INVESTIGATION OF THE CONTROLLED OUTAGES OF FEBRUARY 18, 2006 BY PUBLIC SERVICE COMPANY OF COLORADO

Docket No. 06I-118EG

INITIAL REPORT TO THE
COLORADO PUBLIC UTILITIES COMMISSION
By the Staff of the Colorado Public Utilities Commission

July 7, 2006

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Executive Summary

At 08:47 on Saturday morning, February 18, 2006 (President's Day weekend), Public Service Company of Colorado (PSCo or the Company), a regulated utility operating company and wholly-owned subsidiary of Xcel Energy, Inc. (Xcel Energy), initiated rolling blackouts due to a power supply shortfall of nearly 400 megawatts on its electric power system.

An upslope cold front had moved into the Front Range Region of Colorado the previous day. The ambient air temperature at Denver International Airport dropped as low as minus 13 degrees Fahrenheit (minus 25 degrees Celsius) Saturday morning, well below the temperature forecast by the Company to predict its natural gas and electric power load requirements. While the Company's electric load at 08:47 Saturday morning was only about 65 percent of its historic peak load, approximately 40 percent of the Company's generating capacity, or close to 3,200 megawatts, was unavailable.

More than 371,000 Colorado electric service customers lost power for an average of more than 41 minutes on one of the coldest days in several years. Losing electric power during this event were more than 323,000 PSCo customers, nearly 39,000 Holy Cross Energy (HCE) customers, more than 6,100 Yampa Valley Electric Association (YVEA) customers, and more than 3,000 Grand Valley Power (GVP) customers. Field equipment failures delayed electric service restoration for more than 20,500 PSCo customers after PSCo halted the rolling blackouts, resulting in some customers being out of service for almost six hours.

Initially, most customers were either unable to contact the Company, or they received inaccurate information through the Interactive Voice Response (IVR) system or from Customer Care representatives. An estimated 240,000 telephone calls were unanswered during this event.

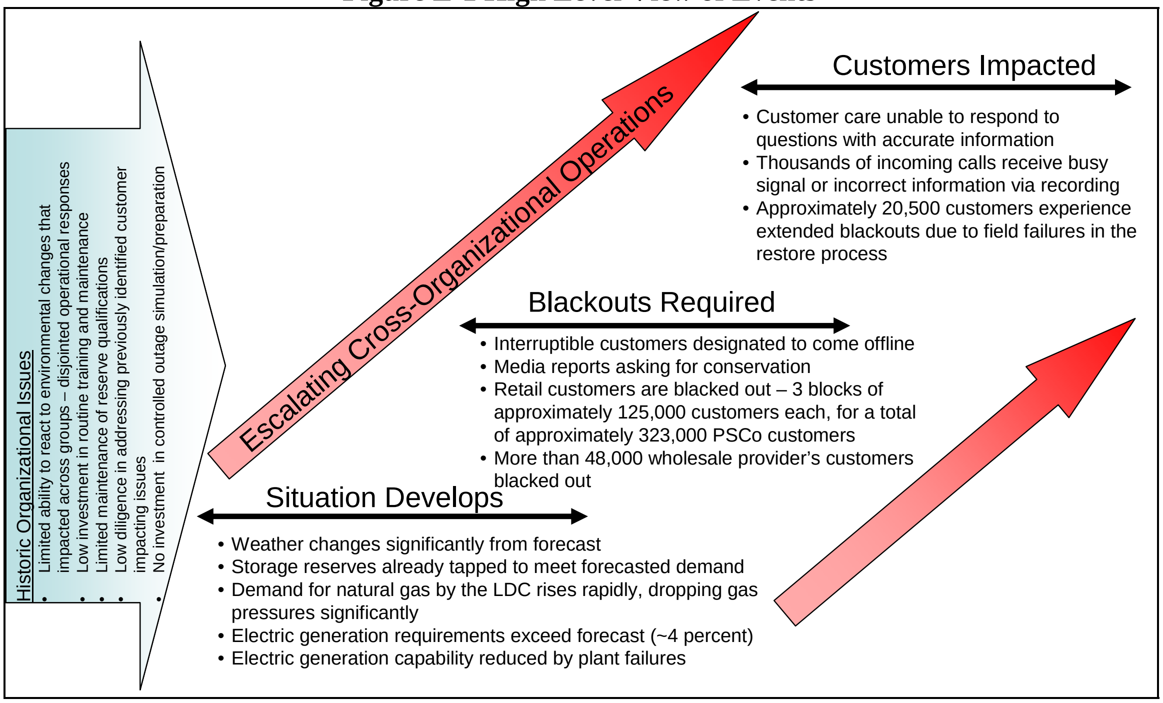
As a result of the blackouts, the Commission directed the Staff to conduct an investigation of the Company's actions on February 17 and 18, 2006. This report provides detailed results of this investigation, including specific concerns and recommendations for improvements. This executive summary provides an overview of the events, findings that summarize global problems observed by the investigative team, specific essential areas for the Commission to consider ordering the Company to address quickly, and finally a summary of recommendations for both the Company and the Commission regarding next steps. Also, this executive summary provides a response to the Company's preliminary report to the Commission and its "Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006 Controlled Outage Event" dated June 15, 2006 (Commitment Log Report).

In addition to the critical and summary recommendations to the Commission and the Company contained in this section, this report contains specific recommendations within each individual section that require detailed attention from the Company. The investigative team believes that addressing all these recommendations is critical to ensuring system reliability in Colorado going forward.

Summary Timeline

For the purposes of this report, the following diagram provides a high level overview of events that contributed to the rolling blackouts of February 18, 2006. Detailed event timelines can be found in individual sections of the full report.

Figure E-1 High Level View of Events



Investigative Team Findings

The following five findings summarize the results of this investigation. Specific details regarding the actions of various departments of the Company that were involved in the event are provided in later sections of this report.

The Company has not adequately addressed the impact of the growing interdependency of the natural gas system and the electric generation system and their related operational and marketing arms within the Company.

During the event of February 18, individual Company departments responded fairly well to manage their specific responsibilities. For example, Gas Control was able to keep the local natural gas distribution company (LDC) intact, and Real-Time Dispatch was able to bring the electric plants in line with their natural gas nominations by Friday evening. However, the two departments did not have a full appreciation of how their independent actions were impacting each other, and the integrity of the system as a whole. Additionally, Xcel Energy has, in the last year, returned to a hybrid operating company structure, with its PSCo operating company functioning to serve the Colorado region. Within PSCo, oversight and responsibility for operational integrity across the gas and electric business units does not appear to be centralized at an executive level.

Within the body of this report, information regarding communication between these departments and actions taken by individual Company organizations is highlighted and explained, particularly in Sections 4 through 6 although virtually every section contains issues relative to this finding.

From a management level, the Company had difficulty responding to the developing situation because of systemic internal communication problems.

As acknowledged in the Company's Initial Report and Commitment Log Report, this investigative team discovered that there are systemic communication problems that need to be addressed at the PSCo corporate level with support from Xcel Energy. These types of issues are not the fault of any particular individual or group, rather they are indicative of the need to reassess communication patterns and organizational structure across the Company to determine how and when communication takes place both routinely and during elevated operations. They are also indicative of a need for strong senior management engagement. This investigative team discovered similar issues with how individual groups communicated with each other, and with a lack of senior management engagement to create a coordinated response. Organizationally, there does not appear to be an "owner" at an executive level within PSCo who is accountable for cross-organizational operations.

Changing this type of environment requires more than a technology deployment, a process document, or a memo. It requires time and effort across all levels of the organization, including top management, to change patterns, habits and expectations of communication and information sharing. It requires practice in particular of how to respond during elevated operations. This requirement for ongoing training and awareness is highlighted in more detail in the next finding.

In the interim since the event, the Company has addressed several of these issues. However, work is still required to ensure that changes are fully implemented, that unresolved items are addressed and that the changes are completely adopted. Communication issues are specifically addressed in Section 2: Customer Communication and Media Relations and Section 10: Internal Communication and Organization. This finding is evident in essentially every section of this report, and is reflected in many of the specific recommendations.

The Company must have a stronger management commitment to training, documentation, controlled outage preparation, and plant maintenance.

This event highlighted the need for PSCo to revisit its training, documentation, preparation, and maintenance in key areas. Within the Company there is a dependency on institutional knowledge that is both at risk through natural attrition and in some instances dated. In other words, people are continuing to function as they traditionally have, even though the environment has changed. Creating new documentation, refreshing existing documentation, providing training on certain procedures, and building new institutional knowledge of appropriate emergency responses during controlled outages will help to address both the ability of the Company to respond to dynamically changing circumstance and the dependency on the historical knowledge of the current staff.

While the Commitment Log Report of June 15, 2006 addresses many of these points, long-term change and diligence is necessary to ensure that practices are institutionalized, maintained and fully adopted. This includes regular execution of mock emergency exercises, simulation training for key areas to develop capabilities to quickly and creatively respond to dynamic conditions and routine review of both cold and hot weather procedures and processes. This is particularly addressed in Section 4: Gas Supply and Gas Control, Section 7: Electric Production and Section 9: Interruption of Firm Electric Load. This finding is discussed in each of the other sections as well.

The Company is not able to produce a continuous, dynamic analysis of the ongoing, ever changing environment within which the Company's gas supply and electric generation systems are called upon to deliver the firm energy supply to its customers in Colorado.
The ways in which weather and load forecasts for gas and electric are developed, applied and maintained over a period of actionable time, and the ways in which all available options are considered relative to reserve margins, online resources, and expected availability of plants and gas supply need to be reevaluated. New processes, standards, and support capabilities need to be implemented.

This interdependency requires that some area of the organization maintain a broad understanding of how and when natural gas fueled electric generation plants can be dispatched, the available fuel options for plants to generate power, the capacity retrievable by interrupting various groups of customers, how reserves are managed, and other key data points that provide a consistent view of the delivery system as a whole, rather than as two distinct functions of gas supply and electric generation. This broad finding is supported by some of the individual department commitments presented in the Company's Commitment Log Report, however, the Commitment Log Report does not go far enough to address all the issues raised in this Report. For example, redesigning the reserve margin calculations used by Gas Supply and Gas Control to ensure consistency is an important step, however, single department solutions must be integrated across the Company to fully address the needs of an integrated company. This issue is specifically addressed in Section 4: Gas Supply and Gas Control, and is supported by additional issues highlighted in Section 5: Electric Transmission System Operations, and Section 6: Energy Trading and Real-Time Dispatch.

Past issues regarding the need to invest in customer care improvements have not been adequately addressed.
In 2004, Staff investigated issues around PSCo outage customer communications. Some of the problems identified in that study are similar to the ones highlighted by this event in 2006. It appears that two years after committing to address issues with the functioning of its Outage Management System (OMS) and Customer Care support systems, PSCo cannot provide rapid and accurate information to customers regarding outage situations. Similar to 2004, the Company has identified specific remedies in its June 15 response. However, given the history of solving specific problems without fully addressing the need for PSCo to provide exceptional customer care to utility customers, the Company's response is deficient in this area. For example, fixing the OMS issues identified by this event is an important step, however, reevaluating the system as a whole and determining if it can in fact deliver the service PSCo customers deserve is a larger effort that is not identified in the Company's response.

This finding is addressed specifically in Section 1: Customer Communications and Media Relations, of the body of this report.

Recommendations to the Commission Requiring Immediate Action

The investigative team recognizes that the issues contributing to this crisis are complex. It is vital to address the specific recommendations in this report to prevent a similar event from occurring. The recommendations provided in this report are fair and reasonable steps for the Company to take to address the problems identified.

There are four recommendations that need to be addressed by the Company quickly and effectively. Staff requests that the Commission require the Company to respond to the first three of these four recommendations within fourteen days. Failure to quickly address these issues identified will likely result in similar occurrences when the PSCo system is stressed by unplanned events. In addition, Staff requests that the Commission require the Company to respond to the last recommendation by no later than August 11, 2006.

1. Staff recommends that the Commission order the Company to respond to identified discrepancies in the emergency escalation plans recently developed and documented in the Commitment Log Report by various Company organizations.
2. Staff recommends that the Commission order the Company to identify and implement short-term (or interim) solutions for the following in addition to longer term solutions identified in the Commitment Log Report and in addition that detailed in the fourth recommendation below:
    - Accurate and timely customer communications.
    - Making gas supply adjustments during off-hours (for example, nights, weekends and holidays) and summer as well as winter peaks.
    - Emergency intra-hour power purchasing processes.
    - Timely communication between Dispatch and Transmission for maintaining system integrity and control.
3. Staff recommends that the Commission order the Company to provide a plan to conduct an overall assessment of the Customer Care supporting systems and processes to ensure that it is adequate to manage industry recognized emergency events.
4. Staff recommends that the Commission order the Company to address each of the specific recommendations made in individual sections of this Report. The Company should provide action plans identifying how and when the recommendations will be addressed, and who in the Company has executive level accountability for ensuring completion and cross-organizational synchronization. For reference, the recommendations contained in the individual sections can be categorized into the following summary actions:
    - Review load forecasting creation and application processes to understand ways in which it must be reconstructed to better account for intra-day changes in temperature, demand, and supply. Develop a dynamic control model approach to incorporate current and expected future environmental variables in an on-going manner across the gas supply and electric generation systems.
    - Develop a corporate response team approach to corporate-wide emergencies that involve multiple Company departments. Create a process whereby a single “owner” or point of contact is quickly identified and is accountable to organize the cross-organizational management response team, driving the response, and to disassemble the response team when appropriate.
    - Incorporate emergency preparedness training relative to controlled outages into the annual training and compliance requirements for all Company staff, as appropriate for their roles and responsibilities. Investigate and implement additional ways to maintain preparedness throughout the organization, including simulations, documentation, and cross-organizational training.
    - Work with industry participants to better define the role of the reliability center, and to establish procedures for engaging the center in emergency management and situation analysis.
    - Across the Company, assess the processes and preparation for managing controlled outages, and other emergency situations, establish and execute cross organizational emergency preparation training.

- Conduct an overall reassessment of system reliability assumptions and validate backup options and resources. This should also include a review of the ways in which reserves are calculated and understood across the Company.
- Review the Company's organizational structure to determine how to integrate an executive level operational manager. This person would be for responsible for maintaining an understanding of cross-system load, supply, reserve margin, options for mitigating shortages and leveraging excess, and balancing across the gas and electric businesses. This operational executive should have accountability for ensuring cross-organizational communication, coordination, and collaboration to provide for system reliability of both gas and electric operations.

Long-Term Recommendations

Within this report, many recommendations will require long-term commitment from the Company. While it is expected that the Company will provide action plans to address these recommendations by August 11, 2006, the implementation of the plans is critical to successfully preventing similar events. To ensure success once the plans are developed, the Commission should require the Company to provide periodic updates on its progress in implementing action plans. The first of these periodic updates should be provided no later than December 15, 2006.

Recognizing that many of the efforts undertaken internally in response to this event will require time and commitment to complete, Staff recommends that by December 15, 2006, PSCo provide to the Commission an independent management and operations review to verify that corporate policies, executive alignment, inter-departmental communication patterns, emergency response changes, long term training plans, and full system analysis capabilities have been established to address the key issues highlighted in this report.

Staff Response to Company Reports

On March 13, 2006, PSCo released an Initial Report to the Commission outlining its assessment and detailing further actions to take over the ensuing 90 days to respond to the issues. On June 15, 2006, PSCo issued its Commitment Log Report. In reviewing the Commitment Log Report, the investigative team acknowledges that many of the specific issues jointly raised in the interim by both the PSCo task force and the Staff investigative team are being addressed, however, the Commitment Log Report does not clearly identify funding and staff level commitments to ensuring completion and does not address all the concerns that contributed to the rolling blackouts. Staff details its concerns regarding the Commitment Log Report in our recommendations throughout this report.

Additionally, in reviewing the Commitment Log Report, and as a result of conducting an independent analysis, it has become apparent that the Company has not kept current its ability to reconstruct events to allow for robust post-event analysis. This is evidenced by the fact that the investigative staff requested and the Company agreed to provide transcripts from key areas on April 17, 2006. As of this report, not all transcripts have been received. Reconstruction of the gas pipeline pressures and capacities are also still in flux, more than four months after the event. Additionally, tracking of instant messages, e-mail, and mobile phone conversations related to important activities have not been accounted for, although their use has increased over time. Good utility business practices support reviewing trading and operational activities, and conducting rapid assessments and root cause analysis of this type of event. This capability needs to be addressed and fortified, to support both internal Company investigations and reports, and Staff audits and investigations.

Conclusion

It is perhaps easy and convenient to conclude that this situation resulted from a poor weather forecast, or from specific failures within Company departments, or from single plant failure. However, this investigative team concludes that such is an oversimplification of a complex situation. It is likely that controlled outages would have been avoided if any one of several different specific events had not occurred. It is also likely that the event could have been mitigated or avoided entirely had the Company responded to escalating events sooner and more effectively. This event exposed serious problems that will take time and executive commitment to address, as captured in the findings highlighted above.

The aggregation of problems that occurred on February 17 and 18 exposed serious deficiencies in the Company's agility and ability to adapt to rapidly changing conditions across its systems. While individuals in the field performed well within the scope of their departments, there was a lack of top management appreciation for the breadth and severity of the situation as it was developing. Inter-departmental coordination and communication, commitment to ongoing training, preparation and maintenance, and improved ability to respond to a dynamic utility environment are systemic problems that require more than a technology implementation or a documented process to change. The Company needs to make a sustained management commitment of both time and money to embrace a new approach to responding to escalating situations.

The investigative team acknowledges that during the series of significant events starting Friday, February 17 through Saturday, February 18, individuals and departments within PSCo responded to the best of their ability to prevent controlled outages from happening, and once it became a crisis, they managed the situation as well as possible within their areas of control. The issues highlighted here and those highlighted by the Company in its reports are broader than any individual or department, and point to ways the organization as a whole responded, and how that response can be improved. The Company has taken steps in the interim, as explained in its report of June 15, 2006, to address some of these issues. However, the Company's commitments are not well defined, lack clearly identified owners, funding, and timelines, and are not sufficient to fully address all the issues identified in this report. As a result, this report contains additional recommendations for the Company to implement to avoid similar events in the future.

Note Regarding Time Formats, Abbreviations, and Acronyms

Please note that this report uses prevailing Mountain Time (Mountain Standard Time = UTC-07 in winter) in 24-hour format since most PSCo operating departments use this time format. The acronyms and abbreviations used in this report are defined in Appendix 1.

Section 1: Introduction

At 08:47 Saturday morning, February 18, 2006, Public Service Company of Colorado (PSCo or Company), a regional utility operating company of Xcel Energy Inc. (Xcel Energy) initiated rolling blackouts in Colorado, interrupting electric service for more than 371,000 Colorado retail electric customers of four electric utility companies. More than 323,000 PSCo electric customers lost power. More than 75 percent of Holy Cross Energy (HCE) customers lost power, as did more than 25 percent of Yampa Valley Electric Association (YVEA) customers and more than 20 percent of Grand Valley Power (GVP) customers.

The Colorado area was experiencing severely cold air temperatures, starting midday on Friday, February 17. In addition to the low air temperatures, which were not predicted by PSCo's weather forecaster, PSCo experienced difficulty reacting to and adjusting for a series of plant failures from major coal-burning and gas burning electric production plants, electric department over burns due to the operation of less efficient plants, trouble activating plants due to low pressure on the gas lines, an under delivery of gas from upstream suppliers, difficulty executing on a capacity interruption of interruptible customers, and difficulty purchasing spot gas over the holiday weekend.

Also impacting the Company's ability to manage gas supply was a Company decision to draw down storage capacity over the weekend, thereby lowering reserve margins. A decision had been made earlier in the month to draw down storage inventory over this particular weekend. PSCo had been close to exceeding its natural gas storage maximum limits through early February after an unseasonably warm January. Drawing down storage in February was partly an effort to manage this contractual obligation. In its decision making, the Company did not fully account for the impact of drawing down storage in calculating reserve margins for the holiday weekend.

All of these factors were further complicated by PSCo's organizational and communication issues, which prevented the Company from rapidly assessing and responding to the situation as it began developing on Friday, February 17. By the morning of Saturday, February 18, the Company was unable to meet its electric generation commitments and had to shed load through rolling blackouts in the region.

The rolling blackouts were planned such that three groups of approximately 125,000 customers each were interrupted for approximately 30 minutes each. However, additional failures in the system caused restore issues for approximately 20,500 PSCo customers, who were without electric service from periods ranging from one to four hours. In addition to retail customer outages, PSCo interrupted service to most of its retail interruptible electric service customers, and curtailed service to some of its wholesale electric power customers. These interruptions were intended to be initiated in a manner consistent with the tariffs and contracts for the respective customers. Once the controlled outages ensued, additional issues were seen regarding providing information to customers and the media, communication across the organization of the emergency management approach, and restoring service to some customers.

During this time, the demand on the natural gas system had caused gas system pressures to drop to levels that could not support the demands of local firm service to natural gas distribution and transport customers, non-firm service gas transportation customers, and electric plant generation needs. At the same time, approximately 150 local natural gas service customers were interrupted, an issue believed to be concurrent but unrelated to this event. The Company was unable to maintain or provide gas pressures to support starting up several electric generation plants, or to maintain gas operations at key electric generation plants. Additionally, the Company lost two major coal-fueled and one natural gas fueled electric generation plants, and experienced a variety of problems with independent power producers (IPPs) being able to meet demand for electric generation, in part due to the unavailability of gas pressure on the system. Many of these IPP plants are under contract using “tolling arrangements” to receive natural gas from PSCo’s pipelines.

How and when the Company sought alternative sources of both gas and electric resources has been raised as a question around this event. Gas nominations for the holiday weekend were essentially in place by Thursday morning, and confirmed early Friday morning for Gas Day 17 (8:00 Friday – 8:00 Saturday). Many in the industry had left early for the weekend, making it difficult to reach out to possible sources for purchasing additional gas, although attempts were made. Furthermore, while gas may have been available from remote locations, gas can only travel at a maximum of approximately 30 miles per hour through a pipeline, and normal field conditions are typically closer to 10 to 20 miles per hour, making it difficult to move resources from suppliers to PSCo’s local natural gas distribution company (LDC). Absent early action, it is unlikely that additional gas could have arrived in time to mitigate the problem of Gas Days 17 and 18. Had the Company recognized and responded to the escalating situation sooner, it may have been possible to acquire more gas from additional daily spot purchases or by establishing an Operational Flow Order (OFO) that would have sent signals to the industry and the region to respond in ways that may have helped to mitigate the event.

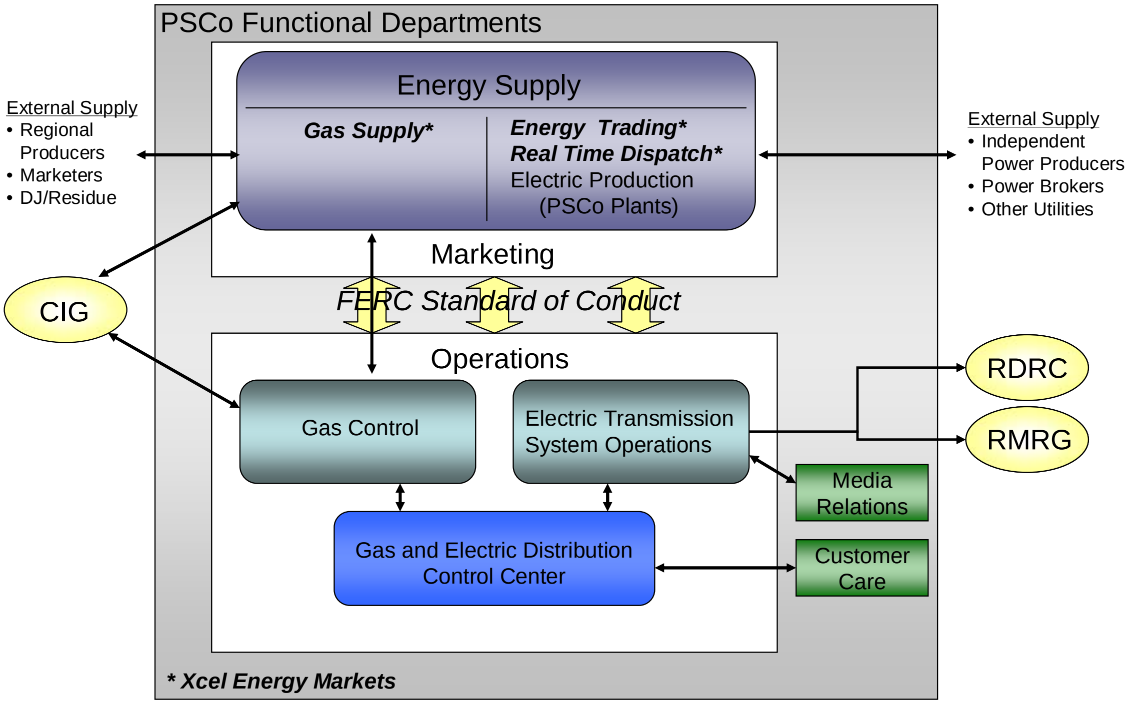
Efforts to purchase additional electricity from both traditional and non-traditional sources were insufficient to prevent outages. This may be attributed in part to the timing of the request by the Company for help from the region, together with a combination of system, process, and communication breakdowns. Once the emergency status was identified and communicated (at approximately 7:00 Saturday), purchases were acquired and transmitted quickly for the subsequent hours (starting at 8:00 on Saturday), preventing a potentially longer and larger outage in the region.

While some outside sources have indicated that there was a willingness to provide gas or electricity into the effected area, routes to key points in the distribution systems for both gas and electric were either unavailable, appeared unavailable, or were constrained by other distribution complexities, as described in more detail later in this report. In some cases, offers of help were simply received too late.

Industry and Company Functional Organization

Throughout this report, there are references to specific departments within PSCo and their functions during this event. The following diagram and discussion is intended to provide a foundation and reference for the functional organization of the environment, to support more detailed discussions later in the report. It is not intended to represent the management and reporting structure of the Company.

Figure 1-1: High Level Organization of Marketing and Operations



This diagram shows six key regional, national and industry bodies, FERC, NERC, WECC, RDRC, RMRG, and CIG. These six entities are briefly described below.

- **FERC**: The Federal Energy Regulatory Commission is the United States government agency that regulates the interstate transmission of natural gas, oil, and electricity. It regulates and oversees the energy industries from an economic, safety, and environmental perspective.
- **NERC**: The North American Electric Reliability Council is a self-regulating electric power utility industry organization that works with all entities involved in the electric power utility industry to ensure reliability, stability, and security of the bulk electric system in North America.
- **WECC**: The Western Electricity Coordinating Council is one of the eight regional electric power reliability councils that compose the NERC. WECC is responsible for promoting electric system reliability and providing a forum for coordinating the operating and planning activities of its 169 member organizations. The members, representing all segments of the electric industry, provide electricity to 71 million people in 14 western states, two Canadian provinces, and portions of one Mexican state.[1]
- **RDRC**: The Rocky Mountain-Desert Southwest Reliability Center is one of the three WECC Reliability Centers that oversee electric system reliability in the Western United States. The Reliability Centers have authority to direct local system operators to take action to ensure the reliability of the grid as a whole.[2]
- **RMRG**: The Rocky Mountain Reserve Group is an industry group whose members voluntarily obligate themselves to maintaining defined levels of reserves, participating in the coordination of reserve sharing and activation, and reserving transmission capacity to support these activities.[3] The primary purpose of the group is to share in the

[1] Business Wire, August 3, 2005.
[2] Business Wire, August 3, 2005.
[3] Bylaws of the Rocky Mountain Reserve Group.

responsibilities of the interconnected system such that emergency conditions can be better met and the overall system can be better maintained.

- **CIG**: The Colorado Interstate Gas division of the El Paso Corporation provides pipelines between most of the major natural gas suppliers and storage areas in the Rocky Mountain region. CIG facilitates the transport of natural gas between entities.

The responsibilities of Company functional areas shown are as follows:[4]

Gas Supply: The Gas Supply department is responsible for purchasing and selling natural gas resources to adequately maintain pressures and meet designated needs (including reserves) for all gas customers. Gas supply is also responsible for supplying alternative fuels (for example, diesel) to PSCo plants.

Gas Control: The Gas Control department is responsible for maintaining the system based on the purchases made by Gas Supply and third-party shippers, and the demands made by customers, including internal PSCo customers (the electric plants). Primary responsibility is to maintain the (LDC).

Energy Trading: The (Electric) Energy Trading department is responsible for the purchase and scheduling of economic energy transactions based on signals from Real-Time Dispatch. This department has limited visibility into operations, to prevent inappropriate buying and selling activities. This department is also responsible for administering third-party contracts with Independent Power Producers (IPPs).

Real-Time Dispatch: The (Electric) Real-Time Dispatch department has primarily responsible for generation control and dispatch for the PSCo electric system on a reliable and economic basis. Plans are based on the forecasted need for capacity, and can be adjusted in near-real-time through purchases or sales of capacity or the dispatch of PSCo-owned or Independent Power Producer (IPP) units. Real-Time Dispatch is responsible for balancing the system, and owns responsibility for the Automatic Generation Control (AGC). Under normal operations, Real-Time Dispatch has limitations on the amount of electric transmission system information available to it based on the FERC Standard of Conduct.

Transmission Operations: The Electric Transmission Operations department is responsible for the reliability and security of the transmission system and serves the PSCO Balancing Authority. Transmission Operations has full access to all available electric network information. Transmission Operations maintains and acts on this information in accordance with the FERC Standard of Conduct. They may take over Automatic Generation Control (AGC) or contact a plant directly to give instructions during an emergency situation.

Gas and Electric Distribution Control: The Denver Distribution Control Center is responsible for monitoring and controlling electric distribution facilities from the substation transformer to the customer meter. Distribution Control responds to gas emergency and non-emergency orders, electric emergency and non-emergency orders, and to write, monitor, and control planned emergency switch requests.

Electric Production (PSCo Plants): The Electric Production department is responsible for maintaining both the PSCo-owned and IPP-managed electric generation units, and for turning units up and down based on signals from Real-Time Dispatch. Alternatively, signals may be provided by Transmission Operations when necessary.

Key customers of the Company's gas and electric businesses are referenced throughout this report, particularly in discussions about customer impacts, obligations, and treatments. The

[4] Audit response OE-PSC 2-2.

following table of key customers is provided to help identify who these customers are, together with their needs for power from PSCo.

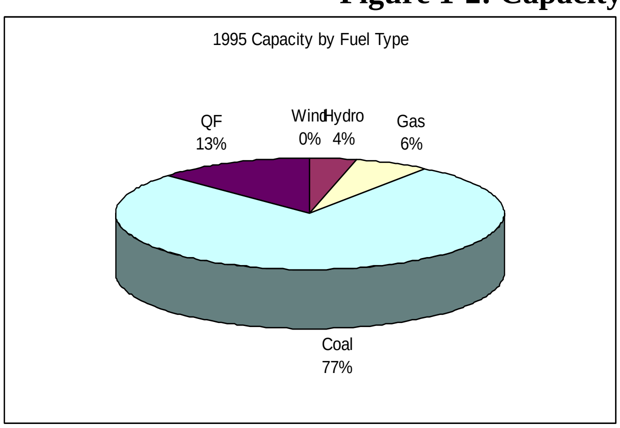
Table 1-1: PSCo Customers

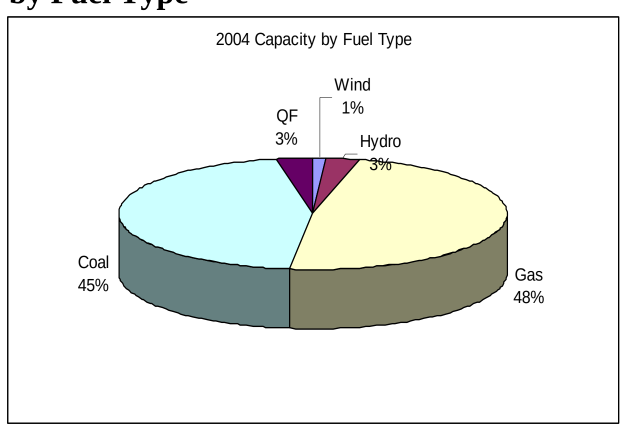
Gas Customers		**Electric Customers**	
Retail/ Commercial Customers	Retail and commercial customers served by the Local Distribution Company.	Retail/ Commercial Customers	General public plus firm commercial customers.
Retail interruptible customers	Customers who have elected to participate in a reduced rate tariff in exchange for periodic outages.	Retail interruptible customers	Customers who have elected to participate in a reduced rate tariff in exchange for periodic outages.
Transport Customers; Firm and Non-firm	Customers who do their own nomination and purchasing of gas supply.	Wholesale Non-Firm Customers	Other electric utilities.
PSCo internal Customers	PSCo-owned electric plants that use natural-gas fuel for generation; Denver Steam System.	Wholesale Firm Customers	Grand Valley Power Holy Cross Energy Intermountain REA Yampa Valley Electric Assn. Aquila, Inc., PRPA, etc.
Electric Plants (IPPs)	Independent Power Producers that create electricity using natural gas supplied by PSCo.	Transmission Services	Moving power from one utility to another across PSCo's system.
Wholesale	Other gas utilities.	Bulk Power Market	Power brokers who buy and sell power.

Gas and Electric Interdependency

The gas and electric businesses have become increasingly interdependent in the last 10 years, and the communication and process connections between them require additional support from senior management. The growth of the interdependency is best illustrated by the increase in electric production capacity from natural gas.[5]

Figure 1-2: Capacity by Fuel Type





[5] Wind Integration Study for Public Service Company of Colorado, May 22, 2006, Page 29.

This shift from primarily using coal to fuel electric generation to using gas and coal about equally, together with other significant shifts in the industry and the Company, has created a new need for cross-organizational communication, management oversight, and understanding among departments. This is a cultural and environmental change that will take time to address, but that must be undertaken with the full commitment and support of PSCo executive management to protect against future disruptions.

In addition to a Company switch to heavier use of natural gas to fuel electric generation, there have been organizational, industry, and regulatory changes in the energy business that have added complexity to the PSCo structure. The Xcel Energy corporate entity is the result the August 2000 merger of Northern States Power and New Century Energies (itself a merger of Southwestern Public Service Company and Public Service Company of Colorado). Several key changes have impacted Xcel Energy and therefore PSCo that challenge the Company organizationally.

- Xcel Energy and its four utility operating companies including PSCo are today organized in a fashion that reflects Xcel Energy's corporate vision and the business and regulatory environment within which it operates. Xcel Energy now sets as its mission to be the lowest cost, most reliable, environmentally sound energy provider.
- PSCo is certified by the State of Colorado as the utility provider of retail electricity and natural gas in specified areas, as approved by the Commission. The production of electric energy and the transmission of bulk power businesses are noted by entry of non-utility entities.
- An attempt is being made by FERC to encourage competitive forces to develop within these markets while still guaranteeing reliable service to end users. Similarly, the business of supplying natural gas and the transportation from producers to distributors and to end users has been transformed by FERC by the promulgation of seemingly ever changing regulations intended to instill competition and ensure fairness. Xcel Energy has created an organizational structure designed to profit within such regulatory mandates and market structure.
- PSCo's gas operation has recently been impacted by the closure of the Leyden gas storage facility. This gas storage facility was highly advantageous to PSCo because of its physical proximity to its retail load. Replacement gas storage capability is located some distance from its load centers.
- The gas supply industry has completed major interstate pipelines, thereby opening the Colorado gas market to participate competitively in regional markets. This means that gas may not be as readily available to the Colorado region, because it can now be committed to outside markets.

These factors, when considered in aggregate, have resulted in the need of the Company to engage in a comprehensive corporate review of communications and actions across departments to assure that the Company can flexibly address issues that are no longer isolated.

Event Significance

This event is significant to understand and respond to given its unprecedented nature, tremendous public interest as expressed in numerous articles in local papers, and its impact on a large number of Colorado customers. Colorado electric demand typically peaks in the summer, not the winter, and this event has underscored the changing environment in which power is supplied to customers, and that new concerns may be developing that supersede long-held beliefs about the stability and reliability of the system, particularly in the wintertime. It is particularly significant that PSCo lost close to 45 percent of its electric generation capacity during a time when electric demand is typically not excessive.

The process whereby power is supplied to retail and wholesale customers is complex. It is hoped that this more detailed report will address the concerns raised by the media and by customers who have taken the time to express themselves to the Commission regarding this event, although responding directly to these issues is not specifically within the scope of this effort.

Staff Investigation

Following the rolling blackouts, the Public Utilities Commission of the State of Colorado opened an investigatory docket, Docket No. 06I-118EG, to review the actions and activities that occurred prior to, during, and immediately following the curtailments relative to the following areas of the business:

- Weather and load forecasting
- Transmission and Interconnected System Operations
- Gas Supply
- Gas Control
- Real-Time Trading/Electric Power Scheduling
- Interruptible Customer Management
- Communication to customers
- Communication to media
- Internal processes and communications

Decision No. C06-0248, adopted on March 15, 2006, provides the PUC Staff (Staff) with the authority to pursue areas of investigation, with a focus on understanding how the shortage occurred, what actions the Company took to address the situation as it was unfolding, and what follow up actions the Company is initiating to prevent such an event from occurring in the future and what actions the Company is taking to provide timely and accurate information to the employees, media and customers.

To implement this directive, an investigative team was formed internally by Staff. Staff team members developed an investigation plan to focus the general directives into an analysis that could be completed within the timeframe requested. As a part of this focus, the team worked with PSCo and industry contacts to identify key areas of the business where interviews, document reviews, and site reviews were merited, and worked with Company and industry representatives to set up appropriate contacts and discussions. Additionally, the team relied on information from previous investigations, documented responses to audit questions, sets of transcripts, PSCo publicly available documentation, and the subject matter expertise of internal resources regarding the key areas of investigation.

Acknowledgement and Identification

This Staff investigation and preparation of this report were accomplished by a Staff team headed by Stephen Brown, together with support from two expert consultants from the North Highland Company. The team is identified in the following table:

Table 1-2: Staff Investigative Team

Team Member	Affiliation and Expertise
Stephen Brown	PUC Staff, Team Leader, Professional Engineer, Utility Operations
Warren Wendling	The North Highland Company, Professional Engineer, Utility Regulation
Julie Williamson	The North Highland Company, Business Process and Communications
Terry Bote	PUC Staff, Media Relations and Communications
Gene Camp	PUC Staff, Professional Engineer, Electric Power Production
Inez Dominguez	PUC Staff, Professional Engineer, Electric Power Transmission
Thomas Finn	PUC Staff, Professional Engineer, Natural Gas Operations
Bill Harris	PUC Staff, Economist, Electric Power and Natural Gas Load Forecasting
Billy Kwan	PUC Staff, Professional Engineer, Natural Gas Operations
Roxi Nielsen	PUC Staff, Customer Relations
Doug Platt	PUC Staff, Customer Relations
Sharon Podein	PUC Staff, Professional Engineer, Electric Load Management
Dr. Larry Shiao	PUC Staff, Professional Engineer, Electric Power Systems and Operations

This team was directed by the Commission pursuant to Commission Order C06-0248, in Docket No. 06I-118EG, to understand the causes and events leading to the controlled outages experienced by Colorado customers on February 18, 2006, and to make recommendations to the Commission as to whether additional Commission action is necessary to minimize the frequency, scope, and duration of such outages.

The investigative team acknowledges that in the interim between February 18, 2006 and the end of June, 2006, PSCo has initiated many efforts across the organization to address the issues that became apparent during this event. Staff has attempted to recognize and incorporate these efforts in our analysis, findings, and conclusions.

Investigation Scope

The scope of this investigation is specific to the events leading up to, during, and immediately following the February 18, 2006 controlled outages experienced by PSCo customers. While the event in question took place on February 18, our timeline for investigation begins on February 17, which marks the beginning of the process of weather and load forecasting for the holiday weekend. Our investigation discusses Company systems, communication channels, and processes (or lack thereof) that contributed to the event and how, at critical junctures, key decisions and actions could potentially have prevented the need to execute rolling blackouts.

Also within the scope of this investigation is consideration of the implementation of recommendations made as a result of the 1998 controlled outages and the 2004 distribution system outages. Finally, this report is scoped to include activities that have occurred in the interim time since the event, and to provide conclusions and recommendations pursuant to the event. These recommendations are in addition to the commitments already made by the Company. In such cases, the Commission will need to decide if the Company should be compelled to respond to the recommendation, and if so, in what manner and timeframe.

This investigation includes, but is not limited to, review and analysis of operational protocols, communication paths, decision making processes, physical plant reliability and related root cause analyses, and relationships between the gas and electric operations and trading environments within PSCo. While this report does make recommendations for addressing identified issues, it does not make specific suggestions regarding technologies to implement.

