Xcel Energy[SM]

PUBLIC SERVICE COMPANY

PUBLIC SERVICE COMPANY OF COLORADO

COMMITMENT LOG REPORT TO THE COLORADO PUBLIC UTILITIES COMMISSION

REGARDING THE FEBRUARY 18, 2006 CONTROLLED OUTAGE EVENT

DOCKET NO. 06I-118EG

JUNE 15, 2006

A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL BECAUSE IT CONTAINS HIGHLY CONFIDENTIAL INFORMATION.

Public Service Company of Colorado

Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006 Controlled Outage Event

Docket No. 06I-118EG

June 15, 2006

Introduction

On March 13, 2006, Public Service Company issued its "Report of Events That Led to Controlled Outages -- Public Service Company of Colorado – Date of Occurrence February 18, 2006"("Report"). In the Report, Public Service Company described the improbable sequence of events beginning on Friday February 17th and continuing through Saturday February 18th that led to the loss of approximately 3200 Megawatts of generating capacity from the Company's electric resource portfolio. The unexpected and unusual loss of this significant amount of generating capacity was critically tied to the use of and availability of natural gas as a generating fuel. Because of colder-than-expected weather, and because the Company replaced higher efficiency gas-fired generation with less efficient gas-fired generation as the more efficient plants experienced unplanned outages, the Company consumed its available gas supplies more quickly than was planned. As a consequence, on the morning of Saturday February 18th, when temperatures along the Front Range were sub-zero and home heating demands were high, the Company's pipeline distribution pressures became dangerously low and the electric system's reserve margins fell to their lowest limit. Finally, at approximately 8:45 a.m., when the Front Range Power Plant in Colorado Springs (one of Public Service's electric suppliers) tripped off line, the Company had no more available options to maintain its operating reserve requirements and we were forced to initiate controlled outages to maintain electric system stability and to avoid impacting neighboring electric systems.

As described in the Report, the Company successfully implemented controlled outages on its system for about 90 minutes on the morning of Saturday February 18th, which avoided further electric system problems. Sufficient electric power was purchased to meet all operating reserve requirements within 90 minutes. However, the Company regrets that we had to resort to the extreme remedy of cutting power to our firm customers when the outside temperatures were below zero and we view this to be serious matter to be avoided, if possible, in the future. In addition, as we described in the Report, our communications to our customers and the general public surrounding the outages were untimely and unclear and need improvement.

At the conclusion of the March 13th Report, the Company made the following recommendations:

- Public Service will investigate whether normal protocols related to gas control, gas supply, economic dispatch, energy trading, reserve levels, and planning criteria should be altered to provide more "cushion" to respond to extremely cold weather conditions and extremely hot weather conditions. The Company is already investigating additional gas storage opportunities. Public Service will investigate how to align and integrate various operations to deal with cold weather, hot weather and special events, with the objective to prevent system degradation to avoid activating more serious emergency procedures.
- Public Service will study how to improve communications among various Company departments so that each department has an accurate understanding of the interrelationships between the operations that each department controls. As part of this effort, Public Service will investigate whether there are barriers to full communications of operational problems, resulting from interpretations of federal Codes of Conduct, that need to be addressed. Public Service will develop operating protocols for Gas Control, Real Time Dispatch/Electric Trading, and Gas Supply so that during elevated operations each department has an accurate understanding of how problems need to be evaluated and communicated to other departments, so that all employees have an accurate understanding of how their respective responsibilities interact.

- Public Service will thoroughly investigate problems that arose, both internal to the Company and with customers, in exercising Public Service's right to interrupt its retail and wholesale customers who have elected to take interruptible service.
- Public Service will work with its generation suppliers to investigate the causes of power plant failures over the Presidents' Day weekend to determine how similar plant failures can be avoided. The Company has fully investigated the operation of its own generation fleet during the time recounted in this report.
- Public Service will study how to improve internal communication channels so that its Media Operations and Call Center personnel have accurate and timely information. Public Service will investigate what technology can be used to provide more accurate information to customers calling to report outages.

Public Service Company Task Force

Following the submittal of the March 13th Report to the Public Utilities Commission, Public Service established an internal Task Force to address the Report's recommendations. In addition, the Company has been cooperating with the PUC Staff as it pursues the inquiry ordered by the Commission in this matter in Decision No. C06-0248, adopted on March 15, 2006.

The Company's internal Task Force is headed by Mary Fisher, Vice President of Colorado Resource Development. Pat Vincent, President and CEO of Public Service Company of Colorado assigned Ms. Fisher this responsibility. The Task Force was organized around the "February 18, 2006 Event Commitment Log." This Commitment Log included nearly 40 separate action items that were identified as needing investigation and follow-up in the Company's March 13th Report.

As a result of the Task Force's efforts, the Company is submitting as its follow-up to the March 13th Report this Commitment Log Report that describes each of the

Commitment Log items, the findings of the investigation regarding the item, a description of the actions taken associated with the identified item and, when appropriate, the date when the action item was completed. The Commitment Log Report includes backup materials supporting the investigation. Because of the operational sensitivity of some of the material assembled by the Task Force, the Company has prepared both a public and non-public version of the Commitment Log Report. An index of the Commitment Log Report is included on Page 12.

Summary of the Task Force's Actions

The Company identified the need to investigate the relationships between gas load forecasting for its Local Distribution Company ("LDC"), load forecasting for electric generation, gas supply purchasing, gas transportation customer supply management, and Gas Control operations. The Task Force determined that the Company did not have clear planning and operating protocols to ensure that there would be sufficient gas supplies available on the distribution system to meet both the LDC and electric generation requirements in extreme weather situations where multiple unanticipated plant outages occurred like those in February (Commitment No. 19). In addition, the Company did not have clear and quantified guidelines regarding the conditions under which it would call Operating Flow Orders ("OFO") to restrict gas consumption for non-LDC customers (transporters and electric generators) to the supplies that had been nominated by these customers and delivered into the Company's distribution system (Commitment No. 15). The absence of clear protocols as to how to handle the multiple and competing call for gas supply during extreme situations with unanticipated plant outages, and an incomplete understanding the actual availability of flowing gas supplies when the Company could calls on Authorized and Unauthorized Overrun supplies from Colorado Interstate Gas Company, contributed to the unacceptably low gas pipeline pressures and gas supply shortages the Company experienced on February 17th and 18th.

To provide clarity for future extreme conditions, the Task Force established new forecasting and operating protocols (Commitment No. 14 and 15) that set specific limits on the acceptable difference between the forecast and actual gas consumption for the power plants (Commitment 19). The new protocols specifically preclude planning to use

Overrun gas supplies as operating cushions under tight conditions and require the Company to either find additional gas supplies or to begin buying electric power under tight conditions. While it is not possible to determine whether operating under these new protocols on February 17th and 18th would have prevented the controlled outages (because of the unprecedented number of plants that went off line for an assortment of reasons), the Company believes these new limits will safeguard gas pipeline pressures under strained operating conditions. In addition, the newly defined conditions for ordering OFOs are designed to ensure a daily balance between nominations and consumption by transportation customers, so that gas pipeline pressures and gas supplies nominated by the Company for its LDC sales customers are not adversely impacted by nomination shortfalls by transportation customers and the power plants, and so that all shippers using the Company's pipeline system are treated fairly in these circumstances.

The Task Force spent considerable time investigating the interdependence of the Public Service's gas delivery and operating systems and its electric generation, dispatch and operating systems. Prior to the events of February 17th and 18th, there was a general understanding and appreciation of this interdependence, and particularly the reliance on the gas delivery network to fuel the needs of the increasing number of gas-fired generation facilities on the Public Service electric grid. The post-mortem of the causes of the gas supply shortage and resultant low pressures on February 17th and 18th, however, revealed that the Company had not developed sufficient operating and communication procedures that integrated among its various departments the steps to take to react to multiple unplanned gas-fueled power plant outages during extremely cold weather conditions. On February 17th and 18th the Company experienced a number of *simultaneous* events that the Company had never experienced, namely, colder-than-expected weather, the need to substitute less efficient gas-fired generating units when more efficient gas-fired generation units unexpectedly became unavailable, the consequent dropping of pipeline pressures through the night (when line pack would normally have been increasing to meet the morning's demand surge), the loss of two of the Company's coal-fired units in the early morning hours, and the difficulties experienced attempting to start certain generators on fuel oil. The new operating protocols (Commitments Nos. 7, 7A and 8) now establish procedures that the Company will employ should there be a recurrence of these improbable conditions. Under these new procedures, the Company will curtail interruptible customers, switch to alternative generation fuels, issue Operational Flow Orders and begin buying additional power on the short-term power market much sooner if similar tight conditions develop.

Public Service is confident that the new protocols should minimize the need to repeat the controlled outages experienced on February 17th and 18th under similar weather and plant outage circumstances. However, the Company needs to continue its analysis of the long-term implications of the interdependence of the gas and electric systems and the balance between gas supplied from storage and flowing gas supplied from production facilities. For example, in its gas supply portfolio for the electric system, the Company has historically relied on the availability of flowing supplies bought on a monthly or daily basis to fuel gas-fired generators, as well as to its own coal plants that occasionally operate on natural gas. These flowing supplies tend to be the lowest cost form of supply but do not provide a great deal of flexibility to manage unanticipated changes in load on the electric system. While in the past flowing supply has been a prudent least-cost planning assumption, the February outage has led to questions concerning the Company's reliance on flowing supplies, as opposed to gas delivered from storage, to supply its gas-fired generation and whether the Company should now subscribe to additional firm natural gas storage. The Company is in the process of developing plans to add new gas storage capacity to its natural gas system (Commitment No. 17). Over the next several months the Company will continue to analyze the interrelations between its gas and electric system planning processes.

The March 13th Report identified several communications shortcomings associated with the controlled outages. As employees diligently worked to maintain the operation of the electric system, we did not clearly communicate to the general public the nature of the Company's supply problems and the expected 30-minute length of the controlled outages. The lack of clear public messages about the controlled outages led many customers to attempt to call the Company's Call Center to report the outages.

However, due to the large call volume, the majority of customers attempting to call in only got busy signals and were not able to connect with the Company to report their outages. Even those customers who succeeded in talking with a Customer Service Representative did not receive the most accurate information regarding the nature of the outages. Customers whose electricity was not successfully restored after experiencing the controlled outage were not able to communicate their continuing outage to the Call Center due to the busy signals.

The Task Force identified several technical and process changes that will improve internal and external communications. Starting with external communications, the Company investigated high volume call answering solutions used by other utilities, as well as the possibility of pro-actively notifying customers via outbound phone calls of pending controlled outage events. The Company has selected a vendor to install a new system later this year to address peak inbound call volumes associated with outages and to proactively notify outage-affected customers. (Commitment Nos. 1 and 2). In addition, in late March this year, the Company switched carriers for its 1-800 service. The new carrier now provides Public Service the ability to immediately record and implement customized messages on its telephone network to provide customers accurate information regarding outages. This new system should alleviate the overloading and busy signals that our customers experienced in February when they were prevented from reporting their outages.

The Task Force reviewed our internal communications. As a result of this review, the Company has implemented process and system changes that will clarify when the Company is moving toward heightened and emergency operations and that will provide a structured process for internally managing the situation (Commitment No. 3). The Company has thoroughly reviewed the lists of key stakeholders, both internal and external, that need to be notified about developing emergency situations and is implementing a process to ensure that communications occur that are timely and accurate.

More specifically, and directly related to the origin of the gas supply shortages that developed on February 17th and 18th, the Company has established clear gas supply operating thresholds that apply in cold-weather and hot-weather conditions, or when there have been meaningful differences between forecast and actual weather conditions. The Company has adopted a color-coded Electric Alert Communication Process (Commitment No. 9) that is predicated on specific system operating and reserve levels exhibited at any given time. If, in real-time, the Company's electric system moves from a Green "normal operating condition" to a Yellow "system could not replace loss of largest unit," or to higher level Orange "system load (including forecast) exceeds capacity" or Red "system load (including forecast) approaching capacity after emergency measures" condition, there are now specific and mandatory internal and external communications processes and required action plans (Commitment Nos. 2, 7 and 9).

The Task Force reviewed the root causes of the outages affecting Public Service's generating facilities (Commitment No. 12) on February 17th and 18th and has developed Cold Weather Policies to prepare our power plants for winter conditions (Commitment No. 10). In addition, the Company has conducted an assessment of the causes of the outages experienced by several of the independent power producers serving Public Service (Commitment No. 32). The Company believes that the independent suppliers experiencing operating problems that took their generating units out of service prior to the outages have identified and remedied the causes of their problems.

The Task Force reviewed the processes the Company used to implement the controlled outages on February 18th (Commitment No. 6). The Company has reviewed the list of the feeders identified that will be subject to interruption and has identified additional feeders that will be added to this feeder list in the future (Commitment No. 5). The Company has established specific alerts to distribution substation electricians to stand by in the event that the Company's switches fail to re-close at the end of the outage (Commitment No. 6). After communications with Holy Cross Energy, one of Public Service Company's wholesale customers, the Company has eliminated certain high priority feeders on the Holy Cross Energy system from the curtailment list. The

Company also recognized that Holy Cross's system was disproportionately affected during the third group of the controlled outage on February 18th. In the future, the feeders serving Holy Cross that are affected by controlled outages will be spread out. Reprogramming the rotating curtailment system that the Company uses to effectuate controlled outages will be completed this September (Commitment No. 35).

Prior to initiating the controlled outages on February 18th, Public Service should have interrupted those retail customers who have signed up for interruptible service. The implementation of the Company's interruptible program was neither timely nor complete. The Company is implementing new hardware and software to manage and conduct the interruptible program. We have improved our employee training with respect to the tariff terms and conditions governing the program so that those customers who have elected interruptible service are interrupted in accord with the interruptible tariff and so that the interruptible program is managed consistent with the system benefits this program is designed to provide (Commitment Nos. 26, 27, 27A and 27B). The Company has also reviewed and updated its procedures for implementing a voluntary load reduction process (Commitment No. 27C) wherein in tight conditions the Company requests large customers to reduce their electric consumption.

The Task Force's review of the February 18th controlled outage event demonstrated that certain of the Company's Emergency Management processes needed to be renewed or refreshed. While in some departments of the Company there are established practices and procedures that worked well during the controlled outages, there were other departmental procedures that had not been updated or could not be used. The Task Force review process itself has caused the various departments involved in the investigation to review and update their processes. The Company has adopted new or updated procedures for its 1) Real-Time Electric Dispatch (Commitment No. 7), 2) Energy Supply (Electric Generation) under various Alert levels (Commitment Nos. 9 and 10), 3) Transmission Operations (Commitment Nos. 6 and 34), 4) Electric Distribution Operations (Commitment No. 6), 5) Gas Control (Commitment Nos. 14 and 15), 6) Gas Supply (Commitment No. 19), 7) Interruptible Electric Customer Load (Commitment No.

13), 8) Weather Forecasting (Commitment No. 8), and 9) Corporate Communications (Commitment No. 3).

Our review of the events of February 18th highlighted the fact that Public Service did not have a robust Emergency Management system. As a result of our review of the outage events and the real-time communications challenges that surrounded that situation, the Company has purchased a new online communications tool called Mission Mode (Commitment No. 3A) that will be used to help manage future emergency situations of all kinds. The tool will facilitate manager and executive notifications and will provide for automatic on-line and conference call collaboration for problem solving during critical situations. Public Service is committed to implementing and testing this new communications tool as part of our on-going commitment to Emergency Preparedness.

The Task Force evaluated the Company's weather and related energy and demand forecasting. As a result of the review, Public Service has implemented changes to our forecasting systems to begin incorporating "Real Feel" temperatures when they are colder than ambient temperatures by four degrees or more (Commitment No. 19 and 20). The Company believes the use of Real Feel temperatures (which incorporate humidity, sunshine, cloud cover, wind and precipitation) will provide a better match between customers' actual higher use of natural gas on cold days than simply using the mean temperature that the Company has used in the past. Public Service believes its methods for forecasting temperature-related electric load are generally accurate. During the events of February 17th and 18th, the unplanned rapid consumption of natural gas by less fuel-efficient generators was a major contributor to the supply shortages. The Task Force's investigation highlighted the need for the Company to develop or acquire better dynamic modeling tools that will provide more accurate forecasts of gas-fired generator fuel consumption as the generator resource mix changes. The Company has changed its processes to incorporate such real time system changes and will investigate dynamic models that can better correlate changes to electric system dispatch and the impact on the gas delivery system.

Next Steps

As is discussed in the Task Force's Commitment Log, the Company has already implemented several process and work practice changes that are designed to minimize and, if possible, prevent the recurrence of the gas supply shortages and low pressures on the gas delivery system that contributed to the controlled outages on February 18th. There are a number of scheduled changes that will take some time to implement. The Company is committed to file a report at end of the calendar year 2006 verifying that the systems and changes that we plan to implement have been accomplished. These improvements include the new phone system, the reprogramming of the feeder interruption system, and the new interruptible customer notification and curtailment system. Public Service will also provide the Commission an update on its overall Emergency Preparedness efforts.

Conclusion

As described in the March 13th Report, Public Service Company believes that the February controlled outages were the result of a highly improbable sequence of events. Overall, the actions of the Company's employees as the situation developed on those days in response to the gas supply and electricity shortages were commendable. Our review found, however, as documented in the numerous process changes included in the Commitment Log, that we could improve certain processes to minimize controlled outages under similar circumstances in the future and that we could improve internal inter-department communications and situational awareness to react to events stressing our utility systems. In addition it was evident from the work of the Task Force that additional training with respect to the requirements of the Company's tariffs and the work processes required to manage those tariffs was necessary. The follow-up investigation of the February 18th controlled outage has resulted in needed changes to the Company's daily management that will result in improved reliability for both the gas and electric utility systems.

FEBRUARY 18, 2006 EVENT COMMITMENT LOG INDEX

Commitment Number	Commitment	Action Items	Assigned to
1	Investigate what technology can be used to provide more accurate information to customers calling about outages	Investigate possible technology options for outage overflow call handling	Call Center
2	Investigate what technology can be used to provide more accurate information to customers calling about outages	Implement a new system to handle overflow calls	Call Center
3	Study how to Improve Communications	Review all departmental communication plans to ensure emergency notification channels are standardized	Communications
3A	Study how to Improve Communications	Implement a new system to handle emergency notifications	Communications
4	Develop Operating Protocols during elevated operations	Complete root cause on the substation feeder breakers that failed to close remotely and identify any necessary actions.	Substation
5	Review Operating Protocols during elevated operations	Review the PSCo controlled outage feeder list and update as needed.	Distribution
6	Study how to Improve Communications during elevated operations	Review transmission and distribution control center communication processes/procedures to ensure they are synchronized.	Distribution
7	Develop Operating Protocols during elevated operations	Update RT Dispatch Emergency Operation Procedure & Trans Ops Emergency Procedure - identify responsibility by group	Electric Dispatch
7A	Determine whether all viable purchase opportunities were pursued	Changed process to use Transmission Operations contacts under Emergency Procedures	Energy Trading
8	Investigate Changing Normal Protocols for unusual weather	Establish an Extreme Weather Communication Process to enhance information exchange with Power Plants	Electric Dispatch
9	Investigate Changing Normal Protocols for unusual weather	Consider utilization of "no touch" days at the Power Plants	Electric Dispatch
10	Develop Operating Protocols during elevated operations	Review existing operating procedures to see what needs to be modified for extreme cold weather	Energy Supply
11	Investigate Changing Normal Protocols for unusual weather	Review existing , modify as needed. Structure of changes will depend on actions taken by others - coordinate response.	Energy Supply
12	Investigate Power Plant failure causes	Review root causes in PSCO plants. Formalize write ups by early May	Energy Supply
13	Investigate Changing Normal Protocols for unusual weather	Develop a daily curtailment priority process for interruption of firm wholesale sales and other transactions	Energy Trading
14	Develop Operating Protocols during elevated operations	1) Identify specific criteria for "elevated operations" 2) Formulate guidelines and language for "Reliability Call" for power plants	Gas Control
15	Investigate Changing Normal Protocols for unusual weather	1) Update and review current "Normal Procedures" 2) Coordinate and agree on weather forecast tools 3) Identify specific criteria for calling Operation Flow Orders	Gas Control
16	Investigate how to align and Integrate various operations to deal with unusual weather	Identify for Gas Controller on duty for each situation of "Elevated Operations" who needs to be informed or involved.	Gas Control
17	Investigate Additional Gas Storage options	Investigate additional storage opportunities in the CO market.	Gas Planning
18	Investigate how to align and Integrate various operations to deal with unusual weather	Review the firm distribution requirements for plants behind the PSCO LDC.	Gas Planning
19	Develop Operating Protocols during elevated operations	Update protocols for Gas Supply during periods of elevated operations	Gas Supply
20	Investigate Changing Normal Protocols for unusual weather	Update and document the Supply Planning process to formally include weather variations and model variances	Gas Supply
21	Study how to Improve Communications	Investigate communication systems to notify affected personnel during periods of elevated operating conditions and identify the proper notification list.	Gas Supply
22	Interpretations of FERC code of Conduct Rules	Define/interpret possible refinements to the current policy and training documents	Legal/Risk
23	Investigate Barriers to full communication of operational problems	Prepare guidelines for gas and electric as to what defines an emergency for purposes of FERC standards of conduct.	Legal/Risk
24	Study how to Improve Communications	See Communication responsibilities	Media
25	Submit update to PUC Staff in 90 Days	Prepare and submit follow-up Report	Regulatory
26	Investigate problems with interruptible loads	Prepare and present an updated report of the interruptible load program every 6-months to Op Groups	Retail Customers
27	Investigate problems with interruptible loads	Complete root cause analysis for the customers who failed to interrupt on February 18, 2006.	Retail Customers
27A	Investigate problems with interruptible loads	Complete root cause analysis for the customers who failed to interrupt on February 18, 2006.	Retail Customers
27B	Investigate problems with interruptible loads	Complete implementation of the Cannon Interruption System for ISOC customers by 12/31/06.	Retail Customers
27C	Examine the value of including a voluntary load reduction process	A voluntary load reduction process has been defined	Retail Customers
28	Study how to Improve Communications	Incorporated with Communication actions at the Call Center	Retail Customers
29	Develop Operating Protocols during elevated operations	Examine each purchased power contract and its operating procedures to ensure that each IPP contract meets our expectations regarding Electric Dispatch and control area instructions.	Third Party Contracts
30	Investigate Changing Normal Protocols for unusual weather	See above.	Third Party Contracts
31	Investigate how to align and Integrate various operations to deal with unusual weather	Discuss whether any internal or external changes to Purchase Power contracts are necessary. Verbally verify with each IPP that it is prepared for an unusual demand event (weather, season, etc) may be required.	Third Party Contracts
32	Investigate Power Plant failure causes	Determine cause of IPP outages	Third Party Contracts
33	Study how to Improve Communications	Examine whether Electric Dispatch or the IPPs believe there were any communication problems identified as a result of the Feb 18th event. Examine whether communication protocols, if any, between Electric Dispatch and Purchase Power need to be changed.	Third Party Contracts
34	Develop Operating Protocols during elevated operations	Update RT Dispatch Emergency Operation Procedure & Trans Ops Emergency Procedure - Identify responsibility by group	Transmission
35	Develop Operating Protocols during elevated operations	Increase the amount of identified curtailment blocks	Transmission
36	Develop Operating Protocols during elevated operations	Communicate offers of Emergency Assistance to the RT Dispatch group during an event	Transmission
37	Investigate Changing Normal Protocols for unusual weather	Establish an Extreme Weather Communication Process to enhance information exchange with Gas Control	Transmission
38	Establish clear procedures for communication when load shedding occurs	Communication procedures were written	Distribution

Commitment 1

February 18, 2006 Event Commitment No. 1

Investigate what technology can be implemented to provide more accurate information to customers calling about outages.

