REVIEW OF APRIL 17, 2006 EMERGENCY ELECTRIC CURTAILMENT EVENT

ERCOT COMPLIANCE

JULY 21, 2006

Review of April 17, 2006 EECP Event

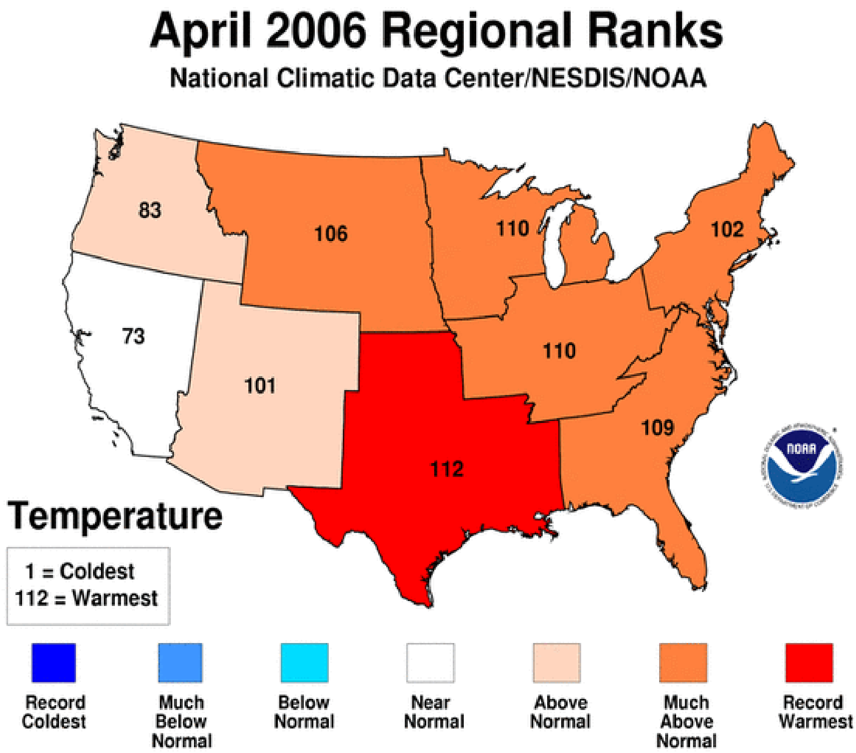
Review of April 17, 2006 EECP Event

Executive Summary:

On April 17, 2006, the ERCOT grid experienced high load conditions driven by unseasonable, record-setting temperatures. To address the decline in system frequency during the mid-afternoon, ERCOT Operations implemented its Emergency Electric Curtailment Plan (EECP). When a group of generators unexpectedly tripped during the event, ERCOT Operators found it necessary to order firm load shed to maintain system frequency. While some instances of failure to meet Protocol criteria or procedures occurred, in aggregate, EECP actions were executed and the desired results were achieved. Post-event analysis has identified problems with ERCOT's load forecast, uncertainty about available generating reserves and issues with procedures, especially emergency communications. This report builds on discussions among stakeholders since the event, adds consideration of compliance with reliability-related requirements, and lists recommendations and actions taken since the event.

Event Description and Timeline:

On April 17, 2006, the ERCOT grid experienced abnormally high temperatures during a month when much generation capacity is off-line, many undergoing maintenance in preparation for summer conditions. After noon, as the day progressed, ERCOT operators found load increases accompanied by decline of system frequency following full deployment of Up Balancing Energy Service (UBES) and Up Regulation Service (URS). Deployments of Non-Spinning Reserve Services (NSRS) and generator Responsive Reserve Service (RRS) failed to arrest the frequency declines, so ERCOT requested two QSEs (Qualified Scheduling Entities) to increase their generation through Verbal Dispatch Instructions (VDIs). When this still did not correct the situation, ERCOT resorted to declaration of EECP Step 1. Nine minutes later, ERCOT moved to EECP Step 2, and interrupted Load-as-a-Resource (LaaR), procured as 1150 MW of the RRS. Manual LaaR deployment helped the situation stabilize until a large amount of generation at dispersed locations tripped within twenty minutes. The ERCOT operator reacted to system frequency decline and apparent lack of reserves by requesting 1000 MW of firm load shed by transmission companies, EECP Step 4. Once this occurred, the frequency improved, additional generation reserves built up as ERCOT crossed peak load, and all interrupted load (both firm load and LaaR) was restored, leading to termination of the EECP event just over four hours after its initiation.



The following material is based upon timelines developed in ERCOT Operations report.

Background and actions up until noon on April 17, 2006:

April 2006 was unseasonably warm across the Region, but April 17th set records and led to great increases in air conditioning usage and total load on the grid. Temperatures for April 17th were predicted to reach 100 degrees F by some services, but ERCOT's primary weather forecasting service provided lower values.

Easter was celebrated on April 16, with many businesses closed starting on Good Friday. Load forecasting software accounts for the effects of holidays and weekends on electrical consumption in its comparisons to similar historical days, and this was considered as well as temperatures and other conditions. One complicating factor in preparations was that some of the effort that went into building grid forecasts for Monday was prepared on Friday or possibly earlier, due to personnel at ERCOT and market participants taking time off from work prior to Easter. That may have shortened the reaction time to issues that developed on April 17th.

18:00 April 16, 2006 ERCOT executed the Replacement Market Day-Ahead with a next day peak forecast of 49,018 MW. Capacity scheduled by QSEs for their base load was 50,661 MW; ERCOT procured additional NSRS and Out-of-Merit Capacity (OOMC) based on its established procedures, an additional 2,542 MW over the QSE base schedules.   The peak load (unadjusted) for April 16 had been 43,834 MW (prior to adjustments).

Just before 1:00, on April 17, ERCOT ran the Replacement Reserve Application in Study mode again, with a 49,531 peak forecast. There was no need for additional capacity predicted as QSEs had increased their generation in the Resource Plans to 54,382 MW during peak hour.

April 17, 2006 – Events from mid-day until declaration of EECP

11:58 Unit A tripped at 243 MW, capability 365 MW. Another unit was brought on-line by the QSE to make up for capacity lost but their Schedule Control Error (SCE) lagged.

12:24 Unit B tripped operating at 163 MW and reduced steamer output by an additional 120 MW. Unit returned to service within an hour and ramped to full output.

12:56 ERCOT ran its Replacement Reserve Application in Study mode once again with a 51,114 MW peak forecast. Still, there was no need for additional capacity predicted as QSEs had increased their generation available (in Resource Plans) to 55,234 MW.

13:45 94% of the UBES Bid Stack was deployed, supplemented by 680 MW of NSRS and instructions for 150 MW more NSRS issued due by 14:30.

13:52 QSE A contacted to verify their Responsive Reserve. They said that only 275 MW of the 850 MW indicated was available, and these reserves would be depleted when their generation increased to meet schedules.

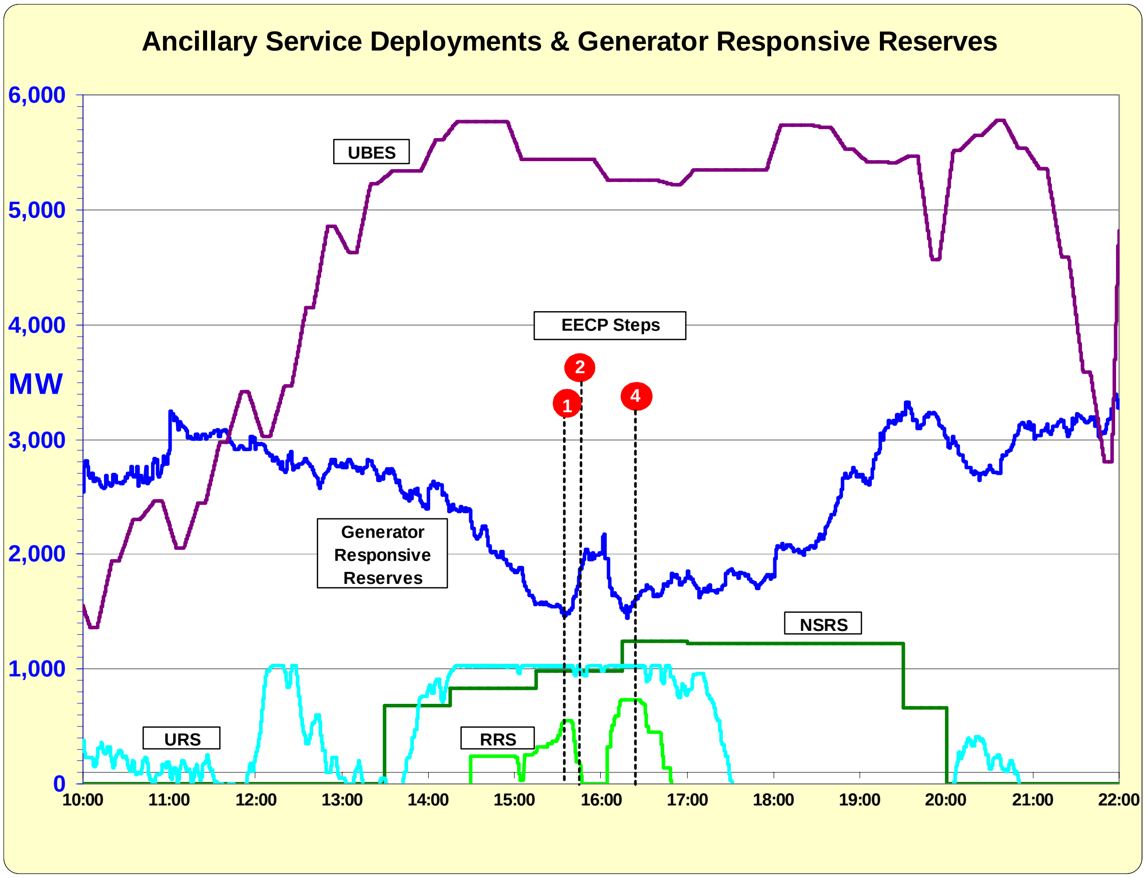
14:21 URS fully deployed; it stayed in this condition for most of the next three hours.