Methodology

The approach for this investigation is based on the questions raised in the Docket, and on the team members' best understanding of where potential issues lie relevant to the controlled outages of February 18, 2006. Staff began the process by brainstorming ideas with the team to develop a robust list of areas to investigate. As we pursued the investigation further, our focus narrowed to the following 9 areas, which support the issues highlighted in the Docket as well as additional issues that became apparent through our discussions with the Company:

- Section 2: Customer Care and Media Relations
- Section 3: Weather and Energy Demand Forecasting
- Section 4: Gas Supply and Gas Control
- Section 5: Electric Transmission Operations
- Section 6: Energy Trading and Real-Time Dispatch
- Section 7: Electric Production
- Section 8: Electric Interruptible Load Management
- Section 9: Interruption of Firm Electric Load
- Section 10: Internal Organizational Communication

The findings highlighted in the executive summary are woven into the issues discussed in each section. For each section, the report contains a list of specific recommendations, an overview of the functional area, a timeline of events, a discussion of key observations and concerns, and conclusions of the investigation Staff.

The Staff investigative team began by working with PSCo representatives to tour critical PSCo facilities and meet with PSCo staff members who participated in the February 18 event. Tours were typically followed by more in-depth interviews with specific Company staff members who had specialized knowledge of standard operating procedures and/or the procedures that were executed during the event. Based on information gained during the tours and interviews, team members constructed audit questions to clarify, document, and further investigate the situation that occurred, and to better establish the veracity of the Company report on the event. In addition to specific audit questions, the investigative team requested and received documentation including transcripts, information on PSCo activities in the three months following the event, and PSCo internal audit efforts. As of June 28, 2006, the investigative team had issued 264 audit questions and received 151 responses, leaving 113 outstanding. Notably, there are sections of transcripts that remain outstanding. Especially critical to our investigation are the undelivered transcripts of conversations between PSCo Transmission Operations and the Rocky Mountain-Desert Southwest Reliability Center and conversations between PSCo Transmission Operations and the PSCo Distribution Control Center on Saturday, February 18, 2006.

During this investigation, the team reviewed the recommendations made in the 1998 outage report submitted October 13, 1998 entitled Report on Staff Investigation of Public Service Company of Colorado Power Outages (1998 Outage Report). The team also reviewed the 2004 report submitted January 14, 2004 entitled Reliability of Public Service Company of Colorado's Electric Distribution System (2004 Outage Report) for possible recommendations or observations that would be relevant to this investigation. The team generally was attentive to previous recommendations that were made that should have impacted PSCo's ability to manage the events of February 18, 2006.

Outside of direct contact with the Company, the team used reports from FERC, WECC, previous outage reports, PSCo statements and reports to the Commission, and media reports to assess and understand the sequence that led to the event that occurred. Team members also spoke with wholesale electric customers, and reviewed IPP contracts. These sources are integrated into the analysis performed by specific team members as appropriate.

Timeline of Events

Based on this investigation, the team has reconstructed the timelines of events shown in each section of this report. The following highlights some of the key contributing events.

Time & Date	Event
before 2/17/06	PSCo Cabin Creek Unit B down for reconstruction. Unavailable electric generation capacity of 162 MW.
before 2/17/06	PSCo Arapahoe Unit 4 down for maintenance. Unavailable electric generation capacity of 111 MW.
08:00 2/17/06	Start of Gas Day 2/17/06.
11:30 2/17/06	Air temperature at Denver International Airport rises to high of 14°F (-10°C).
12:38 2/17/06	Rocky Mountain Energy Center taken off line. Loss of 651 MW of electric generation capacity.
16:15 2/17/06	West Town Border natural gas pressure drops to low of about 320 psi.
23:54 2/17/06	PSCo Fort Saint Vrain Unit 1 trips off line. Loss of 302 MW of electric generation capacity.
00:00 2/18/06	West Town Border natural gas pressure rises to high of about 390 psi.
00:35 2/18/06	PSCo Valmont Unit 5 trips off line. Loss of 186 MW of electric generation capacity.
04:00 2/18/06	West Town Border natural gas pressure drops below 310 psi.
04:07 2/18/06	PSCo Fort Saint Vrain Unit 4 taken off line for blend. Loss of 146 MW of electric generation capacity.
04:10 2/18/06	PSCo Cherokee Unit 4 taken off line. Loss of 352 MW of electric generation capacity.
04:24 2/18/06	PSCo Cabin Creek Unit A switched from pump mode to generate mode to compensate for lost electric generation capacity.
06:00 2/18/06	Air temperature at Denver International Airport drops to low of -13°F (-25°C).
06:26 2/18/06	PSCO Balancing Authority initiates interruption of interuptible customers.
07:16 2/18/06	Reliability Center declares PSCO Level 1 Energy Emergency Alert.
08:00 2/18/06	PSCo Operational Flow Order in effect for Gas Day 2/18/06.
08:41 2/18/06	Front Range Power units trip off line. Loss of 204 MW of electric generation capacity.
08:47 2/18/06	PSCO Balancing Authority begins rolling blackouts to reduce obligation load by 400 MW.
08:51 2/18/06	Reliability Center declares PSCO Level 3 Energy Emergency Alert.
09:00 2/18/06	West Town Border natural gas pressure drops to low of about 240 psi.
10:30 2/18/06	PSCO Balancing Authority ends rolling blackouts. Equipment failures leave 20,507 customers without power.
11:28 2/18/06	Reliability Center declares PSCO Level 2 Energy Emergency Alert.
14:00 2/18/06	Air temperature at Denver International Airport rises to high of 7°F (-14°C).
15:13 2/18/06	PSCo restores the last of its firm electric service customers.
16:09 2/18/06	Reliability Center terminates PSCO Energy Emergency Alert.
17:00 2/18/06	PSCo terminates interruption of interuptible electric service customers.
08:00 2/19/06	PSCo Operational Flow Order ends with Gas Day 2/18/06.

Section 2: Customer Care and Media Relations

Problematic internal and external communication is highlighted in the PSCo preliminary report as a contributing factor to the event that is the focus of this investigation. Consistent with that report, this investigative team found many areas of concern regarding communication issues relative to the activities leading up to, during, and following the events of February 17 and 18. These areas of concern include internal communication challenges that appear to be systemic across the organization, specific issues regarding communication with customers, and some process issues relative to how and when the media is notified of a situation.

This section is divided into two subsections in order to emphasize the different areas of communication that are critical for PSCo to effectively communicate with its customers, and with the media. Customer Care Communication addresses the processes and procedures for providing the customer service representatives with the information necessary in order to facilitate notifying customers and addressing customers' questions and concerns during such an event. Corporate Communications – Media Relations, discusses the manner in which the media is engaged to disseminate information to customers and to keep the public informed, as well as how the Media Relations staff accomplishes its crisis communication goals that affect the entire organization.

The final section of this report, Section 10: Internal Organizational Communication, also deals with communication and organizational issues made evident throughout this investigation. It is a broader section that examines the systemic communication channels and processes within the organization that are used to identify and respond to an emergency situation, and to communicate within and across various work groups.

While this report focuses in total on three areas of communication related concerns, it is noted that customer communication has been historically highlighted as an area of concern, as seen in the 2004 outage report,[6] which discusses significant failures on the part of the Company to provide accurate and timely information to customers during an outage situation. Based on the customer experience during this most recent event, it would appear that these issues have not been adequately addressed since the 2004 outage report.

Customer Care Communication

Communication with customers is vital for a public utility, particularly at a time when customers are or will be experiencing outages. This section reviews the ways in which communication directly to customers was handled during the February 18 event, the steps that have been taken since the event to improve and address specific deficiencies, and additional observations and recommendations from the investigative team regarding the importance of consistent, accurate, and timely information for customers. Note that in this section, the Customer Information Centers are referred to as "Xcel Energy Customer Care" because they serve all four Xcel Energy utility operating companies including PSCo.

During this event, there were system, process, and communication failures that prevented information from reaching customers in a timely manner. While the Commitment Log Report addresses some of these concerns, additional attention is recommended by this team regarding ways in which the Company can ensure better service. These recommendations require

[6] 2004 report submitted January 14, 2004 entitled Reliability of Public Service Company of Colorado's Electric Distribution System – pp 37-41.

management commitment of resources, both time and money, to fully address the highlighted problems.

Customer Care Communication Recommendations

In the Company's Commitment Log Report, Commitment 1 is to investigate technologies that can provide more accurate information to customers calling about outages. This investigation has been completed, and a vendor has been selected to implement a high volume call answering solution. However, senior management has not yet approved the business case for this effort. It is expected that the business case for implementing this technology will be approved on July 6, 2006. Staff recommends that the Company provide an update relative to this commitment within two weeks, together with additional details regarding the development and implementation timeline, including system development, process updates, training, and metrics for the project.

The Company has a history of solving specific customer care problems as they become visible through events like this one, without fully addressing systemic customer care shortcomings.[7] The following recommendations are designed to encompass these broader issues, and require action beyond what has been delivered relative to the Commitment Log Report.

1. Provide for an additional staff resource to be activated during an emergency in Distribution Control who has the responsibility of ensuring accurate and timely information to the Customer Information Centers when a controlled outage (or any other type of emergency management activity) is required.
2. Implement the committed technology to address call overflow. Provide the PUC with a quarterly update on progress towards implementation, until such time as the base system is installed, tested, and fully functioning.
3. Implement the commitment to activate a dedicated, 2-way phone line (ring down line) and provide alternative contact mechanisms (mobile phones, pagers, dial-arounds) should a problem occur with dedicated access, to ensure smooth and accurate communication between Distribution Control and the Customer Information Centers at all times. Provide the PUC with a quarterly update on progress towards implementation, until such time as the line is installed, tested, and fully functioning.
4. Establish a process for streamlining the Outage Management System (OMS) in a proactive controlled outage scenario that does not require manual entry of feeder breaker information, etc.
5. Provide training to staff on use of the emergency crisis communication plan that has been documented and updated since the event. Provide the Commission with a quarterly update on progress until all impacted Xcel Energy and PSCo employees have been adequately trained.
6. Create and manage a policy that requires early notification to Customer Care management if there is the possibility of a service interruption, so they can begin preparing before an outage begins.
7. Consider a reverse voice mail process for notifying customers of the possibility of controlled outages in their area. Even without details of exactly who will be impacted, a warning that a customer might be impacted allows the customer to plan ahead for unexpected complications.
8. Provide for a clear policy of who may craft and when a custom message should be placed on the Interactive Voice Response (IVR) system to address "non-traditional" customer situations and outages.

[7] See, for example, 2004 Report pp 37-41.

9. Develop and implement a change management process that ensures that communication procedures are updated at least annually for all impacted departments and employees.

The Company's Commitment Log Report references anticipated changes to improve customer communication, however, none of the proposed changes will be in effect during the peak summer season. As such, the following recommendation is designed to ensure a bridge between now and the system implementations:

- Create interim communication processes to provide the Customer Information Centers with timely, accurate information as situations develop, to be used until such time as the dedicated lines and additional phone banks are fully installed, tested, and functional.

Customer Care Communication Timeline

Time & Date	Event
07:00-08:00 2/18/06	Distribution Control attempts to call Eau Claire Customer Information Center, does not get through.
08:47 2/18/06	Customer interruptions begin.
08:50 2/18/06	Customer Care is told the Brighton area is impacted, approximately 50K customers.
08:55 2/18/06	Customer Care calls Dispatch for more information, based on the increased number of incoming customer calls.
09:00 2/18/06	Customer Care notifies its Vice President of the controlled outages.
09:15 2/18/06	Customer Care is notified that the affected area is Denver Metro, not only Brighton.
09:45 2/18/06	Customer Care is updated that approximately 140K customers are impacted in the Denver Metro area.
10:52 2/18/06	Controlled interruptions are over, however, some customers remain out of service due to feeder circuit breaker failures.
11:20 2/18/06	Media Relations provides Customer Care with correct information regarding the scale and locality of the outages.

Customer Care Communication Discussion

As of 06:00 Saturday, when Transmission Operations identified a high probability of the need for controlled outages, or even at 07:00 Saturday, when it became apparent that service interruptions were very likely to occur in the next one to two hours, the Customer Information Center in Eau Claire, Wisconsin had only 75 staff members in the Customer Information Center. This is typically the average number of care representatives for all of Xcel Energy's service area for the President's Day holiday weekend. Per discussions with the Vice President of Customer Care, PSCo has a process in place to contact an additional 45 customer service representatives who could be requested to report to work on 15 person "flights" on an as-needed basis. These staff members are to be contacted in a sequence based on their proximity to the Customer Information Center. These reserve representatives were activated shortly after the controlled outages began, with pages going to 48 additional staff, of which 30 reported for duty within one hour. Overall, this staffing and availability plan represents 10 to 15 percent of the total Customer Information Center staff of 700 Customer Care representatives. The Company was not able to significantly improve incoming call handling during the outages largely due to the Customer Information Centers not being notified of the impending service interruptions until after the interruptions were initiated.

In response to these calls, the Customer Information Center Lead Worker contacted Distribution Control to obtain information regarding the conditions in the field and an understanding of what to communicate to customers, as outlined in the timeline above. Distribution Control had been attempting to contact the Customer Information Centers, but did not have a dedicated line. High customer volumes in the queue prevented inter-organizational communication from occurring in a timely, accurate, and useful manner. Without a dedicated line, Distribution Control was attempting to utilize the same path into the Customer Information Centers as an external customer and experiencing the same issues of busy signals or IVR delays. There was not a dedicated line or otherwise reliable connection between Distribution Control and Customer Care during this event.

Distribution Control uses a system known as OMS to provide information to create recorded notification messages based on the perceived severity of an outage. This system is designed to respond to field outages, and determines the outage message and severity on the level at which the problem is detected in the field (one house, a feeder, a substation, etc.). Information is then automatically fed into the Customer Care systems and the IVR. The Distribution Control department is responsible for the OMS system, and uses it to coordinate field dispatch with customer response information. This system is not currently designed to manage controlled outages that are initiated by PSCo, as happened on February 18, 2006, because such a scenario bypasses the elevation processes built into OMS.

During the outage event, call volumes escalated quickly and overwhelmed the staffing and current technology available in Xcel Energy's Customer Information Centers. Between 08:47 and 10:30 Saturday morning, approximately 250,000 calls came in where callers received a busy signal rather than a ring tone. Additionally, of the approximately 20,000 calls that did establish a connection, the limitations Distribution Control was facing with the OMS system resulted in incomplete or incorrect information being presented to customers who did get through to the Customer Information Centers to listen to the recorded message. The Customer Information Center agents handled approximately 2,200 calls in the same time period, however they too had incomplete and inaccurate information. The Vice President of Customer Care indicated that at approximately 08:50, the Customer Information Centers were being advised that call volume was escalating due to 50,000 customers experiencing low gas pressure in Brighton Colorado; when in fact, controlled outages had begun for a much larger area and were anticipated to impact as many as 400,000 customers.

Finally, the PSCo Customer Care and Media Relations staff has an inconsistent understanding of what rolling blackouts (controlled outages) mean (per the industry definition) and how to respond to them. Corporate policy regarding what constitutes an emergency and how it is communicated is discussed in the Internal Organizational Communication subsection in more detail. However, it is important to mention here that additional training and education regarding service interruptions is merited to ensure that staff is aware of the obligations, expectations, processes and industry standards regarding issues like controlled outages. With this additional information, they will be better prepared to address customer and media questions regarding controlled outages, regardless of the internal communication taking place.

Customer Care Communication Conclusions

Communication between Distribution Control and the Customer Information Centers was inadequate to prepare the Customer Information Centers for the calls that occurred as a result of the outages. The systems in place for handling call volumes and load were also insufficient, and the systems used to provide information were neither timely nor accurate. The absence of a dedicated line between the Distribution Control and Customer Care further contributed to this issue by making it difficult to connect directly with the individuals who needed to be notified. In lieu of a dedicated line, pager or mobile phone numbers for Customer Care management should have been available during the event.

The technology used to route calls and manage overload is insufficient to manage a crisis situation similar to the one that occurred on February 18. The Company has made a commitment to investigate a new outside vendor system to better facilitate and manage call overflow, and to develop a business case to support implementing such a system. In addition, the process of activating additional customer service representatives merits review, in particular the logistics of incorporating the Denver Business Service Center staff and a larger base of the Customer Information Center staff when this level of emergency occurs.

The design of OMS to manage internally initiated outages (as opposed to field outages) was insufficient to support the timely delivery of accurate information to customer. It required significant manual intervention to force it through a process of creating recorded messages for the Customer Information Centers, which created extra work for the individuals dealing with the situation in Distribution Control, who were trying to both work with the system and communicate with the Customer Information Centers. A more appropriate approach is greatly needed for utilizing OMS when controlled outages are initiated and when other significant emergency events occur.

Corporate Communication/Media Relations

On February 18, 2006, PSCo had an emergency communication process documented that detailed the processes and steps for managing a crisis situation. This document, known internally as the "Xcel Energy Corporate Crisis Communications Plan," was intended to ensure that the public, media, and internal PSCo staff were informed and prepared for an emergency scenario. This process called for the creation of a crisis communication team with an identified leader, a series of press communications based on templates provided and recommendations regarding timing and execution, and internal communication paths for ensuring that executives and others are aware of the situation.

It appears that this process was not rigorously applied on February 18, 2006. For example, the crisis communication team was never fully convened, all communication took place through one-on-one conversations primarily between two individuals, and only components of the plan were acted out.[8] Post hoc analysis by the key team members indicates that according to the process, the situation would not have merited a severity rating sufficient to activate the plan,[9] which calls the rating system into question given the customer and system impacting nature of the event. Additionally, the version of the crisis communication plan provided to the PUC was revised in December 2005 – well after implementation of OMS and Customer Resource System (CRS) systems, however, it does not incorporate these systems and their related emergency notification processes, indicating that the departments are not synchronized relative to their crisis response processes.

The Media Relations contact was able to notify several news agencies and arrange for a "screen crawl" to notify the public of the need to conserve power the morning of the February 18, at approximately 07:30. Additional media updates were provided throughout the day. While contact with the media was accomplished, other key components of the Crisis Communication Plan were not. Most notably, the plan calls for the team to organize and coordinate communication across the Company. Customer Care, Key Account Management, and other areas of the business were

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[8] Audit responses CPUC4-14, CPUC4-15.
[9] Audit response CPUC4-16.

not effectively in receipt of vital communication as events unfolded throughout the early hours of the morning and into the day.

Corporate Communication/Media Relations Recommendations

In the Company's Commitment Log Report, Commitment Item 24 is assigned to the Media Relations department to investigate how to improve communications. The response to this commitment is cross referenced to Commitment Item 3, which addresses how all departmental communication plans are standardized around emergency notification channels. Commitment No. 3 contains an updated Crisis Communication plan, and revised emergency escalation definitions to be used cross-organizationally. It also includes reference to the deployment of MissionMode, a notification system that provides enhanced internal communication channels. However, this commitment does not reference a commitment from senior management to support the acquisition, development, and implementation of MissionMode or the supporting business practice changes and training required to ensure that it will meet the needs of the organization relative to crisis management. Additionally, in the information provided in the Company's report, MissionMode is only activated as a result of an Energy Alert, however, there are other types of emergencies that merit a coordinated response that are not categorized as Energy Alerts. Finally, the updated Crisis Communication Plan and supporting process flows do not reflect how and when MissionMode will be used. While the identification of a tool is an appropriate step, the Commitment response does not adequately address these other open issues.

In addition to the Company's recognition of the need for better crisis communication, and its supporting commitments discussed above, this investigation highlighted other key areas of concern. Recommendations regarding these concerns are as follows:

1. Revisiting the existing rating system to more heavily weight customer impacting events like controlled outages, to ensure adequate executive level and organizational attention before such outages are initiated.
2. Updating the crisis communication process to include consideration for how to coordinate with the OMS and CRS tools where appropriate.
3. Updating the crisis communication process so that it is initiated sooner than when the crisis becomes a reality to incorporate better preparation, more timely information flow, and a clearer communication across the organization of the impact of the problem, should it occur, rather than after it has occurred.
4. Reviewing the crisis communication process (after updating) and perform training and practice walkthroughs to ensure full understanding of responsibilities and expectations during (and leading up to) a crisis.

Corporate Communication/Media Relations Timeline

Note that in addition to the activities listed here, a Media Relations employee commented that the department fielded numerous news agency inquiries throughout the day, and selectively worked with and tracked contacts with reporters who were working on the story for a given news cycle, rather than tracking all contacts in sum.

Table 2-1: Media Timeline

Time & Date	Event
2/18/06 06:00	Transmission Operations notifies Media Relations that firm load (retail customer) interruptions are a probability
2/18/06 07:00	Transmission Operations notified Media Relations that firm load (retail customer) interruptions are a certainty
2/18/06 07:30	Media Relations notifies the media and requests a "screen crawl" with information
2/18/06 08:00	Media Relations key contacts begin notifying executives and others internally
2/18/06 10:00-10:15	Additional information is distributed to the media
2/18/06 11:00-18:00	Additional media communication via Media Relations key contact

Media Relations Discussion

During the event, Transmission Operations notified Media Relations more than two hours prior to the start of controlled outages that there was a possibility of such an activity taking place. They updated this to a certainty almost one hour and forty minutes before the load shed was started. This advance notice was appropriate given the severity of the potential problem, and allowed for some pre-work to be done by Media Relations to prepare for potential rolling blackouts. The significance of this notification is that the information was available early on Saturday morning. However, not all departments in PSCo were apprised of the situation. In particular, interviews with PSCo's Transmission Operations department and with the Vice President of Customer Care indicate that nobody clearly assumed responsibility and ownership for timely, accurate information flow throughout the organization, starting at 06:00 when it became available to the Media Relations department. While the Media Relations department did respond to the situation by notifying the media, the Crisis Communication Plan was not thoroughly applied and followed, and there was no clear rally of corporate resources to ensure accurate and timely information to both the media and other impacted departments both within and external to PSCo.

Media Relations Conclusions

PSCo had in place a Crisis Communication Plan that has since been revised as an outcome of the events of February 18. The process that was in place was not followed rigorously despite the fact that time for proper notification was available in advance of the rolling blackouts starting. As a result, there was no clear leader organizing communication to various departments within the Company and externally, and owning the accuracy and timeliness of the information. Without rigorous application of the process, cross-checks built into the process were not executed.

For example, per the process, the Crisis Communication Management Team and Media Relations would coordinate communication to multiple internal and external groups, including getting information to the Customer Information Centers via the Client Services and Employee Communications team members. Lacking this type of aggressive approach to managing communication, individuals were left to pursue information on their own, or to pass on information as they had time, potentially contributing to a delay in getting accurate information to the Customer Information Centers, and to others in the organization who may have been able to render assistance.

Section 3: Weather and Energy Demand Forecasting

It has been well documented in the local media that the PSCo weather forecasts produced during the week of the blackouts called for higher temperatures than were observed for Friday, February 17 and Saturday February 18. Staff recognizes that forecasting the weather is difficult, especially in Colorado, and that sudden changes in temperature can be expected. Staff does not believe that the inaccurate weather forecast made on February 17 is the cause of the outages on the 18th; rather it was the first in a series of issues throughout a critical 36-hour period. However, staff does note that while the Company stated that no one had predicted the record low temperatures that occurred, the National Weather Service issued a forecast at 04:00 on Friday, February 17 that called for a low temperature between minus 9 degrees and 1 degree Fahrenheit for Saturday morning,[10] while the Company's forecast for the same period was for a low of minus 1 degree Fahrenheit.[11] This National Weather Service forecast conflicts with statements made by PSCo in the March 13 report.[12]

While the deviation in the predicted low for February 18 was large based on information provided by the Company,[13] weather in Colorado is hard to predict and this will not be the last time that the PSCo weather forecast misses the mark to a significant degree. While the Company has taken and should continue to take steps to continuously improve the weather forecast, the primary focus of this section is on how the Company can improve in forecasting of gas and electric load demand and respond to load changes when the weather changes. Specifically, the investigative team examine the ways in which the weather forecast and the load forecasts are maintained in real-time throughout the day to adjust for changes, and focuses on PSCo's response to translating weather deviating from the anticipated conditions into changes in load demand as the day progresses.

On May 18, the Rocky Mountain News reported in an article titled Xcel Energy Takes Outage Blame that Xcel Energy president "Richard Kelly said the utility didn't realize how cold it would get on February 18 and underestimated the demand for natural gas at a time when the supply was constrained." The investigative team believes that this is true; however it does not address PSCo's need to improve in two critical areas:

- The methods used to forecast demand for gas and electricity, which incorporate the weather forecast.
- The way in which the Company monitors deviations from expected weather patterns and how these changes influence expected load demand and the allocations of power and gas to meet the fluctuating demand.

Weather and Load Forecasting Recommendations

It is important to address both the methods used to forecast demand, and the way in which deviations from expected weather forecasts are monitored. By implementing the forecasting and

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[10] This weather forecast information was provided to the PUC by Bob Glancy, Warning Coordination Meteorologist with the National Weather Service on February 23, 2006.
[11] PSCo Preliminary Report.
[12] On page 10, the report stated that "It was not until the Friday afternoon at approximately 3:30 p.m. that the National Weather Service predicted that temperatures could drop as low as -9°F".
[13] The March 13, 2006 report from the Company presented day-ahead average hourly temperature variations from October 1st through February 27th. The average error was approximately 4.5 degrees Fahrenheit. The February 18th average deviation 15.1°F. The average deviation for the 17th was 10.4 °F.

monitoring suggestions that are presented in this section, PSCo has the opportunity to tighten the deviations in gas and electric operations, and secure against future outages.

1. PSCo should commit to investigating the historical assumptions built into the load forecasting processes, and determine if there are more robust models that can be developed and applied, particularly to how the gas forecast is generated and maintained throughout the day. This investigation should include the following specific areas, in addition to those deemed appropriate by the Company:
   - Separate the forecast into geographic areas so that local usage patterns can be reflected more accurately in the demand forecasts.
   - Take a weighted average of heating degree values by hour rather than only using high and low temperatures in the weather forecast.
   - Incorporate additional weather variables like wind, sunlight and humidity into the forecast process. (The Company has indicated that they have plans to incorporate AccuWeather's RealFeel® into their forecasts.)
   - Monitor the deviations from the expected value in temperatures at several gas and electric facility locations on an hourly basis and update demand forecasts accordingly.
   - Collaborate with Staff to conduct this type of investigation and report on the results.
2. Implement a more robust approach to dynamically assessing both the weather and load forecast against actual conditions. From that, define and use a process for raising concerns across Gas Control, Gas Supply, and Marketing when deviations reach a certain threshold.

Weather Forecasting Discussion

Xcel Energy employs a full-time meteorologist in Denver who produces a weather forecast for each of its operating companies each weekday morning. In the event that the meteorologist is absent, the Company relies upon AccuWeather.com. The forecasts are issued for seven day periods. The forecasts include the estimated high and low temperature, a few words indicating whether it will be cloudy or whether precipitation is anticipated, and a paragraph describing the risks to the forecast for each day.[14] This is distributed via e-mail to Energy Supply, Gas Control, and other key departments. While this forecast is created by a trained meteorologist with a strong background in weather, it does have significant shortcomings, including:

- No statistical confidence intervals which could be used by others to enhance the load forecast.
- No independent estimates for wind, humidity, or percentage of cloud cover, all of which impact demand for energy.
- A heavy weighting towards Denver International Airport, even though the forecast is used to predict demand for the entire PSCo Colorado territory.[15]

While there is no documented process describing the steps in creating the weather forecast, the meteorologist told the investigative team that he takes into account a variety of sources and then adjusts the output based on his own professional judgment.[16] Since the forecast is only for the high and low temperature, the meteorologist may make some "best judgment" adjustments based

[14] Audit response.
[15] PSCo does not serve all of Colorado. Their territory includes the Front Range from Northern Douglas County North to Wellington in Larimer County, the Fort Morgan and Sterling areas, most of the I-70 corridor through the mountains, Pueblo and the Alamosa area.
[16] Interview with PSCo meteorologist.

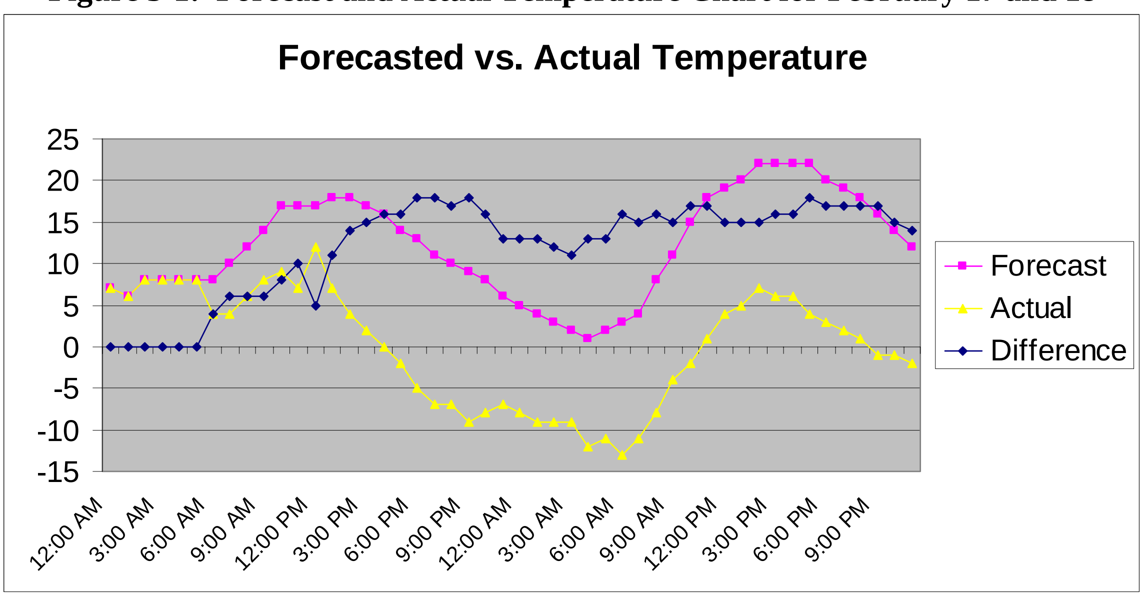
on estimates of wind and cloud cover. This report is then transmitted to the departments responsible for purchasing and scheduling of both electric power and natural gas.

While the forecast that is passed on to the individuals who produce the energy demand forecasts only contains the estimated high and low temperatures for each day, PSCo did provide the PUC with hourly temperature estimates for February 18. This indicates that the hourly values are being produced for each weather forecast. However, the hourly observations are not being utilized in gas demand forecasting.

In Exhibit No. 4 of the Company's Preliminary Report, dated March 13, 2006, the Company indicates that the average hourly error in forecasted temperature has been about 4.5 degrees Fahrenheit over the previous five months. Exhibit No. 3 showed the hourly forecasted temperatures. The report indicates that this was the final weather forecast prior to the weekend and that it was issued at 05:00 on Friday. Based solely on this PSCo provided information, the forecast was off by 4 degrees Fahrenheit by 06:00 on Friday. The observed temperatures continued to record more substantial deviations throughout the morning. By 10:00, the deviation was 8 degrees Fahrenheit and by 11:00 it was 10 degrees Fahrenheit.

Based on the information provided by Gas Control,[17] a ten-degree Fahrenheit difference for one day translates into an additional need for 200,000 decatherms of gas. However, as the day progressed, the deviation continued to increase. By 14:00 the deviation was 14 degrees Fahrenheit and by 16:00, it was 18 degrees Fahrenheit. Based on this observation of actual to forecasted temperature, it was apparent that the PSCo system would need additional gas by the end of Gas Day 17, which is 08:00 of February 18 (Gas Day 17 started at 08:00 February 17 and ended at 08:00 February 18). This need became even more pronounced as the day went on.

Figure 3-1: Forecast and Actual Temperature Chart for February 17 and 18



Note: This graph was produced entirely from information provided by PSCo. It reflects the forecast that that was issued at 05:00 on Friday the 17th. The salient point to consider is that the forecasted temperature started to deviate significantly immediately after the weather forecast was issued.

[17] Interview with PSCo Gas Control Staff, May 16, 2006.

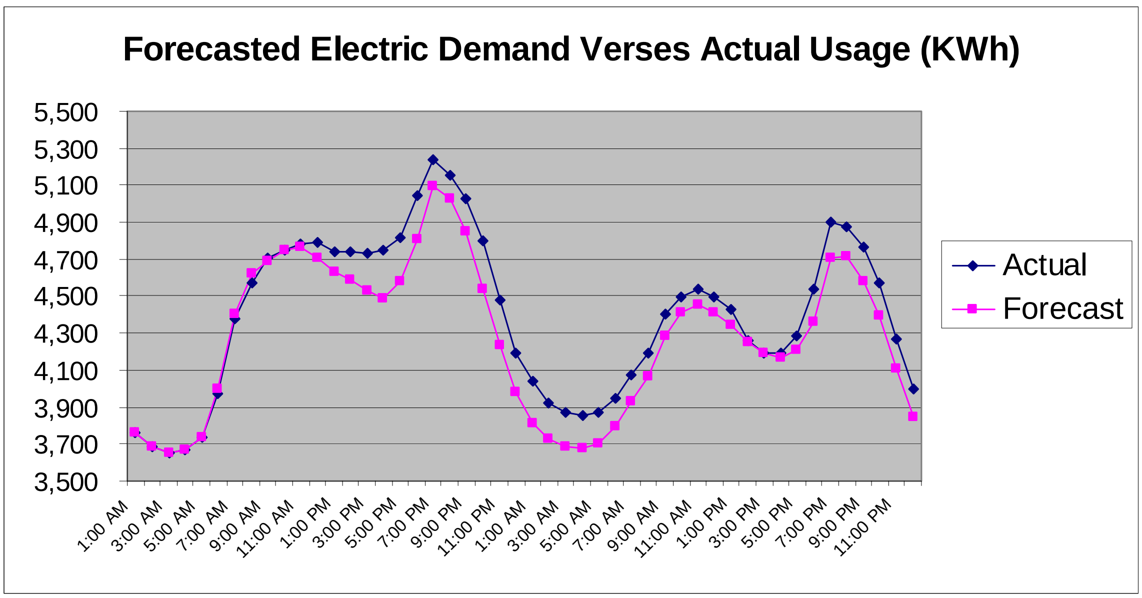
Energy Forecasting Discussion

Electric Power Demand Forecasting

PSCo utilizes a forecasting product called Pattern Recognition Technology (PRT) that is a proprietary product of PRT, Inc. The system's inputs include not only the weather forecast but also generation asset information. The system also allows for automated inputs from AccuWeather. The PRT system is a neural network. A neural network forecasting system is a system that learns from its mistakes and takes in a plethora of variables. The output of the PRT system is estimated demand on an hourly basis which is the minimum duration of purchase agreements.

While the deviation from the expected electric demand is not the sole cause of the outage on February 18, it was a contributing factor. The load forecast for February 18 was issued shortly after the weather forecast was released. In the early hours of the forecast, the load was slightly lower than forecast. By 11:00, the demand exceeded the forecast. By noon, the demand was 1.8 percent or 84 megawatts greater than forecast. This deviation increased until 16:00 when it reached 5.8 percent or 255 megawatts. Between 16:00 on Friday until the commencement of the rolling blackouts, demand was on average 4.5 percent higher than the Company anticipated. Under normal circumstances, this deviation would have been manageable.

Figure 3-2: Forecast and Actual Usage Chart for February 17 and 18



Note: This graph was produced entirely from information provided by PSCo. It reflects the forecast that was issued on Friday the 17th. The salient point to consider is that the actual electricity usage started to deviate noticeably from the forecast on Friday evening. The deviation between the forecasted and actual demand declines during the outage.

Gas Demand Forecasting

The forecast for gas demand is done for each "gas day" which starts and ends at 08:00. Gas nominations are done the weekday before the gas day. A gas nomination is a request for gas to be fed into the PSCo system. It can be either from a long-term contract, a new purchase or a release from storage of previously purchased gas. PSCo owns limited gas storage facilities since they no longer use the Leyden facility in Jefferson County. Hence, PSCo relies heavily on CIG for natural gas storage service. During the week of the blackouts, gas was nominated on Thursday, February

16, for Saturday through Sunday, and then on Friday, February 17, for Monday and Tuesday, February 20-21, because of the holiday. Longer forecasts have larger confidence intervals, which is to say that there is more opportunity for error. However, since PSCo does not include confidence intervals in their weather forecasts, this potential error was not considered when the Company placed its natural gas nominations for Gas Days February 17 and 18.

Gas demand forecasting is done by the Gas Supply department for the LDC, by Energy Trading for the electric generation plants (including IPPs). The electric load forecast was fairly accurate (within 4 percent) and did not change significantly over Gas Day 17, but the electric plants over burned their nominations midday on Gas Day 17. This would indicate that Energy Trading did not accurately forecast its gas demand for Gas Day 17, or that its planning for purchasing versus generation changed during the day, requiring more generation than had been previously forecasted.

Gas Control Forecasting

Gas Control conducts a separate forecast for gas needs on the system. The investigative team has requested, but not received, soft copies of the Excel workbooks used to manage this forecast. Review of these files will be required to fully document their quality.

Based on the information that was provided to the investigative team, these workbooks contain an unnecessary level of variation that could be reduced with more robust forecasting methods. There are several procedures that Xcel Energy should consider implementing to reduce the error within its forecasts. The common theme to these procedures is focusing on producing more data points and combining them into one forecast instead of forecasting a single data series, as is done by the Energy Markets department. Specifically:

1. By only forecasting one series in Energy Markets, Xcel Energy increases the opportunity for error over what it would have if it separated the forecast by geographic area. There are clearly variations in demand determining variables such as temperature, demographics, and wind between geographic areas. These variations are masked within a single series.
2. By only using the high and low temperature to forecast demand, Xcel Energy is limiting the usefulness of this weather variable. This is particularly evident in monitoring the forecast as the day progresses. It would reduce variation in projected gas demand by taking a weighted average of heating degree values by hour.
3. The process that existed at the time of the rolling blackouts did not include variables for wind, cloud cover or humidity. Since then, Xcel Energy has indicated that it has incorporated AccuWeather's RealFeel® into its forecasts.[18]

The other major opportunity that Xcel Energy should leverage is to monitor the deviations from the expected value in temperatures by Gas Control. If Gas Control modeled the demand on an hourly basis instead of daily, there would have been more awareness of the significance of the temperature deviation. While it is recognized that gas nominations are more constrained than electric purchases, a model that projects demand on an hourly basis that preserves the inter-hour slopes while adjusting for the deviation from the latest expected hourly value would give an early warning of possible shortages, or a developing situation. This type of indicator could be used to alert both the electric and gas departments to a potential problem, and allow for proactive measures to be taken.

[18] Commitment Log Report, Commitment Item 19.

Weather and Load Forecasting Timeline

The following timeline is most notable for what it does not reflect. At no point is the demand load forecast for electric or gas supply formally reviewed and updated to reflect the deviation in forecasted to observed temperature. Gas Control makes an effort to rationalize the actual temperature with the forecasted demand, and to balance the nominations on the system, but there is no formal application of actual conditions to forecasts to reconcile the two and address problems that might develop.

Table 3-1: Forecasting Timeline

Time & Date	Event
4:00 2/17/06	National Weather Service issues a Denver forecast calling for a Saturday low temperature of -9°F to 1°F.
5:00 2/17/06	PSCo meteorologist issues a forecast calling for a low of 1°F.
6:00 2/17/06	Temperature is 4 degrees Fahrenheit lower than anticipated.
10:00 2/17/06	Temperature is 8 degrees Fahrenheit lower than anticipated.
10:30 2/17/06	Final gas nominations for the weekend are entered.
11:00 2/17/06	Temperature is 11 degrees Fahrenheit lower than anticipated.
14:00 2/17/06	Temperature is 14 degrees Fahrenheit lower than anticipated.
16:30 2/17/06	Gas Control day staff finalize balancing and nominations for the system, communicate options for generating without gas, and leave for the weekend, believing gas nominations are in balance to meet the LDC and electric generation requirements.
18:00 2/17/06	Temperature is 18 degrees Fahrenheit lower than expected.

Weather and Forecasting Process Flow

- The process originates with the meteorologist issuing the weather forecast based on a variety of sources and professional judgment. This includes historical trends, local knowledge, and a loading factor applied by the forecaster to account for common deviations.
- The weather forecast is then translated into an electricity demand model with other inputs into a neural network forecasting tool called PRT along with other variables including information on generating assets. This tool estimates demand for electricity on an hourly basis. Electricity can be purchased in near-real-time, making an hourly forecast useful.
- The high and low temperatures are entered into an Excel workbook that estimates gas demand. This tool estimates gas needs on a "gas day" basis.
- The electricity and gas demand forecast estimates are transferred to the energy buyers, electricity marketing, and to gas supply.
- The energy traders in Marketing and Gas Supply arrange for purchases and nominations based on the forecast estimates.
- The gas dispatcher in Gas Control does a gut check on the gas demand estimates utilizing independent estimates for weather for multiple geographic areas and estimates of usage by generation and transportation customers.

Section 4: Gas Supply and Gas Control

This section examines the natural gas supply issues that affected both the local natural gas distribution company (LDC) and electric generation on February 17 and February 18, 2006. PSCo has two intertwined departments that are intimately involved in natural gas operations, Gas Supply and Gas Control. Gas Supply, Gas Control and Energy Trading[19] played a part in the decisions that were made February 17 and February 18 that affected the supply of natural gas available for both the LDC system and for electric generation.