Findings of the Investigation:

In reviewing the events, it was determined that a high percentage of customers attempting to reach the Company received busy signals and therefore were not able to receive any information regarding the outage. Current phone trunk capacity was overwhelmed with volume and no redundant capacity was available. The Company also did not have the ability to put customized messages in the telephony network cloud that would have informed the customers of the situation and expected duration of the outage.

Actions taken:

The Company investigated high volume call answering solutions used by other major utilities in the United States. In addition to high volume call answering, the Company also sought a solution that would integrate pro-active notification via outbound phone calls to customers who would be impacted in an outage event. Customer Care management met with the two major vendors who could provide the technology needed to address both areas of opportunity. A vendor has been selected and the Company is moving forward with contract negotiations and plans for implementation.

In late March, the Company switched carriers for 800# number service to Qwest from AT&T. Qwest provides the Company with the ability to immediately record and implement customized messages in the telephony network cloud to provide customers accurate information regarding an outage.

Date Implemented:

Technology vendor selection was completed on May 3, 2006
Targeted technology implementation date is November 2006.

Fisher, Mary J

From: Gabler, Lee E
Sent: Friday, May 05, 2006 9:17 AM
To: Fisher, Mary J
Subject: Call Center - 2/18 Action Item

Mary,

Below is an update for the Call Center action item. We can discuss in more detail during the next conference call.

Action Item:
Interviewed two top vendors in the marketplace for high volume/overflow call answering to resolve trunk capacity issues identified during the February 18, 2006 event. In addition, both vendors interviewed have the technology to provide proactive outbound customer communications during unplanned events.

Plans for Implementation:
A standard timeline for implementation and deployment is 6+ months, which includes contract negotiation. A vendor has been selected and Xcel Energy will be working to expedite deployment.

Commitment 1

The Project Charter Governance Presentation contains highly confidential information and has been filed under seal.

Commitment 2

Commitment Item 2

See Response – Commitment Item 1

Commitment 3

February 18, 2006 Event Commitment No. 3

Description of the commitment:

Review all departmental communication plans to ensure emergency notification channels are standardized.

Findings of the Investigation:

The review revealed that most of the departmental emergency notification plans had different implementation procedures. This led to the discovery of inadequate levels of internal notification.

Actions taken:

Reviewed the PSCo Real-Time Emergency Procedures to tie all other departmental communications/notifications together and identify gaps. Developed the PSCo Corporate Communications Energy Alert Notification Guidelines and created internal notification databases designed to align with new color-coded Energy Alert procedures.

Date Implemented:

The PSCo Corporate Communications Energy Alert Notification Guidelines are pending final executive approval. The Energy Alert database is being established for implementation with Mission Mode.

Commitment 3

The Corporate Communications Energy Alert Notification Guidelines contain highly confidential information and have been filed under seal

Commitment 3

The Xcel Energy Corporate Communications Crisis Communications Plan contains highly confidential information and has been filed under seal

Commitment 3

The Crisis Communications Plan Process Map
contains highly confidential information and has been filed under seal

Commitment 3A

February 18, 2006 Event Commitment No. 3A

Description of the commitment:

All processes and related documentation resulting from the study of how to improve communications.

Findings of the Investigation:

There were issues with regards to timely and effective communication.

Actions taken:

The team took the following actions. A new online tool has been purchased called Mission Mode. It is a web based notification and collaboration tool. Notification of events to any size group within Xcel Energy can now occur within minutes. People with an active role to play during crises can communicate via the tool and/or a conference call. The tool has been loaded with communication information for all operations groups in Colorado and user training is scheduled for June. A test of the system will be conducted by the end of June.

Date Implemented:

The new software was purchase by April 24th. The Corporate Security department was given basic training on the tool on April 28th. Notification and user Information uploaded as of May 30th. Initial user training scheduled for June 6th, 8th and 12th.

Managing Plans

Business Continuity Plans are a fundamental methods by which organizations prepare for crises. Updating these plans can be difficult, time-consuming and restricted to a few experts with the necessary knowledge and applications to change the plans. Yet, in order to be successful, BC plans must reflect the needs of the organization, and that can be achieved through a combination of BC specialists and lines of business.

MissionMode accelerates the creation, management and use of BC plans through its unique management and communications solution.

Review and Change Plans

The review team can be notified that a review is required. Using the existing plan version, the reviewers can discuss and draft any changes. These can then be agreed upon or re-drafted as necessary. Once the plan has been agreed, it can be uploaded into MissionMode and is immediately viewed by the team. All comments and actions are audit logged for later analysis.

Active Plans—Templates

Beyond simple plan storage, MissionMode will take the principle elements of a typical, passive document and turn it into an active plan that can be used to manage an incident – thus providing a single solution for both planning and execution.

Plans can be templated so that:

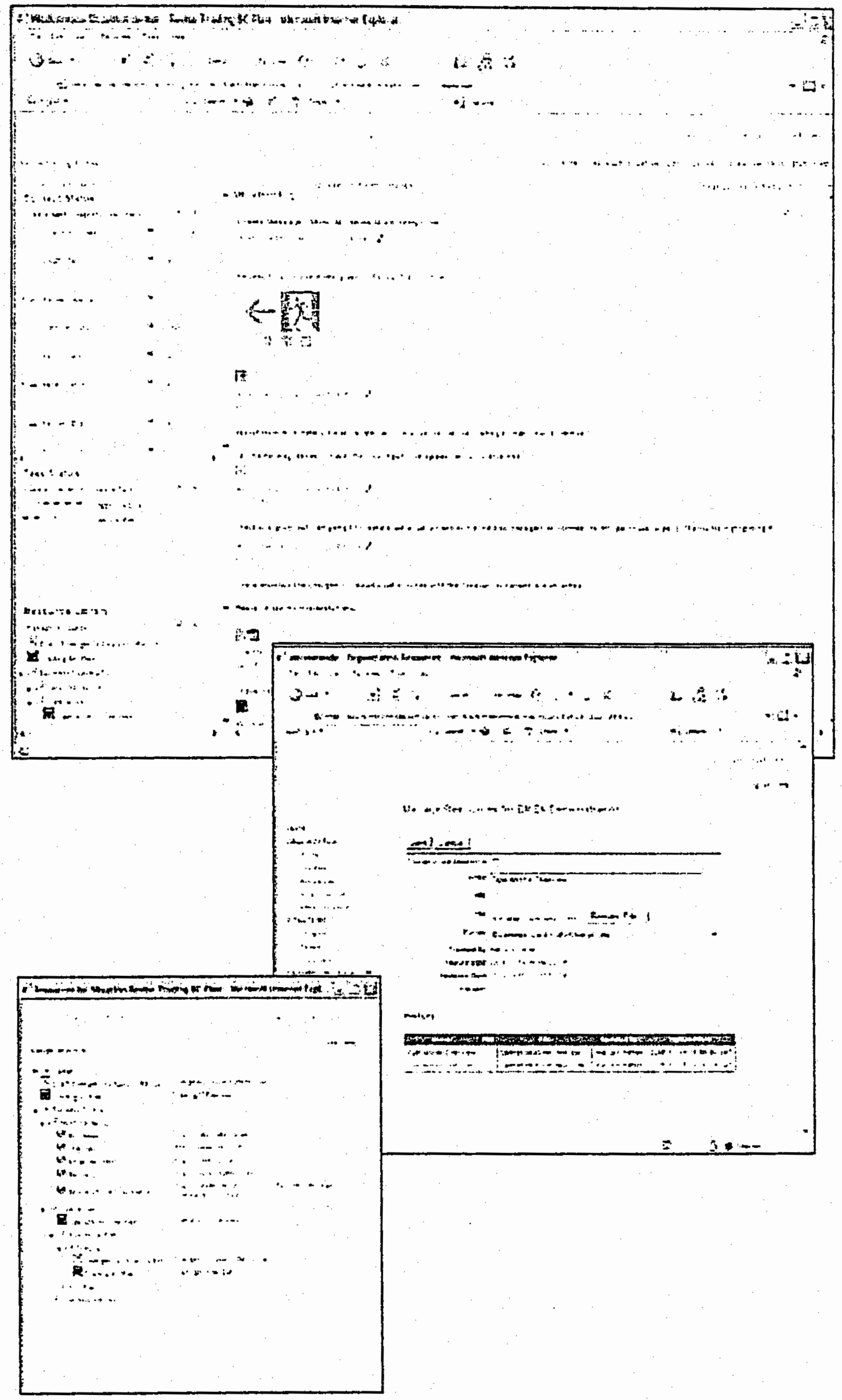
- Contacts can be mobilized
- Checklists are created and made available for use
- Resources are stored and linked

Testing and Exercising

The stored, active, template can be used to test the plan and exercise the business. Using the template, an exercise can be created that will allow participants to use MissionMode as if a real incident was in progress. Using the template to drive MissionMode's Situation Center, users can work as if they are in the same room together and able to conduct business as usual. This removes a lot of the organizational worries associated with an exercise, yet provides a more realistic working environment.

Communicate: Turn Plans into Action

- Hosted and resilient, MissionMode is quick to deploy and operates anytime, anywhere
- Plans and documents can be stored in Templates ready for action or review
- Privacy controls ensure confidential information is secure and shared information is accessible
- Online dashboard enables you to assess status and decide action
- Immediately access key information and key people through select or mass notification
- Simple, easy-to-understand user interface
- Subscription-based to obviate the need for capital expenditure
- Messages can be exchanged across multiple devices keeping your mobile workforce optimized



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MissionMode is a technology services company dedicated to streamlining urgent communications and facilitating team collaboration in a secure hosted environment. Their services reduce the time between knowing about a mission critical issue and doing something about it. MissionMode, which is a privately held company based in St. Paul MN, USA with offices in strategic locations in the USA and Europe, focuses on the Global 5000, government agencies and other high-growth middle market firms. For more information, visit www.missionmode.com

"We thought having the management team carry mobile phones was the answer—until we had to call and get feedback from everyone at once. MissionMode gives us the ability to bring the entire team together with the push of a button. Everyone has the most current information and we reach decisions much faster"

Communications Director

Communicating effectively is key to taking decisive action when you respond to an urgent operational need.

Effective Communications

Communicating effectively is fundamental to managing difficult and urgent situations. It can mean the difference between success and failure. However, with so many teams being dispersed and dynamic, it's almost impossible to gather them quickly and even more difficult for them to work together to take the right action.

Multi-Channel Communications

Relying on a single channel reduces your ability to react and share information. MissionMode communicates across all channels: voice, text, SMS, email, etc, and ensures that your team gets the message and communicates to exploit the opportunity.

Dashboard

MissionMode's Situation Center dashboard ensures that your team communicates quickly and effectively from anywhere, any time. Combining messaging, contact information, status and resources means that there is a single place for the team to respond and get a clear concise understanding of what needs to be done. It makes them take decisive action.

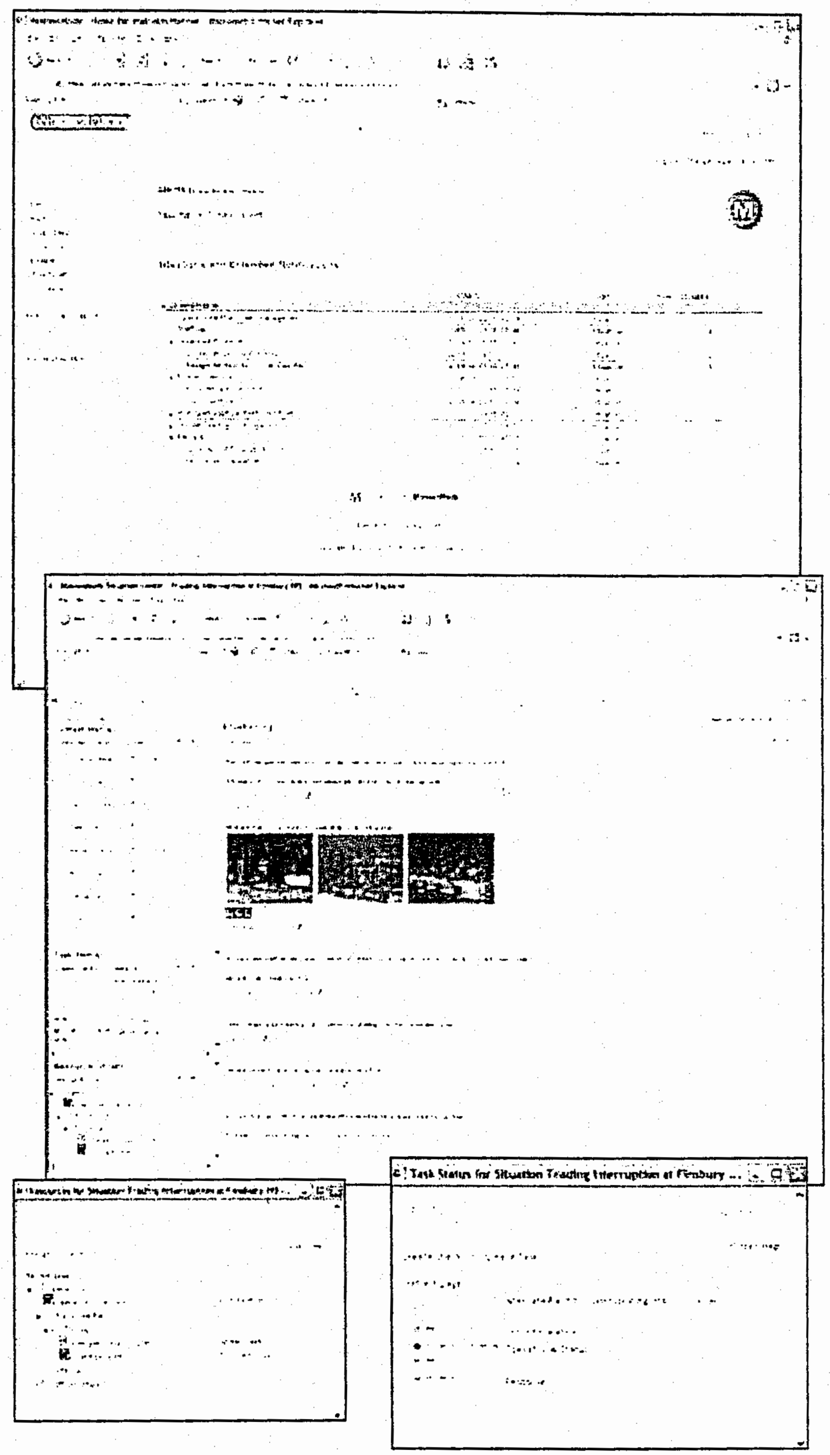
MissionMode in Action

Used by major organizations around the world to shrink response times, MissionMode can work for you. Brand leaders in the aviation, finance and banking, media, retail and utility sectors who rely on MissionMode, attest to the value it brings them:

- Improved success rate
- Reduced cost of operations
- Increased revenue
- Reduced time to resolution
- Brand protection and enhancement

Communicate: Turn Plans into Action

- Hosted and resilient, MissionMode is quick to deploy and operates anytime, anywhere
- Plans and documents can be stored in Templates ready for action or review
- Privacy controls ensure confidential information is secure and shared information is accessible
- Online dashboard enables you to assess status and decide action
- Immediately access key information and key people through select or mass notification
- Simple, easy-to-understand user interface
- Subscription-based to obviate the need for capital expenditure
- Messages can be exchanged across multiple devices keeping your mobile workforce optimized



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MissionMode is a technology services company dedicated to streamlining urgent communications and facilitating team collaboration in a secure hosted environment. Their services reduce the time between knowing about a mission critical issue and doing something about it. MissionMode, which is a privately held company based in St. Paul MN, USA with offices in strategic locations in the USA and Europe, focuses on the Global 5000, government agencies and other high-growth middle market firms. For more information, visit www.missionmode.com

Beyond Notification

MissionMode's Situation Center provides Business Continuity and Crisis Planning, Exercising, Testing, Incident Management and Notification.

Managing Plans

Producing a plan that works is the key to planning success within Business Continuity. To achieve this, the plan needs to be developed, managed, available and tested. MissionMode provides the ideal communications environment to ensure that the correct and most appropriate plans are in place when they're needed. From storing and revising the plan to a completed exercise, MissionMode provides you with the facilities that you need for your organization.

Testing and Exercising

A plan needs regular testing so that it remains relevant and staff needs exercising to ensure they can respond effectively. Using MissionMode, plans can be effectively tested while still maintaining the business as usual, which is so important in today's distributed organizations. Whether a simulation or an online "table-top" is used, MissionMode delivers timely and effective information to and between people.

Incident Management

When a crisis strikes, it is typically communication between people that is the hardest to maintain. Yet, there is a heightened need to communicate during a crisis. In fact, effective communications can radically reduce the impact and cost of an incident.

Customers regularly state that MissionMode significantly reduces the time to recovery, as well as the cost of responding and restoring normal business.

MissionMode in Action

Used in countless crises, from major worldwide events to normal day-to-day operational issues, MissionMode provides a single seamless solution to Business Continuity professionals. Brand leaders in the aviation, finance and banking, media, retail and utility sectors who rely on MissionMode, attest to the value it brings them:

- Improved plan effectiveness
- Reduced cost of plan maintenance
- Reduced time to resolution
- Reduced cost of incident
- Brand protection
- Reduced litigation

Communicate: Turn Plans into Action

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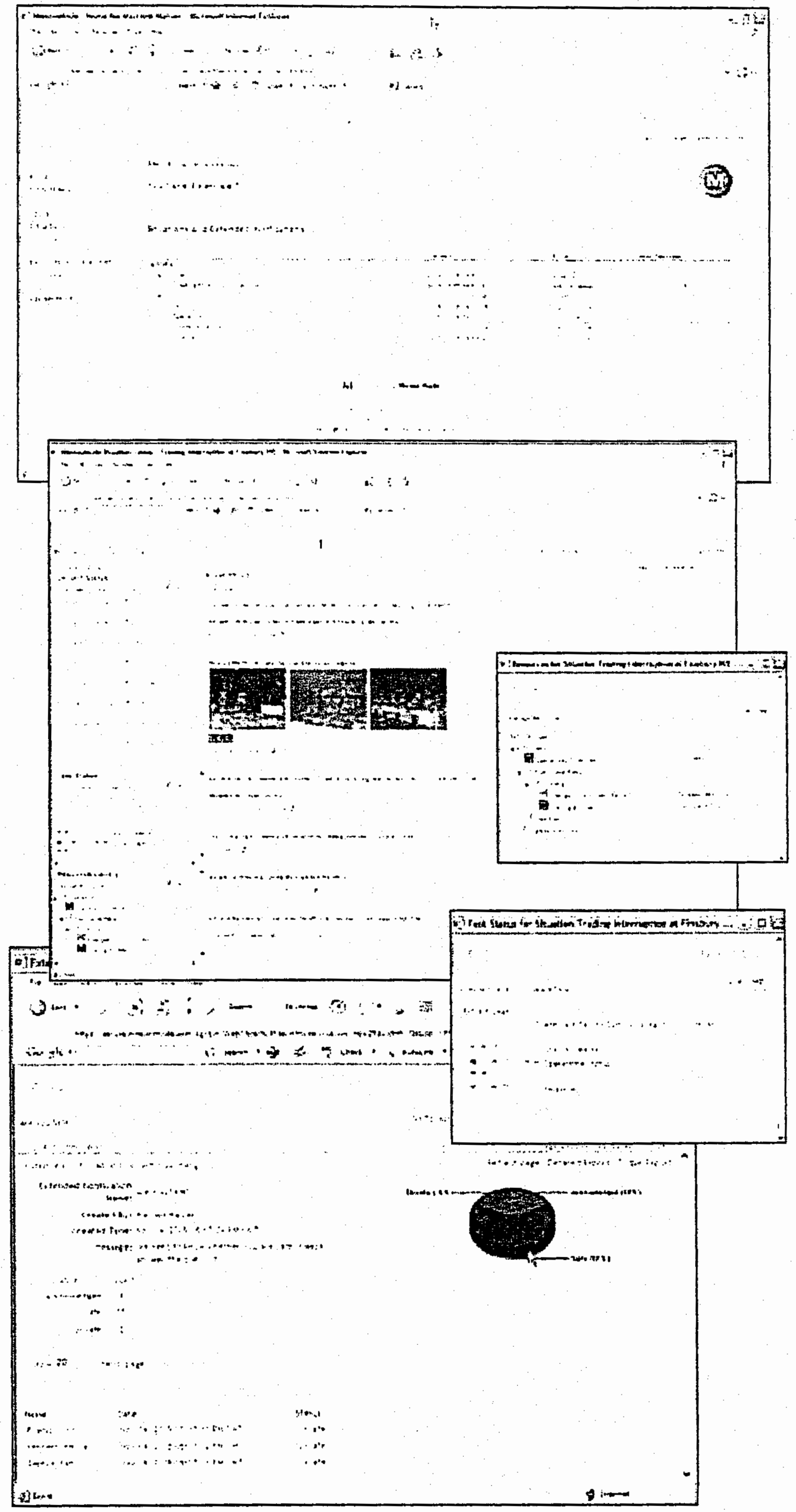

Commitment 4

February 18, 2006 Event Commitment No. 4

Complete a root cause on the substation feeder breakers that failed to close remotely and identify any necessary actions.

Findings of the Investigation:

As a part of the February 18^{th} controlled outages, 188 feeder breakers were successfully opened by remote control. Eleven (6%) of the 188 feeder breakers, failed to close as commanded by the electric system operators. The three main reasons the feeder breakers failed to close were:

- Degraded lubrication due to extreme cold temperatures
- Control circuit & mechanical equipment failure
- SCADA operation error

The majority of the breakers (9 of 11) that would not close were due to the degradation of the breaker mechanism lubrication as a result of the extremely cold temperatures experienced during the time frame the equipment was called upon to operate. The affected substation breakers are housed in an enclosure called metal-clad switchgear. The breakers are heated with one strip heater in each of the un-insulated switchgear cells, as designed by manufacturer per the engineering specification. All heaters were working on February 18^{th}, during the extreme cold weather.