14:36 QSE B contacted and given a VDI of 300 MW; they complied with this request. 242 MW of generation RRS was automatically deployed by the system and frequency indicated 59.94 Hz.   ERCOT issues instructions for an additional 150 MW of NSRS starting at 15:30.   ERCOT’s real-time indication of available spinning reserves that met requirements for RRS, plus its LaaR, amounted to 3,660 MW.

14:48 QSE B contacted and asked to increase their VDI to 400 MW. They replied that their upcoming schedule and obligations would use the reserves indicated, so they were unable to comply with the request.

14:59 QSE C contacts ERCOT about frequency and offers generation. ERCOT issued 100 MW VDI, increased to 200 MW at 15:14 and finally 400 MW at 15:20. QSE C met these requests.

15:00 99% of the UBES Bid Stack was deployed. For Hour Ending 15:00, the demand was 50,265 MW



April 17, 2006 – EECP declared:

15:19 All UBES and URS was in use; instructions for remaining NSRS issued, with deployment due by 16:30. Frequency fell below 59.9 Hz.
15:24 Emergency power across the Eagle Pass DC Tie requested. ERCOT had already begun discussing emergency assistance over the East DC tie with Southwest Power Pool.
15:25 EECP Step 1 hotline call made to inform the market. ERCOT had begun preliminary actions starting at 15:17 per its logs.
15:33 533 MW of Responsive Reserve Service was automatically deployed; frequency indicated 59.84 Hz.
15:34 EECP Step 2 initiated; ERCOT instructed all QSEs to drop LaaRs. Low frequency continued with all UBES and URS deployed until LaaRs were interrupted; frequency then recovered to 60 Hz.
15:46 Unit X began shut down from 38 MW over the next fifteen minutes after loss of cogeneration load, which in turn caused the facility to exceed internal ratings with the generation on-line. Still, the net result was that the facility exported more power than before the generation shutdown, helping ERCOT.
15:51 Unit D tripped while generating 220 MW.
15:55 VDI issued for 35 MW of emergency power over the Eagle Pass DC Tie

16:00 East DC Tie began ramping in 150 MW of emergency power over the next hour. For the hour ending 16:00, ERCOT load was at 51,714 MW.
16:01 Unit E tripped while generating 205 MW.
16:04 Unit F tripped while generating 205 MW.
16:07 Unit G lost 267 MW. Units lost after EECP Step 2 initiated were generating 937 MW. Total impact of these losses were 1089 MW, including reduced spinning reserve capacity and affects on combined cycle steam turbine capacity.
16:09 Hot Line call was made to TOs (Transmission Operators) regarding use of distribution management tools (including voltage reduction).
16:10 ERCOT Frequency Desk alerted QSEs that EECP Step 4 was being initiated.
16:13 EECP Step 4 initiated with TOs via separate hotline call for 1000 MW of firm load shed on a load ratio basis, rotated among customers. ERCOT frequency indicated its lowest level during the event of 59.78 HZ and the Interconnection Control Error was 1,027 MW.
16:17 Unit H tripped while generating 454 MW. Frequency recovery continues after initial dip following this unit trip.
16:25 Public Appeal for Conservation issued by ERCOT to its media contacts. Frequency crossed 60 Hz by 16:30, but UBES continued to be fully deployed for another hour and URS remained near maximum levels.
17:15 VDI issued to QSE V for up to 80 MW. Unit Z trips and reduces steamer capability, 101 MW impact.
17:32 TOs instructed to restore their share of 200 MW of firm load and to move to EECP step 3.
17:51 TOs instructed to restore an additional 200 MW of firm load.
17:56 TOs instructed to remain at EECP Step 4 until all firm load restored.
18:03 TOs instructed to restore an additional 300 MW of firm load.
18:10 TOs instructed to restore the remaining 300 MW of firm load.
18:21 QSEs instructed to restore 50% of LaaRs.
18:26 ERCOT moved from EECP Step 4 to Step 2.
18:29 QSEs instructed to restore the remaining 50% of LaaR.
18:48 ERCOT moved from EECP Step 2 to Step 1.
18:49 Emergency assistance over the East DC Tie discontinued.
18:54 VDI for emergency power over the Eagle Pass DC Tie discontinued.
19:20 EECP Step 1 and emergency operations cancelled, normal operations resumed.

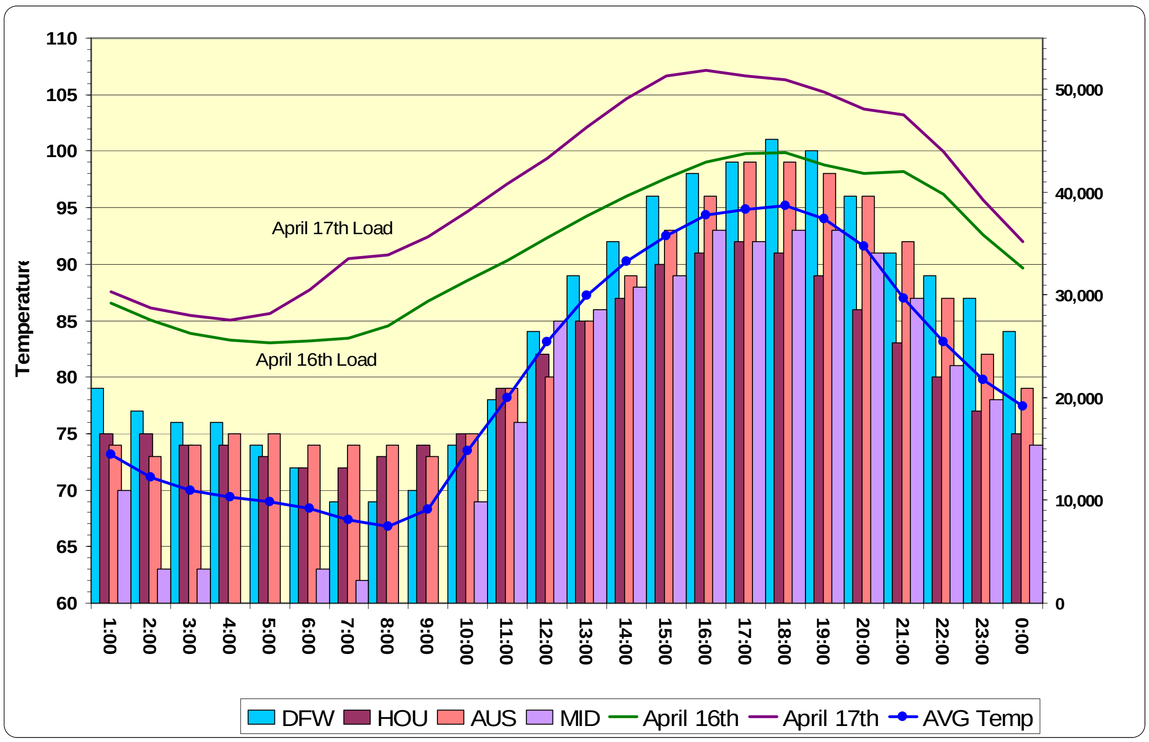
EVENT ANALYSIS & CONTRIBUTING FACTORS

Load Forecast:

Record temperatures were set or tied in Dallas/Ft. Worth, Waco, Austin, and Houston on April 17th. This resulted in a load that greatly exceeded norms, and there were issues with the both the weather and resulting load forecasts. It does not appear that ERCOT or most market participants realized that there were problems with these forecasts until after noon on April 17th.