Many factors played a part, including colder than expected temperatures, natural gas forecasting, communication between divisions, misunderstanding the gas supply and pressure issues by Electric Generation, wavering on calling an OFO, lack of gas available on the spot market and ultimately low LDC system pressures. The lack of natural gas in the marketplace and high gas loads of both the LDC and electric generation stretched PSCo's gas supply to the limit, resulting in Gas Control acting to protect the LDC by restricting electric generation plants from operating on gas. Gas Control experienced a large imbalance caused by under deliverability by the transport customers.[20] Notably, Gas Control did not require transportation customers to balance their nominations on February 17. Throughout February 17, 2006 withdrawals from the LDC system were greater than the gas flowing into the system and pressure or line pack was beginning to drop.[21]

While electricity is not stored and it can be quickly produced to respond to the electric demands that are placed on the system, gas must be produced and transported into the system and then distributed for use. Gas flowing from higher pressure to lower pressure is the fundamental principle that is used for natural gas delivery systems. Under ideal conditions gas can move through the gas transportation system at up 30 miles per hour.

Depending on the gas system pressures, gas usually travels 10 to 20 miles per hour under normal field conditions. Due to the speed at which gas travels there is some lag time between when gas is nominated and injected into an upstream pipeline system and when it arrives at its final delivery point.[22] Unless specified differently, the rate of flow of gas is at a uniform hourly rate and usually the flow cannot exceed 1/24th of the scheduled daily quantity at the any receipt or delivery points. Consequently, even though there was enough gas supplied to the system on February 18, the gas could not be replaced in a manner timely enough to prevent the gas restrictions placed on the LDC system on February 18 due to the overuse on February 17.

This section provides discussion and details regarding Gas Supply and Gas Control during this event. While the Company has acknowledged problems that occurred in these areas, and provided

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[19] The PSCO Report of Events that Led to Controlled Outages, March 13, 2006 report refers to Energy Trading as Electric Trading.

[20] Transport customers are customers that acquired natural gas by separate agreement from other parties and under transportation service agreements PSCo acts to transport gas from receipt point(s) through the PSCo system to the delivery point(s).

[21] Line Pack is defined as natural gas that is occupying all pressurized sections of the pipeline network. Introduction of new gas at receipt points "packs" or adds pressure to the line. Removal of gas at a delivery point "unpacks" or lowers the pressure in the line.

[22] A nomination is a request for a physical quantity of gas under a specific purchase, sales or transportation agreement or for all contracts, be delivered at a specific point. A nomination includes all custody transfer entities, locations, compressor fuel and other volumetric assessments, and the precise routing of gas through the pipeline network to get to its delivery point.

commitments to address them, the results of this investigation indicate that further action is necessary in several critical areas. These recommendations are provided below.

Gas Supply/Gas Control Recommendations

1. The electric department must be treated as a gas customer. An operational flow order (OFO) needs to be called even if it appears that the electric generation department is the one party that is experiencing overruns. Because Gas Control does not have the ability to see what the LDC is burning, its focus must be to protect the LDC system for all parties when unanticipated events occur. There needs to be an operating and balancing agreement between the gas department and the electric generation department and a greater understanding of gas availability by electric generation.
2. Gas Control should to monitor as many real-time gas flow indications as possible to monitor any imbalances on the system, including transportation balances. If imbalances are occurring there needs to be standard operating protocols such that an OFO will be called early enough to give parties time to correct imbalances and to not place the LDC system at risk.
3. PSCo should to fully investigate the outages that occurred in the Todd Creek and Eagle Shadow Subdivisions to determine the cause of the outage and pressure loss across the regulators. PSCo has begun investigation of these outages and should be required to file a report with the Commission on the findings of its investigation to report the specific cause of the outages and to explain the solution employed to remedy the problem.
4. As reliance on natural gas fueled power plants has increased, PSCo should conduct an annual review of operating procedures to ensure that there are protocols in place that address adequate gas supply for both LDC sales and electric generation and to ensure there is timely delivery of the gas for LDC, electric generation and transport customers.
5. PSCo should eliminate off-tariff tolerance of gas imbalance dead bands. This will make tariff penalties transparent and ensure that no “favoritism” is shown, or appears to be shown, towards electric generation.
6. PSCo should engage NERC and NAESB concerning necessary improvements to the gas trading cycle.
7. PSCo should model the LDC system using dynamic/transient simulations. These will indicate how the gas system is likely to respond under different use configurations, including electric generation use of gas off the LDC and low pressure situations.
8. PSCo should be required to develop a system that has a reserve of natural gas to provide a cushion for the LDC and electric generation when unforeseen incidents occur.
9. Staff recommends that any charges for overruns, whether authorized or unauthorized, should be tracked and reported as a separate line item in the GCA. This will assist in investigating whether such costs are prudent and should be passed through to the firm sales ratepayers without express approval by the Commission. This will ensure that PSCo manages the gas supply in the best interest of the ratepayers and has sufficient storage set aside rather than relying on authorized or unauthorized overruns to manage its system.
10. PSCo should investigate if the Brush IPPs are able to withdraw gas directly from Young Storage, and if not what modifications would be needed relating to a cost benefit analysis. If the Brush IPPs can currently pull gas directly from Young Storage, a protocol should be developed to address system operating procedures for efficient operations of both the Manchief and the Brush IPPs.

Gas Supply/Gas Control Timeline

Date	Time	Action/ Activity		Event
02/15/06	~06:00	Prepare load forecast for LDC natural gas requirements for Gas Day 2-16-06; (08:00 Thursday – 08:00 Friday) HE 9 – HE 8.	Manager Gas Supply	The LDC load forecast is 962,360 Dth for Gas Day 2-16-06.
02/16/06	~06:00	Prepare load forecast for LDC natural gas requirements for Gas Day 2-17-06.	Manager Gas Supply	The LDC load forecasted was 1,046,710Dth, leaving Net Reserves of 209,297 Dth.
02/16/06	~07:00	Forecast of gas requirements for electric generation for Gas Day 2-17-06.	Sr. Gas Buyer	Forecasted gas for electric generation is 245,500 Dth, leaving Net Reserves of 140,000 Dth, of which 116,767 is fuel oil equivalent.
02/17/06	~06:00	During Gas Day 2-16 the Pressure at West Town Border dropped to approximately the Low Alarm Level[23] of 350 psi.		The actual load for gas day 2-16 was 1,371,000 Dth which required 531,632 Dth of NNT (38.8%).
02/17/06	~06:00	Actual temperature is 4 degrees Fahrenheit below previous forecast.	Manager Gas Supply	No changes are made to LDC Supply Plan.
02/17/06	~06:00	Revised forecast of gas requirements for electric generation for Gas Day 2-18-06.	Sr. Gas Buyer	Forecasted gas for electric generation is 265,000 Dth, leaving Net Reserves of 128,506 Dth, of which 116,767 is fuel oil equivalent.
02/17/06	~07:00	Low Level Alarm for Longmont sounds.	Gas Control	Low Level Alarm is triggered at 450 psi. Alarm resets at 0845 due to pressure increase.
02/17/06	~07:00	Revised LDC forecast.	Manager Gas Supply	The LDC load forecast was revised to 1,181,670 Dth, for Gas Day 2-17 leaving Net Reserves of 167,857 Dth (utilizing 93,520 of authorized overrun).
02/17/06	~07:30	Low Level Alarm for Fort St. Vrain Inlet sounds.	Gas Control	Low Level Alarm is set at 600 psi.
02/16/06 – 02/17/06	~08:00	CIG[24] Ault Pressure minimum for Gas Day 2-16 is approx 680 psi.		Contract Minimum is 500 psi.
02/17/06	~13:00	Revised forecast of gas requirements for electric generation for Gas Day 2-17-06.		Revised forecast of gas for electric generation is 335,402 Dth. Gas Supply Plan includes 38,649 of authorized Storage Overrun, resulting in Net Reserves of 81,383 Dth, of which 77,840 is fuel oil equivalent.[25]
02/17/06	~13:00	Actual temperature is 10 degrees Fahrenheit below previous forecast.	Manager Gas Supply	No changes were made to LDC Supply Plan.

[23] In response to PSCo 3-78, PSCo stated that a low alarm indicates that "something out of normal operational range" is occurring. The LoLo alarm indicates that "some immediate action must be taken to avoid serious operational consequences" such as loss of pressure and flow to a specific customer or area of the system.
[24] CIG is Colorado Interstate Gas.
[25] The reserve of 77,840 Dth equivalent is calculated as ALL units capable of burning fuel oil do so at max capacity for 16 hours during the rest of the gas day.

Date	Time	Action/ Activity		Event
02/17/06	~12:45 To ~15.41	Phone calls between Gas Control and Gas Supply regarding PSCo generation over burning their nominations.	Manager Gas Control, Manager Gas Supply, Sr. Transportation Analyst (gas Control)	Gas Supply buys 31,543 of intra-day gas and storage nomination is set to max at Young. Manchief plant is started to utilize storage deliverability from Young Storage.
02/17/06	14:31	Verified that Ft. Lupton units could run on oil.	Real-Time Dispatch	Units not committed.
02/17/06	~15:00	LDC is using gas at a rate that would indicate a Gas Day 2-17 burn of 1,337,000 Dth.		No addition purchases for the LDC are made. LDC Net Reserves are approaching ZERO without additional authorized storage overrun.
02/17/06	~15:45	Low Level Alarm for Longmont sounds for the second time on 2/17.	Gas Control	Low Level Alarm is set at 450 psi.
02/17/06	~16:00	Low Level Alarm for Louisville Compressor Inlet sounds.	Gas Control	Low Level Alarm is set at 445 psi.
02/17/06	~16:15	Pressure at West Town Border drops below Low Alarm Level to ~ 320 psi.	Gas Control	Low Level Alarm is set at 320 psi. Actual temperature is 16 degrees Fahrenheit below previous forecast.
02/17/06	~15:20	Recoding of Gas Pressures on CIG and PSCo show sudden significant drop in Pressures.		Blue Spruce #1 and #2 trip due to gas valves operation triggered by “normal” drop in gas pressure.
02/17/06	~18:00	Low Level Alarm for CIG Ft. Lupton Delivery.	Gas Control	Low Level Alarm is set at 590 psi.
02/17/06	~24:00	Pressure at West Town Border recovers to ~ 390 psi. – 40 psi above Low Alarm Level.	Gas Control	Actual temperature is 13 degrees below previous forecast.
02/18/06	~02:45	Low Level Alarm for West Town Border sounds.	Gas Control	Low Level Alarm is set at 350 psi.
02/18/06	~03:30	LoLo Level Alarm for Longmont sounds.	Gas Control	LoLo Level Alarm is set at 375 psi
02/18/06	~04:00	Pressure at West Town Border drops below the LoLo Alarm Level of 310 psi.	Gas Control	Actual temperature is 13 degrees Fahrenheit below previous forecast.
02/18/06	04:21	Ft Lupton units started on Gas and ran at min load.	Real-Time Dispatch	
02/18/06	05:46	FSV operators called to switch Ft Lupton units to oil.	Real-Time Dispatch	With less than 3 hours remaining in Gas Day 2-17 Ft Lupton is switched to oil.
02/18/06	~06:30	LoLo Level Alarm for Louisville Compressor Inlet sounds.		LoLo Level Alarm is set at 400 psi.
02/17/06 - 02/18/06	08:00 - 08:00	CIG Ault Pressure minimum for Gas Day 2-17 is approx 600 psi.		Contract Minimum is 500 psi.
02/18/06	~08:00	Low Level Alarm for Yosemite 24” Inlet sounds.		Low Level Alarm is set at 470 psi.
02/18/06	~08:00	Actual LDC load for Gas Day 2-17 is 1,300,560 Dth.		Actual LDC use is 118,890 Dth over last revised forecast (10.06%).
02/18/06	~08:00	Actual use of Electric Gen for Gas Day 2-17 is 313,016 Dth.		Actual burn for electric generation is 25,929 Dth less than Supply Plans .

Date	Time	Action/ Activity		Event
02/18/06	~09:00	Pressure at West Town Border bottoms out at ~240 psi; 70 psi below LoLo Alarm Level of 310 psi.		

Gas Supply/Gas Control Discussion

Gas supply issues were coming to the forefront beginning in the early morning hours on February 17, 2006. As the temperatures continued to be colder than expected and forecasted by PSCo the natural gas usage by the LDC system continued to increase as well as gas usage by electric generation. At the same time, gas use throughout the LDC system was increasing in response to the actual temperatures, and the line pack began to diminish. The transport customers also were under delivering natural gas which also contributed to the loss of line pack.

Gas Supply

PSCo Gas Supply is responsible for buying and delivering gas for both its retail gas customers' needs served through the LDC system and for the electric power plants that used gas to generate electricity. Most of the gas that is needed for LDC sales and electric generation is purchased on monthly or day-ahead basis, with the remainder of the gas needed coming from storage or spot purchases.[26]

PSCo can draw from Young storage field, which is a CIG storage facility, and from Roundup storage field, which is a PSCo storage facility. Included as part of the storage that PSCo can call on is the No-Notice Storage and Transportation Delivery Service (NNT storage) provided by CIG. The NNT storage allows for gas to be drawn from its contracted storage and delivered into its distribution system on an as-needed basis, without the need to precisely specify the delivery quantity in advance. PSCo states that by having available storage, including the NNT storage, the gas distribution system can be managed such that enough natural gas can be provided to meet both LDC sales and electric generation gas loads should there be any unanticipated events, including cold weather, fuel interruptions and generating plant outages.[27] The events of February 17 and February 18 tested PSCo's Gas Supply's and Gas Control's management, operating procedures, and its reliance and use of gas storage and authorized overruns to overcome events that had not been anticipated.

PSCo Gas Supply is responsible for forecasting the gas supply requirements for the LDC sales load, which is based on the internal PSCo weather forecast of high and low temperatures for the day. PSCo's Energy Trading is responsible for forecasting gas requirements for the electric generation needs, which is based on the electric load forecasts and in turn relies on the internal PSCo weather forecast. The gas forecast for the electric generation needs includes PSCo gas power plants that are both behind the PSCo LDC system and PSCo plants that receive their gas directly from CIG. CIG is a natural gas transporter in the Rocky Mountain region and is connected to most of the major supply basins and production areas in the region. CIG's transmission pipelines act to move large volumes of natural gas from the producing regions to LDCs. It also includes supply needs for independent power producers (IPPs). IPPs provide approximately 50 percent of the electric generation capacity that is available to serve PSCo's

[26] A spot purchase is a short term sale of gas to and end user, LDC, or pipeline for which the delivery duration varies. The spot market is characterized by short-term, interruptible contracts for specified volumes of gas.

[27] Report of Events That Led to Controlled Outages – Public Service Company of Colorado, Page 5, March 13, 2006.

retail load.[28] PSCo contracts for and supplies natural gas to the IPPs that provide electric generation capacity to the PSCo system.

Once the gas supply requirements are forecasted for both the LDC and electric generation, Gas Supply nominates gas on pipelines to meet the forecasted gas requirements. A nomination is a request that a physical quantity of gas under a specific purchase, agreement or contract be delivered to a specific point. A nomination includes all custody transfer entities, locations, compressor fuel and other volumetric assessments, and the precise routing of gas through the pipeline network to get to its delivery point. Pipeline capacity must also be considered, such that firm gas has priority over interruptible gas.

On February 16, 2006 Gas Supply calculated the LDC sales gas load for the gas day of February 17, 2006 that resulted in a forecasted LDC sales load of 1,046,710 Dth. For electric generation Energy Trading forecasted a gas load of 245,500 Dth.[29] Gas Supply purchased spot gas in the amount of 79,402 Dth for use by electric generation in addition to gas supply on hand from baseload supplies and storage withdrawals.

At approximately 06:30 on February 17, 2006 Gas Supply revised the forecasted LDC sales load to be 1,181,670 Dth, 13 percent above the original forecast. At 13:00 the gas requirements for electric generation were revised to be 335,402 Dth, 37 percent above the original forecast, to reflect electric generation over burns as well as an additional Intra-Day 2 gas purchase to provide additional gas to the available supply.[30] The additional Intra-Day 2 purchase was for the amount of 31,543 Dth and was the only purchase that Gas Supply could find on the market. However, due to pipeline constraints resulting from gas flowing at near pipeline capacity, only 23,373 Dth (74 percent) was able to flow into the PSCo system.[31] Intra-Day 2 gas supply cannot "bump" (take priority over) scheduled gas already confirmed in the previous cycles of the gas day. While it was not immediately known that the entire 23,373 Dth could not be transported, pipeline cuts and bumps are a normal occurrence under similar conditions.

As an alternative to using natural gas to fuel electric generation plants, fuel oil is listed as a back-up fuel supply by PSCo when there are natural gas shortages or electric generation has burned its secured supply of gas.[32] On the morning of February 17 there was 116,767 Dth of fuel oil available for use by electric generation.[33] While fuel oil is an important fuel reserve resource for the power plants, it should not be considered firm in calculating natural gas supply reserves in cold temperatures where plants have experienced problems starting on fuel oil due to the low temperature. Due to the difficulties that PSCo experienced when trying to start some of the generation facilities on fuel oil at cold temperatures, and due to the fact that not all plants have the ability to burn fuel oil, PSCo should not rely on fuel oil as a reliable primary source of fuel or even as a backup source during cold weather.

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[28] Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006, Page 2.

[29] A gas day is defined as the period beginning at 08:00 MT on the calendar day and ending at 08:00 MT on the following day.

[30] Intra-Day 2 allows additional gas to be purchased and brought on the system in the middle of the gas day. Intra-Day 2 gas supplies begin to flow at 2000 (MST).

[31] Exhibit 5, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.

[32] Exhibit 5, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.

[33] Exhibit 5, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.

The gas supply requirements for the LDC system and electric generation were forecasted on the morning of February 17 for the Gas Day of February 18. The Gas Supply department forecasted a LDC sales gas load of 942,039 Dth and Energy Trading forecasted an electric generation gas load of 265,000 Dth. On the morning of February 18, at 07:00 Gas Supply revised the LDC sales gas load to be 1,147,930 Dth, 22 percent above the original forecast, due to colder that expected temperatures. Due to loss of line pack that resulted from using more gas used than brought into the system on February 17, Gas Supply purchased an additional 128,600 Dth of intra-day spot gas for the February 18 Gas Day. Only 124,597 Dth was delivered due to pipeline capacity constraints.[34] No revisions were made to the electric generation gas load for the Gas Day of February 18.

In order to meet the natural gas load that was forecasted for both the LDC sales and electric generation, PSCo relied on its baseload supplies, the Young and Roundup storage fields and the NNT storage. For February 17 and 18 Gas Supply relied on the internal PSCo weather forecast when forecasting the LDC sales load and on the Energy Trading department's forecast for the electric generation load. Gas Supply looks at the gas load forecast and then compares the forecast to the available gas supply on hand to decide if any additional natural gas needs to be bought and nominated on the system.

For the gas days of February 17 and February 18, PSCo had already scheduled the maximum amount that could be withdrawn from Young Storage and Roundup Storage. Additionally, PSCo had planned to withdrawal the maximum amount allowable from the NNT storage as part of their gas supply to meet the forecasted load. This did not leave PSCo much opportunity to rely on storage reserves if the gas load exceeded the gas load forecast. The only remaining option was to request a storage overrun if gas supplies got tight. PSCo requested and was granted authorized storage overruns for both February 17 and February 18.

If the gas load been correctly forecasted, there likely would have been enough gas supply. However, the load forecasts and the actual gas used by LDC sales and electric generation differed. The gas load forecasts for both the LDC system and electric generation were underestimated and the actual usage by the LDC system and the electric generation stretched what available gas there was to the limits.

For February 17, 2006 the revised forecast for the LDC sales gas load was 1,181,670 Dth, the actual gas use by LDC sales was 1,350,552 Dth, which was 168,882 Dth (14 percent) over the revised forecast amount and 303,842 Dth (29 percent) over the original LDC sales forecast amount.[35] For February 17, 2006 the forecasted gas load for electric generation was 335,402 Dth, the actual gas used for electrical generation was 313,016 Dth, which was 22,386 Dth (7 percent) under the revised forecasted amount and 67,516 Dth (28 percent) over the original forecasted amount.[36] PSCo has also reported that there was a LDC transportation imbalance for the Denver/Pueblo and Front Range operation areas due to an under delivery on February 17 of 83,204 Dth.[37] Table 4-1 summarizes the gas forecast, gas supply available and the actual gas

[34] Exhibit 5, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[35] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-29, PSCo reported that the amount of gas used by the sales customers on February 17 was 1,350,552 MMBtu.
[36] 1st Set of Internal Investigation Questions Natural Gas Supplies, February 24, 2006, Response to question PSCO 1-14.
[37] Seventh Set of Audit Requests of the CPUC Staff, PSCo Response to Audit Request No. CPUC7-17.

used by LDC sales and electric generation for February 17. The fuel oil that PSCo listed as backup supply was not shown in Table 4-1 because fuel oil is not available for every plant and due to the problems staring plants in cold weather that were experienced on February 17 and 18. At this time using fuel oil for electric generation, particularly in cold weather, has some reliability issues that are further discussed in Section 6.

Table 4-1: Gas Supply, Forecast, Actual Use – Gas Day February 17, 2006

Friday, February 17, 2006	LDC Load	%	Electric Load	%	Transportation	Total
Actual Use	**1,350,552**		**313,016**			
Forecast Sales (original)	1,046,710		245,500			
Forecast Sales (revised)	1,181,670		335,402			
Actual Use - Forecast (original)	303,842	29%	67,516	28%		
Actual Use - Forecast (revised) =	168,882	14%	-22,386	-7%		
Baseload Supplies	376,358		183,000			
Roundup Storage	37,931					
Young Storage	187,000	Max	6,351			
NNT Storage	662,649	Max				
Daily Spot Purchases	0		102,775			
Gas Supply Sub-Total	**1,263,938**		**292,126**			
Authorized Storage Over-run	93,520		27,000			
Gas Supply Total	**1,357,458**		**319,126**			
Gas Supply Sub-Total - Actual Use	**-86,614**		**-20,890**			
Gas Supply Total - Actual Use (Over-run or Under-run)	**6,906**		**6,110**		**-83,204**	**-70,188**

Table 4-1 demonstrates that the combined gas system was deficient 70,188 Dth for the gas day of February 17. Staff was informed that the authorized storage overrun was reduced to 27,000 Dth for the electric generation gas supply because not all of the 36,649 Dth was used. One of the Manchief facility units was offline and was not able to burn the gas out of the Young storage field.[38]

[38] The 27,000 Dth amount was an estimate supplied by PSCo and an actual volume was requested at a meeting with Gas Supply on June 9, 2006.

Table 4-2: Gas Supply, Forecast, Actual Use – Gas Day February 18, 2006

Saturday, February 18, 2006	LDC Load	%	Electric Load	%	Transportation	Total
Actual Use	**1,300,335**		**266,395**			
Forecast Sales (original)	942,039		265,000			
Forecast Sales (revised)	1,147,930		265,000			
Actual Use - Forecast (Original)	358,296	38%	1,395	1%		
Actual Use - Forecast (revised) =	152,405	13%	1,395	1%		
Baseload Supplies	376,358		183,000			
Roundup Storage	37,362					
Young Storage	187,000	Max	6,351			
NNT Storage	662,649	Max				
Daily Spot Purchases	124,597		91,439			
Gas Supply Sub-Total	**1,387,966**		**280,790**			
Authorized Storage Over-run	0		0			
Gas Supply Total	**1,387,966**		**280,790**			
Gas Supply Sub-Total - Actual Use	**87,631**		**14,395**			
Gas Supply Total - Actual Use (Over-run or Under-run)	**87,631**		**14,395**		**12,858**	**114,884**

As can be seen in Table 4-2, the gas system ended gas day February 18 with an excess of 114,884 Dth for the gas day of February 18.[39] As related in Table 4-2, the actual use did not exceed what was available for gas supply and thus authorized overruns have not been included in Table 4-2.[40] Although there is a positive imbalance for gas day February 18, 2006 the gas arrived too late to relive the low pressure situation and remedy the supply problems caused from the gas deficiency of gas day February 17 that actually occurred in the early morning hours of February 18, 2006. PSCo has also reported that there was a LDC transportation imbalance for the Denver/Pueblo and Front Range operation areas due from an over delivery on February 18 of 12,858 Dth.[41]

Only a subset of PSCo's natural gas burning electric power plants is behind the LDC. Counting only those units for the front-range area, electric generation did have an over-burn of its nominations for gas day February 17 and under-burn on gas day February 18. Resulting in net imbalances for gas day February 17 of -27,589 Dth and for gas day February 18 of 13,690 Dth.[42] The gas system deficiency of gas day February 17 was carried over into the gas day of February 18 and caused the loss of additional line pack of the LDC system.

[39] For gas day February 18 PSCo received an authorized storage overrun of 59,437 Dth for LDC sales and an authorized overrun of 38,649 Dth for electric generation.

[40] An authorized overrun (on a daily basis) is gas that is allowed in advance to be taken, within specified parameters, above the contract demand volume.

[41] Seventh Set of Audit Requests of the CPUC Staff, PSCo Response to Audit Request No. CPUC7-17.

[42] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-8, PSCo reported daily net imbalances for PSCo-owned and controlled generation facilities for which PSCo Electric is responsible for managing natural gas for the Front Range areas.

The volumes in the tables represent electric generation plants that are both behind the LDC system and on the CIG system.[43] The tables for February 17 and February 18 use system numbers which Staff believes represent the complete LDC and electric generation picture for gas days February 17 and February 18. Over-burns localized to the Front Range area would have exacerbated the gas shortage in the Front Range area and dropped pressures through the LDC along the Front Range, while not necessarily showing up as an over burn system wide.

The investigative team received conflicting data concerning withdrawals from PSCo's Roundup storage facility. Staff relied on the PSCo provided numbers that for Roundup Storage showing withdrawals for the February 17 gas day of 37,931 Dth and for the February 18 gas day of 37,362 Dth.[44] In the PSCO report dated March 13, 2006 PSCo lists the Roundup Storage withdrawals as being 30,000 Dth for both February 17 and February 18.[45] However, in the 1st Set of Internal Investigation Questions provided by PSCo, dated February 24, 2006, PSCo states that the Roundup withdrawals for February 17 were 38,005 Dth and for February 18 were 37,366 Dth.[46] Staff has requested that PSCo provide reconciliation of conflicting numbers and requested that PSCO provide actual verified numbers relating to gas supply, but has not received them at this time. Even if the increased storage withdrawals from Roundup are accurate, it still would have left a deficiency of supply on February 17.

As the data contained in Tables 4-1 and 4-2 indicates, there were several assumptions that contributed to the tightness of the gas supply on February 17 and February 18. The gas forecasts for the LDC and electric generation were originally too low, which can be attributed to using the original internal PSCo weather forecast. PSCo has stated that based on the load forecasting model the gas forecast for the LDC for February 17 was deficient by approximately 101,220 Dth (16,870 Dth times 6 degrees Fahrenheit).[47] As the weather differential continued to increase, the load forecast was only slightly revised and the weather forecast was never officially recast, which resulted in PSCo having to request authorized storage overruns in an attempt to supply enough gas to satisfy the gas loads for February 17, 2006.

PSCo was planning on pulling maximum amounts of gas from Roundup Storage, Young Storage, and NNT Storage from the onset of the planning for the gas day of February 17 and 18 to decrease its gas inventory. An unseasonably warm January and early February had contributed to PSCo reaching its upper limit of storage capacity, and plans had been made in advance of the holiday weekend to draw down storage at that time. With the onset of colder weather PSCo did not modify its plans. The Company did not withhold its capacity to withdraw gas from storage as safety net, and thus decreased its available reserves. Not modifying its plans created a situation where PSCo had to rely on authorized storage overruns to act as reserves. As the gas loads increased due to dropping temperatures through the day on February 17, PSCo had little success buying any additional spot gas due to the holiday weekend and suppliers leaving their offices

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[43] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-8, PSCo reported daily net imbalances for PSCo-owned and controlled generation facilities for which PSCo Electric is responsible for managing natural gas for the Front Range areas.
[44] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-10(r).
[45] Report of Events that Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[46] 1st Set of Internal Investigation Questions Natural Gas Supplies, February 24, 2006, Response to question PSCO 1-10.
[47] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-35, PSCo reported daily net imbalances for PSCo-owned and controlled generation facilities for which PSCo Electric is responsible for managing natural gas for the Front Range areas.

early. PSCo had to rely on authorized overruns since the storage maximums were already allocated for use. PSCo did not have a protocol in place defining appropriate reserve margins and how to calculate that margin based on scheduled storage withdrawals, NNT storage capability and as a last resort authorized storage overruns.

The gas distribution system was stretched to the limit for the gas day of February 17 and could not recover adequately for the gas day of February 18 to allow electric plants to burn gas to generate power, either because pressures were not adequate to bring plants online, or because pressures dropped too low to continue running plants that were either online or expected to be online. The unavailability of these plants contributed to the need to initiate the rolling blackouts that took place on February 18, 2006.

Gas Control

PSCo Gas Control is responsible for the operation of PSCo's pipelines, including the LDC system. Gas Control has the ability to provide real-time monitoring of the LDC system and directing gas throughout the system to ensure that adequate supply can reach the natural gas demands on the system. Gas Control can monitor the real-time burn rates of the electric generators that are located on the PSCo system and for PSCo electric generation plants directly connected to the CIG system. Nominations for gas transported over the PSCo system are made to Gas Control so they can be scheduled to ensure that the pipelines have adequate capacity for the natural gas to flow through the PSCo pipelines. Gas Control also has the ability to monitor LDC system pressures, which indicate the availability of line pack throughout the system and monitor pressure alarms throughout the systems.

PSCo has stated, in response to audit, that no noticeable drop in the gas system pressure occurred until after 20:00 on February 17, 2006.[48] However, that information is inconsistent with other information provided to the investigative team.[49] At approximately 06:00 on February 17 the low level alarm for Longmont sounded, followed by the low level alarm for Fort St. Vrain Inlet, which sounded at approximately 07:30. At approximately 08:45 the low level alarm for Longmont was reset as gas pressures rose temporarily above the low level alarm set point of 450 psi. The low level alarm for Forth St. Vrain Inlet would not reset until approximately 12:00 on February 18 when pressures climbed above the low level alarm reset point of 600 psi. Table 4-3 identifies the Low and LoLo level alarms and the approximate times that they sounded to notify Gas Control of pressure issues during the days of February 17 and February 18.

[48] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-37(a).
[49] Exhibit No. 11, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.

Table 4-3: Low and LoLo Pressure Alarms for February 17 and 18[50]

Date/ Time	Alarm Level	Alarm Location	Alarm Point	Alarm Reset
2/17/06 06:00	Low	Longmont	450 psi	2/17 @ 0845
2/17/06 07:30	Low	Fort St. Vrain Inlet	600 psi	2/18 @ 1200
2/17/06 15:45	Low	Longmont	450 psi	2/18 @ 1130
2/17/06 16:00	Low	Louisville Compressor Inlet	445 psi	2/18 @ 1130
2/17/06 16:15	Low	West Town Border	350 psi	2/17 @ 1900
2/17/06 18:00	Low	CIG Ft. Lupton Delivery	590 psi	2/18 @ 1130
2/18/06 02:45	Low	West Town Border	350 psi	2/18 @ 1030
2/18/06 03:30	LoLo	Longmont	375 psi	2/18 @ 0900
2/18/06 04:00	LoLo	West Town Border	310 psi	2/18 @ 1000
2/18/06 06:30	LoLo	Louisville Compressor Inlet	400 psi	2/18 @ 0900
2/18/06 08:00	Low	Yosemite 24" Inlet	470 psi	2/18 @ 0930

PSCo has stated that the "Low" system alarm indicates that "something out of normal operational range" is occurring.[51] Once a Low alarm is sounded it is standard operating practice for the Gas Controller to take a closer look at the specific situation and determine if any operational changes need to be made to remedy the situation. The "LoLo" system alarm indicates that "some immediate action must be taken to avoid serious operational consequences" such as loss of pressure and flow to a specific customer or area of the system. When an alarm sounds the Gas Controller analyzes current pressure and flow, historic trending of pressure and flow, and current temperature and forecasted temperature across the system.[52]

Although some Low alarms occur in the normal course of a gas day as use varies, the system will also exhibit recovery cycles of low alarms. In the case of February 17 and February 18 the Low and LoLo alarms indicated a trend over time of lower gas pressure throughout the LDC system.

[50] Data in Table taken from: Exhibit No. 11, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[51] 3rd Set of Internal Investigation Questions Natural Gas Supplies, March 3, 2006, Response to question PSCO 3-78.
[52] 3rd Set of Internal Investigation Questions Natural Gas Supplies, March 3, 2006, Response to question PSCO 3-78.

Gas Control monitors in real-time the electric generator burn rates and calculates the average burn rate for the electric power plants and projects that average burn rate over the gas day. From the very beginning of the February 17 gas day, the electric plants were burning at a very high rate to generate electricity.

PSCo states that at approximately 14:30 on February 17, 2006 Gas Control called Gas Supply and was very concerned about the electric plants over burning and wanted to know if the electric plants were going to continue to burn at the same rate all day as they had up to that point.[53] However, the first call from Gas Control to Gas Supply that expressed concern about the over burning occurred at 12:52, not at 14:30.[54] During the call between Gas Control and Gas Supply it was decided that gas nominations for the electric department needed to be increased due to the excess burn rate of the electric generators. As shown in Table 4-4 the average burn rate, which is projected as a straight line, for the rest of the gas day after 14:00 would exceed the amount of gas originally nominated for electric generation by 96,000 Dth (39 percent of original forecast). This projection is linear in nature and assumes that the burn rate for the power plants will stay constant for the entire gas day. In actuality, this did not happen and at the end of the day the data indicates that electric generation had enough gas supply, in part because many plants were not allowed to start due to low gas pressure on the LDC.

Table 4-4: Straight Line Average Example for Electric Generation Gas Burns

Electric Generation Natural Gas Use	
Gas Day, February 17, 2006	Burn Rate per Hour
Hour Ending	MMBtu[55]
09:00	14,456
10:00	15,254
11:00	14,570
12:00	13,609
13:00	14,234
14:00	13,444
Original Forecast = 245,500 MMBtu	
Average Burn Rate per Hour for HE 09 through 14 = 14,261 MMBtu	
Projected Average Burn Rate Over Entire Gas Day Total (avg.*24) = 342,264 MMBtu	
Estimated Over Burn (Projected Burn Rate - Original Forecast) = 96,764 MMBtu	

On February 17, Gas Supply revised it forecast for electric generation load. After receiving the call at 14:22 from Gas Control, Gas Supply began looking for intra-day gas that it could purchase and move into the PSCo system so the electric generation would not over burn its nominations. Since the high electric generation over burns happened in the early hours of gas day February 17, the linear projection used by Gas Control continued to indicate that electric generation was over burning what it nominated for the day. During the phone call between Gas Control and Gas Supply at 14:22, it appears that Gas Control began to realize that the LDC system was going to have gas supply and pressure problems if no additional gas was purchased and brought onto the system. Gas Control commented "earlier we just thought if we bring all the Young gas [on] and

[53] Page 14, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[54] Transcript of Gas Supply Manager's recorded line, Page 6, call at 12:52:43 PM, February 17, 2006.
[55] As defined in the PSCo tariff, a dekatherm (Dth) is the energy equivalent to 10 therms, or 1,000,000 Btu, or 1 MMBtu. One therm is the equivalent to 100,000 Btu.

with our authorize we'd be okay, but it not getting any better."[56] Gas Control and Gas Supply discussed that some transportation customers were short on their gas deliveries into the LDC and commented that the only way that they could get transportation customers to balance their nominations with their use was to call an Operational Flow Order (OFO).[57]

PSCo defines an OFO in its gas tariff as:

> "An order issued for a specific Gas Day(s) and designed Operational Area by Company to alleviate conditions which threaten or could threaten the safe operation or integrity of Transporter's system or to maintain operations required to provide efficient and reliable firm service under the following conditions: a) when delivery system pressure or other unusual conditions are reasonably expected, in Company's judgment, to jeopardize the operation of the Company's system; b) when transmission, storage, or supply resources are being used at or near maximum deliverability; c) when one or more upstream pipelines call an operational flow order and such operational flow order creates conditions on Company's system which necessitates calling an Operational Flow Order; and d) when Company is unable to fulfill its firm service obligations or to maintain overall operational integrity of the system."[58]

As indicated by Table 4-4, gas pressures in the LDC system began to fall throughout February 17. Beginning at 12:52 on February 17, Gas Control expressed concerns over the possible over burning of gas by the electric generation. The question that should have been addressed, but never was is: if the over burn rate continues by the electric generation and there is a shortage of 90,000 Dth for the gas day of February 17, would that "jeopardize the operation of the Company's [PSCo's] system" such that it would require an OFO be called?

If the over burn was a threat to the system an OFO should have been called according to PSCo's gas tariff, without regard for the source or sources of the problem (in this case, at least in part, the Company's own electric plants) or the timing (late in the gas day). An OFO can also be called when "supply resources are being used at or near maximum deliverability." Throughout the gas day of February 17, all of the following seem to indicate that supply resources were being used at maximum deliverability: the storage and NNT storage were planned to be withdrawn at the maximum amount allowable; pressures in the pipeline were falling indicating that more gas was being used than was being delivered; PSCo was relying on authorized storage overruns for gas supply; and, the additional spot gas purchased could not be fully delivered onto the system because of pipeline cuts due to the large amount of gas that was flowing that day and reaching pipeline capacity.

At approximately 14:34 Gas Control and Gas Supply talked again. Gas Supply sought more gas, but didn't know how much luck that they would have considering it was Friday afternoon beginning a holiday weekend. Gas Control and Gas Supply discussed again the possibility of calling an OFO and Gas Supply indicated that Energy Trading did not want to back off the electric generation using gas to generate because "purchasing power is like triple digit prices…"[59]

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[56] Transcript of Gas Supply Manager's recorded line, Page 11, call at 2:22:37 PM, February 17, 2006.
[57] Transcript of Gas Supply Manager's recorded line, Page 11, call at 2:22:37 PM, February 17, 2006.
[58] PSCo Gas Tariff, Gas Transportation Terms and Conditions, Sheet No. T4.
[59] Transcript of Gas Supply Manager's recorded line, Page 12-13, time not listed when call was placed but it is approximated to be at 2:35 PM, February 17, 2006.

Energy Trading at this point in the day had made the choice to keep burning gas based on economics rather than conserving the gas supply.

Energy Trading stated that the standard operating procedures were followed to the letter with regard to forecasting, scheduling and nominating energy supplies for February 17 and February 18.[60] However, it should be noted that both CIG's tariff and PSCo's own tariff require that gas be delivered at a constant rate throughout the day equal to an hourly flow rate of 1/24th of daily nomination. The original gas load forecast for electric generation was 245,000 Dth, which would have been being delivered into the gas system at an approximate rate of 10,208 Dth per hour. The electric generation burn rate was 14,261 Dth per hour through 14:00 on February 17, which was greater than what was being delivered into the system at that time.

At 15:02 Gas Control called Gas Supply and again talked about calling an OFO. It was still projecting that the electric generation gas burns indicated that the electric generation plants would still over burn what it nominated for the gas day. Gas Control commented that if an OFO is called "[electric] are the ones that are going to be whacked. So I mean it just – cause there is no reason for me to do it, penalize everybody for this one customer."[61]

At 15:17 Gas Control called Gas Supply and talked about the penalty due to the electric gas overruns and that there was probably not be any more gas available due to it being late on Friday.[62] At 15:28 when Gas Supply called Gas Control, Gas Supply stated that even at the penalty for gas overruns Energy Trading still wants to burn gas rather than buy electricity due to the high price of buying power. Gas Control stated that he "can't call an OFO because the only customer that's killin' us is the electrics."[63]

Even though Gas Control can monitor the real-time usage by the power plants, PSCo has said that it does not have the capability of monitoring real-time LDC usage. While Gas Control was watching the burn rate for the electric generation plants, the LDC was using more gas than was nominated for the February 17, gas day. The LDC was averaging a gas throughput of 76,299 Dth, with an average transportation component of 21,703 Dth and an average LDC use of 54,596 Dth.[64] At the end of the gas day for February 17 the LDC would have a total actual use of 1,350,552 Dth, 14.3 percent above the revised forecast and 29.0 percent above the original forecast.[65]

At approximately 15:45 on February 17 the pressures throughout the LDC began to drop. Additionally, pressures for CIG's pipelines that feed into the PSCo system also began to drop.[66] It is unclear what caused this drop in the pipeline pressure, but reviewing the LDC throughput data there is a jump in gas throughput from the hour ending at 14:00 to hour ending at 15:00 of

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60 Response to question PSCO 1-4; 1st Set of Internal Investigation Questions Weather Forecasting, February 24, 2006.
61 Transcript of Gas Supply Manager's recorded line, Page 17, call at 3:02:42 PM, February 17, 2006.
62 Transcript of Gas Supply Manager's recorded line, Page 17-18, call at 3:17:40 PM, February 17, 2006.
63 Transcript of Gas Supply Manager's recorded line, Page 18-19, call at 3:28:33 PM, February 17, 2006.
64 Gas throughput is the total of transportation and tariff sales; all gas volumes delivered.
65 Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-29, PSCo reported that the amount of gas used by the sales customers on February 17 was 1,350,552 MMBtu. In Exhibit No. 5 of the Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006 the revised Forecast Sales Load was 1,181,670 Dth and the original Forecast Sales Load was 1,046,710 Dth.
66 Exhibit No. 11 shows the Cig and PSCo pipeline pressure for February 16 through 18. Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.

approximately 3,000 Dth. The pressure of the LDC had been reduced and thus the line pack reduced in the early hours of the February 17 gas day, so a modest increase of gas use may have started the system to depressurize or unpack, especially if the LDC system was just holding at equilibrium. The increase in LDC gas throughput could have been caused by automatic thermostats turning on gas heaters to raise the temperature of homes before people returned from work.