'Degraded Lubrication' to the breakers means the lubricant that the breaker utilizes in the pivot points of the operating mechanism can no longer perform it duties due to various components, one of which is environmental factors such as extremely low temperatures. Lubricants can deteriorate due to constant exposure to environmental low temperatures. When lubricants deteriorate they can increase the frictional resistance of circuit breaker mechanisms. At temperatures below 0 degrees Fahrenheit, petroleum-based oil greases tend to get thick, hard and may not function properly. Some grease will separate leaving only a dry thickener, which can slow breaker action. Some grease can change in physical form, leaving what appears to be a varnish-like residue in critical areas. Temperature extremes can make most common lubricants fail. Other things that can cause degraded lubrication are normal wear particles, dust, ash, etc.

The nine breakers that failed to close all exhibited the same visual / operational characteristics as were observed by the substation electricians as they responded to the breaker failure-to-close situations. The electricians racked the breakers out of the cell to work on them in the aisle of the metal-clad. They removed barriers to expose the breaker mechanisms and then operated the breakers closed and open to observe the failure cause. All of the breakers failed to completely close and were very slow to attempt the close as was observed by the electricians. Based upon the training and experience of these electrical technicians, they determined that these breakers had degraded lubrication and as a result, the breakers would not fully close to make up the contacts. The responding substation electricians immediately utilized a commercial deep penetrating lubricant that displaces any moisture and loosens seized mechanical pivot points. After utilizing this lubricant and operating the breakers, all of the affected breakers would close and trip normally without any abnormal characteristics. <u>Following are those breakers that were impacted by 'Degraded Lubrication' due to extreme low temperature.</u>

- Bancroft Substation Feeder #1816 – Temperature Degraded Lubrication
- Boulder Terminal Feeder #1357 – Temperature Degraded Lubrication
- Greenwood Feeder #1436 - Temperature Degraded Lubrication and blown control fuse due to overload of DC voltage as a result of slow breaker operation.
- Greenwood Feeder #1438 – Temperature Degraded Lubrication
- Havana Feeder #1937 – Temperature Degraded Lubrication
- Leggett Feeder #1322 – Temperature Degraded Lubrication
- NCAR Feeder #1557 – Temperature Degraded Lubrication
- Semper Feeder #1953 – Temperature Degraded Lubrication
- Sullivan Feeder #1806 – Temperature Degraded Lubrication and burned up breaker close coil due to overload of DC voltage as a result of slow breaker operation.

Two feeder breakers had a delay due to what is classified as a SCADA issue or problem. SCADA is the acronym for System Control and Data Acquisition. It means the system we utilize in the industry to communicate and control remote equipment in a substation to and from the system operating control center. This system utilizes phone lines, fiber-link communication paths and electronic components. The substation informs the control operator of local substation equipment parameters on a continual basis through the SCADA system and the operators in the control center can issue commands, such as trip and close of substation equipment, through the SCADA system to the substation equipment. On February 18, 2006, two substation SCADA circuits either did not temporarily operate properly, there was an external communication system failure or the substation system control operators waited an extended amount of time to operate the feeder breakers to close on a second close command which was successful. <u>The following feeder breakers were those that were deemed to be breakers that did not close due to SCADA.</u>

- North Substation Feeder #1425 – SCADA time between failed close command and second successful close command – 1 hr and 3 minutes.
- Littleton Substation Feeder #1738 – SCADA time between failed close command and second successful close command – 1 hr and 3 minutes.

Actions taken:

All eleven (11) breakers that failed to close after their sequence of being opened for 30 minutes were adequately lubricated, had component replacement or the SCADA system checked to ensure functionality. The breakers were placed back into service either on February 18^{th}, or within 3 days when electrical components could be purchased, delivered and installed.

Maintenance work for five of the eleven breakers maintenance was performed under specific work orders that were created on the first normal work day after the 2/18/06 event. On the remaining six breakers, maintenance work was completed under a 'Blanket' work order. The use of a Blanket work order does contain information to document the work specifically performed. A Blanket work order is generally used to support emergency restoration activities. Work performed under a Blanket work order cannot be tracked against a specific job task.

Date Implemented:

The root cause investigation was completed on February 27, 2006
Required repair work was completed on all breakers by February 21, 2006.

Commitment 4

Maintenance and Testing Data
contains highly confidential information and has been filed under seal

Commitment 5

February 18, 2006 Event Commitment No. 5

Review the PSCo controlled outage feeder list and update as needed.

Findings of the Investigation:

Capacity planning and operations personnel met in March to review the current list and identify necessary action items. It was discovered that the present controlled outage feeder list had not been updated in several years and that additional feeders could be added to the list.

Actions taken:

The team took the following actions. Capacity Planning met with Transmission Operations to discuss the timeline required to have the updated list entered into the system prior to the start of the summer season and the possibility of expanding the controlled outage feeder list to include significantly more feeders. It was agreed that Distribution Capacity Planning would have the updated and expanded list to Transmission Operations no later than May 15, 2006. An updated list was provided to the Transmission Operations department at Lookout Center.

Date Implemented:

The updated controlled outage feeder list was completed on May 11, 2006.

Commitment 5

2006 Original Load Shed List
contains highly confidential information and has been filed under seal

Commitment 6

February 18, 2006 Event Commitment No. 6

Review Transmission and Distribution Control Center communication processes/procedures as well as distribution control center and call center communication processes/procedures to ensure they are synchronized.

Findings of the Investigation:

Generally, the communications between the transmission and distribution control centers were handled well. However, it was noted that the processes and procedures associated with load shedding events had not been reviewed between the transmission and distribution control centers in several years.

Regarding communications between the distribution control center and call center, there was a delay in contacting the call center after the outages began. This delay was associated with the high customer call volumes that were experienced in the call center. Also, the communication from the control center regarding the nature and extent of the outages was not clearly defined.

Actions taken:

The following actions are either completed or underway as described below:

- Reviewed and edited the Load Shed Coordination procedure documentation.
- Developed and implemented a Load Shed Roles and Responsibilities document for the transmission operators, electric system operators, control center management, and media relations.
- Replaced the existing Load Shed Coordination procedure document in the emergency handbooks at Lookout Center, and LDC Control Center.
- Shared and reviewed the Load Shed Coordination procedure document, and the Load Shed Roles and Responsibilities documents with the transmission operators, electric system operators, Lookout Center management team, LDC Control Center management team, and Media Relations.
- Shared and reviewed the Load Shed Roles and Responsibilities document with the call center Resource Management team.
- Updated the Outlook distribution lists associated with both documents.
- A "ring down" phone line is being established between the distribution control center and the call center.

Date Implemented:

The updated communication procedure was completed on May 8, 2006 and was communicated to all control center employees by May 22, 2006. The "ring down" phone line is scheduled to be functional by August 1, 2006.

Commitment 6

The Electric Load Shed Events Memo
contains highly confidential information and has been filed under seal

Commitment 6

Load Shed Coordination Procedures
contain highly confidential information and have been filed under seal

Commitment 7

February 18, 2006 Event Commitment No. 7

Update the RT Dispatch Emergency Operation Procedure and forward to Transmission Operations for integration into a merged Emergency Plan. Responsibilities identified within the enhanced plan are to be specified by group.

Findings of the Investigation:

It was determined that while various groups were working to mitigate the situation and preserve service for all of the Company's gas and electric customers, each department maintained separate Emergency Plans. Although each group has distinct and separate responsibilities, several responsibilities and actions require coordinated responses when implementing their respective plans. It was not clear who was responsible for taking a specific action during the emergency condition.

Actions taken:

An action item that was identified by the Task Force was to evaluate whether the various Emergency Plans could be merged into a single common procedure. Secondly, it was deemed valuable to ensure that the responsibilities detailed within the common Emergency Plan were assigned to a specific operation group, in order to prevent uncertainty in critical operating conditions. The action plan addressed the improvement opportunity to reduce seam coordination issues identified on February 18th. The RT Dispatch Emergency Operation plan has been redrafted and distributed to the various operations groups within the Company for evaluation. The improved Emergency Operation plan has specifically identified responsibilities for each group. This plan will help ensure that the communications while operating under stressed conditions are more efficiently conducted, and assist in a more coordinated response.

Date Implemented:

The first revision of the procedures were completed on May 25, 2006. Transmission Operations is actively evaluating the document and will integrate it into their own Emergency Plan.
RT Dispatch will continue to conduct training utilizing the procedure, and will participate in any subsequent Company training for Emergency Operations.

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Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
1-4 Days Ahead	GREEN	*every day*	Trading Analyst	Send unit commitment plan to RT Ops, Transmission, Gas Supply	
1-4 Days Ahead	GREEN	DA model calls for contracts for capacity or economics	Trading Analyst	Call for day-ahead contracts (BH40, PAC)	
1-7 Days Ahead	GREEN	Forecast extreme weather (<15°, >95°, or high wind)	Meterologist	Send courtesy warning to tight-conditions distribution list (RT Ops, Transmission, Gas Supply, Gas Control, Purch Power, Dmd Side Mgt, and others as requested of analyst)	When available, the "Mission Mode" application will be used for this communication
1-4 Days Ahead	GREEN	DA model projects that,*unless 48-hour-notice units are online*, system will have <500MW excess capacity	Trading Analyst	Send courtesy warning to tight-conditions distribution list (RT Ops, Transmission, Gas Supply, Gas Control, Purch Power, Dmd Side Mgt, and others as requested of analyst)	
1-4 Days Ahead	GREEN	DA model projects that,*unless 48-hour-notice units are online*, system will have <500MW excess capacity	Trading Analyst	Increase documentation of all model assumptions; arrange with manager for extre analyst to assist if workload requires	
1-4 Days Ahead	GREEN	DA model projects that,*unless 48-hour-notice units are online*, system will have <500MW excess capacity	Trading Analyst	Call for 48-hour notice units to go warm (Brush 1/3)	
1-4 Days Ahead	YELLOW	If, after previous step: DA model projects <500MW excess capacity	Trading Analyst	If QFs UNC and Monfort are not already scheduled to operate, request on that they run on an emergency basis. If plants refuse to run, verify on a recorded line the operator name and reason for unavailability. Ask to speak with plant management for confirmation.	Jeff Klein, Manager Purchased Power 303.308.2732 Jim Lynch, Gas Buyer 303.308.6118
1-4 Days Ahead	YELLOW	DA model projects <500MW excess capacity	Trading Analyst	Notify all plants of "no-tweak, no-tuna" rule. Testing / maintenance is only permitted if required by time constraints or to ensure unit reliability, and if RT dispatch notified.	
1-4 Days Ahead	YELLOW	DA model projects <350MW excess capacity	Trading Analyst	Advise peaking units that they are likely to be needed. Ask Black Hills to staff Valmont 7&8 (not a contract requirement)	
1-4 Days Ahead	YELLOW	DA model projects <350MW excess capacity	Trading Analyst	Attempt to reschedule any planned outages. For tolling plants that have contractual rights to scheduled outages, evaluate whether PSCo should pay to reschedule the maintenance	
1-4 Days Ahead	YELLOW	DA model projects <200MW excess capacity	Trading Analyst	Instruct DA Trading to arrange purchases from local resources that must be specfically committed (TST Burlington, CSU Birdsall, PRPA Diesels) to recover 200MW margin	
1-4 Days Ahead	YELLOW	If, after previous step: DA model projects <200MW excess capacity	Trading Analyst	Verify that, (If transmission is available but there is no market offer) DA Trading exercises capacity call options in accordance with analyst's prices from the DA model.	
When condition foreseen	YELLOW	Any circumstance will cause gas requirement to deviate significantly from Day-Ahead Nomination, or if extreme weather is likely to put stress on the gas system	RT Dispatch	Contact Gas Control to verify that fuel supplies are adequate to meet the expected generation requirements. If Gas Control is concerned that they may not be able to support electric needs, follow the special instructions at the end of this document:	Tim Carter, Director Gas Supply 303.308.2791 PSCo Gas Control 303.571.7811
When condition foreseen	YELLOW	RT position sheet projects that,*unless slow-start units are online*, system will have <500MW excess capacity	RT Dispatch	Commit long lead-time units : Brush 1/3,4 (2 hr start), Zuni (4+ hr cold start, 2+hr hot start), Limon (4hr gas notice)	
When condition foreseen	YELLOW	If ALL available units will be needed to cover peak	Trading Analyst	Investigate whether any units have capacity that is normally unavailable for emissions limits but that can be used for short periods over peak	Olon Plunk, VP Environmental 720.497.2015
When condition foreseen	YELLOW	If system incremental prices are expected to reach the "top 160", "Top 80", or "Top 40" hours of the year, per the trading analyst's DSM planning sheet.	Trading Analyst	Activate ISOC "economic" provision; does not guarantee interruption; sends price estimate to customers, who have option to buy-through at system incremental cost. For 2006: ~24MW can be interrupted for 40 hours per year ~80MW can be interrupted for 80 hours per year ~2MW can be interrupted for 160 hours per year To see specific customers and remaining hours available, reference sheet: /Analyst$/PSCO Analyst/ ISOC Saverswitch/PSCo Interrupt Tracker 2006.xls	Once the application becomes available, customers can be notified through Cannon webpage. Until then contact the following employees, who will notify customers through the Envoy communication system: Jon Gill, Load Mgmt w612.330.6273 c763.226.6529 h763.712.1758 Dave Warden, Load Mgmt w612.330.6410 c612.228.6973 Joe Petraglia, Marketing w303.294.2979 c720.206.7092 h303.790.1140 Yvonne Pfeifer, Load Mgmt Mgr. w612.330.5740 PSCo ISOC Interruption Procedures *[3]*
4hrs before ALL units needed online	YELLOW	If ALL available units will be needed to cover peak	RT Dispatch	Commit all units including peakers. (Rationale: If ALL units will be needed, start well before actual need so plant engineers have time to resolve startup failures. If NOT ALL units will be needed, dispatch on normal notice as extra units are available to cover failed starts.) - This is a case of heavy use of the gas system; contact Gas Contol and provide a forecast of unit commitment / gas use for balance of day	Ft. Lupton: Contact FSV control room for start. Remote start-up permitted for DCS only. Fruita: Contact Cameo control room after remote start-up. Report fuel oil burns to Cameo. Alamosa: Remote, contact John Halvorson w719.589.4240 c719.580.4930 h719.589.1320 Other Contacts: Fred Johnson (Mgr CO pkrs) w720.497.2068 c303.517.6093 h303.670.5787 Lloyd Hilgart (Director Peakers) w612.330.1940 c612.597.8728
2hrs before needed at full	YELLOW	If ALL contract power will be needed to cover peak *(if not already done for economics)*	RT Dispatch	Schedule all dispatchable capacity contracts at maximum	
1hr before Savers Switch deadline (2:15PM) / ASAP	YELLOW	RT position sheet projects <200MW excess capacity *(if not already done for economics)*	RT Dispatch	Implement Savers Switch: Time of program is fixed at 3PM-7PM, Only available June-August, 15 times per season, Prefer 45 minutes notice to initiate response by 3PM, but can be implemented late	Jon Gill, Load Mgmt w612.330.6273 c763.226.6529 h763.712.1758 Dave Warden, Load Mgmt w612.330.8410 c612.226.6973 Yvonne Pfeifer, Load Mgmt Mgr. w612.330.5740 <u>Send Fax *[4]*</u>
When condition foreseen	YELLOW	If, after previous step: RT position sheet projects <100MW excess capacity	RT Dispatch	Identify all interruptible (WSPP non-Firm) sales out of PSCo system. Instruct transmission Ops to curtail all such schedules, referenced by tag number	List of sales / order of cuts will be provided daily by trading group. (majority of system sales made by PSCo are*not* interruptible) PSCo Transmission Operations - 303.273.4811 Leader, Control Center, Keith Carman - 303.273.4758 Manager, West Transmission Operations - Blane Taylor, 303.273.4797
			Trans Ops	Curtail interruptible (WSPP non-Firm) sales out of PSCo system as instructed by RT Dispatch	Director, Xcel Transmission Operations - Geg Pieper, 612.330.2922
After previous step	YELLOW	If, after previous step: RT position sheet projects <100MW excess capacity	RT Trading	Apply rule of "no new firm sales". Existing sales will be honored until NERC Energy Emergency Alert 1 is declared.	

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Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
After previous step	YELLOW	If, after previous step: RT position sheet projects <100MW excess capacity *As policy, ISOC customers will only be curtailed for capacity AFTER interruptible sales have been cut. However, for ISOC customers that require 1hr notice, this action must be initiated BEFORE cutting sales.*	RT Dispatch	Implement ISOC Interruptions on a "capacity" interruption provision. For 2006: ~13MW are available on one-hour notice only ~93MW are available on ten-minute notice To see specific customers and remaining hours available, reference sheet: /Analyst$/PSCO Analyst/ ISOC Saverswitch/PSCo Interrupt Tracker 2006.xls	Once the application becomes available, customers can be notified through Cannon webpage. Until then contact the following employees, who will notify customers through the Envoy communication system: Jon Gill, Load Mgmt w612.330.6273 c763.228.6529 h763.712.1758 Dave Warden, Load Mgmt w612.330.6410 c612.226.6973 Joe Petraglia, Marketing w303.294.2979 c720.206.7092 h303.790.1140 Yvonne Pfeifer, Load Mgmt Mgr. w612.330.5740 PSCo ISOC Interruption Procedures [3]
		If interruptions are needed on 10-minute basis	Transm Ops	Verify that 10-minute customers are interrupting own load; Open substation breaker if necessary to remove load	Controlling ISOC customers is a two part process where Cannon is used to communicate the interruption and Moscad is used to physically control loads for customers on the 10-minute notice option. Only one Moscad terminal exists, located at Lookout Operations. RMSM (Pueblo Steel Plant) must be contacted manually to control, however the customer's load may be removed from the system by substation breaker activation.
When condition foreseen	ORANGE	RT position sheet projects that *after activating all planned capacity including Savers Switch and ISOC Capacity Interrupt*, PSCo will have <100MW excess capacity	RT Dispatch	Communicate projected tight conditions to Control Area Operator, declare Orange Alert. Communicate condition to Energy Markets management	Manager, Generation Control and Dispatch - Jeff Pavlovic 303.308.6186 Director, Power Operations - John Welch 303.809.0693 Managing Director of Power - Eric Pierce 303.809.4065
			RT Dispatch	Notify all plants of tight conditions, enhanced "no-tweak, no-tune" rule. No testing permitted, only maintenance required to ensure unit reliability, if RT dispatch notified.	
			Transm Ops	Communicate with with Reliability Coordinator (WECC Rocky Desert RC, Loveland) - Advise that a NERC Emergency "Alert 1" is foreseen Declare PSCo System Orange Alert - Notify Media Relations, explain nature of problem and probability of upgrade to "Red"	WECC RDRC 970.461.7516, 7517 seccoord@rdsc.org, rdsc@fnl.com *NERC Emergency Procedures 1-EOP-002-0 Energy Emergency Alerts* *[Binder Tab 1]* *Corp Communications Crisis Communications Plan / Public Notifications Guidelines* *[2]* When available, the "Mission Mode" application will be used for this communication
			Media Relations/ Corp Comm	Communicate Orange Alert to Corp Comm, company executives, colorado mgrs and load mgt - Request curtailment of in-house power use - Issue "soft" public service announcements such as energy conservation suggestions - *Prepare* for media plea, pass info to Customer Service	Media Relations 303.294.2300 Steve Roalstad, Director Media Relations, w612.215.5322 c612.366.8573 Pam Fricke, Director Employee Communications 612.215.5318
			RT Trading	If other operating companies are also expecting tight conditions, consider double-scheduling trading shifts to provide maximum assistance in securing RT emergency energy	
When condition foreseen	ORANGE	If, after previous step: RT position sheet projects <100MW excess capacity *(if not already done for economics)*	RT Dispatch	Activate Lamar Tie for emergency power (schedule F) from SPS: SPS must curtail interruptible loads if necessary to provide PSCo with up to 210MW emergency power; SPS will not shed firm load or jeopardize its own reliability to send.	*Procedure Document on Lamar Tie Scheduling* [5]
After previous step	ORANGE	As required to balance growing load	RT Dispatch	Dispatch available generation to Max Dependable Capacity, including gas topping, except units carrying reserves. Contact Gas Control prior to the utilization of any gas	Reserve-carrying units must be limited in AGC to prevent dispatch into reserves. Per WECC MORC *[6]* , CAs must NOT dispatch into reserves except in response to contingency
			RT Dispatch	Verify that all generation limits are accurately entered in EMS	
After previous step	ORANGE NERC EEA 1	RT excess capacity <100MW and expected to deteriorate	RT Dispatch	Advise Control Area to request NERC Energy Emergency Alert 1 from Security Coordinator	
			Transm Ops	Request NERC Energy Emergency Alert 1 ("All available resources in use") from Security Coordinator	*NERC Emergency Procedures 1-EOP-002-0 Energy Emergency Alerts* [1]
After previous step	ORANGE NERC EEA 1	RT excess capacity <100MW and expected to deteriorate	RT Dispatch	Identify all RT and Daily (WSPP firm) sales out of PSCo system. This includes both Gen Book and Prop book sales. This does NOT include long-term contracts (WAPA CRSP, MEAN, ARPA, WPC). Instruct transmission Ops to curtail specific schedules, referenced by tag number. Not all must be cut at once, but all such sales should be cut before moving to next step.	Order of cuts will be established on a daily list from trading group. Per WSPP contract, PSCo will compensate counterparties to cut sales at "liquidated damage" replacement cost. To minimize these costs it is important to cut only the amount necessary and to follow the order provided by trading. OATI tagger can be set to filter for PSCo sourced tags to verify transactions scheduled to flow out of the system. Additionally, the PSCo Portfolio "All Delivery" ACES filter can be referenced to evaluate schedules.
			Trans Ops	Curtail RT and Daily (WSPP firm) sales out of PSCo system as instructed by RT Dispatch	
When condition foreseen	RED NERC EEA 1	RT position sheet projects that after following all steps including Lamar Tie Emergency Import and Cut All Sales PSCo will have <100MW excess capacity	RT Dispatch	Communicate projected tight conditions to Control Area Operator, declare Red Alert. Communicate condition to Energy Markets management	Manager, Generation Control and Dispatch - Jeff Pavlovic 303.308.6186 Director, Power Operations - John Welch 303.809.0693 Managing Director of Power - Eric Pierce 303.809.4065
			RT Dispatch	Notify all plants of enhanced "no-tweak, no-tune" rule. No testing / maintenance permitted.	
			Transm Ops	Communicate with with Reliability Coordinator (WECC Rocky Desert RC, Loveland) - Advise that a NERC Emergency "Alert 2" is foreseen Declare PSCo System Red Alert - Initiate Voluntary Industrial Load Reduction Notification procedure - Notify Media Relations, explain nature of problem and expected duration	WECC RDRC 970.461.7516, 7517 seccoord@rdsc.org, rdsc@fnl.com *NERC Emergency Procedures 1-EOP-002-0 Energy Emergency Alerts* *[1]* *Corp Communications Crisis Communications Plan / Public Notifications Guidelines* *[2]* *Large Commercial and Industrial Customers Voluntary Load Reduction Plan* *[15]* When available, the "Mission Mode" application will be used for this communication
			Load Mgt	Communicate Red Alert to large customers - Request voluntary minimization of power use	
			Media Relations/ Corp Comm	Communicate Red Alert to Corp Comm, Company executives, colorado mgrs and load mgt Communicate Red Alert to Media - Public appeal for reduced power use - Provide information to Customer Service Control Room, Xcel website, etc	Media Relations 303.294.2300 Steve Roalstad, Director Media Relations, w612.215.5322 c612.366.8573 Pam Fricke, Director Employee Communications 612.215.5318

