP (Emergency Electric Curtailment Plan) was developed to respond to short supply situations and restore Responsive Reserve to required levels. It was not intended to insure timely response to frequency disturbances when there is adequate Responsive Reserve. In this event, if ERCOT had deployed fast response Hydro Responsive and LaaRs by deployment action (by operator action or automatic action), frequency would have recovered within the required 15 minute timeframe.

This situation will be addressed by developing a procedure that provides for ERCOT to post an Emergency Notice either prior to or after manually deploying Hydro Responsive and/or LaaRs, instead of declaring EECP.

This procedure will direct the System Operator to declare an Emergency Notice for frequency restoration purposes, and deploy Hydro Responsive and LaaRs after the initial 33% of RRS has been deployed from generation automatically by the ERCOT control system. The amount of Responsive Reserve carried by LaaRs may be up to 50% of the total obligation and is typically 1,150 MW of the 2300 MW Responsive Reserve requirement. The procedure will further establish criteria for determining that frequency is not recovering in time to meet NERC criteria and establish the required timing for the decision points. The amount deployed will be based on frequency deviation, system bias, and the required timing.

In addition, ERCOT will take the following actions to aid compliance to NERC Standards on frequency disturbances:

- Explore raising the 33% threshold of initial Responsive Reserve deployment on generation and giving System Operators the authority to deploy the remaining generation resources after the initial amount is used.

- Investigate raising the frequency threshold for deployment of Responsive Reserve above 59.91 Hz and the Emergency Assistance set point, where ramp rate limitations on deployment of Regulation Service – Up are eliminated, above 59.94 Hz.

- Fully investigate response of generators supplying RRS during this event to determine if their response met requirements.

- Evaluate whether all participants were supplying their obligated schedule amounts and ERCOT deployment requirements.

- Review how often the ERCOT frequency bias setting should be changed and whether the value in place during this event had a detrimental effect upon response actions.

Appendix G – NERC DCS Penalty Calculation

Table 1: NERC DCS Penalty Calculation

ACE_M ERCOT ACE at 10:14:20 (adjusted for additional tripped unit at minimum sustainable limit)	-194.64
MW_{Loss}	1114.59
R_i Percent Recovery 15 Minutes After Start of Event Using NERC Performance Std Training Doc Sect. C.2 (using 15 minute recovery): $Ri = (MW_{Loss} - max(0, -ACE_M)) / MW_{Loss} * 100$ (For $ACE_A >= 0$)	82.54
Average Percent Recovery for the Quarter, based on two reportable disturbances, the second on August 19th with recovery of 100% on 8/19/04:	91.27
Reserve Adjustment Percentage, $CRA_{Quarter,}$ based on second reportable disturbance recovery of 100% on 8/19/04: $CRA_{Quarter} = 200 - Sum(R_{1,\ldots}R_n) / n_{Quarter}$	108.73
Most Severe Single Contingency MW (Summer 2004 Capability Test)	1250.00
Reserve Increase MW	109.14