Gas Control comments in an email to Energy Trading and Gas Supply that "I can't call a system wide OFO because I [can't] physically bring the gas on to the system."[67] While gas may not have been available on the market if an OFO was called, calling the OFO may have forced the transporters on the LDC to ensure that they were using only what they nominated and could have prevented the transportation under delivery on February 17 of 83,204 Dth.[68] If an OFO had been called early, there may have been the opportunity to have transporters arrange for intra-day gas to flow into the system.

In fact PSCo has stated that at times in the past, OFO transporters have over delivered into the system. An OFO would have also alerted the Real-Time Dispatch of the gas shortage, correcting Dispatch's impression that physical gas is still readily available.[69] As a result, Real-Time Dispatch continued to operate based only on economic and not gas pressure reasons. Energy Trading continued to act as if there was plenty of gas and continued to use gas for generation rather than buying power.

At 17:34 on February 17, Gas Control talked to CIG and requested CIG to increase the pipeline pressure. CIG stated it couldn't provide more pressure and that it needed to lower the pressure in the line to get more gas out of storage. CIG also pointed out that CIG's pressure obligation to PSCo is 500 psi.[70] At this time the pressures have continued to drop in both the PSCo LDC system and CIG pipelines.[71] As shown on the CIG and PSCo pressure graph, the LDC pressure recovered slightly from about 19:00 on February 17 to until about 00:30 on February 18 when the LDC system began to lose pressure until the gas pressure bottomed out at approximately 08:30 on February 18.

The pressure drop that the LDC experienced was caused by not having enough gas to replace what was being used. The CIG Ault connection dipped to a low pressure of around 600 psi early in the gas day of February 18, 2006. The contract minimum pressure of the CIG Ault connection to PSCo is a minimum of 500 psi, which CIG maintained during the events of February 17 and 18. In the early morning of February 18, (end of the gas February 17 gas day) the gas pressures continue to drop and Gas Control, unable to get more gas into the system, tried to control the fall of the gas pressure throughout the LDC system. At approximately 06:00 February 18, Gas Control decided to call an OFO for the February 18 gas day.[72] Due to the plant failures and the condition of the LDC system, a statement made during a conversation sums up how the morning

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[67] Entry on February 17 at 15:49; February 17 and 18 Gas Control Communication and Event Log.
[68] Seventh Set of Audit Requests of the CPUC Staff, PSCo Response to Audit Request No. CPUC7-17.
[69] Exhibit No. 10, page 4 at 16:28:00. Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[70] February 17 at 17:34 February 17 and 18 Gas Control Communication and Event Log.
[71] Exhibit No. 11. Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[72] The February 18 gas day started at 08:00 MST on February 18 and ended at 08:00 MST on February 19.

of February 18 had shaped up for LDC customer, “we can put ‘em out of gas, or we can put ‘em out of electric.”[73]

In PSCo’s Commitment Log Report dated June 15, 2006 set forth a number of commitments that are intended to set protocols for Gas Supply and Gas Control when planning and operating the system during adverse weather conditions. Event Commitment No. 14 is to develop operating protocols during elevated operations. Event Commitment No. 16 is to investigate how to align and integrate various operations to deal with unusual weather. At the time of February 17 and February 18 PSCo did not have written procedures in Gas Control for normal or elevated operations, unless the situation was listed in the Gas Emergency Plan. PSCo defines “Elevated Operations” as any situation where actions are required outside of monitoring and controlling flow rates and pressures. PSCo also sets forth specific situations that would be considered as elevated operations and implements what it refers to as a “Reliability Call.” If conditions exist that threaten or could threaten the safe operation or integrity of PSCo’s gas system and observations are made at Gas Control that PSCo Electrics do not have adequate supply of gas a Reliability Call will be made. A Reliability Call will be made to Real-Time Dispatch and must be made either prior to or coincident with calling an OFO. It seems that this step is duplicating what calling an OFO would accomplish. Instead of having a Reliability Call, it is unclear why PSCo cannot rely on an OFO serving notice to the Real-Time Traders.

PSCo writing of Gas Control operating protocols will become a tool that can be used to address future incidents. It is unclear however, why some of the thresholds that PSCo used in its new protocols were chosen. One situation that dictates an elevated operation is a forecast ambient air temperature below 5 degrees Fahrenheit (minus 15 degrees Celsius). The protocols are in bullet form. Then there are additional seasonal caveats for mean temperatures that would cause an elevated operating condition, but again no explanation why these temperatures are thresholds. The protocols focus on what actions need to be taken to avoid problems within the LDC; Staff is not sure if the protocols adequately provide solutions to some of the problems that occurred February 17 and February 18. Specifically Section 3, when the weather forecast changes by more than 5 degrees Fahrenheit, or is missed by more than 5 degrees Fahrenheit within the gas day, the protocol calls for Scheduler Action to: “Check storage withdrawal nominations and projections to ensure sufficient daily supply. This includes Asbury, Roundup, Young Gas and NNT. Review load forecast intraday to ensure adequate supply reserve of 150,000 Dth.” However, on February 17 the maximum storage amounts were already listed for maximum withdrawals and there was little to no spot gas available on the market. With no storage gas originally held in reserve there are no additional gas supplies that can be drawn on except authorized storage overruns.

One possible method to address this would be to implement policies prohibiting commitment of 100 percent of gas available in storage and NNT storage to fulfill the gas demand forecast on any given day. If only 85 percent of the volume in storage and NNT storage would be considered as “available” gas when the temperature is suppose to drop below 20 degrees Fahrenheit, then if there was an emergency caused by weather or plant outage there would be storage gas available to drawn on before requesting an authorize overrun. In the instant case if 15 percent of the storage was held in reserve and additional gas was purchased to cover for the reserve gas, an additional 131,947 Dth would have been available to pull from storage to aid in the gas shortage caused by plant outages and incorrect weather and load forecasts. After any such additional storage is used, PSCo could then request and utilize authorize overrun amounts as a method of last resort. As stated in the CIG tariff, authorized overrun amounts should not be relied upon as a source of natural gas except in extreme conditions. Not only is an additional charge incurred for authorized

[73] February 17 and 18 Gas Control Communication and Event Log, comment at 06:17.

overruns, but the overrun gas is transported on an interruptible basis, potentially impacting the reliability of the system.[74] Gas that flows on an interruptible basis is a low priority and interruption on short notice can occur by reason of claim of firm service customers and higher priority users.

Commitment Log Item 19 is to develop Gas Supply Protocols during elevated operations. On Page 1 of 2 of the Elevated Operating Protocols in Commitment Log Item 19, an Elevated Operating Protocol is defined as “Any time an Operational Flow Order has been issued.” However, in Commitment Log Item 14, Elevated Operations are “any situation where actions are required outside monitoring and controlling flow rates and pressures. Section headings indicate the situations identified. The definition and meaning of “Elevated Operations” should be consistent across the gas divisions of PSCo. Commitment Log Item 19 acts to alert Gas Supply personnel when various thresholds are crossed on the electric and gas systems. In the Gas Supply Protocols if the mean temperature is equal to or less than 5 degrees Fahrenheit, enough gas has to be purchased for electric to meet the load generation plus and additional 80,000 Dth. The 80,000 Dth is meant to be equivalent to replacing a 500-megawatt plant for 16 hours. It is unclear why a 500-megawatt plant was chosen for 16 hours, but the protocols begin to set forth some gas to be held in reserve. The protocols also cover various options that are available to Gas Supply including intra-day planning. One factor still to be addressed is what steps to take if a situation occurs similar February 17 and February 18, and there is little or no gas available of the market.

Commitment Log Item 18 is to investigate changing normal gas operation supply protocols for unusual weather. Some of this is also covered by Commitment Log Item 19. PSCo states here that the reserve margin will not include authorized overruns from CIG which Staff agrees with and advocates in this report. By implementing this practice authorized overruns can then be used as a last resort and provide emergency gas reserve to use in dire conditions.

Gas Shortage Impact on Power Plants

In response to a FERC audit question, PSCo stated that Thermo Carbonic was the only electric generation facility that experienced an outage related to insufficient gas pressure.[75] However, on the morning of February 18 Gas Control began to restrict electric generation plants from starting or operating on natural gas due to low gas pressure and the gas system not being able to support electric generation activities. At 05:14 Gas Control ordered Plains End off-line because of low natural gas pipeline pressures. At 05:35 Gas Control reported that Valmont 7 & 8, Brighton 1 & 2, Brush 4 and Plains End could not be supplied natural gas until further notice due to low gas pressure. Gas Control also reported that the turbines at Fort Lupton could not run on natural gas much longer due to low pressure.

At approximately 06:00 on February 18 the PSCo LDC throughput increased, more likely than not to respond to customers turning up their thermostats to heat the house in the morning. At 06:14 Gas Control informed Real-Time Dispatch that the electric department cannot use additional gas off the system today and that Valmont 6 cannot run due to low gas pressures. Real-Time Dispatch at this time tells Gas Control that because the gas-fired electric generation can not run, the electric system will be deficit and an emergency might have to be declared. Gas Control responded that power will have to be purchased from the market. At 07:11 Real-Time Dispatch calls Gas Control and asks if a start up of the RMEC plant could be supported, Gas Control replies that they cannot support RMEC due to low gas pressures.

[74] Colorado Interstate Gas Company Gas Tariff, Section 5.1 Overrun Transportation.
[75] PSCo response to Audit Question OE-PSC 2-41.

At 07:30 Gas Control informs Real-Time Dispatch that Limon cannot be started due to low gas pressure. At 08:40 real-time requests a start up of Fruita and Alamosa on gas, Gas Control replies that they can start the units on gas, but then they need to switch to oil. PSCo's response to the FERC audit question seems to be that only if an electric plant is operating and then goes offline due to low gas pressures has it experienced an outage. Several electric plants were not allowed to start due to low gas pressure, which then resulted in rolling blackouts. The plant capacity that failed to start due to the unavailability of gas should not be considered available reserve (Operating Reserve, Spinning Reserve, Contingency Reserve or Nonspinning Reserve).

On February 18, 2006, at 06:06 Gas Control and Natural Gas Services made the decision to call an OFO for the February 18 gas day, which acted to give notice to the interruptible gas sales customers to stop using gas, and required the gas transportation customers to match their gas nominations with their burns. Between approximately 06:00 and 09:00 the gas pressures in the LDC had "bottomed out" and at 10:00 began to recover and build line pack. The LDC gas pressure began to rise from more gas flowing into the system than being used, due to the curtailment of gas being used by the power plants. Additionally, more and more gas appliances are using electric spark ignition to start burners rather than having pilot lights that are constantly lit. Without electricity a gas appliance that uses a spark igniter cannot operate. As a result when the rolling blackouts occurred not only did those customers lose electricity, but they also lost the ability to use any gas appliances that have electronic spark ignition, and those customers lost the ability to use furnaces that require fans or pumps to operate. Customers effectively experienced both an electric and gas outage at the same time. The blackouts also acted to cut gas use by those affected by the rolling blackouts and thus reduced gas load on the system as well as electric load. The temperature also began to rise in this time period which may have reduced gas used for heating. By 13:00 on February 18 all of the LoLo and Low gas alarms had been cleared due to rising pressures in the LDC system.

Gas Pressure

PSCo has stated that there were no gas outages of sales customers due to a failure of gas supply during the period February 15 to February 21.[76] On Saturday February 18 approximately 150 customers within the Todd Creek and Eagle Shadow Subdivisions experienced outages. PSCo attributes that this outage to a restriction in the line that connects two regulators on its system and claims the restriction in the line caused an excessive pressure drop which then greatly reduced the delivery pressure in the system after the line restriction.[77] PSCo reported that this problem occurred on Saturday February 18 when the LDC system pressures were at their lowest point.

However, this same anomaly did not occur during the period December 4 through December 10 when gas usage was high throughout the LDC system. The low pressure situation on February 18 may have not been the sole cause of the customers' outage, however it does seem to have been a factor in the sales customers' gas outages.

PSCo has begun investigation of the Todd Creek and Eagle Shadow Subdivisions. The current system study that is underway appears to indicate that the line might be restricted in two possible areas. Additional investigation by PSCo experts of the root causes of the loss of load to gas customers in these areas needs to occur. Subsequent to the root cause analysis, a remedy for this problem should be identified and implemented. PSCo should be required to file a report with the Commission on the findings of their investigation and report the solution employed to remedy the problem.

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[76] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-43.
[77] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-43.

PSCo has stated that it has not modeled the PSCo natural gas system to simulate what would happen to the system if the gas received from the CIG interconnections was limited to the contractual minimum pressures.[78] When meeting with PSCo to discuss its gas capacity planning, PSCo stated that its model for 100 percent Coincidence (this model is suppose to represent peak day conditions) uses the pressures that PSCo would "normally" expect from CIG and the not the minimum contract pressures.

By contract, CIG is required to provide a contract minimum pressure to the PSCo system of 500 psi at the CIG Ault connection. At no time, over the gas day of February 16 through the gas day of February 18, did CIG fail to provide the contract minimum pressure at their connections to PSCo.[79] As CIG made clear to PSCo on February 17, CIG's pressure obligation is 500 psi and in times of high gas use CIG will lower pressures in some of its pipelines in order to be able to remove more gas out of storage.[80] Due to low gas pressures, on February 18 PSCo had to dispatch nine workers to operate bypass valves on pressure regulator stations to ensure that the LDC customers would continue to receive gas. Normal operating conditions do not include contract minimum pressure from CIG. As can be seen over the days of February 17 and 18, when things go wrong there is no reason to think that "normal conditions" will exist, and designs and system analysis need to consider "worst case" scenarios.

This minimum pressure should be considered as a "worst case" pressure scenario when designing, analyzing and modeling the LDC. The worst case pressure scenario would enable PSCo to analyze gas delivery availability to LDC customers. Model simulations could also be used to identify weaknesses of the system and allow possible improvements to be simulated before they are constructed. A transient model will allow PSCo to observe how the system will act under different gas loads as well as what effect electric generation plants will have on pressure and flow of the LDC system when they come online or drop offline. The model will also indicate what problems exist in the LDC system under low-pressure conditions when gas delivered into the system will be at contract minimums or slightly over. With a transient model the system could be analyzed to calculate what system or delivery pressures are needed for certain gas power plants to be utilized.

When asked about the loss of the processing plants in the DJ basin, PSCO stated that the "PSCo gas system is a complex web of different sizes of pipe connected to various supplies of gas at various pressures."[81] PSCo also stated that only a pipeline simulator operating in transit state mode, rather than steady state mode, could possibly estimate the amount of pressure drop that such a plant shutdown could have on the PSCo system. The more complex a system, the more that a computer model that simulates possible configurations is needed, not only for planning of future gas systems, but also for the ability to simulate if additional compression is needed, how to manage the system in low pressure situations, and what impact electric generation plants have on the system pressure and flow rates.

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[78] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-68.
[79] The pressure at the CIG Ault connection had a low pressure of approximately 595 psi on February 18, at approximately 13:30 Exhibit No. 11 - CIG and PSCo Pressure February 16 through 18, Report of Events That Led to Controlled Outages – Public Service Company of Colorado, March 13, 2006.
[80] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-59(b), see also February 17 at 17:34 February 17 and 18 Gas Control Communication and Event Log.
[81] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-37(l).

The PSCo Gas Purchase Plan (GPP) sets forth the LDC Forecasted Design Peak Day Requirements for the Denver, Northern Front Range, Pueblo, Mountain and San Luis Valley areas. The LDC system should be designed and managed such that the LDC system can provide natural gas to meet the design peak day load set forth in the GPP. As PSCo points out in its response to Staff's audit questions, the Design Peak Day Quantity was not exceeded for any day in the time period of February 15, 2006 through February 21, 2006.[82] Even though the Design Peak Day Quantity was not exceeded PSCo gas pressures fell low enough to set off numerous alarms, electric generating power plants could not be operated on gas and ultimately rolling black outs resulted.

From a gas supply standpoint, PSCo benefited from the fact that February 17 and 18 were not peak days. Friday February 17 did not require a peak day gas volume, such that it was under the designed peak day. On February 18 the gas supply that was secured with authorized overruns would have been insufficient to meet peak day loads, and the situation could have been much worse.

Even though the design peak day is considered more of a capacity issue, the capacity of a system is tied to gas pressures and operation of the system. The design peak day load on the LDC gas system is modeled such that CIG gas delivered into the system is at 800-900 psi, which has been described by PSCo as the "normal" pressure range that CIG usually delivers into its system.[83] At the end of the gas day for February 17 and the beginning of the gas day for February 18, the CIG pressures fell to approximately 600 psi as indicated Exhibit 11 of the PSCo report. PSCo has stated that they are unaware what minimum pressure is needed from CIG for them to meet its design peak day load. However, if CIG only delivers gas into PSCo system at the contract minimum pressure, PSCo acknowledges that it would not be able to provide the LDC with enough gas to meet the design peak day gas load that includes LDC load and only Fort St. Vrain using gas to generate electricity. Once a transient model has been used to analyze the system, PSCo would be in a place to calculate the cost benefits for any improvements to the LDC system and to decide if improvements or modifications of the LDC system are needed and warranted.

In PSCo's Commitment Log Item 18 the Asset Management Department completed a study of what would be need to provide firm pipeline capacity to power plants served only by the PSCo system. By increasing the firm transportation capacity, the shipper is protected from being interrupted for capacity reasons, but not for supply reasons. PSCo also stated that since the gas supply for the electric portfolio is operated separately from the gas supply portfolio for the LDC, additional firm transportation capacity for electric generation would not have increased the gas supply available to electric generation on February 17-18 and the gas supply problems that were experienced would not have been averted. PSCo did mention that it could connect the Ft. Lupton plant to an adjacent CIG pipeline at a cost in excess of $600,000.

Another option that Staff looked at is that the Brush Plants could take gas directly out of Young Storage like Manchief. In discussions with the PSCo Gas Control department, Staff learned that, when Manchief went offline, there was overrun gas available for electric generation from Young that Manchief couldn't use. In PSCo's stated in an internal response that Gas Supply on February 17 "advised the Power Desk that additional gas was available to run the Manchief and Brush

[82] Seventh Set of Audit Questions, May 26, 2006, Reply to Audit Request No. CPUC7-9. PSCo references the Design Peak Day Quantity.
[83] Interview with PSCo Gas Capacity Planning, May 24, 2006.

Plants using gas delivered from Young Storage.[84] In further investigations by Staff and speaking with CEM (the Brush IPP operator), it became unclear if the Brush Plants could burn gas directly from a connection to Young Storage or if the gas has to flow through a PSCO connection and then back to the Brush Plants. PSCo should investigate weather by construction a short run of additional pipe or by making valving modifications an alternative source of gas drawn directly from Young storage could provided to electrical generation

In PSCo's Commitment Log Item 17, PSCO states that they are investigating additional storage options. While additional storage might have provided an additional source of gas to be drawn on, it would depend on how the storage facility was managed. While Staff is interested in PSCo's investigations, it is unclear how additional storage would have helped on February 17 and February 18 if no gas reserve, supply and storage management protocols were in place.

Gas Control/Gas Supply Conclusions

The gas supply problems that occurred on February 17 and 18 revealed more problems that just missed weather forecasts. A new approach needs to be taken when securing gas supply to ensure that there will be enough for both the LDC and electric generation when unforeseen events occur. As PSCo points out, cold weather is not unusual in Colorado and it is not unusual for weather forecasts to be incorrect. When PSCo has forecast errors and all the storage was used to calculate gas supply, PSCo falls back on authorized overruns, which incurs an authorized fee that is passed on to the ratepayer.

In Staff's assessment, the ratepayer should not be paying for natural gas supply management errors that are caused by events that PSCo should have been able to recognize and respond to. PSCo should have had a dynamic gas supply management plan to compensate for unpredictable weather, and do a better job of managing reserve margins consistently, particularly during peak periods, and during time frames when an accurate and timely forecast is difficult (holiday weekends, etc.). As PSCo points out, cold weather is not unusual in Colorado and it is not unusual for weather forecasts to be incorrect. Communication must also be improved between the gas and electric departments to allow for complete system planning during critical situations. The electric system and gas system operate and respond in different ways. While electric can respond much more quickly, the gas system needs time to schedule gas and have it delivered into the system, making timely adaptations to changing conditions especially important.

Simply put there were supply issues and lack of a "safety net" or reserve of storage gas that contributed to the rolling blackouts. The supply issues were brought on by missed weather forecasts, which in turn provided incorrect gas load forecasts. PSCo underestimated the natural gas demand on February 17 and February 18 and for a period of time when more gas was being used from the system than what was being delivered. Line pack was lost and as a consequence resulted in extremely low pressure throughout the LDC system and the LDC could not supply enough gas for electric generation on the morning of February 18.

[84] Response to question PSCO 1-10; 1st Set of Internal Investigation Questions Natural Gas Supplies, February 24, 2006.

Section 5: Electric Transmission Operations

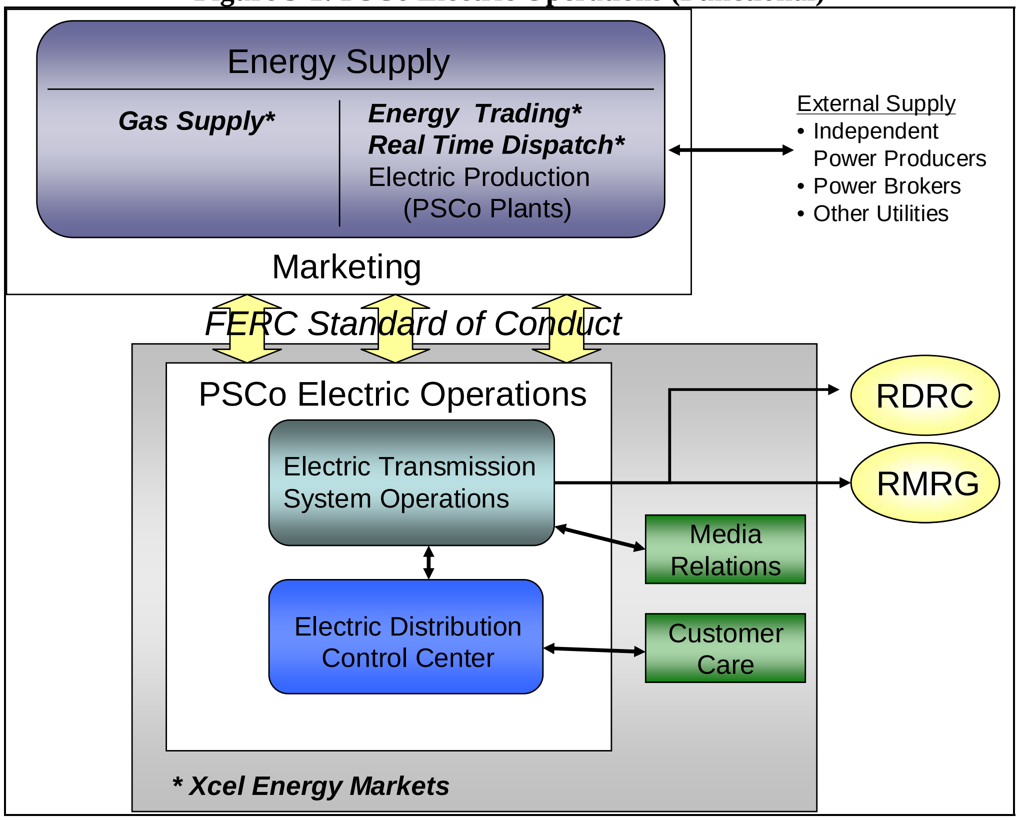
The Electric Transmission Operations department (Transmission Operations) is responsible for communicating with the Rocky Mountain-Desert Southwest Reliability Center (RDRC) during both normal and elevated operations. This department works closely with the Real-Time Dispatch department to coordinate generation and supply, however, in an emergency, Transmission Operations is designated as the lead for all decisions relative to stabilizing the power grid. The Transmission Operations department is accountable for coordinating with the RDRC to declare a NERC Energy Emergency Alert (EEA Levels 1 through 3, with one being the lowest), and for making the final decision to shed load for firm customers. The Transmission Operations group is not responsible for making the determination to "buy at any cost" for power on the market. That responsibility rests with Real-Time Dispatch (Dispatch). Dispatch is also responsible for taking interruptible customers offline, although it does so in close coordination with Transmission Operations.[85] In addition to operational responsibilities, Transmission Operations is tasked with providing information to and coordinating with Media Relations regarding customer impacting events. Through this function, Transmission Operations can, for example, request that Media Relations issue a media report asking for voluntary reductions from retail and commercial customers. Transmission Operations is the official designated Balancing Authority for PSCo. The Balancing Authority is the entity that is responsible for balancing load and generation in real-time in its Control Area.[86] Within PSCo, this function is routinely performed by Dispatch in Energy Marketing.

The following excerpt from the diagram presented in the Introduction of this document highlights Transmission Operations' functional role.

[85] Audit response OE-PUC 2-6.

[86] A Control Area, now known as a Balancing Authority area, is an electric system bounded by interconnection metering and telemetry, which measure the current, voltage, power flow, and status of transmission equipment.

Figure 5-1: PSCo Electric Operations (Functional)



This section focuses on the transmission systems that interconnect with PSCo's Control Area, and the activities of Transmission Operations during this event. In particular, there are concerns relative to how Transmission Operations evaluated alternative paths into the PSCo region, when Transmission Operations engaged the RDRC, when the Energy Emergency Alerts were declared, and what information was available to Transmission Operations for making decisions about available resources. Specifically, the information that was available to the Transmission Operations staff versus the RDRC both through systems and by virtue of regulatory restrictions is examined. Finally, the role of Transmission Operations staff in assuming control of the AGC (Automatic Generation Control), and their capabilities with the tools required to do so is discussed. The following recommendations address these areas.

Transmission Operations Recommendations

1. Clarify expectations regarding issuing Energy Emergency Alerts during a developing situation (This is partially addressed by Commitment Log Report Item 7), and practice through simulation training in coordination with the RDRC. This recommendation is only partially addressed by Commitment Log Report Item 34).
2. Clarify roles and responsibilities between Real-Time Dispatch and Transmission Operations Define how and when roles and responsibilities change during emergency situations. This recommendation is only partially addressed by Commitment Log Report Item 7.
3. Establish a training program for the system operators so they know the critical transmission paths that pass power into PSCo's control area. Training should include

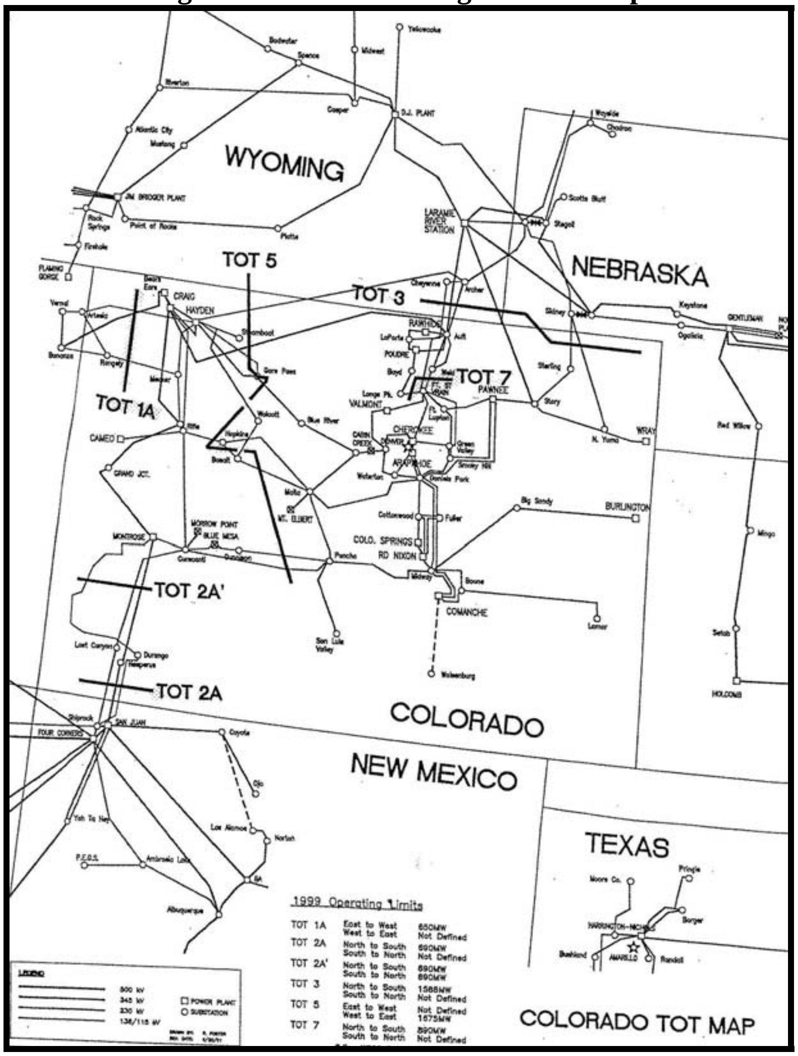
practicing interactions under different schedule scenario. This recommendation was not addressed by Commitment Log Report Item 34).

4. Activate the PI active view terminal or its equivalent to provide full information, within the regulatory requirements, to Transmission Operations staff, and train staff on its use. Training should help operators make informed decisions as to the status of the critical transmission paths and other transmission systems that can be used to import power into the PSCo control area.
5. Execute targeted training for the Transmission Operations staff on the AGC. Clarify and clearly define when it is appropriate for Transmission Operations to assume control of the AGC.
6. Synchronize the processes used by Transmission Operations and Real-Time Dispatch (and other departments within PSCo) for establishing emergency levels with those of NERC. This issue is only partially addressed in Commitment Log Report Item 7.
7. Clearly define when the FERC Standard of Conduct rules may be suspended to allow for more open discussion between Real-Time Dispatch and Transmission Operations, and what steps are required to subsequently bring PSCo back in alignment with the regulations. This alignment is not addressed in Commitment Log Report Items 7, 34, or 36 and needs to be made clear, concise and identical in all three Commitment responses.
8. Work with other utilities to evaluate winter ratings of WECC transmission paths, together with protocols and guidelines on how to create an emergency rating of a path taking into consideration the current ambient conditions.
9. Work with neighboring utilities and the other utilities in WECC to create an emergency protocols and plans of action to schedule power in non-standard methods to other utilities during times of emergencies. One such non-standard method is "displacement scheduling", as described below. This is not currently addressed in the Commitment Log Report.

Electric Load Background

This section looks closely at the critical transmission paths that bring in power to the PSCo area. A WECC transmission path (also known as a TOT – pronounced "tote") is a group of transmission lines that work together, usually in parallel, to transfer power from one area to another. Each TOT has a reliable operating limit that is monitored to insure the reliable operation of the system. The WECC transmission paths that bring in power to the PSCo area are TOT1 from Utah into the Craig area in northwest Colorado, TOT2 in the southwest from New Mexico into the western Colorado area, TOT3 to the north bringing in power from Wyoming into Colorado, and TOT5 from western Colorado to eastern Colorado. Figure 5-2 is provided for reference regarding the Colorado regional TOTs.

Figure 5-2: Colorado Region TOT Map



The majority of Colorado's electric load is located in Colorado's Front Range Region which includes the greater Denver metropolitan area. Other major load areas are located on either side of Interstate Highway I-25 all the way from Wyoming to the New Mexico border. The two major WECC transmission paths that feed the Front Range Region are TOT3 and TOT5. Once TOT3 has reached its limit, the Front Range Region can not import or schedule any more power.

Transmission Operations Time Line

This section focuses on the February 18 04:00-16:00 time frame. This encapsulates the critical time during which Transmission Operations began looking at the possibility of having to shed firm customer load. This was precipitated when, shortly after 04:00, Cherokee 4 came off line. The loss of this capacity, together with the events that were transpiring on the natural gas supply side for electric generation, was an important event as it marked a serious additional deterioration of the electric system, which had been steadily losing capacity throughout the night. From 04:00 to 08:30, PSCo had approximately 4.5 hours to resolve the upcoming load serving problem by importing power from the other WECC members. Load shedding started at about 08:48. It appears that the last triggering element that precipitated the load shedding was the loss of the gas-fired Front Range generation of 480 megawatts at 08:37, of which 204 megawatts were under contract to PSCo.

Table 5-1 below shows the available transfer capacity in megawatts on TOT1A, TOT2A, TOT3, TOT5, and TOT7 for the February 18 04:00 to 11:00 timeframe. It was created by aggregating information provided by the Company regarding scheduled power flows and limits on key WECC transmission paths and actual power flows on the same paths. On this Table 5-1, note that there are two sets of numbers under each of the WECC transmission paths with one set in parenthesis. The numbers in parenthesis were calculated from the information of PSCo Audit Response OE – PSC 2-16 by taking the path limit and subtracting from it the greater of the actual flow or the scheduled flow. The other numbers are from PSCo's Audit Response OE-PSC 2-42 which subtract the scheduled flow from the limit. In applying either approach, significant transfer capacity was available on all the paths.

The column Comments/Events captures some of the information that helps identify some key events that may have happened between the hours shown on the timeline and identifies information that was known or should have been known as a result of the event. This event information was aggregated from transcripts and other information provided by the Company in response to audit questions. Notably, the information provided by the Company does not indicate when in this timeline the FERC Standards of Conduct were (or could be) suspended, or when contact was made with the RDRC to declare Energy Emergency Alerts.

Table 5-1
WECC Transmission Paths Available Transfer Capacity in Megawatts on February 18, 2006

Time	TOT1A	TOT2A	TOT3	TOT5	TOT7	Events and Comments
2/18/2006 04:00:00	513 (650)	420 (312)	635 (587)	937 (861)	331 (321)	Cherokee Unit 4 tripped off line at 04:10; Generation situation deteriorates.
2/18/2006 05:00:00	550 (650)	383 (375)	600 (574)	979 (942)	324 (313)	“Buy at any price” signal issued at 05:35.
2/18/2006 06:00:00	533 (650)	373 (342)	669 (536)	985 (973)	315 (307)	No transmission for Tucson offer at 06:24; ISOC interruptions at 6:26; Generation problems intensify.
2/18/2006 07:00:00	535 (624)	357 (329)	540 (510)	981 (963)	297 (289)	Request for help to RDRC at 07:16; Transmission from DJ full at 07:43; CAISO offer help but no transmission.
2/18/2006 08:00:00	564 (575)	318 (291)	489 (503)	979 (991)	271 (269)	No transmission for SMUD offer at 8:40; Firm load shedding starts at 08:47.
2/18/2006 09:00:00	573 (523)	251 (257)	441 (430)	904 (842)	257 (259)	Firm load shedding in progress.
2/18/2006 10:00:00	558 (539)	123 (243)	299 (401)	597 (574)	207 (195)	Firm load shedding stops at 10:30; 20,507 PSCo customers remain out.
2/18/2006 11:00:00	556 (456)	70 (112)	393 (314)	699 (653)	142 (100)	Firm load restoration continues.

Transmission Operations Discussion

WECC Transmission Paths

From Table 4-1, it appears that there was sufficient transmission capacity available on February 18 to schedule additional purchases in amount of the 360 to 428 megawatts PSCo shed from 08:50 to 09:50. TOT1A and TOT5 are two transmission paths in series that could have accommodated the necessary power to get it to the Front Range of Colorado. This additional power would have had to have been available for purchase from the Utah utilities, possibly Utah Power and Light and/or Deseret G and T. However, there is no record of contacts with these utilities to see if they had generation available to sell and schedule to PSCo, and it is undetermined if they actually had power to sell during the time in question. Therefore, this is offered as an example of a potentially unexplored possibility for bringing power onto the system.

TOT3 consistently had over 299 megawatts of capacity to have accommodated the resultant loop flow as a result of schedules on TOT1A and TOT5. Also, the limit shown on TOT3 per FERC response OE-PSC 2 for HE 04 through 11 is consistent with both the Sidney and the Stegall asynchronous ties having no power scheduled. This means that utilities on the eastern interconnection were potential candidates for power purchases that could have been scheduled across the Stegall and Sidney ac-dc-ac ties, of up to 300 megawatts, to help PSCo.

In addition to the above observations, if an EEA1 had been declared by the RDRC at about 04:05~04:10, when Cherokee 4 and Ft. St. Vrain were lost, there is the possibility that other utilities could have responded sooner, and that PSCo could have done some creative power purchases, such as "displacement scheduling," that could have prevented the rolling blackouts. For example, Transmission Operations and Real-Time Dispatch could have worked together to identify and contact warm weather areas, say the San Diego-Los Angeles, California utilities, and asked for start up of combustion turbines for sale to PSCo. Jointly, PSCo could have worked with owners of the Intermountain Power Project (IPP) in west-central Utah to work out a displacement deal. IPP is assumed to be base loaded with schedules to southern California utilities using the IPP-Adelanto dc line to deliver its power. The San Diego-Los Angeles utilities could displace the IPP schedules with local generation and IPP could schedule a similar amount to PSCo over the IPP-Mona-Bonanza-Craig 345kV path and on to the Denver-Boulder load area over TOT5.[87] As the power purchase displacement deal was being made, PSCo could have been arranging for transmission service for the IPP-Craig-TOT5 transmission path described previously. (Other displacement scenarios could be developed from some other part of the WECC system to achieve similar results). These types of creative solutions can only be developed through robust simulation training, as there is no practical way to document and retain all possible permeations of solutions in an accessible format.

Electric System Control

The head of Transmission Operations has stated that if necessary, Transmission Operations can take control of the operation of generation and transmission systems to navigate through an emergency. However, the department has not received training (although it is now scheduled), nor are the facilities in place to deliver training.[88] Additionally, the department has not received regular or robust training on the WECC transmission paths and how to creatively approach

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[87] Analysis done by PUC Staff.
[88] From discussions with Transmission Operations staff.

bringing power into the system during an emergency. For example, it was communicated to the investigative team that Real-Time Dispatch was aware that Nevada Power had power to sell but was not aware of a transmission path to get it to PSCo. In addition to the AGC, the department does not have a functional view of the PI Active Terminal[89] system used by the RDRC to get as complete a picture as possible of the grid and availability.

Reliability Center Engagement and Industry Impacts

The RDRC's main responsibility is to ensure the reliability of the WECC interconnected system by preventing cascading situations.[90] On February 18, 2006, the RDRC fulfilled its job. The rolling blackouts in the PSCo system were consistent with the governing rules of the RDRC. However, it is possible the RDRC could have been more helpful to PSCo during this emergency, if better communication channels had been in place. From an industry perspective, it is still unclear exactly what role the RDRC can and should play during this type of event. The RDRC covers a large footprint in WECC and monitors power flows and voltages as a matter of course. It could certainly be a great resource to utilities in sharing and dispersing useful information, especially in times of emergencies such as the one of February 18.

The RDRC's evolution is an example of what is happening in other operational areas in the electric industry as a result of FERC's orders and mandates. In the case of the February 18 emergency, a crisis was made worse by one part of the Company not knowing what was happening in other parts of the region – Real-Time Dispatch did not have real-time information as to the status of its neighbors' transmission systems. It had to depend on posted numbers on the Open Access Same Time Information System network (OASIS) which may have not necessarily reflected the limits and loadings of transmission paths. Each transmission entity posts on OASIS its interconnection transmission paths, its associated real-time limits, firm schedules, and available transmission capacity. Real-Time Dispatch also had to depend on the electric power transmission side of the business for transmission access information where the transmission staff may not have known either, if they were also depending on OASIS information. The February 18 PSCo emergency amplified the weaknesses of the Real-Time Dispatch department not knowing the status of the electric transmission network on a real-time basis as mandated by FERC.[91]

Finally, the combined loss of Fort St. Vrain Unit 4 and Cherokee Unit 4 early on Saturday morning was not fully appreciated at the time that it occurred. This is evidenced by the fact that Transmission Operations did not request that the RDRC declare an EEA1, and did not work with Real-Time Dispatch to transfer responsibilities to Transmission Operations consistent with the system being in crisis. While the system may NOT have been in crisis at that very moment, the loss of Fort St. Vrain Unit 4 and Cherokee Unit 4, in conjunction with other plant failures, changing weather, and gas pressure issues, were significant enough to have merited a stronger proactive response. In the Investigative Team's assessment, a proactive response to initiate some of these processes could have mitigated a crisis, rather than waiting for the crisis to occur and then reacting.