PSCo Real-Time Emergency Procedures

Rev. 12 **6/13/2006**

Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
After previous step	RED NERC EEA 1	If, after previous step: RT excess capacity <100MW, expected to deteriorate	RT Dispatch	Request Emergency Diesel Generators	Cherokee=5.5MW FSV=1.2MW Valmont=.6MW Pawnee=.5MW Lookout=1MW RMEC=1MW There are environmental limits on the use of FSV, Valmont, and Pawnee diesels. If they will be required over multiple days, trading analyst should verify that permits are not near exceedance, with the following contacts: FSV - Joe Pinner 303.620.1193 Pawnee - Collen Young 970.842.1235 Valmont - Jann Nesshoefer 303.440.2572 Environmental Services - Eldon Lindt 720.497.2110; Chad Campbell 720.497.2111; Gary Magno 720.497.2112
After previous step	RED NERC EEA 1	If, after previous step: RT excess capacity <100MW, expected to deteriorate	RT Trading	Make purchases at any cost. If specific purchases identified but no ATC available, identify opportunities to Transmission Ops (even if bottleneck is not not PSCo Trans)	
After previous step	RED NERC EEA 2	If, after previous step: RT excess capacity <100MW, expected to deteriorate	RT Dispatch Transm Ops RT Trading Transm Ops Transm Ops Transm Ops RT Trading RT Dispatch Transm Ops	Advise Control Area to request NERC Energy Emergency Alert 2 from Security Coordinator Request NERC Energy Emergency Alert 2 ("Load management procedures in effect") from Security Coordinator Attempt to locate emergency assistance by contacting all potential providers. If specific assistance offers are identified but no ATC available, identify opportunities to Transmission Ops (even if bottleneck is not not PSCo Trans) - Ask Reliability Coordinator to assist by posting emergency on WECC.net - Direct parties offering assistance to RT Trading for scheduling and accounting entry Respond to Reliability Coordinator inquiries on reevaluating transmission operating limits Reconfigure transmission system to maximize ATC per Reliability Coordinator instruction - Check OASIS for increased ATC posted by Reliability Coordinator - Schedule imports (at any cost or emergency basis) as soon as extra ATC allows - Follow Reliability Coordinator instructions on generation redispatch to improve ATC Monitor changes to Unscheduled Flow Procedures initieted by RC. Curtail or reload schedules as these procedures require Throughout Alert 2, give (at least) hourly status updates to Reliability Coordinator	*NERC Emergency Procedures 1-EOP-002-0 Energy Emergency Alerts* [1]
In conjunction with EEA2	RED NERC EEA 2		Transm Ops	Evaluate and consider suspension of the FERC 2004 Standards of Conduit to facilitate RT and Trans Ops communications.	Transmission Operations will evaluate if it would be beneficial to suspend the FERC 2004 Standards of Conduit to allow unconstrained communications between the Control Area Operator and Merchant functions for the duration of the Emergency. *NERC Emergency Procedures 1-EOP-001-0 Emergency Operations Planning* [1]
After previous step	RED NERC EEA 2	If, after previous step: RT capacity insufficient to maintain required reserves	RT Dispatch Transm Ops RT Dispatch Transm Ops	Request Control Area to activate the RMRG Reserve Sharing Pool Emergency Assistance Procedure Activate RMRG Reserve Sharing Pool Emergency Assistance Procedure (This is a seperate procedure from RMRG reserves for Unit Trips) Request Control Area to activate WAPA CRSP Emergency Assistance Request Activate the WAPA CRSP Emergency Assistance Request	*RMRG Reserve Activation/Deactivation Procedures* [7] To request Emergency Assistance, a Member must have firm load at risk and must have exhausted (or expects to exhaust) all of its operating reserves and resource purchase opportunities during the period for which the assistance is requested. A group response request (while not required) will maximize the effectiveness of Emergency Assistance requests. Emergency Assistance requests can be made at any time, but whenever possible, requests should be made with sufficient notice to utilize normal scheduling practices. *WAPA CRSP Emergency Assistance Request*
After previous step	RED NERC EEA 2	If capacity is available at gas generation that has been manually limited to avoid gas over-burns	RT Dispatch	Request permission from PSCo Gas Control and other Gas Transporters to temporarily increase gas consumption beyond nominated burn rate. Verify how much over-burn can be supported and increase dispatch of gas units up to the maximum sustainable level.	PSCo Gas Control 303.571.7811 Colorado Interstate Gas (CIG) 800.238.3764
After previous step	RED NERC EEA 3	If, after previous step: RT capacity insufficient to maintain required reserves	RT Dispatch RT Dispatch Transm Ops Transm Ops Transm Ops Transm Ops Transm Ops Transm Ops	Verify that all units including quick-start (offline operating reserves) units are online. Verify that all available generation is dispatched to Max Dependable Capacity, except units carrying reserves. Per WECC MORC, CAs should NOT dispatch reserves except to respond to a contingency. Reserve-carrying units should be limited in AGC to prevent dispatch into reserves. Advise Control Area to request NERC Energy Emergency Alert 3 from Security Coordinator Request NERC Energy Emergency Alert 3 ("Firm load interruption imminent or in progress") from Security Coordinator Suspend FERC 2004 Standards of Conduct. Respond to Reliability Coordinator inquiries on utilizing transmission short-time limits Respond to Reliability Coordinator inquiries on reevaluating transmission operating limits Respond to Reliability Coordinator instructions on Load Shedding Throughout Alert 3, give (at least) hourly status updates to Reliability Coordinator	*WECC MORC:* "If inadequate relief is obtained from [requests for assistance], then, control area(s) shall initiate relief measures as required, up to and including shedding load, to maintain reserves" *NERC Emergency Procedures 1-EOP-002-0 Energy Emergency Alerts* Transmission Operations notifies Merchant Function by phone, and Transmission Management (D Jaeger, G Pieper), Regulatory Affairs (D Sparby) and Legal (Jim Johnson) by email. Regulatory Affairs submits notica to FERC within 24 Hours of suspension.

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Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
After previous step	RED NERC EEA 3	If, after previous step: CA unable to maintain ACE within L10 Limits or respond to DCS contingency	Transm Ops RT Dispatch	If related to sudden loss of a unit, Control Area will activate the RMRG Reserve Sharing Pool for Unit Trips If related to sudden loss of a unit, operator may dispatch into reserves to recover ACE	*RMRG Reserve Activation/Deactivation Procedures* [7] WECC MORC allows up to 60 minutes to restore reserves
After previous step	RED NERC EEA 3	If, after previous step: CA unable to maintain ACE within L10 Limits or respond to DCS contingency	RT Dispatch	Curtail Firm, long-term capacity sales in accordance with contracts. The following contracts can be curtailed just prior to shedding PSCo native firm load: - WAPA CRSP: up to 150 MW - MEAN: 23 MW fixed schedule -ARPA: 3 MW fixed schedule	Wayne Read (Senior Originator) 303.308.6148 3.1. Conditions for Curtailments: The Company cannot curtail scheduled Firm Capacity and Associated Energy for economic reasons, although the Company may curtail energy schedules for reasons of Force Majeure, or during times of system emergencies after all interruptible load has been fully curtailed on the PSCo system and just prior to the curtailment of non-interruptible firm retail and firm wholesale customers on the PSCo system. At that point, the Firm Energy deliveries associated with this transaction may be curtailed, such curtailment to be done on a pro-rata basis with all of the Company's other Firm Capacity sales to the extent feasible under the circumstances. Energy schedules shall be subject to curtailment procedures as implemented by the transmission provider from whom PSCo has acquired transmission services to deliver energy from PSCo's generation resources to CRSP. 4.1. Conditions for Curtailments: The Company cannot curtail scheduled Firm Capacity and Associated Energy for economic reasons, although the Company may curtail energy schedules for reasons of Force Majeure, or during times of system emergencies after all interruptible retail load has been fully curtailed on the PSCo system, and just prior to the curtailment of non-interruptible firm native load retail customers on the PSCo system. At that point, the Firm Energy deliveries associated with this transaction may be curtailed, such curtailment to be done on a pro rata basis with all of the Company's other non-retail firm loads to the extent feasible under the circumstances. Energy schedules shall be subject to curtailment procedures as implemented by the transmission provider from whom PSCo has acquired transmission services to deliver energy from PSCo's generation resources to MEAN. The term "Firm Power Service" shall mean that quantity of firm capacity and associated energy that the Company will make continuously available to the Customer. The Company cannot curtail scheduled Firm Power Service energy ("Scheduled Energy") except in times of (i) Force Majeure, (ii) a system emergency on the Company's system, just prior to the curtailment of native-load customers on the Company's system ("System Emergency") or (iii) Line Load Relief or Transmission Loading Relief orders from the Western Electric Coordinating Council (or other applicable transmission provider) that directly impact the transmission reserved for deliveries hereunder; provided farther that any curtailment shall be limited to the amount of reduction ordered by the transmission provider or necessary to relieve the emergency condition.
After previous step	RED NERC EEA 3	If, after previous step: CA unable to maintain ACE within L10 Limits or respond to DCS contingency	Transm Ops	- Initiate Rolling Outages that are intended to last approximately 30 minutes. Critical loads (hospitals, emergency response facilities, etc.) are excluded whenever possible. - Full Requirements Customers in PSCo control area should be curtailed on a pro-rata basis. - Inform RT Dispatch of how much load is expected to be shed, so they can curtail long-term capacity sales according to contracts - Inform Media Relations of Rolling Outages: cause, extent, and expected duration Communicate Rolling Outage Corp Comm, company executives, colo mgrs, load mgt, PUC Communicate Rolling Outage to Media	Full Requirements Customers in PSCo Control area: Center, Grand Valley, Holy Cross, IREA, Julesburg, Yampa Valley John Svensk (Manager Wholesale Accounts) 303.308.6133 When available, the "Mission Mode" application will be used for this communication
			Media Relations/ Corp Comm	- Public appeal for reduced power use - Provide information to Customer Service Control Room, Xcel website, etc	Media Relations 303.294.2300 Steve Roalstad, Director Media Relations, w612.215.5322 c612.366.8573 Pam Fricke, Director Employee Communications 612.215.5318
			RT Dispatch	Curtail Firm, scheduled long-term capacity sales in accordance with contracts. - West Plains (Aquila) 233MW : curtail by 1 MW for every 4 MW of native load PSCo curtails - Cheyenne150MW , Burlington 6MW: curtail pro-rata with PSCo native load If no information is available on how much load is shed by Transmission Ops, RT Dispatch should use its own estimate based on its RT Position worksheets	West Plains Contract: The Company may curtail deliveries to the Customer such that for every 4 MWs of firm native load that Company curtails, Company may reduce 1 MW of Customer's Contract Capacity for the duration of the system emergency as determined by Company. Mike Martin (Regional Sales Manager) 806.378.2376
			RT Dispatch	Call to upper management to inform them of current situation	Pat Vincent (President PSCo) 303.294.2722 Tom Imbler (VP Commercial Operations) 303.308.6114 Fred Stoffel (VP Policy Development) 303.294.2013 David Wilks (President Energy Supply) 720.497.2022 Paul Bonavia (President Utilities Group) 612.215.4548

Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
		DE-ESCALATION PROCEDURES			
As operating condions improve	Red	If capacity margins and transmission conditions have improved to the level where Red Alert is no longer warranted, and are expected to remain stable or improve	RT Dispatch / Transm Ops	RT Dispatch and Transm Ops must declare jointly that all conditions necessitating the Red Alert level have been alleviated, and the sytem Alert level can be de-escalated from Red to Orange	
	Orange		RT Dispatch	Communicate condition to Energy Markets management	
	Orange		RT Dispatch	Notify all plants of improved conditions, diminished "no-tweak, no-tune" rule.	
	Orange		Transm Ops	Notify Media Relations, explain condition and future prognosis	When available, the "Mission Mode" application will be used for this communication
	Orange		Media Relations	Communicate diminished Alert to Corp Comm, company execs, colorado mgrs and load mgt	
As operating condions improve	Orange	If capacity margins and transmission conditions have improved to the level where Orange Alert is no longer warranted, and are expected to remain stable or improve	RT Dispatch / Transm Ops	RT Dispatch and Transm Ops must declare jointly that all conditions necessitating the Orange Alert level have been alleviated, and the sytem Alert level can be de-escalated from Orange to Yellow	
	Yellow		RT Dispatch	Communicate condition to Energy Markets management	
	Yellow		RT Dispatch	Notify all plants of improved conditions, diminished "no-tweak, no-tune" rule.	
	Yellow		Transm Ops	Notify Media Relations, explain condition and future prognosis	When available, the "Mission Mode" application will be used for this communication
	Yellow		Media Relations	Communicate diminished Alert to Corp Comm, company execs, colorado mgrs and load mgt	
Throughout alert original timeframe	Yellow		RT Dispatch	Continue to monitor generation capacity margin.	
Throughout alert original timeframe	Yellow	If alert level diminishes as originally forecasted for the tight conditions list	RT Dispatch	Do not need to re-send notice	
Throughout alert original timeframe	Yellow	If alert level lasts significantly longer than originally forecasted for the tight conditions list	RT Dispatch	Re-send notice to tight conditions list with updated system status	When available, the "Mission Mode" application will be used for this communication
Throughout alert original timeframe	Green	If alert level diminishes significantly earlier than originally forecasted for the tight conditions list	RT Dispatch	Re-send notice to tight conditions list with updated system status	When available, the "Mission Mode" application will be used for this communication
		SPECIAL INSTRUCTIONS FOR TIGHT GAS DAYS			
		Gas Control is concerned that they may not be able to support electric needs	RT Dispatch	Evaluate the current day gas burn in comparison to the nomination using file at : Analyst$/PSCO Analyst/Gas Noms/Current Month. If Gas Control or Gas Supply requests forecasted gas burn for the remainder of the gas day, utilize this spreadsheet to complete a burn estimate	Select the proper gas day tab on the bottom of the spreadsheet. Gas day runs from HE 9 to HE 9; Delete the date at the top of the page on the applicable gas day tab. Re-enter the date and PI should recalculate the current burn through the most recent hour of the gas day
		>>	RT Dispatch	Ensure that fuel-oil facilities (ie, Blue Spruce) remain staffed even if not currently dispatched	
		It is likely that electric will over-burn their gas nomination	RT Dispatch	Maintain contact with Gas Control and ask if the over-burn can be supported. Ask if the over-burn is likely to jeopardize or impact the reliability of the gas system.	
			RT Dispatch	Gas Supply should NOT be asked to estimate a penalty price for gas over-burns. This practice has led to misunderstandings about the availability of penalty gas. If gas is unavailable beyond nominated quantities, those quantities should not be exceeded at any price.	Gas Buyer - Jim Lynch 303.308.6118 / Manager Gas Supply - Jeff Ishee 303.308.2826 / Manager Gas Supply - Craig Rozman 303.308.2844
		Gas Control or Gas Supply determine that the current or forecasted over-burn is likely to impact the reliability of the gas system	Gas Control	Declare an Operational Flow Order (OFO) on the PSCo gas system.	Gas Control 303.571.7811
		OFO Declared by PSCo gas system	RT Dispatch	Limit all gas-restricted plants in AGC to burn no more than the gas day nomination, or less as specified in any reliability dispatch instruction from Gas Control. These limitations should be treated as any other unit derating for the purposes of calculating the hourly resource position and avoided/incremental costs, ie, do not count capacity that would require gas overburn. However, spinning reserves can continue to be counted on unloaded gas capacity; this capacity could be used for a short time in a contingency.	RT Dispatch should treat an OFO on the PSCo gas system as an OFO on all its gas supply. Overburn on another transport network is likely to cause supply problems for the PSCo gas system, for no net benefit.
		>>	RT Dispatch	Contact plants with dual fuel capability (Blue Spruce, Ft. Lupton, Alamosa, Fruita, Zuni) and alert them to the likelihood of running on fuel oil. They should be started as economic or capacity needs dictate, given a calculated RT position where other gas units are restricted to burning nominated fuel or less as specified by Gas Control.	Due to environmental restrictions, Zuni can only be dispatched on fuel oil if Gas Control has issued an OFO on the gas system or if Transmission Operations has declared an electric system Emergency. If RT dispatchers foresee the need to start Zuni on fuel oil, they should remind operators at Gas Control of the need for an OFO in order to commit the unit.
		>>	RT Dispatch	Investigate whether the TCTI plant can alleviate draw from the PSCo gas system by pulling from the CIG system	General rule for burning gas at Thermo is to follow this order: 1. The first 13, 000 dth/day should flow on the Duke Direct line 2. Anything above the 13,000 dth/day should be pulled from CIG pipeline. Running on CIG is now more economic than PSCO. 3. PSCO is available if needed. Also, in the winter months, CIG can now be used if pressure problems occur on PSCO. The penalties have been mitigated to the point that pulling emergency supply is acceptable.
		>>	RT Dispatch	Contact management to inform them of the situation, and to begin delivery of fuel oil if necessary.	Director of Gas Supply - Tim Carter 720.273.4800 Director Power Operations- John Welch 303.809.0693
		>>	RT Dispatch	Request overnight or extended run @ QF facilities (if gas available and if contract allows): Brush 2; UNC Greeley; Monfort	Manager, Purchased Power - Jeff Klein 303.308.2732 Gas Buyer - Jim Lynch 303.308.6118
		>>	RT Dispatch	Implement all steps in the general emergency procedure above, in the order described as applicable	
		Tri-State offers emergency assistance off of fuel oil capabilities of Brighton and Limon	RT Dispatch	Accept offers to buy power from Limon 2, which is owned and dispatched by Tri-State. At this time PSCo cannot accept offers to dispatch Brighton 1-2 or Limon 1 on fuel oil; per current PPA Contracts, this would obligate PSCo to pay $4.5 million for Limon and $8.1 million for Brighton fuel oil capabilities over the duration of the contracts.	*Brighton 1-2 and Limon 1 PPA's*

Timeframe	Alert Level	If:	Who	What	Details / Phone Numbers / Reference Documents / Citations
		SYSTEM ALERT COLOR CODE DEFINITIONS	Green - Normal	This is the normal condition of operation.	
			Yellow - Warning	This condition exists when: 1.) PSCo real-time load is is approaching or forecasted to approach the level where the system could not replace the loss of its largest single generation contingency and restore operating reserves given available resources OR 2.) The transmission system is operating at or near defined real-time operating limits and is able to withstand any first contingency failure.	
			Orange - Danger	This condition exists when: 1.) PSCo real-time load is is approaching or forecasted to approach available capacity including the activation of interruptible customers. OR 2.) Elements of the transmission system are loaded beyond defined operating limits and/or the transmission system is operating outside established operating guides; the next contingency may result in a major loss of load, islanding, or transmission system collapse.	
			Red - Emergency	This condition exists when: 1.) PSCo real-time load is approaching or forecasted to exceed available capacity after following all emergency measures. OR 2.) Elements of the transmission system have faulted and the system is operating outside of established guidelines; the system is experiencing major loss of load, islanding, or system collapse.	

ABBREVIATIONS

ACE: Area Control Error
ARPA: Arkansas River Power Authority
BH: Black Hills Corp.
CIG: Colorado Interstate Gas
CRSP: Colorado River Storage Project
CSU: Colorado Springs Utilities
DA: Day-Ahead
DCS: Disturbance Control Standard
DSM: Demand-Side Management
EMS: Energy Management System
FERC: Federal Energy Regulatory Commission
FSV: Fort Saint Vrain
ISOC: Interruptible Service Option Credit
JOA: Joint Operating Agreement
L10: L-sub-10 (Allowable range for NERC Control Performance Standard)
MEAN: Municipal Energy Agency of Nebraska
MORC: Minimum Operating Reliability Criteria
NERC: North American Electric Reliability Council
OASIS: Open Access Same-Time Information System
OFO: Operational Flow Order
PAC: Pacificorp
PPA: Purchased Power Agreement
PRPA: Platte River Power Authority
RDSC: Rocky Desert Security Coordinator
RMEC: Rocky Mountain Energy Center
RMRG: Rocky Mountain Reserve Group
RT: Real-Time
SPS: Southwestern Public Service
TST: Tri-State Generation and Transmission Association
WAPA: Western Area Power Administration
WECC: Western Electricity Coordinating Council
WSPP: Western Systems Power Pool

OTHER DOCUMENTS INCLUDED IN BINDER

WECC Regional Reliability Plan	*[10]*
RDSC Reliability Coordination Communication and Operating Procedures	*[11]*
WECC Reliability Coordination Subcomittee FAQ	*[12]*
PSCo (Transmission) Emergency Operations Plan	*[13]*
Xcel Energy Supply System Operating Code Response	*[14]*
Rocky Mountain Region Black-Start Procedure	*[16]*

Commitment
7A

February 18, 2006 Event Commitment No. 7A

Communicate offers of Emergency Assistance to the Transmission Operation group during an event when normal means of scheduling power is exhausted

Findings of the Investigation:

It was determined in an after-the-fact review of the event in coordination with an assembled WECC Detailed Disturbance Report Task Force initiative that RT trading had turned down Emergency Assistance from other WECC entities when the available transmission import capability had been exhausted

Actions taken:

In the future, if Emergency Assistance is turned down due to posted transmission availability, RT Trading will inform Transmission Operations

Date Implemented:

This notification process is identified as part of the improved Emergency Operation plans that were redrafted and currently in place.

Commitment 8

February 18, 2006 Event Commitment No. 8

Establish an Extreme Weather Communication Process

Findings of the Investigation:

The Task Force identified an opportunity to improve the normal protocols for providing information to various company personnel for periods when the meteorologist forecasts unusual weather to impact an operating company's region.

Actions taken:

The action item was for the Company to establish an extreme weather communication process to enhance information exchange with the power plants. Although it was already standard protocol for the Day-ahead analyst to communicate routinely with the power plants on the Monday-Wednesday-Friday conference call, as well as on an as needed basis to provide additional updates, the new procedure was an enhanced mechanism to ensure that the plants had sufficient notice to prepare for extreme cold, extreme hot or other extraordinary forecast weather condition.

Date Implemented:

This action item was completed and rolled into the daily Trading Analyst procedures effective May 3, 2006 forward.

Commitment 8

Weather Notification Protocols
contain highly confidential information and have been filed under seal

Commitment 8

The Standardized Alert Level Definition Document
contains highly confidential information and has been filed under seal

Commitment 9

February 18, 2006 Event Commitment No. 9

Consider development of "no touch" procedure for communications between Plant Operations, RT Dispatch and Transmission Operations

Findings of the Investigation:

The Task Force identified that in addition to the extreme weather notification improvements on a next-day forecast basis, it would be beneficial to have a shorter-term notification process in place to enable efficient and standardized communication protocols for real-time operations. This notification would help establish when the unit should cease non-essential maintenance that may risk the reliability or availability of the unit.

