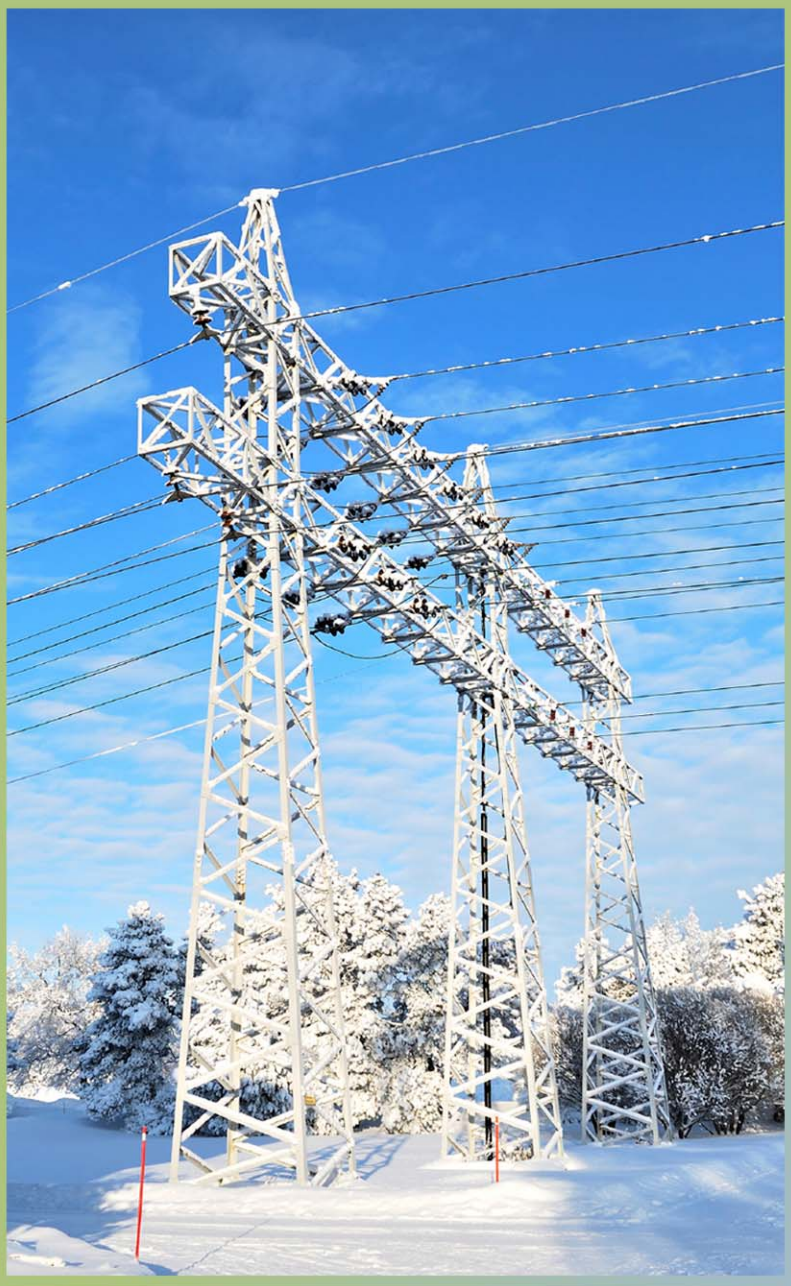

Report on

Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

Causes and Recommendations

Prepared by the Staffs of the
Federal Energy Regulatory Commission
and the
North American Electric
Reliability Corporation

August 2011

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I. Introduction

The southwest region of the United States experienced unusually cold and windy weather during the first week of February 2011. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to -7 degrees over the period, compared to an average high of 51 degrees and a low of 26 degrees. Dallas temperatures ranged from 14 degrees to 19 degrees, compared to an average high of 60 degrees or above and average lows in the mid-to-upper 30s. Many cities in the region would not see temperatures above freezing until February 4. In addition, sustained high winds of over 20 mph produced severe wind chill factors.

Electric entities located within the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and the Southwest Power Pool (SPP) were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona.

Between February 1 and February 4, a total of 210 individual generating units within the footprint of the Electric Reliability Council of Texas, Inc. (ERCOT), which covers most of Texas, experienced either an outage, a derate, or a failure to start. The loss of generation was severe enough on February 2 to trigger a controlled load shed of 4000 MW, which affected some 3.2 million customers. On February 3, local transmission constraints coupled with the loss of local generation triggered load shedding for another 180,000 customers in the Rio Grande Valley in south Texas. El Paso Electric Company (EPE), which is outside the ERCOT region, lost approximately 646 MW of local generation over the four days beginning on February 1. It implemented rotating load sheds on each of the days from February 2 through February 4, totaling over 1000 MW and affecting 253,000 customers. The Salt River Project Agricultural Improvement and Power District (SRP), located in Arizona, lost 1050 MW of generation on February 1 through February 2 and shed load of 300 MW, affecting approximately 65,000 customers. The New Mexico communities of Alamogordo, Ruidoso, and Clayton lost approximately 26 MW of load, affecting a little over 21,000 customers, when Public Service Company of New Mexico (PNM) experienced localized transmission failures, although these were largely unrelated to the extreme weather.

In total, approximately 1.3 million electric customers were out of service at the peak of the event on February 2, and a total of 4.4 million were affected over the course of the event from February 2 through February 4.

Natural gas customers also experienced extensive curtailments of service during the event. These curtailments were longer in duration than the electric outages, because relighting customers' equipment has to be accomplished manually at each customer's location. Local distribution companies (LDCs) interrupted gas service to more than 50,000 customers in New Mexico, Arizona and Texas; New Mexico was the hardest hit with outages of over 30,000 customers in areas as widespread as Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo and Placitas.

In the wake of these events, the Arizona Corporation Commission, the Public Regulation Commission of New Mexico, the Public Utilities Commission of Texas (PUCT), the Texas Railroad Commission (TRC), the New Mexico state legislature and the Texas state legislature all initiated inquiries or investigations. The PUCT directed TRE, the regional entity authorized by the North American Electric Reliability Corporation (NERC) to cover the ERCOT region, to investigate the decisions and actions ERCOT took in initiating the rolling blackouts.

On February 7, 2011, NERC announced that it would work with the affected Regional Entities to prepare an event analysis that would examine the adequacy of preparations for the event and identify potential improvements and lessons learned. NERC also stated it would review electric and natural gas interdependencies, in light of the shift toward a greater reliance on natural gas to produce electricity.

On February 14, the Federal Energy Regulatory Commission (FERC) initiated an inquiry into the Southwest outages and service disruptions. The inquiry had two objectives: to identify the causes of the disruptions, and to identify any appropriate actions for preventing a recurrence of the disruptions. FERC stated it was not at that time initiating an investigation into whether there may have been violations of applicable regulations, requirements or standards under FERC's jurisdiction, and that any decisions on whether to initiate enforcement investigations would be made later. Consequently, while this report describes actions which in some cases appear to warrant further investigation, it does not reach any conclusions as to whether violations have occurred.

From the beginning of their inquiries into the causes of the outages and disruptions, the staffs of FERC and NERC have cooperated in their data gathering and analysis. On May 9, FERC and NERC announced their staffs would create a joint task force to combine their separate inquiries. This report is a product of that effort.

The inquiry performed by the joint task force was far-reaching. Noted below in summary form are some of the steps taken by the task force to develop its understanding of the electric and natural gas disruptions that were experienced in the Southwest in early February.

Scope of Data Reviewed

The task force received approximately 54 GB of data through data requests issued to entities in both the electric and natural gas industries, conducted numerous follow-up calls and meetings, and issued follow-up requests to discuss questions raised by the data responses.

For the electric industry, the task force issued 122 data requests to generator operators, transmission operators, balancing authorities, and a reliability coordinator. The task force also utilized event analysis information which NERC and the affected Regional Entities received from 79 registered entities (72 from TRE, four from WECC and three from SPP). Additional event information was received through a request for information issued by NERC and Regional Entities to those entities affected by the extreme weather event. For the gas industry, the task force issued 92 data requests to pipelines (interstate and intrastate), storage facilities, gas processing plants, producers, and public utilities.

The data compiled by the task force focused on the causes of the outages and curtailments during the February cold weather event, critical entities' preparations for the forecasted cold weather and their performance in connection with the rolling blackouts and natural gas curtailments, and any lessons learned that could be applied in the future. As part of its analysis, the task force also reviewed historical data and recommendations compiled during past cold weather events in Texas and elsewhere in the Southwest, to determine whether the 2011 event was unprecedented or whether entities might have been better prepared to deal with it.

Electric Facility Site Visits

Staff from FERC and NERC, together with representatives of TRE and WECC, conducted site visits with various entities involved in the outages, toured facilities and conducted interviews with operations personnel, compliance personnel and company executives. The task force visited ERCOT, four transmission operators in ERCOT, and 15 generators in ERCOT (including coal, natural gas, and wind units); two generators in WECC; and two balancing authorities in WECC. During the generator site visits the task force toured the units, viewing any equipment that led to trips, derates, or failures to start; viewed winterization measures; and discussed maintenance and winterization processes,

fuel supply and market participation. During visits to the balancing authorities and transmission operators, the task force toured control centers and discussed the progression of the events, including specifics on load forecasting, market mechanics, system operations, load shedding and load restoration. The task force also discussed transmission system winterization and load shedding procedures with the transmission operators.

Natural Gas Meetings

The task force conducted numerous meetings with various entities from the gas industry to discuss the curtailments and shortages experienced in early February and the specifics of the entities' winter operations. These meetings included operations and regulatory personnel from two interstate pipelines doing business in Texas, New Mexico, Arizona, Colorado, and California; one LDC/intrastate pipeline located in New Mexico; one LDC from Arizona; and one intrastate pipeline located in Texas. The meetings focused on the companies' preparations for the storm, communications among LDCs, pipelines, marketers, and producers about unfolding events, system operations, underlying causes of the gas supply problems, and lessons learned. In most instances, interviews led to supplemental data requests that provided additional information about the events. The task force also held numerous telephone conferences with companies in the pipeline, LDC, processing and production sectors, both to gather information and to clarify information received in response to data requests.

Outreach Meetings

Task force staff conducted outreach meetings with the following industry associations and groups: the Electric Power Supply Association, the American Gas Association, the Independent Petroleum Association of America, the Texas Pipeline Association, the Interstate Natural Gas Association of America, the Natural Gas Supply Association, the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the (ERO) Southwest Outage Advisory Panel. The task force shared its preliminary findings and recommendations on a non-public basis with members of these organizations in order to obtain feedback and, with respect to the recommendations, input as to their practicality and feasibility. The feedback and input provided by these organizations was considered and in a number of instances reflected in the findings and recommendations included in this report.

Coordination with State Inquiries

The task force also reviewed materials acquired in the course of inquiries into the event conducted by legislative bodies and regulatory commissions. The

task force followed legislative and regulatory hearings in Arizona, New Mexico and Texas and reviewed transcripts, testimony and webcasts from the proceedings.

Through contacts with state regulatory agencies, staff was able to review responses to data requests issued by those bodies to ensure that the task force was in possession of all potentially relevant materials. Task force staff also monitored legislative efforts taken in response to the February outage, including conferring with sponsors of pertinent legislation concerning, among other things, the anticipated impacts of their proposals. The task force tracked the bills throughout the legislative process. In addition, as regulatory agencies moved forward with their inquiries into the outage, task force staff reviewed draft and final copies of all relevant reports.

The task force also collaborated with ERCOT's Independent Market Monitor (IMM), which conducted an inquiry into potential market manipulation during the event at the request of the PUCT. Task force staff conducted calls with the IMM to discuss market conditions and reviewed its written assessment of the market impacts from the event. The task force also contacted the TRC regarding gas curtailment matters, submitted written questions about the TRC's activities in connection with the event, and reviewed all information the TRC collected concerning the event.

To assist in its analysis of the materials received, the task force commissioned one outside consultant's study to examine impacts of the cold weather event on gas production, reviewed studies conducted on behalf of regulatory and other bodies, and prepared extensive in-house studies by staff analysts.

This report documents the information received by the task force and presents the task force's conclusions as to the causes of the electric outages and natural gas curtailments that occurred during the February 2011 event. It is divided into several sections, beginning with an overview of the electric and natural gas industries that provides background for the event, discusses the event itself and prior cold weather events in the region, and ends with a summary of key findings and recommendations. Also included are a list of acronyms, a glossary, and a number of appendices which treat in fuller detail many of the matters mentioned in the body of the report.

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II. Executive Summary

The arctic cold front that descended on the Southwest during the first week of February 2011 was unusually severe in terms of temperature, wind, and duration of the event. In many cities in the Southwest, temperatures remained below freezing for four days, and winds gusted in places to 30 mph or more. The geographic area hit was also extensive, complicating efforts to obtain power and natural gas from neighboring regions.

The storm, however, was not without precedent. There were prior severe cold weather events in the Southwest in 1983, 1989, 2003, 2006, 2008, and 2010. The worst of these was in 1989, the prior event most comparable to 2011. That year marked the first time ERCOT resorted to system-wide rolling blackouts to prevent more widespread customer outages. In all of those prior years, the natural gas delivery system experienced production declines; however, curtailments to natural gas customers in the region were essentially limited to the years 1989 and 2003.

Electric

Going into the February 2011 storm, neither ERCOT nor the other electric entities that initiated rolling blackouts during the event expected to have a problem meeting customer demand. They all had adequate reserve margins, based on anticipated generator availability. But those reserves proved insufficient for the extraordinary amount of capacity that was lost during the event from trips, derates, and failures to start.

In the case of ERCOT, where rolling blackouts affected the largest number of customers (3.2 million), there were 3100 MW of responsive reserves available on the first day of the event, compared to a minimum requirement of 2300 MW. But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW. Combining forced outages with scheduled outages, approximately one-third of the total ERCOT fleet was unavailable at the lowest point of the event. These extensive generator failures overwhelmed ERCOT's reserves, which eventually dropped below the level of safe operation. Had ERCOT not acted promptly to shed load, it would very likely have suffered widespread, uncontrolled blackouts throughout the entire ERCOT Interconnection.

ERCOT also experienced generator outages in the Rio Grande Valley on February 3, again due to the cold weather. This area is transmission constrained,

and the loss of local generation led to voltage concerns that necessitated localized load shedding.

Spot prices in ERCOT hit the $3,000 per MWh cap on February 2, the worst day of the event. Given the high demand and the huge loss of generation, this was not a surprising development. In fact, very high prices are an expected response to scarcity conditions, one that is built into ERCOT's energy-only market. ERCOT's IMM reviewed market performance during the event and found no evidence of market manipulation.

EPE and SRP likewise suffered numerous generator outages, necessitating load shed of 1023 MW in EPE's case, and 300 MW in SRP's case. As with ERCOT, many of these generators failed because of weather-related reasons.

A number of entities within SPP also experienced outages during the event. In their case, however, load shedding was not required, principally because the utilities were able to purchase emergency energy from other SPP members. One other utility in the Southwest, PNM, experienced blackouts, but these were localized and the result of transmission outages that were mostly unrelated to the weather.

The actions of the entities in calling for and carrying out the rolling blackouts were largely effective and timely. However, the massive amount of generator failures that were experienced raises the question whether it would have been helpful to increase reserve levels going into the event. This action would have brought more units online earlier, might have prevented some of the freezing problems the generators experienced, and could have exposed operational problems in time to implement corrections before the units were needed to meet customer demand.

The February event underscores the need to have sufficient black start units available, particularly in the face of an anticipated severe weather event. In ERCOT's case, for instance, nearly half of its black start units were either on scheduled outage at the time of the event or failed during the event itself, jeopardizing the utility's ability to promptly restore the system had an uncontrolled, ERCOT-wide blackout occurred.

The majority of the problems experienced by the many generators that tripped, suffered derates, or failed to start during the event were attributable, either directly or indirectly, to the cold weather itself. For the Southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. At least

another 12 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching).

Low temperatures returned to the region on February 10. In fact, ERCOT set a new winter peak that day. But no load shedding proved necessary, largely because the temperatures were not quite as cold or sustained as those of the previous week, the winds were less severe, and many of the repairs and protective measures taken by the generators on February 2 remained in place.

Natural Gas

Problems on the natural gas side largely resulted from production declines in the five basins serving the Southwest. For the period February 1 through February 5, an estimated 14.8 Bcf of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas.

The production losses stemmed principally from three things: freeze-offs, icy roads, and rolling electric blackouts or customer curtailments. Freeze-offs occurred when the small amount of water produced alongside the natural gas crystallized or froze, completely blocking off the gas flow and shutting down the well. Freeze-offs routinely occur in very cold weather, and affected at least some of these basins in all of the six recent cold weather events in the Southwest with the possible exception of 1983, for which adequate records are not available. During the February event, icy roads prevented maintenance personnel and equipment from reaching the wells and hauling off produced water which, if left in holding tanks at the wellhead, causes the wells to shut down automatically. The ERCOT blackouts or customer curtailments affected primarily the Permian and Fort Worth Basins and caused or contributed to 29 percent (Permian) and 27 percent (Fort Worth) of the production outages, principally as a result of shutting down electric pumping units or compressors on gathering lines.

Processing plants suffered some mechanical failures, although most of their shortfalls resulted from problems upstream at the wellhead. The production declines, coupled with increased customer demand, reduced gas volume and pressure in the pipelines and in those limited storage facilities serving the Southwest. These entities in turn were unable in some instances to deliver adequate gas supplies to LDCs.

When LDCs suffer declines in gas pressure on their systems, they must reduce the amount of gas being consumed to prevent pressures from falling so low that their entire systems might fail. As a result of the high gas demand and the

falling pressures on their systems, four LDCs in New Mexico, Arizona and Texas were forced to curtail retail service or were unable to supply gas to all customers. These curtailments or outages affected more than 50,000 customers in those states, including the cities of El Paso in Texas; Tucson and Sierra Vista in Arizona; and Hobbs, Ruidoso, Alamogordo, Silver City, Tularosa, La Luz, Taos, Red River, Questa, Española, Bernalillo, and Placitas in New Mexico. In contrast to the relative ease of restoring electric service, restoration of gas service was complicated by the necessity to have LDC crews manually shut off gas meters and then relight pilot lights on site.

Winterization

Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed.

The experiences of 1989 are instructive, particularly on the electric side. In that year, as in 2011, cold weather caused many generators to trip, derate, or fail to start. The PUCT investigated the occurrence and issued a number of recommendations aimed at improving winterization on the part of the generators. These recommendations were not mandatory, and over the course of time implementation lapsed. Many of the generators that experienced outages in 1989 failed again in 2011.

On the gas side, producers experienced production declines in all of the recent prior cold weather events. While these declines rarely led to any significant curtailments, electric generators in 2003 did experience, as a result of gas shortages, widespread derates and in some cases outright unit failure. It is reasonable to assume from this pattern that the level of winterization put in place by producers is not capable of withstanding unusually cold temperatures.

While extreme cold weather events are obviously not as common in the Southwest as elsewhere, they do occur every few years. And when they do, the cost in terms of dollars and human hardship is considerable. The question of what to do about it is not an easy one to answer, as all preventative measures entail some cost. However, in many cases, the needed fixes would not be unduly expensive. Indeed, many utilities have already undertaken improvements in light of their experiences during the February event. This report makes a number of recommendations that the task force believes are both reasonable economically and which would substantially reduce the risk of blackouts and natural gas curtailments during the next extreme cold weather event that hits the Southwest.

Electric and Gas Interdependency

The report also addresses the interdependency of the electric and natural gas industries. Utilities are becoming increasingly reliant on gas-fired generation, in large part because shale production has dramatically reduced the cost of gas. Likewise, compressors used in the gas industry are more likely than in the past to be powered with electricity, rather than gas. As a result, deficiencies in the supply of either electricity or natural gas affect not only consumers of that commodity, but of the other commodity as well.

Gas shortages were not a significant cause of the electric generator outages experienced during the February 2011 event, nor were rolling blackouts a primary cause of the production declines at the wellhead. Both, however, contributed to the problem, and in the case of natural gas shortfalls in the Permian and Fort Worth Basins, approximately a quarter of the decline was attributed to rolling blackouts or customer curtailments affecting producers.

The report explores some of the issues relating to the effects of shortages of one commodity on the other, including the question of whether gas production and processing facilities should be deemed "human needs" customers and thus exempted or given special consideration for purposes of electric load shedding. However, any resolution of the many issues arising from electric and natural gas interdependency must be informed by an examination of more than one cold weather event in one part of the country. For that reason, the report does not offer specific recommendations in this area, but urges regulatory and industry bodies to explore solutions to the many interdependency problems which are likely to remain of concern in the future.

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III. The Electric and Natural Gas Industries

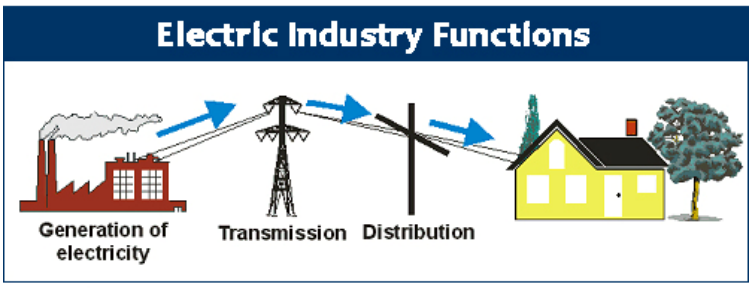
Electricity and natural gas are two of the most essential commodities for the conduct of modern life. However, the industries that produce electricity and natural gas and deliver these commodities from their points of production to consumers differ greatly from one another, as do the regulatory schemes governing them. This section provides an overview of the electric and natural gas industries, their market structures, and the regulatory authorities under which they operate, focusing particularly on the southwest region of the country. This background will be useful in understanding the causes of the outages and curtailments experienced during the first week of February 2011, the actions taken by the entities affected, and the recommendations the task force is suggesting to prevent a recurrence of the widespread service disruptions.

A. The Electric Industry

This subsection describes the structures under which electricity is generated and transmitted, the regulation of electric service providers, and the characteristics of the electricity markets found in the Southwest. A more detailed description of how electricity is produced, transmitted and delivered can be found in the appendix entitled "Electricity: How it is Generated and Distributed."

Overview of Electric Power Production and Delivery

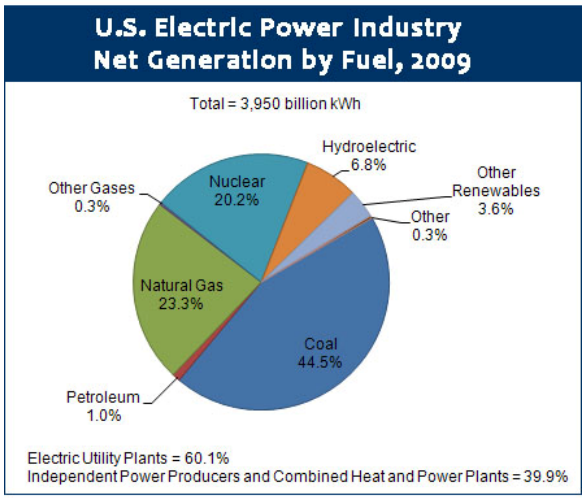
The electric power industry is comprised of three separate functions: generation, transmission, and distribution. These are depicted in the figure below.