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[89] A PI active terminal is a computer terminal that displays the power flows on each of the transmission paths the RDRC monitors. The information monitored on the flows includes the path limit, the scheduled flow and the actual power flow.

[90] FERC Standard IRO-001-0 – Reliability Coordination – responsibilities and Authorities, Effective April 1, 2005.

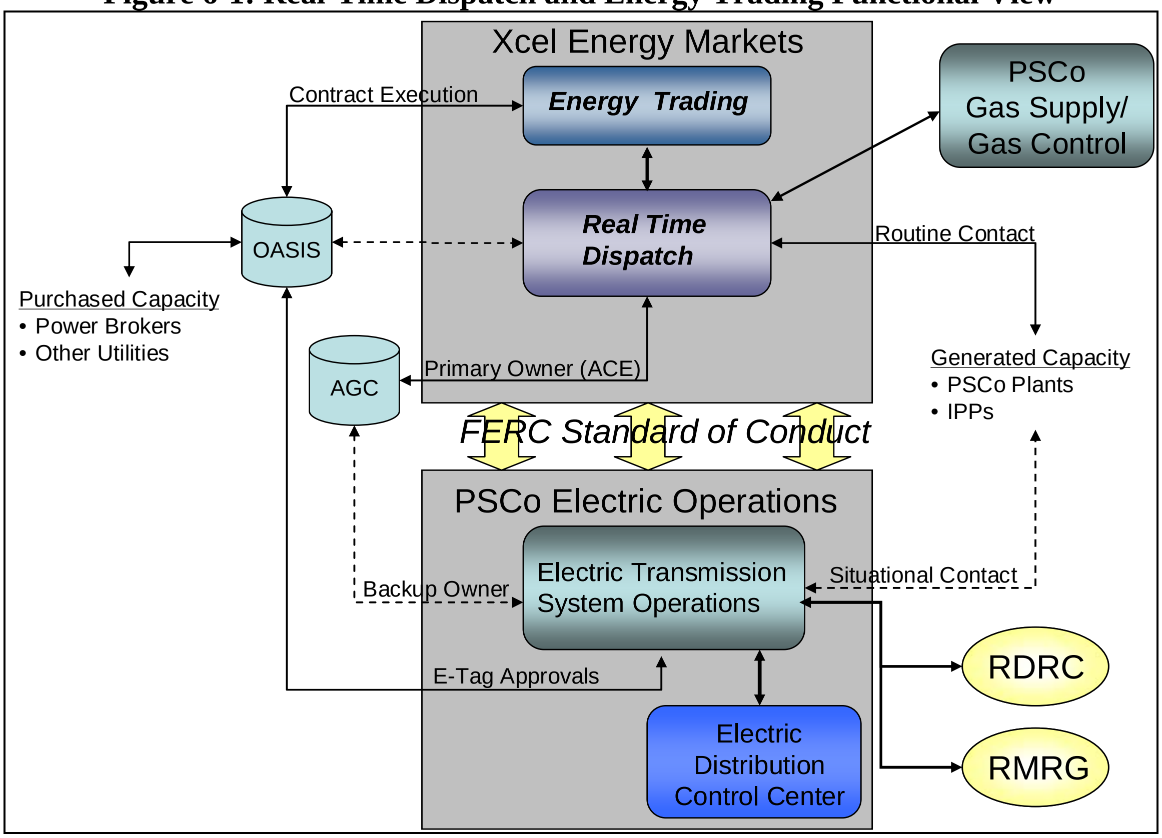
[91] Per FERC Standard EOP-0010-0, Emergency Operations Planning, effective April 1, 2005, each transmission operator and Balancing Authority needs to develop, maintain and implement a set of plans to mitigate operating emergencies.

Section 6: Energy Trading and Real-Time Dispatch

Energy Trading and Real-Time Dispatch are two departments within Energy Supply with responsibilities for establishing and meeting firm commit load for electric power. They are technically a part of Xcel Energy Markets, and support all four operating companies, including PSCo. In Real-Time Dispatch, there are three staffed desks, one for each Balancing Authority. This section focuses primarily on how the departments serve PSCo, and on the Real-Time Dispatch desk dedicated to PSCo.

The following diagram provides an overview of how Real-Time Dispatch and Energy Trading interact with the operational part of the PSCo business. The current relationships between these organizations are multi-faceted, adding complexity to the communication process, particularly when the system is in crisis mode. In this diagram, solid lines indicate a normal connection; dotted lines indicate a backup or contingency connection. For reference, this section includes a more detailed discussion of ACE and AGC.

Figure 6-1: Real-Time Dispatch and Energy Trading Functional View



The Energy Trading department has responsibility for the actual purchasing and scheduling of power through energy transactions with regional partners, and for selling PSCo resources as appropriate. Energy Trading is also responsible for calculating the gas requirements to support projected generation needs, and for communicating those requirements to Gas Supply to support day-ahead nomination and purchasing of gas for electric generation.[92] Depending on the situation, Energy Trading acts on an economic basis to maximize profits or on a reliability basis to ensure regional power grid stability. Balancing these requirements is a primary function of

[92]Provided by PSCo staff during site visits.

Real-Time Dispatch, and during a reliability crisis, Energy Trading may be instructed to switch to a "buy at any cost" purchasing mode, based on signals from Real-Time Dispatch.

Real-Time Dispatch is responsible for generation control and dispatch for the PSCo electric system on a reliable and economic basis. Plans are based on the forecasted need for capacity and PSCo's supply (primarily generation and market purchasing/transport, since electricity cannot be stored the way gas can be). Plans can be adjusted in near-real-time through purchases of additional capacity or the dispatch of PSCo-owned or Independent Power Producer (IPP) units. Real-Time Dispatch may provide the signal to Energy Trading to initiate "buy at any cost" purchasing when necessary to ensure supply to meet the firm commit load. Arranging electric transmission is a critical aspect of effecting such transactions. Other options for mitigating a shortage are to turn up additional units to generate power internally, and to curtail interruptible customers.

Real-Time Dispatch has been delegated responsibility for balancing the system as a whole and for the Automatic Generation Control (AGC) system under normal conditions. Typically, Real-Time Dispatch has limitations on the amount of operational information available to it because information such as transmission capacity, indications of needs, generation capacity, and load could allow for potential power price manipulation. These limitations are based on the FERC Standard of Conduct. However, these limitations may be removed in an emergency situation, to ensure rapid response to a problem with the power grid. If this occurs, specific follow-up steps are taken to post activities in OASIS and to identify what transactions were conducted outside of the Standard of Conduct.

The PSCo Balancing Authority, ACE , and AGC

Prior to the FERC Order 888, PSCo operated as a vertical integrated utility that generated, transmitted, and distributed power to its electric customers. The PSCo Control Area Dispatch Center performed these functions. On a daily basis, the Control Area forecasted power requirements and scheduled and committed power plants and also balanced Area Control Error (ACE) of the PSCo Control Area and managed generation units with Automatic Generation Control (AGC) and reserve requirements. The PSCo Control Area was responsible for PSCo's daily power system reliability, meeting interchange requirements, arranging reserve requirements, and balancing load and resources.

In compliance with the mandates of FERC Order 888 and FERC Order 889, Xcel Energy and its operating companies, including PSCo, separated its generation, transmission and distribution functions and created a new business unit, Xcel Energy Services, Inc. (XES), which provides various services to Xcel Energy operating companies. Real-Time Dispatch is a part of this department. Among various services, XES manages PSCo's power marketing functions to meet its daily load requirements. The power marketing function, including purchasing and selling power, is no longer centralized under the Control Area. Today, the Xcel Energy Marketing office in Denver performs trading functions for all four electric operating companies within Xcel Energy.

The Transmission Operations department, which serves as the PSCo Balancing Authority and Transmission Provider, operates at a secure location outside of Denver. The Distribution Control Center operates out of yet another Denver area location.

The Transmission Operations group has the responsibility of maintaining PSCo Control Area reliability according to Western Electricity Coordinating Council (WECC) interconnection requirements. Transmission Operations also communicates with a WECC security and reliability center, Rocky Mountain and Desert Southwest Reliability Center (RDRC) located near Loveland, Colorado, neighboring transmission providers including the Western Area Power Administration (WAPA), Tri-State Generation and Transmission Association, Inc. (TSGT), energy control centers, and the City of Colorado Spring Utilities (CSU) concerning PSCo's system conditions. However, Transmission Operations does not usually balance PSCo's load and resource and does not manage PSCo's ACE and AGC, since these functions now are handled by Real-Time Dispatch.

Currently, PSCo's Transmission Operations department manages the transmission system and is the registered Balancing Authority for PSCo. As the Balancing Authority (BA), Transmission Operations should have visibility and access to all of the PSCo Balancing Authority Area's generation, transmission, export and import and interchanges information. In compliance with FERC's order, PSCo's Energy Traders and Real-Time Dispatch should only have visibility to load and resource information. FERC permits certain functions to be delegated to different Company departments as long as that department agrees to follow the Company's Code of Conduct for performing the delegated functions. Within PSCo, primary responsibility for ACE has been delegated to Real-Time Dispatch, which functionally manages some of the control area's mission, such as balancing load and resources, ACE and AGC. Transmission Operations is designated as the backup to Real-Time Dispatch for these functions.

During the period of February 17 through 18, 2006, Real-Time Dispatch performed load and resource balancing and maintained the PSCo's system reliability until the morning of February 18, 2006. During this period, it is unclear whether Transmission Operations had the responsibility to perform any functions in support of this effort. It appears that Transmission Operations took control only when the Real-Time Dispatch could no longer maintain PSCo's system reliability. At this point, the only tool available to Transmission Operations was to initiate controlled outages. Had control been smoothly transferred earlier in the event, there may have been other tools available (voltage reductions, brown outs, public appeals, etc.) to mitigate the situation.

Organizational Interdependencies

This investigation found that Energy Trading and Real-Time Dispatch still hold a deeply entrenched view of themselves as a separate organization from Gas Control, who they seem to consider almost exclusively as a supplier rather than an integral part of the electric system. While this position may have been reasonable ten years ago, the shift in the resource portfolio that includes significantly more natural gas fueled plants (highlighted in the introduction of this document) indicates a need for a better understanding of the interdependencies of the two areas to protect against future blackouts. While generator unit availability is addressed in calculating overall reserve margins during resource planning, Real-Time Dispatch is the centralized point where real-time adjustments must be assessed and applied. By assuming 100 percent availability of plants that run on natural gas, Energy Supply essentially overlooks consideration of critical system implications, including the impact of low gas pressures on the pipelines. In several interviews and discussions with Real-Time Dispatch representatives, it was indicated that Gas Control did not clearly communicate the situation on Gas Day 17, creating a misperception in Real-Time Dispatch that gas was readily available on the system. In an integrated organization, it is reasonable to expect that individuals across organizations can have educated discussions, particularly about such critical interdependencies, and that appropriate questions can be asked on both sides of the discussion.

Energy Trading is responsible for communicating gas requirements to Gas Supply for day-ahead nominations and purchases for gas-fired generation plants under PSCo's control. On Gas Day 17, the electric plants began over-burning their nominations in the early afternoon, causing concern at both Gas Supply and Gas Control, as evidenced by transcript reviews of discussions between Gas Supply and Gas Control in the Friday afternoon timeframe. These discussions indicate that Energy Trading wanted to continue generating (and was willing to assume the penalty assessment for over-burning) rather than purchasing power because market prices were extremely high at the time. By Friday evening, additional gas had been nominated for the electric plants, and they were back to burning within their nominations. They apparently did not significantly over-burn for Gas Day 17 (see Section 4 of this document), however, the Friday early and mid-day significant gas burns at the generation plants contributed to the loss of line pack across the system. The communication between Gas Supply, Gas Control, and Real-Time Dispatch at this time reflects the concerns that all participants had about the situation, but there is not a cohesive and coordinated forward looking response crafted between the departments to ensure uninterrupted service.

It is apparent from the transcripts reviewed that the Real-Time Dispatcher who came on duty Saturday morning quickly realized the severity of the situation and took action, including signaling to Energy Trading to initiate "buy at all cost" at 5:40 Saturday.[93] The severity may have been more obvious to staff overnight if there was a better understanding of the dependencies that exist and how the system as a whole works together. Transcript reviews indicate that in Real-Time Dispatch, there was hope that in the early morning hours of Saturday, on a "new gas day", gas would be available. This raises concerns about general knowledge and understanding of way gas flows on the pipeline and how gas purchases are completed. It is not expected that a Real-Time Dispatcher would have a detailed understanding of Gas Supply and Gas Control. However, knowing enough to realize that low gas pressures cannot be addressed quickly or easily on a Saturday morning, and that gas purchases happen on significantly different cycles than electric generation would have assisted a Real-Time Dispatcher in realizing the severity of the situation Friday night, and perhaps prompted questions and actions. This became evident Saturday morning when the Real-Time Dispatcher was told by Gas Control that there was insufficient pressure in the LDC system to start a number of plants.

Transcript review also points to Real-Time Dispatchers being unsure of which plants had alternative fuel capabilities, and how to switch the plant from one fuel source to another. There were also questions regarding how to supply the plants with the alternative fuel if necessary. This type of uncertainty does not support rapid and effective emergency management and decision making.

Additional issues were found regarding how emergencies are identified and formally called, and the communication and coordination between Real-Time Dispatch and Transmission Operations. These concerns are highlighted by two specific examples. First, the process documentation provided in this investigation indicates that in an emergency, control of the system can be transferred to Transmission Operations. Subsequent discussions and transcript reviews indicate that in fact, during this event, responsibility for ACE was apparently never transferred to Transmission Operations to assume the role of the Balancing Authority. Whether this transfer is optional or required, and who makes the decision is not consistently understood between the two departments, and is not consistently represented in documentation. There was also never a clear official suspension of the FERC Standard of Conduct, and there was a lack of understanding

[93] Audit Response.

regarding who is responsible for officially suspending the Standard of Conduct, and who is accountable for ensuring the appropriate follow-up activities are completed when it is re-instated.

Second, the delay in requesting Energy Emergency Alerts (Energy Emergency Alerts) from the RDRC, and the Company's position that the NERC emergency standards are optional and therefore not rigorously attended to during emergencies,[94] indicates a lack of adherence to industry accepted practices for managing emergencies. These practices are designed to engage the industry participants in managing what can potentially be regionally impacting events. Real-Time Dispatch and Transmission Operations were not able to effectively coordinate with each other to have Energy Emergency Alerts issued in a timely manner. This raises significant concerns. Additionally, once the EEA1 was issued, responses from other companies were not routed and managed effectively between the two departments (see Commitment Log Report Item 7A).

The Company's Commitment Log Report addresses some of the issues highlighted by this investigation. The following breakdown of the information provided in the Commitment Log Report addresses some of these concerns (commitments may be paraphrased):

- Commitment Log Report Item 7 – Update the Real-Time Dispatch Emergency Operation Procedure and forward to Transmission Operations for integration into a merged Emergency Plan.
    - The integration of the proposed plan with Transmission Operations is, according to the Commitment Log Report, still underway. This integration is crucial to addressing the communication problems highlighted by this event, and additional information and tracking of how and when it will be accomplished is not provided in the report. While documentation is important, for complex and detailed execution requirements in a stressed situation, training is even more critical. The commitment response does not contain information regarding specifically how Real-Time Dispatch will conduct and maintain training and competencies relative to this procedure.
- Commitment Log Report Item 7A – Communicate offers of Emergency Assistance to the Transmission Operation department during an event when normal means of scheduling power is exhausted.
    - This commitment states that the new emergency operations plans include steps for ensuring communication between Real-Time and Transmission Operations regarding offers of assistance during an emergency. It is unclear where this step is included in the Commitment Log Report and how the issue will be addressed.
        - If the plans referenced are those provided in Commitment 9, a review of this commitment does not indicate that this update has been made.
        - If the plans reference are those provided in Commitment 7, it seems inconsistent with the line item in the Procedure that states "Direct parties offering assistance to Real-Time Trading for scheduling and accounting entry".
    - This proposed change does not address the fundamental problem that occurred, which is that an offer of assistance was not routed properly for evaluation and consideration during an emergency situation.
- Commitment Log Report Item 8 – Establish an Extreme Weather Communication Process
    - This commitment provides a new procedure for identifying "extreme" weather days and how such a condition is communicated across the organization. It also contains alert levels (Green, Yellow, Orange, and Red), however, these alert

[94] Per discussion with Dispatch Manager, June 27, 2006.

levels are inconsistent with those provided in response to Commitment 9. These discrepancies should be reviewed and addressed, and changes communicated to the appropriate departments. Cross organizational testing of new or updated processes is necessary to make these types of inconsistencies visible.

- Commitment Log Report Item 9 – Consider development of “no touch” procedure for communication between Plant Operations, Real-Time Dispatch and Transmission Operations
    - This commitment provides a new emergency procedure based on another Xcel Energy operating company’s standards and procedures. The commitment response indicates that this is a work in progress. The commitment does not indicate how training will be conducted and how consistency between organizations will be ensured. Additionally, the procedure as provided does not cohesively synchronize with industry standards set by NERC for emergency alerts. While the plants are not directly involved in Energy Emergency Alert escalation, a no-touch indication should trigger a discussion or consideration for an Energy Emergency Alert as appropriate. The Company should address these concerns.
- Commitment Log Report Item 11 – Investigate changing normal protocols for unusual weather.
    - The response to this commitment is apparently included in the response to Commitment 9, the creation of the System Operating Code Response. The response indicates that training for various departments on the new procedure will be completed by June 30, 2006, however, no additional details are provided regarding the type of training and how it will be delivered and tested. Additionally, the ongoing commitment necessary to training and maintenance of the procedures is not provided.
- Commitment Log Report Item 13 – Develop a daily curtailment priority process for interruption of firm wholesale sales transactions.
    - The response to this commitment indicates that a new daily practice has been implemented to provide Day Ahead Traders with current and timely information regarding energy sale schedules that can be cut during an emergency. This procedure has been documented and is being carried out, and appears to address the identified issue of providing adequate information to traders.
- Commitment Log Report Item 22 – Investigate the impact of the FERC Standards of Conduct had on the controlled outage event.
    - This commitment is primarily targeted towards Transmission Operations, but it impacts Real-Time Dispatch as well. While it contains a commitment to train Company employees on the new procedures, information regarding how and when the training will occur, and how it will be scheduled going forward, is not provided.

The following recommendations are provided as additional areas requiring improvements in this department.

Energy Trading and Real-Time Dispatch Recommendations

1. PSCo needs to clearly identify the differences between the Real-Time Dispatcher and the transmission operator roles and responsibilities, particularly as situations develop and operational issues begin to surface. While responses to audit questions indicated good documentation of these roles, discussions with team members and the actions taken during this event highlighted a lack of clarity on the part of individuals.

2. The Transmission Operations department, as the backup for ACE, needs training and accessibility to the AGC and other tools used to maintain system balance, and needs to stay current on how to execute these functions. The conditions under which this ownership transfers to another group or individual during difference scenarios should be clarified and supported by management of both organizations.
3. Real-Time Dispatchers need additional training and practice for responding to the loss of a major generation power plant under a variety of conditions. The load forecast, reserve margin, and available capacity need to be more dynamically applied to the real-time environment, and Real-Time Dispatchers need a better understanding of how to incorporate changes in these key areas into their decisions regarding purchases, plant utilization, and grid stability.
4. The contractual obligations of the firm wholesale customers to curtail load during a reliability crisis need to be enforced consistently and appropriately. The Company should review the treatment of these customers to ensure there was not a violation of contracts and if there was preferential treatment of certain wholesale customers.
5. The treatment of firm load and firm sales if controlled outages are necessary to maintain system reliability needs to be evaluated to determine if firm sales during an outage should have been allowed to take place, and if so, under what conditions.
6. As events unfolded on Friday night, very little additional assistance was available to the on-duty staff as the system became more difficult to manage. As a part of its new emergency escalation procedures, PSCo should evaluate the Real-Time Dispatch and Energy Trading functions relative to ensure resource allocation is appropriate in an emergency situation.
7. Communication between Gas Control and Real-Time Dispatch needs to be improved on both sides. Real-Time Dispatch needs a better understanding of the interdependencies of the departments, in order to more appropriately respond to signals from Gas Control.

Energy Trading and Real-Time Dispatch Discussion

The significance of the low pressures on the gas system relative to plant availability and PSCo generation capacity was not recognized and appreciated on Friday night and early Saturday morning, up to approximately 05:00. During this time, discussions occurred between Gas Control and Real-Time Dispatch about the developing situation, and transcripts indicate that Energy Trading was continuing to maintain economic purchasing signals, which indicated that it was better to assume the “buy through” penalty and acquire additional gas to generate rather than purchasing as the market prices, which were high in that time period.[95] Through Friday night, Real-Time Dispatch continued to maintain economic purchasing signals for Energy Trading. Transcript review indicates that the switch to “buy at any cost” was made at approximately 05:40 Saturday morning[96] by the Real-Time Dispatch Power System Trader on duty at the time, who, upon starting his shift, seemed to quickly recognize and respond to the severity of the problem that had developed during the night.

The relationship between Real-Time Dispatch and Transmission Operations is unclear; particularly when situations are developing that require someone to be responsible for identifying and proactively taking action. For example, according to documentation provided, Transmission Operations can take over ACE in an emergency, however, there is little clarity regarding what types of interactions should routinely take place as a situation develops to prevent an emergency from occurring, and what in fact constitutes an emergency. The Company has addressed some of

[95] Transcript review, Gas Control/Dispatch.
[96] Audit Response OE-PSC 2-23.

these issues by revisiting its emergency procedures and processes; however, additional work is required to synchronize across the departments and to establish clear roles and responsibilities. This synchronization needs to include consideration for the NERC standards of Energy Emergency Alerts (Energy Emergency Alerts) as well.

The following table highlights this concern. On February 18, it appears that Real-Time Dispatch and Transmission Operations had not coordinated to request a Level 1, 2, or 3 Energy Emergency Alert when appropriate per NERC Capacity and Energy Emergencies Standard EOP-002-0.[97]

Energy Emergency Alerts

Saturday, February 18, 2006

<table>
<tr><th>time period</th><th>NERC Alert</th><th>symbol</th><th>balancing authority</th><th>reliability center</th></tr>
<tr><td>07:16–08:51</td><td>Energy Emergency Alert Level 1</td><td>EEA1</td><td>PSCO</td><td>RDRC</td></tr>
<tr><td colspan="5">EEA2 not declared until 11:28 despite ISOC interruptions 06:26–17:00</td></tr>
<tr><td>08:51–11:28</td><td>Energy Emergency Alert Level 3</td><td>EEA3</td><td>PSCO</td><td>RDRC</td></tr>
<tr><td>11:28–16:09</td><td>Energy Emergency Alert Level 2</td><td>EEA2</td><td>PSCO</td><td>RDRC</td></tr>
</table>

The investigative team concludes that appropriate timing for the EEA1 would have been approximately 4:24 on Saturday morning, after losing both the Cherokee 4 and Fort St. Vrain generation capacity. At the same time, a signal to begin purchasing at any price would have been appropriate. This would have allowed for several more hours for both purchasing of power, and coordination with Transmission Operations to evaluate how to move power into the region.

An EEA2 should have been requested when the interruptible customers were designated to go offline. This was never coordinated with Transmission Operations and requested from the RDRC during the event. While this is not necessarily a required step, good emergency practices would indicate that it is both a logical sequence and an appropriate step to take when seeking assistance from regional participants, as it indicates to others the severity of the situation within the PSCo region. Without the EEA2, the RDRC and other power producers in the region remained without official notification of the developing crisis. As a result, assistance that may have been forthcoming from other power producers was not adequately considered or explored.

The EEA3 was requested just minutes after the initiation of load shedding, an acceptable timeframe given the NERC standards and procedures for Energy Emergency Alerts.

Energy Emergency Alert Criteria

Saturday, February 18, 2006

<table>
<tr><th>alert criteria</th><th>event time</th><th>significant event</th><th>alert declared</th><th>time declared</th><th>delay minutes</th></tr>
<tr><td>EEA1</td><td>04:10</td><td>Loss of 490 MW of Capacity</td><td>EEA1</td><td>07:16</td><td>186</td></tr>
<tr><td>EEA2</td><td>06:26</td><td>Start of ISOC Interruptions</td><td rowspan="2">EEA3</td><td rowspan="2">08:51</td><td>145</td></tr>
<tr><td>EEA3</td><td>08:41</td><td>Loss of 204 MW of Capacity</td><td>10</td></tr>
<tr><td>EEA2</td><td>10:30</td><td>End of Firm Load Interruptions</td><td>EEA2</td><td>11:28</td><td>58</td></tr>
<tr><td>EEA0</td><td>17:00</td><td>End of ISOC Interruptions</td><td>EEA0</td><td>16:09</td><td>-51</td></tr>
</table>

In the PSCo defined roles and responsibilities, Real-Time Dispatch is responsible for identifying shortages that require assistance to solve and for identifying when interruptible customers should

[97] NERC Standards documentation.

go offline.[98] Documentation provided by PSCo supports that this is true in both economic and stability scenarios.[99] Transmission Operations is responsible for making the final decision to shed firm commit customer load, and for communicating with the RDRC about the need for Energy Emergency Alerts. Documentation indicates that in an emergency, Real-Time Dispatch defers to Transmission Operations, and that all activities are coordinated between the two departments.

Effective and efficient coordination and communication between these two departments is critical; however, this investigation indicates that it was insufficient on February 17 and 18, as evidenced by this example of the timing and sequence of Energy Emergency Alerts being issued.

Regardless of who is responsible for what and when, between Real-Time Dispatch and Transmission Operations there is clearly a need for tightly coupled operations and smooth execution particularly during an escalating situation. If Real-Time Dispatch is to have any responsibility for executing ACE functions, they must fully understand industry standards relative to this function. The lack of understanding on the part of Real-Time Dispatch relative to industry standards like Business Rule 17, which allows for inter-hour purchases of power during an emergency,[100] indicates that additional training and attention is required to ensure that this department is capable of performing these critical functions. Review of the purchasing timelines indicates that once the emergency was fully realized, and load shedding was considered inevitable, aggressive purchasing was successfully completed to limit the scope and magnitude of the outage. Had this approach been taken even two hours earlier, it is possible that outages could have been avoided. The lack of clarity regarding who is responsible for realizing and declaring an emergency, and ensuring timely response to avoid rather than responding to such a situation clearly contributed to this delayed response.

Real-Time Dispatch Timelines

Because the Real-Time Dispatch activities are inter-related with other departments, including Gas Control and Transmission Operations, this timeline reflects activities that took place both by Real-Time Dispatch and other areas. This timeline is derived primarily from transcript reviews. A separate timeline is provided to show when purchases were made during this event. These timelines do not include Generation Book transactions, which were limited to system generated accounting adjustments during this time.[101] Review of the Generation Book logs does not indicate inappropriate transactions taking place. The times noted in this timeline are based on analysis of transcripts, rather than actual times as noted in Section 7 for plant outages.

Starting Time	Unit Name/Communication	MW	Comments
02/17/06			
	Prescheduled Sales	70	Two prescheduled sales (day-ahead) up to a maximum of 70 MW – Sale is for all day.
12:00		7600	PSCo assumed available capacity.
12:38	RMEC	-640	Tripped – inlet filter plugged.
12:39	Blue Spruce #2	150	Dispatched.
15:18	Blue Spruce #1&#2	-300	Tripped – gas value malfunction.
	Cabin Creek A	150	Dispatched.
16:00	SPS	200	Purchase.

[98] Audit Response OE-PSC 2-6.
[99] Commitment Log Report, Commitment 9 Response.
[100] Per discussion with the Dispatch Manager.
[101] Audit response CPUC5-1, CPUC 5-2, CPUC 5-5, CPUC 5-6.

Starting Time	Unit Name/Communication	MW	Comments
17:32	Blue Spruce #1	150	Switched to fuel oil.
17:35	Manchief 12	143	Gas from Young Storage
19:56	Manchief 12	-143	Tripped – too cold
21:30	Blue Spruce #1	-150	Tripped
23:54	Ft. St. Vrain Unit 4	-295	Tripped – lost steam boiler
23:55	Plains End		Dispatched
02/18/06			
	Prescheduled Sales	10	One prescheduled sale (day-ahead) for Hour 1 to 7 and Hour 24
00:35	Valmont #5	-160	Tripped – Frozen Control
00:49	Plains End	113	Dispatched – Gas
01:24	Plains End	-113	Dispatched – Off
04:10	Ft. St. Vrain	-150	CT #4 Tripped
04:10	Cherokee #4	-340	Tripped – Control Room
04:15	Plains End	113	Dispatched – Gas
04:15	Ft. Lupton		Dispatched – Minimum – Gas
04:24	Cabin Creek	150	Dispatched
05:14	Plains End		Dispatched – Ordered Off
05:20	Blue Spruce Unit 1	150	Dispatched – Fuel Oil
05:28	Thermo	-200	Lost Gas Flow
05:27	Ft. Lupton		Change to Oil
06:14	Valmont #6	-53	No Gas Pressure
06:15	Real-Time tells Traders to buy 600 MW at any price for Hour Ending 08:00.		
06:15	Real-Time discussed with Transmission CA operator available options; purchase energy, curtailment of interruptible customers, diesel generation.		
06:35	Thermo	-33	Reduce additional MW
06:39	First call to Rocky Mountain Steel for interruptible curtailment		
06:51	RMSM called back to confirm curtailment		
06:55	Gas Supply asks Real-Time to switch all generation to oil.		
06:59	Zuni plant could not start		
07:01	PSCo Transmission discussed with Real-Time the need to purchase at any price.		
07:11	Gas Control informs Real-Time that it cannot support the startup of RMEC due to low gas pressure.		
07:16	RDRC declares a PSCo Level 1 Energy Emergency Alert.		
07:30	Limon dispatched, but cannot start due to low gas pressure.		
07:39	CAISO calls to offer assistance to Real-Time traders.		
08:40	FRPC	-204	Tripped – Frozen water valve, total installed capacity 480 mw, PSCo contracted 204 mw.
08:50	PSCo Transmission Operations begins a firm load curtailment of about 400 mw		

On February 17, the following purchases were made by Energy Trading:

PSCo Real Time Purchase on Feburary 17, 2006 (Noon to Mid-night)

	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
									20	10	20		11
	100	100	100	100	100	100	100	100	100	100	100	100	100
				40	65	65	75				100	100	
						239	200	200	200	200	200	200	200
								83	83	83			
								27	27	27			
								15	15	15			
							50	50			50	50	
							90	90	90	90			
									50				
Total	100	100	100	140	165	404	515	565	585	525	470	450	311

On February 18, the following purchases were made by Energy Trading:

PSCo Real Time Purchases on Feburary 18, 2006 (From Hour 01 to Noon)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
	0	60	112	40		100	50	267	370	458	578	450
	25	160	125	150	234	174	180	290	421	482	431	336
	200	200	200	200	200	200	200	200	200	200	200	200
total	225	420	437	390	434	474	430	757	991	1140	1209	986

Real-Time Dispatch Capacity Management

This event highlights the need to reassess the way in which capacity is calculated and applied, to adjust system impacting events. While the original load forecast was close during this period (with a maximum variance of ~4 percent - see Section 2 for more details), significant changes regarding plant availability and gas supply were impacting the likelihood that PSCo could meet the load forecast.

For example, shortly after noon of February 17, 2006, PSCo's system lost the 640-megawatt Rocky Mountain Energy Center (RMEC) power plant, which represented about 13 percent of load at that time. This does not appear to have triggered a reassessment of capacity to determine what would be required to replace not just the lost generation but also to replace lost reserves. The Company still apparently had more than 40 percent of capacity available than load requirements to meet its forecasted load, however, the loss of significant generation capacity should still merit a recasting to ensure margins are appropriate. Additionally, further review of what capacity is considered to be available is warranted. PSCo typically will not nominate natural gas for those units that are not committed, therefore, the actual capacity available to meet forecast should typically not include those plants.

Interrelated to this issue is the need to adjust capacity based on real-time dynamics of alternative fuels, such as fuel oil. Real-Time Dispatch staff should be able to make considerations for actual conditions, and have enough knowledge of system requirements to know what conditions may jeopardize actual capacity for generation of power. For example, it is not appropriate to count fuel oil as a generation reserve option if the ambient temperature is less than approximately five degrees Fahrenheit, and the unit has not been kept running and warm.

On February 17-18, Real-Time Dispatch was apparently calculating capacity generation including wind resources. For Friday and Saturday, PSCo forecasted that wind sources would provide on the average of more than 100 megawatts per hour to its system.[102] On the morning of February

[102] Audit Response to CPUC 5-9.

18, 2006 there was no wind from 3:00 to about 11:00, and generation was not as expected. Furthermore, the PSCo Real-Time Dispatch operator seems to have assumed that all natural gas-fired power plants would be available to replace capacity from an unplanned outage of a committed plant. Based on these assumptions, as of noon on February 17, 2006, Real-Time Dispatch assumed that it had 7600 megawatts of capacity available,[103] which was about 60 percent more than its load requirements.[104] The process and dependability of making these types of assumptions should be re-evaluated by Real-Time Dispatch.

WECC minimum operating reliability criteria requires that "...only the amount of unloaded generating capacity that can be loaded within ten minutes of notification can be considered as reserve."[105] PSCo has about 450 megawatts of generating capacity in various units that can be on-line in ten-minutes, provided that the plants are appropriately staged. For example, the Cabin Creek pumped storage units once used needs to pump water back to the upper reservoirs, which can take as long as ten hours, otherwise, the units will not be available or ready for the next contingency. For natural gas-fired power plants, gas must be readily available with adequate pressures on the line for startup. Wind capacity is uncertain in general, and cannot be guaranteed on ten minutes notice. Fuel oil is only an option under certain conditions, and is not a reliable option for cold-starts of units in cold weather conditions, or if fuel storage has not been maintained. PSCo needs to reevaluate its unit commitment plans, rules, and procedures to manage contingencies and reserve margins so that these types of units are not counted as reserve when they are not in a "ready" state.

Energy Trading Purchasing and Scheduling Analysis

On a typical day, Xcel Energy Marketing's Power Scheduler forecasts, by 05:00, the temperature and load requirements for the day using available weather parameters. The load requirements are then used to determine loading of power plants and decremental and incremental prices of its power system for the day. The PSCo day-ahead power trader makes day-ahead Generation Book purchases and sales for the day, optimizing PSCo's power system resources and maximizing the profit for Xcel Energy. These profit margins are shared with customers pursuant to the ECA.

Purchases are tracked through a system of tags used by the industry participants to identify commitments. Tags are generated and transmitted to all Transmission Providers (TPs) and other Balancing Authorities (BAs) regarding the timing and amount of energy transfer. Upon receiving this Tag, TP approves, denies, or suspends the Tag depending upon information provided in the Tag and whether transmission capacity is available. By noon, power schedules for the day are generally completed across the industry.

The Transmission Providers use all transmission request information from received Tags to determine whether transmission requests have overloaded the transmission system and whether curtailments and adjustments are necessary. If changes are necessary due to transmission constraints or a Tag being denied, the day-ahead schedules are adjusted in real-time. Per the investigative team's review of the e-tags, it does not appear that any tags were denied during this event, although transcript review indicates that some tags required follow up discussion to complete. Using Generation Book (Gen Book) purchases and sales information committed by day-ahead traders, the Transmission Operations desk determines transmission capacity requirements and uses the OASIS to reserve transmission needs. In addition to Generation Book

[103] Per PSCo Initial Report, dated March 13, 2006.
[104] Extrapolated from Exhibit 12, PSCo Initial Report, dated March 13, 2006.
[105] Section 1,Western electricity Coordinating Council Minimum Operating Reliability Criteria, Revised April 6, 2005.

purchases and sales, PSCo power traders also conduct purchases and sales for off-system purchases and sales for the day.

PSCo's Commitment Log Report discussed that its weather forecast deviated substantially from actual recorded weather conditions and discussed the shortage of natural gas supply. For a long weekend, PSCo forecasted weather and load requirements for Friday and Saturday on Wednesday. PSCo's pre-scheduled data indicates that the Power Scheduler committed power plants and made day-ahead sales from its system from February 16 to February 18. It also indicates that purchases were pre-scheduled using its Direct Current (DC) tie on all four days of the holiday weekend. During the capacity deficit period, PSCo real-time traders also made off-system purchases and sales, however none of these sales were connected with power that could have been available to the impacted areas.

The XES Director of Power Operations is responsible to "direct the generation dispatch and power system optimization for Xcel Energy regulated operating utilities to ensure adequate supply for native customers and to increase the efficiency and profitability of Xcel Energy."[106] During this period, PSCo traders did make two day-ahead sales of about 810 megawatthours on February 17; one day-ahead sale of 70 megawatthours on February 18 and one real-time sale of 27 megawatts on February 18. PSCo traders also made Generation Book purchases in real-time at within a normal price range. PSCo traders made a few Generation Book purchases in day-ahead trading. No Generation Book sales were made in real-time during this event.

PSCo traders, however, did make day-ahead transactions for off-system sales during this event. PSCo did not curtail either Generation Book day-ahead scheduled or long-term sales during this event. While these sales did not take power away from the affected region during the timeframe of the event, it is possible that the traders who were working these sales could have been redirected to assist with finding additional power and transmission capabilities to address the immediate crisis. While not necessarily their area of specialty, during this type of event, PSCo should consider all possible resource allocations to assist wherever possible. The investigative team understands that these resources may have been assisting with this event and that their participation may not have been clear in the transcripts reviewed.

Energy Trading and Real-Time Dispatch Conclusion

Within the electric business as a whole, the load forecast was fairly accurate, and throughout this event, actual usage did not deviate significantly from the forecast, even when adjusted for the outages. However, this needs to be understood in the context that many gas-fired plants could not operate due to low gas pressure. As a result, if those plants had operated, the actual usage may have deviated from the forecasted usage. The problem seems to lie with the way in which capacity was predicted, accounted for, and applied to meeting the load forecast as it was set by Friday morning. Real-Time Dispatch assumed 100 percent availability of plants that were in fact unavailable, or became unavailable for a variety of reasons (see Section 7). Additionally, uncertain sources like wind generation were included in the reserve margin count. The combined impact of the dramatic change in weather, the problems with gas availability, and the loss of significant generation capabilities was not fully appreciated on Friday night, and the response to these events was not rapid enough or significant enough to successfully avoid shedding load on Saturday morning.

[106] Audit Response to CPUC 1-6.A1-A3.

Section 7: Electric Production

The controlled outages that occurred on February 18, 2006 were partially the result of approximately 3,461 megawatts of generating capacity being unavailable for a variety of reasons. Going into the weekend, PSCo's Report of Events That Led to Controlled Outages (Initial Report)[107] of the events indicates that approximately 7,650 megawatts of capacity were available. In other words, PSCo lost over 45 percent of its generating capacity. As a result, many questions have been raised regarding PSCo power plant operations and maintenance. At the same time, questions have been posed concerning PSCo's contracts with Independent Power Producers (IPPs) and operations and maintenance issues related to these plants. These two key areas are the focus of this section.

The investigative team examined IPP contracts, root cause analysis documentation, additional plant documentation, and visited the two PSCo coal-fired plants and the PSCo gas-fired combined cycle plant that experienced problems between February 17 and 18. In general, it was found that some plants were offline for scheduled maintenance, others had problems related to the cold weather and were unable to come online, some were unable to start or maintain generation due to low gas pressures, and still others had operational problems unrelated to the cold temperatures.

PSCo had one unit, Cherokee 4, which was scheduled to go offline for maintenance on Friday, February 17 in the afternoon. This maintenance schedule was initiated, but was quickly stopped and the unit was restocked with coal and brought back to full power at approximately 16:00 on Friday to support the growing apparent need for generation capacity. This unit later went offline due to an operational failure unrelated to the cold weather. The investigative team verified that the maintenance schedule was in fact stopped, and that the plant was kept running up until the point of failure, at approximately 04:05 Saturday morning.

The investigative team has reviewed the sections of the Company's Initial Report and the Commitment Log Report.[108] The Commitment Log Report provides new processes, procedures, and preventative actions. However, these only partially address the issues identified. The following recommendations should be addressed by the Company to protect against future unexpected generation loss.

[107] "Report Of Events That Led To Controlled Outages – Public Service Company of Colorado, Date Of Occurrence February 18, 2006", dated March 13, 2006.
[108] "Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006 Controlled Outage Event", Docket No. 06I-118EG, June 15, 2006.