Cause of errors and magnitude:

As thoroughly described by ERCOT Operations in their report, errors in the April 17th load forecast primarily occurred for the North and Coastal zones. North zone error between forecast and actual peak of 1250 MW was primarily due to temperatures exceeding the Day-Ahead forecast by 5 degrees F. The "West Texas dry-line" shifted further eastward than predicted by the weather services, reaching to the Dallas-Ft. Worth region. The resulting drier air in the North Texas zone resulted in higher temperatures and loads. The chart below provides hourly temperatures in Dallas/Ft. Worth (DFW), Houston (HOU), Austin (AUS) and Midland (MID), as well as average temperatures (AVG) and ERCOT total load on April 16th and 17th.



ERCOT's vendor, AREVA, examined the Load Forecast Model and concluded that the computed total error in the forecast was 3100 MW, with the majority - 2568 MW – in the Coast Load area. AREVA traced much of this back to model development that used a "filter factor" based on weeks instead of days which restricted ability of the tool to adjust to the actual load and weather ERCOT experienced on April 17th. The load on Sunday, April 16th was 43,895 MW, the highest April load in the last two years. The next highest April load of 41,484 MW occurred on April 28, 2005. The April 17th peak greatly exceeded both of these. Similar days for comparison by the software tool may not fit conditions on the "extreme" day, even with several years of historical records.

The temperature and load variations within the day were also a factor. Low temperatures at the start of the day were in the 60's, which created an unusually large temperature variation. No days with similar temperature conditions existed in ERCOT's historical database. Another challenge occurred in trying to compare this to similar conditions. While the peak load approached summer levels, the overall load profile apparently did not share a characteristic decrease in the rate of load growth around 15:00 observed on a typical summer day.

History of changes

ERCOT's load forecasting tool was recently updated and had the last two years worth of historical data loaded into its databases for regression-based analysis, using current ERCOT weather zones. It appears that ERCOT's acceptance of this software followed expected processes with due diligence applied in set-up. ERCOT Operations currently is running both its older load forecast software and the newer update; actions have been taken to address the software deficiencies identified.

Weather conditions forecast and review by operators:

ERCOT Operations' procedures call for review of weather data and checking against alternative sources, although they do not specify any criteria for action. These procedures were followed, based on the information available in logs and recordings. Operators do have the ability to override the primary source if other indications suggest this, but it is not clear that consistent, conflicting information appeared across ERCOT's other weather information sources.

Reserve and Capacity Issues

ERCOT's studies consistently indicated that it had adequate generation reserve margins to meet projected loads, but numerous factors impacted what the operator actually had available, both in studies looking towards peak hours and in real-time. QSE responses to ERCOT after the event indicated that they also believed adequate capacity was available to serve their loads and obligations. Only two QSEs indicated concerns about capacity for April 17th when asked after the event: one had limitations on a key generator due to temperature derating, and the other expressed concerns about the potential for high demand.

Windfarm capacity in Replacement Reserve calculations

Analysis by ERCOT Operations after the event revealed that wind generator capacity was included in its Replacement Reserve studies, overstating what was available for deployment. The Resource Plans for windfarms at HE16:00 showed high sustainable limits on these windfarms at 1615 MW, with a planned output level of 787 MW. Actual generation at windfarms varied; a snapshot at 16:00 indicated 582 MW. Shortly after the event, ERCOT Operations revised its handling of windfarm capacity from study data to only include estimated MW output of windfarms.

At the time of the event, the real-time spinning and responsive reserve calculations used by ERCOT's operators did not include wind capacity above actual generation. These values are calculated in a separate software program that uses real-time telemetry to determine reserves, and this program explicitly omitted wind farm capacity. It did not incorporate Resource Plan data used in Replacement Reserve studies. The differences in these calculations would tend to overstate the reserves before the Operating Period.

Responsive Reserve definition issues

ERCOT Operations tracks all undeployed generation capability in real-time that meets the criteria for responsive reserves, whether or not the capacity is part of the 1150 MW awarded for RRS to generators and automatically deployable. In the ERCOT Operations report, this is termed "physical responsive reserve" when added to LaaR awards and is invariably greater than 2300 MW, but less than the total online spinning reserves. This has caused confusion among market participants in discussions and questionnaires after the event and may have further confused communications during the event about additional capacity reserves. For instance, in post-event questionnaires, QSE R indicated that their remaining responsive reserves were the difference between their RRS award and deployments. Later in the questionnaire, they indicated limited additional capacity could be obtained by exceeding their high operating limits, but this was not characterized as responsive reserve. Other QSE responses were similar, and other personnel have used the term to represent amounts used for long-term system planning.

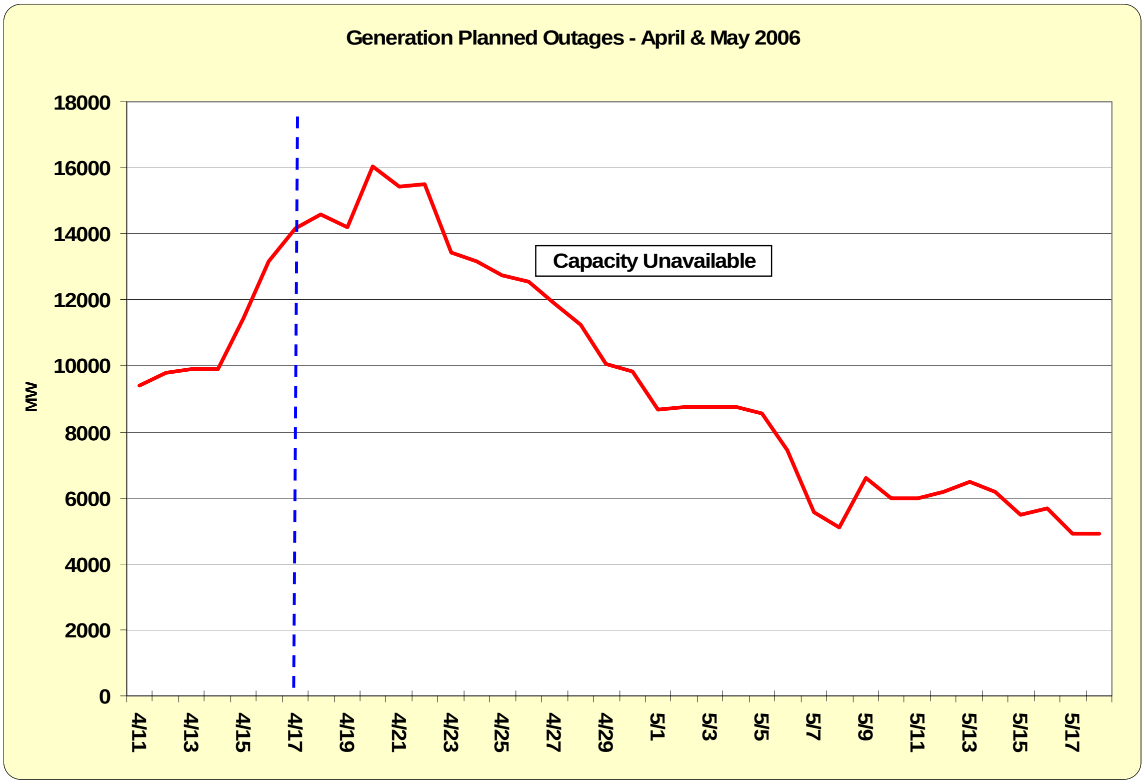
Non-spinning reserve issues

Non-spinning reserve services may be provided from unloaded capability on units that are running, as well as those offline that can start in 30 minutes. ERCOT doesn't have a means to identify specifically which units will provide non-spin. One result is that some capacity shown as on-line reserves will be used for non-spinning deployments, adding some uncertainty to reserve indications, at least until all NSRS is deployed. Another consequence is that ERCOT cannot accurately identify units targeted for NSRS in its studies. On April 17th, QSEs Resource Plans indicated that over half of on-line units were checked as usable for NSRS obligations, and further showed over 1,868 MW of off-line, NSRS-capable units (30 minute start capability). ERCOT Operations could not be certain whether output was directed toward NSRS deployments or support of schedules and additional UBES bids.

Another minor matter is the occasional conflict between NSRS awarded in the afternoon of the day-ahead market and OOMC of units following the replacement studies. QSE W could not meet both and was issued a VDI for 22 MW for this; the impact was small but it occurred during the EECP.

Planned outages

April is also a month with many generators down for maintenance to prepare for summer conditions, and the chart below indicates that this maintenance activity was near a peak around April 17th. ERCOT had 63 Units on Planned Outage representing 14,163 MW at the start of planning for April 17th.