Actions taken:

NSP utilizes the "System Operating Code Response" procedure as a mechanism to establish a set of phrases with which Energy Marketing Real-time Dispatch or Transmission Operations can establish the current or forecast operating condition for the system in order to convey what the corresponding response for plant operations personnel is expected. During strained market conditions, capacity shortages or other transmission conditions, it is essential that Energy Marketing Real-time Dispatch, Transmission Operation, and the Plant Control Room Operators are able to communicate with a minimum expenditure of time and with a complete understanding as to what actions are to be taken. It was undertaken as an action item for the Task Force to evaluate whether the NSP procedure could be adopted by the PSCo and SPS systems to streamline communication with the plants during various system conditions. It was determined that it could and should be adopted as a mechanism to help improve communication with the plants in real-time. The NSP procedure is being redrafted to make it applicable for the other systems.

Date Implemented:

The RT Dispatch revision to the redraft of the new procedure was completed on May 4, 2006

The Task Force continues to collect input on the procedure and will distribute a final draft this spring

Each plant will develop their own internal procedure detailing their response to a system condition change

Commitment 9

Energy Supply Operations - Procedure
contains highly confidential information and has been filed under seal

Commitment 10

February 18, 2006 Event Commitment No. 10

Review the existing operating procedures to determine what modifications, if any, are needed for extreme cold weather.

Findings of the Investigation:

Each plant did have a process or procedure in place to deal with cold weather preparation and response. However, not all facilities had specific requirements to notify or return the completed work sheets or checklists to management after the procedure was completed.

Several of the procedures were not descriptive enough for extreme cold weather conditions.

Actions taken:

Colorado Energy Supply has assembled and reviewed all the plant cold weather procedures. Each plant will have a formal procedure in place that requires management be notified when the procedure has been implemented and completed.

In addition, Colorado developed a Cold Weather Policy that establishes the requirements and management expectations associated with the proper protection necessary for periods of cold weather throughout the Colorado Energy Supply Operations facilities.

Changes to the existing procedures were requested and completed to assure management notification after procedure completion.

Hayden, Cameo and Zuni were requested to formalize their cold weather procedures.

Date Implemented:

The Colorado Energy Cold Weather Policy was approved by Mike Price, General Manager Colorado Generation on May 25, 2006.
(ESO-OP-CO-6.151)

ESO-OP-CO-6.151 will be reviewed with all Plant Directors during the General Managers June Staff meeting.

1.0 PURPOSE

This policy establishes the requirements and management expectations associated with the proper protection necessary for periods of cold weather throughout the Colorado Energy Supply Operations facilities.

2.0 **APPLICABILITY**

All ESO personnel and support departments performing work at PSCO Colorado generating facilities.

3.0 RESPONSIBILITIES

3.1 Directors are responsible to assign roles supporting this policy and establish a cold weather procedure at their plant.
3.2 The Operations Manager or equivalent is responsible to establish and review the freeze protection checklist prior to cold weather season (on or before September 1 of each year). This procedure should be reviewed each year to ensure that the checklist is up to date.
3.3 Maintenance Manager or equivalent is responsible for keeping the freeze protection equipment in good working condition.

4.0 REQUIREMENTS

4.1 General Requirement is to establish an overall freeze protection plan for all systems at electric generating facilities.
4.2 Checklists are to be established to assure completion of critical steps in protecting the plant during cold weather periods and shall be utilized.
4.3 Checklists must be completed and returned to Operations Manager or equivalent.
4.4 Preventative Maintenance with checklists shall be issued to the Maintenance Department to verify the operating condition of the freeze protection equipment.
4.5 Electricians shall verify heat-tracing circuits for proper operation and correct any deficiencies.
4.6 Electricians shall verify all heat lamps and electrical heaters are ready for service and correct any deficiencies.
4.7 Maintenance to ensure that the building heaters are operating properly.
4.8 Maintenance shall verify proper insulation and freeze protection and correct any deficiencies.
4.9 Maintenance shall verify all propane heaters are ready for service. Plant will verify adequate supply of propane on-site.
4.10 Maintenance to ensure that snow removal equipment is checked and in proper working order. Plant to ensure adequate supply of sand and salt for walk areas.
4.11 Operations to check and properly position doors, windows, vents, louvers, and other areas that open to the outside and could let cold air in buildings.

4.12 Operations should insure that moisture from instrument air and sootblowing air tanks and related equipment will properly bleed off.
4.13 Instrumentation will check that all air dryers are drying air to proper operating parameters.
4.14 Operations shall pre-stage all portable freeze protection equipment in critical areas.
4.15 Operators shall notify the Shift Supervisor if local weather conditions are cooling off to where freezing equipment is a concern.
4.16 Shift Supervisor to notify all plant supervision of pending cold weather and enact Cold Weather Protection Procedure.
4.17 Operations will fire up portable propane heaters, electric heaters, and turn on heat lamps in areas that require additional heating.
4.18 During initial stages of a cold weather front with ambient temperatures below 15 F, Operators shall make one round per shift with a heat gun to check enclosures, piping and remote areas of the plant that may require additional freeze protection. Any areas of concern shall have enclosures sealed up and temporary sources of heat installed.
4.19 At the end of the cold weather season, Operations should see that all materials are returned to the proper storage location.
4.20 Inspect vehicle and diesel equipment for winter operation (such as diesel fuel additive, anti-freeze, engine heaters, windshield wipers, window scrapers, etc..)
4.21 Personnel should be notified of the dangers of cold weather (chill factor) and be prepared for snow and ice (ice cleats, ice melt, and provisions for cleaning walk ways).
4.22 Stores personnel will check stock to verify adequate cold weather PPE is available.

5.0 REQUIRED RECORDS

5.1 Check list must be completed and returned to the Operations Manager or Equivalent. These records should be retained for two years.

6.0 REFERENCES & DEFINITIONS

6.1 Plant Normal Operation Standard GTE-O-040.
6.2 Energy Supply Operations Policy ESO-OP-6.100, Operations Standard Operating Procedures - minimum content by Plant type, Plant Normal Operation, 13) Preparation for cold weather freeze protection.

7.0 REVISION HISTORY

Date	Revision Number	Change
05-25-2006	**0**	**None – initial edition**

Commitment 11

February 18, 2006 Event Commitment No. 11

Investigate changing normal protocols for unusual weather.

Review existing protocols and modify as needed. Structure of changes will depend on actions taken by others, coordinated response.

Findings of the Investigation:

In reviewing the existing process it was noted that a coordinated response process was not fully implemented. There are a number of organization processes being used, but they are not integrated across various functional groups.

Actions taken:

A standard system response procedure was developed in conjunction with cross-functional organizations. The final policy is ESO-OP-6.14OP "*System Operating Code Response*"

Date Implemented:

The procedure was finalized on May 23, 2006 – see Commitment 9.
Procedure was formally approved on May 24, 2006.
Training on the new procedure for RT Dispatch, Transmission Operations, Plants and Gas Supply will be completed by June 30, 2006.

Commitment 12

February 18, 2006 Event Commitment No. 12

Investigate power plant failure causes.

Complete root cause investigations or event reports for affected plants during the February 18th incident.

Findings of the Investigation:

Cherokee – Unit 4 experienced an electrical failure of the uninterrupted power supply for the control system. A damaged contactor coil failed and the protective fuse for the bypass system was damaged preventing the UPS from switching to the by-pass power source. The unit tripped at 4:05 AM on February 18th. Unit 4 was scheduled to be removed from service at 8:00 AM on February 18th for a major overhaul and the work scope required to troubleshoot and repair the UPS was estimated to take at least 8 hours. The unit was safely secured and the major overhaul work commenced.

There was a concern that the Cherokee 4 overhaul was moved from the Fall to the Spring of 2006. Reviewing past revisions of the Overhaul Schedules, Cherokee 4 was originally scheduled for the Spring. The overhaul was reduced in duration from 5 weeks to 4 weeks.

FSV

Unit 1 (Steam Turbine) –The steam turbine tripped when the #3 HRSG drum level transmitter froze. The HRSG low level drum alarm occurred and the Control Specialist (CS) started to assess and correct the situation. The HRSG tripped and the CS instructed an operator to set equipment in the proper sequences to protect ancillary components. The boiler feed pump tripped and ultimately led to a steam turbine trip. This was the proper sequence for the sequence of operating events.

Unit 2 – Unit was at minimum load and tripped due to flame instability. The FSV combustion turbines do not have a combustion dynamics monitoring system to monitor flame patterns during HRSG start-up.

Unit 3 – Unit was at minimum load and tripped due to flame instability. The FSV combustion turbines do not have a combustion dynamics monitoring system to monitor flame patterns during HRSG start-up.

Unit 4 - Unit was at minimum load and tripped due to flame instability. The FSV combustion turbines do not have a combustion dynamics monitoring system to monitor flame patterns during HRSG start-up.

Valmont – Unit 5 experienced a high drum level trip at midnight the morning of February 18th. The full load trip resulted in an overpressure situation causing the boiler safety valves to open. This sequence occurred a second time and during that second episode of excess boiler pressure the unit experienced a water wall tube rupture. This type of failure was typical due to previous hydrogen damage to the boiler. The failure was significant and required weld repairs to the failed tube. The drum level sensing lines appeared to have plugged from boiler deposits and debris was observed during the sensing line cleaning process. A combination of deposits and freezing temperatures were the identified as the root cause for this event.

Actions taken:

Root cause or event evaluations were completed for Cherokee 4, Fort Saint Vrain and Valmont. The review documentation is attached for each incident. One of three facilities were impacted by maintenance or operating issues that were not related to the weather conditions during the February 18^{th} incident. (Cherokee 4) However, the impact to the system warranted a review of the issues and identification of the corrective actions to mitigate future occurrences.

A table of the recommended action items and status of the recommended actions is attached. The majority of the recommendations have been completed. Several of the outstanding items are scheduled to be completed later in 2006 in conjunction with scheduled maintenance outages.

The root cause action items will be tracked until completed by Dan Lusk. This will ensure that all items closed out. In addition, the root cause and event reports will be reviewed with all plant directors during the June 19, 2006 Unplanned Outage Rate conference call.

Date Implemented:

See the attached action item summary document that identifies each item for a specific facility and the current status.

Each item that is not completed has a defined due date listed. A person in Energy Supply has been assigned the responsibility to monitor the status of the outstanding items until completed.

General review of all events will be discussed during the June 19, 2006 Unplanned Outage Rate conference call.

Cherokee Station Unit 4 UPS
April 10, 2006
Draft

Incident Summary:

On February 18, 2006, at approximately 0405 hours, the UPS on Unit 4 failed due to a bad coil on the UPS output contactor. This coil failure caused a control fuse to blow. This control fuse also provided power to the UPS static switch which transfers the UPS load to the bypass source. The bypass failed to operate, causing loss of power to the UPS loads, which resulted in Unit trip. The Unit was scheduled to come off-line at 0800 hours for a 4 week planned overhaul. This event caused a loss of 1,379 MWHrs.

Time Line:

Date:	Time:	Action/Activity	Who	Comments/Analysis
02/18/06	04:05	Unit 4 UPS failed, Unit 4 tripped		The bypass failed to operate due to blown fuse.
02/18/06	08:00	Unit 4 Planned Overhaul start		

Team Analysis:
Tom Stelmach, Plant Electrician Specialist, and Bob Aguirre, Technical Specialist, performed a root cause analysis.

The root cause was determined to be a faulty contactor coil.

Recommendations are as follows:

- Repair UPS during Unit 4 2006 Spring Planned Overhaul
- Have OEM vendor out to perform analysis of Unit 4 UPS failure.
- Perform routine inspections of all coils and fuses in the UPS.

Employees assigned and scheduled to complete recommendations:

Tom Stelmach was assigned to have the UPS repaired.

Bob Aguirre was assigned to perform the failure analysis and make recommendations based on the analysis.

In summary, the following table recaps related issues for the Unit 4 UPS and actions needed to eliminate future occurrences.

Cause	Solution/Action	Immediate or Long Term	Responsible Person	Due Date
UPS Coil Failure	Replace failed coil and blown fuse.	Long Term	Tom Stelmach	Complete 3/10/2006
	Perform failure analysis	Long Term	Bob Aguirre	Complete 3/21/2006
	Inspections PM set up	Long Term	Bob Aguirre & Doug Foster	Complete 3/21/2006

COLO Region Outage Schedule for: 2006, Rev 1

Printed on: 12/9/03

ID	Unit	MW	MWhrs based on days duration	Start	End	Days	Wks & Days	Outage Scope
1215	Cherokee 4	352	329472	Feb 17, Fri	Mar 27, Mon	39	5w 4d	LP Turbine Inspection, Turbine Valve Inspections, Boiler Inspection
1004	Arapahoe 4	111	15984	Mar 8, Wed	Mar 13, Mon	6	0w 6d	Boiler cleaning outage
1003	Arapahoe 3	45	6480	Mar 29, Wed	Apr 3, Mon	6	0w 6d	Boiler cleaning outage
1093	Cabin Creek A&B	162	85536	Apr 3, Mon	Apr 24, Mon	22	3w 1d	Spring maintenance outage
1081	Hayden 1	139	153456	Apr 14, Fri	May 29, Mon	46	6w 4d	LP Turbine & Generator Inspection, Boiler Inspection
984	Fort St. Vrain 3	235	56400	Apr 15, Sat	Apr 24, Mon	10	1w 3d	Combustion Inspection
1094	Cabin Creek A&B	162	85536	Sep 11, Mon	Oct 2, Mon	22	3w 1d	Fall maintenance outage
1070	Cameo 2	49	37632	Sep 22, Fri	Oct 23, Mon	32	4w 4d	Boiler Inspection, HP-LP Turbine Inspections, Turbine Valve Inspections
985	Fort St. Vrain 2	235	124080	Oct 1, Sun	Oct 22, Sun	22	3w 1d	Hot Gas Path Inspection
1007	Arapahoe 4	111	15984	Oct 25, Wed	Oct 30, Mon	6	0w 6d	Boiler cleaning outage
1142	Arapahoe 3	45	6480	Nov 1, Wed	Nov 6, Mon	6	0w 6d	Boiler cleaning

557520

In The Matter Of Service Outages Of The Electric System Of Public	)	**Internal Investigation Electric Supplies- 2nd Set of Questions**
Service Company Of Colorado	)	**Electric Supplies, Contracting & Control**
On February 16 And 17, 2006	)	**Dated February 28, 2006**
	)	
	)	
	)	

Period under investigation means Friday 17 February 2006 through Saturday 18 February 2006.

WECC Report:

- PSCo deficiency was more than 1,000 MW.
- Midday Friday, February 17, 2006, 600 MW were unavailable from Rocky Mountain Energy Center.

PSCO 2-4 What caused the tripping of units at Blue Spruce and Fort St. Vrain?

RESPONSE:

FSV unit 1 tripped (11:36pm, 2/17) – frozen level instrumentation on unit 3 heat recovery steam generator

FSV unit 4 tripped (4:07am, 2/18) – due combustion instability at low temperature during transition from simple to combined cycle

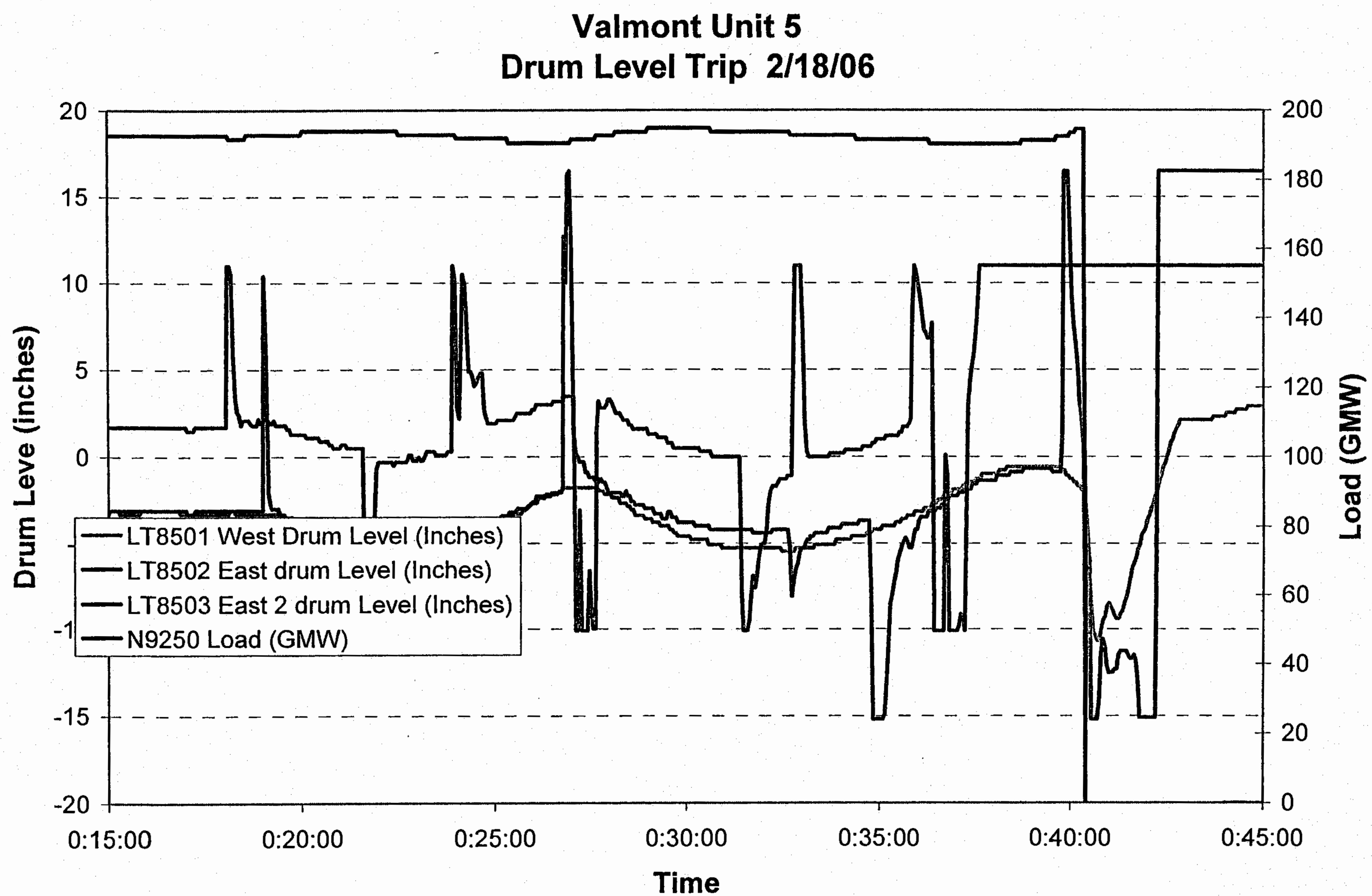
FSV unit 2 tripped (1:24pm, 2/18) - due combustion instability at low temperature during transition from simple to combined cycle

FSV unit 3 tripped (4:37pm, 2/18) - due combustion instability at low temperature during transition from simple to combined cycle

Sponsor: Marty Block **Date:** 3/01/06

Commitment 12

The Generation Station Event Report
contains highly confidential information and has been filed under seal