Electric Production Recommendations

PSCo Production Units:

1. Require that all PSCo units actively participate in the root cause, corrective action and action to prevent reoccurrence activities when issues are identified that could potentially affect other production units. The Company's Commitment Log Item 12 does address this issue in its commitment that "the root cause and event reports will be reviewed with all plant directors during the June 19, 2006 Unplanned Outage Rate conference call". While this action is appropriate, it is recommended that the root cause, corrective action and action to prevent reoccurrence procedure be modified to require positive affirmation that appropriate review and actions have been taken by all of the Company's potentially affected production units as well as its Independent Power Producers and Non-Regulated Generators.
2. A collaborative effort should be made to assure that Predictive or Preventative Maintenance (PM) procedures implemented at each individual production unit have been considered for the entire PSCo generating fleet. The Company's Commitment Log Items 10 and 11 address this issue in its issuance of "Cold Weather Policy" ESO-OP-CO-6.151, Revision 0, and approved May 25, 2006. The policy requires that each plant establish plant specific cold weather procedures, but a specific completion date is not specified. The Company should establish an issuance deadline for the plant specific cold weather procedures.
3. The PM procedures should require the periodic blow-down of all instrumentation lines where sediment or sludge build-up is a potential problem. The Company's Event Commitment No. 12 does confirm that this issue was addressed for the specific instrumentation lines at Valmont where the failure occurred, but there is no assurance that this issue has been assessed for similar lines at Valmont or at other potentially affected production units. See recommendation 2 above for the additional recommend action.
4. Considering the problems encountered at Valmont and FSV, a review should be made of all water filled instrumentation lines routed through non-insulated unheated spaces that could potentially freeze. The Company should perform a similar assessment for all PSCo production units to determine whether the issue extends beyond Valmont and FSV. Again, the Company's Event Commitment No. 12 does confirm that this issue was addressed for the specific instrumentation lines at Valmont where the failure occurred, but there is no assurance that this issue has been assessed for similar lines at Valmont or at other potentially affected production units. See Recommendation 1 above for the additional recommended action.
5. Investigate whether solutions implemented at Valmont 5 and FSV provide the same level of protection from freezing.
6. Implement use of the special ultrasonic sensor designed at the request of Valmont staff that allows for the Low Frequency Eddy Current assessment of tube wall conditions around corners at all plants where similar design and equipment merits similar examination.
7. Design change should be considered for Cherokee Unit 4 to allow switching from UPS to line power regardless of the condition of the UPS. Perform assessment of all PSCo production units to determine whether this issue extends beyond Cherokee Unit 4. The Company's Commitment Log Item 12 does confirm that this issue was addressed for the specific UPS at Cherokee Unit 4 where the failure occurred, but there is no assurance that this issue has been assessed for UPS equipment at other production units. See Recommendation 1 above for the additional recommended action.

8. Develop a system to notify all PSCo generation facilities as to the level of elevated operations (i.e., normal – excess generating capacity and reserves, elevated – limited excess generating capacity and reserves, high – only marginal excess capacity or reserves available). The Company's Commitment Log Items 8 and 9 address this issue in its issuance of its "Standardized Alert Level Definition" and its Energy Supply Operations – Procedure, "System Operating Code Response" ESO-OP-6.140, Revision 0, and approved June 6, 2006. These documents establish standard alert levels and applicable plant response. It is the assessment of investigative staff that the new procedures would have resulted in only a mandatory alert notification to the generating fleet of a "System Condition ORANGE – Danger" at 08:40 Saturday morning; no earlier notification would have been required since a "System Condition YELLOW – Warning" does not require notification to the generation plants. The investigative team requested[109] that the Company modify the procedures proposed in the Company's Commitment Log Report unless it can demonstrate that the investigative team's analysis is incorrect. At the time of this writing, PSCo had not responded to that request.
9. Considering that the existing gas supply system is not capable of delivering natural gas to the entire electric generation fleet during peak LDC conditions, PSCo should develop a simple dynamic model that forecasts a two-day-ahead fuel burn rate for its gas fired generation fleet. A model with this capability would allow Real-Time Dispatch to schedule units based on availability of natural gas and fuel oil instead of strictly on an economic basis.

Independent Power Producers and Non-Regulated Generators:

10. Require that all tolling units actively participate in the root cause, corrective action and action to prevent reoccurrence activities when issues are identified that could potentially affect other production units. The Company's Event Commitment No. 32 does confirm that this issue was addressed for the specific issues encountered the weekend of February 17 and 18, but there is no assurance that that the plant specific issues were assessed for other potentially affected production units. See Recommendation 1 above for the additional recommended action.
11. Although the Company concluded that its contract with its IPPs were adequate in its Event Commitment Nos. 29 and 30, on the basis that "IPPs are required to promptly comply with Real-Time Dispatch and control area instructions at all times, including during Emergencies and elevated or unusual weather conditions", it would appear that there is still room for improvement. It is recommended that contractual changes be made to assure that "Cold Weather Policy" implemented for PSCo production units is similarly required for the entire tolling unit fleet. Going forward, the Company should include language in IPP contracts to establish a baseline expectation for response during an emergency situation.
12. Require the review of combined cycle tolling units to determine whether the issues of steam drum level instrumentation tubing freezing that occurred at FSV may potentially occur in IPP combined cycle units. See also recommendation 4 above.
13. Develop a system to notify all tolling units as to the level of elevated operations (i.e., normal – excess generating capacity and reserves, elevated – limited excess generating capacity and reserves, high – only marginal excess capacity or reserves available. The Company's Event Commitment Nos. 32 and 33 address this issue by adding the IPPs to the list of persons to be notified under tight conditions.

[109] Audit Request Set No. CPUC-20 of the Colorado Public Utilities Commission - Served on Public Service Company, Dated: Friday, June 16, 2006.

14. Going forward, PSCo should exercise the contract clauses regarding performance of tests for reliability for both summer and winter conditions as well as for alternative fuel capabilities.

Generating Unit Outages

This section focuses on PSCo's as well as the Independent Power Producer's (IPP) power plant operations and maintenance activities as they relate to the outage.

Electric Production Timeline

Indicated in the timeline below are those significant events related to the loss of availability of PSCo and contracted generating units.

Date/ Time	Facility/Owner/Description	Event	Total Lost Capacity
02/17/2006 12:38	Rocky Mountain Energy Center (RMEC) / Calpine / 651 MW, Natural Gas-Fired, 2x1 Combined Cycle units	Units forced offline due to inlet filter plugging. **Availability Loss of 651MW**.	**651**
02/17/2006 14:27	Manchief 11 & 12/ CEM / 146 MW, 2 Unit, Natural Gas Fired, Simple Cycle	Real-Time Dispatch requests that Manchief start-up one unit.	
02/17/2006 15:17	Manchief 11	Manchief Unit 11 online with 146 MW Capacity.	
02/17/2006 15:18	Blue Spruce Units 1 and 2 / Calpine / 302 MW, 2 Unit, Natural Gas or Fuel Oil Fired, Simple Cycle	Both units tripped due to drop in gas pressure. **Availability Loss of 302 MW.**	**953**
02/17/2006 16:00	Blue Spruce Units 1 and 2	Real-Time Dispatch requests that Blue Spruce Units restart on fuel oil.	
02/17/2006 16:00	Cherokee Unit 4 / PSCo / 350 MW, Coal-Fired Unit	Real-Time Dispatch requests that Cherokee Unit 4 delay planned maintenance outage until 2/18, 2006 gas day begins at 8:00 Saturday.	
02/17/2006 16:15	Blue Spruce Unit 1	Unit 1 failed to fire on oil. Operator indicates they will attempt to start unit 2.	**1104**
02/17/2006 16:50	Blue Spruce Units 1 and 2	Both units fail to start on oil after two attempts on each.	**1255**
02/17/2006 17:21	Manchief 12	Real-Time Dispatch requests that 12 be started.	
02/17/2006 17:26	Blue Spruce Unit 1	Unit 1 is successfully started on fuel oil. **Availability Gain of 151MW.**	**1104**
02/17/2006 17:26	Blue Spruce Unit 1	Unit 1 is put in AGC.	
02/17/2006 18:37	Blue Spruce Unit 2	Declared unavailable due to instability running on fuel oil.	
02/17/2006 19:53	Manchief 12	After attempting to get the unit in compliance and online, it was declared unavailable due to emissions. **Availability Loss of 146 MW.**	**1250**

Date/ Time	Facility/Owner/Description	Event	Total Lost Capacity
02/17/2006 21:13	Blue Spruce Unit 1	Real-Time Dispatch orders Unit 1 off due to falling evening loads.	
02/17/2006 23:33	Ft St Vrain / PSCo / 739 MW, Natural Gas-Fired, 3x1 Combined Cycle units.	Plant operations told Real-Time Dispatch that they were having problems with the Unit 3 LP drum level indicator.	
02/17/2006 23:50	Ft St Vrain	The Unit 3 LP Drum Level LoLo indicator caused a Boiler Feedwater Pump trip and the diverter damper went closed. At this time the Main Steam and Hot Reheat isolation valves were going closed. Unfortunately, the Intermediate Pressure (IP) Drum level transmitter froze. When this happened the indicated IP drum level went high causing a Steam Turbine trip. **Availability Loss of 302 MW.**	**1552**
02/18/2006 00:35	Valmont 5 / PSCo / 186 MW Coal Fired Unit	A High-High Drum Level indication on the two East transmitters resulted in control logic executing a full load turbine trip. The resulting overpressure resulting in Safety Relief Valve lifting. The SRVs reset and lifted a second time. Following the second SRV lift, the boiler experienced a full face window type water wall tube rupture requiring an extended outage for repair. **Availability Loss of 186 MW.**	**1738**
02/18/2006 04:05	Cherokee 4	UPS Failure results in DCS screens all going dark. Operators immediately commence with controlled shutdown. **Availability Loss of 352 MW.**	**2090**
02/18/2006 04:10	Ft St Vrain, Unit 4 Combustion Turbine	The Unit 4 Combustion Turbine trip while attempting to reduce load to blend in the steamer. **Availability Loss of 146 MW.**	**2236**
02/18/2006 05:28	Ft Lupton / TCTI / 278 MW, Natural Gas-Fired, 5x5 Combined Cycle cogeneration plant.	Lost a CT due to low pressure. Down to 4x2 operation. **Availability Loss of 116 MW.**	**2352**

Date/ Time	Facility/Owner/Description	Event	Total Lost Capacity
02/18/2006 05:35	Valmont 7 & 8 / Black Hills / 83 MW, Natural Gas-Fired, Simple Cycle CTs	Units unavailable due to lack of natural gas. **Availability Loss of 83 MW.**	**2435**
02/18/2006 05:35	Brighton 1 & 2 / TSGT / 152 MW, Natural Gas or Oil Fired, Simple Cycle CTs	Units unavailable due to lack of natural gas. **Availability Loss of 152 MW.**	**2587**
02/18/2006 05:35	Brush 4D / CEM / 140 MW, Natural Gas-Fired, 2x1 Combined Cycle units	Units unavailable due to lack of natural gas. **Availability Loss of 140 MW.**	**2727**
02/18/2006 05:35	Plains End / Goldman Sachs / 113 MW, Natural Gas, Reciprocating Engine plant	Units unavailable due to lack of natural gas. **Availability Loss of 113 MW.**	**2840**
02/18/2006 06:14	Valmont 6 / PSCo / 53 MW, Natural Gas-Fired, Simple Cycle CT	Units unavailable due to lack of natural gas. **Availability Loss of 53 MW.**	**2893**
02/18/2006 06:35	Ft Lupton / TCTI	Lost a second CT due to lack of natural gas. Down to 3x1 operation. **Availability Loss of 39 MW.**	**2932**
02/18/2006 07:28	Limon / TSGT / 52 MW, Natural Gas-Fired, Simple Cycle CT	Units unavailable due to lack of natural gas. **Availability Loss of 52 MW.**	**2984**
02/18/2006 08:40	Front Range / FRPC / 204 MW under long term contract and 217 MW Reserve as part of RMRG, Natural Gas-Fired, 2x1 Combined Cycle units.	Lost the entire facility due to frozen water valves. **Availability Loss of 421 MW.**	**3405**
02/18/2006 08:40	Fruita / PSCo / 20 MW, Natural Gas-Fired, Simple Cycle CT	Real-time Dispatch issues remote start. Unit fails to start. **Availability Loss of 20 MW.**	**3425**
02/18/2006 08:40	Alamosa 1 & 2, 36 MW, Natural Gas-Fired, Simple Cycle CTs	Real-time Dispatch issues remote start. Units fail to start. **Availability Loss of 36 MW.**	**3461**
02/18/2006 08:40	Lookout Center	Initiates 400 MW Controlled Rolling Blackouts.	

Electric Production Discussion

Plant availability has been an issue in the past for PSCo, as documented in the 1998 outage report.[110] In the 1998 report, it was noted that maintenance personnel had shifted to a "diagnostic maintenance" policy, which seems to no longer be the standard. Instead, the personnel Staff interviewed all articulated the use of Preventative Maintenance (PM) schedules, which are used to routinely maintain equipment, and which are managed through an online system that provides daily schedules of activities that are required in the plant. Other areas noted in the 1998 report have been addressed. For example, in addition to the distribution of written root cause analysis reports to all PSCo generating plant managers, which was the process in 1998, there is now a group conference call once a month to share lessons learned and to identify common issues. Additionally, the PMs have now been loaded into an online system that tracks what has been

[110] Staff Investigation – "Report on Staff Investigation of Public Service Company of Colorado Power Outages", Colorado Public Utilities Commission, October 13, 2006.

done and what needs to be done, and provides the plant manager with a list of activities for any given day, based on annual as well as more frequently scheduled maintenance requirements. In the interim since the event, PSCo has updated the PMs to include additional cold weather maintenance procedures, and has updated the tracking process for confirming that maintenance activities are completed.

The review of the events leading up the controlled outages yielded several observations: cold weather conditions contributed to the loss of 2,305 megawatts of capacity (PSCo 634 megawatts and IPP 1,250 megawatts), lack of natural gas directly resulted in the loss of 748 megawatts of capacity (PSCo 53 megawatts and IPP 695 megawatts) and factors unrelated to the cold or lack of gas resulted in the loss of 408 megawatts of capacity (PSCo 408 megawatts).

It must be noted that the IPP units operate under tolling agreements with PSCo. Under the tolling agreements, PSCo is responsible for the nomination, purchase and delivery of natural gas and distillate fuel oil. The typical Power Purchase Agreement[111] (PPA) between PSCo and IPPs specifies that unit will be unavailable when PSCo fails to supply acceptable natural gas fuel to the facility.

Cold Weather Factors

The cold weather was a contributing factor leading to the unavailability of several of the generating units. A brief summary of the weather related problems are provided below along with any corrective action already taken:

Plant and Unit	Owner	Capacity	Discussion of Problem
Rocky Mountain Energy Center (RMEC) Units 1 & 2	Calpine	651 MW	The PSCo Internal Investigation[112] provides a narrative of the tolling unit purchased power generating unit issues. The RMEC plant problems were the result of inlet filters plugging. Calpine personnel said that the plant was designed with the cooling tower to the east of the CT's since the prevailing wind is west to east. Occasionally when the wind reverses (to an east to west upslope), the plume from the wind cooling towers blows into the inlets. When the weather is very cold, this causes freezing mist that can plug the filters. Calpine stated that on Friday, February 17, the cooling tower "looked like a giant snowmaking operation like you would see at a ski area." Once the plant was offline, additional issues with instruments freezing occurred. Further narrative explains that similar, but not as extensive problems occurred in both January and December of 2005. Because of this, RMEC had already begun installation of an inlet heating system to address the problem. Calpine has a similar heating system at its Calgary Energy Center in Alberta, so its employees are confident that this will address the problem.

111 "Power Purchase Agreement Between Quincy Energy Center, LLC and Public Service Company of Colorado", Dated as of January 26, 2001.

112 PSCo Internal Investigation, 1st Set of Internal Investigation Questions, Electric Supply & Operations, dated February 24, 2006, Response to PSCo 1-18, Attachment PSCo 1-18c.

Plant and Unit	Owner	Capacity	Discussion of Problem
Blue Spruce Energy Center (BSEC) Units 1 & 2	Calpine	302 MW	Again, the PSCo internal investigation provides a narrative of the tolling unit purchased power generating unit issues. The BSEC units were operating on gas on 2/17 when they tripped off about 15:18; this was the result of gas pressure swings. Restarting both units on oil was attempted, but only unit 1 was successfully restarted. The problem on unit 2 was related to instrumentation for the NOX water injection system. BSEC subsequently completed a valve positioner upgrade and heat traced the water injection system. Calpine personnel stated that "the BSEC units are very difficult to start on oil". Also Calpine indicated that this was the first time that these BSEC units were requested to operate on fuel oil other than for testing.
Manchief, Unit 12	CEM	146 MW	Once again, the PSCo Internal Investigation provides a narrative of the tolling unit purchased power generating unit issues. Colorado Energy Management (CEM) personnel indicated that "Manchief's unavailability was caused by two factors, both of which have been existing issues with the plant. CEM indicated that unit #12 consistently runs outside of emission compliance when temperatures drop below zero. This was the case on 2/18. CEM believes that there are options to fix this problem and they will be following up with Xcel Energy to discuss further. 2) A persistent problem at Manchief has been the cooling tower drift from Pawnee that "clogs" the intake system of the plant. CEM stated that the inlet system was blocked on 2/18 due to Pawnee cooling output, which led to Manchief being unavailable. CEM does not see an easy or inexpensive solution to this problem so the expectation is that it will remain an issue in the future."
Ft. St. Vrain Units 1-4	PSCo	739 MW	PSCo's Generation Station Event Report[113] concluded that drum level sensing lines on FSV Unit 3 falsely indicated a low-low level indication for the Low Pressure drum resulting in a control system trip of the Boiler Feedwater Pump. The Unit 3 Intermediate Pressure drum level transmitter then froze with an indication of a high drum level resulting in a Steam Turbine trip. These events resulted in the loss of the steam turbine generating capacity. The Unit 2 and 3 Generation Station Event Reports[114,115,116] indicated that after determination that drum levels were acceptable, two of the combustion turbines (CT) experienced problems with combustion stability during load blending operations. In the meeting with FSV personnel,[117] it was verified that corrective action already completed included the installation of 7.5 kW IR heaters in all of the drum houses to prevent freezing of the sensing

[113] Generation Station Event Report, Plant: Ft. St. Vrain, Unit: 1, Date: 2/17/06, Time: 23:36:00.
[114] Generation Station Event Report, Plant: Ft. St. Vrain, Unit: 2, Date: 2/18/06, Time: 13:24:00.
[115] Generation Station Event Report, Plant: Ft. St. Vrain, Unit: 3, Date: 2/18/06, Time: 16:37:00.
[116] Generation Station Event Report, Plant: Ft. St. Vrain, Unit: 3, Date: 2/18/06, Time: 23:47:00.
[117] Meeting with Ft. St. Vrain Station Director and Shift Supervisor, Friday, June 2, 2006.

Plant and Unit	Owner	Capacity	Discussion of Problem
			lines in the future. In addition, FSV has issued a new "Frigid Weather" Predictive Maintenance (PM) procedure[118] requiring inspection of drum house enclosures to assure louvers are closed and regular temperature measurements of equipment in the drum houses when temperatures are below -5°F. Last, FSV is in the process of procuring flame stability measurement equipment to facilitate further tuning of CT nozzles to mitigate future flame stability issues.
Valmont Unit 5	PSCo	186 MW	PSCo's Generation Station Event Report[119] concluded that sediment / sludge accumulation in drum level sensing lines in addition to possible freezing of the lines that are routed through un-insulated, unheated pipe chase contributed to false high level indications. The false readings on two of the three sensors resulted in a control system trip of the unit at full load. The full load trip caused system overpressure conditions resulting in the lifting of the Safety Relief Valves (SRVs) twice to reduce system pressures. Following the second SRV lift, the boiler experienced a full face window type tube failure requiring an extended outage for repair. In the meeting with station personnel,[120] PSCo indicated that corrective action implemented was two-fold. In order to prevent freezing of the level sensing lines in the future, the sensor sending units are in the process of being relocated to inside the drum houses. Second, a new PM was developed requiring periodic blow-down of the level sensing lines to eliminate sediment / sludge build-up.

[118] Audit Request Set No. CPUC-16 of the Colorado Public Utilities Commission - Served on Public Service Company, Dated: Friday, June 8, 2006.
[119] Generation Station Event Report, Plant: Valmont, Unit: 5, Date: 2/18/06, Time: 00:40:21.
[120] Meeting with Valmont Station Director, Shift Supervisors and Plant Engineer, Wednesday, May 31, 2006, 3-5 pm.

Plant and Unit	Owner	Capacity	Discussion of Problem
Cherokee Unit 4	PSCo	350 MW	PSCo's Incident Report[121] concluded that a coil failed in the UPS output contactor causing a control fuse to blow. The control fuse also provided power to the UPS static switch which transfers the UPS load to the bypass source. In the meeting with station personnel,[122] the plant engineer indicated that the UPS Powerware vendor Eaton checked its database of known issues and indicated that there was no record of similar occurrences. As a result, PSCo accepted the vendor's conclusion that no design modification was required. In addition to replacing the fuse and coil, PSCo has modified the Predictive Maintenance[123] procedure (PM) to require periodic operational testing of the UPS static transfer switch. Considering that the purpose of a UPS system is to prevent to loss of power to the Distributed Control System (DCS) by providing two sources of power, a single failure of a fuse that results in loss of both UPS and line is a system design issue that should be addressed.
Front Range Power Corp (FRPC)	FRPC	421 MW	PSCo's internal investigation provides a narrative of the tolling unit purchased power generating unit issues. "The plant tripped off at about 08:30 on 2/18 and was off for a few hours before starting back up." A plant staff member commented that "there is a condensate collection pot in the horizontal exhaust from the steam turbine, which froze on the morning of February 18". "FRPC plans to address this problem by insulating and/or heat tracing the condensate pot and adding some level indication instrumentation".

[121] Cherokee Station Unit 4 UPS, April 10, 2006, Draft, Incident Report.
[122] Meeting with Cherokee Station Director, Shift Supervisors and plant engineer, Wednesday, May 31, 2006, 1-2:45 pm.
[123] Audit Request Set No. CPUC-16 of the Colorado Public Utilities Commission - Served on Public Service Company, Dated: Friday, June 8, 2006.

Natural Gas Availability
As indicated previously, the IPP units operate under tolling agreements with PSCo. Under the tolling agreements, PSCo is solely responsible for the nomination, purchase and delivery of natural gas and distillate fuel oil. The typical Power Purchase Agreement[124] (PPA) between PSCo and IPPs specifies that PSCo is responsible for the purchase and delivery of natural gas fuel required for the production of the contract energy dispatched by PSCo.

Natural gas availability was the issue at the following plants:

Plant and Unit	Owner	Discussion of Problem
Ft Lupton	TCTI	Unavailable due to lack of natural gas.
Valmont 7 & 8	Black Hills	Unavailable due to lack of natural gas.
Brighton 1 & 2	TSGT	Unavailable due to lack of natural gas.
Brush 4D	CEM	Unavailable due to lack of natural gas.
Plains End	Goldman	Unavailable due to lack of natural gas.
Valmont 6	PSCo	Unavailable due to lack of natural gas.
Limon	TSGT	Unavailable due to lack of natural gas.

[124] “Power Purchase Agreement Between Quincy Energy Center, LLC and Public Service Company of Colorado”, Dated as of January 26, 2001.

Maintenance Spending
It was desired to make an assessment of PSCo's maintenance spending for production facilities. All regulated electric power generating companies are required to file with the Federal Energy Regulatory Commission (FERC) what is known as a FERC Form No. 1. Utility companies file this form each year. Included on the form is the utility's spending for maintenance activities for Steam Power Generation (fossil fuel thermal plants) and Other Power Generation (Combustion Turbines and Combined Cycle plants). The amounts reported by PSCo are indicated below for the years 1998 through 2005.

Year	Maintenance Expenses, $	
	Steam Plant (Coal)	Other Plant (SC & CC)
1998[125]	$13,860,996	$2,975,896
1999[126]	$13,905,764	$3,984,200
2000[127]	$11,738,336	$2,846,043
2001[128]	$14,091,799	$7,500,749
2002[129]	$15,323,598	$9,462,405
2003[130]	$19,844,732	$5,902,544
2004[131]	$19,781,082	$6,036,364
2005[132]	$22,316,321	$4,100,102

Considering that there were no significant plant expansions or additions during this period, it would appear that maintenance funding is consistently growing from year-to-year. One would expect some significant decreases and increases in intermediate years as the result of certain major maintenance activities.

IPP Maintenance and Contracts

The typical Power Purchase Agreement[133] (PPA) between PSCo and IPPs requires that the IPPs provide, on no more than forty (40) minutes notice, personnel capable of starting, running, and stopping the facility when requested by Real-Time Dispatch. In addition, PSCo is chartered with using its reasonable best efforts to notify the IPP 24 hours in advance of potentially critical start-ups, and upon such notification and during such critical period, personnel capable of starting,

[125] FERC Form No. 1, Public Service Company of Colorado, Date of Report 06/30/2003, Year/Period of Report End of 1998/Q4, pp 320 and 321.
[126] FERC Form No. 1, Public Service Company of Colorado, Date of Report 06/30/2003, Year/Period of Report End of 1999/Q4, pp 320 and 321.
[127] FERC Form No. 1, Public Service Company of Colorado, Date of Report 06/30/2003, Year/Period of Report End of 2000/Q4, pp 320 and 321.
[128] FERC Form No. 1, Public Service Company of Colorado, Date of Report 06/30/2003, Year/Period of Report End of 2001/Q4, pp 320 and 321.
[129] FERC Form No. 1, Public Service Company of Colorado, Date of Report 06/30/2003, Year/Period of Report End of 2002/Q4, pp 320 and 321.
[130] FERC Form No. 1, Public Service Company of Colorado, Date of Report 11/10/2005, Year/Period of Report End of 2003/Q4, pp 320 and 321.
[131] FERC Form No. 1, Public Service Company of Colorado, Date of Report 11/10/2005, Year/Period of Report End of 2004/Q4, pp 320 and 321.
[132] FERC Form No. 1, Public Service Company of Colorado, Date of Report 04/18/2006, Year/Period of Report End of 2005/Q4, pp 320 and 321.
[133] "Power Purchase Agreement Between Quincy Energy Center, LLC and Public Service Company of Colorado", Dated as of January 26, 2001.

running, and stopping the facility shall be continuously available at the facility. Other than manning the facility, there is no language describing the expected responses during elevated operations, or during an emergency.

Finally, evidentiary documentation demonstrating the required seasonal and fuel source testing stipulated in the contracts was requested by the investigative team,[134] but not produced by the Company. This leads one to question whether testing is done regularly or adequately documented if it is conducted.

Electric Production Conclusions

It was observed that the power plant operations and maintenance staff members of both PSCo and its contract generators have identified the specific issues that contributed to the controlled outages of February 18, made a determination as to the root cause for issues unrelated to lack of natural gas and initiated corrective action to both repair and mitigate the specific issue identified. What appears to be missing is an assessment as to whether similar conditions exist for other systems or other plants, what additional action may be required to prevent reoccurrence and last what metrics need to be established to assure that action taken was effective. Two examples are provided below to demonstrate this conclusion.

During the meeting with plant personnel at Cherokee Station Unit 4, it was asked how management at other plants would be notified about the single point failure of the coil and fuse in the UPS. The Cherokee Station Director indicated that PSCo has monthly conference calls that include all plant managers and supervisors where current issues are discussed including the plant incident reports and root cause evaluations. While at Valmont and FSV, plant managers indicated the same. The problem was identified when the investigative team asked Valmont personnel about whether they had a similar issue with their UPS; they were unaware of the specifics of the problem at Cherokee.

The problem of drum level sensing lines freezing at Valmont was corrected by relocating the sensor sending units to inside of the drum houses. A similar problem with the drum level sensing lines occurred at FSV where the sensor sending units were already located inside the drum houses, yet there was freezing of the lines; the solution was to install heaters inside the drum houses. While it is possible that both solutions may yield acceptable results, there does not appear to be any collaborative effort to investigate or resolve these issues. Also, there is no evidence in the incident reports that the investigations went beyond looking at the specific instrumentation line freezing, nor was there evidence that all similar water filled instrumentation lines in unheated locations reviewed. Last, there was no formal notification to other plants in PSCo's generation fleet or to the independent power producers. Plant management indicated that the monthly generation manager's conference call is the means by which this information is communicated.

When asked whether there was any standard level of reporting from Real-Time Dispatch as to the overall condition of generation operations, all plant personnel interviewed indicted no. While there is nothing that suggests that operations at the plant would have differed, all acknowledged that it would be helpful for power plant operations personnel to understand when operations are normal, elevated or high.

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[134] Audit Request Set No. CPUC-17 of the Colorado Public Utilities Commission - Served on Public Service Company, Dated: Friday, June 8, 2006.

Last, lack of natural gas was a major contributing factor to the loss of availability of many of the generating units. While it is addressed elsewhere in this report, it was established that the existing gas supply system is not capable of delivering natural gas to the entire electric generation fleet during peak LDC conditions.

Section 8: Electric Interruptible Load Management

Interruptible load management is included as a part of this investigation to address concerns regarding if interruptible customers were appropriately notified and taken offline during the event, to free up resources for firm commitment customers. Interruptible customers include electric retail customers, electric wholesale customers, and gas transmission. This section focuses on electric retail customers. Gas wholesale, gas transport, and gas retail customers will be addressed in Section 4: Gas Supply and Gas Control. Electric wholesale interruptions are addressed in Section 9: Interruption of Firm Electric Load.

This section discusses the procedures implemented for capacity interruptions as opposed to the procedures used for economic interruptions. This investigation found that there are concerns regarding how interruptions of retail electric interruptible customers are conducted, and if the Company is appropriately enforcing the interruptions during capacity shortages. Some of these concerns have been addressed by the Company in the interim, others remain in progress, as detailed in this section.

The Company has addressed issues with interruptible load management in its Commitment Log Report, specifically in Commitments 26, 27, 27A, and 27B. These commitments include training for operators regarding the interruptible load program, root cause analysis for failures relative to ISOC customer interruptions, and the limitations of the current systems used to support the interruptible program. The actions take for these commitments were similar, and included a commitment that interruptible program will be reviewed with operators every six months. Additionally, these commitments address training on the new system (Cannon), updates that have been made in the existing system (Envoy) for the interim period, the expected deployment schedule for Cannon, and updates to procedures that support the interruptible program.

In addition to the Company's commitment responses, the recommendations from this investigation relative to these concerns are as follows:

Electric Retail Interruptible Recommendations

1. It is recommended that the Company further improve training for all impacted departments (transmission, gas control, account managers) regarding the details of the tariff. This may include additional information for account managers regarding the appropriateness of the tariff for various types of customers, to ensure that exceptions are not necessary going forward.
2. As committed to in an e-mail from the manager of the Transmission Operations staff, and in response to the Commitment Log Report, periodic updates and reviews of the tariff policies should be scheduled with the Transmission Operations Center to ensure continued understanding and compliance with the requirements of the tariff.
3. Until such time as the Cannon system is fully deployed, tested, and functional it is recommended that the Company provide Staff with quarterly updates regarding the Cannon system deployment, including on-site hardware implementations.
4. Until such time as the Cannon system is fully deployed, tested, and functional, it is recommended that the Company conduct quarterly tests of the MOSCAD system to ensure the hardware is functioning properly and can reliably execute an interruption as needed.
5. Within the ENVOY system, it is recommended that internal Company managers be placed on a combined list with customers, so they receive identical notifications to what is received by the customer. This should help address the user error that resulted in

Company management receiving notification when no official notification was delivered to customers. Additionally, procedures should be established to ensure that these lists are updated regularly.

Electric Retail Interruptible Customers

Interruptible customers are eligible ISOC customers who elect to participate in the Company's Interruptible Service Option Credit schedule that provides for a monthly credit in exchange for periodic disruptions in service due to economic or availability concerns. For all interruptions these customers agree to a pre-determined notification of ten minutes, one hour, or eight hours, and to a selected number of interruptible hours over the course of a calendar year. Currently there are nineteen interruptible customers, thirteen of which are on a one hour notification, and six of which are on a ten minute notification. Of the six who are on a ten minute notification requirement, one, Rocky Mountain Steel Mills (RMSM), receives a phone call and is interrupted via a substation breaker under Company control, while the other five are interrupted via a Motorola product called MOSCAD, which activates relays at the meter locations on customer site, and is used for capacity interruptions. MOSCAD includes a two way radio system for communication from the Company's Transmission Operations Center to the customer location. While MOSCAD provides the Company with the ability to send signals to interrupt load and to restart, the physical control device remains on the customer site and the actual interruption uses the customer's equipment. All systems were tested in the fall of 2005 at each customer location to ensure that it functioned as designed.

The Company has committed to implementing a new system to establish direct control over interruptible customer load that will allow the Company to interrupt and reclose outside of the customer premise. This system, known as Cannon, is in development, and it targeted to be deployed by year-end 2006. However, the hardware required for installation on the customer premise may not be available until 2007. In addition, Cannon will replace ENVOY, the current notification system used to communicate with interruptible customers about an impending interruption.

The interruptible customers are grouped according to their notification status, and all interruptions occur for an entire group, rather than for individual customers within a group. ENVOY stores multiple contact numbers and devices for each customer, and attempts to communicate through a priority order with each customer, delivering a pre-designed script with information regarding the interruption.

Electric Retail Interruptible Timeline

Date and Time	Event
02/18/06 6:26	Transmission Operations activated the MOSCAD system.
02/18/06 6:39	MOSCAD system activated, relays set for 5 of the 10 minute customers.
02/18/06 6:40	Phone call to RMSM to inform them of the interruption.
02/18/06 6:45-7:00	RMSM temporarily drops its load.
02/18/06 7:32	RMSM calls to request power to finish a melt that was in progress, request is granted.
02/18/06 8:30	The ENVOY system was activated to send a message to customers to go offline.
02/18/06 8:30	Internal PSCo managers received the ENVOY message regarding interruption notification.
02/18/06 8:48	Retail customer controlled outages begin.
02/18/06 9:15-10:00	Account managers began making calls to one hour customers to provide further information regarding the interruption.
02/18/06 13:01	RMSM load drops off (approximately 6 hours after permission was granted to finish the melt).
02/18/06 16:09	MOSCAD signal deactivated by Transmission Operations.
02/18/06 16:45	Load Mgmt. reports that the ENVOY message was not sent to customers as was previously believed.
02/18/06 17:00	ENVOY message received by Company representatives regarding deactivation of the interruption.

Electric Retail Interruptible Discussion

A summary table of the load relief from interruptible customers was reviewed by the investigative team. This table shows the customers that were in compliance with the tariff requirements, and those who were not. Root cause analysis has been provided to the investigative team in response to audit questions regarding the issues that caused some customers to be out of compliance. For example, two customers were found to have faulty wiring in their MOSCAD relay, resulting in a failure to open the breakers and shed load. These systems had been tested in August, 2005 for reliability and found to be in good working order. The reason for the failure on February 18 is not known; however, the problems have been repaired and tested as of this report.[135]

Prior to this event, the Company did not have clear visibility across organizational departments regarding the interruptible contracts and tariff requirements. A need was identified to synchronize operations, energy markets, and interruptible account management to ensure consistent understanding of obligations, requirements, and contract terms relative to interruptible customers.

During the interruption period, RMSM initially interrupted service, but then came back online to complete a melt. This was done following discussions between the account manager, the customer, and Transmission Operations. According to contract provisions RMSM is allowed to seek permission from the Company to restart its ladle refining furnace 20 minutes after the start of a capacity or contingency interruption. At the time the interruption was called there was confusion on the part of Transmission Operations as to whether safety issues were a consideration in the request by RMSM for load resumption. In the absence of such issues RMSM should not have been allowed to resume load. Compounding the problem was the fact that the Company failed to monitor operations at RMSM so that a second interruption could have been issued later in the morning. The Company's treatment of RMSM is inconsistent with the provisions in the

[135] Per Staff interview with Interruptible Accounts Manager.

tariff and is also inconsistent with the treatment of other customers in the identical situation. The terms of the Company's contract with RMSM should be written so as to be consistent with the tariff provisions in addition to being aligned with the principles underlying the tariff.

The failure of the ENVOY system due to user error is a concern, particularly as it affects the Company's ability to enforce penalties or other remediation as a result of non-compliance. While the Company has taken steps to address this problem, additional follow up may be merited in the future to ensure customers receive notification, particularly while the ENVOY system is still in place. Direct calls to customers by account managers, periodic testing of the system to ensure current contact information is in place, and revisiting the group distributions periodically may be ways to prevent this type of situation from occurring in the future. Additionally, the delay in informing customers of the end of the controlled outages and of the interruption should be addressed. The initial message (which was not actually received by customers) indicated a stop time of 23:45. In fact, the stop time was closer to 16:09, however, customers were not notified until 17:00 via the ENVOY system.

Individual account managers were somewhat effective in calling out to the one hour notice option customers and requesting compliance, with four customers voluntarily curtailing their load upon request. Coordination among account managers and others who can call customers directly should be synchronized to maximize the impact of these efforts during a controlled outage situation.

Electric Retail Interruptible Conclusions

While the investigative team recognizes that even with full compliance from all interruptible customers, the curtailments would still have been required, it is still considered valuable to evaluate and discuss the issues related to management of interruptible customers during a controlled outage that is caused by a shortfall in the natural gas supply. Our discussions with the director of the group responsible for interruptible customers[136] and our review of the documentation available indicate that the key issues that arose on February 18 are:

- The ENVOY system was not correctly utilized to notify customers due to user error.
- The MOSCAD system was faulty with the two customers who failed to shed load.
- RMSM was permitted to come back online by Operations, despite the system stability emergency curtailment.

The team recognizes that new processes and training have been developed subsequent to the event that should assist in preventing such issues going forward.[137] These new processes include, but are not limited to:

- Semi-annual tests of the processes in place
- Management reviews have been and will be conducted with Operating Center staff regarding tariffs and their enforcement
- The groups in ENVOY have been renamed to avoid confusion
- A release script to inform customers when an interruption is over has been created
- A process document for managing interruptions that outlines how both ENVOY and MOSCAD should be utilized, how the Cannon system intersects with these two systems, and how RMSM should be managed has been developed.

[136] Staff Interview – Interruptible Customer Management.
[137] Per response to Audit Question, Root Cause Analysis.

PSCo is continuing to work towards deploying the Cannon system, which should assist in enforcing the interruptible tariff by providing both a centralized system and on-site hardware to allow the Company to control outages rather than depending on customer equipment to do so.

It is the conclusion of this investigation that rapid deployment of the Cannon system will assist in management and implementation of controlled outage situations similar to that experienced on February 18, 2006, however, the system deployment must be accompanied by the full deployment of customer-site hardware to ensure appropriate application of the tariff conditions for interruptions. If further delays are anticipated due to backordered hardware or supplier unavailability, the Company may want to pursue other alternatives for the implementation of external controls. In May of 2005 the Company committed to this type of system, and the deadline for the full deployment is still uncertain, almost a year later.

Subsequent to the February 18 event, the Company has conducted training to ensure proper administration of the interruptible tariff and has specifically addressed protocol pertaining to RMSM. Participation was limited to Transmission Operations and Interruptible Account Managers and centered on the administration of the service agreement for RMSM. Inconsistencies between the service agreement and tariff provisions continue to be a problem. With regards to the specialized treatment of RMSM, as indicated above, it remains inconsistent with the tariff requirements. Additional monitoring, management, and training of staff that interact with this customer may is merited to create parity among the tariff customers.

Section 9: Interruption of Firm Electric Load

The PSCo Balancing Authority initiated the controlled interruption of firm electric load (rolling blackouts) at 08:47 Saturday morning, February 18, 2006. The Balancing Authority initially confined the interruptions to PSCo customers in the greater Denver metropolitan area, but at 09:56, the Balancing Authority expanded the interruptions to include the PSCo Western Region, including the Grand Junction and Parachute areas, and three of the four rural electric associations that PSCo supplies with wholesale electric energy: Grand Valley Power (GVP) including the Clifton area; Holy Cross Energy (HCE) including the Aspen, Basalt, Carbondale, Vail, Wolcott, Avon, Beaver Creek, and Gypsum areas; and the Yampa Valley Electric Association (YVEA) including the Craig and Steamboat Springs areas. The Balancing Authority interrupted three load groups of electric service customers before halting the controlled interruptions at 10:30 Saturday morning. A total of 371,370 electric service customers of the four utility companies were interrupted for an average of 41.5 minutes. The failure of ten PSCo electric distribution feeder circuit breakers to close on command caused 20,507 PSCo electric service customers to remain interrupted for periods of 63 to 349 minutes. PSCo restored all firm electric service to customers by 15:13 Saturday afternoon.[138]

The Company's Commitment Log Report regarding the February 18 event contains several commitments for addressing operations and equipment failures. These commitments are discussed in more detail later in this section. The following recommendations are provided to ensure that the issues made visible by this event are fully addressed by the Company.