Planned outages need to be accurately reflected in the Resource Plans, along with proper indication of availability, so that ERCOT will know if it can call upon units that are offline. In reviewing Resource Plans, only two instances were noted that incorrectly showed a unit available while it was still shown as out for maintenance in the ERCOT Outage Scheduler. One was not called upon to start by ERCOT due to its lead time, and corrections were made during the operating day, so it was not a factor. Another unit, this one jointly-owned, was shown by QSE G as "on-line" during peak hour, but not by the other QSEs with a share. This unit's capacity was counted in ERCOT's Replacement Reserve studies during peak hour, since it was shown as on-line, which overstated the reserve margin. An extended outage was expected to be completed; the unit ultimately did start on April 17th, but it was later in the day than Resource Plans indicated.

DC Tie Curtailments and Issues

The East DC tie can carry 600 MW of imports into ERCOT. Transmission issues in the Eastern Interconnect on April 17th led to implementation of Transmission Load Relief (TLR) procedures there, starting in the morning. This in turn caused ERCOT import schedules to be cut, reducing the DC tie imports during the day, and effectively removing almost half its import capability.

During the start of EECP Step 1, ERCOT made arrangements with the DC tie operator and Southwest Power Pool to use some of this capacity vacated due to TLR for 150 MW of emergency assistance. It took some time to coordinate scheduling this emergency assistance – once the long ramp period began, the full 150 MW was not imported until 17:00, long after EECP Step 4.   This still left additional capacity available on this tie that had been affected by earlier TLR, but no arrangements to utilize it could be made in the time frame of the emergency.

Additionally, there were equipment problems with the North DC tie, first reported at 13:31 just before EECP Step 2 began. Its import was reduced by 10 MW before 16:00 and the ERCOT Operator understood an increased risk of loss of the 200 MW that it was carrying.

Generating Unit MW Capabilities

Most generating plants have lower output capability with higher ambient temperatures. ERCOT requires seasonal tests to validate capability and provide operational information; test values are entered into ERCOT's operational database when received. Summer 2005 seasonal MW test values add up to less than 97% of 2006 Winter season tests in total, although this figure omits peaking units that reduce this percentage further. In April, however, ERCOT's database held values for Winter or Spring MW capacity tests, which would tend to overstate capability and reserves. Since ERCOT's computer takes the lowest of the Resource Plan limit, the real time limit and the seasonal test, QSEs need to update their Resource Plan and telemetry values to ensure that the capacity available reflects current conditions. When comparing Resource Plan data for HE1600 to available MW capability tests, many units' high sustainable limits were below their Winter or previous Summer seasonal test levels. While not all units have tests for comparison, a Resource Plan snapshot at 15:31 indicates 2,000 MW less capacity than shown on 2005 Summer tests. This suggests that efforts were made to adjust high limits in the Resource Plans.

Several QSEs did report loss of capability due to extreme high temperatures or mechanical problems.   Some of these changes were verbally communicated to ERCOT, not entered into Resource Plans or real-time limit telemetry. Operator logs and QSE questionnaire responses identify less than 250 MW of unit capability derating; others were not quantified.   Fuel curtailments at two QSEs were reported to ERCOT, one which lasted just over fifteen minutes, and the other only involving 3 MW's.   It is likely that some degree of additional deratings related to temperatures could have been applied to other units, but this does not appear to have been ignored by QSEs in their limits, either.

QSEs provide both a High Sustainable Limit (HSL) and a High Operating Limit (HOL) to ERCOT. The latter is intended only for short term operations, and most units do not provide a different value for the two parameters.   Reviewing Resource Plan data for HE1600, the difference between these limits across all online units totaled 395 MW, less than 1% of capability.   Some units were able to generate above their limits during the event for a period of time, and several QSEs provided documentation of requests to maximize unit MW output during the emergency.

Unit forced outages and trips

The forced outages of several units clustered together in a short time period necessitated further action by ERCOT Operations due to the frequency decline that resulted. After the event, QSEs were contacted at these plants to determine whether there was common cause, perhaps related to system frequency. None of the plants appeared to have been lost due to protection equipment or limiter settings overly sensitive to system frequency or other conditions, which may have indicated violation of Operating Guide requirements for generators to withstand transient conditions. The only link identified is that one unit tripped while trying to pick up load after another unit in the QSE tripped.

Total generation lost between EECP Step 2 and declaration of EECP Step 4 was 937 MW. Additionally, these removed 152 MW of spinning reserve capacity above the amount tripped, including impacts on combined cycle plant steam turbine capability. None of this capacity returned to service on April 17th.

Three units had forced outages (runback or trip) reducing generation or capacity by 616 MW after EECP Step 4, one immediately after the declaration. All of these units were either generating or available before the EECP was cancelled.

With one exception, ERCOT Operations was notified of unit trips or forced outages, although there were apparently long delays in some instances where efforts were made to restart units. Resource Plan updates were also made although some were delayed by one or more hours beyond expected update times; again, efforts to restart units were in progress. Real-time reserve calculations do not count units that have tripped once they fall below minimum operating limits, but studies for future hours consider tripped units as “on-line” until their status is updated in the Resource Plan.

The table below lists unit forced outages of units that were actually generating on April 17th:

Unit	MW at time of outage	MW Output and Reserves Reduced	Time of outage	Cause of forced outage	Returned to service on April 17th?
A	243	365	11:58	Forced draft fan failure	Returned to service during EECP Step 4
V	163	245 - including combined cycle impact	12:24	Loss of vibration probe	Returned to service before EECP
W	11	11	14:26	Coolant leak	Restarted during EECP Step 2
X	38	0 - total facility generation remained at limit	15:46	Cogeneration load at facility tripped due to controls problem, resulting in generation above limits on internal transmission. Unit was backed down starting at this time and taken off-line after 15 minutes.	No
B	220	350 - including combined cycle plant impact	15:51	Unit trip caused by Blade Path spread, a separation in temperature through the paths of rows in the turbines not related to frequency or grid instability.	No
E	205	225	16:01	Temperature transmitter monitoring part of the gas turbine cooling air flow failed; unit could not be restarted.	No
F	206	214	16:04	Generator over-excitation protection operated. No relationship between over-excitation settings and system frequency during the event was established; owner identified a defective transducer.	No
G	268	300	16:07	Defect in factory wiring for new controls resulted in overheating when unit raised to full capability. Owner postponed planned tests normally conducted following just-completed overhaul to assist with grid capacity emergency.	No
H	454	454	16:17	Unit's controls attempted to pick up additional load following the last unit trip, leading to low water level in the boiler drum and unit trip.	Returned to service during restoration of EECP
Y	58	61	16:26	Relay problem led to runback starting at this time; unit taken off-line.	Available again during EECP restoration
Z	74	101 - including combined cycle plant impact	17:15	Equipment linkage problem	Returned to service before end of EECP restoration

Two peaking units that could not be started after late addition to HE1700's Resource Plan are not listed above. QSE Y personnel continued to attempt starting the units during the afternoon. The QSE met its obligations with other units.

Schedule Control Error (SCE) issues

SCE indicates QSE adherence to obligations in real-time. As detailed in the ERCOT Operations report, several QSEs had SCE contributing to low frequency prior to EECP. The two largest SCE's resulted from QSE inability to meet large balancing deployments. QSE A had an error in balancing bids while its portfolio recovered from a unit trip, significant telemetry errors and a brief fuel curtailment at one unit. QSE G failed to meet its balancing bids, had a planned unit start late, and also indicated unit deratings and a limited fuel issue. These were discussed with ERCOT operators. Other QSEs mentioned in the ERCOT Operations report indicated deratings of units, late starts or unit trips as causes of lagging behind obligations.

ERCOT Compliance attempted to review SCE performance between 14:00 and 18:00 using the monthly metrics, but these are of limited value due to the amount of exclusions for unit trips, VDI's, RRS and NSRS deployments and treatment of LaaR deployment in SCE. Additionally, 16 QSEs were overgenerating at some point in this event under emergency conditions, a net benefit to ERCOT.

Late starts on units occurred several times during the day. Real-time reserve calculations do not count these units until they are above minimums, but late starts are often reflected in SCE and create uncertainty for the ERCOT Operators as to when the capability will be available. Study results were also affected: the last replacement study run included two late-starting units as "on-line" at HE1600 along with a unit that tripped. Even subtracting these, that study still indicated sufficient other reserves to meet all requirements, but it inflated the reserve margin by 793 MW. Somewhat offsetting this, ERCOT and QSEs communicated about SCE and QSEs persisted in efforts to bring units on-line. Most units with starting difficulties overcame them between 16:00 and 19:00.