Valmont Unit 5
Drum Level Trip 2/18/06
Drum Leve (inches)
Load (GMW)
Time
LT8501 West Drum Level (Inches)
LT8502 East drum Level (Inches)
LT8503 East 2 drum Level (Inches)
N9250 Load (GMW)
20
15
10
5
0
-15
-20
200
180
160
140
120
100
80
60
40
20
0
0:15:00
0:20:00
0:25:00
0:30:00
0:35:00
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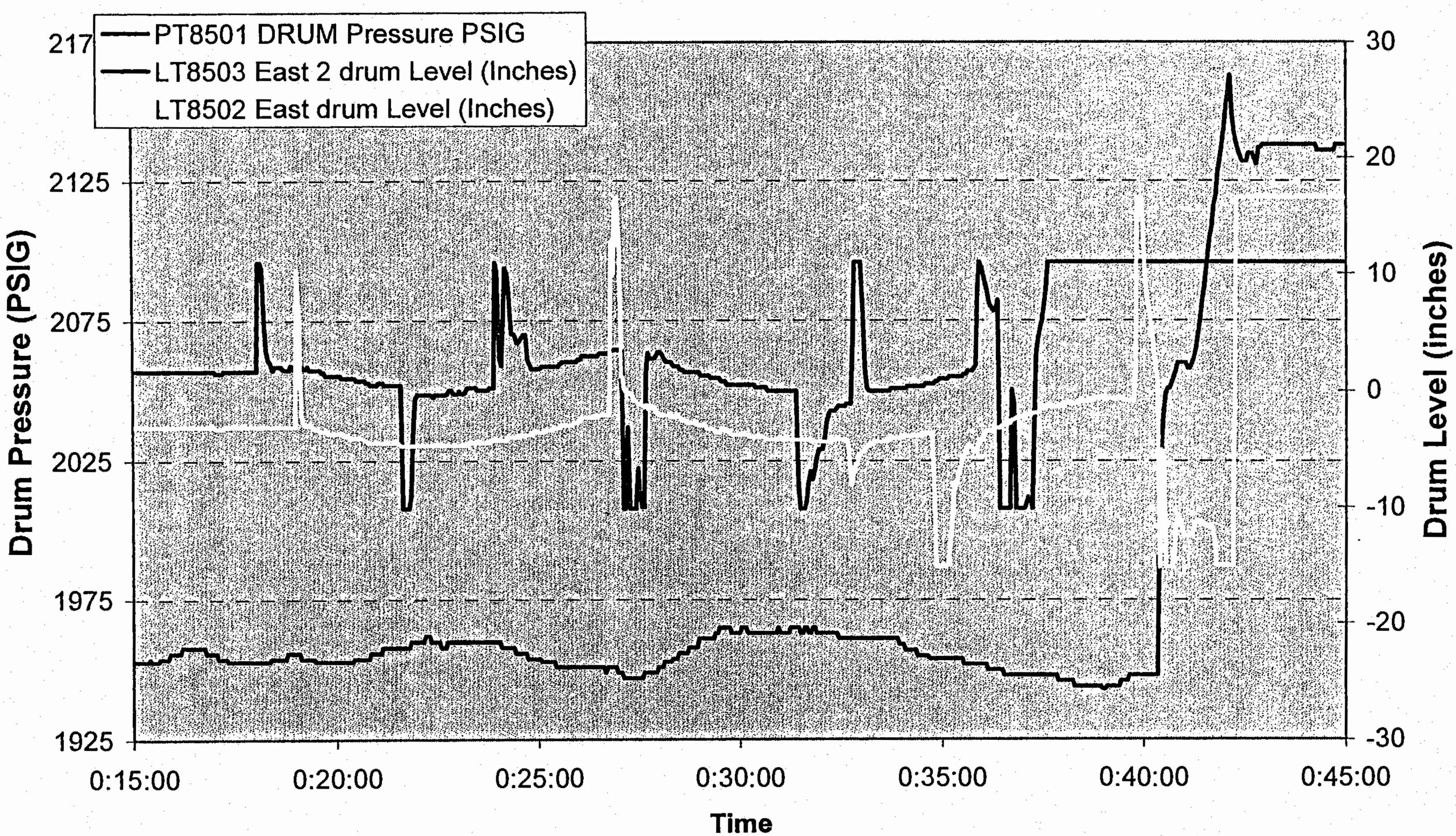
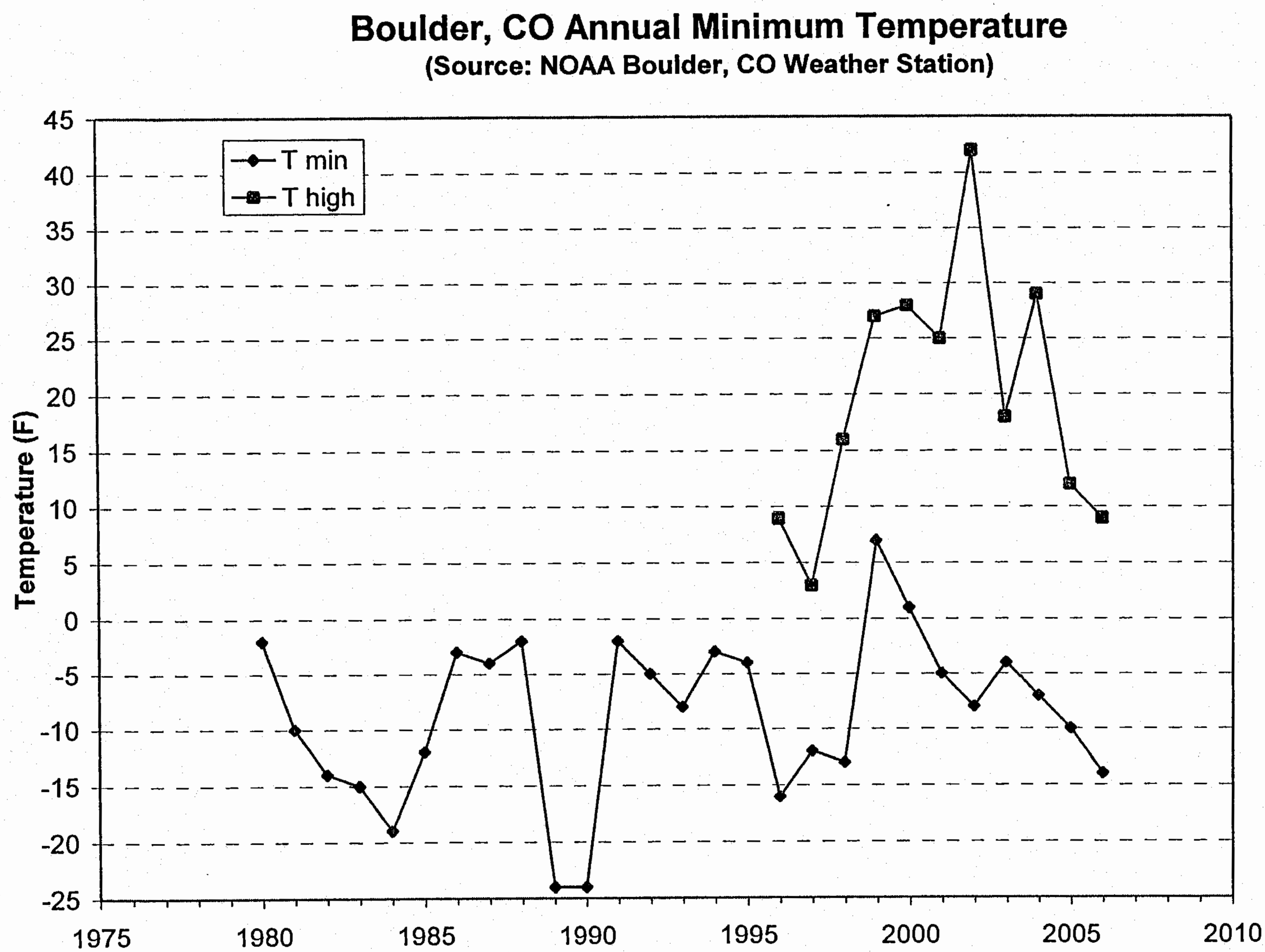
0:45:00

Valmont Unit 5
Drum Level Trip 2/18/06





Boulder, CO Annual Minimum Temperature
(Source: NOAA Boulder, CO Weather Station)
T min
T high
Temperature (F)
45
40
35
30
25
20
15
10
5
0
-5
-10
-15
-20
-25
1975
1980
1985
1990
1995
2000
2005
2010

Commitment 13

February 18, 2006 Event Commitment No. 13

Develop a daily curtailment priority process for interruption of firm wholesale sales transactions

Findings of the Investigation:

An item that was identified by the Company's February 18th task force is that it was difficult to quickly assess the firm wholesale sales customers that could be interrupted during an Emergency. The contract provisions were available to the RT Dispatch and RT Trading group, however it was not readily accessible. Additionally, the specific OATI tag information was not as easily accessible as would have been preferred during strained system operations.

Actions taken:

The action item identified by the Task Force was to develop a list of interruptible schedules, prioritize the list in order of curtailment, and identify the delivery point of the transaction and the OATI tag associated with the schedule. The new process includes a daily update of the interruptible schedules and priority of curtailment established by the trading group, while the scheduling group will identify the tag information. The schedulers will take responsibility for delivering the curtailment priority list to the RT Dispatch group on a daily basis. The curtailment list will be readily available to the operations group in the future, enabling more efficient evaluation of schedule curtailment options.

Date Implemented:

This action item has been completed for PSCo and the new process was effective for May 1, 2006.

Aldrich, Marsha L

From: Fisher, Mary J
ent: Friday, May 26, 2006 10:32 AM
To: Aldrich, Marsha L
Subject: Com 13

-----Original Message-----
From: Pavlovic, Jeff
Sent: Thursday, April 27, 2006 11:42 AM
To: Welch, John T; Pierce, Eric; Smith, Kyle; Heit, Jeff; Titus, Lance; Thomas, Bill; Cline, Ryan; Hayes-James, Wanda; Courtright, Nancy; Johnson, Marie; Kechter, Ann; Klava, Mark; Roldan, Robyn; Wetteland, Phillip
Cc: Fisher, Mary J
Subject: PSCo Daily Tag Cut List

Part of our commitment to improving practices post Feb-18th is to compile an ordered list of sale tagged energy sales and provide it to the RT System Desk each day.
This process is now in place, and has been done starting with Monday's schedules. Process will be as follows:

1. DA Traders (ususally Jeff or Lance) provide to the Schedulers a list of Daily and Monthly sales from PSCo and order in which they should be cut.
2. Schedulers (Wanda or Ryan) compile tag numbers from these sales and long-term scheduled sales onto a "cut list" sheet.
3. Schedulers will post this sheet on the clipboard hanging next to the PSCo System desk. They will also post an electronic copy on EMOnline.
4. If necessary as part of the PSCo emergency procedures (in the red binder on the PSCo desk), RT Traders will cut schedules in the order posted.

.MOnline will store the permanent records, so there is no need to retain the paper copies once days have passed.

Many thanks to Jeff and Ryan for developing this process, and to everyone who will be carrying it out on a daily basis..

Jeff Pavlovic
Xcel Energy
303 308 6186

Curtailment Priority	Delivery Period			
1 Non Firm Sales	**Counterparty**	**Quantity**	**Delivery Point**	**Tag Number**
2 Short term Firm Sales	**Counterparty**	**Quantity**	**Delivery Point**	**Tag Number**
3 Wholesale Customers	**Counterparty**	**Quantity**	**Delivery Point**	**Tag Number**
	Westplains	233	Midway	
	Mean	23	Midway	
	WAPA	100	Craig	
	ARPA	3	Midway	
4 Full Requirements Customers	**Counterparty**	**Quantity**	**Delivery Point**	**Tag Number**
	Burlington	6	Story	
	Cheyenne	150	Stegall	

1- Every morning, for the next prescheduled day, traders will assign curtailment priorities to non firm and short term sales based on delivery points, quantity and market conditions.

2- By 11:00 am, traders will pass the curtailment sheet to schedulers who will supply the tag or tags associated with each transaction.

3- By 2:00 pm, schedulers will delivery the curtailment sheet to system operators and realtime traders to be used for system emergencies.

Commitment 14

February 18, 2006 Event Commitment No. 14

Develop operating protocols during elevated operations.

Findings of the Investigation:

Gas Control reviewed its current procedures for elevated operations. Prior to this time there were no written procedures in Gas Control for normal or elevated operations except those situations listed in the Gas Emergency Plan in the Xcel Energy Gas Standards Manual.

Actions taken:

Gas Control reviewed as many situations as it has experienced or may experience which would require actions outside normal monitoring and control of the system. These situations were specifically spelled out as meeting the criteria for elevated operations. Each situation was reviewed for actions to be taken by personnel in Gas Control. As part of each item, the communications required and persons or departments to be notified are included.

In addition, some of the situations require Gas Control to make decisions to maintain the safety and reliability of the Gas Transmission System. One level of this decision is to limit the electric generating plants dispatched by PSCo to their nominated gas volumes or require them to supply additional gas. This limitation has since become know as the "Reliability Call". The criteria for such a call and the language to be used for this call have been documented as a result of this review. Gas Control, Gas Supply and Real Time Dispatch have all agreed on the criteria and language for this call.

Date Implemented:

Gas Control Procedures for Elevated Operations document completed on May 15, 2006

Reliability Call document completed on May 15, 2006

RELIABILITY CALL

When will the Reliability Call be made?

Pursuant to PSCo's gas tariff, an OFO can be called to alleviate conditions which threaten or could threaten the safe operation or integrity of PSCo's gas system or to maintain operations required to provide efficient and reliable firm gas service. If those conditions exist, and observations are made at Gas Control that there is insufficient supply for PSCo Electrics, if they continue to burn at the current or projected rates, which are expected to exceed nominated quantities, and Gas Supply for PSCo Electrics is not able to increase nominations by increasing storage withdrawals, decreasing injections or purchasing more supply, then this Reliability Call to Real Time Traders must be made prior to, or coincident with calling an OFO. If an OFO is called, it is required that gas supply for PSCo Gas Sales load customers and distribution system also have sufficient supply as well as a reserve available.

Commitment 14

Gas Control Operating Procedures
contain highly confidential information and have been filed under seal

Reliability Call to Real Time Desk

To restrict over burns:

This is ______________________ at XCEL Gas Control at Lookout Center.

PSCo Gas Control hereby requests PSCo Electric Dispatch to operate in a manner necessary to assure the continued reliability of the PSCo gas system.

For Gas Day ______ from ____ to ____ Mountain Clock time PSCo's gas system is in a state of heightened operational constraint, such that it cannot supply any gas over the current day nomination, which we show as ___________ Dekatherms for all the electric power plants that are fueled by gas from PSCo ("PSCo Electric Plants"), both on PSCo's system and on CIG.

Specific plants and current burn status:

	Run	Start + Run	Start Limited	Offline/Alt. Fuel
High BTU				
Blue Spruce	_____	_____	_____	_____
Brighton	_____	_____	_____	_____
CPP	_____	_____	_____	_____
Ft Lupton	_____	_____	_____	_____
FSV	_____	_____	_____	_____
Pawnee	_____	_____	_____	_____
Plains End	_____	_____	_____	_____
Thermo	_____	_____	_____	_____
Low BTU				
Alamosa	_____	_____	_____	_____
Arapahoe	_____	_____	_____	_____
Arapahoe 5&6	_____	_____	_____	_____
Cherokee N.	_____	_____	_____	_____
Cherokee S.	_____	_____	_____	_____
Denver Steam	_____	_____	_____	_____
Valmont	_____	_____	_____	_____
Zuni	_____	_____	_____	_____
CIG				
Comanche	_____	_____	_____	_____
Blue Spruce	_____	_____	_____	_____
Brighton	_____	_____	_____	_____
Hudson	_____	_____	_____	_____
Midway	_____	_____	_____	_____
Skyline	_____	_____	_____	_____
Grand Junction				
Fruita	_____	_____	_____	_____
Cameo	_____	_____	_____	_____

Real Time traders must inform Gas Control of any unexpected outages or any condition which will require additional gas burns.

Reliability Call to Real Time Desk

To restrict under burns:

This is ____________________ at XCEL Gas Control at Lookout Center.

PSCo Gas Control hereby requests PSCo Electric Dispatch to operate in a manner necessary to assure the continued reliability of the PSCo gas system.

For Gas Day ______ from ____ to ____ Mountain Clock time PSCo's gas system is in a state of heightened operational constraint, such that it cannot accept any gas in excess of the current day nomination, which we show as ___________ Dekatherms for all the electric power plants that are fueled by gas from PSCo ("PSCo Electric Plants"), both on PSCo's system and on CIG.

Real Time traders must inform Gas Control of any unexpected outages or any condition which will require leaving additional gas on the system.

Commitment 15

February 18, 2006 Event Commitment No. 15

Investigate changing normal protocols for unusual weather.

Findings of the Investigation:

The investigation determined that unusual weather was involved in more than one of the situations detailed in the Gas Control Procedures for Elevated Operations document. This document has been created in response to Commitment No. 14.

In addition, the investigation revealed the need for Gas Control and Gas Supply to coordinate and agree on load forecast and weather forecast tools used to create those load forecasts.

Finally it was determined that more specific criteria are needed for Gas Control, Natural Gas Services and Gas Supply to be in sync as to when PSCo system Operational Flow Orders are called.

Actions taken:

Normal procedures for unusual weather were reviewed and included in the Gas Control Procedures for Elevated Operations document.

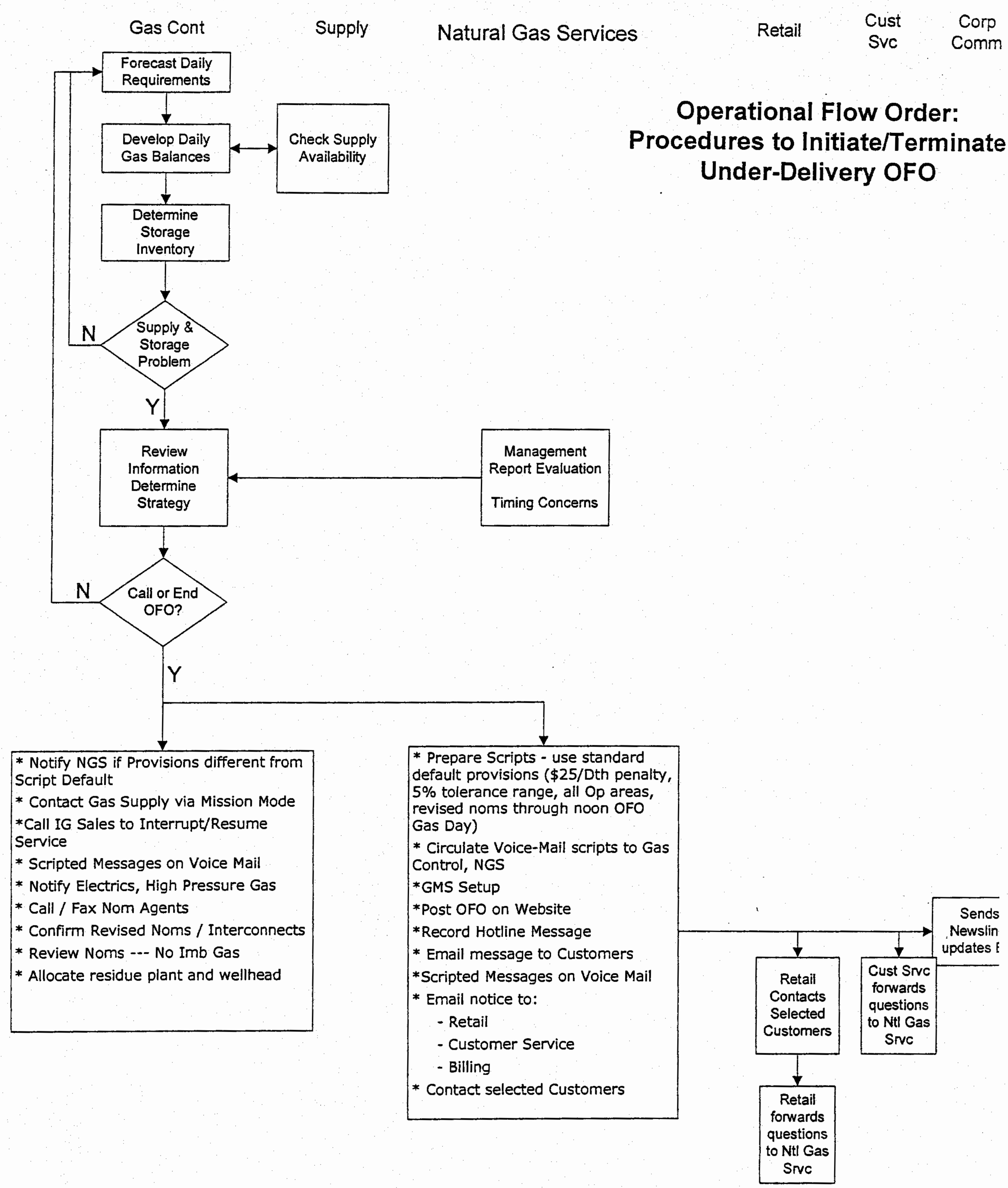
A load forecast tool was created from existing procedures with some additional forecasting methodology added. This was reviewed and agreed to by Gas Supply. The tool provides forecasted load for non-electric transportation shippers and on system sales (LDC). This is combined with forecast and nominations for PSCo electrics, nominations for shippers and purchases and storage plans for the LDC. The final comparison indicates if sufficient reserve exists for the system.

Specific criteria were identified for calling an OFO on the PSCo system. In this document the minimum gap between expected load and known supply is specifically spelled out, and when that gap requires that an OFO be called, or if additional supply is to be purchased by PSCo.

Date Implemented:

Gas Control Procedures for Elevated Operations document completed on May 15, 2006 – See commitment #14
Weather and Load Forecast sheet completed on May 15, 2006.
OFO Criteria document completed on May 15, 2006

Operational Flow Order: Procedures to Initiate/Terminate Under-Delivery OFO



Updated 5/8/2006

Commitment 15

The Xcel Energy- Gas Control OFO Procedure
contains highly confidential information and has been filed under seal

Commitment 16

February 18, 2006 Event Commitment No. 16

Investigate how to align and integrate various operations to deal with unusual weather.

Findings of the Investigation:

As a part of investigating normal procedures during unusual weather, and establishing criteria for elevated operations it was noted that documentation did not exist for Gas Control communications with various departments during unusual weather and elevated operating conditions.

Improved knowledge of one another's departmental functions would make communications go better during elevated operations.

Actions taken:

Communications with other departments was included in the specific actions to be taken by Gas Control personnel in unusual weather and elevated operating conditions. This document will be shared with all those departments so that no gap exists between perceptions of departments as to when how or why communications will occur.

On May 23, 2006 John Welch, Jeff Pavlovic, Jeff Haskins and Joe Froehle visited Gas Control at the Lookout Center. System layout and issues with gas delivery at specific power plants were discussed. Procedure was discussed for RealTime calls to Gas Control, and how important information is on how long the plant is expected to burn gas, and at what Dth per hour rate it is planned to burn at. This helps Gas Controller to set up the system to better deliver gas to the plant and decide if there is sufficient supply and/or pressure if elevated operating conditions exist.

Date Implemented:

Gas Control Procedures for Elevated Operations document completed on May 15, 2006 – See commitment No. 14

Commitment 17

February 18, 2006 Event Commitment No. 17

Investigate additional natural gas storage options

Findings of the Investigation:

The Company has reviewed multiple storage options in the Rocky Mountain Region including possible expansion of existing fields. As a result of this review the Company has decided to enter into confidential negotiations to further investigate the preferred storage options. It is anticipated that a preferred alternative will be recommended to Management by mid-summer.

Actions taken:

A number of storage options have been investigated and reviewed. The preferred storage options are now being finalized. The leading preferred option has been reviewed with Management and the PUC Staff. The Company is continuing to develop the preferred option and expects to make a final recommendation in mid-summer. Additional meetings will be held with the PUC Staff and the OCC once the recommendation has been finalized.

Date Implemented:

Initial study results presented to Management on April 12 and to the PUC Staff on April 21, 2006.

Commitment 17

The CIG Gas Storage Procedure
contains highly confidential information and has been filed under seal

Commitment 18

February 18, 2006 Event Commitment No. 18

Investigate how to align and integrate various operations to deal with unusual weather.

Findings of the Investigation:

Asset Management has completed a study of the system reinforcements needed to provide firm pipeline capacity to the power plants served only by the PSCo gas system. The following table lists by power plant the capital cost to reinforce the gas system, the type of reinforcement needed, the current risk of interruption and the available alternative fuel. No capital is currently budgeted for these improvements.

Power Plant	**Plains End expansion 222MW**	**Valmont 6,7&8 127 MW**	**Arapahoe Units 5,6,7 120 MW**	**Fort Lupton Units 1&2 100 MW**	**Total**
Capital for Gas System Reinforcement	$6.9M	$19.6M	$0M	$0.18M	$26.68M
Reinforcement	8 miles of 12" pipeline and Yosemite plant piping modification	8 miles of 24" pipeline and 6.4 miles of 16"pipeline	No system improvements required	Valve set modification connect to alternative pipeline	
Interruption Risk and Alternative Fuel	High During Cold Weather Alternative Fuel: None	Very High During Cold Weather Alternative Fuel: None	Limited to Very Extreme Weather Now Alternative Fuel: None	High During Cold Weather Alternative Fuel: Yes #2 Fuel Oil	
Total Annual Firm Capacity Cost	$2,110,132	$4,864,732	$2,040,048	$1,112,227	$10,127,139
Total Annual Interruptible Capacity Cost	$420,440	$249,352	$1,302,797	$18,773	$1,991,362
Annual Cost Increase for Firm Verses Interruptible Capacity	$1,689,692	$4,615,380	$737,251	$1,093,454	$8,135,777

In addition to cost, it should be noted that the generation capacity necessary to serve the peak electric requirements in the summer is far greater than the requirements for a winter peak day. As a result, on peak electric days in the winter, the generation portfolio has spare generation capacity available and further studies need to be completed to assess the firm fuel requirements as part of the overall availability of the generation fleet.

Actions taken:

Study was completed and is currently being discussed with senior management.

Date Implemented:

Study was sent to senior management on May 12, 2006.

Commitment 18

The Firm Transport Capacity Report for February 17 and 18 contains highly confidential information and has been filed under seal

Commitment 19

February 18, 2006 Event Commitment No. 19

Develop Gas Supply Operating Protocols during elevated operations.