Source: EIA

Most of the power produced in the United States uses coal, natural gas, or nuclear fission as the energy source to produce steam or other hot combustion gas that turns a turbine and thereby creates electricity. The figure below shows the fuel source percentages for electricity produced in the US in 2009, with the majority of electricity coming from fossil fuels (coal and natural gas totaling a 68

percent share). While wind and solar energy have experienced fairly rapid growth over the past several years, renewable fuels (including hydroelectric generation's seven percent share) accounted for about 11 percent of the electricity generated in the United States in that year. Wind generation is more common in the Southwest than in most other regions; its share of total generation is about 3.8 percent.[1]



Generating units typically fall into three categories: base load, intermediate, and peaking units. Base load units, usually coal-fired or nuclear, have a relatively low operating cost and have fairly slow or expensive ramping rates.[2] These units are seldom cycled on and off, and are instead scheduled to cover the base levels of projected load. Peaking units, which are generally gas-fired, can be started up very quickly and have relatively expensive operating costs. Accordingly, they are generally last in the dispatch order and are used to cover seasonal (and sometimes daily) peak load levels. Intermediate plants fall somewhere in between base load and peaking with respect to operating characteristics, start-up times, and capacity factors.[3]

Generating plants produce power at a relatively low voltage level, so the power must be "stepped up" to a higher voltage in order to be more efficiently

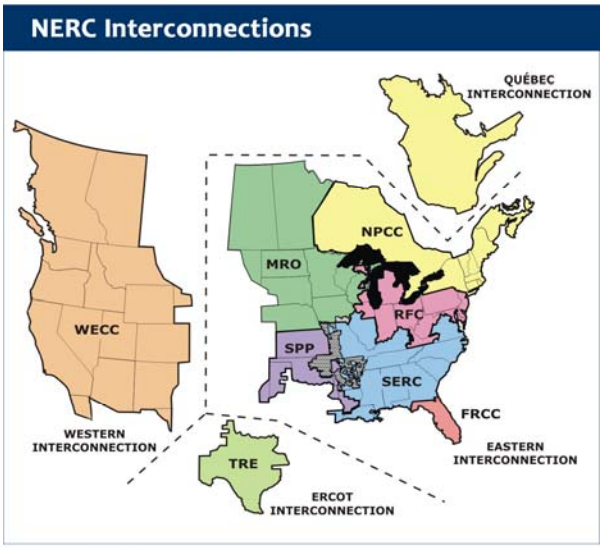
[1] United States Energy Information Administration (EIA), *Electric Power Monthly*, Table 6 - Total Renewable Net Generation by Energy Source and State, 2009 (released August 2010) and *Electric Power Annual*, Figure 2.1 – U.S. Electric Industry Net Generation by State, 2009 (released November 2010, revised January and April 2011).

[2] "Ramping" refers to the generator's ability to produce more or less power on request.

[3] "Capacity factor" refers to the ratio of average generation to the capacity rating of an electric generating unit for a specified period (expressed as a percentage).

transmitted to its ultimate point of use. Energy is carried at these higher voltages over transmission lines (usually between 138 kV and 765 kV) to load centers, where voltage is then stepped back down to a distribution level for delivery to end-use customers. While distribution lines are generally considered to be those operating at 69 kV and below,[4] some industrial end-use customers may take service at transmission-level or intermediate-level voltages.

Virtually all of the transmission system in the continental United States is operated as an alternating current (AC) system, although the West and a few other areas make use of some direct current (DC) lines for long-haul transportation of power or for system stability. DC ties are also used to provide limited connectivity between the three electrically independent grids currently found in the United States: (1) the Eastern Interconnection, which covers the eastern two-thirds of the United States and contiguous parts of Canada; (2) the Western Interconnection, which covers the western third of the United States, the Canadian provinces of Alberta and British Columbia, and a small portion of Baja California Norte, Mexico; and (3) ERCOT, which covers most of the state of Texas. (A fourth interconnection, the Quebec Interconnection, is located wholly in Canada.)



Source: NERC

[4] The bulk electric system, which constitutes transmission as opposed to distribution, has been described by FERC as those facilities operating at 100 kV or above except for defined radial facilities, with exemptions for those facilities not necessary for operating the interconnected transmission network. *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 75 Fed. Reg. 72,910 (Nov. 26, 2010), 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

Within each interconnection, power generally flows freely across the entire grid. An imbalance of generation versus demand that is significant enough to cause instability on one utility's system can ultimately affect the stability of all systems operating in that interconnection.[5]

Evolution and Regulation of the Electric Industry

Under part II of the Federal Power Act,[6] FERC has jurisdiction over the rates, terms and conditions of wholesale sales of electric energy and transmission services in interstate commerce that are provided by jurisdictional entities (which generally excludes electric cooperatives and federal or state entities, including municipal utilities). Notably, wholesale electric energy sales and transmission services provided wholly within ERCOT are not considered to be interstate under the Federal Power Act, and are therefore not subject to FERC jurisdiction. States generally regulate retail sales of electric energy and distribution services, although publicly-owned and member-owned entities (such as electric cooperatives and municipal utilities) may be exempt from direct state regulatory oversight. In Texas, the PUCT exercises jurisdiction over wholesale sales of energy and the provision of transmission services wholly within the ERCOT footprint.

Historically, all three of the electric sector functions (generation, transmission, and distribution) were provided by one vertically-integrated utility, which was typically granted a monopoly franchise by states to serve retail customers within a given geographic area. While wholesale sales or exchanges of electric energy did occur between utilities, utilities historically planned their systems, both generation and transmission, to serve their own native peak load requirements.

Entities Providing Electric Services in the United States

The electric sector in the United States is made up of a variety of entities, including investor-owned utilities, publicly-owned utilities (including municipal utilities, public utility districts, and irrigation districts), member-owned utilities (generally rural electric cooperatives), Federal electric utilities, and

(cont'd)

[5] *See generally* U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations at 5-10 (April 2004) (2003 Blackout Report), *available at* http://www.ferc.gov/industries/electric/indus-act/reliability/blackout.asp#skipnav (last visited Aug. 2, 2011).

[6] 16 U.S.C. § 824 et seq.

independent power producers. Investor-owned utilities (IOUs) are private entities that were historically vertically-integrated, *i.e.*, owning generation, transmission and distribution assets. However, in states with restructured electric markets, many IOUs were required or strongly incentivized to divest or spin-off their generation assets, and now own only transmission and distribution assets as part of the utility company. Based on 2007 data from the United States Energy Information Administration, IOUs serve about 71 percent of the retail customers in the country. Publicly-owned electric utilities and electric cooperatives have generally been exempted from state restructuring initiatives, and have not been required to offer customer choice or to divest generation assets. There are approximately 2,000 publicly-owned utilities in the United States (which own about 9 percent of the installed generating capacity) and over 880 electric cooperatives (which own approximately 4 percent of the installed capacity).

Since the 1970s, a number of changes occurred to alter this traditional, vertically-integrated model. In 1978, Congress created a class of non-utility generators called qualifying facilities (QFs), and in 1992 created a class of independent generators called Exempt Wholesale Generators. This legislation opened the door not only for independent owners to develop generating plants in multiple regions, but also for utilities to develop generating plants in regions outside their service territory.[7]

FERC took a number of steps to further encourage the development of a competitive wholesale market for generation, including by (1) authorizing generation owners to sell wholesale power at market rates if they can demonstrate that they lacked market power in the relevant market; and (2) requiring transmitting utilities to provide open access transmission service for the delivery of power to wholesale customers on terms and conditions comparable to the transmission service the utilities provided themselves in serving their native load customers.[8]

[7] Energy Policy Act of 1992, Pub. L. No. 102, 486.

[8] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part*

FERC also encouraged the formation of Independent System Operators (ISOs)[9] and Regional Transmission Organizations (RTOs).[10] ISOs/RTOs serve a number of functions critical to operation of the wholesale market within a given region, including control and operation of the transmission grid, operation of real-time and day-ahead markets, and transmission system planning.[11] Not all regions in the United States have adopted an ISO/RTO structure, although they may rely on other power pool structures. The map below shows the footprint of the nine ISOs or RTOs currently operating in the US and Canada.

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sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002) (Order No. 888).

[9] ISOs grew out of Order No. 888, issued in 1996, as a means of satisfying FERC's requirement that jurisdictional utilities provide non-discriminatory access to transmission services. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730; and *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v.* FERC, 272 F.3d 607 (D.C. Cir. 2001).

[10] In 1999, as part of Order No. 2000, FERC created and sought to encourage the voluntary formation of Regional Transmission Organizations to oversee electric transmission and ancillary services and transmission planning services across a broader territory. ISOs and RTOs perform similar functions, but RTOs are only recognized as such if they meet FERC's minimum characteristics and minimum functions as set out in Order No. 2000. In addition, ISOs tend to be smaller in geographic size, or are not subject to FERC jurisdiction. *See* "The Value of Independent Regional Grid Operators: A Report by the ISO/RTO Council," *available at* <http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/Value_of_Independent_Regional_Grid_Operators.pdf>. Order 2000: *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[11] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730 (1996).

Regional Transmission Organizations/Independent System Operators

In markets where an ISO/RTO has been approved, the ISO/RTO is generally responsible for dispatching generating units based on hourly energy prices offered by the generation owner or other energy marketer. Initially, these competitive wholesale markets were structured to reflect only energy products and ancillary services,[12] with no compensation for the provision of capacity[13] and no corresponding obligation on the part of generators to offer into a specific market.[14] Many of the markets have undergone modifications over time, including

[12] Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers, and in RTO or ISO-based markets are generally procured through a mechanism or market separate from the energy market. Ancillary services typically include regulation, synchronized or spinning reserves, non-spinning reserves, and black-start services. Among ERCOT's various categories of ancillary services are responsive reserve service (RRS) and non-spinning reserve service (NSRS). RRS are operating reserves intended to help control the frequency of the system. NSRS are reserves intended to cover the uncertainties in forecasting load and wind power output.

[13] Capacity (or installed capacity) refers in this context to the maximum kW or MW of output offered into a capacity market and required to be available except as otherwise provided by the relevant market rules. Payments by load serving entities for capacity are made regardless of whether energy is actually provided, as long as the relevant availability requirements are met. Penalties are generally imposed if a supplier fails to meet the availability requirements or otherwise provide energy when called upon.

[14] After an offer is accepted in a given energy or ancillary services market, the generator or its marketer has the obligation to deliver the energy or to cover the real-time cost of replacement if the generator experiences a forced outage or derate. In addition, even in an energy-only market, certain generators that are deemed essential for reliability (often referred to as reliability must-run generators or RMRs), are paid an amount above the base energy payments to ensure that the unit remains operational and available; these generators are subject to some form of penalty if the unit is not available as provided for under the market rules or specific RMR contract.

implementation of day-ahead markets, virtual bidding,[15] nodal pricing,[16] and separate capacity markets.

Energy-Only Markets versus Capacity Markets

In an energy-only market, load serving entities purchase energy on an hourly basis (even if secured or scheduled on a day-ahead or forward basis), and are generally also required to cover minimum ancillary services requirements, including voltage support, regulation, and spinning or non-spinning reserves. These load-serving entities are not obligated to secure capacity to cover their projected peak loads going forward, and generators can only recover their capital costs through payments for hourly energy and ancillary services.

In markets with capacity-based payments, load serving entities are responsible for procuring capacity (including adequate reserves) to cover their peak loads. In the Northeast, capacity prices are set through forward capacity markets, and while generators receive the benefit of a more predictable revenue stream, they must also accept certain obligations to ensure that their unit is available and offered into the energy market when needed, or face penalties for failure to do so.

Reliability Oversight by FERC, NERC and Regional Entities

In 1968, following the extensive 1965 blackout in the Eastern United States and Canada, members of the electric utility industry formed a voluntary council (NERC)[17] to coordinate regional planning for the industry and develop operating

[15] A form of transaction where buyers and sellers place trades based on differences between day-ahead prices and real-time prices. Virtual bidding is intended to improve market efficiency as real-time and day-ahead prices converge.

[16] Nodal pricing uses the locational marginal price (LMP, or the cost of supplying the next megawatt of load) at each specific electric location or bus. In a completely unconstrained system, the nodal price will be the same at each node on the system. When transmission constraints occur, the nodal price will reflect the cost of dispatching generating units out of economic merit order in order to serve load within the constrained area. Nodal pricing allows for separate energy prices at each bus, while zonal pricing sets a locational price for much larger, pre-established zones.

[17] The council was originally named the National Electric Reliability Council, but the name was later changed to North American Electric Reliability Council to reflect Canadian

guides and voluntary standards and practices to protect the reliability of the interconnected system.[18] While efforts were undertaken in the 1990s to require adherence to NERC reliability policies and guidelines, mandatory reliability standards were not adopted in the United States until Congress passed the Energy Policy Act of 2005 (EPAct 2005). That act required FERC to certify an independent Electric Reliability Organization (ERO) tasked with developing and enforcing such mandatory reliability standards.[19]

Pursuant to EPAct 2005, FERC certified NERC as the ERO on July 20, 2006.[20] Under implementation procedures adopted by FERC, NERC is permitted to delegate a portion of its responsibilities for enforcement and for regional standards development to Regional Entities, which NERC in turn oversees. NERC has provided such delegated authority to eight Regional Entities in the United States and Canada, each of which has primary authority for enforcement in the regions shown below.[21]

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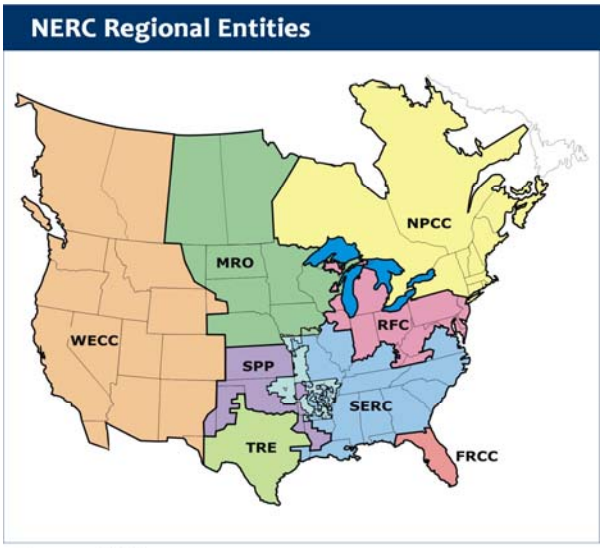
member participation, and changed again to North American Electric Reliability Corporation in 2007 to reflect its new role as the independent Electric Reliability Organization. *See NERC Company Overview: History*, http://www.nerc.com/page.php?cid=1|7|11.

[18] Responsibility for the voluntary standards and operating guidelines was originally given to the North American Power Systems Interconnection Committee (NAPSIC, formed earlier in the 1960s). NAPSIC later became part of NERC. *Id.*

[19] *See* Energy Policy Act of 2005, Pub. L. No. 109-58. The renewed efforts to adopt mandatory reliability standards that prompted this section of the Energy Policy Act came in response to the Northeastern blackout of August 14, 2003, and to the recommendations made in a report prepared by a joint US-Canada task force that reviewed the causes of the blackout. *2003 Blackout Report* at 3 (adopting as its first recommendation: "Make reliability standards mandatory and enforceable, with penalties for noncompliance.")

[20] *N. Am. Elec. Reliability Corp*. 116 FERC ¶ 61,062 (2006).

[21] The eight Regional Entities operating under delegated authority from NERC are Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Southwest Power Pool Regional Entity, Texas Reliability Entity, and Western Electric Coordinating Council.



Source: NERC

Under Section 215 of the Federal Power Act, NERC must submit its proposed Reliability Standards to FERC for approval before they may become mandatory and enforceable. In order to approve a Reliability Standard, FERC must find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest, after giving due weight to the technical expertise of the ERO.[22] In addition, while the ERO has the authority to propose a penalty for violation of a Reliability Standard following notice and opportunity for a hearing, that penalty may only take effect after it has been filed with FERC. FERC can exercise the option to review, set aside, or modify the penalty, on its own motion or on application by the entity subject to the proposed penalty.[23] FERC also has the authority, on its own motion or on complaint, to order compliance with a Reliability Standard or to impose a penalty for violation of a Reliability Standard.[24]

In Order No. 693, FERC approved the first set of 83 Reliability Standards, which became enforceable on June 18, 2007.[25] NERC maintains a Compliance

[22] 16 U.S.C. § 824o(d)(1) and (2).

[23] *Id*. at § 824o(e)(1) and (2).

[24] *Id.* at § 824o(e)(3).

[25] NERC and the Regional Entities may assess penalties for non-compliance with the Reliability Standards. In order for such a penalty to take effect, NERC must file a notice of penalty with FERC. Each penalty determination is subject to FERC review. In the absence of an application for review or action by FERC, each penalty filed by NERC is affirmed by operation of law after 30 days.

Registry that identifies all entities subject to compliance with the approved Reliability Standards. Users, owners and operators of the bulk power system are required to register with NERC under the appropriate functional categories, and each Reliability Standard designates each category of entity to which it applies. Currently, there are over 1900 registered entities subject to the Reliability Standards (a number of entities are counted more than once as they are registered under more than one category). The categories of registered entities are set out in the appendix entitled "Categories of NERC Registered Entities."

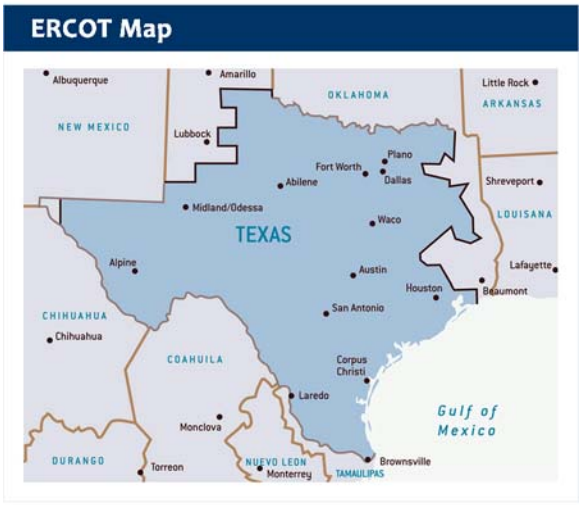
Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the appropriate Regional Entity and to NERC. The Regional Entity and/or NERC in turn undertakes various levels of analysis to determine the causes of the events, assure tracking of corrective actions to prevent recurrence, gather information needed to assess compliance, and provide lessons learned to the industry. The event analysis process also provides input for training and education, reliability trend analysis efforts and Reliability Standards development, all of which support continued reliability improvement. Under NERC's field trial of its event analysis program, the February 2 and February 3 event was classified as a category 4 event due to the overall significance and impact of the event (loss of over 5,000 MW but less than 10,000 MW of load or generation). Based on the scope of the needed analysis, and the fact that it impacted multiple regions, NERC determined that the event review should be coordinated at the NERC level.

Southwest Electricity Markets, Pools and Reserve Sharing Groups

The Southwest contains two ISO/RTOs (ERCOT and SPP), and a number of vertically integrated utilities that are located within the WECC region. These are described below.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is an ISO that covers approximately seventy-five percent of the landmass within Texas, excluding the El Paso area, part of the northern panhandle, and part of the region east of Houston. ERCOT manages access to the transmission system within its footprint and operates the Texas energy and ancillary services markets (it does not have a capacity market).



Source: ERCOT

ERCOT schedules power over 40,500 miles of transmission lines and is responsible for the dispatch of more than 550 generating units.[26] It was founded in 1970 as one of the NERC regional reliability coordination councils, and is currently the registered balancing authority for 85 percent of the electric load in Texas.[27] When it became an ISO in 1996 it undertook a number of new responsibilities, including operation of the wholesale competitive electricity market. When Texas restructured its electric industry in 2002, implementing customer choice for most retail customers and requiring divestiture of generation by IOUs, ERCOT also undertook administration of customer switching for those retail customers in Texas that can choose their electric service provider.

ERCOT is a summer-peaking region, and experienced its highest peak demand to date (68,294 MW) on August 3, 2011. Generation in ERCOT is fairly diverse in terms of fuel sources. Natural gas represented the highest percentage of installed capacity in 2009 (at 59 percent), but coal and nuclear power combined to provide over 50 percent of the energy produced for that year. [28]

ERCOT operates as a functionally separate interconnection, although it has five asynchronous ties with other interconnections.[29] Three of the ties allow

[26] For ERCOT background, *see generally* ERCOT 2009 Annual Report, *available at* http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf.

[27] ERCOT is also registered in NERC's Compliance Registry as an interchange authority, planning authority, reliability coordinator, resource planner, and transmission service provider. In addition, it also partners with other transmission operators in Texas and in that capacity is listed as a "coordinated functional registration."

exchanges with Mexico (through the Comisión Federal de Electricidad, or CFE): the Laredo Variable Frequency Tie, the South Tie (also called Eagle Pass), and the Railroad Tie, the latter located near McAllen, Texas. Two of the ties allow exchanges with the Eastern Interconnection through SPP: the North Tie, located near Oklaunion, Texas, and the East Tie, located near Mt. Pleasant, Texas. The maximum amount of energy that can be imported on all the ties is 1090 MW (approximately 2.3 percent of ERCOT's 2010/2011 forecasted winter peak), with most of that attributable to the ties to the Eastern Interconnection.[30]

ERCOT originally employed a zonal market design, under which the region was divided into pricing zones and all generators within a zone received the same price for the power they provided. It shifted to a nodal market design in December 2010, under which prices are assessed at points (nodes) where electricity enters or leaves the grid. The settlement price at each node is referred to as the locational marginal price (LMP). A nodal market design allows for more precise price signals and greater dispatch efficiencies than a zonal market design, and permits direct assignment of congestion costs through the more granular locational marginal prices.

Under its previous zonal market, ERCOT had no day-ahead energy market (although ancillary services were procured on a day-ahead basis to ensure sufficient capacity would be available). Under its current nodal market, ERCOT has a day-ahead energy market, which is co-optimized with ancillary services.