Interruption of Firm Electric Load Recommendations

1. PSCo should create two distinct procedures (and supporting systems) for controlled interruptions: (1) a procedure for PSCo Balancing Authority load shedding that distributes controlled interruptions proportionately across the PSCo geographic regions and its four rural electric wholesale customers, and (2) another procedure for local load shedding in response to transmission or substation restrictions that targets specific geographic areas. These procedures should fully comply with all FERC, NERC, and WECC rules, standards, and procedures including NERC Capacity and Energy Emergencies Standard EOP-002-0.
2. The PSCo Balancing Authority should request that its NERC Reliability Center declare an Energy Emergency Alert as soon as the Balancing Authority identifies conditions meeting one of the three levels of alert criteria in NERC Capacity and Energy Emergencies Standard EOP-002-0. A Balancing Authority may choose to wait and see if conditions improve before requesting an Energy Emergency Alert, but valuable time to seek electric power support may be lost, as it was on February 18. An Energy Emergency Alert may be cancelled with little adverse effect when conditions improve.
3. PSCo Transmission Operations and Real-Time Dispatch should update their internal alert protocols to coordinate with the Energy Emergency Alert criteria of NERC Capacity and Energy Emergencies Standard EOP-002-0.
4. PSCo should interrupt all Interruptible Service Option Credit (ISOC) electric service customers during Level 2 and Level 3 Energy Emergency Alerts for the PSCo Balancing Authority.

[138] Electric distribution feeder circuit interruption data from the Xcel Energy Report of the Events that Led to Controlled Outages – Public Service Company of Colorado – Date of Occurrence February 18, 2006 as corrected in PSCo Response to Staff Audit Request CPUC-19-1.

5. PSCo should curtail firm pre-scheduled wholesale electric energy sales at the earliest opportunity specified in each wholesale electric energy sales contract during Level 2 and Level 3 Energy Emergency Alerts for the PSCo Balancing Authority.
6. PSCo should adequately staff all 24-hour dispatch desks to provide sufficient time for operations training.
7. PSCo should conduct emergency simulation training exercises for operations personnel including Real-Time Dispatch, Energy Trading, Transmission Operations, Distribution Control Center, Media Relations, Customer Care, and its four rural electric association wholesale customers.
8. PSCo should notify its four rural electric association wholesale customers of all future Energy Emergency Alerts for the PSCo Balancing Authority.
9. PSCo and its four rural electric association wholesale customers should negotiate responsibilities for future emergency load curtailments.
10. PSCo and its four rural electric association wholesale customers should reevaluate annually the suitability of each of their electric distribution feeder circuits for load curtailment.
11. PSCo should evaluate whether engineering specifications for substation switchgear are adequate for operation at site-specific historical low and high temperatures.
12. PSCo should open and close any medium voltage circuit breaker or recloser in a substation that has not operated in the previous 30 months, operating conditions permitting.
13. PSCo should replace all substation medium voltage circuit breaker or recloser mechanisms that have failed to operate properly on two or more separate occasions in the previous ten years
14. PSCo should replace all substation medium voltage air magnetic circuit breaker mechanisms that are more than 25 years old.
15. PSCo should place substation electricians on alert during Level 2 and Level 3 Energy Emergency Alerts for the PSCo Balancing Authority.

Interruption of Firm Electric Load Timeline

Time & Date	Event
07:16 2/18/06	Reliability Center declares PSCO Level 1 Energy Emergency Alert.
08:47 2/18/06	Transmission Operations begins interruption of Load Group 1.
08:51 2/18/06	Reliability Center declares PSCO Level 3 Energy Emergency Alert.
08:56 2/18/06	Transmission Operations completes interruption of Load Group 1.
09:19 2/18/06	Transmission Operations begins interruption of Load Group 2.
09:19 2/18/06	Distribution Control begins restoration of Load Group 1.
09:20 2/18/06	Havana Substation 13.8 kV Feeder Breaker 1937 fails to close.
09:24 2/18/06	Greenwood Substation 13.8 kV Feeder Breaker 1436 fails to close.
09:30 2/18/06	Transmission Operations completes interruption of Load Group 2.
09:31 2/18/06	Distribution Control completes restoration of Load Group 1.
09:49 2/18/06	Distribution Control begins restoration of Load Group 2.
09:49 2/18/06	Legget Substation 13.8 kV Feeder Breaker 1322 fails to close.
09:49 2/18/06	Littleton Substation 13.8 kV Feeder Breaker 1738 fails to close.
09:52 2/18/06	Bancroft Substation 13.8 kV Feeder Breaker 1816 fails to close.
09:52 2/18/06	Transmission Operations begins interruption of Load Group 3.
09:54 2/18/06	NCAR Substation 13.8 kV Feeder Breaker 1557 fails to close.
09:56 2/18/06	Transmission Operations extends controlled interruptions to the PSCo Western Region, GVP, HCE, and YVEA.
09:57 2/18/06	Transmission Operations opens Steamboat Substation 13.8 kV Feeder Breaker ST931 without notifying YVEA crew in substation.
09:58 2/18/06	Semper Substation 13.8 kV Feeder Breaker 1953 fails to close.
09:58 2/18/06	Transmission Operations completes interruption of Load Group 3.
09:58 2/18/06	Distribution Control completes restoration of Load Group 2.
10:14 2/18/06	Distribution Control begins restoration of Load Group 3.
10:14 2/18/06	Greenwood Substation 13.8 kV Feeder Breaker 1438 fails to close.
10:14 2/18/06	Boulder Terminal 13.8 kV Feeder Breaker 1357 fails to close.
10:15 2/18/06	Sullivan Substation 13.8 kV Feeder Breaker 1806 fails after closing.
10:15 2/18/06	North Substation 13.8 kV Feeder Breaker 1425 fails to close.
10:15 2/18/06	Distribution Control closes Steamboat Substation 13.8 kV Feeder Breaker ST931 without notifying YVEA crew in substation.
10:30 2/18/06	Distribution Control completes restoration of Load Group 3. Equipment failures leave 20,507 PSCo electric customers without power.
10:53 2/18/06	Littleton Substation 13.8 kV Feeder Breaker 1738 closed after 94 minutes open.
10:59 2/18/06	North Substation 13.8 kV Feeder Breaker 1425 closed after 63 minutes open.
11:28 2/18/06	Reliability Center declares PSCO Level 2 Energy Emergency Alert.
12:39 2/18/06	Legget Substation 13.8 kV Feeder Breaker 1322 closed after 200 minutes open.
12:48 2/18/06	Havana Substation 13.8 kV Feeder Breaker 1937 closed after 240 minutes open.
13:00 2/18/06	Greenwood Substation 13.8 kV Feeder Breaker 1436 closed after 250 minutes open.
13:04 2/18/06	Bancroft Substation 13.8 kV Feeder Breaker 1816 closed after 225 minutes open.
13:05 2/18/06	Greenwood Substation 13.8 kV Feeder Breaker 1438 closed after 193 minutes open.
14:02 2/18/06	Boulder Terminal 13.8 kV Feeder Breaker 1357 closed after 247 minutes open.
15:09 2/18/06	Semper Substation 13.8 kV Feeder Breaker 1953 closed after 339 minutes open.
15:13 2/18/06	NCAR Substation 13.8 kV Feeder Breaker 1557 closed after 349 minutes open. PSCo restores last firm electric service customers.
16:09 2/18/06	Reliability Center terminates PSCO Energy Emergency Alert.

Interruption of Firm Load Discussion

Shortly after the Front Range Power Company electric generation units tripped off line on Saturday morning, February 18, the PSCo Balancing Authority determined that it had no alternative but to request that the Rocky Mountain-Desert Southwest Reliability Center (RDRC) declare a Level 3 Energy Emergency Alert (in accord with NERC Capacity and Energy Emergencies Standard EOP-002-0). At 08:47, the PSCo Balancing Authority began a controlled interruption of electric service to retail electric customers to reduce the Balancing Authority obligation load by approximately 400 megawatts.

During a controlled interruption of firm electric load, a load group of electric service customers with a combined electric power demand roughly equal to the power supply shortfall (400 megawatts in this instance) is interrupted for approximately one half hour. After about 30 minutes, the first group of customers is restored while a second group is interrupted. After another 30 minutes, the second group of customers is restored while a third group is interrupted. This process continues until the Balancing Authority supply and demand balance is reestablished. If all electric customers available for interruption have been interrupted once before balance is restored, customers may be interrupted for a second or even third time.

In addition to serving its own electric service customers, PSCo provides wholesale electric energy for four rural electric associations in Colorado: GVP, HCE, YVEA, and the Intermountain Rural Electric Association (IREA). The PSCo Balancing Authority also includes the Colorado electric operations of Aquila, Inc and the Platte River Power Authority (PRPA), a generation and transmission association owned by the cities of Fort Collins, Loveland, Longmont, and Estes Park.

The first load group included 129,391 PSCo customers who were interrupted for an average of 39.1 minutes. PSCo opened 63 feeder circuit breakers with a total load of 428 megawatts between 8:47 and 8:58 and closed the breakers back in between 09:19 and 09:31, except for two PSCo breakers that failed to close on command. The two failed PSCo feeder circuit breakers were manually closed at 12:48 and 13:00.

The second load group included 128,197 PSCo customers who were interrupted for an average of 59.4 minutes. PSCo opened 54 feeder circuit breakers with a total load of 360 megawatts between 09:19 and 09:30 and closed the breakers back in between 09:49 and 09:58, except for five PSCo breakers that failed to close on command. The five failed PSCo feeder circuit breakers were manually closed at 10:53, 12:39, 13:04, 15:09, and 15:13.

The third load group included a total of 113,782 electric service customers who were interrupted for an average of 24 minutes. This group included 65,598 PSCo customers who were interrupted for an average of 26.6 minutes, 38,984 HCE customers (75.6 percent) who were interrupted for an average of 20.3 minutes, 6,181 YVEA customers (25.1 percent) who were interrupted for an average of 22.3 minutes, and 3,019 GVP customers (20.4 percent) who were interrupted for an average of 18 minutes. PSCo opened 71 feeder circuit breakers with a total load of 405 megawatts between 09:52 and 09:58 and closed the breakers back in between 10:14 and 10:30, except for three PSCo breakers which failed to close on command. The three failed PSCo feeder circuit breakers were manually closed at 10:59, 13:05, and 14:02.

Had the PSCo Balancing Authority needed to extend the load curtailment beyond 10:30, many of these same customers would have been interrupted again with electric power back on for about an hour before losing power again for about a half hour. This cycle of rolling electric service interruptions would continue until the electric power supply came back into balance with the electric power demand.

PSCo failed to notify any of its four rural electric association wholesale customers of either the Energy Emergency Alerts or the controlled interruptions. GVP, HCEA, and YVEA were unable to provide their customers with important information about their service interruptions. A YVEA crew was working in the Steamboat Substation when PSCo Transmission Operations tripped electric distribution feeder circuit breaker ST931 at 09:57. The PSCo Distribution Control Center closed the breaker back in 18 minutes later. The YVEA crew had no warning or explanation of either of these operations, but fortunately no one was injured.[139]

To minimize the stress to substation distribution transformers when service is restored, it is good utility operating practice to limit the number of feeder circuits interrupted simultaneously per transformer to one feeder circuit per transformer feeding five or fewer feeders, or two feeder circuits per transformer feeding six or more feeders. Seven feeder circuits were interrupted simultaneously at the Aspen Substation. The simultaneous interruption of several feeder circuits at a substation creates an extensive blackout area.

The following six pages provide additional information about the 188 electric distribution feeder circuits that were interrupted.[140]

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[139] Yampa Valley Electric Association, June 13, 2006.

[140] Electric distribution feeder circuit interruption data from the Xcel Energy Report of the Events that Led to Controlled Outages – Public Service Company of Colorado – Date of Occurrence February 18, 2006 as corrected in PSCo Response to Staff Audit Request CPUC-19-1.

Electric Distribution Feeder Circuits Interrupted on February 18, 2006

company	*region*	*substation*	*circuit ID*	*time opened*	*close command*	*time restored*	*outage minutes*
PSCo	SWMD	Allison Substation	1143	08:47	09:19	09:19	32
PSCo	SEMD	Clark Substation	1190	08:47	09:19	09:19	32
PSCo	NMD	North Substation	2293	08:47	09:19	09:19	32
PSCo	NMD	Simms Substation	1020	08:47	09:19	09:19	32
PSCo	BR	Leggett Substation	1324	08:48	09:19	09:19	31
PSCo	NMD	Argo Substation	1546	08:48	09:20	09:20	32
PSCo	DMD	Havana Substation	1937	08:48	09:20	12:48	240
PSCo	SWMD	Marcy Substation	1220	08:48	09:20	09:20	32
PSCo	SEMD	Sullivan Substation	1807	08:48	09:20	09:20	32
PSCo	NMD	Ralston Substation	2741	08:48	09:20	09:20	32
PSCo	DMD	Tower Substation	1240	08:48	09:21	09:21	33
PSCo	NMD	Russell Substation	1674	08:48	09:22	09:22	34
PSCo	NMD	Semper Substation	1954	08:48	09:22	09:22	34
PSCo	NMD	Simms Substation	1029	08:48	09:22	09:22	34
PSCo	SEMD	Leetsdale Substation	2497	08:48	09:22	09:22	34
PSCo	SWMD	Bancroft Substation	1811	08:49	09:22	09:22	33
PSCo	SEMD	Meadow Hills Substation	2058	08:49	09:21	09:21	32
PSCo	SEMD	Clark Substation	2069	08:49	09:21	09:21	32
PSCo	NMD	North Substation	2324	08:49	09:21	09:21	32
PSCo	SEMD	Jewell Substation	1033	08:49	09:23	09:23	34
PSCo	BR	Louisville Substation	1498	08:49	09:23	09:23	34
PSCo	NMD	Quaker Substation	1905	08:49	09:23	09:23	34
PSCo	FRR	Bergen Park Substation	2524	08:49	09:23	09:23	34
PSCo	SWMD	Santa Fe Substation	1150	08:50	09:24	09:24	34
PSCo	NMD	Russell Substation	1671	08:50	09:24	09:24	34
PSCo	SEMD	Tollgate Substation	1768	08:50	09:24	09:24	34
PSCo	SEMD	Greenwood Substation	1436	08:50	09:24	13:00	250
PSCo	NMD	Arvada Substation	1707	08:50	09:24	09:24	34
PSCo	BR	Boulder Terminal	1358	08:50	09:24	09:24	34
PSCo	NMD	Quaker Substation	1909	08:50	09:24	09:24	34
PSCo	SWMD	West Substation	1291	08:50	09:24	09:24	34
PSCo	SEMD	Clark Substation	1195	08:50	09:24	09:24	34
PSCo	SEMD	Meadow Hills Substation	2056	08:51	09:24	09:24	33
PSCo	NMD	Argo Substation	1549	08:51	09:25	09:25	34
PSCo	BR	Louisville Substation	1493	08:51	09:25	09:25	34
PSCo	NMD	Riverdale Substation	1646	08:51	09:25	09:25	34
PSCo	SEMD	Tollgate Substation	1764	08:51	09:25	09:25	34
PSCo	SEMD	Jewell Substation	1032	08:51	09:25	09:25	34
PSCo	SEMD	Greenwood Substation	1442	08:51	09:26	09:26	35
PSCo	DMD	University Substation	1924	08:51	09:26	09:26	35

Electric Distribution Feeder Circuits Interrupted on February 18, 2006

company	region	substation	circuit ID	time opened	close command	time restored	outage minutes
PSCo	BR	NCAR Substation	1556	08:52	09:26	09:26	34
PSCo	NMD	Arvada Substation	1704	08:52	09:26	09:26	34
PSCo	BR	Boulder Terminal	1344	08:52	09:27	09:27	35
PSCo	SWMD	Lakewood Substation	1558	08:52	09:27	09:27	35
PSCo	DMD	Sandown Substation	1746	08:52	09:26	09:26	34
PSCo	SEMD	Tech Center Substation	1054	08:52	09:27	09:27	35
PSCo	NMD	Mapleton Substation	1755	08:52	09:27	09:27	35
PSCo	SEMD	Surrey Ridge Substation	1282	08:52	09:27	09:27	35
PSCo	NMD	Washington Substation	1263	08:54	09:27	09:27	33
PSCo	SWMD	Allison Substation	1144	08:54	09:27	09:27	33
PSCo	BR	Leggett Substation	1326	08:54	09:27	09:27	33
PSCo	NMD	Argo Substation	1547	08:54	09:29	09:29	35
PSCo	FRR	Idaho Springs Substation	2944	08:54	09:29	09:29	35
PSCo	SEMD	Leetsdale Substation	2493	08:54	09:29	09:29	35
PSCo	NMD	Ridge Substation	2042	08:54	09:29	09:29	35
PSCo	SEMD	Surrey Ridge Substation	1281	08:55	09:29	09:29	34
PSCo	SEMD	Clark Substation	1192	08:55	09:27	09:27	32
PSCo	NMD	North Substation	2323	08:55	09:27	09:27	32
PSCo	NMD	Glenn Substation	1918	08:55	09:31	09:31	36
PSCo	NMD	Russell Substation	1672	08:55	09:31	09:31	36
PSCo	SEMD	Sullivan Substation	1802	08:55	09:31	09:31	36
PSCo	SEMD	Leetsdale Substation	2494	08:55	09:31	09:31	36
PSCo	NMD	Arvada Substation	1701	08:56	09:31	09:31	35
PSCo	BR	Leggett Substation	1322	09:19	09:49	12:39	200
PSCo	SWMD	Littleton Substation	1738	09:19	09:49	10:53	94
PSCo	NMD	Semper Substation	1951	09:19	09:50	09:50	31
PSCo	DMD	University Substation	1922	09:19	09:49	09:49	30
PSCo	SWMD	Bancroft Substation	1816	09:19	09:52	13:04	225
PSCo	NMD	Broomfield Substation	2731	09:20	09:52	09:52	32
PSCo	NMD	Semper Substation	1957	09:20	09:52	09:52	32
PSCo	SEMD	Leetsdale Substation	2488	09:20	09:52	09:52	32
PSCo	SWMD	Kendrick Substation	1974	09:21	09:52	09:52	31
PSCo	DMD	Sandown Substation	1743	09:21	09:52	09:52	31
PSCo	NMD	Quaker Substation	1903	09:21	09:52	09:52	31
PSCo	SEMD	Greenwood Substation	1437	09:21	09:52	09:52	31
PSCo	DMD	Tower Substation	1242	09:21	09:52	09:52	31
PSCo	NMD	Mapleton Substation	1752	09:21	09:52	09:52	31
PSCo	NMD	Broomfield Substation	2734	09:21	09:52	09:52	31
PSCo	SEMD	Buckley Substation	1270	09:22	09:53	09:53	31
PSCo	SWMD	Marcy Substation	1225	09:22	09:53	09:53	31

Electric Distribution Feeder Circuits Interrupted on February 18, 2006

company	region	substation	circuit ID	time opened	close command	time restored	outage minutes
PSCo	NMD	Ralston Substation	2744	09:22	09:53	09:53	31
PSCo	SWMD	West Substation	1293	09:22	09:53	09:53	31
PSCo	SEMD	Clark Substation	1197	09:22	09:53	09:53	31
PSCo	SWMD	Kendrick Substation	1978	09:23	09:54	09:54	31
PSCo	BR	Louisville Substation	1495	09:23	09:54	09:54	31
PSCo	SWMD	Prairie Substation	1357	09:23	09:54	09:54	31
PSCo	SEMD	Tech Center Substation	2074	09:23	09:54	09:54	31
PSCo	SEMD	East Substation	1574	09:23	09:54	09:54	31
PSCo	BR	NCAR Substation	1557	09:24	09:54	15:13	349
PSCo	NMD	Quaker Substation	1906	09:24	09:54	09:54	30
PSCo	DMD	South Substation	1534	09:24	09:54	09:54	30
PSCo	SEMD	Greenwood Substation	1444	09:24	09:54	09:54	30
PSCo	NMD	Arvada Substation	1706	09:25	09:54	09:54	29
PSCo	BR	Boulder Terminal	1347	09:25	09:55	09:55	30
PSCo	SWMD	Lakewood Substation	1563	09:25	09:55	09:55	30
PSCo	SEMD	Sullivan Substation	1805	09:25	09:55	09:55	30
PSCo	SEMD	Tech Center Substation	1052	09:25	09:55	09:55	30
PSCo	NMD	Argo Substation	1545	09:26	09:55	09:55	29
PSCo	NMD	Washington Substation	1267	09:26	09:55	09:55	29
PSCo	BR	Louisville Substation	1492	09:26	09:55	09:55	29
PSCo	SWMD	Prairie Substation	1354	09:26	09:55	09:55	29
PSCo	SEMD	Clark Substation	1194	09:26	09:55	09:55	29
PSCo	NMD	Argo Substation	1548	09:26	09:56	09:56	30
PSCo	BR	NCAR Substation	1554	09:26	09:56	09:56	30
PSCo	SWMD	Prairie Substation	1356	09:26	09:56	09:56	30
PSCo	DMD	South Substation	1532	09:26	09:56	09:56	30
PSCo	SEMD	Surrey Ridge Substation	1284	09:26	09:56	09:56	30
PSCo	SEMD	Greenwood Substation	1441	09:27	09:57	09:57	30
PSCo	SEMD	Tollgate Substation	1766	09:27	09:57	09:57	30
PSCo	NMD	Ralston Substation	2747	09:27	09:57	09:57	30
PSCo	NMD	Arvada Substation	1702	09:28	09:57	09:57	29
PSCo	SEMD	Meadow Hills Substation	2103	09:28	09:57	09:57	29
PSCo	FRR	Bergen Park Substation	1942	09:30	09:58	09:58	28
PSCo	SWMD	Lakewood Substation	1557	09:30	09:58	09:58	28
PSCo	BR	Louisville Substation	1497	09:30	09:58	09:58	28
PSCo	NMD	Semper Substation	1953	09:30	09:58	15:09	339
PSCo	SEMD	Tollgate Substation	1761	09:30	09:58	09:58	28
PSCo	NMD	Broomfield Substation	2733	09:52	10:14	10:14	22
PSCo	SWMD	Kendrick Substation	1977	09:52	10:14	10:14	22
PSCo	SEMD	Leetsdale Substation	2490	09:52	10:14	10:14	22

Electric Distribution Feeder Circuits Interrupted on February 18, 2006

company	*region*	*substation*	*circuit ID*	*time opened*	*close command*	*time restored*	*outage minutes*
PSCo	NMD	Semper Substation	1958	09:52	10:14	10:14	22
PSCo	DMD	Sandown Substation	1747	09:52	10:14	10:14	22
PSCo	DMD	Tower Substation	1243	09:52	10:14	10:14	22
PSCo	NMD	Quaker Substation	1904	09:52	10:14	10:14	22
PSCo	SEMD	Greenwood Substation	1438	09:52	10:14	13:05	193
PSCo	NMD	Mapleton Substation	1754	09:53	10:14	10:14	21
PSCo	NMD	Ridge Substation	2043	09:54	10:14	10:14	20
PSCo	DMD	University Substation	1923	09:54	10:14	10:14	20
PSCo	SEMD	Buckley Substation	1271	09:54	10:14	10:14	20
PSCo	SEMD	Clark Substation	2068	09:54	10:14	10:14	20
PSCo	SEMD	Meadow Hills Substation	2057	09:54	10:14	10:14	20
PSCo	NMD	Glenn Substation	1916	09:54	10:14	10:14	20
PSCo	SEMD	Jewell Substation	1036	09:54	10:14	10:14	20
PSCo	NMD	Russell Substation	1673	09:54	10:14	10:14	20
PSCo	SEMD	Tech Center Substation	2076	09:54	10:14	10:14	20
PSCo	BR	Louisville Substation	1496	09:54	10:14	10:14	20
PSCo	SWMD	Kendrick Substation	1979	09:55	10:14	10:14	19
PSCo	SWMD	Martin Substation	1681	09:55	10:14	10:14	19
PSCo	SEMD	Tech Center Substation	2077	09:55	10:14	10:14	19
PSCo	SEMD	Buckley Substation	1273	09:55	10:14	10:14	19
PSCo	DMD	Sandown Substation	1748	09:55	10:14	10:14	19
PSCo	BR	Boulder Terminal	1357	09:55	10:14	14:02	247
PSCo	SWMD	Littleton Substation	1732	09:55	10:15	10:15	20
PSCo	SEMD	Sullivan Substation	1806	09:55	10:15	10:15	20
PSCo	SEMD	Tech Center Substation	1053	09:55	10:15	10:15	20
PSCo	NMD	North Substation	1425	09:56	10:15	10:59	63
HCE	PIT	Basalt Distribution Substation	BA451	09:56	10:15	10:15	19
YVEA	MOF	Craig Transfer Substation	CT961	09:56	10:15	10:15	19
HCE	EAG	Vail Substation	VA411A	09:56	10:15	10:15	19
HCE	PIT	Aspen Substation	AP411A	09:56	10:15	10:15	19
PSCo	WR	Grand Junction Substation	1102	09:56	10:15	10:15	19
PSCo	WR	Parachute Substation	2474	09:56	10:15	10:15	19
HCE	PIT	Aspen Substation	AP441A	09:56	10:15	10:15	19
HCE	PIT	Basalt Distribution Substation	BA461	09:56	10:30	10:30	34
YVEA	MOF	Craig Transfer Substation	CT921	09:56	10:27	10:27	31
HCE	PIT	Aspen Substation	AP421C	09:56	10:30	10:30	34
HCE	GAR	Crystal Substation	CD431B	09:56	10:30	10:30	34
PSCo	WR	Parachute Substation	2475	09:56	10:30	10:30	34
HCE	EAG	Vail Substation	VA421A	09:56	10:30	10:30	34
HCE	EAG	Beaver Creek West Substation	BC421B	09:56	10:30	10:30	34

Electric Distribution Feeder Circuits Interrupted on February 18, 2006

company	*region*	*substation*	*circuit ID*	*time opened*	*close command*	*time restored*	*outage minutes*
HCE	PIT	Aspen Substation	AP431A	09:57	10:15	10:15	18
HCE	EAG	Avon Substation	AV461A	09:57	10:15	10:15	18
PSCo	WR	Grand Junction Substation	1104	09:57	10:16	10:16	19
HCE	EAG	Vail Substation	VA431A	09:57	10:15	10:15	18
HCE	PIT	Basalt Distribution Substation	BA411	09:57	10:16	10:16	19
YVEA	ROU	Steamboat Substation	ST931	09:57	10:15	10:15	18
HCE	EAG	Beaver Creek West Substation	BC431A	09:57	10:15	10:15	18
HCE	EAG	Cooley Mesa Substation	CM411A	09:58	10:16	10:16	18
HCE	GAR	Crystal Substation	CD451B	09:58	10:16	10:16	18
HCE	PIT	Aspen Substation	AP451A	09:58	10:16	10:16	18
HCE	EAG	Beaver Creek West Substation	BC441B	09:58	10:16	10:16	18
HCE	EAG	Vail Substation	VA431B	09:58	10:16	10:16	18
HCE	EAG	Wolcott Substation	WC411A	09:58	10:16	10:16	18
GVP	MES	Ute Grand Junction Substation	G941	09:58	10:16	10:16	18
HCE	EAG	Beaver Creek West Substation	BC461A	09:58	10:15	10:15	17
HCE	PIT	Aspen Substation	AP451B	09:58	10:16	10:16	18
HCE	EAG	Cooley Mesa Substation	CM421A	09:58	10:16	10:16	18
PSCo	WR	Grand Junction Substation	1108	09:58	10:16	10:16	18
HCE	EAG	Vail Substation	VA411B	09:58	10:16	10:16	18
HCE	EAG	Wolcott Substation	WC421A	09:58	10:16	10:16	18
HCE	GAR	Crystal Substation	CD421B	09:58	10:16	10:16	18
HCE	PIT	Aspen Substation	AP461B	09:58	10:16	10:16	18
HCE	EAG	Avon Substation	AV411A	09:58	10:16	10:16	18
HCE	EAG	Wolcott Substation	WC451A	09:58	10:16	10:16	18
HCE	PIT	Basalt Distribution Substation	BA471	09:58	10:16	10:16	18
HCE	EAG	Cooley Mesa Substation	CM451A	09:58	10:16	10:16	18
PSCo	WR	Grand Junction Substation	1106	09:58	10:17	10:17	19
HCE	EAG	Vail Substation	VA421B	09:58	10:16	10:16	18

Customer Average Interruption Duration in Minutes = 41.498

Electric Distribution Abbreviations

company acronym	region abbreviation	company name	region name
GVP		Grand Valley Power	
HCE		Holy Cross Energy	
IREA		Intermountain Rural Electric Association	
PSCo		Public Service Company of Colorado	
YVEA		Yampa Valley Electric Association	
IREA	ADA	Intermountain Rural Electric Association	Adams County
IREA	ARA	Intermountain Rural Electric Association	Arapahoe County
PSCo	BR	Public Service Company of Colorado	Boulder Region
IREA	CLE	Intermountain Rural Electric Association	Clear Creek County
PSCo	DMD	Public Service Company of Colorado	Denver Metro Division
IREA	DOU	Intermountain Rural Electric Association	Douglas County
HCE	EAG	Holy Cross Energy	Eagle County
YVEA	EAG	Yampa Valley Electric Association	Eagle County
IREA	ELB	Intermountain Rural Electric Association	Elbert County
PSCo	FRR	Public Service Company of Colorado	Front Range Region
GVP	GAR	Grand Valley Power	Garfield County
HCE	GAR	Holy Cross Energy	Garfield County
PSCo	GR	Public Service Company of Colorado	Greeley Region
PSCo	HPR	Public Service Company of Colorado	High Plains Region
IREA	JEF	Intermountain Rural Electric Association	Jefferson County
GVP	MES	Grand Valley Power	Mesa County
YVEA	MOF	Yampa Valley Electric Association	Moffat County
PSCo	MR	Public Service Company of Colorado	Mountain Region
PSCo	NMD	Public Service Company of Colorado	North Metro Division
PSCo	NR	Public Service Company of Colorado	Northern Region
IREA	PAR	Intermountain Rural Electric Association	Park County
HCE	PIT	Holy Cross Energy	Pitkin County
YVEA	ROU	Yampa Valley Electric Association	Routt County
PSCo	SEMD	Public Service Company of Colorado	Southeast Metro Division
PSCo	SLVR	Public Service Company of Colorado	San Luis Valley Region
PSCo	SWMD	Public Service Company of Colorado	Southwest Metro Division
IREA	TEL	Intermountain Rural Electric Association	Teller County
PSCo	WR	Public Service Company of Colorado	Western Region

PSCo continued to sell firm pre-scheduled wholesale electric energy to four electric power organizations throughout the firm electric service customer interruptions. From 07:00 to 10:00 Saturday morning, PSCo sold 228 megawatts of electric power to Aquila, Inc., 150 megawatts to the Colorado River Storage Project (CRSP), 23 megawatts to the Municipal Energy Agency of Nebraska (MEAN), and 3 megawatts to the Arkansas River Power Authority (ARPA). From 10:00 to 23:00 Saturday, PSCo reduced its electric power sales to CRSP to 50 megawatts, but continued all other firm wholesale power sales as usual. The PSCo firm wholesale contracts with CRSP, MEAN, and ARPA permit PSCo to curtail sales as soon as all PSCo native interruptible load has been interrupted.[141] The PSCo firm wholesale contract with Aquila, Inc. permits sales to be curtailed by 1 megawatt for every 4 megawatts of firm native load that PSCo curtails.[142] A curtailment of the PSCo sales to Aquila proportionate to Aquila's share of the PSCo Balancing Authority load would have placed a fair share of the burden of Balancing Authority load shedding on Aquila.

The burden of load curtailment was spread unevenly among PSCo and its four rural electric association wholesale customers. PSCo interrupted 26 percent of its own electric service customers, 75.6 percent of HCE customers, 25.1 percent of YVEA customers, 20.4 percent of GVP customers, but no IREA customers. PSCo only interrupted electric distribution feeder circuit breakers that it owned and controlled. A NERC Balancing Authority may order constituent utilities to shed a proportionate share of their load. The burden of load curtailment was not spread evenly among the PSCo service regions. No PSCo customers were interrupted in five PSCo geographic regions. The following table provides a summary the electric service interruptions.[143]

Colorado Electric Service Interruptions

Saturday, February 18, 2006

electric utility company	number of electric customers interrupted	total number of electric customers	percent of electric customers interrupted	customer average interruption minutes
Public Service Company of Colorado	323,186	1,240,965	26.0%	44.637
Intermountain Rural Electric Association	0	131,000	0.0%	0.000
Holy Cross Energy	38,984	51,600	75.6%	20.333
Yampa Valley Electric Association	6,181	24,617	25.1%	22.315
Grand Valley Power	3,019	14,800	20.4%	18.000
	371,370	1,462,982	25.4%	41.498

Eleven of the 151 PSCo feeder circuit breakers (7.3 percent) failed when commanded to close. Two of the feeder circuit breakers failed to receive close commands via the Supervisory Control and Data Acquisition (SCADA) System. These two breakers were successfully closed about an hour later on command via the SCADA System. Eight of the feeder circuit breakers failed to close due to lubricant degradation due to low temperature. One feeder circuit breaker managed to close, but its closing coil was permanently damaged due to very slow operation caused by lubricant degraded by low temperature. All of the eleven failed breakers were equipped with

141 PSCo 3-81 in response to Staff Audit Request CPUC-01-4.

142 PSCo 3-81 in response to Staff Audit Request CPUC-01-4.

143 Electric distribution feeder circuit interruption data from the Xcel Energy Report of the Events that Led to Controlled Outages – Public Service Company of Colorado – Date of Occurrence February 18, 2006 as corrected in PSCo Response to Staff Audit Request CPUC-19-1.

functioning strip heaters[144] and none of the substations lost station power.[145] All nine circuit breaker mechanisms that failed were of an air-magnetic arc expulsion design. These nine failed mechanisms protected 13 percent of the 69 interrupted PSCo feeder circuits protected by air-magnetic circuit breakers.[146] Although PSCo does not perform scheduled maintenance on substation medium voltage circuit breakers, substation electricians open and close circuit breakers that have been inactive for more than one year. The following table provides details of the eleven failed PSCo circuit breakers.[147]

Failed Electric Distribution Feeder Circuit Breakers

Saturday, February 18, 2006

substation	*circuit breaker*	*type of mechanism*	*source of failure*	*time opened*	*time failed*	*time closed*	*outage minutes*
Havana Substation	1937	air-magnetic	lubricant	08:48	09:20	12:48	240
Greenwood Substation	1436	air-magnetic	control fuse	08:50	09:24	13:00	250
Leggett Substation	1322	air-magnetic	lubricant	09:19	09:49	12:39	200
Littleton Substation	1738	air-magnetic	SCADA	09:19	09:49	10:53	94
Bancroft Substation	1816	air-magnetic	lubricant	09:19	09:52	13:04	225
NCAR Substation	1557	air-magnetic	lubricant	09:24	09:54	15:13	349
Semper Substation	1953	air-magnetic	lubricant	09:30	09:58	15:09	339
Greenwood Substation	1438	air-magnetic	lubricant	09:52	10:14	13:05	193
Boulder Terminal	1357	air-magnetic	lubricant	09:55	10:14	14:02	247
Sullivan Substation	1806	air-magnetic	close coil	09:55	10:15	10:15	20
North Substation	1425	vacuum	SCADA	09:56	10:15	10:59	63

The ten PSCo feeder circuit breakers that failed to close extended the electric service interruption of 20,507 PSCo customers by an average of nearly four hours. These interruptions with equipment failures lasted an average of more than nine times as long as their controlled interruptions should have.

Interruption of Electric Firm Load Conclusions

1. Staff commends PSCo for its prompt, measured, and efficient curtailment of electric load that protected the bulk electric power system of the Rocky Mountain region on February 18, 2006.
2. PSCo failed to curtail most of its firm pre-scheduled wholesale electric energy sales during the controlled electric service interruptions.
3. PSCo failed to notify any of its four rural electric association wholesale customers of the Energy Emergency Alerts.

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[144] A strip heater is a small electric heating device used to maintain temperature in an enclosure.
[145] Station power is an electric service provided exclusively for a substation or power station.
[146] Commitment No. 4 of the Xcel Energy – 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.
[147] Electric distribution feeder circuit breaker data from the Xcel Energy Report of the Events that Led to Controlled Outages – Public Service Company of Colorado – Date of Occurrence February 18, 2006 as corrected in PSCo Response to Staff Audit Request CPUC-19-1.

4. PSCo interrupted only PSCo customers in the greater Denver metropolitan area for the first 69 minutes of the control interruptions.
5. PSCo disproportionately interrupted its customers in the PSCo regions, with no PSCo customers interrupted in five of the PSCo geographic regions.
6. PSCo disproportionately interrupted the customers of its four rural electric association wholesale customers, with 75.6 percent of HCEA customers interrupted but no IREA customers interrupted.
7. PSCo failed to set up enough electric distribution feeder circuit breakers for extended PSCo Balancing Authority load shedding.
8. PSCo failed to adequately distribute electric distribution feeder circuit interruptions to prevent several feeder circuits fed from a single transformer from being interrupted simultaneously.
9. PSCo did not interrupt any network service customers and only two customers with automatic throwover (ATO) switches[148] were briefly interrupted.
10. All 188 electric distribution feeder circuit breakers selected for interruption opened on command, but 11 of the 151 circuit breakers on PSCo feeder circuits (7.3 percent) failed when commanded to close. Nine of the 69 air-magnetic circuit breaker mechanisms on interrupted PSCo feeder circuits (13 percent) failed. No circuit breakers on GVP, HCE, or YVEA feeder circuits failed.

On June 15, 2006, PSCo filed a Commitment Log Report to the Colorado Public Utilities Commission Regarding the February 18, 2006, Controlled Outage Event (Commitment Log Report) with the Commission. As part of this Commitment Log Report, PSCo provides documentation from various people and organizations within the Company supporting the Company's internal investigation of the outages. Intermingled with the documentation, the Company provides notes and data on the status of action items resulting from the Company's internal investigation. The Executive Summary also provides the Company's response to specific overarching concerns. A number of tabs in the Commitment Log Report provide information directly related to problems encountered during the execution of the controlled outages. As part of the Staff analysis, we have reviewed the Company's actions to date, and future commitments related to the execution of the controlled outages. The following summary provides staff's assessment of the Company's actions and commitments.

Response to PSCo Commitment No. 4:
PSCo repaired or cleaned the eleven feeder circuit breakers that failed and placed them back into service by February 21, 2006. Unfortunately, PSCo makes no further commitment to prevent similar circuit breaker failures in the future.

All nine circuit breaker mechanisms that failed employed an air-magnetic arc expulsion design. These nine failures represented 13 percent of the interrupted PSCo feeder circuits protected by air-magnetic circuit breakers. Air-magnetic circuit breaker mechanisms can deteriorate with the number of operations performed, age, and exposure to heat, cold, dust, moisture, and other adverse environmental conditions. Medium voltage air-magnetic circuit breakers have been largely superseded by simpler, smaller, and more reliable vacuum circuit breakers. Direct replacement vacuum circuit breaker mechanisms are now available for many older models of air-magnetic circuit breakers. Many utilities have instituted programs to replace aging air magnetic circuit breaker mechanisms with new vacuum circuit breaker mechanisms. PSCo reports that it

[148] An automatic throwover switch is used to automatically select one of two independent sources of power, e.g., feeder circuits from two different substations. Automatic throwover switches are used to provide power to critical electric power customers such as hospitals.

has replaced about 88 substation medium voltage air-magnetic circuit breaker mechanisms with vacuum circuit breaker mechanisms in the past two years.

While the repair and cleaning of the circuit breaker mechanisms that failed is a short term solution, Staff recommends that circuit breaker mechanisms that are likely to fail be replaced to avert future equipment failures.

Please see Section 9 Recommendations 11, 12, 13, 14, and 15 above for further details.

Response to PSCo Commitment No. 5:
After the February 18 event, PSCo discovered that its controlled interruptions feeder circuit list was several years out of date. PSCo Capacity Planning has since updated this list.

Staff believes that PSCo should create two distinct procedures (and supporting systems) for (1) Balancing Authority load shedding, and (2) local load shedding in response to transmission or substation restrictions. PSCo should coordinate the controlled interruptions feeder circuit lists with its four rural electric association wholesale customers. PSCo and its four rural electric association wholesale customers should reevaluate each year the suitability of each of their electric distribution feeder circuits for load curtailment.

Please see Section 9 Recommendations 1, 9, and 10 above for further details.

Response to PSCo Commitment No. 6:
While PSCo Transmission Operations and the Distribution Control Center executed the controlled interruption of firm electric load quite well, the Distribution Control Center did not fully understand the protocol for controlled interruptions and was unable to convey an accurate description of the situation to Customer Care. Transmission Operations did not adequately apprise Media Relations of the situation either.

PSCo Transmission Operations and the Distribution Control Center have since written a coordination protocol for controlled electric service interruptions. This protocol only covers a small portion of controlled electric service interruptions issues. Simulation training is needed to thoroughly familiarize personnel with this new protocol.

Please see Section 9 Recommendations 1, 2, 3, 4, 5, 6, and 7 above and also the Recommendations in Sections 2 and 10 for further details.

Response to PSCo Commitment No. 38:
This commitment is identical to PSCo Commitment No. 6.

Please see Section 9 Recommendations 1, 2, 3, 4, 5, 6, and 7 above and also the Recommendations in Sections 2 and 10 for further details.