Adherence to Emergency Procedures and Requirements

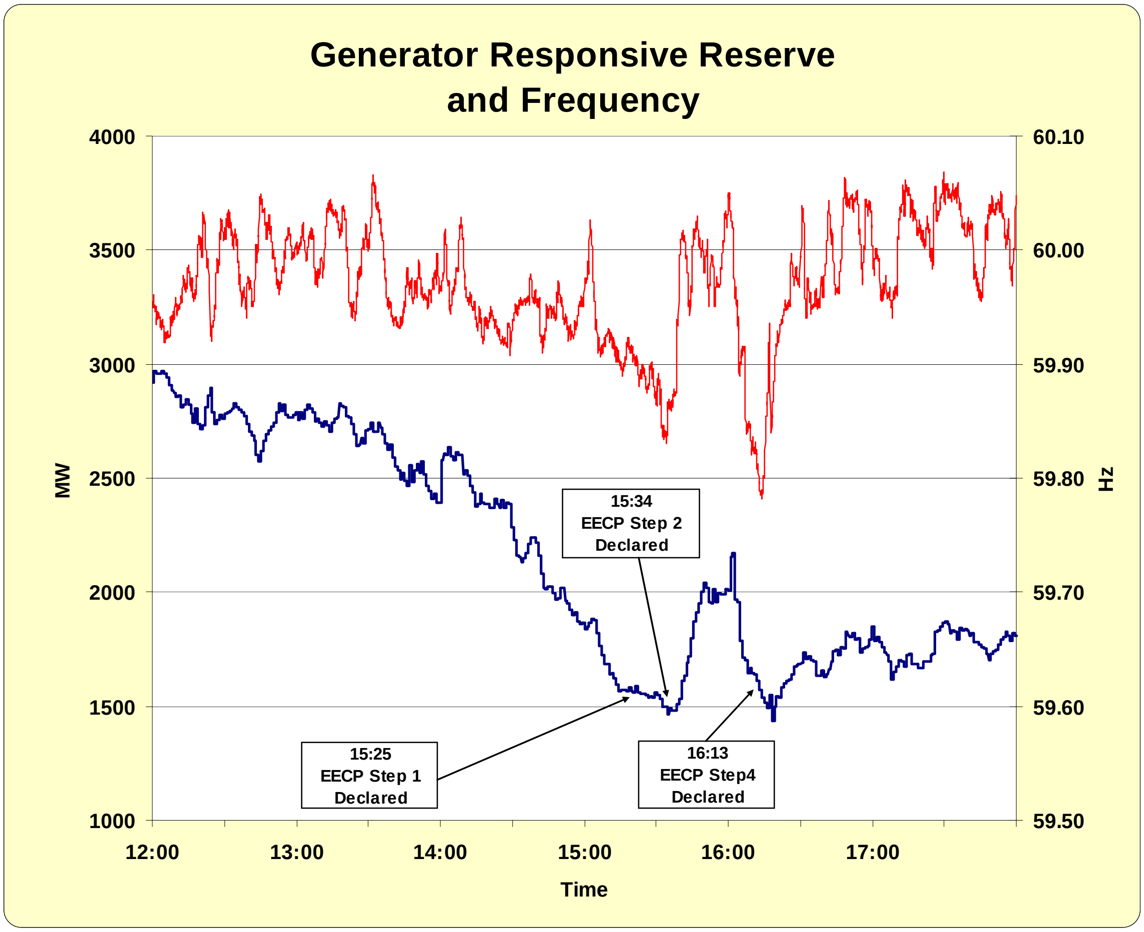
This section reviews emergency-related actions expected per ERCOT Protocols and Operating Guides, as well as ERCOT Operations Procedures. Generally, the actions taken by both ERCOT and market participants were consistent with these expectations. Shortcomings in individual responses or communications did not affect the overall outcome of the EECP implementation. Consideration must be given to the appropriateness of all EECP actions for the specific needs of this situation; in this event, the capacity shortage was identified near the peak hour of the day, not well in advance, and it was accompanied by a frequency decline.

Use of Operating Condition Notices, Alerts and Advisories

Operating Conditions Notices, Alerts, and Advisories are pre-emergency communications oriented towards violent weather conditions or transmission events. Based on the conditions in the Operating Guides for their use and the results of studies and forecasts, ERCOT did not have a clear basis to declare any of the above conditions prior to EECP, at least as they were written at the time of this event. Studies indicated sufficient capacity and reserves for peak conditions, as detailed in the ERCOT Operations report. It is not clear whether declaring any of these conditions would prompt action by the market, either, as these notices did not require specific actions by QSEs at the time of the event.

Actions prior to Initial EECP Implementation by ERCOT

ERCOT Operations staff conducted studies to validate its day-ahead plans. The last replacement study run at 1300 appeared to confirm that capacity was sufficient. Problems with unit trips, SCE and telemetry errors following 1300 surfaced; operators appear to have followed procedures related to reviewing these issues. When confronted with large SCE, the ERCOT Operators face additional uncertainty about how much of the remaining reserves will be depleted to correct QSE SCE. UBES and URS were fully deployed automatically. NSRS was deployed according to procedures based on the amount of balancing energy deployed. Frequency was often low but did not cause full automatic deployment of Responsive Reserve Services from generators. Prior to EECP Step 1, ERCOT looked to two QSEs with reserves above 100 MW for additional support of frequency and issued Verbal Dispatch Instructions (VDI's). Both QSEs were able to respond initially; one in fact actually called ERCOT and offered additional support prior to EECP implementation based on their observation of frequency.



EECP Step 1

The criteria for initiating EECP Step 1 calls for maintaining reserves at 2,300 MW; EECP Step 1 does not trigger on frequency declines, which had already begun. Based on the information available through its systems, the ERCOT Operators saw a continued frequency decline and drop in available reserves while the balancing stack and up regulation were both fully deployed. Instructions to deploy remaining NSRS had been issued. ERCOT procedures call for initiation of EECP if responsive reserves drop below 2300 MW. Given the issues with load growth, reserves, frequency, SCE and the deployment of other ancillary services, it was appropriate for ERCOT to declare EECP with indicated reserves above 2,300 MW.

ERCOT Operators appear to have considered all relevant actions. In particular, ERCOT initiated a request for emergency assistance with the DC Tie operator and worked with Southwest Power Pool, ultimately obtaining 185 MW of emergency assistance, 150 MW through the East DC Tie and 35 MW from the South DC Tie. ERCOT Operations confirmed that all RMR capability was in use. Block load transfers did not appear to be useful as they are time-consuming to implement.

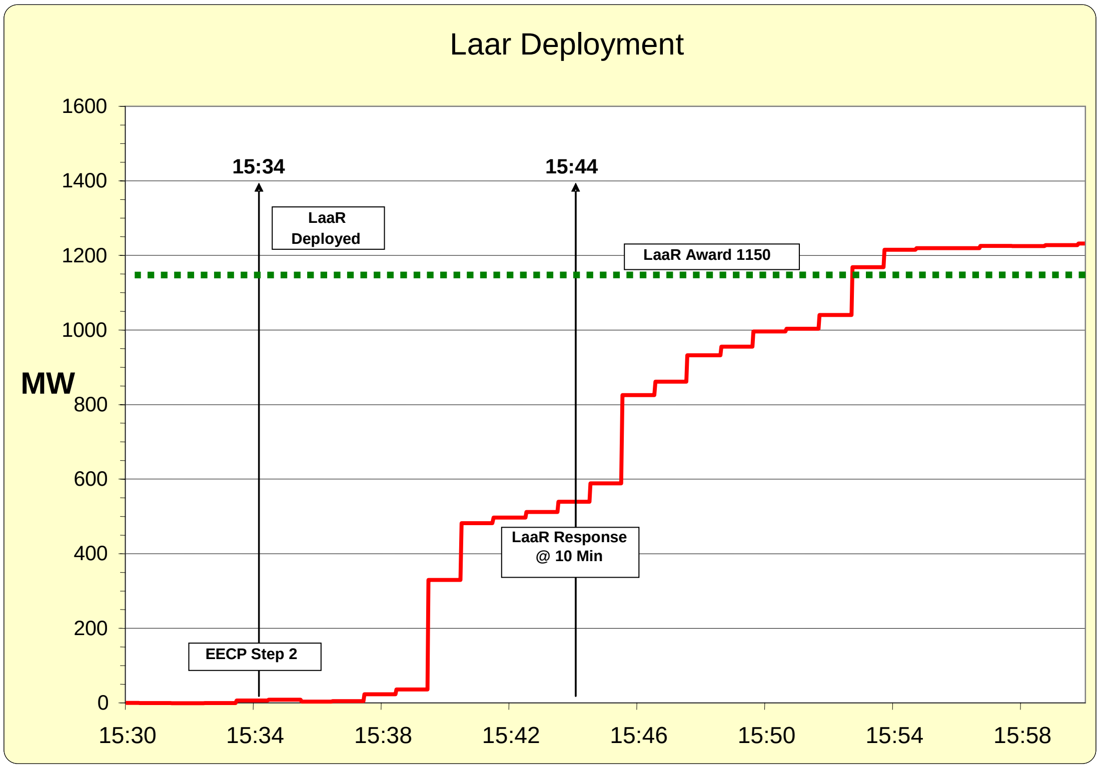
After declaring Step 1, ERCOT did not issue OOMC or VDI to any other QSEs except for DC tie assistance, nor did any QSEs respond to ERCOT that they had additional units available in the "timeframe of the emergency", which was likely to be only a couple of hours since ERCOT was near projected peak load. This short time period would limit the number of units that could reasonably be started to assist. The most viable units appear to have been utilized. For example, QSEs indicated that only 534 MW of their NSRS awards came from off-line units. The Resource Plans listed over 1,868 MW of off-line, NSRS capable units (30 minute start capability) and every one of them either generated or failed to start after attempts were made, nearly 1,300 MW of capability. While some were started prior to EECP, QSEs indicated that these units were started to provide additional capacity beyond that required for their NSRS awards. Review of Resource Plans does indicate a few units that were not utilized; ERCOT Operations did not request their startup and QSEs did not inform ERCOT that they were available. Five available units had start times of one hour or less, totaling 90 MW (one unit rated 34 MW was fuel restricted and not likely to provide more than brief support). Eight more units, totaling an additional 645 MW, were listed in Resource Plans as capable of starting in 2 hours, but these would not have been producing power at the time of immediate need. There were other units available but with even longer start times. In summary, it does not appear that ERCOT Operations could expect a useful amount of offline capacity to start up at the time of EECP Step 1 notification, and QSEs were still engaged in bringing up many units that they started without instructions.