ERCOT has an energy-only market, as opposed to both an energy market and a capacity market. Capacity markets are used to address resource adequacy concerns; typically, a planning reserve margin is established to maintain reliability goals, and the ISO/RTO imposes capacity obligations on load-serving entities that are met through bilateral contracting or a centralized capacity market. In contrast, an energy-only market relies on energy price signals to spur investment in new generation. Thus, by design, ERCOT's energy-only market would be expected to

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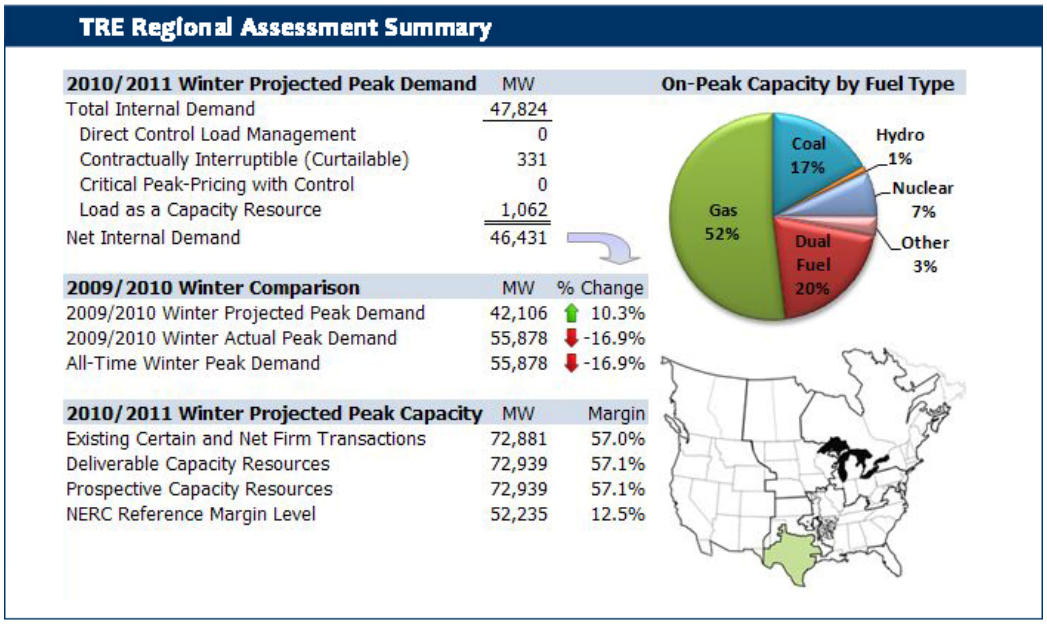
[28] ERCOT reported the following percentage fuel mix of installed capacity in 2009, in declining order: (1) natural gas, 59 percent; (2) coal, 22 percent; (3) wind, 11 percent; (4) nuclear, 6 percent; and (5) hydroelectric and biomass, 2 percent. ERCOT reported the following percentages for energy produced for 2009: (1) natural gas, 42 percent; (2) coal, 37 percent; (3) nuclear, 14 percent (4) wind, 6 percent; and (5) hydroelectric and biomass, 1 percent. ERCOT 2009 Annual Report at 2.

[29] Four are DC interties and one is a variable frequency transformer (VFT) inter-tie.

[30] The maximum MW that can be imported on each of the ties (actual limits may vary based on real-time conditions) is as follows: North, 210 MW; East, 600 MW; South/Eagle Pass, 30 MW; Railroad, 150 MW; and Laredo, 100 MW.

result in higher prices during times of scarcity and produce more volatile prices in general than do dual energy and capacity markets. These price signals are intended to encourage investment in energy resources, such as new generation plants, demand response, and energy efficiency, to meet growing demand.

NERC's regional assessment summary for TRE, which includes the ERCOT control area, for the winter of 2010/2011 is presented in the following chart.[31]



Source: NERC Winter Reliability Assessment 2010/2011

WECC Region and Southwest Reserve Sharing Group

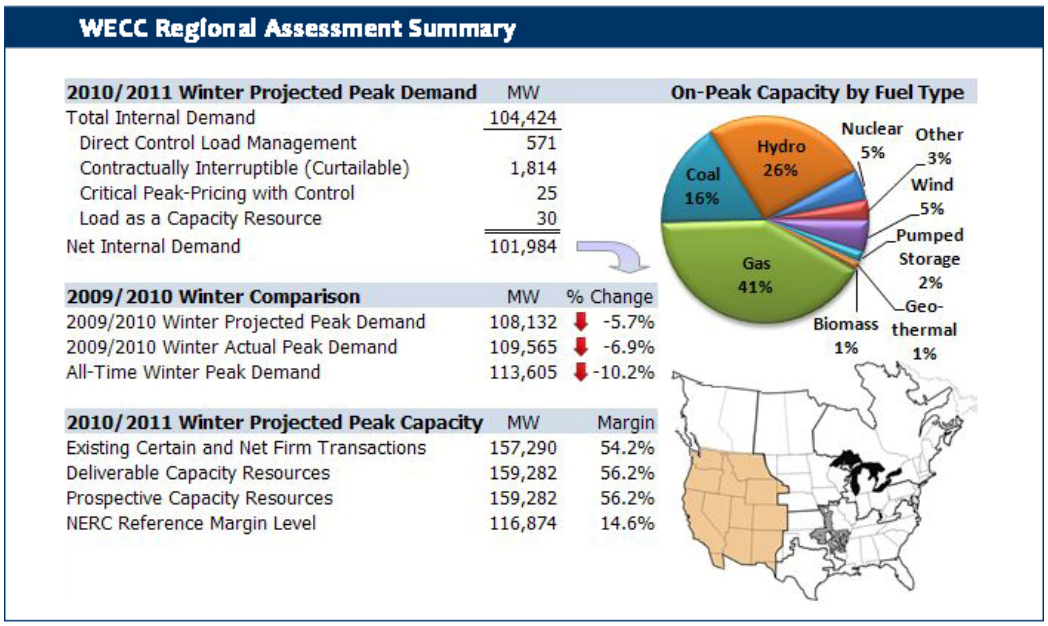
WECC is the largest geographically of the eight NERC Regional Entities, with responsibility for coordinating and promoting system reliability throughout the Western Interconnection. WECC's service territory covers Alberta and British Columbia, the northern part of Baja California in Mexico, and all the states in between, constituting an area of about 1.8 million square miles.

WECC's bulk power system generally transfers energy over long transmission lines from remotely located generators to load centers. The lack of redundant transmission facilities demands a high level of operational scrutiny in order to maintain correct voltages and power flows on the many stability limited transmission paths that exist in the Western Interconnection.

[31] NERC 2010/2011 Winter Reliability Assessment, *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf.

WECC has registered 34 balancing authorities;[32] 52 transmission operators, and 3 reserve sharing groups. The California Independent System Operator (CAISO) is the only balancing authority in the Western Interconnection that operates as an ISO or RTO.

NERC's regional assessment summary for WECC for the winter of 2010/2011 is presented in the following chart.[33]



Source: NERC Winter Reliability Assessment 2010/2011

Two of the entities that experienced rolling blackouts during the February event, SRP and EPE, are located in the WECC region. SRP, one of Arizona's largest utilities, is vertically integrated and a subdivision of the State of Arizona. Serving over 933,500 retail customers, SRP's eleven main generating stations, combined with numerous smaller facilities, have a peak retail load of over 6400 MW, and serve a 2,900 square mile area. SRP is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

[32] NERC defines "balancing authority" as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within the BA area, and supports interconnection frequency in real-time.

[33] NERC 2010/2011 Winter Reliability Assessment.

EPE is a vertically integrated electric utility providing generation, transmission, and distribution service in west Texas and southern New Mexico. EPE serves approximately 372,000 customers over a 10,000 square mile service territory via five major generating stations, including three stations local to El Paso, Texas. It has a native peak load of 1616 MW. Like SRP, EPE is registered with NERC for all bulk power system functions except interchange authority, reliability coordinator, and reserve sharing group.

Both SRP and EPE participate in the Southwest Reserve Sharing Group (SRSG), which provides for the sharing of contingency reserves among its participants pursuant to a Participation Agreement. SRSG was formed in 1998 as the successor to an earlier pool, and has participants in Arizona, New Mexico, southern Nevada, part of southern California and El Paso, Texas. SRSG is a NERC Registered Entity, and administers certain requirements related to disturbance control and emergency operations standards. Its participants are obligated to carry reserves in accordance with a contractual formula, and to provide power within a certain time frame to other participants experiencing a disturbance on their systems.

Southwest Power Pool

SPP is both an RTO and a NERC Regional Entity responsible for the enforcement of Reliability Standards within its region. SPP had its origins in 1941, when eleven regional power companies formed the pool in order to ensure sufficient electric service to aluminum plants needed for the war effort. The pool remained intact after the war and was a founding member of NERC in 1968. SPP implemented operating reserve sharing arrangements among its members in 1991, and became a FERC-approved RTO in 2004.

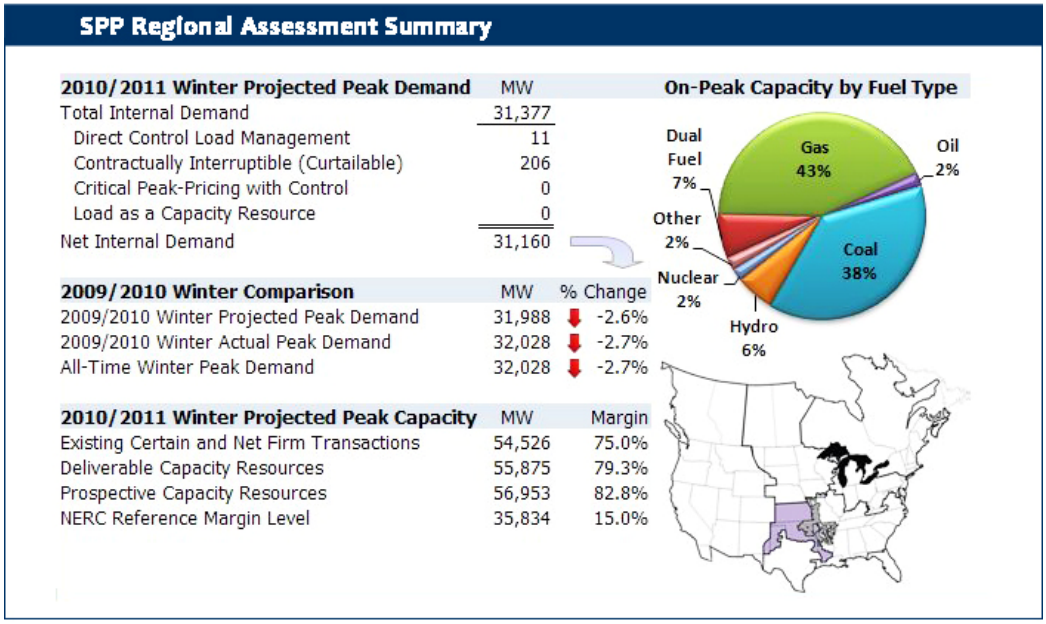
SPP covers a 370,000 mile area that includes all or portions of nine states: Nebraska, Kansas, Oklahoma, Missouri, Arkansas, Louisiana, Texas, New Mexico, and Mississippi.[34] SPP operates 48,930 miles of transmission lines, and has a coincident peak demand within its reliability coordinator[35] footprint of approximately 55,000 MW.

[34] SPP actually has five "footprints," with differing membership and oversight functions, as (1) a NERC Regional Entity; (2) a reserve sharing group; (3) a reliability coordinator area (29 balancing authorities and transmission owners, including certain balancing authorities in SERC and the Midwest Reliability Organization); (4) an RTO (with 15 balancing authorities); and (5) an energy imbalance services (EIS) market region (with 15 balancing authorities). *See* http://www.spp.org/section.asp?pageID=28 (last visited Aug. 2, 2011).

[35] NERC defines "reliability coordinator" as the entity that is the highest level of authority responsible for the reliable operation of the bulk power system, has the wide area view

At present, SPP's market operations are relatively limited, currently allowing participants to buy and sell energy in real time and to settle out any energy scheduling imbalances based on the real-time market price. SPP does not currently operate a separate market for reserves but is working to implement a new integrated marketplace that includes a day-ahead energy and operating reserves market.[36]

NERC's regional assessment summary for SPP for the winter of 2010/2011 is presented in the following chart.[37]



Source: NERC Winter Reliability Assessment 2010/2011

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of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

[36] Unlike California, Texas, and the Northeast, most of the states SPP covers have not undertaken a broad restructuring of the electric industry through retail access and/or mandatory unbundling of generation from transmission and distribution. Accordingly, most utilities operating within SPP's footprint still supply a large portion of their customers' electricity needs through their own generation and do not need to access the market to do so.

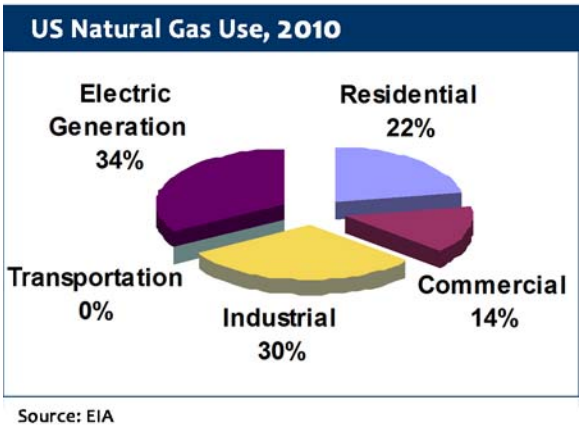
[37] NERC 2010/2011 Winter Reliability Assessment.

B. The Natural Gas Industry

This subsection provides an overview of the manner in which natural gas is produced and delivered, the jurisdictional structures applicable to the industry, and the various producers and pipelines located in the Southwest. A detailed description of the geology and physics of natural gas production and delivery can be found in the appendix entitled "Natural Gas: Production and Distribution."

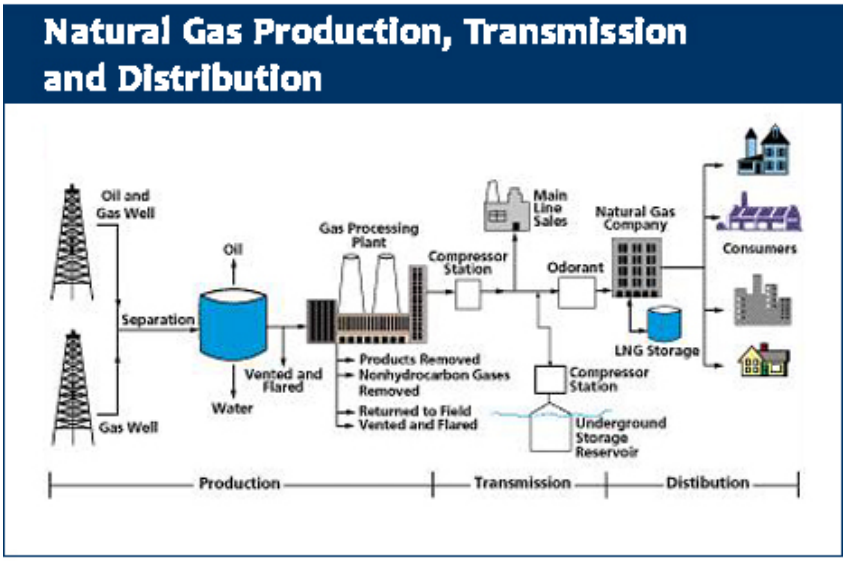
Overview of Natural Gas Production and Delivery

Natural gas is a fossil fuel, formed through the decomposition of organic matter found in underground geological formations. It is a significant source of energy representing 25 percent of the United States energy consumption. In 2010, approximately 22 percent of gas consumption was used for residential heating and cooking, 14 percent for commercial use, 30 percent for industrial processes, 34 percent for electric generation, and less than one percent for transportation.[38]



The delivery framework for natural gas includes production, separation of fluids at or near producing wells, natural gas liquids (NGL) processing, pipeline transmission, storage, and finally distribution by an LDC. The following chart is a simplified schematic of this framework.

[38] EIA, *Natural Gas Consumption by End Use*, http://www.eia. gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm (last visited Aug.27, 2011).

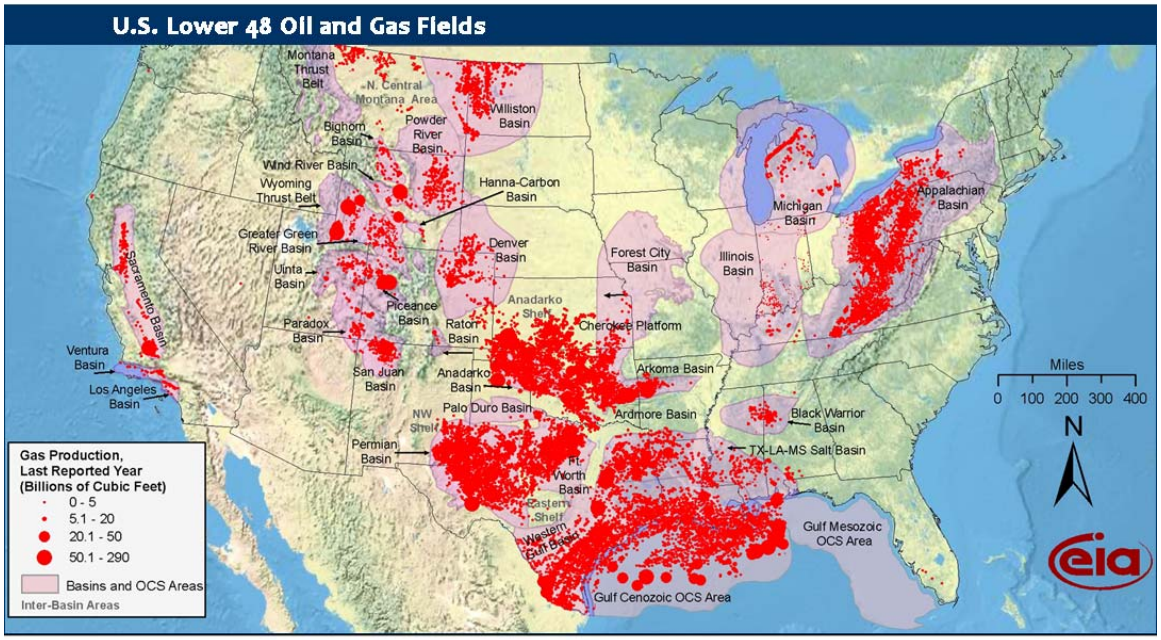


Source: EIA

Natural gas is often produced in locations distant from demand centers. The Energy Information Agency estimates that in 2009 there were 493,100 gas wells in the United States. The majority of these wells were located in the Gulf Coast, Southwest and the Appalachian Basin. The five states with the largest number of wells that year were Texas, 93,507; Pennsylvania, 57,356, West Virginia, 50,602; New Mexico, 44,784, and Oklahoma, 43,600.[39] The following chart shows production basins and the concentration of reported natural gas production.[40]

[39] EIA, *Natural Gas, Number of Producing Wells*, http://www.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm (last visited Aug.2, 2011).

[40] EIA, *Gas Production in Conventional Fields*, http://www.eia.gov/oil_gas/rpd/conventional_gas.pdf (last visited Aug. 2, 2011).



Source: EIA based on data from HPDI, IN Geological Survey, USGS, April 8, 2009

Major oil companies and large independent companies account for a substantial portion of the gas production in the United States. In the first half of 2009, the five largest producers and their daily production were as follows: BP, Inc, 2.33 Bcf per day; Anadarko Petroleum Corporation, 2.33 Bcf per day; XTO Energy, Inc., 2.29 Bcf per day (acquired by ExxonMobil in 2010); Chesapeake Energy Corporation, 2.21 Bcf per day; and Devon Energy Corporation, 2.13 Bcf per day. These producers together accounted for approximately 20 percent of United States production.[41]

In the Southwest, production takes place at the many thousands of wellheads located throughout the basins. The wellhead consists of equipment on top of the well that is used to manage flows of oil and gas, often produced together, arising from the underground formations. The high pressure gas in formations is lighter than air and will often rise on its own through the wellhead to surface pipes. In other gas wells, as well as oil wells with associated natural gas, flow requires lifting equipment. Typical lifting equipment consists of the "horse head" or conventional beam pump. The pumps are recognizable by the distinctive shape of the cable feeding fixture, which resembles a horse's head.[42] They are

[41] Reuters, http://www.reuters.com/article/2009/12/14/xto-exxon-natgas-producers-idUSN1420089920091214; and EIA, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm. "Bcf" refers to a billion cubic feet.

[42] *Well Completion*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/well_completion.asp (last visited Aug. 2, 2011).

often called "pumpjacks" and are seen throughout west Texas and southeastern New Mexico. The following two photographs are of a wellhead and a pumpjack.

Wells and lift equipment are monitored on a daily basis and maintained by oil and gas company employees, who are often referred to as "pumpers" or "gaugers." Their responsibilities include reporting malfunctions and spills, and ensuring that field processing equipment is operational and that production is correctly measured. Onshore gaugers may drive many miles per day to monitor dozens of wells.

Processing Natural Gas

The natural gas used by consumers consists almost entirely of methane. However, produced gas often contains other hydrocarbons such as ethane, propane, butane, pentanes and liquids such as condensates. It may also include water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds. Some field processing occurs near production wells to remove the water and condensates, but complete processing usually occurs at a gas processing plant. Natural gas processing plants remove other hydrocarbons to produce what is known as "pipeline quality" dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities. The removed hydrocarbon NGLs are sold separately.

Natural gas is transported to processing plants[43] typically through small-diameter and low-pressure gathering pipelines. There were an estimated 20,552

[43] More than 500 processing plants operated in the United States in 2004 with 166, or over 31 percent, in the state of Texas. EIA, *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market*, (Jan. 2006), http://dnr.louisiana.gov/assets/docs/oilgas/productiondata/ngprocess_20060131.pdf.

miles of gathering system pipelines in the United States in 2009.[44]

After gathering and processing, interstate and intrastate transmission pipelines transport gas to LDCs (as well as to directly attached users such as power plants). Within the United States, the pipeline network delivers gas to 65 million residential, commercial, industrial, and power generation customers. It includes at least 210 gas pipeline systems with a total of more than 300,000 miles of transmission pipelines.[45] The pipeline system also includes more than 1,400 compressor stations, 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points.[46]

Pipeline companies monitor and control gas flow with computerized supervisory control and data acquisition (SCADA) systems, which provide operating status, volume, pressure, and temperature information. In addition to real-time monitoring, the SCADA system may enable a pipeline to start and stop some facilities remotely.[47]

The following map shows the breadth and integrated nature of the natural gas transmission grid.[48]

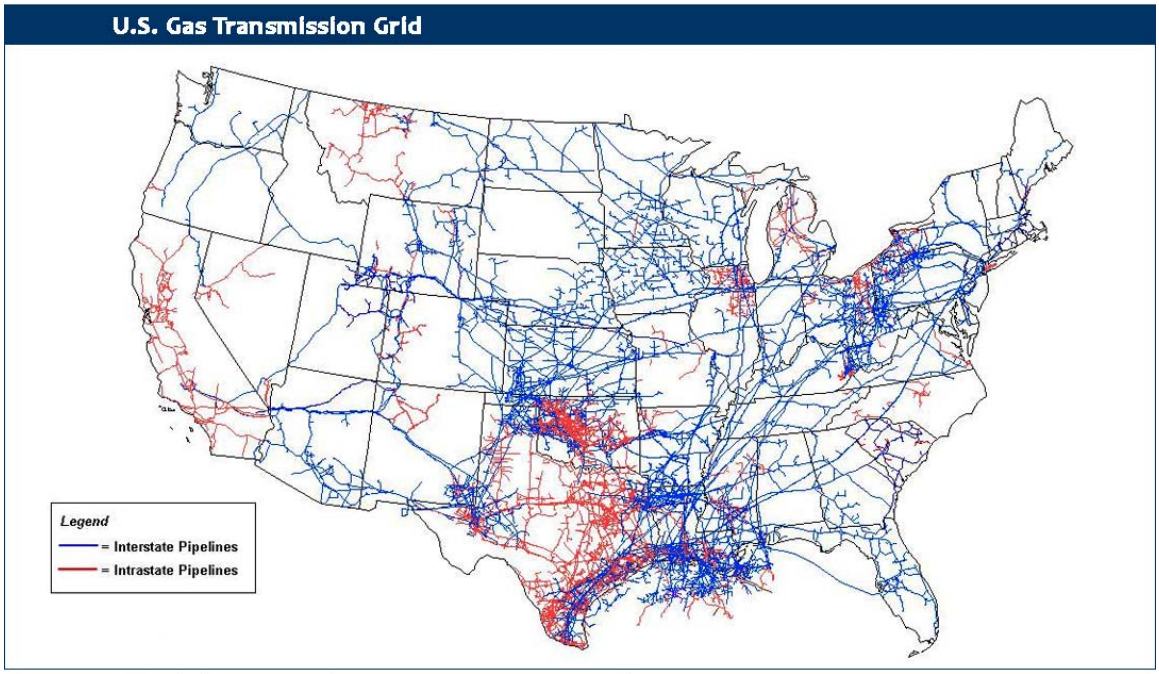
[44] U.S. Dep't of Transp. Pipeline & Hazardous Materials Safety Admin., *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, (Jun. 30, 2011), http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=036b52edc3c3e110VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[45] Am. Gas Assn., *About Natural Gas*, http://www.aga.org/Kc/aboutnaturalgas/Pages/default.aspx (last visited Aug. 2, 2011). These pipelines are high pressure systems and operate at 500 to 1,800 psi. The lines are usually 20 inches to 42 inches in diameter. http://www.naturalgas.org/naturalgas/transport.asp.