Section 10: Internal Organizational Communication

In each of the sections of this document, internal cross-organizational communication is cited as a contributing factor to the development of a situation that led to PSCo shedding retail customer load on February 18, 2006. The Company was not a bystander in the activities leading up to this event. Rather, what this event has made visible is that the Company was unable to quickly respond and adapt organizationally to changing conditions that required coordination across departments to be effectively addressed before spiraling into an emergency situation.

This final section is intended to summarize many of the issues already highlighted, to provide focus regarding specific organizational communication issues, and to offer recommendations for further improvements to protect against future events. The Company has acknowledged and is addressing inter-organizational communication problems, as noted in its Commitment Log Report to the Commission. The recommendations provided here are intended to enhance and add to the efforts underway internally.

Many of the commitments in the Commitment Log Report contain components of communication resolutions. Specifically, Commitment Log Report Items 3, 3A, 6, 21, 28, and 38 focus on addressing inter-organizational communication, and others have communication improvements included. While these make a first step towards identifying key communication issues, they do not effectively extend to solutions. Specifically, these commitments do not contain information on management commitment of resources (time and money) to continually improve and ensure organizational communication, there is limited consistency in the solutions offered across commitments, most do not include information on training and practice/simulation opportunities for staff, and they do not clearly align with industry best practices.

Changing organizational behaviors requires full commitment from senior management, and active support of change activities. In most companies, it also requires a single executive sponsor, typically with a direct line report to the CEO, who is accountable for ensuring consistency across operations. Without this type of commitment, the work that has been initiated in the Commitment Log Report will stagnate, and the processes that have been drafted remain static words on paper rather than an accurate representation of how the Company behaves, both day to day and in times of crisis. The following recommendations represent an array of areas that require additional attention from the Company to adequately address the problems highlighted by this event; however, none of these recommendations will be effective without long-term commitment and attention. Nor, for that matter, will the commitments identified in the Company's Commitment Log Report.

Internal Organizational Communication Recommendations

Organizational Structure

1. Create a role in the organization with a direct line report to the CEO who is accountable for operational consistency, oversight, and an communication between both the gas and electric units.

Communication to support emergency processes

2. The emergency notification system (MissionMode) apparently contains test/exercise capabilities. PSCo should create a schedule for running tests twice a year, and consider reviewing results with the PUC.
3. Create and maintain processes for corporate emergency identification and response – identify roles and responsibilities across the organization, what departments will lead the response, how it will be communicated to the organization and the public, and

what general steps will be taken to engage and communicate with cross-functional groups.[149]

4. Clearly establish senior management participation in Company-impacting events, and define their roles and accountability during such events.
5. Work with the industry to better define and clarify the role of the RDRC in executing emergency processes.

Customer communication regarding the event

6. A retroactive communication to customers through a bill stuffer to identify the top issues that occurred, and the ways in which the Company is addressing them, per the Commitment Log Report, would be an opportunity to make amends for the problems customers experienced on February 18.

Training and Preparation

7. Reinstitute the OFO dry run process for training and staff development.
8. Reinstitute educational sessions for suppliers to inform them of emergency processes.
9. Create, deploy, and maintain training that incorporates an approach to simulating emergencies that span departments and external industry groups. Ensure that all affected employees are provided with simulation training generally, and that specific simulations are created for roles like Real-Time Dispatch, Gas Supply and Gas Control to help them understand appropriate responses to various situations, including shortages.
10. Revisit existing documentation of training and processes and ensure that the Company is executing on what it has committed to in documentation.

Cross-Organizational and Industry Communication

11. Improve communication between plants and Real-Time Dispatch to ensure adequate visibility of overall system stability, and rapid communication of developing situations.
12. Improve communication between Real-Time Dispatch and Gas Control to rapidly identify when issues are developing on either the electric or gas side. Establish processes whereby the two departments can work collaboratively to address problems before they escalate to emergencies.
13. Improve communication between Real-Time Dispatch and Transmission Operations to ensure a smooth and articulate transfer of control between the departments during an emergency situation. Alternatively, update processes and training to reflect that Real-Time Dispatch will maintain control during emergencies, and that Transmission Operations will support Real-Time Dispatch in this type of environment, and ensure that staff understand and execute to the new processes.
14. Clarify the FERC Standard of Contact and the stipulations under which it can be suspended, communicate this broadly to the organization. Communicate this with Gas Control, Energy Supply, and Transmission Operations, and perform scenarios to ensure understanding of both when it is appropriate to suspend the Standard of Conduct, and what follow-on activities are required post-fact to come back in compliance.
15. Ensure consistency across departments regarding activities during an escalating situation, and clarify cross-department intersections and dependencies for emergency responses. Practice these activities to ensure understanding and commitment across organizations.

[149] This activity is in progress according to the Commitment Log Report.

Internal Communication Discussion

Internal communication issues spanned departments and levels in the organization. During the event, there was no consistent understanding of the status of PSCo as a whole, the degree or level of the crisis, and the appropriate response from a corporate perspective. Operational departments executed their emergency plans reasonably well, as is evidenced by the fact that the outage was controlled, the scheduled 30-minute intervals were sufficient to contain the problem quickly, and the follow-on steps to address the field issue of breakers not closing were initiated and completed per the defined process. However, there is no consistent understanding in the organization of what constitutes an emergency, and how to mitigate developing emergencies appropriately across organizations. There was no cohesive process for officially calling for controlled outages, there is no cross-organizational owner of that decision (although Transmission Operations clearly owns making the final decision on-site) and associated processes for ensuring the correct actions are taken across the organization. In some cases, defined processes were not followed or were not fully executed. This must be remedied, in documentation, in training, and in practice.

Within their areas of responsibility, individuals acted appropriately with regard for their areas. However, no one owned making sure the crisis was being addressed – there was no single point of contact. This lack of coordination resulted in individuals taking actions that may have been "helpful" but didn't cohesively remedy the situation.

Communication and Management of a Developing Situation

While much attention has been paid to how PSCo responded on Saturday morning as load shed became inevitable, there were a series of communication breakdowns that occurred in the 24 hours prior that contributed to the eventual crisis situation.

As actual weather conditions and field conditions changed on February 17, individual departments responded to stabilize their own environments. For example, Gas Control took the steps necessary to stabilize the LDC and to meet nominations for the day on Friday. Real-Time Dispatch took steps to turn up generation plants and to activate IPPs to cover growing demand based on its understanding of the changing forecasts. Additionally, Real-Time Dispatch proceeded with the assumption that additional gas could be purchased at a penalty price if necessary. However, there was limited inter-departmental discussion (formal or informal) to review the situation as it unfolded and to establish a concrete plan of action for going into the evening hours. Gas Control had significant concerns about the burn rates of the electric generation plants[150] through Friday afternoon. Conversely, the Real-Time Dispatcher had some concerns about the gas available on the system.[151] However, there was no direct communication between the departments to clarify the needs and potential responses, and as a result, inappropriate assumptions were made regarding mitigation options.

This lack of communication can be seen as a contributing factor to the way subsequent events, including the loss of generation capacity and the difficulty in bringing additional units online due to low gas pressures (discussed in Section 4) and through several generation units going offline, (discussed in Section 7) quickly spiraled into a significant crisis that might have been easier to address if the departments had been communicating regularly about their relative situations.

This problem can be seen in the events that unfolded on February 17 and 18. On the afternoon of February 17, Gas Control recognized that it might be heading toward a problem on the system

[150] Transcript, Audit response.
[151] Transcript, Audit response.

because of the excessive draw of gas from PSCo-owned electric plants[152]. Gas Control contacted Gas Supply to discuss the situation. Additionally, Real-Time Dispatch recognized that the schedule for electric was probably not sufficient for the actual load, given the forecasted to actual temperature differences that were becoming apparent as early as Friday afternoon[153]. However, there was no clear synchronization of these two alert situations, as each department responded independently to appropriately manage the developing situation within their respective areas.

On the afternoon of February 17, Real-Time Dispatch felt enough of a sense of urgency to request a delay of the Cherokee 4 planned maintenance cycle until 08:00 Saturday morning[154]. In evaluating the transcripts from Friday afternoon, it is apparent that there was concern regarding a potential crisis. At Gas Control, rather than calling an Operational Flow Order (OFO), which would have indicated an developing situation in Gas Control, and a subsequent balancing of nominations, Gas Control elected to enact several steps prior to close of business Friday to stabilize the system, including, for example:

- Requesting (informally) that nominations be balanced across all gas customers.
- Making suggesting to Real-Time Dispatch about other alternatives for power (primarily fuel and purchasing.)
- Seeking out alternative sources of gas on the system.

Without an OFO or direct communication, the Real-Time Dispatch desk did not fully appreciate the potential gas system constraints that were developing. As discussed in Section 4, a combination of decisions, including those to draw down gas inventory that had built up through an unseasonably warm January and early February (to stay in compliance with storage requirements) and the over burn that was taking place early in the day on Friday from the natural gas-fired electric plants meant that going into Friday evening, reserves were lower than necessary to meet growing demand related to the dropping temperatures. Because these two departments did not have clear visibility into each others' issues on Friday, and no one person or group had a sense of the interlocking system of gas supply and electric generation, as the situation began to deteriorate Friday night and into Saturday the organization was not able to respond as quickly as it might have as the situation developed.

In addition to the operational communication challenges, Transmission Operations and the Distribution Control Center struggled to communicate effectively with their primary contacts internally. They were engaged in the activities required to stabilize the system and, when it became necessary, to initiate and manage the controlled outages. While Transmission Operations did engage Media Relations early on Saturday morning, Distribution Control was not able to provide similar forewarnings to Customer Care, as highlighted in Section 2. This caused significant problems relative to accurate information being provided to customers, and in the Company's ability to manage the volume of calls into the Center.

During the event, the Company's Crisis Communication Plan was not fully activated or followed. When retroactively applying the standards put forth in the Plan for understanding the criticality of a situation, it appears that even today, this event would not have merited a high level of response for communication of the situation both internally and externally. This type of process discrepancy is discussed in more detail in Section 2, however, it is indicative of the broader need to review and refine cross-organizational processes to ensure consistency and appropriateness of responses.

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[152] Gas Control transcript review.
[153] Dispatch transcripts review.
[154] PSCo Preliminary Report pg. 12.

At no point during this crisis was an executive management team engaged to communicate with the staff about the situation and to ensure cross-organizational consistency in response. Lacking the execution of a corporate policy for determining an emergency situation or to identify a developing situation and managing it, each organization operated within its own protocols and requirements. A joint effort may have provided different results, particularly if the need had been identified and the process undertaken Friday afternoon or evening rather than Saturday morning, when the situation had deteriorated so thoroughly that rolling blackouts were required.

Defined Emergency Response Procedures Across Groups

Throughout the various departments in PSCo, there were, as of February 18, many different definitions of what constitutes an emergency or a crisis, and what is required in response to such a situation. For example, the Gas Emergency Plan refers to Level 1-4 Emergencies, and outlines the conditions under which they are determined and the respective actions taken both by Gas Control and other parts of the Company (for example, media relations, customer relations, Real-Time Dispatch)[155]. In contrast, the Media Relations Crisis Communication Plan categorizes emergencies as High, Medium, or Low and takes action respectively, and the Transmission Operations department uses a Red and Blue Alert Plan[156]. On the electric side, Real-Time Dispatch had one set of emergency levels, Transmission Operations had another, and alerts are issued from the industry coordination point (RDRC) as Energy Emergency Alert Level 1, Level 2, and Level 3, each with associated requirements for being issued.

While it is true that there may be silo emergencies – in other words, crises that do not extend across organizational boundaries, the lack of a mechanism for recognizing and responding to a cross-organizational or corporate level crisis has been identified by both the investigative team and the Company as a problem that this event made visible. Additionally, the growing interdependence of the gas and electric systems makes it more important than perhaps has historically been necessary for cross-organizational visibility of problems as they develop, and coordination in how departments respond. Additionally, while many of the departments have extensive procedures developed for field emergencies, including gas leaks, power outages, or a natural disaster, the procedures for controlled outages and the ways in which they differ from other types of emergencies is not clear.

Communication of FERC Standard of Conduct Requirements

The FERC Standard of Conduct contains stipulations regarding when and about what certain departments can communicate. This is designed to prevent inappropriate trading from taking place during the normal course of business. During an emergency situation, these communication constraints can be waived to support a rapid and effective response to the emergency, provided the Company moves to clarify activities and get back in compliance quickly when the event is over.

It appears that PSCo has diligently implemented the FERC Standard of Conduct within its organization, as evidenced by individual concern for compliance, and the physical delineations that have been put in place (walls, moving departments to new buildings)[157]. It may be that in doing so, PSCo has not fully made people aware of when the Standard of Conduct can and should be suspended, and/or that people are unclear about the parameters. Additionally, there is not a clear policy or process whereby executive management engages during an emergency and

[155] Pg. 18.1.2, Gas Emergency Plan, Audit Response OE-PSC 2-8.
[156] Pg. 4, PSCo Emergency Plan, Audit Response OE-PSC 2-7.
[157] As noted by the investigation team during site visits.

communicates quickly and effectively to the Company regarding the suspension of the FERC Standard of Conduct, and when it is reinstated following the stabilization of the situation.

Commitment Log Report Items 22 and 23 specifically address some of these concerns through the creation of additional documentation and updated training. However, the Company must maintain its commitment to keeping staff current and aware of FERC requirements and when they can and should be waived. The Company should support the commitments made with financial and resource support of ongoing training programs in this area. While documentation is important, in a crisis situation, staff will not have time to refer to documentation and processes, and must know how and when to respond quickly.

RDRC Engagement and Communication

The Rocky Mountain-Desert Southwest Reliability Center (RDRC) is an industry supported coordination point for power distribution throughout the region. Communication with and from the RDRC merits further analysis, and potentially changes should be agreed to by the industry participants and implemented within the Center. For example, the Energy Emergency Alert (EEA) messages that were distributed by RDRC to others in the region contained a request that anyone with energy to sell call the Xcel Energy marketing department[158]. However, the messages did not contain contact information, an emergency number, or other details that may have expedited connecting with others in the region that had available energy.

PSCo used the RDRC process to move from an EEA1 to an EEA3 (the highest level), without any EEA2 indications. Typically, the RDRC issues an EEA1 when a participant company requests one as a result of a problem being detected or anticipated, an EEA2 is requested when interruptible customers are taken off for safety rather than for economic reasons, and an EEA3 is issued when retail load is shed. It is unclear why the Level 2 alert was not issued prior to going to a Level 3. As the system stabilized on Saturday morning, a Level 2 alert was issued at 11:28, and a final EEA0 (alert termination) was issued at 16:09 indicating that the system had returned to normal.[159] While it is not the role of the RDRC to proactively make inquiries regarding the sequence of alerts, this example may merit industry discussions regarding the role of the RDRC in issuing Energy Emergency Alerts, and the ways in which it enforces the sequence.

Communication with the Reliability Center is controlled by Transmission Operations. Transmission Operations interacts with the RDRC to request emergency alerts, which impact Real-Time Dispatch. It is the Real-Time Dispatch department that owns balancing the system and identifying when an EEA may be required. As such, Transmission Operations becomes the hinge between the RDRC and Real-Time Dispatch (see Sections 5 and 6 for more information). This loop may be cumbersome, but it supports the separation of information from Transmission Operations and Real-Time Dispatch as necessary, helping to ensure that information is sent and received in such a way as to prevent inappropriate trading from taking place. Its nature makes good communication between Real-Time Dispatch and Transmission Operations vital at all times. This communication was lacking on February 18, as is evidenced by the poor and untimely sequencing of Energy Emergency Alerts.

From an industry perspective, it may be worthwhile to consider the timing and the content of alerts from the RDRC. In this event, the alerts were neither timely nor informative. The EEA1 should have been requested by PSCo shortly after the loss of Fort Saint Vrain Unit 4 at 04:07 and the loss of Cherokee Unit 4 at 04:10 Saturday morning (see Section 7 for more details on plant

[158] Audit response OE-PSC 2-4.
[159] Audit response OE-PSC 2-4.

losses.) An EEA2 alert should have been requested when the interruptible customers were taken offline at approximately 06:26 Saturday morning, and an EEA3 alert was requested prior or close to concurrently with the first group of retail firm-commit outages. The content of the message for the EEA1 requested that entities with energy to sell call Xcel Energy's marketing department, but no contact information was provided. Including contact information would involve an additional step for the RDRC, but would support more rapid regional responses particularly from entities that might not normally do business with Xcel Energy.

Training and Documentation

Training and documentation are areas that appear to have been sidelined for some time. In some cases, good documentation exists, but it is not used, or people are unsure of how to execute on the processes as they are written. In other areas, training has fallen off the schedule, and is not being conducted on a regular basis. Regular opportunities to practice cross-organizational functions like emergency responses have not been a normal part of the PSCo culture, and need to be developed. There is a high dependency in the organization on historical knowledge, and without regular attention to training and development of new people, this places the Company in jeopardy, as retirements become a reality, and as the environment changes such that historical knowledge is no longer accurate.

Specifically, the following areas are noted as concerns:

- Cross-departmental training to support a more systemic appreciation for the complexities of the system, and how they interrelate. For example:
    - Real-Time Dispatch made the decision to switch to fuel oil, however, it was unaware of how the plants get scheduled to receive fuel (which is the job of Gas Supply, per OE-PSC 2-2), so when the plants asked about fuel deliveries, there was no good answer.
    - Real-Time Dispatch exhibited a limited awareness of how quickly line pack could be restored on Saturday morning.
    - The ISOC tariff and its requirements were not fully understood by all of the departments and employees who are required to enforce it.
- Training exists regarding how to conduct an OFO, however, it has not been delivered in at least a few years.
- Training on FERC requirements may be incomplete by not fully providing information regarding how and when the Standard of Conduct can be waived.
- Documentation of blackstart and mock emergency responses (per audit question response and supporting materials)[160] indicates that exercises are to be conducted annually in these areas, however, such exercises have not taken place in at least the last two years.
- Documentation on the crisis communication plan was not utilized, and the process was not executed by the Company during this event.
- Documentation indicating that training will be done is incorrect or inconsistent with actual business practices.

All of these points raise concerns regarding PSCo's long-term commitment to making the changes indicated in the Commitment Log Report. Many of the commitments address problems through documentation and reference future training for staff. While documentation is important, and initial training is a required first step, these types of complex and infrequent scenarios require diligent and regular attention. Senior management must fully commit financially and through

[160] Pg. 8, PSCo Emergency Plan, Audit response OE-PSC 2-7.

personal attention to running an organization that is ready to function under both normal and stressed conditions.

Documentation and Reproduction of Key Communications

As a part of generally good business practices, PSCo has historically recorded transactions, contractual agreements, and other key communications between departments. Typically these take place over the phone, with special equipment in place to capture and record conversations for later transcription. The process for recording these types of conversation has not been updated to manage current technologies including instant messaging, e-mail, digital telephone lines, and mobile phone use. Additionally, the recording technology that is in place is extremely dated and difficult to use. This became evident when the investigation team requested transcripts on April 17, 2006, and by June, 2006, they were still being processed by the Company. The ability to recreate critical communications is important for event reconstruction, for building business cases to support new systems or process development, and to ensure internal audits can be conducted for training, performance evaluation, and consistency of delivery.

Internal Organizational Communication Summary

This report contains many recommendations that address individual areas of concern, ranging from fixing field equipment to replacing faulty technology in plants to implementing systems to support better collaborative decision making. While these individual recommendations are necessary to protect against future problems in these areas, the broader issues identified in the findings of this report are even more critical. They are not, however, easy to address. They require long-term commitment from senior management, allocation of funds, and support of all levels in the organization to be successful. No one department can successfully address these problems internally, without synchronization across the Company. For this reason, the investigative team recommends consideration of an executive level individual tasked with oversight for the short term to ensure implementation of solutions to the concerns identified, and for the long term to maintain and support operational integrity in the PSCo region.

Appendix 1: Definitions, Abbreviations, and Acronyms

AGC	Automatic (electric power) generation control. See http://www.shomepower.com/dict/a/automatic_generation_control_agc.htm
ARAP	The Arapahoe Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3662-2_171_258-0,00.html
Aquila	Aquila, Inc. dba Aquila Networks-WPC fka WestPlains Energy. See http://www.aquila.com/
ARPA	The Arkansas River Power Authority. See http://www.arkansasriverpowerauthority.org/.
BA	A NERC Balancing Authority. See http://www.nerc.com/~org/index.html
BEPC	Basin Electric Power Cooperative. See http://www.basinelectric.com/
BHC	Black Hills Corporation. See http://www.blackhillscorp.com/
BHCO	Black Hills Colorado, a wholly-owned electric generation subsidiary of Black Hills Corporation. See http://www.bhenergycap.com/
BHP	Black Hills Power, a wholly-owned electric utility operating subsidiary of Black Hills Corporation. See http://www.blackhillspower.com/
BSEC	The Blue Spruce Energy Center, owned by Calpine Corporation. See http://www.calpine.com/power/plant.asp?plant=193
CA	A NERC Electric Power Control Area. See http://www.nerc.com/~org/controlareacertification.html
CABI	The Cabin Creek Pumped Hydroelectric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3663-2_171_258-0,00.html
CAISO	The California Independent (electric power) System Operator. See http://www.caiso.com/
CAME	The Cameo Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3664-2_171_258-0,00.html
CAMU	The Colorado Association of Municipal Utilities. See http://www.coloradopublicpower.org/
CC	A combined-cycle energy conversion process. See http://en.wikipedia.org/wiki/Combined_cycle
CCEGS	A (natural gas-fired) combined-cycle electric generating station. In a combined-cycle power plant, one or more combustion turbines generate electricity and the waste heat from the combustion turbines is used to make steam to generate additional electricity via a steam turbine. This last step enhances the efficiency of electricity generation. See http://en.wikipedia.org/wiki/Combined_cycle
CCPG	The Colorado Coordinated (electric power) Planning Group. See http://ccpg.basinelectric.com/12-9-04%20CCPG%20Mtg%20Minutes-Final.pdf
CDD	Cooling degree day. See http://en.wikipedia.org/wiki/Heating_degree_day
CEF	The Colorado Energy Forum. See http://www.coloradoenergyforum.org/
CF&I	CF&I Steel, LP (formerly Colorado Fuel & Iron Company) dba Rocky Mountain Steel Mills Division of Oregon Steel Mills, Inc. See http://www.osm.com/RMSM/index.htm
CHER	The Cherokee Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3665-2_171_258-0,00.html

CIG	Colorado Interstate Gas, a wholly-owned natural gas transportation subsidiary of the El Paso Company. See http://www.cigco.com/default.asp
CLRTPG	The Colorado Long-Range (electric power) Transmission Planning Group. See http://www.rmao.com/wtpp/Clrtpg/CLRTPG_FINAL_REPORT_42704.pdf
COMA	The Comanche Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3666-2_171_258-0,00.html
CRS	Customer Resource System. See http://www.lynksoftware.com/target.htm?customer_response_system.htm
CRSP	The Colorado River Storage Project of the United States Bureau of Reclamation. See http://www.usbr.gov/dataweb/html/crsp.html.
CSU	Colorado Springs Utilities. See http://www.csu.org/
CT	A combustion turbine. A combustion turbine is an engine where fuel, typically natural gas or No. 2 distillate fuel oil, is continuously burned with compressed air to produce a stream of hot, fast moving gas. This gas stream is used to power the compressor that supplies the air to the engine as well as providing the necessary energy required to turn a generator to produce electricity. These units are also known as gas turbines. See http://en.wikipedia.org/wiki/Combustion_turbine
DMS	An (electric power) distribution management (computer) system. See http://www.powersystem.org/services/utilityautomation/distributionmanagement/distributionmanagement.aspx
DSM	Demand-side (energy) management. See http://en.wikipedia.org/wiki/Energy_demand_management
Dth	Dekatherm(s). See http://www.mge.com/about/gas/glossary.htm#d
EEA	Energy Emergency Alert. See ftp://www.nerc.com/pub/sys/all_updl/standards/rs/EOP-002-0.pdf
EEI	The Edison Electric Institute. See http://www.eei.org/
EMS	An (electric) energy management (computer) system. See http://www.powersystem.org/services/utilityautomation/energymanagement/energymanagement.aspx
EPRI	The Electric Power Research Institute, Inc. See http://www.epri.com/
FERC	The United States Federal Energy Regulatory Commission. See http://www.ferc.gov/
FRP	The Front Range Pipeline, owned by Wyco Development, LLC. See http://www1.xcelenergy.com/webebb/html/gasindex.asp
FRPC	The Front Range Power Company. See http://www.springspower.com/
FSVR	The Fort Saint Vrain Combined Cycle Electric Generating Station http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3667-2_171_258-0,00.html
GCA	Gas Cost Adjustment. See http://www.dora.state.co.us//puc/rules/723/723-8.doc
GIS	A geographic information system. See http://en.wikipedia.org/wiki/Geographic_information_system
GMS	A (natural) gas management (computer) system. See http://www.psioilandgas.com/gas_business_solutions/gas_management_system.jsp?r0=Gas%20Business%20Solutions&r1=Gas%20Management%20System&r2
GPP	Gas Purchase plan. See http://www.dora.state.co.us/puc/rules/723-8.pdf
GVP	Grand Valley Rural Power Lines Inc. dba Grand Valley Power. See http://www.gvp.org/http://www.gvp.org/.

HAYD	The Hayden Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3669-2_171_258-0,00.html
HCE	The Holy Cross Electric Association Inc. dba Holy Cross Energy. See http://www.holycross.com/.
HDD	Heating degree day. See http://en.wikipedia.org/wiki/Heating_degree_day
HE	The hour-ending, e.g., HE 17 is the sixty minute period from 16:00 to 17:00 local time. See http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=95
HEGS	The hydroelectric generating station. See http://en.wikipedia.org/wiki/Hydroelectricity
High	The first level of natural gas high pressure alarm.
HiHi	The second level of natural gas high pressure alarm.
HRSG	A heat recovery steam generator. In a combined cycle plant, the gas turbine drives one generator directly; the hot exhaust gases from the gas turbine are used to boil steam in what is known as a heat recovery steam generator. This steam is then fed to a steam turbine driving a second generator resulting in higher efficiency electricity production. See http://en.wikipedia.org/wiki/Heat_Recovery_Steam_Generator
IP	Intermediate pressure. The PSCo-owned natural gas piping system that transports gas from high pressure receipt points to gas regulator stations.
IPP	An independent power producer. An IPP is non-utility generator that produces electricity for sale in wholesale power markets. See http://energytrends.pnl.gov/glosi_m.htm. See also NUG.
IREA	The Intermountain Rural Electric Association. See http://www.intermountain-rea.com/.
IVR	An interactive voice response system. See http://www.webopedia.com/TERM/I/IVR.html
kV	Kilovolt(s). See http://www.m-w.com/dictionary/kilovolt
LDC	A local (natural gas) distribution company. See http://www.naturalgas.org/naturalgas/distribution.asp
LoLo	The second level of natural gas low pressure alarm.
Low	The first level of natural gas low pressure alarm.
LRS	The Laramie River (steam electric generating) Station, owned by Basin Electric Power Cooperative. See http://www.basinelectric.com/EnergyResources/Electricity/Base-load/LRS.html
MEAN	The Municipal Energy Agency of Nebraska. See http://www.nmppenergy.org/mean.htm.
MDT	Mountain Daylight Time or UTC-06. See http://en.wikipedia.org/wiki/Mountain_Time_Zone
MST	Mountain Standard Time or UTC-07. See http://en.wikipedia.org/wiki/Mountain_Time_Zone
MT	Prevailing Mountain Time, either Mountain Standard Time or Mountain Daylight Time, whichever is in effect at the time. See http://en.wikipedia.org/wiki/Mountain_Time_Zone
MW	Megawatt(s). See http://teachmefinance.com/Scientific_Terms/Megawatt_MW.html
MWh	Megawatthour(s). See http://teachmefinance.com/Scientific_Terms/Megawatthour_MWh.html
NAESB	The North American Energy Standards Board. See http://www.naesb.org/

NERC	The North American Electric Reliability Council. See http://www.nerc.com/
NNT	No-Notice Storage and Transportation Delivery Service. See http://ebb.cigco.com/ebbCIG/ebbmain.asp?sPipelineCode=CIG
NO_X	Nitrogen Oxides, or NO_X, is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. Many of the nitrogen oxides are colorless and odorless; however, one common pollutant, nitrogen dioxide (NO_2) along with particles in the air can often be seen as a reddish-brown layer over many urban areas. Nitrogen oxides form when fuel is burned at high temperatures, as in a combustion turbine or coal-fired power plant. See http://en.wikipedia.org/wiki/Nitrogen_oxide#NOx
NSP	The NERC Balancing Authority operated by Xcel Energy and Northern States Power Company Minnesota. See http://www.rmao.com/xfpp/nsp_main.html.
NSP-MN	Northern States Power Company Minnesota, a wholly-owned utility operating subsidiary of Xcel Energy Inc. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_18554_21043-745-2_171_258-0,00.html
NSP-WI	Northern States Power Company Wisconsin, a wholly-owned utility operating subsidiary of Xcel Energy Inc. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_18554_21043-745-2_171_258-0,00.html
NUG	Non-utility (electric power) generation. See http://www.appro.org/definitions.html. See also IPP.
NVP	Nevada Power Company, a wholly-owned electric utility operating subsidiary of Sierra Pacific Resources. See http://www.nevadapower.com/
OASIS	Open Access Same Time Information System. See http://en.wikipedia.org/wiki/Open_Access_Same-Time_Information_System
OFO	Operational Flow Order. See http://www.xcelenergy.com/docs/corpcomm/psco_gas_entire_tariff.pdf#page=14
OMS	An (electric power) outage management (computer) system. See http://www.powersystem.org/services/utilityautomation/outagemanagement/outagemanagement.aspx
PA	A NERC Planning Authority. See http://www.nerc.com/~org/index.html
PdM	Predictive maintenance. See http://en.wikipedia.org/wiki/Predictive_maintenance. See also PM.
PHEGS	A pumped energy storage hydroelectric generating station. See http://en.wikipedia.org/wiki/Pumped_storage
PM	Preventative or Predictive Maintenance. PSCo's acronym for its preventative or predictive maintenance procedures. Both terms were used by PSCo plant personnel. See http://en.wikipedia.org/wiki/Predictive_maintenance. See also PdM.
PPA	A Power Purchase Agreement. The Power Purchase Agreement is the long-term contractual agreement between the IPP and PSCo that defines the terms for purchase of electricity energy and capacity. See http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html
PRT	Pattern Recognition Technology. A forecasting engine that consists of multiple intelligent system based models that employ artificial neural networks, fuzzy logic, evolutionary computing/genetic algorithms and similar-day type technologies. See http://www.prt-inc.com/eloadfcst.htm
PSCo	Public Service Company of Colorado, a wholly-owned utility operating subsidiary of Xcel Energy Inc. See http://www.rmao.com/xfpp/psc_main.html. Compare with PSCO.

PSCO	The NERC Balancing Authority operated by Xcel Energy and Public Service Company of Colorado. See http://www.oatioasis.com/psco/. Compare with PSCo.
RC	A NERC Reliability Coordinator. See http://www.nerc.com/~org/index.html
RCM	Reliability centered maintenance. See http://en.wikipedia.org/wiki/Reliability_Centered_Maintenance
RDRC	The Rocky Mountain / Desert Southwest Reliability Center. See http://www.nerc.com/~org/entities/wecc.html
RMEC	The Rocky Mountain Energy Center, owned by Calpine Corporation. See http://www.calpine.com/power/plant.asp?plant=198
RMPA	The Rocky Mountain Power Area, a WECC subregion. See http://www.nerc.com/~org/entities/wecc.html
RMR	The Western Area Power Administration Rocky Mountain Region. See http://www.wapa.gov/rm/RM.HTM
RMRG	The Rocky Mountain (electric power) Reserve Group. See http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=314
RMSM	Rocky Mountain Steel Mills Division of Oregon Steel Mills, Inc. See http://www.osm.com/RMSM/index.htm. See also CF&I Steel, LP (formerly Colorado Fuel & Iron Company)
RRO	A NERC Regional Reliability Organization. See http://www.nerc.com/~org/index.html
RTD	A real-time (electric energy) dispatcher. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-5_2521_21396-1420-2_171_258-0,00.html
SC	Simple Cycle: Simple Cycle can refer to either (1) the normal operation of a Combustion Turbine that does not have combined cycle capability or to (2) a combined cycle unit operating without recovering the waste heat from the gas turbine. See http://en.wikipedia.org/wiki/Combined_cycle
SCADA	A supervisory control and data acquisition system. See http://en.wikipedia.org/wiki/SCADA
SEGS	A (pulverized coal, oil, or natural gas-fired) steam electric generating station. See http://en.wikipedia.org/wiki/Steam_electric
SHOS	The Shoshone Hydroelectric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3674-2_171_258-0,00.html
SPS	Southwestern Public Service Company, a wholly-owned electric utility operating subsidiary of Xcel Energy Inc. Also, the NERC Balancing Authority operated by Xcel Energy and Southwestern Public Service Company. See http://www.rmao.com/xfpp/sps_main.html.
SRP	The Salt River Project Agricultural Improvement and Power District, an Arizona public utility. See district http://www.srpnet.com/about/facts.aspx
TCTI	The Thermo Carbonic Combined Cycle Electric Generating Station and the Thermo Industries Combined Cycle Electric Generating Station.
TOP	A NERC Transmission Operator. See http://www.nerc.com/~org/index.html
TP	A NERC Transmission Planner. See http://www.nerc.com/~org/index.html
TSGT	Tri-State Generation and Transmission Association, Inc.
UTC	Coordinated Universal Time. See http://en.wikipedia.org/wiki/Coordinated_Universal_Time
UTC-06	The time zone six hours earlier than Coordinated Universal Time, also known as Mountain Daylight Time (MDT) and Central Standard Time (CST). See http://en.wikipedia.org/wiki/Mountain_Time_Zone

UTC-07	The time zone seven hours earlier than Coordinated Universal Time, also known as Mountain Standard Time (MST) and Pacific Daylight Time (PDT). See http://en.wikipedia.org/wiki/Mountain_Time_Zone
VALM	The Valmont Steam Electric Generating Station & CT. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3676-2_171_258-0,00.html
WACM	The NERC Balancing Authority operated by the Western Area Power Administration Rocky Mountain Region. See http://www.wapa.gov/rm/RM.HTM
WAPA	The Western Area Power Administration. See http://www.wapa.gov/
WECC	The Western Electricity Coordinating Council. See http://www.wecc.biz/
WestGas	WestGas InterState, Inc., a former wholly-owned natural gas transport subsidiary of Xcel Energy Inc. See http://www1.xcelenergy.com/webebb/html/gasindex.asp
Wyco	Wyco Development, LLC. See http://excite.brand.edgar-online.com/EFX_dll/EDGARpro.dll?FetchFilingHTML1?SessionID=vS-EImmKL9Wq110&ID=3846038
Xcel Energy	Xcel Energy Inc., a public utility holding company. Xcel Energy utility operating companies provide natural gas and electric power service in Colorado, Minnesota, Wisconsin, North Dakota, and Michigan, and electric power service only in Texas, New Mexico, South Dakota, Kansas, and Oklahoma. See http://www.xcelenergy.com/
XEL	The stock symbol of Xcel Energy Inc. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_18554-127-2_171_258-0,00.html
XEmkt	The Energy Trading department of Xcel Energy Services, Inc., a wholly-owned services subsidiary of Xcel Energy Inc. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-5_2521_21396-1420-2_171_258-0,00.html
XES	Xcel Energy Services, Inc., a wholly-owned services subsidiary of Xcel Energy Inc. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_18554_21043-745-2_171_258-0,00.html
YVEA	The Yampa Valley Electric Association, Inc. See http://www.yvea.com/
ZUNI	The Zuni Steam Electric Generating Station. See http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_4797_4010-3677-2_171_258-0,00.html

Appendix 2: Commitment Log Report Cross-Reference

At the conclusion of its March 13^{th} Report, the Company made several general commitments to investigate or study certain aspects of its electric, gas, and Customer Care operations, and promised to provide to the Commission within 90 days the results of those efforts. On June 15, 2006 PSCo submitted to the Commission its "Commitment Log Report" regarding the February 18, 2006 Controlled Outage Event. That Commitment Log Report describes the item as it was originally captioned by the Company's internal Task Force, the findings of the Company's internal investigation regarding the item, a description of the actions taken associated with the findings (these varied in some cases from the original caption) and the date when the action item was completed or when it would be completed or addressed.

Staff has organized this report of its investigation in what is hoped to be a logical, readable and understandable fashion. Staff has grouped common themes or topics into single Sections. The Commitment Log Report's numerical sequence of items is not organized in the same fashion as Staff's report. The following table provides a cross-reference or key as to where in this report each Commitment Log Report item is addressed.

Cross-Reference

ID	Commitment Log Report Item	Staff Section
1	Investigate what technology can be used to provide more accurate information to customers calling about outages	Section 2 – Customer Care and Media Relations
2	Investigate what technology can be used to provide more accurate information to customers calling about outages	Section 2 – Customer Care and Media Relations
3	Study how to Improve Communications	Section 2 – Customer Care and Media Relations
4	Develop Operating Protocols during elevated operations	Section 9 – Interruption of Firm Electric Load
5	Review Operating Protocols during elevated operations	Section 9 – Interruption of Firm Electric Load
6	Study how to Improve Communications during elevated operations	Section 9 – Interruption of Firm Electric Load
7	Develop Operating Protocols during elevated operations	Section 6 – Energy Trading and Real-Time Dispatch
7A	Determine whether all viable purchase opportunities were pursued	Section 5 – Energy Trading and Real-Time Dispatch, and Section 6 – Transmission Operations
8	Investigate Changing Normal Protocols for unusual weather	Section 3 – Weather and Energy Demand Forecasting, and Section 7 – Electric Production
9	Investigate Changing Normal Protocols for unusual weather	Section 6 – Energy Trading and Real-Time Dispatch, and Section 7 – Electric Production
10	Develop Operating Protocols during elevated operations	Section 7 – Electric Production

ID	Commitment Log Report Item	Staff Section
11	Investigate Changing Normal Protocols for unusual weather	Section 7 – Electric Production
12	Investigate Power Plant failure causes	Section 7 – Electric Production
13	Investigate Changing Normal Protocols for unusual weather	Section 6 – Energy Trading and Real-Time Dispatch
14	Develop Operating Protocols during elevated operations	Section 4 – Gas Supply and Gas Control
15	Investigate Changing Normal Protocols for unusual weather	Section 3 – Weather and Energy Demand Forecasting, and Section 4 – Gas Supply and Gas Control
16	Investigate how to align and Integrate various operations to deal with unusual weather	Section 4 – Gas Supply and Gas Control
17	Investigate Additional Gas Storage options	Section 4 – Gas Supply and Gas Control
18	Investigate how to align and Integrate various operations to deal with unusual weather	Section 4 – Gas Supply and Gas Control
19	Develop Operating Protocols during elevated operations	Section 4 – Gas Supply and Gas Control
20	Investigate Changing Normal Protocols for unusual weather	Section 3 – Weather and Energy Demand Forecasting, and Section 4 – Gas Supply and Gas Control
21	Study how to Improve Communications	Section 4 – Gas Supply and Gas Control
22	Interpretations of FERC code of Conduct Rules	Section 10 – Internal Communication
23	Investigate Barriers to full communication of operational problems	Section 10 – Internal Communication
24	Study how to Improve Communications	Section 2 – Customer Care and Media Relations, and Section 10 – Internal Communication
25	Submit update to PUC Staff in 90 Days	Executive Summary
26	Investigate problems with interruptible loads	Section 8 – Electric Interruptible Load Management
27	Investigate problems with interruptible loads	Section 8 – Electric Interruptible Load Management
27A	Investigate problems with interruptible loads	Section 8 – Electric Interruptible Load Management
27B	Investigate problems with interruptible loads	Section 8 – Electric Interruptible Load Management
27C	Examine the value of including a voluntary load reduction process	Section 8 – Electric Interruptible Load Management
28	Study how to Improve Communications	Section 2 – Customer Care and Media Relations
29	Develop Operating Protocols during elevated operations	Section 7 – Electric Production
30	Investigate Changing Normal Protocols for unusual weather	Section 7 – Electric Production
31	Investigate how to align and Integrate various	Section 7 – Electric Production

ID	Commitment Log Report Item	Staff Section
	operations to deal with unusual weather	
32	Investigate Power Plant failure causes	Section 7 – Electric Production
33	Study how to Improve Communications	Section 7 – Electric Production
34	Develop Operating Protocols during elevated operations	Section 5 – Electric Transmission Operations
35	Develop Operating Protocols during elevated operations	Section 5 – Electric Transmission Operations
36	Develop Operating Protocols during elevated operations	Section 5 – Electric Transmission Operations
37	Investigate Changing Normal Protocols for unusual weather	Section 3 – Weather and Energy Demand Forecasting, and Section 5 – Electric Transmission Operations
38	Establish clear procedures for communication when load shedding occurs	Section 9 - Interruption of Firm Electric Load