Findings of the Investigation:

On Friday (February 17th) at approximately 12:45 p.m., Gas Control notified Gas Supply that the electric plants were projected to exceed their daily gas nomination based on their current rate of gas use. Gas Supply took immediate action to source additional supply and discussed with Real Time Dispatch regarding additional mitigation actions such as delaying the scheduled Cherokee Plant outage and switching to fuel oil. Discussions regarding the economics of penalty gas also occurred.

On Saturday (February 18th) between 6:30 and 7:00 am, the Director of Gas Supply and the Manager of Gas Supply for the PSCo system were contacted regarding the lack of gas supply on the PSCo system. They both headed for the office along with the Manager of Gas Supply for the Mid-Continent system. Although there was little that could be done within gas supply to help the immediate situation they began working on buying intra-day gas supplies for February 18th.

Gas Supply personnel were available and engaged in trying to source additional gas supplies for the PSCo system prior to 16:00 on Friday and beginning again at 7:00 a.m. on Saturday, however due to the developments outside of the normal nomination cycles that occurred between Friday evening and early Saturday morning there were no additional steps that could have been taken with regard to sourcing additional gas supply.

Actions taken:

A formal procedure (Elevated Operating Protocols) has been written and implemented that details that the Gas Supply personnel will be alerted when various thresholds are crossed on both the gas and electric systems. The document also addresses the options available to Gas Supply depending on the time of day that they are notified. These procedures have been integrated with Real Time Dispatch and Gas Control.

Date Implemented:

The procedures were approved by the Director of Gas Supply and implemented on May 2, 2006.

Commitment 19

LDC Gas Purchasing Procedures
contain highly confidential information and have been filed under seal

Commitment 19

Gas Supply Operating Protocols
contain highly confidential information and have been filed under seal

Commitment 19

Generation Gas Purchasing Procedures
contain highly confidential information and have been filed under seal

Commitment 20

February 18, 2006 Event Commitment No. 20

Investigate changing normal gas supply protocols for unusual weather.

Findings of the Investigation:

For gas day February 17th, the actual temperatures (mean temperature of minus 2) experienced on the PSCo system were dramatically different from the original forecast (mean temperature 12 degrees) used to generate the load forecast on the morning of February 16th and the revised forecasted used to generate the load forecast on the morning of February 17th (mean temperature 4 degrees). Despite the change in temperature forecasts between February 16th and 17th it still appeared that there was adequate reserve margin on the PSCo system as of Friday morning for gas day February 17th. In addition, the reserve margin for gas day February 18th as forecasted Friday morning (based on a mean temperature of 12 degrees) appeared to be adequate.

The colder than forecasted temperatures and the loss of efficient gas-fired generation and coal fired generation units created demand for gas supply that exceeded both the forecasted load requirements and the reserve margin.

In reviewing the forecasting methodology it was determined that using Real-Feel temperatures when they are forecasted to be colder than the ambient temperature by 4 degrees or greater provides a more accurate load forecast for the PSCo system (LDC).

Actions taken:

Gas purchasing procedures (LDC Gas Purchasing Procedures) to create and maintain adequate reserve margins on the PSCo system have been documented, approved and implemented. The reserve margin will not include authorized overrun from CIG. Real-Feel temperatures will be used to create the load forecast when they are colder than the ambient temperature by 4 degrees or greater.

Gas purchasing procedures (Generation Gas Purchasing Procedures) have been documented, approved and implemented for electric generation that include minimum gas reserve margins based on forecasted temperature thresholds and will not include generation available on fuel oil.

In addition, the thresholds for the PSCo system are consistent with Gas Control's thresholds for calling an Operational Flow Order.

Date Implemented:

The procedures were approved by the Director of Gas Supply and implemented on April 28, 2006.

Commitment 21

February 18, 2006 Event Commitment No. 21

Study how to improve communications for Gas Supply.

Findings of the Investigation:

Gas Supply personnel were notified of the lack of gas supply on the PSCo system between 6:30 and 7:00 am on Saturday February 18th. At that time all available units (except for Zuni) had been switched to fuel oil and an Operational Flow Order (OFO) had been called effective at 8:00 am on February 18th. Due to the standard gas nomination timelines Gas Supply personnel could not procure additional supplies that would provide immediate relief to the system.

Actions taken:

Thresholds have been developed for both Gas Control and Real Time Dispatch that will trigger notification of Gas Supply Personnel for both the PSCo Gas System (OFO has been issued) and the PSCo Electric System (alert level – Yellow). This is documented in Gas Supply's procedures for Elevated Operating Protocols and has been incorporated into both Gas Control and Real Time Dispatch procedures.

Gas Supply personnel contact information has been sent to Scott McCoy for inclusion in the emergency notification process.

Date Implemented:

The procedures for Elevated Operating Protocols were approved by the Director of Gas Supply and implemented on May 2, 2006 – see commitment #19.

The contact information for Gas Supply personnel was sent via e-mail on May 3, 2006.

Commitment 22

Description of the commitment: No. 22

Investigate the impact of the FERC standards of conduct had on the controlled outage event.

Findings of the Investigation:

In reviewing the events, it was determined that the new Standards of Conduct rules promulgated under FERC Order 2004 may have contributed to the events that led to the controlled outages. The FERC Standards of Conduct generally require the separation of a transmission provider's transmission function from its wholesale merchant function, and prohibit wholesale merchant function employees from having access to transmission-related information. While the FERC Standards of Conduct allow communication between transmission function employees and wholesale merchant function employees (including Real Time Dispatch) upon the declaration of an emergency, and allow crucial operating information to be shared by transmission function employees and wholesale merchant function employees, the Company's employees failed to take complete advantage of such permissible communications during the events of February 17 and 18 due to uncertainty about the scope of the FERC Order 2004 communication restrictions in such a situation. Transmission Control was hesitant to declare an emergency and suspend the Order 2004 restrictions, until it was certain that a true emergency existed. In addition, Gas Control employees were hesitant to disclose the severity of the operational situation on the gas delivery system to Real Time Dispatch and to Gas Supply due to uncertainty about whether such communications were permissible or prohibited under the FERC rules. Because these departments were not freely communicating with one another, some critical departments did not have an accurate and full picture of the pending overall problems until it was too late to avoid the controlled outages. Although the employees understood the requirements under the Standards of Conduct and the basic types of communications that were permitted, the employees did not sufficiently understand and apply the permitted scope of communications in the face of the significant events that occurred on February 17 and 18 until it was too late to avoid the controlled outages.

Actions taken:

The Company has reviewed FERC orders and decisions that are relevant to this matter and has determined that the FERC Standards of Conduct should be flexible enough to permit utility employees to communicate the status of problems with each of the gas and electric systems to other utility departments at an earlier stage in development of an emergency. The Company has developed new procedures that address elevated system operations that include provisions for permissible communications among Company departments. Company employees are being trained in these new procedures.

FERC (Federal Energy Regulatory Commission) Order No. 2004
Standards of Conduct for Transmission Providers
The *No Conduit Rule*: What is it? How do I comply with it?
Version 4 March 21, 2006

The purpose of this document is to provide guidance to Xcel Energy "support employees" on how to comply with *FERC Order No. 2004, Standards of Conduct for Transmission Providers* ("SOC" or "the Standards"). This information is designed to provide guidance to employees who do not work directly within the Transmission Function in the Utilities Group (UG) or the Wholesale Merchant Function (WMF) in UG and Energy Supply, but who have (or could have) access to market-sensitive transmission information in order to perform their jobs. All Xcel Energy support employees are subject to the Standards, specifically the No Conduit rule.

Am I a support employee?

You are a support employee of Xcel Energy subject to the No Conduit rule if you:

- Provide services to both the Transmission Function and the Wholesale Merchant Function or to an Energy Affiliate, or
- Provide support to the Transmission Function, or
- Have access to transmission information to perform your job.

If you have been given this briefing, your management considers you a support employee.

Support employees at Xcel Energy must:

1. Comply with the No Conduit rule;
2. Protect market-sensitive transmission information from preferential disclosure to the Wholesale Merchant Function and Energy Affiliate Employees; and
3. Report violations or possible violations to the Standards of Conduct Chief Compliance Officer.

Why should I care about the Standards of Conduct?

The Xcel Energy Employee Code of Conduct requires employees to comply with the law. The FERC Order No. 2004 Standards are federal law. So Xcel Energy employees are required to comply with the Standards under the Employee Code of Conduct. Violations could lead to discipline or even termination.

At Xcel Energy, we want to give employees the tools they need to fully comply. So here is information you need as a support employee to understand and comply with the SOC rules. If you have further questions, please do not hesitate to ask your supervisor, your compliance liaison or the Chief Compliance Officer. See the attached list for names of compliance liaisons and the Chief Compliance Officer.

Why did FERC implement Standards of Conduct?

The purpose of the SOC rules is to encourage competition in wholesale power and natural gas markets by ensuring "comparable and non-discriminatory access" to Xcel Energy's electric and natural gas transmission systems for all competitors. The rules prohibit Xcel Energy companies that own electric or natural gas transmission facilities and provide interstate transmission services from providing preferential treatment to Xcel Energy's Wholesale Merchant Function or Energy Affiliates. The Xcel Energy companies affected by the Standards are: NSP, NSP-Wisconsin, PSCo, SPS, Cheyenne and WestGas InterState, Inc. (a small natural gas pipeline). Under the Standards, these companies are known as "Transmission Providers" Since they provide open-access transmission services to all eligible market participants.

Note: Xcel Energy has operated under similar standards of conduct rules since the mid 1990s. However, FERC recently expanded its requirements and mandated training for employees. This briefing is part of our compliance effort.

What are the implications of the Standards for Xcel Energy?

Xcel Energy management must ensure that "Transmission Function" employees, who manage or operate the transmission system, function independently from the "Wholesale Merchant Function" or "Energy Affiliate" employees who buy or sell electricity or natural gas in wholesale markets.

The Xcel Energy Transmission Providers (listed above) must also treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis and cannot operate our transmission system to benefit preferentially our Wholesale Merchant Function or an Energy Affiliate. In essence, we must provide "equal access" to our electric and natural gas transmission systems to competitors.

The most important SOC requirement for support employees is the prohibition on "preferential disclosure" of non-public Transmission Information. FERC is concerned that information sharing to Wholesale Merchant Function or Energy Affiliate employees could provide a market advantage to Xcel Energy's Wholesale Merchant Function or Energy Affiliates, so the Standards also require us to provide "equal access" to transmission information. Transmission Function employees must either (a) not share non-public Transmission Information with Wholesale Merchant Function or Energy Affiliate employees, or (b) make the transmission information available to all competitors at the same time.

What is the No Conduit rule?

The No Conduit rule is part of the FERC requirement that Xcel Energy provide "equal access" to transmission information. **The rule states that a support employee may not provide non-public transmission information to Wholesale Merchant Function or Energy Affiliate employees if a Transmission Function employee could not provide that same information directly.**

As a support employee, you are not allowed to be a "conduit" of market-sensitive transmission information to Wholesale Merchant Function or Energy Affiliate employees meaning that you cannot share transmission-sensitive information in any format (e.g., verbally, electronically, in hard copy, etc.), including casual conversation.

Support employees subject to the No Conduit rule include both Xcel Energy employees and contractors and consultants (such as IBM) who currently have or could have access to non-public transmission information.

Which Xcel Energy employees must not receive non-public transmission information?

Wholesale Merchant Function employees must not receive non-public transmission information. Most of the affected employees report to Tom Imbler, VP Commercial Operations and David Eves, VP Resource Planning & Acquisition. The affected Energy Affiliates are Borger Energy Assoc., L.P. and Windpower Partners 1994, L.P. Doug Johnson of Quixx Corporation is the affected Energy Affiliate employee.

If you are a support employee with access to sensitive transmission information and you provide support services to these parts of Xcel Energy, you need to be careful not to violate the No Conduit rule in performing your job functions.

What information is subject to the No Conduit rule?

The No Conduit rule applies to the transmission information defined in the **Communication Restrictions Appendix A** of the "Standards of Conduct and Implementing Guidelines for the Xcel Energy Electric Transmission Providers." The Appendix is attached to this briefing paper for your convenience.

In brief, prohibited information includes information that has not been made public through posting on the public internet (XcelEnergy.com and our three OASIS sites) or via filings with governmental agencies including but not limited to:

- Technical transmission operating data
- Outage schedules and curtailments
- System service requests, expansion plans
- Planned or potential transmission capital projects

I don't think I'm affected, but could you provide some examples?

The following are three examples of "real life" situations where support employees need to be careful to comply with the No Conduit rule:

- A transmission operator calls an Energy Supply plant control room operator and asks him to reduce load because a transmission line is temporarily out and there is congestion in the area. The plant reduces load as requested and then receives a call from the Wholesale Merchant Function checking on the plant. The plant operator can only say that he reduced load under the instructions of the transmission operator. The plant operator cannot elaborate as to why they were asked to reduce the load. Reminder: Energy Supply plant control room operators are permitted to talk to transmission operators.

- An employee in Corporate Budgeting helps prepare the annual capital budgets for upcoming years, including both Transmission Operations and Commercial Operations (wholesale trading) budgets. The Transmission Operations capital budget includes the schedule and amount of expenditures for planned transmission projects. Information about the projects, including the details of the in-service dates may not yet be public. If this information is used inappropriately, it could result in an unfair competitive advantage for Commercial Operations, which is precisely what the FERC Order 2004 was created to prevent. In any budget communications, the Corporate Budgeting employee must 1) be careful not to share the Transmission Function budget information with WMF or EA employees, and 2) remind other employees that the capital budget report contains market sensitive transmission information that must not be shared, directly or indirectly, with WMF/EA employees.

- An employee is working in a dispatch facility to respond to customer calls after a storm damages electric transmission and distribution facilities and causes customer outages. A transmission repair crew calls in to notify the dispatch center that the damaged transmission line will be back in service at 11:00 p.m. The employee may tell callers when their distribution service is expected to be back in service, but should not discuss the in-service time for the specific transmission line.

How do I ask questions or report potential violations?

Contact the Chief Compliance Officer at SOCChiefComplianceOfficer@XcelEnergy.com.

How do I find current FERC Order 2004 resource materials?

Go to this link to find FERC Order 2004 resource materials including our Implementing Guidelines, liaison lists, meeting procedures and other helpful information:

http://xpressnet/FERCOrder2004/index.htm

Appendix A
Xcel Energy Electric Transmission Providers
Transmission and Wholesale Merchant Function/Energy Affiliates
Communication Restrictions

Version 2-- Effective January 25, 2005

Overall Requirements: Transmission system operations for the Xcel Energy Operating Companies (including Service Company employees performing transmission system operations) must function independently from the Wholesale Merchant Function and Energy Affiliates (including Service Company employees assigned to the Wholesale Merchant Function or Energy Affiliates). The Transmission Function must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate the transmission system to preferentially benefit its affiliated Marketing (Wholesale Merchant Function) or Energy Affiliates.

Prohibited communications: The Transmission Function must operate in a manner such that affiliated Wholesale Merchant Function and Energy Affiliates do not have access to any information about the transmission system or operations that is not contemporaneously available to all users of an Open Access Same-time Information System (OASIS) or Internet website. This information includes, without limitation:

- Inquiries about potential transmission services, facilities or expansion, prior to a formal OASIS request
- Requests for new or expanded transmission services prior to a formal OASIS request
- Transmission flows
- Transmission equipment status
- Transmission system modeling
- Transmission operating procedures
- Available transfer capability
- Transmission maintenance activity
- Scheduled transmission outages
- Curtailments of transmission service
- Ancillary services
- Potential generation sites based on transmission data (unless we produce a public plan locating favorable injection sites)
- Planned or potential Transmission system capital projects (expansions, upgrades, retirements, replacement, etc)
- Information about or from a third party or potential transmission customer unless the other party consents in writing and OASIS information posted
- Storage (West Gas InterState Inc. only)
- Balancing (West Gas InterState Inc. only)

This information must be initially requested and provided to the Wholesale Merchant Function and Energy Affiliates through the Public Internet (the applicable OASIS or xcelenergy.com). Transmission Function employees or representatives may not disclose to affiliated Wholesale Merchant Function or Energy Affiliate employees or representatives through communications any information concerning the Transmission Function's transmission systems or operations or the transmission system of another Transmission Provider, including information obtained from non-affiliated transmission providers. If prohibited non-public disclosures are made, they must be immediately reported to the Standards of Conduct Chief Compliance Officer (CCO) at SOCChiefComplianceOfficer@xcelenergy.com and posted on the applicable Public Internet site.

Permitted non-public communications: The following categories of communications are permitted -

(1) The Transmission Function and affiliated Wholesale Merchant Function (or Energy Affiliate) may communicate regarding regulatory, regional transmission organization (RTO) and regional reliability council (RRC) proceedings, including **policy** and rulemaking activities. Each such meeting should begin with a reminder that the Xcel Energy SOC compliance guidelines apply to communication during the meeting. In addition, specific non-public Transmission Function information as listed above shall not be discussed. Meeting minutes or a summary shall be prepared by the meeting organizer, and shall be forwarded to the CCO and retained for three years by the CCO.

(2) The Transmission Function and affiliated Wholesale Merchant Function (or Energy Affiliate) may communicate about the affiliate's **existing transmission service arrangements**, including billing issues and existing interconnection facility operation and maintenance coordination. However, the Transmission Function should conduct such communications in the same manner as non-affiliated customers, and non-public transmission information shall not be disclosed.

(3) The Transmission Function may share with its Wholesale Merchant Function generation information necessary to perform **generation dispatch** and maintain operations of the transmission system. Applicable "fire walls" within the Energy Management System (EMS) shall be preserved, and standard EMS dispatch records retained. Such communication shall not include specific information about (a) an individual third party transmission transaction, (b) potential third party transmission arrangements, or (c) generation dispatch by non-utility generators (e.g., IPPs) without a written consent by the non-utility generator for the Wholesale Merchant Function to receive this information or act as the operating agent of such non-utility generator as described below.

(4) Once a valid transmission service request has been made by the affiliated Wholesale Merchant Function or Energy Affiliate, or any other transmission customer, the Transmission Function is not required to contemporaneously disclose (e.g., post on OASIS) information solely related to the affiliated Wholesale Merchant Function's or Energy Affiliate's **specific request for transmission service** beyond the information required for other similar requests by non-affiliates. The Transmission Function and the affiliated wholesale merchant function or Energy Affiliate can meet and discuss specific issues related to the transmission service request, including specific interconnection facility options related to the request. An agenda shall be prepared, and meeting minutes prepared, and both shall be forwarded to the CCO and retained for three years by the CCO. The Transmission Function shall not provide advance information

to the Wholesale Merchant Function, Energy Affiliates, or any other transmission customer regarding a general transmission system expansion project because that would not be transaction-specific and such information would give the Wholesale Merchant Function or Energy Affiliate an undue competitive advantage. A notice of availability for final transmission service study reports and draft interim reports must be posted on the Public Internet for all transmission service requests so that all customers are treated in a comparable and non-discriminatory manner.

(5) Once a valid transmission request has been made, the Transmission Function may have transmission interconnection request **scoping or capacity expansion or new development meetings** pursuant to FERC Order No. 2003 and the Joint OATT. In accordance with FERC Order No. 2003 (Large Generation Interconnection Procedures), the Transmission Function must also post notice of a scoping meeting with their Wholesale Merchant Function or Energy Affiliates on the Public Internet. A notice of availability of final interconnection study reports and draft interim reports must be posted on the Public Internet for all interconnection customers so all customers are treated in a comparable and non-discriminatory manner.

(6) Pursuant to the Network Integration Transmission Service and Network Operating Agreement provisions of the Xcel Energy OATT, the Transmission Function may conduct periodic **data collection processes** (generation, loads and demand-side management) to collect information from transmission customers, including the Wholesale Merchant Function or Energy Affiliates, regarding point-to-point or network resources and load and the need for potential expansion of the transmission network. The Transmission Function shall use comparable information gathering methods for all transmission customers. The Wholesale Merchant Function may have a representative on the Network Operating Committee. The Transmission Function may disclose transmission expansion projects and plans to the Wholesale Merchant Function, Energy Affiliates and other Network Operating Committee members only if the information is contemporaneously posted on the Public Internet or communicated at a public open meeting.

(7) The Transmission Function may communicate without documentation with affiliated Wholesale Merchant Function employees regarding **procedural** matters for obtaining transmission service, such as study procedures, transmission service request procedures and interconnection procedure schedules. Such communications shall occur in the same manner as similar communications with non-affiliates. However, no substantive discussion regarding transmission information shall be held with Wholesale Merchant Function employees as described above unless documented, forwarded to the CCO, and retained for three years.

(8) The Transmission Function may communicate third party transmission customer information to the affiliated Wholesale Merchant Function or Energy Affiliate employees, or any other transmission customer, if the **third party transmission customer has consented** in writing and the consent and disclaimer are posted on the Public Internet. Such consents should be obtained from (a) wholesale customers purchasing capacity and/or energy from the Wholesale Merchant Function and where the Wholesale Merchant Function is obtaining transmission services for the benefit of the wholesale customer, and (b) any entity proposing to enter into a purchased power agreement (PPA) and interconnecting a new generator to the transmission system of an Xcel Energy Operating Company. The written consent must be noted on the Public Internet and retained for the duration of its effective period. Also, the COO shall retain the written consent for at least three years after the consent expires.

(9) The Transmission Function and affiliated Wholesale Merchant Function may communicate in an **emergency situation** declared pursuant to Sections 13.6.1 and 33.7 of the Xcel Energy OATT. However, the communications must be disclosed on the Public Internet as promptly as possible (not more than 24 hours) and provide a report to FERC (and the Department of Energy and any state commissions, if required) within 24 hours of the emergency declaration.

(10) Information necessary to **maintain the operations** of the transmission system.

'No-Conduit' Provisions for Other Affected Employees:

The "No Conduit" rule states that an Affected Employee not working in the Transmission Function of the Xcel Energy Operating Companies (or Service Company or their agents) may not provide non-public transmission information to Wholesale Merchant Function or Energy Affiliate employees if the Transmission Function could not provide that same information directly.

The "No Conduit" rule applies to the transmission information defined in the **Prohibited Communications** section above.

Affected employees subject to the "No Conduit" rule include shared and support employees and any other employee, contractor, or consultant who has or may have access to non-public transmission information.

1) Shared employees provide services to both the Transmission Function and Wholesale Merchant Function and/or Energy Affiliates. Shared employees are mostly found in the following business units or organizations:

   - Senior officers
   - Energy Supply
   - General Counsel
   - Corporate Financial Operations
   - Governmental and Regulatory Affairs
   - Human Resources
   - Business Systems
   - Audit Services
   - Corporate Communications
   - Nuclear Management Company

2) Support employees provide services to either the Transmission Function or Wholesale Merchant Function/Energy Affiliates as well as to other operations not defined as Transmission Function or Wholesale Merchant Function/Energy Affiliates

An example of compliance with the "No Conduit Rule":

Xcel Energy Inc. senior officers established a Project Review Council to review and approve generation, transmission, distribution and other capital investments in excess of $5.0 million for any

Xcel Energy Transmission Provider for purposes of corporate governance. The Project Review process is supported by the Chief Financial Officer business unit. The Project Review process shall be conducted in a manner such that senior officers and CFO personnel do not act as a conduit of non-public transmission information to Wholesale Merchant Function or Energy Affiliate employees. All documents related to Project Review approval of transmission capital projects shall include the caption "Contains Non-Public Transmission Information -- Do Not Share with Wholesale Merchant Function or Energy Affiliate Personnel."