[46] EIA, *About U.S. Natural Gas Pipelines-Transporting Natural Gas* (June 2007), http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/fullversion.pdf (EIA: About U.S. Natural Gas Pipelines).

[47] INGAA, *Supervisory and Data Acquisition (SCADA)*, http://www.ingaa.org/cms/33/1339/109/134.aspx (last visited Aug. 2, 2011).

[48] EIA: About U.S. Natural Gas Pipelines.



Source: EIA, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

To meet higher gas demand at various times of the year, gas is stored underground in depleted oil and gas reservoirs, aquifers or caverns formed in salt beds.[49] Storage facilities may be interstate and regulated by FERC, or intrastate and non-jurisdictional. There are over 390 underground storage facilities in the United States,[50] of which approximately 205 are under FERC jurisdiction.[51] Depleted oil and gas reservoirs account for 87 percent of the total FERC jurisdictional storage capacity, with salt caverns (3 percent) and aquifers (10 percent) accounting for the rest.[52] A detailed discussion of the types of storage facilities and their characteristics is included in the appendix entitled "Natural Gas Storage."

[49] EIA, *Natural Gas Explained: Delivery and Storage of Natural Gas*, http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_delivery (last updated June 8, 2011).

[50] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html (last updated Aug. 2004).

[51] http://www.ferc.gov/EventCalendar/Files/20060615103625-A-3-TALKING-PTS.pdf.

[52] http://www.ferc.gov/industries/gas/indus-act/storage/fields.asp.

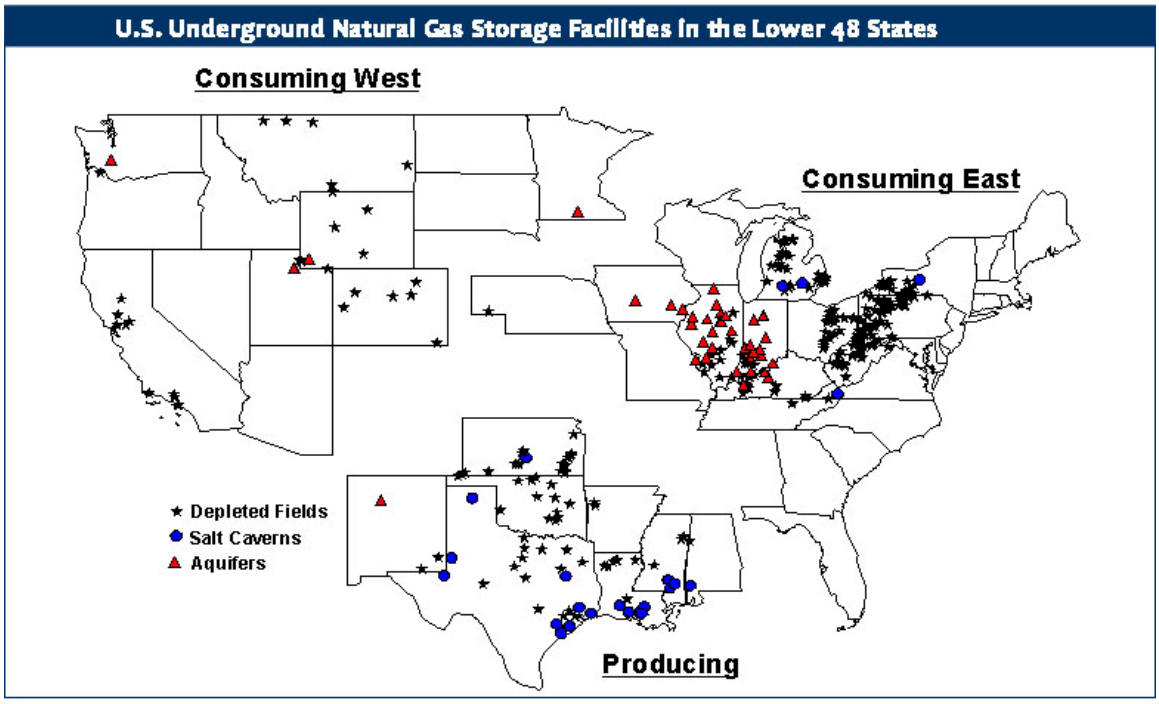
Gas Storage Facilities

- Depleted reservoirs consist of porous and permeable underground formations (average of 1,000 to 5,000 feet deep). The gas is divided into two categories, working or top gas, which can be withdrawn, and cushion or base gas, needed as permanent inventory to maintain adequate reservoir pressure and deliverability rates. Gas is generally withdrawn in the winter heating season and injected during the summer, although the demand for gas in summer months is increasing due to an increase in gas-fired generating plants. This type of storage facility can be used for both system supply and peak day demand.

- Aquifer storage fields are bounded partly or completely by water-bearing rocks. They have a high cushion gas requirement, generally between 50 to 80 percent. They also have high deliverability rates and, similar to depleted reservoirs, gas is generally withdrawn in the winter season and injected in the summer season.

- Salt cavern facilities use solution mining to recover minerals in underground salt deposits (salt domes or salt formations). Salt caverns usually operate with only about 20 to 30 percent cushion gas. Working gas can be recycled multiple times per year. Salt cavern storage has high deliverability and injection capabilities and is used for short peak day deliveries. Salt caverns are more expensive to construct due to the increased capital cost associated with leaching and mining the salt.

The following figure shows the location of United States storage facilities.[53]



Natural Gas Regulation

Natural gas production is not comprehensively regulated, and no government agency monitors daily production activity. However, some aspects of production are subject to regulation; gas-producing states monitor well drilling and permitting, and in Texas, for instance, the TRC has jurisdiction over oil and gas wells located in the state and over persons owning or engaged in drilling oil and gas wells located in the state.[54] Congress deregulated the price on natural gas at the wellhead.[55] FERC does not regulate natural gas producers, but does provide

[53] EIA, *The Basics of Underground Storage*, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html.

[54] Among the matters covered by the TRC are space and density of drilling; prevention of waste; approval of water flood permits; location exceptions; intrastate pipelines; environmental and safety aspects of production, including well plugging; regulation of the injection of carbon dioxide into reservoirs; and maintenance of well records including logs, maps and production reporting. Jack M. Wilhelm, Texas Land Institute, *What Every Landman Should Know about the Railroad Commission of Texas* (2005), *available at* http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/wilhelm.pdf.

[55] Natural Gas Wellhead Decontrol Act, Pub L. No. 101-60, 103 Stat. 157 (1989).

that producers have not unduly preferential or discriminatory access to transportation on jurisdictional pipelines, and that no undue treatment bias is exercised with respect to transportation services and gas quality standards. Retail natural gas sales to consumers are regulated by state public utility commissions, not by FERC.

FERC's jurisdiction over the transportation of natural gas,[56] which also includes the provision of natural gas storage services, begins when the gas is delivered to an interstate pipeline and continues until the gas is delivered to the wholesale purchaser, absent some intervening transaction which renders the activity exempt from federal jurisdiction under the Natural Gas Act (NGA) or the Natural Gas Policy Act of 1978 (NGPA). While generally the activities of intrastate pipelines and LDCs are exempt from FERC jurisdiction, when those entities engage in the transportation of natural gas in interstate commerce or the wholesale sales for resale of natural gas, their activities are subject to FERC jurisdiction.

FERC's responsibilities include:

- Issuance of certificates of public convenience and necessity to construct and operate interstate pipeline and storage facilities, and oversight of the construction and operation of pipeline facilities at United States points of entry for the import or export of natural gas.
- Regulation of transportation and sales for resale in interstate commerce that are not first sales.
- Regulation of the transportation of natural gas as authorized by the NGPA and the OCSLA (Outer Continental Shelf Lands Act).
- Regulation of liquefied natural gas facility siting.
- Regulation of the abandonment of jurisdictional facilities and services.
- Establishment of rates and terms and conditions for jurisdictional services.

Pipelines publish FERC-approved tariffs that pertain to services, terms of conditions and rates for gas transportation. The North American Energy Standards Board (NAESB) provides business standards for the pipelines in areas such as the scheduling of pipeline transportation.

[56] FERC also has NGA jurisdiction over sales for resale of natural gas that are not deemed first sales. A first sale does not include the sale by an interstate pipeline, intrastate pipeline, or LDC, or affiliate thereof, unless such sale is attributable to volumes of their own production.

Most interstate pipelines no longer offer sales services. The two broad categories of transportation service on an interstate pipeline are firm and interruptible transportation, subject to specified exceptions such as force majeure clauses. (The pipeline companies sell transportation, not the gas itself, which almost always is purchased separately from the producer by the shipper.) Firm transportation is characterized by a reservation of capacity. Shippers customarily pay a charge for the reservation of guaranteed capacity rights on the pipeline and a separate usage charge; pipeline firm rates thus include cost recovery of pipeline facilities in addition to recovery of variable transportation costs such as fuel. Interruptible service rates are usage charges that are derived from the firm service rates. There is no reservation of capacity under interruptible service, and capacity is provided to a shipper only to the extent it is available.[57]

Prior to the deregulation of wellhead gas prices and open access transportation established under Commission Order No. 436 in 1985 and Order No. 636 in 1992, producers typically sold gas to both intrastate and interstate pipelines; these entities in turn sold the gas to LDCs that delivered the gas to end users. With the issuance in 1992 of Order No. 636, the Commission required interstate pipelines to unbundle their services to separate the transportation of gas from the sale of gas. Thus, today most interstate pipelines do not engage in the buying and selling of natural gas except for operational purposes.

Order No. 636 further required interstate pipelines to set up informational postings to show available pipeline capacity and to ensure that all participants have access to available capacity. Additionally, holders of the firm capacity can, through capacity release, resell those rights on a temporary or permanent basis.

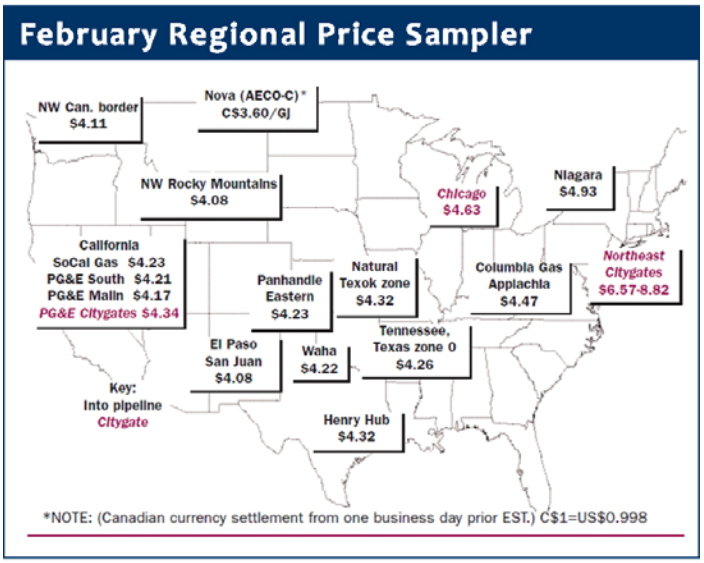
Natural Gas Marketing

Natural gas marketing mushroomed after the opening of access to pipeline capacity. Producers and marketers, in conjunction with the deregulation of wellhead gas, were granted blanket authorization to make sales at market rates. Marketers may now be affiliates of producers, pipeline companies, or local utilities, or be separate business entities unaffiliated with any other industry players. Marketers may also be associated with financial institutions. Marketing natural gas typically includes ensuring secure supplies and arranging for pipeline

[57] Pipeline Knowledge and Development, *The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model* (August 2010), *available at* www.ingaa.org/File.aspx?id=10751.

transportation, storage and accounting. Marketers also trade financial instruments to hedge commodity price risk and to speculate.[58]

For illustrative purposes, the following map depicts the February 2011 price for some regional gas trading hubs.[59] Waha and El Paso San Juan, shown on the map, are trading prices respectively applicable to the San Juan and Permian Basins. These two basins are important Southwest supply areas and figured prominently in the weather event of February 1-5.



Source: Platts Inside FERC's Gas Market Report February 2011

LDCs often make the final sale and transfer of gas to retail consumers. Unlike the interstate pipeline companies, many LDCs provide bundled sales and delivery services, although some may provide delivery services only. Many commercial and industrial customers contract for their own supply and purchase only transportation service from the LDC. There are more than 1,200 LDCs in the United States. LDCs can be stand-alone gas utilities, combination electric-gas utilities, or parts of integrated energy companies. The largest LDC is Southern California Gas Company (SoCalGas) with more than 20 million customers, followed by Pacific Gas and Electric Company and Atmos Energy Corporation.

[58] *Natural Gas Distribution*, NATURALGAS.ORG., http://www.naturalgas.org/naturalgas/marketing.asp (last visited Aug. 2, 2011).

[59] PLATTS INSIDE FERC'S GAS MARKET REPORT (Feb. 2011). Reprinted with permission of Platts.

Natural gas distribution companies typically deliver smaller volumes through smaller diameter pipes and at lower pressures than pipeline companies with systems that end at an individual household or place of business. Compressor stations are generally smaller than those found on the larger pipeline systems. Natural gas traveling through distribution pipelines will often be at a pressure as low as 3 psi to 0.25 psi at the customer's meter.[60]

Natural Gas Production in the Southwest

Texas and New Mexico are both prolific producers of natural gas, while Arizona has negligible production. In January 2011, Texas produced 31 percent of total United States production and New Mexico produced 6.2 percent.[61]

Texas and New Mexico contain a number of natural gas basins. The most significant of these with respect to the outages and curtailments experienced during the February cold weather event are the Permian, San Juan, and Fort Worth Basins.[62] Together, these three basins are responsible for almost 18 percent of total United States natural gas production.

The San Juan Basin straddles the Colorado and New Mexico border in the Four Corners region, and is a leading coal bed methane producing area. The basin is approximately 270 miles wide and covers over 4,000,000 acres.[63] Production is approximately 2.99 Bcf per day. The Permian Basin is located in West Texas and Southeastern New Mexico. It underlies an area approximately 250 miles wide and 300 miles long,[64] and produces on average 2.52 Bcf per day. The Fort Worth Basin contains the Barnett Shale Formation, with one of the largest producible

[60] *Natural Gas Distribution*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/distribution.asp (last visited Aug. 2, 2011).

[61] In 2009, U.S. dry gas production was 20,580 billion cubic feet (Bcf) or 56.4 Bcf per day. Texas produced 17.5 Bcf per day on and off shore, and New Mexico produced 3.5 Bcf per day. EIA, *Natural Gas Withdrawals and Production*, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm (last visited Aug. 15, 2011).

[62] Other onshore basins in the region include East Texas, the Gulf Coast and South Texas.

[63] La Plata Cnty. Energy Council, Gas Facts: San Juan Basin Map, http://www.energycouncil.org/gasfacts/sjbmap.htm (last visited Aug. 2, 2011).

[64] Charles D. Vertrees, *Handbook of Texas Online: The Permian Basin*, TEX. STATE HISTORICAL ASSN., http://www.tshaonline.org/handbook/online/articles/ryp02\ (last visited Aug. 2, 2011).

reserves of any natural gas field in the United States.[65] The basin produces 4.83 Bcf per day.[66]

Gas processing companies in the San Juan, Permian and Fort Worth Basins include DCP Midstream Partners, L.P., Enterprise Products Partners L.P., Williams Partners, L.P., Southern Union Gas Services, and Frontier Energy, L.L.C.

Natural Gas Pipelines in the Southwest

Intrastate gas pipelines in Texas comprise 45,000 miles out of the 58,600 total miles of gas pipeline in the state. This intrastate network delivers much of the region's natural gas, including deliveries to many large refining and petrochemical facilities, numerous electric generating facilities, and pipeline interconnects.[67] The largest intrastate pipelines in Texas are Enterprise Texas Pipeline LLC (8,750 miles) and the Energy Transfer Partners L.P. (8,800 miles). Other large systems include Atmos Pipeline – Texas (6,162 miles) and the Kinder Morgan Pipeline's Texas Intrastate Natural Gas Group (5,900 miles). Together these pipelines provide for transmission from west Texas supply and market hubs such as Waha, and for gas production in south Texas to the Houston Ship Channel, Katy Hub, the Dallas-Forth Worth area and other markets. Intrastate pipelines have expanded significantly due to increased demand for capacity to transport natural gas from the Barnett Shale Formation in the Fort Worth Basin south to the Katy area or out of the state. The following map shows the Texas intrastate pipeline grid.[68]

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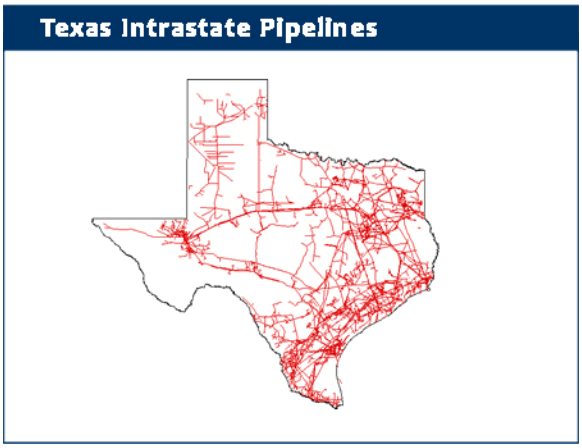
[65] The Perryman Group, *Bounty from Below: The Impact of Developing Natural Gas Resources Associated with the Barnett Shale on Business Activity in Fort Worth and the Surrounding 14-County Area*, at 5 (May 2007), *available at* http://www.barnettshaleexpo.com/docs/Barnett_Shale_Impact_Study.pdf. The Barnett Shale is one of the most significant onshore natural gas fields in North America, with thousands of wells producing hundreds of billions of cubic feet of natural gas each year. Production has risen sharply over the past several years as a result of improvements in recovery techniques.

[66] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek Energy LLC (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; additional materials were also obtained from natural gas pipelines.

[67] EIA, *Natural Gas Pipelines in the Southwest Region*, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/southwest.html (last visited Aug. 2, 2011).

[68] EIA, *About U.S. Natural Gas Pipelines - Transporting Natural Gas:* Intrastate Natural Gas Pipeline Segment, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/intrastate.html (last visited Aug. 2, 2011).

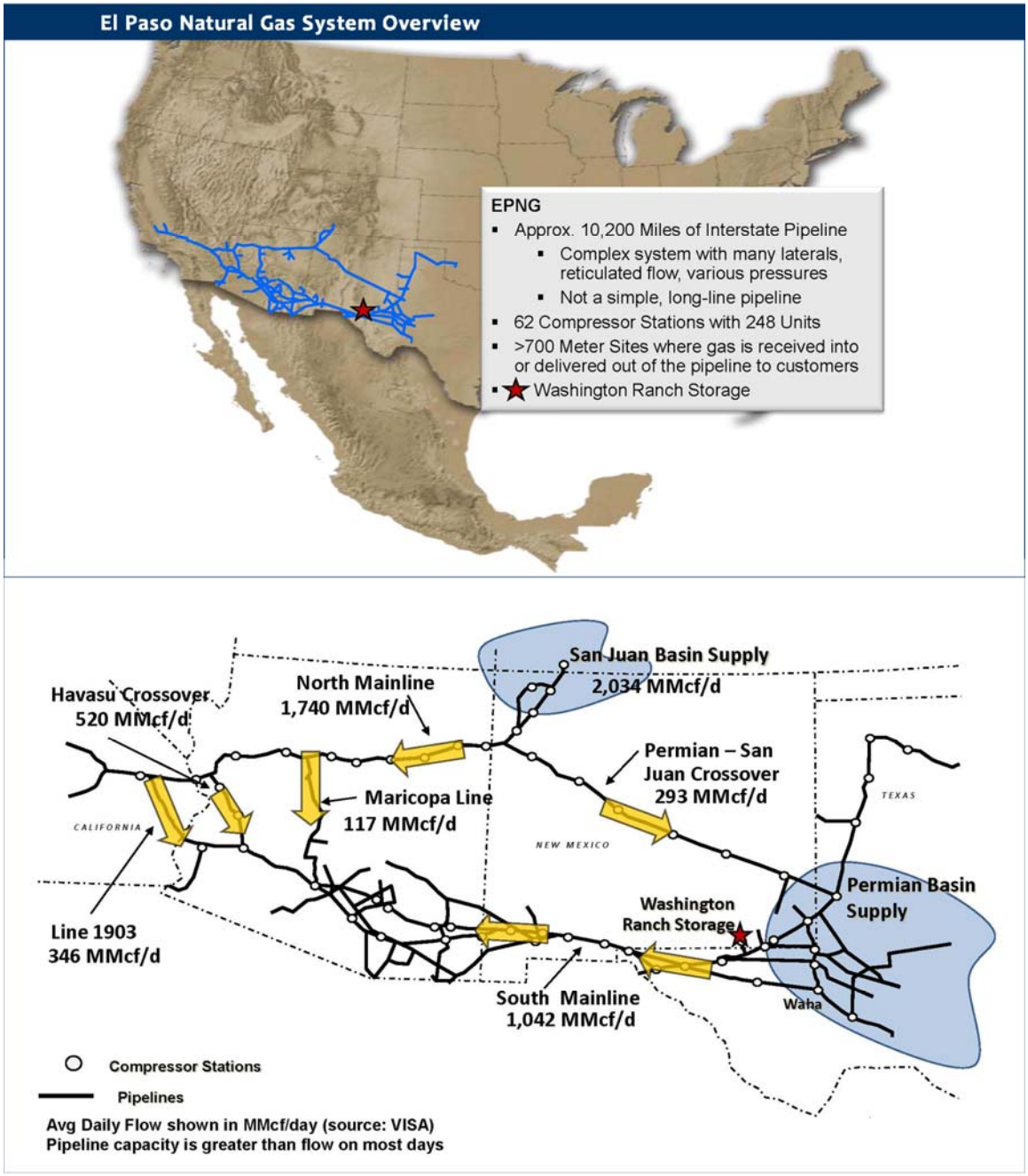


Source: Energy Information Administration

New Mexico and Arizona are supplied largely by two interstate transmission pipelines, Transwestern Pipeline Company, LLC (Transwestern) and El Paso Natural Gas Company (El Paso). These pipelines transport natural gas primarily from the San Juan and Permian Basins to the western regions of the United States. (The many other interstate pipelines that operate in Texas tend to transport gas to the Midwest and Northeast.)