Generally, there appeared to be a noticeable amount of confusion during this and other EECP hotline calls. While some of this is not surprising during an emergency, a review of responses to the calls indicates a lack of awareness of EECP and hotline equipment among some of those on the call. This is important also because ERCOT Operations did not use a script detailing all actions expected per the Protocols and Operating Guides, but relied on market participants to know what actions were expected with each EECP Step, as well as understand general obligations in Operating Guide 4. In reviewing QSE responses in particular after the event, it does not appear that this philosophy is consistently understood, and this highlights a need for more clarity about expected actions by QSEs and TOs during all EECP steps. The same is likely true of communications between QSEs and TOs to those market participants that they represent; it is unclear what messages were passed to the loads, generators and smaller transmission companies.

EECP Step 2 Implementation

Criteria for initiating EECP Step 2 is based on maintaining reserves equal to the largest unit on-line, typically 1,250 MW. ERCOT's calculations indicated that the amount of unloaded generation that met the requirement for RRS (termed "physical responsive reserves" in the ERCOT Operations report) was above this level. However, the ERCOT Operators' evaluation of the situation, given the issues with the quality of the reserve information and the depletion of balancing and regulation ancillary services, suggests that shedding LaaR was the appropriate option. ERCOT did request that TOs consider voltage reduction if appropriate. A hotline call was placed thirty-five minutes after EECP Step 2 was declared; as noted earlier, ERCOT Operators did not read scripts of all actions, instead expecting TO personnel to be familiar with the requirements. Block load transfer was not suggested as it is a lengthy, manual process.

QSEs with LaaR ultimately provided the expected response but it took longer than 10 minutes after notification to achieve criteria defined in the Protocols, as the chart below indicates. Six of nine QSEs with LaaR did not shed 95% of the MW of their LaaR RRS award within 10 minutes of verbal deployment; the chart below indicates what the ERCOT operator would have seen.



Several QSE communications with ERCOT regarding LaaR provide insight into this performance. One asked whether ERCOT would shed the load or the QSE; another asked if they could restore load prior to EECP termination. There was at least one instance of an individual LaaR load re-energizing before ERCOT issued directives for restoration of LaaR, although this did not bring the QSE under its obligation. One QSE failed to provide any LaaR support during the first hour after EECP Step 2 was declared; their real-time operator called in belatedly and asked if their QSE was supposed to participate.

However, overall MW response reached 1,093 MW within 19 minutes, which is 95% of the LaaR RRS target of 1,150 MW. LaaR MW response increased further afterwards and remained somewhat above the target throughout the deployment (still within the overall maximum of 150% of award). LaaR delivered total expected MW requirements for RRS, although belatedly.

Other related actions by Market Participants

TOs were asked by ERCOT to initiate voltage reduction if they deemed it beneficial. Eight of the sixteen TOs implemented such plans, although not all believed that it was effective at the time of EECP Step 2. Approximately 70 MW total demand reduction was estimated (three did not quantify their results, and timing of efforts varied). The others either had no plan or did not implement it. Reasons included: determination that it would be ineffective due to the inductive nature of their load under these conditions, or that it could not be carried out along with EECP Step 4 load shed, or that the distribution grid in their area lacked suitable equipment.

QSEs do not directly report on conservation or load shed efforts to ERCOT Operations in their Resource Plans or other information exchange, outside of LaaR. If such measures are in place, ERCOT Operations had no direct means to trigger their use; even EECP Step 3 is a voluntary appeal for conservation. Some actions were taken to reduce load outside of the transmission company efforts and LaaR deployment. One QSE reported a contract-based program that produced roughly 100 MW of reduction; two municipals exercised their air-conditioner cycling programs but did not indicate results. Others may exist but were not reported. Another QSE reported that several of its larger plants turned off auxiliary equipment to reduce demand temporarily. Several QSEs reported suspension of maintenance activities at generating units as well.

EECP Step 4 Implementation

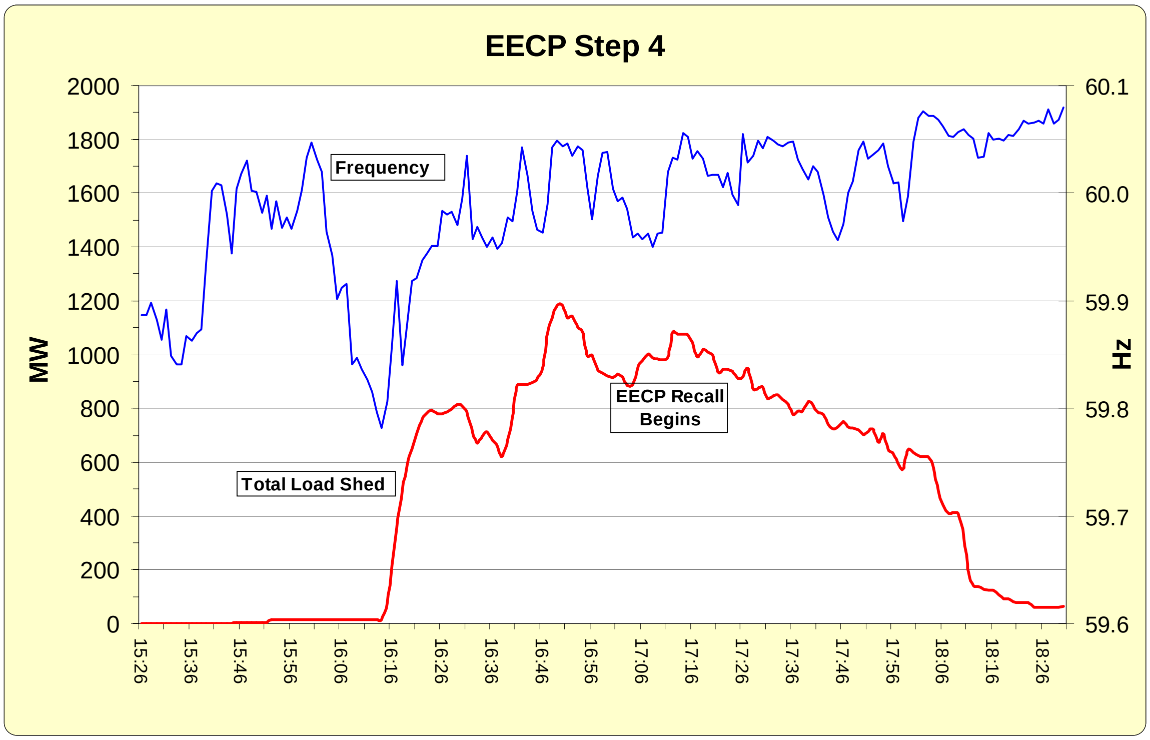
After the unit trips above, ERCOT generation capability was reduced by over 1,000 MW. Before the first unit trip at 15:50, only twenty minutes after EECP Step 2 was declared, ERCOT frequency had recovered to 60 Hz and all Responsive Reserve Service was recalled. By 16:10, Responsive Reserve Service deployments had increased to 600 MW to address the unit trips. Frequency continued to decline and approached 59.8 Hz. ERCOT Operations procedures suggest that at this frequency, EECP Step 4 may be declared immediately, and that was the action taken. EECP Step 3 primarily involves public appeal for conservation, and cannot be expected to produce immediate results.