If you have questions about these Communications Guidelines or their application:

Please contact the CCO at SOCChiefComplianceOfficer@xcelenergy.com

Xcel Energy
FERC Standards of Conduct -- Meeting Guidelines

Purpose: These SOC Meeting Guidelines should be and reviewed by participants at the beginning of all meetings involving both Xcel Energy Transmission Function (TF) and Wholesale Merchant Function (WMF) or Energy Affiliate (EA) employees.

Introduction

Xcel Energy Inc. and its subsidiaries are committed to full compliance with all laws and regulations, including FERC Order No. 2004, the rules establishing Standards of Conduct (SOC) for electric and natural gas Transmission Providers. Compliance with the FERC SOC rules is a requirement of the Xcel Energy employee Code of Conduct.

Among other things, the SOC rules prohibit preferential or special access to non-public transmission information by WMF and/or EA employees that may provide the WMF or EAs a competitive advantage. FERC is concerned that internal meetings provide an opportunity for possible preferential disclosure of non-public transmission information. These guidelines are designed to avoid such disclosures and help assure SOC compliance at Xcel Energy.

Meeting Guidelines

The following guidelines will help you comply with the SOC rules during meetings:

- **Prepare** a written agenda and then follow it. Include review of these SOC Guidelines on your agenda.
- **Invite** an SOC compliance liaison to attend the meeting to provide guidance on SOC issues if they arise.
- **Prepare** written meeting minutes, including a list of meeting attendees. If WMF or TF employees leave the meeting (to comply with the SOC), note that in the minutes. Forward a copy of the minutes to SOCChiefComplianceOfficer@xcelenergy.com after the meeting.
- **Review** the list of types of non-public transmission information below.
- **Do not** discuss non-public market sensitive transmission information.

Important: If a TF employee discloses non-public transmission information during the meeting, **contact the SOC CCO immediately** so the information can be contemporaneously posted on the applicable Xcel Energy OASIS.

Sensitive Transmission Information That Should Not Be Discussed

Examples of market sensitive transmission information include but are not limited to:

- Transmission flows
- Transmission equipment status
- Transmission system modeling
- Transmission operating procedures
- Available transfer capability (ATC)
- Transmission maintenance activity
- Scheduled transmission outages
- Curtailments of transmission service
- Potential low cost generation sites based on transmission data
- Planned or potential transmission system expansions, upgrades, retirements, replacement, etc.
- Potential transmission services, facilities or expansion, prior to a formal WMF/EA request on OASIS
- Requests for new or expanded transmission services prior to a formal WMF/EA request on OASIS
- Information about or from a third party or potential transmission customer unless the other party consents in writing and consent information is posted on OASIS

No Conduit Rule

In addition to prohibiting direct disclosures between the TF and WMF/EA employees, the SOC rules prohibit other Xcel Energy employees from acting as a "conduit" of non-public transmission information. If you attend a meeting with TF employees where non-public transmission information is discussed, you may not share that information with WFM or EA employees.

If You Need More Information

If you have questions about the FERC SOC rules, please review the Xcel Energy SOC Compliance Guidelines at http://xpressnet/FERCORder2004/align_and_comliance/FERC_Guidelines/guidelines.html or contact the SOC CCO at SOCChiefComplianceOfficer@xcelenergy.com].

Commitment 22

The Web Based SCADA Information Memo
contains highly confidential information and has been filed under seal

Commitment 23

Commitment Item 23

See Response - Commitment Item 22

Commitment 24

Commitment Item 24

See Response – Commitment Item 3

Commitment 25

Commitment Item 25

PUC Report to be submitted on June 15, 2006

Commitment 26

February 18, 2006 Event Commitment No. 26

Prepare and present an updated report of the interruptible load program every 6-months to Energy Markets and Transmission Operations.

Findings of the Investigation:

It was determined that the procedures for implementing a capacity interruption for the Interruptible Service Option Credit customers were confusing and time consuming. Some operators were unfamiliar with the ISOC group names.

Actions taken:

The procedures for implementing an ISOC interruption were reviewed, and revised. Copies were sent to Energy Markets and Transmission Operations in May. Sections were added to provide background information, and how the systems operate. Training on the new Cannon interruption system has been scheduled for early June 2006. ISOC Group names in Envoy have been revised and simplified, and operators have received training. A new interruption system (Cannon) is being implemented. The Cannon System will replace the Envoy and Moscad systems and will make it easier and faster to issue an ISOC interruption.

Date Implemented:

Revised ISOC Interruption procedures were completed on May 1, 2006. Training for Load Management Analysts was completed on March 10, 2006. The Cannon Interruption system is scheduled for partial implementation in mid June 2006. Full implementation of the Cannon System is set for 12/31/06. Transmission Operations and Energy Markets personnel will receive additional Cannon System and ISOC training in early June 2006.

Commitment 26

The ISOC Interruption Procedures
contain highly confidential information and have been filed under seal

Commitment 27

February 18, 2006 Event Commitment No. 27

Complete root cause analysis for the Company's failure to interrupt ISOC customers properly on February 18, 2006.

Findings of the Investigation:

Transmission Operations failed to follow established procedures for interrupting ISOC customers. Lack of familiarity and training of the ISOC/Envoy group designations resulted in some of the less than 10-minute and all of the 1 hour notice option ISOC groups not receiving notification of the interruption on 2/18/06. Rocky Mountain Steel Mills (RMSM) was notified of a Capacity Interruption at 6:39 a.m. on 2/18/06 and shut down its entire interruptible load within 10 minutes of notification, as required. The Company permitted RMSM to restart its Ladle Refining Furnace (LRF) approximately forty minutes (7:31 a.m.) after it was initially shut down when it appeared that the approximately 10 MW load associated with the LRF would no longer be needed. However, due to confusion on the part of Company personnel regarding the Company's right to re-interrupt the LRF if necessary, the LRF was not re-interrupted when conditions changed after 8:00 a.m. and it became apparent that a controlled outage would have to be initiated. See "Root Cause Analysis Loss of ISOC Interruptible Load on 2/18/06" for a full explanation of the Company's actions with respect to RMSM.

Actions taken:

The procedures for implementing an ISOC interruption, including those applicable to RMSM, were reviewed and revised. Copies were sent to Energy Markets and Transmission Operations in May. Sections were added to provide background information, and how the systems operate. Training on the new Cannon interruption system has been scheduled for June 2006. ISOC Group names in Envoy have been revised and simplified, and operators have received training. A new interruption system (Cannon) is being implemented. The Cannon System will replace the Envoy and Moscad systems and will make it easier and faster to issue an ISOC interruption.

Date Implemented:

ISOC Interruption procedure revisions were completed on May 1, 2006. Training for Load Management Analysts was completed on March 10, 2006. The Cannon Interruption system is scheduled for partial implementation in June 2006. Full implementation of the Cannon System is set for 12/31/06. Transmission Operations and Energy Markets personnel will receive additional Cannon System and ISOC training in June 2006.

Commitment 27

Loss of ISOC Interruptible Load Root Cause Analysis
contains highly confidential information and has been filed under seal

Commitment 27

Summary of ISOC Interruptible Load Relief Schedule
contains highly confidential information and has been filed under seal

Commitment 27A

February 18, 2006 Event Commitment No. 27A

Complete root cause analysis for the customers who failed to interrupt on February 18, 2006.

Findings of the Investigation:

Transmission Operations failed to follow established procedures for interrupting some ISOC customers. Lack of familiarity and training of the ISOC/Envoy group designations resulted in the less than 10-minute and 1 hour notice option ISOC groups not receiving notification of the interruption on 2/18/06. Two less than 10-minute notice option customers failed to interrupt load on 2/18/06. Follow-up investigation showed that the customer's equipment failed to operate and remove their load from the system. See "Root Cause Analysis Loss of ISOC Interruptible Load on 2/18/06" for a full explanation of those customers who failed to interrupt. Xcel Energy successfully interrupted over 85% of the available interruptible load from ISOC customers on 2/18/06.

Actions taken:

The procedures for implementing an ISOC interruption were reviewed, and revised. Copies were sent to Energy Markets and Transmission Operations in May. Sections were added to provide background information, and how the systems operate. The two less than 10 minute notice option customers who violated the 2/18/06 interruption have repaired their equipment and it has subsequently been verified and tested fine. Training on the new Cannon interruption system has been scheduled for June 2006. ISOC Group names in Envoy have been revised and simplified, and operators have received training. A new interruption system (Cannon) is being implemented. The Cannon System will replace the Envoy and Moscad systems and will make it easier and faster to issue an ISOC interruption.

Date Implemented:

ISOC Interruption procedure revisions were completed on May 1, 2006. Training for Load Management Analysts was completed on March 10, 2006. Customer equipment was verified and tested in April 2006. The Cannon Interruption system is scheduled for partial implementation in June 2006. Full implementation of the Cannon System is set for 12/31/06. Transmission Operations and Energy Markets personnel will receive additional Cannon System and ISOC training in June 2006.

Commitment 27B

February 18, 2006 Event Commitment No. 27B

Complete implementation of the Cannon Interruption System for ISOC customers by 12/31/06.

Findings of the Investigation:

The current systems used to interrupt and notify ISOC customers are cumbersome.

Actions taken:

A new interruption and notification system (Cannon) is being implemented. The Cannon System will replace the Envoy and Moscad Systems and will make it easier and faster to issue an ISOC interruption.

Date Implemented:

The Cannon Interruption system is scheduled for partial implementation in mid June 2006. Full implementation of the Cannon System is set for 12/31/06. Transmission Operations and Energy Markets personnel will receive additional Cannon System and ISOC training in June 2006.

Commitment 27C

February 18, 2006 Event Commitment No. 27C

Examine the value of including a voluntary load reduction process for large commercial and industrial customers as part of overall alert notifications.

Findings of the Investigation:

In view of the 2/18 events, the Company reviewed the possibility of enhancing the public notices for voluntary load reduction with a more direct request process with large commercial and industrial accounts to cut back on their electric usage as well. It was decided that an automated phone system could be utilized to contact up to 200 of our large customers in just a few minutes. The possible voluntary load reduction would be an asset in reducing load faster in emergency situations.

Actions taken:

The company had several departments review the voluntary reduction issue and a process is now being established. The amount of load that could be impacted would depend on time of day, weather, and day of the week but we would expect that 100 to 200 large customers could participate. We are investigating two possible phone software systems in the process.

Date Implemented:

The process will be documented by May 26, 2006. The process will require contacts with all participating customers, set up of the phone system and scripts to contact the customers, and internal notification steps to be finalized. Implementation of the process is expected to be June 30, 2006.

Commitment 27C

Large Commercial and Industrial Customer
Voluntary Load Reduction Process
contains highly confidential information and has been filed under seal

Commitment 28

Commitment Item 28

See Response – Commitment Item 1

Commitment 29

February 18, 2006 Event Commitment Log No. 29

Develop operating protocols during elevated operations: Purchase Power will examine contracts and operating procedures to ensure each IPP contract meets our expectations regarding Electric Dispatch and Control Area Instructions.

Findings of the Investigation:

Given the explanation below of contract requirements, IPPs are required to promptly comply with Electric Dispatch and control area instructions at all times, including during Emergencies and elevated/unusual weather conditions.

Actions taken:

Each contract was examined to ensure appropriate language is included that requires each IPP to comply with dispatch and control area instructions. Depending on the age of the contract, the IPP and/or the applicable interconnection contracts allow the Company to take appropriate action in the event of an emergency including directing the IPP to increase or decrease power production. In addition, depending on the age of the contract, a IPP contract will require the IPP to staff, control, and operate the Facility consistent at all times with the contract's Operating Procedures and that PSCo's SCC (Electric Dispatch) operator shall have the right to determine the dispatch control of the Facility including start-ups, shutdowns and generation loading levels associated with Contract Capacity and Contract Energy.

Depending on the age of the contract, the IPP contracts include one or more of the following clauses that require IPPs in part to (i) represent that the facility (including the Electrical Interconnection Facility and Fuel Interconnection Facility) has been designed and constructed, and has been and will be maintained by the IPP in accordance with "Good Utility Practice"; (ii) those portions of the Facility that directly affect Buyer's electrical system shall be operated and maintained in accordance with Buyer's reasonable requirements, applicable rules of the CPUC or the FERC, and the Agreement for Interconnection Service; (iii) operate the Facility in a manner that complies with all national and regional reliability standards, including standards set by WSCC, NERC, FERC, and the CPUC, and (iv) the extent the IPP contributes in whole or in part to actions which result in monetary penalties being assessed to PSCo by WSCC, NERC, or any successor agency, for lack of compliance with reliability standards, the IPP is obligated to reimburse PSCo for its share of such penalties.

In certain contracts, PSCo agrees it shall make reasonable efforts to provide the IPP at least twenty-four (24) hours advance notice of the Facility's generation levels. However, this is subject to and may be pre-empted by real-time operating conditions on PSCo's electric system such as, but not limited to, Emergency, reliability, stability and economic conditions.

Date Implemented:

This review was completed on or about April 26, 2006.

Commitment 30

February 18, 2007 Event Commitment Log No. 30

Investigate changing normal protocols for unusual weather: Purchase Power will examine contracts and operating procedures to ensure each IPP contract meets our expectations regarding Electric Dispatch and Control Area Instructions.

Findings of the Investigation:

Given the explanation below of contract requirements, IPPs are required to promptly comply with Electric Dispatch and control area instructions at all times, including during Emergencies and elevated/unusual weather conditions.

Actions taken:

Each contract was examined to ensure appropriate language is included that requires each IPP to comply with dispatch and control area instructions. Depending on the age of the contract, the IPP and/or the applicable interconnection contracts allow the Company to take appropriate action in the event of an emergency including directing the IPP to increase or decrease power production. In addition, depending on the age of the contract, a IPP contract will require the IPP to staff, control, and operate the Facility consistent at all times with the contract's Operating Procedures and that PSCo's SCC (Electric Dispatch) operator shall have the right to determine the dispatch control of the Facility including start-ups, shutdowns and generation loading levels associated with Contract Capacity and Contract Energy.

Depending on the age of the contract, the IPP contracts include one or more of the following clauses that require IPPs in part to (i) represent that the facility (including the Electrical Interconnection Facility and Fuel Interconnection Facility) has been designed and constructed, and has been and will be maintained by the IPP in accordance with "Good Utility Practice"; (ii) those portions of the Facility that directly affect Buyer's electrical system shall be operated and maintained in accordance with Buyer's reasonable requirements, applicable rules of the CPUC or the FERC, and the Agreement for Interconnection Service; (iii) operate the Facility in a manner that complies with all national and regional reliability standards, including standards set by WSCC, NERC, FERC, and the CPUC, and (iv) the extent the IPP contributes in whole or in part to actions which result in monetary penalties being assessed to PSCo by WSCC, NERC, or any successor agency, for lack of compliance with reliability standards, the IPP is obligated to reimburse PSCo for its share of such penalties.

In certain contracts, PSCo agrees it shall make reasonable efforts to provide the IPP at least twenty-four (24) hours advance notice of the Facility's generation levels. However, this is subject to and may be pre-empted by real-time operating conditions on PSCo's electric system such as, but not limited to, Emergency, reliability, stability and economic conditions.

Date Implemented:

This review was completed on or about April 26, 2006.

Commitment 31

February 18, 2006 Event Commitment Log No. 31

Investigate how to align and integrate various operations to deal with unusual weather: John Welch, Tim Carter and Jeff Klein will discuss whether any internal or external changes they may propose will affect Purchase Power and its suppliers and whether any contract or department changes are also required. Verbally verifying with each IPP that it is prepared for an unusual demand event may be required.

Findings of the Investigation:

Purchased Power representatives have been added to Operations' list of persons to be notified of "tight conditions".

Operations agreed that both departments will coordinate providing communications to the IPPs to ensure the IPPs are prepared for unusual forecasted weather and upcoming seasonal conditions.

Actions taken:

Tim Carter (Gas Supply), Jeff Pavlovik and Jeff Haskins (RT Operations) and representatives of Purchased Power met and discussed potential procedural and operational changes they may implement.

RT Operations is preparing an updated emergency operating procedure. Purchase Power suggested certain additions to their communication processes so that PP management was included in notices of elevated conditions. We have asked Operations to keep us apprised of potential procedural and operational changes so that Purchased Power may advise Operations if IPP contract amendments would be required to implement the proposed changes. Purchased Power has reviewed all of Operations' proposed updated emergency operating procedures; so far these procedures will not require modifications to the IPP contracts.

Gas Supply will work with Operations to prepare and implement a greater fuel oil testing schedule (Blue Spruce).

Date Implemented:

This review was completed on or about April 26, 2006.

Commitment 32

February 18, 2006 Event Commitment Log No. 32

Investigate power plant failure causes: See Separate spreadsheet:

Findings of the Investigation:

IPP implementation plans are complete and addressed on a separate spreadsheet that was developed and which outlines the corrective actions taken by the IPPs.

Actions taken:

Purchased Power surveyed the various IPPs and obtained information in regard to the corrective actions taken by the IPPs.

Date Implemented:

This review was completed on or about April 26, 2006.

Commitment 32

Power Plant Failure Analysis
contains highly confidential information and has been filed under seal

Commitment 32

TCP Gas Supply and Operations Letter
contains highly confidential information and has been filed under seal

Commitment 33

February 18, 2006 Event Commitment Log No. 33

Study how to improve communications: We will examine whether Electric Dispatch or the IPPs believe there were any communication problems identified as a result of the Feb 18th event. We will examine whether communication protocols, if any, between Electric Dispatch and Purchase Power need to be changed.

Findings of the Investigation:

The IPPs believed that communications provided by PSCo were good during the subject weekend. Purchase Power does not believe there is a need to provide any recommendations in response to this action item.

Actions taken:

Purchased Power surveyed various IPPs and asked them whether the communications on Feb 18 between each company demonstrated a need for improvement. The IPPs believed that communications provided by PSCo were good during the subject weekend. Operationally, some IPPs requested advance notice of unusual weather events and communication of the status of the PSCo system.

Date Implemented:

This review was completed on or about April 26, 2006.

Commitment 34

February 18, 2006 Event Commitment No. 34

Description of the commitment:

Develop Operating Protocols During Elevated Operations

Findings of the Investigation:

In reviewing the existing Operating Protocols it was determined that it would be beneficial to modify the procedures to enhance the coordination between various groups.

Actions taken:

The Transmission Operations Emergency Plan attached to this Commitment. It was revised to codify the procedures relating to communication and coordination during elevated operations.

Date Implemented:

The procedures were completed on May 3, 2006

Commitment 34

Emergency Operations Plan
contains highly confidential information and has been filed under seal

Commitment 35

February 18, 2006 Event Commitment No. 35

Description of the commitment:

Enhance the Energy Management System (EMS) Load Shed program.

Findings of the Investigation:

The existing EMS load shed program contains 36 load blocks. During the February 18^{th}, 2006 capacity deficiency Transmission Operations utilized all 36-load blocks (approximately 12 blocks rotated every 30 minutes). It was determined that additional load blocks are necessary to avoid having to shed the same customers if the load relief problem continued.

Actions taken:

Additional feeders have been identified for inclusion into the existing load shed program expanding the program by a factor of three. A formal request to PSCo's EMS team to implement this enhancement has been requested. The EMS team has estimated this enhancement at 120 programming man-hours. We expect the enhancement to be completed by September 15, 2006.

This item is related to Commitment #5. IBM ticket to implement is Mercury 483747

Date implemented:

The procedures were completed on May 10, 2006.

Commitment 35

XDM - Application Change Request
contains highly confidential information and has been filed under seal

Commitment 36

February 18, 2006 Event Commitment No. 36

Description of the commitment:

Enhance Emergency Assistance communication during elevated operations.

Findings of the Investigation:

Upon investigation of the Feb 18^{th} event it was determined that offers of emergency assistance were not internally communicated.

Actions taken:

Transmission Operations has modified the emergency plan per the Standardized Alert Level Definitions (Attached) to allow for enhanced communication during elevated operations by defining the point at which the suspension of FERC 2004 Standards of Conduct is considered to enhance communications between the reliability function and the affiliated marketing function. The enhancement to the emergency plan was coordinated with the newly developed XEM Real Time Emergency Procedures. PSCo Transmission and XEM Real Time have both adopted and defined a new color-coded alert scheme that defines and communicates on common terms the current operating condition for the system.

Date Implemented:

The procedures were completed on May 10, 2006.

Commitment 36

Standardized Alert Level Definition Document
contains highly confidential information and has been filed under seal

Commitment 37

February 18, 2006 Event Commitment No. 37

Description of the commitment:

Establish enhanced communication procedures between Transmission Operations and Gas Load Control during elevated operations.

Findings of the Investigation:

The investigation of the February 18th, 2006 event showed that good communication between Transmission Operations and Gas Load Control was occurring. However, there were no procedures in place that define the need and process for this communication.

Actions taken:

Transmission Operations has modified the emergency plan (See Commitment No. 34) to include the communication requirement between Gas Dispatch and Transmission Operations during capacity and energy emergencies. Public Service Company has also adopted an internal color-coded alert level that will quickly convey the urgency of each situation. The appropriate alert level will be communicated to all impacted parties as soon as the emergency condition is known and defined.

Date Implemented:

The procedures were completed on May 17, 2006.

Commitment 38

February 18, 2006 Event Commitment No. 38

Description of the commitment:

Documented communication procedure between PSCo Electric Distribution Dispatch and Transmission Operations.

Findings of the Investigation:

The investigation yielded a deficiency in conveying the current state of the system internally as well as externally to the various media outlets. A procedure is required to insure accurate and timely dissemination of information.

Actions taken:

Transmission Operations has coordinated with various departments to establish guidelines and communication requirements during load shedding events. The attached Load Shed Coordination Procedures defines the required communication between Transmission Operations, Distribution Dispatch and Media Relations. This coordination will ensure accurate timely notification to all internal parties as well as the public through our Media Relations department.

Date Implemented:

The procedures were completed on May 10, 2006.

Commitment 38

Load Shed Coordination Procedures
contain highly confidential information and have been filed under seal

CERTIFICATE OF SERVICE

I hereby certify that on this, the 15th day of June 2006, the original and seven (7) copies of the foregoing **Public Version of Public Service Company of Colorado – Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006 Controlled Outage Event** along with the original and seven (7) copies of the **Highly Confidential Version of Public Service Company of Colorado – Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006 Controlled Outage Event** were served via hand delivery on:

Doug Dean, Director
Colorado Public Utilities Commission
1580 Logan, OL-2
Denver, CO 80203

copies of both the Public Version and Highly Confidential Version of this report were hand delivered addressed as follows:

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