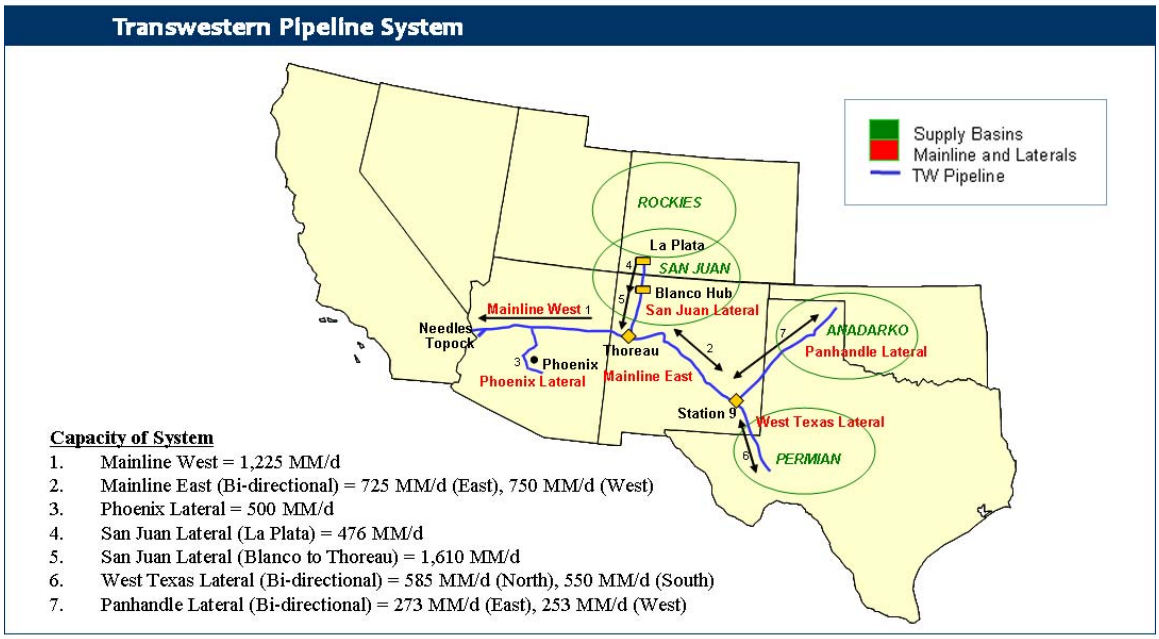
A brief description of these two interstate pipeline systems follows.

El Paso owns a transmission delivery system consisting of approximately 10,200 miles of pipeline. It is a complex, highly networked pipeline system with many laterals and interconnections, operating at a variety of flows and pressures. It includes 62 compressor stations and more than 700 meter sites where gas is delivered. It has 53 delivery meters to New Mexico Gas Company (NMGC), 216 meters to Southwest Gas Corporation (Southwest Gas), and 28 meters to Texas Gas Service. The system also includes the Washington Ranch Storage Field, one of the two storage facilities in the area between west Texas and the Arizona-California border.



Source: El Paso Natural Gas Company

Transwestern has approximately 2,700 miles of pipeline and 26 compressor stations. Its mainline capacity flowing west is 1,225 MMcf/day, and its San Juan Lateral capacity is 1,610 MMcf/day.[69]

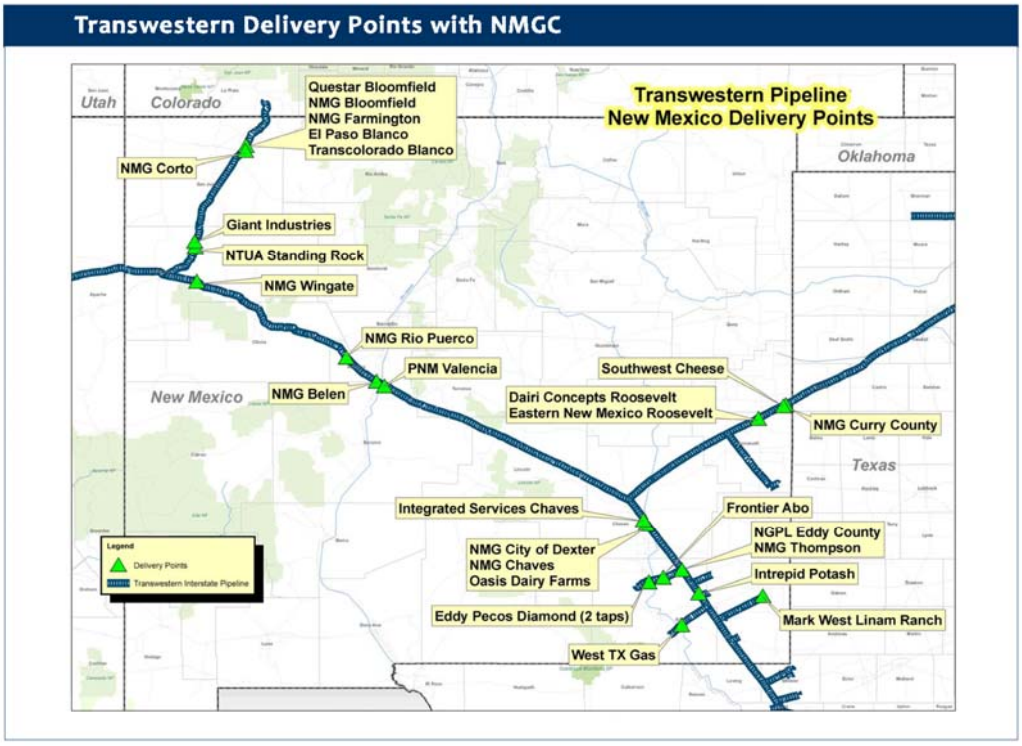


Source: Transwestern Pipeline Company, LLC

Transwestern has at least ten delivery points with NMGC.[70] In terms of flow volumes, the most significant of these during the February cold weather event was the NMG Rio Puerco, as shown in the following map.

[69] Throughout the report, MMcf refers to a million cubic feet, and Mcf to a thousand cubic feet.

[70] http://www.energytransfer.com/ops_interstate.aspx, and materials provided by Transwestern Pipeline Company, LLC to the task force.



These two pipeline companies, Transwestern and El Paso, are the interstate providers to those LDCs that experienced customer curtailments or outages in February 2011. Those LDCs are:

- New Mexico Gas Company, headquartered in Albuquerque. It provides gas service to more than 500,000 customers and maintains approximately 12,000 miles of natural gas pipelines.[71]
- Southwest Gas Corporation, providing gas service to more than 1.8 million residential, commercial and industrial customers in Arizona, Nevada and portions of California.[72]
- Texas Gas Service, the third largest natural gas distribution company in Texas. It provides gas to more than 603,000 customers in Austin, El Paso, and Rio Grande Valley areas as well as Galveston, Port

[71] New Mexico Gas Company, *About Us*, http://www.nmgco.com/about_us.aspx (last visited Aug. 2, 2011).

[72] Southwest Gas Corporation, *Profile of Southwest Gas*, http://www.swgas.com/about/aboutus/index.php (last visited Aug. 2, 2011).

Arthur, Weatherford and several communities in the Permian Basin and the Texas panhandle. [73]

- Zia Natural Gas Company, which provides gas service to over 35,000 customers in five New Mexico counties, serving primarily residential and small commercial users. In Lincoln County, where the city of Ruidoso experienced gas outages during the February event, Zia obtains gas from a direct interconnection to the El Paso Natural Gas pipeline.

Natural Gas Storage Facilities in the Southwest

There are two major natural gas storage facilities in the Southwest:

- **Washington Ranch Storage Field**, part of the El Paso system, is located in Eddy County, New Mexico, approximately nine miles southwest of Whites City. This facility has a working storage capacity of slightly more than 47.6 bcf and a maximum daily withdrawal capacity of 250,000 Mcf.

- **Chevron Keystone Storage Facility**, owned by Chevron Corporation, is located in Winkler County, in west Texas near Midland. This is a salt cavern facility with 6.38 Bcf of working gas. Its maximum daily injection capability is 200,000 Mcf and its maximum daily withdrawal capacity is 400,000 Mcf. It has interconnects to Transwestern, El Paso and the Northern Natural Gas Company's pipeline systems.

[73] Texas Gas Service, *Profile*, http://www.texasgasservice.com/en/About.aspx (last visited Aug. 2, 2011).

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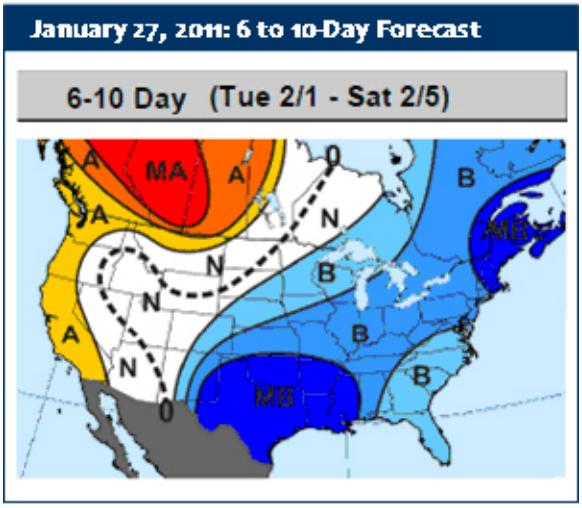
IV. Preparations for the Storm

A severe arctic cold front hit the central and northeastern United States and southern Canada on February 1, 2011, and lasted for several days. It was dubbed the "Groundhog's Day Blizzard of 2011."[74] The front was not unexpected. About a week prior to the event, long-range forecasts predicted an outbreak of very cold temperatures for the first week of February, with wind, ice, and snow from Texas to Mississippi. Arctic air was expected to extend southward to the Gulf Coast by February 2, bringing daytime highs to as low as 30 degrees below normal. Sustained winds of 20-25 mph, with higher gusts, were also anticipated.[75]



[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.][76]

[74] National Oceanic and Atmospheric Administration National Climatic Data Center (NCDC), *State of the Climate: Global Hazards for February 2011*(March 2011), http://www.ncdc.noaa.gov/sotc/hazards/2011/2#winter.

[75] Weather data used in this section is drawn from NCDC data. Raw land-based observation data was obtained at http://www.ncdc.noaa.gov/oa/land.html. Quality controlled local climatological data was obtained at http://cdo.ncdc.noaa.gov/qclcd/QCLCD?prior=N. Additional data, unless otherwise noted, is drawn from materials provided to the task force by BAs, transmission operators, generators, producers, processing plants, pipelines and LDCs.

[76] EarthSat is a private forecasting service used by many entities in the energy industry and by the Commission in connection with its market monitoring efforts.

A. Weather Conditions During the Event

Actual weather conditions between February 1 and 5, 2011 turned out to be largely as predicted by the National Weather Service's long-range forecasts. However, actual temperatures were a few degrees lower than forecasted, especially in west Texas and New Mexico. In some places, temperatures did not rise above freezing until February 4. Low temperatures in Albuquerque ranged from -7 degrees to 7 degrees over the four-day period, in Midland from 6 degrees to 12 degrees, and in Dallas from 13 degrees to 19 degrees.[77]

As the storm hit during the early morning hours of Tuesday, February 1, temperatures in the western-most cities of the Southwest plummeted dramatically. Daily highs at Albuquerque and Dallas fell 20 degrees (to 28 degrees and 39 degrees respectively) from the previous day, while at Midland the recorded high was 30 degrees, which was 43 degrees below that of the previous day. Houston's temperatures started out on February 1 at 70 degrees, but by 7:00 AM had dropped to 45 degrees.

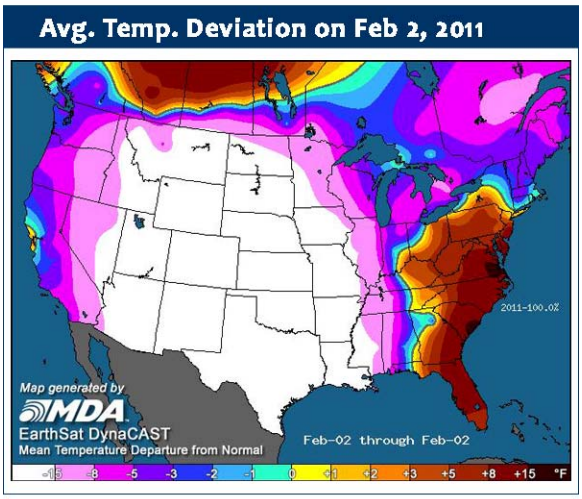
The wind profile was also changing dramatically. Wind speeds had rarely exceeded 10 mph the preceding day, but by the morning of February 1 Albuquerque was experiencing sustained wind speeds of 20 mph (representing a wind chill index of 4 degrees), with gusts to 27 mph. Winds in Midland hovered around 20 mph and gusted to over 30 mph. Light snow began falling in both cities around midnight. It was also windy in Dallas on February 1, with speeds of up to 25 mph and gusts between 20 and 40 mph.

Conditions worsened at all locations through the day, and by midnight temperatures were extremely low. Albuquerque was at 4 degrees, with continuing high winds and snow. Temperatures at Midland were 14 degrees and at Dallas 16 degrees. The cold air finally hit Houston late in the day, with temperatures of 27 degrees and winds of 14 mph, although without precipitation.

By Wednesday, February 2, early morning conditions had become severe. In Albuquerque, the temperature at 8:00 AM was 1 degree, almost 40 degrees below the average for that date, and the wind was blowing at 26 mph. Temperatures in El Paso and Midland hovered around 10 degrees for much of the day, with wind speeds of 15 mph. El Paso set a record low for the day of 6 degrees at 5:00 AM, and recorded the third coldest day in 38 years. In fact, February 2 turned out to be one of the coldest days on record in the last 25 years across the state of Texas, with average temperatures well below freezing and only

[77] All temperatures in this report are in degrees Fahrenheit.

Brownsville escaping severe conditions (with average temperatures of about 35 degrees). Significant winds accompanied the frigid temperatures, with wind chill factors dropping the perceived temperatures to -6 degrees in Dallas and 6 degrees in Austin.



Source: MDA EarthSat

On Thursday, February 3, weather conditions began to marginally improve in some areas, although in Albuquerque and El Paso it would rank as the coldest day in 38 years. Albuquerque, Midland and El Paso were still experiencing highs near 15 to 20 degrees, but the winds had begun to diminish. From Dallas to San Antonio, temperatures moderated about 5 to 10 degrees, but wind speeds remained high.

On Friday, February 4, conditions improved across the region. Temperatures in the western cities finally rose above freezing, and in a few of the eastern-most cities rose above 40 degrees. Nonetheless, during the early morning hours, El Paso hit a low of 3 degrees before reaching a high of 37 degrees, ranking the day as the city's second coldest in 38 years. Four to six inches of snow fell in the Dallas Metropolitan area, causing cancellation of more than 300 flights at Dallas airports just as fans were arriving for the Super Bowl.

Cold weather hit the region again on February 9 and February 10. The coldest temperatures were seen on February 9, when El Paso recorded a low of -2 degrees, and Midland a low of 7 degrees. Daily highs, however, were in the 30s and 40s. Other cities saw lows dip into the 20s and teens, with high temperatures rising into the 40s and 50s.

There is no question that the cold and windy weather during this first week of February was both sustained and severe. Just how severe, when compared to

prior storms, is examined in the section of this report entitled "Prior Cold Weather Events."

B. Preparations for the Storm: Electric

Three balancing authorities in the Southwest shed load during the cold weather event: ERCOT, SRP and EPE. (PNM lost some 26 MW of load as well, although this was the result of localized transmission issues largely unrelated to the storm). Customers in ERCOT were affected the most, by a large margin. ERCOT shed 4000 MW of load, affecting 3.2 million customers, on February 2. It shed another 300 MW on February 3, affecting 180,000 customers. In comparison, SRP shed 300 MW of load, affecting 65,000 customers, and EPE shed a little over 1000 MW of load, affecting 253,000 customers.[78]

The preparations for the storm taken by these three entities are discussed below.

ERCOT

Going into the winter season of 2010/2011, ERCOT had substantial reason to believe it could meet its projected demand with available generation and imports. ERCOT's peak demand for the winter of 2010/2011 was forecasted to be 47,824 MW, with the peak anticipated to occur in January.[79] (This forecasted peak was 11 percent higher than the forecasted peak for the previous winter.[80]) To meet that peak demand, ERCOT had projected generation capacity plus imports of 72,881 MW.[81] Thus, for planning purposes, ERCOT could anticipate a

[78] In the case of ERCOT, these numbers represent the amount of load the transmission providers were directed to shed. Actual load shed was somewhat higher (5411.6 MW on February 2 and 459.5 MW on February 3), for reasons discussed in the section of this report entitled "The Event: Load Shed and Curtailments."

[79] NERC, *2010/2011 Winter Reliability Assessment*, at 16 (Nov. 2010), *available at* http://www.nerc.com/files/2010_Winter_Assessment_Final_Posted.pdf. NERC prepares its reliability assessments based on data and information submitted by the applicable Regional Entity, which in ERCOT's case is TRE.

[80] ERCOT modified the forecasting models because it had experienced extreme cold weather in January of 2010, with load tracking notably higher than forecasted.

[81] Resources listed in the NERC 2010-2011 Winter Reliability Assessment consisted of available generation (72,500 MW) and net firm imports (381 MW), and did not include generating units which were known well in advance to have scheduled maintenance outages spanning the expected peak load period. Demand was calculated based on a 50/50 load forecast (47,824 MW), meaning the forecast is expected to be exceeded five years out of every ten.

comfortable reserve margin of 57 percent. This percentage compares favorably with NERC's reference reserve margin for ERCOT of 13 percent, considered by NERC to be the base level required for reliability.[82]

The estimated demand for the season included only firm load, and therefore did not include ERCOT's two categories of contractually curtailable load: Load Resources (formerly designated as Load Acting as a Resource, or LaaR), which may be automatically disconnected when system frequency drops below a prescribed threshold (totaling 1062 MW as of February 2); and Emergency Interruptible Load Service (EILS), which permits curtailment prior to firm load shedding (totaling 331 MW as of February 2).

Although ERCOT seemingly had a generous reserve margin going into the winter of 2010/2011, the reserve margin cited did not take into account planned outages that were not yet known at the time of the forecast. ERCOT is a summer-peaking system, and the high summer temperatures and demand often extend into what would be considered shoulder seasons in more northerly regions. For that reason, it is not unusual for generators in ERCOT to schedule maintenance outages in February. ERCOT does not have the authority to prohibit generators from scheduling such outages or from taking them as scheduled, unless the outage is scheduled eight days or less before the outage date, or the outage would keep ERCOT from meeting applicable Reliability Standards or its own Protocol requirements.[83] At most, pursuant to its Protocols, ERCOT can ask generators to refrain from taking a scheduled outage if it believes it may need the generator's output. ERCOT also does not have authority under its Protocols to require generators that are on planned outage to come back into service early (assuming the generator is even in a condition to do so). Nor are there any market mechanisms to compensate generators for any costs associated with delaying or coming back early from a scheduled outage.

Despite these potential limitations, ERCOT was far from being generation deficient for winter 2010/2011 seasonal planning purposes. Nor, as will be seen, did it appear to be deficient going into the storm itself. A little background is needed to put in context the generation that ERCOT thought it would be able to call upon during the storm.

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[82] NERC 2010/2011 Winter Reliability Assessment at 16.

[83] ERCOT Nodal Protocols § 3.1 (Nov. 20, 2010), *available at* http://www.ercot.org/mktrules/nprotocols/2010/index. ERCOT is considering revising this provision to permit it to deny an outage request if it is scheduled 90 days or less from the outage date.

ERCOT uses proprietary forecasts (performed both on a seasonal and daily basis) to predict its load.[84] ERCOT used those weather forecasts, coupled with historical and other information, to gauge expected customer demand during the approaching event. A task force review of ERCOT's forecasts determined that they accurately predicted the February storm conditions, and in some cases their weather estimates were even slightly more accurate than those of the National Weather Service.

ERCOT then compared the anticipated demand[85] against its generation capacity, both for purposes of scheduling power in the day-ahead market and for determining whether it would meet reliability and reserve requirements. For operating purposes, ERCOT's Protocols include a responsive reserve requirement (also referred to as Physical Response Capability, or PRC) of 2300 MW. The primary purpose of the responsive reserves is to restore system frequency to 60 Hz within the first few minutes after the system experiences a significant frequency deviation. The 2300 MW amount is based on a 1988 study that determined the reserves that would be needed to prevent the shedding of firm load upon the simultaneous loss of the two largest generation resources in the ERCOT region.[86] (Actual online responsive reserves at any given time typically exceed the 2300 MW requirement.[87])

ERCOT Protocols

The ERCOT protocols set forth the procedures and processes used by ERCOT and its market participants for the orderly functioning of the ERCOT system and market. They contain

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[84] ERCOT relies on Telvent DTN and Pattern Recognition Technologies (PRT) for the weather data used in its load forecasts.

[85] ERCOT's load forecast projected loads of 52,673 for February 1 and 57,436 for February 2.

[86] This is a more conservative measurement than that required by NERC Reliability Standard BAL-002-0 R3, which sets a "contingency reserve" requirement to cover the loss of the single largest contingency on a Balancing Authority's or Reserve Sharing Group's system (N-1), not the loss of the two largest contingencies. Because ERCOT is not synchronously linked with other interconnections, a larger reserve amount than N-1 is required to maintain proper frequency response.

[87] ERCOT's daily morning report listed responsive reserves of 4196 MW for February 1 and 5944 MW for February 2, projected for the peak hours of those days.

policies for scheduling, operations, planning, reliability, and settlements, as well as ERCOT's rules, guidelines, procedures, and standards. The protocols are developed and amended through stakeholder committees for approval by the ERCOT Board of Directors. Once approved at ERCOT, the protocols are submitted to the PUCT for final approval. In addition to its task of enforcing the FERC-approved Reliability Standards, TRE is responsible for compliance monitoring and enforcement of the ERCOT Protocols.