Initially, ERCOT Operations considered 500 MW of load shed and an informational hotline call was made to QSEs. When the transmission companies were contacted shortly thereafter, ERCOT Operations determined to request a higher amount, 1,000 MW, due to further deterioration in frequency and reserves.

Transmission Company Load Shed

All TOs were properly notified of EECP Step 4's implementation. There were some issues with the hotline at one company, but load shed was initiated by all contacted. The chart below indicates the aggregate results, based on input from each company. The larger TOs responded very quickly as they have automated this process, including rolling the load interruption among customers. Other companies rely on more manually directed actions or must work through a second company before the load shed occurs. The

Operating Guides provides no criteria for how quickly the load must be shed by individual companies as with LaaR; emergency load shed is dispersed and companies rotate the interruption. Two TOs were short of their targets due to operator misunderstanding of the requirement. One company took nearly an hour to report any load shed. Logs and responses from TO questionnaires indicate that only half of the TOs confirmed with ERCOT when the load shed was completed. These are minor considerations, as the load shed was clearly effective in frequency recovery despite the loss of an additional generator shortly after EECP Step 4 was implemented.



Bypass of EECP Step 3

EECP Step 3 was bypassed by ERCOT Operations when frequency reached 59.8 Hz. Step 3 actions alone were not likely to produce rapid results to address the immediate frequency concern. However, per Operating Guides Section 4.5.3.2, Step 3 measures were to be conducted in addition to those in Step 4. It is not clear that everyone understood that Step 3 actions needed to be implemented without a declaration. Two actions are specified for ERCOT, although the value to the grid was limited due to EECP Step 4 already in effect.

One action is an appeal to the media for voluntary load reduction. ERCOT's Chief System Operator initiated the media appeal after Step 4; communications were sent to a pre-arranged list of media and government contacts. It does not appear that ERCOT Operations specifically requested that transmission companies carry out their own media appeals, a guideline suggested in an Appendix to the ERCOT Shift Supervisor's

Procedural Manual. There are no Operating Guides statements concerning media alerts by individual market participants. Nevertheless, based on their responses to questionnaires after the event, the majority the sixteen TOs started programs to inform local media or government about the condition. The scope of these programs vary widely, but most indicated that they had active efforts to issue notifications, while others prepared their media relations staff for questions or conducted web postings.

Part of EECP Step 3 in the Operating Guides and ERCOT Operating Desk Procedures (but not the Protocols) calls for ERCOT to “confirm that all generators are at maximum generation”. In reviewing recordings and logs during the event, there is no clear record of this confirmation as a specific request by ERCOT, nor are there clear responses from QSEs that they were providing this. The intent of this item in the Operating Guides lacks specificity and was therefore subject to misinterpretation. In follow-up surveys, almost all QSEs indicated that their units were at their full capability and they had moved them there to meet obligations or provide additional assistance to ERCOT. One QSE identified 30 MW in its portfolio that could be obtained by taking units off automatic generation control (AGC), which restrict output somewhat but are necessary for ancillary services. Similar situations may have existed elsewhere, but were not quantified. Several QSEs indicated that they would not take such actions unless specifically directed by an ERCOT instruction. On the other hand, other QSEs had taken units off AGC on their own so they could operate with “valves wide open” and maximize output, in some instances operating with a positive SCE. Since this level of output cannot be sustained indefinitely, judgment as to the “time frame of the event” again comes into play.

As noted, UBES and URS were fully deployed, and the last NSRS capacity was expected to be fully ramped in by 16:30. The ERCOT system did not fully deploy Responsive Reserve; the maximum deployment level was 740 MW, suggesting over 400 MW remained. Some of this RRS was in portfolios with tripped units and would not be available. Additionally, MW from generator governor action to increase unit output is not reflected in ERCOT’s RRS deployment setpoint. Last, some QSEs were generating with a positive SCE, above their schedules or ancillary service obligations.

EECP Recall and Restoration Activities

ERCOT began restoration of firm load at 17:32 after RRS recall was complete. ERCOT Operations initially declared Step 3 prior to load restoration in Step 4. A correction was issued after discussion on the hotline. From that point, restoration appeared to progress in an orderly fashion. Transmission company firm load restoration was completed with only one incident reported involving a mechanical failure that prolonged some outages until 17:55. Some frequency swings occurred as load (including LaaR) was restored in blocks. Some LaaR took longer than the 3 hours called for in the Protocols for restoration, but arrangements were made to cover this with generation capacity. Other than some inconsistency in confirming load restoration, procedures were followed.

NERC STANDARDS COMPLIANCE

Emergency Operations Plan Execution

NERC Standard EOP-002-0, Requirements 2, 3 and 9 measure ERCOT's response to a capacity and energy emergency, in accordance with plans. Requirement 2 basically requires that ERCOT implement and "appropriately follow" its plan for capacity and energy emergencies, essentially the EECP Steps. These appear to have been effectively implemented in this situation. The measurement also calls for evaluation of whether the level and timing of communications was appropriate. While recommendations can be made to improve actions, and arguments can be made that EECP Step 1 could have been initiated sooner, EECP communications and actions directed by ERCOT to QSEs and TOs were clearly effective in addressing the situation that developed. Requirements 3 and 9 as written do not apply to ERCOT. Other market participants' involvement in EECP is not measured by this standard at this time.

Frequency Control

NERC's measurement of recovery from loss of generation, the Disturbance Control Standard (BAL-002-0), is not applied in situations such as this with multiple unit losses spread over an extended period. None of the unit trips encountered was large enough to meet the measurement "window" of 1,000-1,250 MW tripped within a one minute period. However, a draft standard proposed to replace DCS is triggered by frequency dropping below 59.932 Hz for over thirty minutes. ERCOT would have violated this standard prior to EECP declaration from the time period 14:05-14:38. During the period in which the EECP was in effect, ERCOT actually would have passed the requirement of the draft standard since frequency recoveries accompanied both Step 2 and Step 4. Ensuring future compliance will either require changes to ERCOT Procedures and possibly Protocols, or revisions to the proposed standard before it is balloted.

Transmission Security

NERC Standard TOP-007-0 addresses reporting and actions related to transmission security operating limits, which are based on first-contingency loading on 138 kV and 345 kV elements. West-North 345 kV transmission flows exceeded calculated limits for a period starting at 16:11 just before EECP Step 4, but did not reach the thirty minute threshold in NERC Standards for a possible violation of Interconnection Reliability Operating Limits (IROLs). There is a potential grid stability concern on these transfers under certain circumstances and therefore this interface is monitored under this standard. ERCOT Operations identified the concern on April 17th and re-calculated the limits at 16:35 based on changes in system conditions since the time that the limits were originally calculated. The resulting increase in transfers eliminated the concern.

There were seven alerts issued during the event for 138 kV transmission lines approaching or exceeding first contingency limits, in accordance with procedures. First contingency limits identify situations where the loss of an element will result in other elements exceeding their ratings, but are at least one outage away from an actual overload. Based on logs, actions were taken to successfully address at least one of these during the time of the EECP; the others were ended as loading dropped later in the day.

Two actual overloads, not first contingency violations, were reported on 138 kV lines. One at 103% of rating lasted just over an hour and was addressed by transmission company action that switched load to a different circuit. Another at 104% of rating lasted from 14:30-17:00 and was related to an alert condition; no other actions were apparently identified and taken, except monitoring the situation to see that it did not progress above these levels.

None of these instances of exceeding security limits on the 138kV system is recognized as a potential IROL that could produce major impact to the bulk electric system, and there is no reportable violation. Future revisions to this standard may be more demanding for issues at lower voltages.

PROTOCOL AND GUIDE VIOLATIONS

Apparent violations of the following were found in reviewing the April 17th event:

Protocols 6.5.4 (2) Responsive Reserve Service

A QSEs Load acting as a Resource must be loaded and capable of unloading the scheduled amount of RRS within ten (10) minutes of instruction by ERCOT and by action of under-frequency relays as specified by the Operating Guides.

Protocols 5.6.7 EECP STEPS

In addition to measures listed above, ERCOT will instruct, in 100 MW blocks, all TDSPs having control over distribution feeder breakers and/or control of breakers serving retail customers to shed Load in order to maintain a steady state system frequency of 59.8 Hz. ERCOT will allocate manual Load shedding for ERCOT-wide emergencies based on the amount of Load that is served by each TDSP.

Operating Guide 4.5.3 Implementation

The ERCOT System Operator shall declare the EECP steps to be taken by QSEs and TDSPs. QSEs and TDSPs shall implement actions under that Step (and all above if not previously accomplished) <u>and shall report back to the ERCOT System Operator when the requested step has been completed.</u>

Operating Guide 8.3.3 QSE and TDSP Responsibilities (Hotline equipment)

- Hotline must be a 500 set not attached to the Market Participant's Phone System.