In addition to the responsive reserve requirement, ERCOT must meet a non-spinning reserve requirement.[88] These reserves are intended to address the risks of load uncertainty and wind power output variability. For February 2011, the non-spinning reserve requirement was set at 2000 MW. (The sources counted for non-spinning reserves are not included in the calculation of available resources for purposes of meeting the responsive reserve requirement of 2300 MW.[89])

Notwithstanding the fact that 11,566 MW of generation were on scheduled outage as of February 1,[90] ERCOT had more than 3100 MW of responsive

[88] Non-spinning reserves in ERCOT are generation resources capable of being ramped to a specified output level within thirty minutes and running at that level for at least one hour, or Load Resources that are capable of being interrupted within thirty minutes after being asked for interruption and remaining de-energized for at least one hour.

[89] Wind resources, which are forecasted on an hourly basis, are also not included in the calculation of available resources for purposes of meeting the responsive reserve requirement. One of the most significant differences between the NERC Winter Assessment and ERCOT operations is how wind power is handled. The NERC Winter Assessment assigns a fixed average output of 8.7 percent of nameplate rating as "existing-certain" generation capacity. For the 9317 MW of installed wind capacity (aggregate nameplate rating) in ERCOT, this amounts to 811 MW. Operations, on the other hand, utilizes wind power forecasts derived from highly localized wind speed forecasts, which provide wind power output values for each of the upcoming 48 hours. The forecasts are re-run hourly and the results updated accordingly, yielding a "rolling" 48 hour look-ahead. ERCOT's Current Operating Plan (COP) for wind power uses a conservative estimate which has an 80 percent chance of being met or exceeded, and already takes into account any equipment outages, either scheduled or forced. On the morning of February 2, the aggregate COP for wind power peaked at about 5200 MW at 3:00 AM and decreased steadily each hour down to 3500 MW at 8:00 AM. The actual wind power output followed the same downward trend, but fell short off the COP numbers anywhere from 400 MW to 1000 MW, depending on the specific hour. (This snapshot picture exhibits the variability of wind power.)

[90] This number grew to 12,413 MW on February 2; however, the additional units might have been ones that experienced forced outages on February 1 and then transitioned into scheduled outages.

reserves available throughout the entire 24 hours of that day, running as high as 5600 MW in the early morning and again during the mid-afternoon hours. This exceeded the responsive reserve requirement of 2300 MW by a comfortable amount.[91]

Thus, on paper, ERCOT had reason to believe it had ample generation going into the storm.[92] As it turned out, the large number of generator outages, derates and failures to start that occurred on February 1 and February 2 would reduce that margin below acceptable levels.

Aside from determining it had sufficient operating reserves listed as available, ERCOT took other steps to prepare for the storm. On January 31, ERCOT issued an Operating Condition Notice (OCN) to its market participants, advising them of the expected cold front. On February 1, it issued another OCN at 2:45 AM and an Advisory at 9:05 AM. ERCOT also reported to the PUCT that it was expecting temperatures in the teens to the low 20s and maximum temperatures near or below freezing, with anticipated impacts on 50 percent or more of its major metropolitan areas.[93]

Notices and Emergency Declarations

The ERCOT Protocols set out three types of preliminary notices to be issued by ERCOT to inform market participants of a potentially adverse operating condition, including extreme weather conditions such as hurricanes and protracted periods of below-freezing temperatures. The type of notice is determined based on the time available for the market to respond before an emergency condition may occur.

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[91] On February 2, responsive reserves would hover in the range of 2700 MW to 3300 MW in the early morning hours, dropping to around 3000 MW at 4:30 AM and then plummeting rapidly.

[92] In addition to the outages already underway, three planned generation outages were scheduled to begin during the time period covered by the anticipated storm. ERCOT requested one of these generators to delay the outage, as discussed later in the report.

[93] ERCOT did not provide any further market notices or indications of projected capacity shortages until 3:00 AM on February 2, when it issued an OCN and an Advisory reporting that reserves were below 3000 MW. These notices, as well as the other actions that took place on February 2, are discussed in the following section of this report entitled "The Event: Load Shed and Curtailments."

- Operating Condition Notice -- issued to inform participants of a possible future need for more resources due to conditions that could affect system reliability; allows ERCOT to confer with transmission providers and participants regarding the potential for adverse reliability impacts and contingency preparedness when adverse weather conditions are expected.

- Advisory -- issued when conditions are developing or have changed such that more ancillary services will be needed, or when weather or conditions require more lead-time than the normal day-ahead market allows; allows ERCOT to increase ancillary services requirements above the quantities originally specified in the day-ahead market, and to require information from participants regarding their fuel capabilities for the next seven day period.

- Watch -- issued when additional ancillary services are needed in the current operating period, or when forced outages or abnormal operating conditions have occurred or may occur that require operating with transmission security violations; allows ERCOT to instruct transmission owners to reconfigure ERCOT system elements to improve reliability in ERCOT; and allows ERCOT to take steps to procure additional regulation services, RRS services, and non-spinning services.

ERCOT issues the fourth level of Notice, an Emergency Notice, when it cannot maintain minimum Reliability Standards or meet its Protocol requirements during the operating period or is otherwise in an unreliable condition. Depending on the severity level, ERCOT may take additional steps to resolve the system emergency, including relaxing transmission constraints, issuing public appeals for conservation, deploying Load Resources and EILS resources, and requiring firm load shedding.

Between January 28 and January 31, ERCOT cancelled, withdrew, or delayed planned outages on ten 345 kV transmission lines, 27 138 kV transmission lines, two 345/138 kV auto-transformers and one 138/69 kV transformer (outage cancellation rules differ as between transmission and generation). On January 31, ERCOT requested one generating unit (Mountain Creek SES Unit 8 at 568 MW) to begin start-up due to its long start-up lead time, and requested another unit (Lake Hubbard SES Unit at 397 MW) to convert from natural gas to fuel oil in anticipation of possible gas curtailments.[94] ERCOT reports that it did not request any generators to return early from scheduled

[94] Texas Reliability Entity, *Event Analysis Report – Feb.2, 2011 EEA-3 Event* at 16 (Apr. 15, 2011) (TRE Report).

outages, nor did it request any generators to defer scheduled outages that were slated to start during the cold weather event.[95]

In the afternoon of January 31, ERCOT decided to adjust its load forecast to factor in the potential effect of the high winds that had been predicted (ERCOT's forecasts do not normally factor in wind chill effects). ERCOT made a manual adjustment to its load forecast for the remainder of February 1 and for February 2, adding 4000 MW.

The storm hit on February 1. Beginning at approximately 12:00 PM on that day, power plants across Texas experienced problems due to the cold weather. These included freezing instrumentation, freezing pipes, freezing drain lines, natural gas curtailments, and natural gas pressure reductions due to high usage.[96] Between noon and midnight on February 1, two large coal units and 18 natural gas units tripped or failed to start for varying periods of time. Another six natural gas units and 13 wind plants were derated during this period. As of midnight on February 1, unavailable generation capacity in ERCOT (not counting scheduled outages) reached 6022 MW.[97]

In addition to the generation scheduled for February 2 by its economic dispatch model, ERCOT committed 24 additional generating units, totaling 3400 MW, through its reliability unit commitment (RUC) process.[98] By midnight, all available generation had been instructed to run on February 2.

[95] ERCOT did discuss with generators deferring scheduled outages planned for the February 10 period, when cold weather was again anticipated. Some of those scheduled outages were postponed.

[96] TRE Report at 7. The details of the types and causes of the forced outages experienced during the February 1-5 weather event are discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions."

[97] This is a net cumulative number; that is, if a failed unit came back online, it is not counted as unavailable.

[98] ERCOT initially committed 13 units through the RUC process on February 1, to be deployed on February 2; it later cancelled six of those unit commitments, leaving a net value of 2049 MW in additional generation as of midnight on February 1. At 3:03 AM on February 2, ERCOT committed 19 units through its RUC process, totaling 1351 MW. Unit generation added on both days through the RUC process for February 2 deployment totaled 3400 MW.

ERCOT's RUC Process

After ERCOT completes the run of its day-ahead market, which matches buy and sell offers for energy and ancillary services for the following operating day, ERCOT runs a Day-Ahead Reliability Unit Commitment (DRUC) study to ensure that sufficient capacity is available to serve load. For each hour of the following day, the DRUC examines whether sufficient resources have been committed, through Day-Ahead awards or as otherwise reflected in each resource's Current Operating Plan (COP), to meet the forecasted load for each hour. If ERCOT determines that any additional resources are needed, it can physically commit those resources for the hours needed, with certain payment levels guaranteed to the resources when ordered to run.

ERCOT runs the DRUC study in the afternoon prior to the operating day studied. Hourly RUC (HRUC) studies are run thereafter, comparing resources and load for each hour remaining in the DRUC period and reflecting any changes in resource commitments (such as forced outages or modified COPs) or other changes in system conditions since the DRUC was run.

The RUC process takes into account resources committed in the Day-Ahead market, resources self-committed in the COPs, and resources committed to provide ancillary services. The RUC process can also recommend decommitment of resources where transmission constraints are not otherwise resolvable. ERCOT can order any available resource to come online as part of the RUC process.

If a resource is selected by the RUC, the resource will at a minimum be made whole for its startup and minimum-energy costs. However, if the energy revenues received during the RUC-commitment period are greater than these guaranteed costs, the resource may be subject to a "clawback" under certain conditions.

Could or should ERCOT have done more to prepare for the event? ERCOT procedures specifically include provisions for severe cold weather operations.[99] In anticipation of severe cold weather, ERCOT may issue an OCN, Advisory, Watch, or Emergency Notice. These various alerts allow ERCOT to react to potential operating conditions by: reviewing planned and existing outages; determining if more lead-time is needed for generating resources to meet their commitments than the normal day-ahead market allows; determining if additional ancillary services are required; ordering on additional units; and increasing staffing. Under the

[99] ERCOT Operating Procedure Manual: Shift Supervisor Desk § 7.5 (July 18, 2011), *available at* http://www.ercot.org/mktrules/guides/procedures/. Severe cold weather is defined by expected temperatures in the mid to low 20 degree range with expected maximum temperatures near or below freezing, impacting 50 percent or more of major metropolitan areas.

various alerts, ERCOT's RUC Operator may also confer with transmission operators and QSEs[100] regarding preparedness, fuel capabilities, the need to reconfigure system elements, or to vary from market timing deadlines.[101]

In anticipation of the event, ERCOT arguably could have better utilized these tools to prepare for the severe cold weather, particularly by increasing ERCOT's responsive reserves well in advance of its decision late on February 1 to schedule all available units for the next day.[102] As events proved, the extensive generator outages substantially exceeded ERCOT's reserves, and would have done so even if the reserves had been substantially larger in number. But this was not known by ERCOT going into the event. Furthermore, if generating units had been online and running, they would have been better able to withstand freezing temperatures,[103] a consideration ERCOT might have factored into its decision-making process.

Another strategy that might have improved generator response would have been the use of pre-warming techniques.[104] ERCOT does not currently have the authority to require generators to engage in these actions, but if generators had done so, they might have prevented some of the extensive freezing problems that developed. Running quick start units prior to their scheduled start time could also

[100] A "Qualified Scheduling Entity" (QSE) is a market participant qualified by ERCOT as a resource entity or a load serving entity, for purposes of communications with ERCOT and the settling of payments and charges.

[101] ERCOT Operating Procedure Manual, Reliability Unit Commitment Desk, Section 6.1 (July 20, 2011), *available at* http://www.ercot.com/mktrules/guides/procedures/.

[102] ERCOT Protocols formerly required it to increase its spinning reserves by an amount at least equal to its responsive reserves during cold weather alerts. *See* Elec. Reliability Council of Tx., *ERCOT Operating Guide No. 12* (May 1989). ERCOT advised the task force that this protocol had been changed to account for the variability of wind power. ERCOT now carries non-spinning reserves continuously rather than only during peak hours, as was its former practice. ERCOT stated its belief that the continuous availability of non-spinning reserves serves virtually the same purpose as the former practice of doubling the spinning reserves.

[103] The use of a generating unit's own radiant heat to prevent freezing is discussed in the section of the report entitled "Key Findings and Recommendations."

[104] For conventional gas steam units, pre-warming can be accomplished by establishing a fire in the boiler to produce warming steam for the turbine while it is on turning gear. This keeps metal temperatures warm enough to prevent freezing in piping and instrumentation lines and helps bring lubricating and hydraulic oils up to proper operational temperatures. Combustion turbines can run at full speed no-load operation for short periods of time prior to start up, in order to warm vital parts, instrumentation, and lubricating oils.

have identified problems before the output of the units was needed, giving them time to make corrections.[105]

Had ERCOT and the generators undertaken these additional measures, it is possible that fewer generating units might have failed. ERCOT might still have been forced to shed load, but the extent of the load shed might well have been reduced. Every generator that could have escaped failure on February 1 and February 2 would have improved the situation for Texas consumers.

ERCOT Generators

Most generators in ERCOT's footprint reported having employed freeze protection measures to protect their facilities. These measures generally fell into two categories: physical readiness and operational readiness.

To prepare physical facilities for the cold weather, generators variously reported that they installed portable heaters to maintain ambient air temperature, added extra insulation to exposed components, installed temporary windbreaks to exposed areas, drained non-essential water systems, and determined that the water in essential water systems was circulating.

Some generators also reported adjusting their operations to adapt to the cold weather. They called in more operating and maintenance staff, increased the frequency of operator rounds, performed checks of freeze protection panels and heat tracing circuits, and added windbreaks. Plant staff also tested emergency equipment, added fuel to heaters and emergency generators, stocked extra supplies of fuels as well as food and other emergency items in case deliveries were disrupted, and prepared sleeping arrangements for employees if roads became impassable. Some generators utilized pre-operational warming during the event.[106]

Despite these reports of having taken steps to prepare for the cold weather event, many generating units in ERCOT failed to perform or suffered derates after

[105] On February 1 and 2, approximately 19 simple cycle and combined cycle units in ERCOT tripped for non-weather related causes and were restored within two hours. Many of the simple cycle and combined cycle unit trips occurred immediately during start-up sequences or very soon after synchronization.

[106] On February 10 as well, some generators utilized pre-operational warming for that day's cold weather snap. At least five generators kept their units running, started units earlier or took other measures to keep from having a "cold start." These generators credited these strategies for their improved performance on that date.

the storm hit. And they failed, in the majority of cases, because of weather-related problems. The various generator outages and their causes are examined in the section of this report entitled "Causes of the Outages and Supply Disruptions."

Salt River Project

SRP is a vertically integrated utility and owns its own generation, transmission, and distribution facilities. Its preparations for inclement weather therefore needed to encompass all three functions. In terms of its forecasting, SRP uses an Artificial Neural Network Short-Term Load Forecaster model, which projects control area loads. This model incorporates SRP's own meteorologist's weather forecast as well as hourly historical load data. SRP reported that while weather on February 2 matched its weather forecasts, its load forecast was lower than actual load demands. The disparity, however, was within five percent.

SRP has generating facilities located throughout central and northern Arizona. Winter temperatures tend to be mild in and around the Phoenix Valley but can be noticeably colder in the more remote areas where the company's two coal burning facilities are located. SRP reports that it carries out preventative maintenance for facilities that have winterization equipment, which generally consists of heat tracing[107] and insulation. Gas-fired generating plants in and around the Phoenix valley use winterization equipment to protect against expected conditions, while hydro generating facilities are almost exclusively contained inside protected buildings. SRP's coal generating facilities at the Coronado and Navajo stations have winterization systems that consist mostly of heat tracing and insulation. SRP advised the task force that every year in the fall, planners for the Coronado and Navajo stations develop work orders to inspect and test these winterization systems to verify they are working properly, and that during the winter months, staff conduct weekly winterization and freeze protection equipment checks.

SRP's immediate preparations for the February event were limited. It did not issue a cold weather alert in advance of the storm.[108] SRP reports that management at the Navajo Generating Station did inform its operators at the beginning of shifts that cold weather was approaching, and inquired if there was anything the employees needed to help them do their job. SRP does not employ a

[107] Heat tracing refers to the application of a heat source to pipes, lines, and other equipment.

[108] Indeed, the only alert the SRP Balancing Authority provided to generators was a "Capacity Alert," indicating that maintenance and operations activities on all operating generating units were to be stopped.

formal checklist of activities that should be carried out prior to a winter storm, and the company reported that the Operations and Maintenance Group at the Navajo Generating Station did not take any formal actions to prepare the station for the anticipated severe weather. However, SRP informed the task force that the group did hold meetings at which the need for staff to frequently check the generating equipment for potential weather-related problems was emphasized.

El Paso Electric

Like SRP, EPE is a vertically integrated utility. It reported to the task force that at the beginning of the winter of 2010/2011, as at the beginning of every winter, it took steps to winterize its generating facilities. This winterization included verifying that heat tracing was properly functioning, as well as making sure insulation was properly installed.

EPE also reported that it verified that the equipment in its substations, the part of the transmission and distribution system most susceptible to cold temperature extremes, could withstand the expected cold temperatures.

On January 31, 2011, EPE initiated preparations for the anticipated severe weather, which included verifying winterization of generation, transmission and distribution facilities, reviewing system operations plans, checking on the availability of fuel, preparing for potential pipeline constraints, and placing employees on call as needed during the weather event. The Systems Operations group requested EPE's Power Marketing and Fuels group to keep additional generation online. In response, the Power Marketing and Fuels group made arrangements to leave on Rio Grande Unit 6, to continue with the start-up of Newman Units GT-3 and GT-4, and verified the ability of Newman Unit 3 to operate on fuel oil.

In contrast to some other areas in the region, EPE reported that actual weather during the event was more severe than forecasted (and significantly colder than historical temperatures). For February 2, EPE reported that the actual high temperature in El Paso was 15 degrees compared to a forecasted high of 37 degrees, and the actual low temperature was 6 degrees compared to a forecasted low of 14 degrees. The forecasted high for February 3 was 30 degrees, compared to an actual high of 18 degrees, and the forecasted low was 14 degrees, compared to an actual low of 1 degree. For February 4, the last day of the freeze event in EPE's service territory, the forecasted high of 43 degrees compared to an actual high of 37 degrees, and a forecasted low of 21 degrees compared to an actual low of 3 degrees. EPE did not report the exact location for its temperature statistics, but presumably they occurred in the west Texas and New Mexico regions.

C. Preparations for the Storm: Natural Gas

Varying levels of preparation for the February cold front were employed by the producers, processing plants, interstate pipelines, intrastate pipelines, and LDCs that together make up the natural gas delivery chain. Depending on the type of facility, preparations included at least one, if not several of the following items: monitoring the weather, increasing staffing, methanol injection, pigging, insulation, tarps, heat tracing, building line pack[109] in pipelines by injecting more gas, over-purchasing gas supplies and enhancing winterization equipment. For the most part, facilities began their preparations by either Sunday, January 30 or Monday, January 31.

This section describes the preparations taken by individual companies in west Texas, the Texas panhandle, north Texas and New Mexico and by the LDCs in Arizona and New Mexico.

Producers

As discussed in detail in the section of this report entitled "Causes of the Outages and Supply Disruptions," the difficulties encountered by LDCs in trying to meet customer demand stemmed principally from supply declines in the basins, and secondarily from problems encountered at processing plants. The preparations for the cold weather event taken by producers is therefore of special interest.

Of the 15 producers who provided information to the task force on this issue, all reported that they had used winterization techniques of one sort or another. The following table shows by basin the numbers of producers that used one of or more of the listed methods.

[109] Line pack refers to the volume of gas in the system at any given point in time.

	PERMIAN	SAN JUAN	FORT WORTH	EAST TEXAS	TEXAS GULF
Methanol Injection or Drip	✓✓✓✓✓✓✓	✓✓✓	✓✓✓✓✓	✓✓✓✓✓✓✓	✓✓✓✓✓✓
Increased Pigging or Clearing of Liquids	✓✓✓	✓	✓✓	✓	✓
Tarps or Cold Weather Barriers	✓	✓✓		✓✓	✓✓
Increased Hauling of Fluid	✓✓	✓	✓✓✓	✓✓✓	✓✓
Heated Anti-Freeze		✓			
Heat Trace	✓	✓✓	✓	✓✓✓✓	✓
Hot Oil Trucks	✓				
Insulation	✓✓✓	✓	✓✓	✓✓	
Burial of Lines	✓				
Heat Lamps or heaters	✓✓	✓			✓

A short description of some of these techniques gives a fuller picture of the actions the producers reported having taken:

- Methanol (an anti-freeze type solution) injection or drip is a common practice for freeze protection of wellbores and pipelines. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. Also, separators (used to separate liquids such as oil from the natural gas) may be filled with heated antifreeze to prevent freezing.

- Pigging refers to the practice of using pipeline inspection gauges or "pigs" inside a pipeline to perform various operations without stopping the flow of gas. Pigging operations are conducted on a year-round basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased to remove liquids that might be prone to freezing.

- Cold weather barriers are a relatively simple weather precaution involving the erection of wind walls around certain compressors to block cold winds that exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines and other locations may also help prevent freezing and the stoppage of fluid flow.

- Hauling oil and produced water from storage tanks is a necessary part of the production process, since tanks that are not emptied can trigger fail safe shut-in devices that will automatically shut down the well. Prior to cold weather, and in anticipation of trucks not being able to reach the facilities, the tanks may be emptied to reduce the likelihood of automatic shut-off.

- Heat can prevent freezing problems; if the gas is never allowed to reach freezing temperatures, ice cannot form. However, heat application involves expensive equipment and requires additional fuel. Heat is also a potential hazard as it can provide an ignition point for the gas. Nonetheless, heat systems can be very effective for a localized freezing problem, and include heating blankets, catalytic heaters, fuel line heaters, or steam systems. Coupling heat systems with insulation is a common technique for protecting flow lines in northern climates.

- Hot oil trucks may be utilized to thaw out flow lines. Typically the hot oil truck will be filled with water, which is then heated and directly sprayed onto lines at risk of freezing.

As it turned out, the various measures producers described as having employed to prepare for the projected cold weather proved inadequate; a substantial number of wells in the affected basins suffered freeze-offs, which had a significant effect on production during the February cold weather event.

Processing Plants

Individual processing plants reported making anywhere from minimal to extensive preparations. Their winterization included:

- Making equipment checks;
- Adding 24-hour staff and adding to nighttime crews;
- Installing insulation;
- Confirming that heat trace equipment was operational;
- Placing tarps as wind breaks and to capture heat;
- Draining water from cooling systems and fluids from piping low points;
- Coordinating with upstream gathering;
- Reviewing past winter events; and
- Installing hot oil heaters.

A representative sampling of processing plant preparations follows.

The Crosstex Energy-affiliated Silver Creek natural gas processing plant in Weatherford, Texas processes Barnett Shale production from the Fort Worth Basin. In preparation for the weather event, operating personnel reportedly performed checks on all equipment, confirmed that all heat trace equipment was turned on prior to the storm, installed tarps on critical equipment, and drained all air supply low points. (Despite these precautions, the plant did experience a shut down of a steam boiler due to a freezing amine/water mixture.)

Enbridge Energy Company, Inc. operates processing plants in east Texas and in north Texas. Generally speaking, operations in both the east Texas and north Texas plants continued in a routine manner prior to the storm.

Energy Transfer Corporation (Energy Transfer) owns and operates the La Grange processing plant in east Texas and the Godley processing plant in north Texas. As part of its general preparation for cold weather at the La Grange plant, Energy Transfer wrapped air regulators and hung tarps around vessels. In late January, an extra operator was placed on duty. With regard to the Godley plant, Energy Transfer had previously installed louvers on all amine still overhead condensers[110] to assist in cold weather operations. A hot oil heater had also been installed in a still condenser to prevent freezing. In addition, prior to the February weather event, Energy Transfer insulated condenser piping at two plants.

[110] The term “amine still overhead condensers” refers to a piece of equipment used to remove the acid gases from the natural gas stream.

MarkWest Energy Partners has two processing plants in Texas. The company reported that both processing facilities are equipped to run during extreme cold weather and that no additional maintenance, insulation or heat tracing was performed prior to the February cold weather event.

Williams Midstream has four processing facilities, the Markham Cryogenic processing plant in Matagorda County, Texas; the Milagro treating plant in San Juan County, New Mexico; the William FS Kutz (Kutz) processing plant in San Juan County, New Mexico; and the Lybrook processing plant in Rio Arriba County, New Mexico. The company reported that the Milagro plant and related facilities are designed to operate in cold weather. Nevertheless, it is standard practice at the plant to check heat tracing controls and piping insulation in the fall months. For the February event, preparations consisted of round-the-clock staffing for certain facilities and adding staffing for the night crew. Standard winter preparation at the Kutz plant reportedly includes coordination with upstream gathering, draining of water cooling systems, placing catalytic heaters into service, installation of wind barriers and group review of past events. In January and February 2011, additional contractor personnel were provided for night operations and additional heat wagons were placed based on needs. The Lybrook plant had also addressed winter preparation prior to 2011 by upgrading and inspecting piping, tracing, and insulation, and by making repairs to hot oil pumps.

Pipelines

Pipelines also prepared for the anticipated cold snap. Typical preparations for both interstate and most intrastate pipelines included:

- Maintaining higher than normal line pack;
- Optimizing compressor operations;
- Enhancing internal communication such as cold weather operational meetings;
- Increasing availability of personnel;
- Cancelling scheduled maintenance where possible; and
- Communicating with customers.

Interstate Pipelines

Individual interstate pipelines reportedly took the following preparations:

EL Paso prepared for the forecasted colder weather by maintaining higher than normal line pack throughout the weekend of January 29 and January 30. (El

Paso considers line pack volumes between 7,200 MMcf and 7,800 MMcf at any given point in time to be in the normal range; at line pack quantities below 7,200 MMcf or above 7,900 MMcf, El Paso generally considers its system to be at or approaching stressed operational conditions.) On Monday afternoon, January 31, El Paso began gas withdrawals from its Washington Ranch Storage Facility, reaching the field's maximum withdrawal rate by the morning of February 1. This was done to compensate for gas supply underperformance in the San Juan and Permian Basins.

Natural Gas Pipeline Company of America (NGPL) uses its Texas facilities to receive gas in Texas and redeliver that gas to markets in the upper Midwest. For February 1 through February 3, NGPL put in place a severe weather operating procedure that provided for management of cold, high winds, ice and snow. This procedure included conferences and communications involving the managers of the gas control and commercial groups of impacted NGPL facilities. Additional actions reportedly taken by the gas control group included adjusting pipeline pressures to meet anticipated load increases, manning facilities on an around-the-clock basis, and carrying out operating procedures designed to keep facilities from freezing.

Transwestern began operating its compression stations to maximize pressures in New Mexico in advance of the cold weather event.

ANR Pipeline Company (ANR) has no facilities in New Mexico, Arizona or California, and only limited facilities in Texas, which are located in the northeast corner of the Texas panhandle (this is the southern-most part of ANR's Southwest Area). To prepare for and respond to operating concerns and ongoing and expected weather events, ANR conducted daily morning operations meetings. An additional "cold weather" operational meeting specifically addressed the week of February 1. ANR reported reduced horsepower at all its Southwest Mainline compressor stations to help flow gas south into the Texas area if scheduled supply decreased, with the aim of maintaining adequate line pack and constant pressures in Texas and Oklahoma.

Intrastate Pipelines

Intrastate pipelines in general employed many of the same preparations as did the interstate pipelines. Reported examples are provided below.

Atmos Pipeline –Texas began building line pack on January 31, and advised shippers to be in hourly and daily balance effective 9:00 AM on February 1. This action assisted with maintaining line pack. Electric generation customers

were advised that deliveries would be limited to Tier 3[111] beginning at 9:00 AM on February 1. Third-party interruptible storage customers were advised that they would be limited to 50 percent withdrawals effective February 1 at 9:00 AM.

Energy Transfer Partners reported ensuring that critical stations were staffed, spare compressors were placed on standby, line pack was increased, and all scheduled maintenance was postponed.

Enterprise Products Partners reported closely monitoring nominations. Staffing coverage was extended in addition to employees' normal schedules. Operations were also reviewed for potential service adjustments that might be required, although none were anticipated.

The Kinder Morgan Texas Pipes' natural gas pipeline operations and gas control group initiated the Kinder Morgan Gas Pipelines' severe weather operating procedure, designed to manage facilities in the event of severe cold, high winds and frozen precipitation. The procedure prescribes conferences and communications among managers and the gas control and commercial groups, and these communications began several days prior to the cold weather event. The gas control group also adjusted pipeline pressures in anticipation of increased load. In the field, some facilities were reportedly staffed around-the-clock, and procedures were put in place to keep facilities from freezing.

Local Distribution Companies

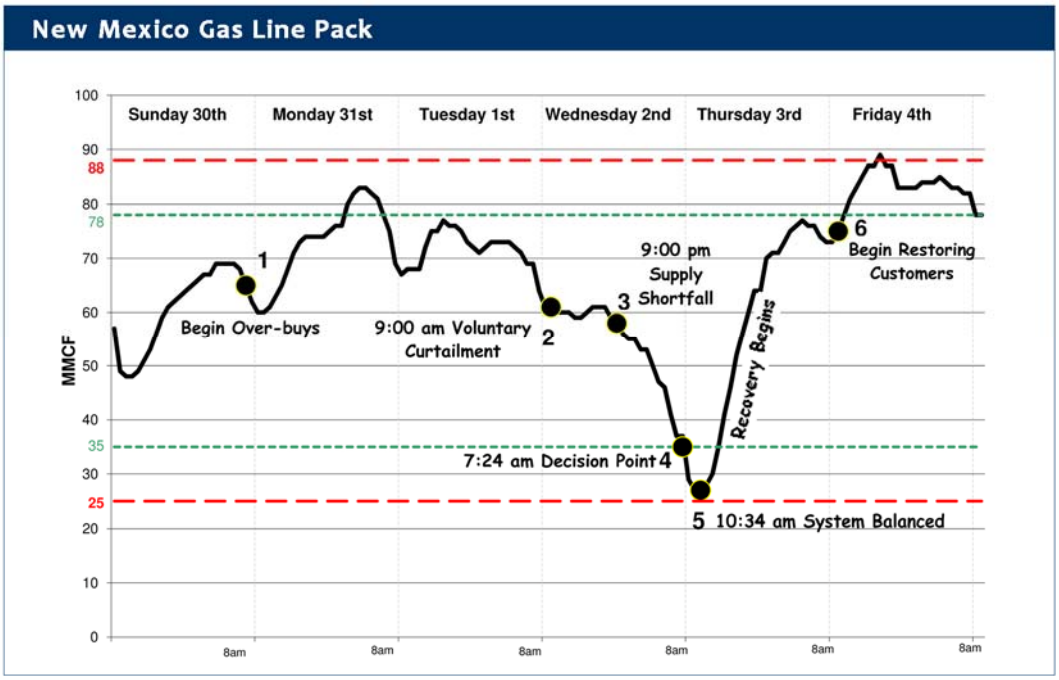
Each of the four LDCs that curtailed customers during the February weather event reported making preparations. They monitored weather forecasts before the event and revised their load forecasts upward. They also increased their purchases of gas to accommodate increased demand and to compensate for freeze-offs, and communicated with suppliers and the pipelines about pending conditions. As conditions worsened, these communications became more frequent.

New Mexico Gas Company packed transmission lines with extra gas, and confirmed that the storage facility it accesses was positioned for withdrawals. Additional gas was purchased for the expected increased demand and in anticipation of freeze-offs. From February 1 through February 3, NMGC had, for each respective day, pre-purchased 36 percent, 55 percent, and 62 percent more gas than its forecasted need. NMGC issued an Alert to all transportation customers concerning the weather forecasts. Given the severity of the anticipated

[111] Tier 3 restrictions applying to electric generating units limit the amount of natural gas the units can take.

storm, at 9:00 AM on February 2, NMGC began requesting that large industrial and commercial customers throughout the state voluntarily reduce or curtail their gas usage. In total, NMGC reported contacting 39 customers, asking for voluntary curtailment.

The following is a chart of NMGC's line pack, juxtaposed with its preparation events.



Source: New Mexico Gas Company

Southwest Gas monitored current weather forecasts on January 30 and January 31, which indicated colder temperatures were expected for southern Arizona. On February 1, a scheduled meeting of engineering and technical services personnel was expanded to include discussions concerning cold weather preparations and system monitoring.

Zia Natural Gas Company (Zia), after observing the dramatically dropping temperatures forecasted for February 1 through February 4 for the state of New Mexico, contacted its primary supplier on January 30 to discuss its supply and receipt options. On February 1, Zia discussed maximum volumes that could be nominated on its pipeline transportation contract.

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V. The Event: Load Shed and Curtailments

When the storm hit the Southwest on February 1, both electric and natural gas facilities began experiencing outages and other production difficulties. These difficulties escalated and ultimately led to load shedding by three electric balancing authorities and service curtailments by four gas LDCs, beginning on February 2. The unfolding events that led to these disruptions, and the conduct of the load shedding and curtailments, are described in this section.

A. Electric

ERCOT, SRP and EPE all engaged in load shedding during the cold weather event. Other electric entities in the area, although they experienced generation losses, were able to avoid load shedding (with the exception of PNM, which experienced some small, localized load loss from transmission issues). Each affected utility's actions are discussed separately below. (All times referenced are expressed in local time.)

ERCOT

ERCOT's required responsive reserve level is 2300 MW.[112] This is the amount that ERCOT has determined to be necessary on its system to ensure that the system will maintain frequency and voltage stability; that thermal and voltage limits will remain within applicable ratings; and that there will be no loss of demand, curtailment of firm transfers, or cascading outages.[113] If reserves drop below specified amounts, ERCOT is required by its Protocols to take actions to bring them up again, including the shedding of load.

ERCOT has specified in its Protocols certain triggering events that require taking action to prevent the uncontrolled loss of firm load. In doing so, it has patterned its emergency alert protocol on the Reliability Standard that prescribes

[112] As discussed in the section of this report entitled "Preparations for the Storm," this amount was based on a 1988 study designed to determine the amount of reserves needed to prevent shedding of firm load if ERCOT's two largest contingencies occurred.

[113] This minimum level of reserves is based on an N-2 criterion, a more conservative requirement than that required by the FERC-approved Reliability Standard BAL-002-0 R3.1, which requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." ERCOT's N-1 largest single contingency would be the loss of a nuclear-powered generating unit at the South Texas Nuclear Project, rated at 1354 MW.

an energy emergency alert procedure.[114] Both the Reliability Standard and the ERCOT Protocol categorize these triggering events into three levels, Levels 1, 2, and 3; ERCOT further subdivides Level 2 into 2A and 2B.

ERCOT had to make decisions throughout the morning of February 2 regarding the declaration of these various emergency alert levels and actions. That was particularly so with respect to Level 3, which requires the shedding of firm load.

Energy Emergency Alerts

Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's reliability coordinator, and are categorized by level of severity:

- EEA 1 - For conditions where all available resources are committed to meet firm load and reserves, all non-firm sales have been curtailed, and the entity is still concerned about sustaining its operating reserves.

- EEA 2 - For conditions when the entity is no longer able to meet expected energy requirements, and is designated an Energy Deficient Entity.

  The entity is to do the following, as time permits:

  Public appeals to reduce demand,
  Voltage reduction,
  Interruption of non-firm loads,
  Demand-side management, and
  Utility load conservation measures.

  Other entities are to provide emergency assistance as appropriate and available.

- EEA 3 - For conditions when the energy available to the Energy Deficient Entity is only accessible with actions taken to increase transmission transfer capabilities.

  At this point, firm load interruption is imminent or in progress.

(cont'd)

[114] *See* Reliability Standard EOP-002-2.1 (Capacity and Energy Emergencies).

ERCOT:

ERCOT has particularized this emergency energy alert system to the requirements of its own system. It is required under its Protocols to perform certain actions upon the occurrence of distinct triggering events. These are as follows:

Level / Triggering Event / System Operations Actions

- EEA 1 — Less than 2300 MW of Reserves:
  Use capacity available from DC ties, dispatch uncommitted units.
- EEA 2A — Less than 1750 MW of Reserves:
  Deploy Load Resources (LR); begin block-load transfers of load to neighboring grids.
- EEA 2B — To maintain system frequency at 60 Hz or reserves trending downward or not available:
  Deploy Emergency Interruptible Loads (EILS) if available.
- EEA 3 — To maintain system frequency at 59.8 Hz or greater:
  Instruct transmission operators to shed load via rotating outages in blocks of 100 MW.

As discussed in the preceding section of this report, "Preparations for the Storm," severe weather conditions on February 1 precipitated numerous forced generator outages within ERCOT's footprint. By midnight on February 1, 6022 MW of generation capacity was unavailable due to weather-related forced outages and derates, and conditions worsened overnight.

Generation Shortfalls on February 2

By 3:00 AM on February 2, responsive reserves had dropped below 3000 MW. ERCOT issued both an OCN and an Advisory to market participants, notifying them of the severe weather and the falling reserve level.[115] It followed this communication with an emailed report to the PUCT about the falling reserves.

[115] The communication steps taken by ERCOT appear to be consistent with its Operating Guidelines and Protocols. However, a number of transmission providers have stated they could have been better prepared to implement their required load shed if they had had more information about ERCOT's deteriorating system status much earlier during the overnight period of February

At 4:30 AM, ERCOT operators instructed deployment of 1840 MW of non-spinning reserves, principally combustion turbines. (Non-spinning reserves require 30 minutes or longer to come on-line or to ramp up to their next block of power output.) Ten of the units, or a total of 669 MW of capacity, were unable to respond, many because they failed to start. By 5:08 AM, reserves had dropped below 2500 MW, and ERCOT issued a Watch.

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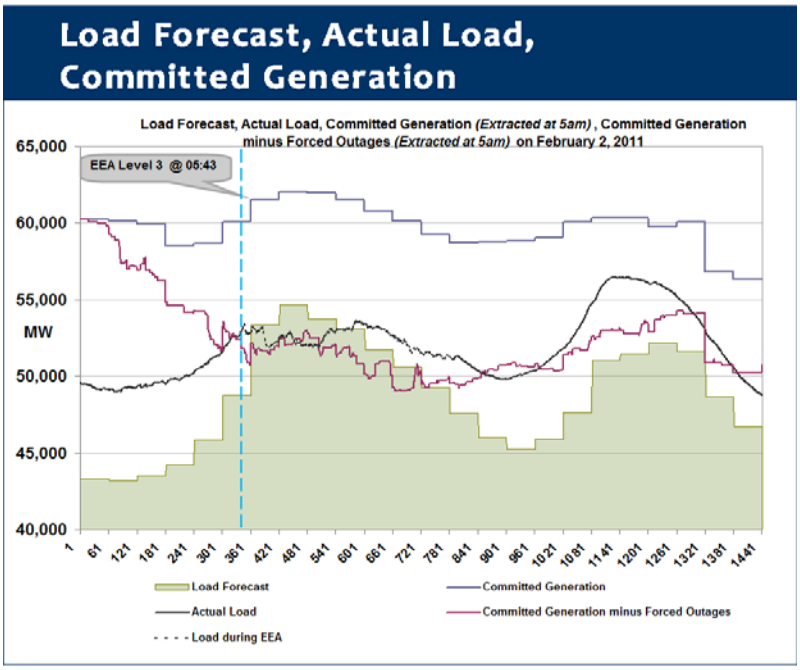
ERCOT calculates its operating reserves on a real-time basis by comparing metered demand with its available generation resources. At the same time generation was dropping off during the morning of February 2, demand was rising. The cold weather and winds were placing extraordinary demands for power on the system, and load was running consistently higher than had been forecasted for the day. In fact, at 5:20 AM the demand was 2760 MW higher than on any other day in the history of the ERCOT region at that hour, and was rapidly climbing.[116] The following chart, prepared by TRE, compares actual demand with forecasted demand.



Source: TRE

The actual peak demand for the day, which typically occurs in the morning around 8:00 AM, was artificially skewed downward because of the load shed. The

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1 to February 2. They would have liked to have received such information as soon as ERCOT began seeing a high number of forced generator outages.

[116] Potomac Economics, Ltd., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, at 3 (April 21, 2011) (Potomac Report), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf.

IMM (Potomac Economics, Ltd.), the market monitor for ERCOT, estimated that the demand that would have materialized absent any load reductions or curtailments would have peaked at 59,000 MW, just after 7:00 AM.[117] This estimate suggests that the high demands already being placed on the system in the early morning hours would likely have continued to escalate.

At 5:09 AM, reserves dropped below 2300 MW, the triggering event for ERCOT's declaration of an EEA 1 (although it was not declared, presumably because events were moving so swiftly). At 5:20 AM, responsive reserves had dropped below 1750 MW, and ERCOT issued an EEA 2A. It also deployed 888.5 MW of Load Resources, with 881.7 MW responding. Load Resources are counted as responsive reserves and, as such, their deployment reduces ERCOT's responsive capability. In this case, however, two factors worked to offset this reduction:

- The dropping of 881.7 MW of load increased the margin between generation and load, and ERCOT allowed a fraction of this increase to be allocated to responsive reserves. (The fraction ERCOT allots is typically 20 percent, but varies based on the specific generation online at any given time.)

- The Load Resources were being deployed over a 10-minute interval during which some additional generation was actually coming online, despite all the problems on the system.

As a result of these factors, for a short time while Load Resources were being deployed, responsive reserves actually increased by about 200 MW. It was not long, however, before additional forced outages and derates of generation, combined with the normal pick-up of morning demand, again decreased the level of responsive reserves.[118]

At 5:26 AM, ERCOT deployed RRS reserves, a form of interruptible load, which briefly raised the reserve level to above 1400 MW.

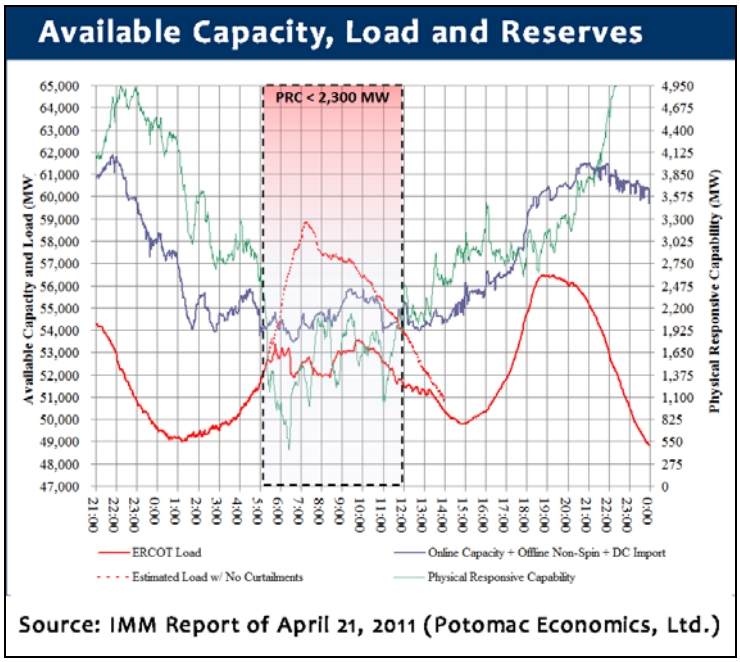
[117] Potomac Report at 3-5. The estimate was based on several factors, including the actual load and rate of load increase prior to the implementation of the first load curtailments, the load shape on similar days, and ERCOT load forecasts produced just after 3:00 AM on the morning of February 2.

[118] Responsive reserves would ultimately fall to a low point of 447 MW at 6:25 AM, after the load shed had already begun.

More units, however, continued to trip off-line. Responsive reserves briefly dipped below 1354 MW (the N-1 contingency reserve level required for safe operation of the system) twice before 5:40 AM. At that time, the responsive reserves dropped below the N-1 contingency level for an extended 73 minute period.[119]

At 5:43 AM, ERCOT declared an EEA 3 and began the process of shedding load.

The following graph[120] indicates the relationship between ERCOT's available capacity, loads and reserves throughout the day.



Counting both February 1 and February 2, a total of 193 generating units in ERCOT tripped, had derates, or failed to start, representing a loss of 29,729 MW of capacity.[121] At the lowest point of available generation, which occurred at 6:12

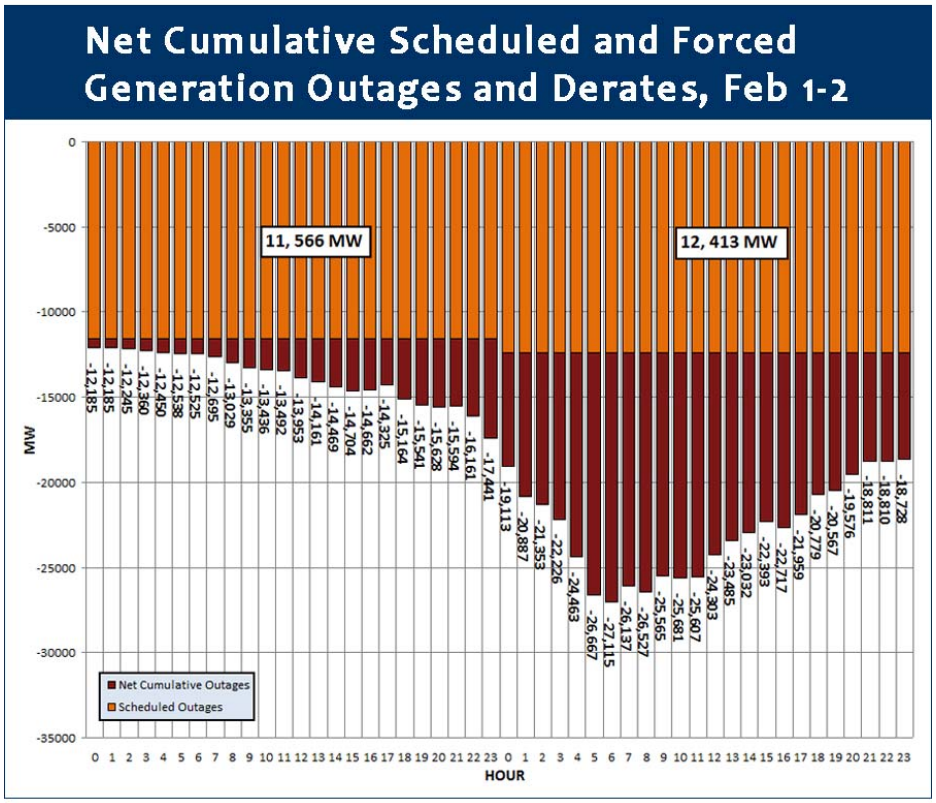
[119] There were six times during the morning of February 2 when ERCOT's response reserves fell below 1354 MW. Those times are: 5:23-5:29 AM, 5:31-5:32 AM, 5:40-6:52 AM, 7:11-7:30 AM, 8:39-8:52 AM, and 10:58-11:15 AM, for a total of two hours and 14 minutes, with the longest interval 73 minutes. (Calculation of the time periods includes the beginning and ending minutes.)