Operating Guide 4.5.3.2 EECP

Direct all TDSPs and their agents to shed firm load, in 100 MW blocks, distributed as agreed and documented in the ERCOT Operating procedures in order to maintain a steady state system frequency of 59.8 Hz.

RECOMMENDATIONS AND FOLLOW-UP

Load Forecast

ERCOT has taken steps to re-examine its load forecasting methodology and correct issues identified with the software; work should continue until completed. ERCOT re-installed its older forecasting software and is placing an extra margin on its forecast equivalent to one standard deviation of historical forecast error.

Reserve Calculations

Wind Farm Capacity in Calculations

ERCOT has modified its use of wind capacity in Replacement Reserve studies so that only planned MW are included. This should be evaluated for impact as the amount of wind generation in the system grows.

Operational Reserve Capacity

ERCOT and ROS are working to develop a more realistic assessment of QSE reported reserve capability, given discrepancies that occur between reserves found using Resource Plan or telemetry data and what QSEs can actually deliver when called upon. This effort has led to proposing a standard derating factor of 7%, based on ERCOT Operations analysis. This factor would be used to trigger emergency notifications earlier than is done presently.

Unit Testing

Unit testing for Net Dependable Capability as defined in Protocol 6.10.2 needs to be redefined. The verbiage is not as clear as it should be. To be useful to ERCOT Operations, unit tests need to be conducted in the first part of the season and the data turned into ERCOT as soon as possible after the tests are completed. The 168 hour verbiage is not useful to either ERCOT or the QSE, since if the unit did not run at full load in the first 168 hours; it could be limited to the amount that it had run in the first 168 hours. This could mean that available generation is not available due to a constraint for not testing in the first 168 hours. ERCOT Compliance recommends that a close look be given into testing the units within the first month of the season and submitting the test data as soon as the test is complete.

HOL as capability

Using the HOL as the capability does not ensure that a unit can perform in emergency situations that last longer than one hour. It may be better to consider using HSL as capability in that units should be able to sustain the amount listed for long periods of time when needed as opposed to the one hour limit.

Resource Plans and Limit Telemetry Updates

Any number of times, there have been instances where ERCOT Operators call for generation and the QSE replied that they just do not have it. It is apparent that when these situations occur and there is no reasonable answer as to why the Resource Plans or telemetry have not been changed to reflect the true available capacity; these need to be cited as not following ERCOT Protocols. There needs to be a concerted effort on the part of the QSE Participants to update the Resource Plan as soon as possible after conditions have changed to warrant the update. It is recommended that ERCOT Operations take a lead in recognizing these situations and elevating them to Compliance for follow up.

Training and Drills

EECP Training

When ERCOT Compliance performs audits at QSE and TOs it is almost without exception that the Operators have the EECP procedures within reach. They contend that they do some training on these and know what to do should EECP occur. In the April 17, 2006 EECP event, there was much confusion from some Participants as to what an EECP was. Some Market Participants responded to follow-up questions by ERCOT Compliance that they attended the ERCOT EECP training. There has not been much EECP training offered by ERCOT; the 2006 Operations Training Seminar had no sessions dedicated to EECP, although emergency preparedness and black start were covered. While more training is being discussed for the 2007 Operations Training Seminar, it is imperative that Market Participants have some sort of training program that familiarizes their real-time operators with the EECP steps and what to do when it occurs. More drill opportunities for EECP simulations under various scenarios should improve familiarity with Steps and expected communications. These must be mandatory and encompass all real-time operators in order to be effective. It would be desirable to also include Southwest Power Pool and other agencies outside ERCOT in these drills. The first of these has already been conducted on July 6, 2006.

Definition of Reserve Terminology

ERCOT should provide clarification and education on terms related to reserves and how they are used, specifically “physical Responsive Reserves”, as well as continue discussion among stakeholders on which units are assigned to NSRS.

LAAR deployment

ERCOT Compliance feels it is imperative that QSE Participants verify that LAAR can be dropped within the parameters set by the Protocols. In the April 17, 2006 event, there were several QSEs whose LaaR response did not meet the ten minute criteria. Those LaaR-owning QSEs unable to achieve Protocols criteria should rehearse manual load drop and restoration to achieve expected 10-minute delivery upon ERCOT instructions and recovery within 3 hours of recall instructions. It is recommended that additional training be done by the QSE to the LAAR in their portfolio to ensure that the proper deployment can be achieved.

EECP Procedures and Steps

Deficiencies in EECP Procedures:

Specific expectations of both ERCOT and market participants need to be more clearly defined in each EECP Step. It may be appropriate to go into further detail with lists of specific actions expected from all Market Participants – primarily ERCOT, QSEs and TOs, but possibly also generators, loads and others. Consistency between the language in Protocols, Operating Guides and ERCOT Operating Desk Procedures can be improved.

ERCOT should consider use of scripted communications for EECP Steps as part of its Procedures, given the lack of familiarity and experience among many real-time operators.

Modifications have been proposed to move public notification (government, law enforcement and media) earlier into the EECP Steps and combine certain actions; work should continue to approve revisions. The need for local as well as ERCOT-wide communications needs to be considered. These need to preserve the ERCOT operators’ flexibility in declaring EECP under varying conditions.

Include consideration of QSE communications about any conservation or load reduction measures that their Load Serving Entities may be able to provide. ERCOT Operations should be informed of possible use of such programs under emergencies.

Coordinating ERCOT Hot Line Calls:

ERCOT Operations should ensure that Hot Line calls are made in proper sequence. In the April 17, 2006 event, the Frequency Desk made a call to the QSE stating that Step 4 was being initiated and that load shedding for 500 MW block would be needed. The Transmission Security Operator made the Hot Line call a couple of minutes later to the

Transmission Companies communicating the need for dropping their portion of a 1,000 MW block. While this did not violate procedures, it did lead to confusion in at least one Market Participant's shop. ERCOT Compliance recommends that the Hot Line call in this step be made to the Transmission Operators first, then inform the QSEs from the Frequency Desk as a means of keeping them up to date.

Emergency Communications

Pre-emergency Notifications:

ERCOT should re-evaluate its pre-emergency communications plans to determine if additional notices of system conditions should be given to the market and public and to evaluate the timing of notices. OCN's, advisories and alerts may need more flexibility to trigger on highly unusual conditions such as unseasonable temperatures. A procedure change is in draft to accomplish this; it will also trigger pre-EECP notices based on declining reserve levels.

EECP Communications by ERCOT:

ERCOT is working on internal communications procedures to ensure that ERCOT officers and the Communications Department are aware of situations or events in a timely manner. These in turn should help communicate situations to regulators, government officials, emergency operations centers and others as appropriate. Work is well underway and certain additional notifications are already provided.

Hotline Equipment and Call Content:

There were some problems during the April 17 event with hotline calls and some notifications to confirm actions were apparently not made. Hotline equipment and procedures may merit further review, including clarifications intended to help manage the need for responses on completion of EECP steps. If every Market Participant is expected to affirm completion of each EECP activity, the burden of handling these calls may become excessive.

Market Participant EECP Communications:

The Operating Guides call for communication between QSEs and TOs to the market participants for each EECP Step. The amount and content of such messages merits review, as well as what information should be provided back to ERCOT following such messages. This can create significant additional work and communications burden if followed to the letter, but some communications are essential down to the generators, loads and smaller transmission companies.

Transmission Load Shed in EECP Step 4

When Step 4 is called and the load is in need of being reduced, it needs to be done as quickly as possible to relieve the situation. While some can do this rather quickly, it is apparent that not all can. On April 17, 2006, some TDSPs took over an hour to shed the firm load. While LAAR obligations require that contracted LAAR be shed within 10 minutes of being ordered by the ERCOT System Operator, there is no time limit for TDSPs to shed firm load. A review of best practices used in EECP Step 4 is desirable. Performance expectations for load shed should be developed, as well as preparatory activities similar to the annual underfrequency load shed survey, perhaps included in drills. A predetermined time limit should be addressed and added to the ERCOT Guides.

CONCLUSION

Problems with ERCOT forecasting and reserve tools further reduced the tight margins between generation and load on April 17th. It is doubtful that the need for EECP measures could have been avoided entirely under existing practices. The objective of the EECP is to provide for the maximum possible continuity of service while maintaining the integrity of the ERCOT transmission grid, in order to reduce the chance of cascading outages. This may be accomplished by the orderly curtailment of demand during such emergencies. Once implemented on April 17th, EECP Steps were effective in the time frame of the emergency, with only minor variations from expected actions by ERCOT Operations, QSEs and TOs. Follow-up on all issues identified will only help to further reduce the likelihood and duration of future emergencies.