[120] Potomac Report at 6.

[121] This is a gross cumulative number; a unit is counted as having failed regardless of whether it came back online at some point during the event. This measurement gives an

AM, there were 14,702 MW of generation offline from such trips, derates, or failures to start. Adding that number to the scheduled outages for the day of 12,413 MW, means that 27,115 MW, or approximately one-third of the total ERCOT fleet, was unavailable to provide power.

The following two charts depict the net and gross cumulative capacity reduction resulting from forced outages, derates, and failures to start, as added to the scheduled outages, for these two days.[122] Comparing these numbers to total ERCOT generation of approximately 79,700 MW[123] gives a picture of the magnitude of the generation loss, as well as of the difficulties that confronted ERCOT's operators on those two days.



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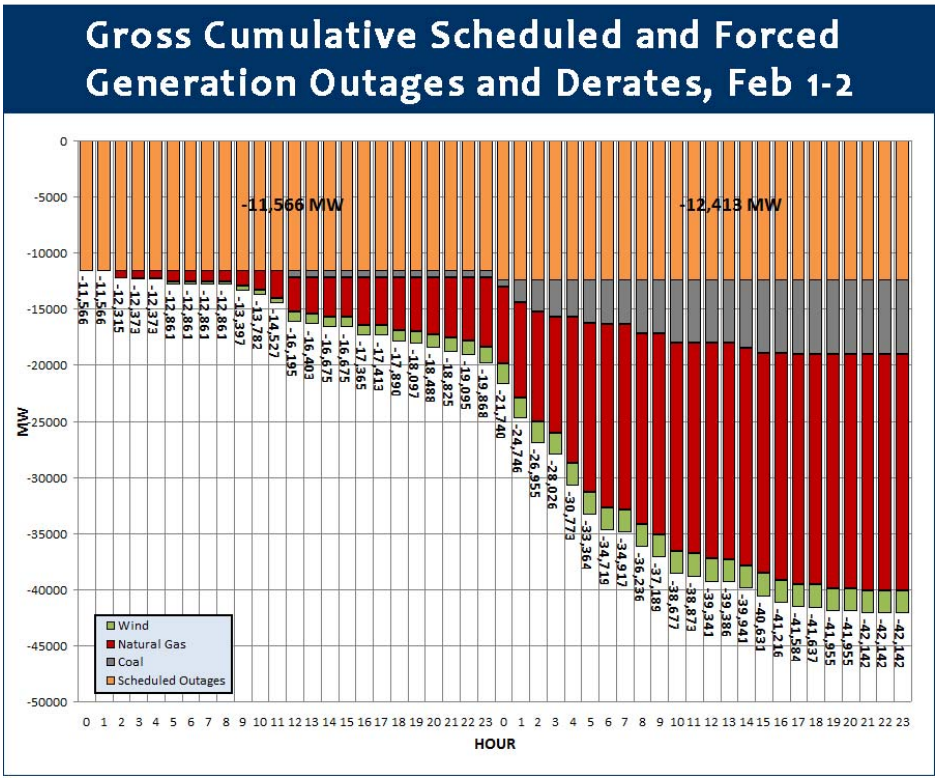
indication of the total amount of capacity that failed during the event (rather than the amount offline at any given point in time).

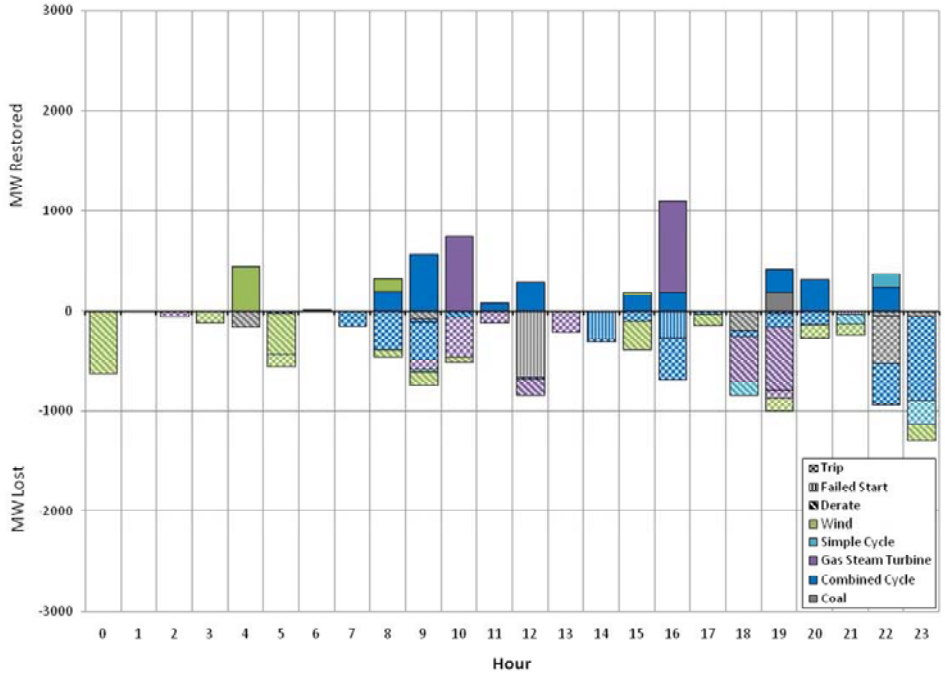
[122] The first chart depicts net outages after subtracting out units that came back online. The second chart shows cumulative outages with no adjustment for units that came back online.

[123] The 79,700 MW number represents total ERCOT fleet capacity, online and offline, measured at 8:00 AM on February 2 (it does not include imports over the DC ties). The wind power capacity embedded in that number, as well as in the capacity reductions for the outages, derates, and failures to start, has been adjusted to reflect the actual hourly wind speed conditions (in lieu of using straight "nameplate" values which pertain only to optimum wind speeds that produce full rated output).

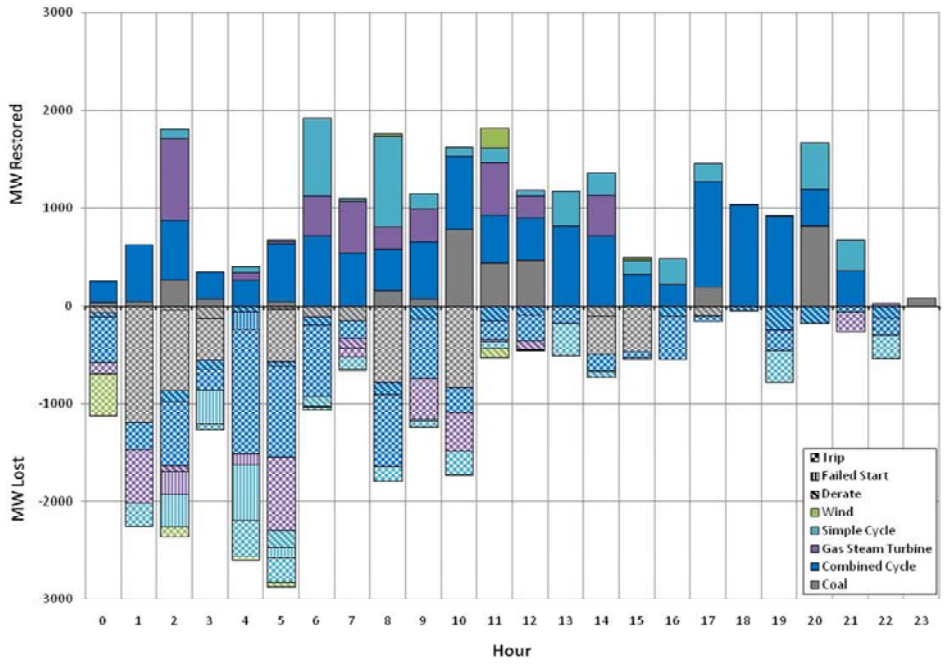


The task force has also prepared charts for February 1 and February 2 that depict, hour by hour, the MWs that failed and the MWs that were restored, both by fuel type and by type of failure (trip, derate, or failure to start). These charts give a running picture of the fluctuations in available capacity, by fuel type, at any given point in time throughout the event.

Capacity Fluctuations by Fuel Type on Feb. 1, 2011



Capacity Fluctuations by Fuel Type on Feb. 2, 2011



The various reasons for the outages, derates and failures to start that occurred during the event (the majority of which were weather-related, either

directly or indirectly) are discussed in the following section of this report entitled "Causes of the Outages and Supply Disruptions."

Adjusted Wind Power Capacity

The capacity of a wind power installation is typically reported on a "nameplate" basis, with the nameplate value representing what the facility can produce when the actual wind speed is optimum for the particular turbine design. When a wind farm is offline on a scheduled or forced outage, the capacity unavailable to the system is also typically reported on a nameplate basis; the same is true for partial outages, which are reported as derates (collectively, nameplate outage value).

The actual wind speed, however, is seldom sufficient to produce full nameplate output simultaneously throughout ERCOT. Therefore, the nameplate outage values must be adjusted downward to realistically represent the impact of outages and derates of individual wind facilities.

Adjusted Outages and Derates

The total installed wind power nameplate capacity in ERCOT is 9321 MW**.** If the aggregate nameplate outage values reported during February 1 and February 2 are subtracted from this 9321 MW total, nameplate available values are obtained on an hourly basis. Dividing the actual measured aggregate wind power output for any given hour by the nameplate available value for the same hour produces a percentage output that reflects how strongly the wind is blowing compared to full-output levels. Over the course of February 1 through February 2, that percentage varied from 40 to 75 percent (which is atypically high). To determine adjusted outage values, the percentage for any given hour is applied to the nameplate outage value for that same hour. For example, if the reported nameplate outage value for the 5:00 AM hour was 3200 MW, and the percentage output was 50 percent, the adjusted outage value is 1600 MW. This value more realistically represents the additional wind power that would have been supplied to the ERCOT grid had it not been for the wind farm outages and derates.

Although this method does not take into account the fact that the wind speed at a specific location where a forced outage has occurred may or may not correlate with the average value, any errors at individual locations should tend to offset one another. The method also assumes that the reports of forced outages and derates were made on a timely basis, which may or may not have been the case.

(cont'd)

Adjusted Capacity

NERC used 8.7 percent of nameplate capacity in calculating the contribution of wind power to existing generation in its 2010-2011 Winter Assessment of the TRE region. This is a planning number that has merit for the seasonal overview, but is not applicable to the high wind conditions of February 1through February 2. Therefore, in determining the wind power capacity in ERCOT for purposes of this inquiry, the task force multiplied the total installed capacity of 9321 MW by the percentage of output actually achieved by those facilities that remained in service, compared to nameplate capacity. The resulting adjusted capacity represents what the total wind power output would have been in ERCOT had there not been any outages or derates during February 1 through February 2. Since the percentage varies with the wind speed, adjusted capacity values were calculated hourly. At 8:00 AM on February 2, the percentage of output vs. nameplate was 57 percent, yielding an adjusted capacity of 5313 MW (0.57 x 9321 MW). This number was then used as wind power's contribution to the total generation fleet. Counting all units, both online and off, that total came to 79,658 MW for the 8:00 AM hour. (Since the adjusted capacity value changes hourly based on wind speed, so too will the numerical size, in MWs, of the total generation fleet.)

The Load Shed Decision

Load shedding is implemented to correct an electrical power imbalance if load exceeds supply and system operators cannot bring the system back into balance through other measures. Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to recover from an under-frequency condition, or to return voltage to a normal level. The operation can be manual (operator-initiated) or automatic (relay- initiated), depending on how quickly the frequency is decaying or the voltage is falling. For slowly declining frequency or voltage issues, the manual option is usually chosen. For rapidly declining frequency or voltage, the automatic option will respond without operator intervention.

ERCOT utilized operator-initiated load shedding on February 2, which preserved the system's ability to implement automatic load shedding had system conditions continued to deteriorate. Had ERCOT not instituted manual load shedding, automatic under-frequency load shedding would have been a last resort before a possible system collapse. Manual load shedding also helped raise the frequency levels, preventing damage to generator turbines.

The task force considered the question of whether ERCOT's decision to manually shed load prevented more extensive blackouts than were experienced as a result of the load shed itself. While a definitive answer would require extensive

modeling and data inputs, the task force concluded, based on the information available, that ERCOT's declaration of an EEA 3 probably prevented widespread, uncontrolled blackouts throughout the ERCOT Interconnection. Because ERCOT operates as a functionally separate interconnection from its neighboring Eastern and Western Interconnections and is linked only by asynchronous ties, the blackouts would not have propagated further.[124]

Frequency Response and Automatic Under-Frequency Load Shedding

Frequency as a measure of the reliability status of a power system can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the overall integrity of operations. Maintaining frequency requires balancing a system's aggregate generation output to load moment-to-moment. It also requires having sufficient reserves available at all times to withstand the sudden loss of the largest generator on the system, in order to instantaneously make up for the loss of power and thus reestablish balance.

In spite of the enormous amount of generation that was forced off line in successive waves in ERCOT on February 1 and February 2, especially during the overnight and early morning hours between the two days, the overall frequency response of the system was not problematic during the event. Nonetheless, the need to maintain frequency to prevent a collapse of the system was the fundamental driving force behind ERCOT's decision to shed firm load.

Because ERCOT is not synchronously connected to either the Eastern or Western Interconnections, all frequency response must come from internal resources. And because ERCOT is smaller than the other interconnections, the loss of a generator results in a steeper frequency decline, necessitating a more robust frequency response. For this reason, in 1988 ERCOT established a minimum responsive reserve requirement of 2300 MW, based on an N-2 criterion covering the loss of the two largest generators in ERCOT (one nuclear-powered unit and the next largest unit on the system). This is a larger reserve than the N-1 criterion required by Reliability Standard BAL-002-0 R3.1. On the morning of

(cont'd)

[124] NERC has prepared a study on the reliability implications of the February cold weather event entitled "Analyses of Reliability Impacts on the Bulk Power System." The study discusses the impacts on the WECC Interconnection of the events in SRP, EPE, and PNM, and presents an analysis of frequency response performance during the event by the Eastern Interconnection and the ERCOT Interconnection. NERC plans to make the study publicly available.

February 2, 2011, the largest single contingency was an online nuclear-powered generating unit with a capability of 1354 MW.

ERCOT maintains and closely monitors its responsive reserve levels (also referred to by ERCOT as its Physical Response Capability, or PRC), to comply both with its own 2300 MW criterion and with the 1354 MW minimum criterion.

ERCOT relies on demand side load resources to provide up to 50 percent (1150 MW) of its 2300 MW responsive reserve requirement. These resources automatically disconnect when the frequency declines to 59.7 Hz. The purpose of the responsive reserves, both generation and load, is to arrest frequency declines before they reach 59.3 Hz (the trigger threshold for the first block of automatic under-frequency load shedding (UFLS)), and to restore frequency to 60 Hz within a few minutes following an event. Should either generation or load resources be deployed manually by system operators, they are no longer available to provide frequency response.

Between 5:15 AM and 1:20 PM on February 2, responsive reserves dropped below the 2300 MW N-2 criterion three separate times, of varying durations. Ultimately, responsive reserves dropped below the 1354 MW N-1 criterion. This occurred six separate times between 5:23 AM and 11:15 AM, for a combined total of 134 minutes, with the longest interval being 73 minutes. During the times when responsive reserves were below 1354 MW, had the largest generator tripped, reserves would have been insufficient to reestablish the balance between generation and load. The result would have been an inexorable decline in frequency which, when it reached 59.3 Hz per second, would have triggered the first block of automatic under-frequency load shedding, which would have dropped five percent of the system load, or roughly 2600 MW.

Even though the under-frequency load shedding would have tripped automatically, this response would have taken out firm load and would be in addition to any firm load that operators may have already shed, starting with the first directive ERCOT issued at 5:43 AM. Depending on the particular circumstances surrounding the moment of activation of the automatic under-frequency load shedding, it is possible that an overvoltage condition could have occurred in one or more localized areas, that frequency could have significantly overshot the 60 Hz norm, or that other electrical perturbations could have developed that would have resulted in the tripping of even more generation. Only a detailed dynamic simulation could answer the question as to how widespread the February 2 blackout would have been had the automatic under-frequency load shedding been triggered.

ERCOT's Black Start Capability

If the load shed had not prevented an ERCOT-wide blackout, the outages would not only have been more widespread, they might have been of a much longer duration. The task force reviewed the state of ERCOT's black start units to determine whether they could have promptly brought the system back had a collapse occurred. "Black start" refers to restarting the system after a major portion of the electrical network has been de-energized, and generators that have black start capability are those that can be started independently and without external power.

ERCOT has 15 primary and six alternate black start generators. During the event, roughly half of these generators were unavailable: two (totaling 97 MW of capacity) were on planned outage; four (totaling 141 MW) failed to start due to the extreme cold weather; three (totaling 423 MW) tripped offline after starting due to freezing equipment; and one (26 MW) tripped offline due to natural gas fuel curtailment. Had a total blackout of the ERCOT system occurred, the unavailability of 10 of ERCOT's 21 (primary and alternate) black start resources, comprising 687 MW out of a total 1150 MW of black start capacity, could have jeopardized ERCOT's ability to promptly restore the system.

The Load Shed Process

ERCOT accomplishes a controlled load shed by issuing directives to its transmission providers,[125] ordering the load shed to proceed in defined blocks of power (each transmission provider being responsible for its allocated share of the total). On February 2, ERCOT issued its first load shed directive at 5:43 AM and its third and last at 6:23 AM. In total, it directed that 4000 MW be shed.

ERCOT began load restoration at 7:57 AM, and firm load was fully restored at 1:07 PM.

[125] "Transmission provider" is a generic term. ERCOT uses "transmission service provider" to mean an entity that owns or operates transmission facilities to transmit electricity and provide transmission service on the ERCOT grid. NERC uses different terminology to describe the various types of transmission providers, including "transmission service provider," "transmission operator," and "transmission owner." (The definitions of these terms can be found in the appendix entitled "Categories of NERC Registered Entities.") Under NERC terminology, ERCOT is the only "transmission service provider" for its Interconnection. To avoid confusion, the term "transmission provider" will be generally used in the narrative portions of this report to refer to any of those various categories of entities who provide transmission service and who were directed to shed load and took the necessary actions to do so (including load shedding both within and outside of ERCOT).

The actual load shed process and eventual restoration of the system to an EEA 0 state[126] proceeded as follows:

ERCOT issued its first instruction at 5:43 AM, ordering a load shed of 1000 MW. Shortly thereafter, ERCOT also deployed 384.2 MW of Emergency Interruptible Load Service, ERCOT's form of demand response.[127]

At 6:04 AM ERCOT directed the transmission providers to shed an additional 1000 MW of load. In the next second, 6:05 AM, ERCOT's frequency dropped to 59.576 Hz, its lowest point during the event.

At 6:23 AM ERCOT issued its third and last load shed directive, directing the transmission providers to shed an additional 2000 MW. This resulted in a total load shed directive of 4000 MW.

As the transmission providers were implementing ERCOT's directives to shed load, additional generation became unavailable; between 5:45 and 6:30 AM, 18 generating units tripped offline, were derated, or failed to start, totaling 1643 MW of output. (During this same time, 12 units came back online, totaling 774 MW.)

At 6:25 AM, ERCOT's reserve level dipped to 447 MW, its lowest point of the day.

At 6:59 AM, ERCOT issued a media appeal for energy conservation. This was the first notification to the public of the problems ERCOT was experiencing on its system.[128]

At 7:57 AM, ERCOT issued its first load restoration directive, beginning with a 500 MW block. Three seconds later, a combined cycle unit loaded at 77

[126] "EEA 0" signifies a normal state of operation.

[127] While some EILS customers failed to reduce load as contracted (thus exposing themselves to potential penalties), others responded with a load reduction in excess of their contracted amount. The net result was that total EILS load reduction fell short of obligated levels on February 2 in only one fifteen-minute interval.

[128] ERCOT has acknowledged that it could improve its communications with the general public, which it suggests could be accomplished through use of an automated system for contacting the media, deployment of representatives to meet with the media, and through designation of supplemental communications staff to answer phone inquiries during a period of emergency.

MW tripped offline, causing reserve levels to again fall below 1354 MW. However, ERCOT did not shed any additional load.

At 8:22 AM, ERCOT directed the transmission providers to restore another 500 MW block of shed load. ERCOT would issue six more load restoration directives over the course of the next several hours, completing the process at 1:07 PM.[129]

At 8:53 AM, ERCOT deployed an additional 83.5 MW of EILS, at which point reserves increased above the 1354 MW limit.

At 9:25 AM, ERCOT called all QSEs and instructed them not to take any resources offline unless so instructed.

Additional units, including an 849 MW coal unit, continued to trip offline. At 10:58 AM, reserves again dropped below the 1354 MW limit. This situation lasted until 11:15 AM.

At 12:12 PM, ERCOT reported to the QSEs that the Texas Commission on Environmental Quality (TCEQ) had issued a waiver for certain air permitting requirements that might otherwise have prevented generators from producing power during the emergency. (The TCEQ's actual communication did not mention a waiver, but rather indicated it would exercise its "enforcement discretion.")

At 1:57 PM, ERCOT recalled RRS Block 2 Load Resources (463 MW).

At 2:01 PM, ERCOT returned to a state of EEA 2B.

At 2:55 PM, ERCOT recalled RRS Block 1 Load Resources (437 MW).

At 3:14 PM, ERCOT returned to a state of EEA 2A. Reserve levels rose to approximately 2900 MW.

At 7:15 PM, ERCOT set a record winter peak demand of 56,480 MW.

On February 3, at 10:00 AM, ERCOT declared a state of EEA 0 and recalled all EILS loads.

[129] Directives were issued in 500 MW blocks at 9:25 AM, 11:39 AM, 12:04 PM, 12:25 PM, 12:49 PM, and 1:07 PM.

Summing every transmission provider's peak load shed amount (which did not occur at the same time), the cumulative load shed on February 2 was 5411.6 MW. The largest amount of load shed at one point in time (8:02 AM) was 4947.9 MW.[130]

The load shed process by ERCOT's transmission providers is discussed below.

Conduct of the Load Shed by ERCOT's Transmission Providers

ERCOT communicated its oral dispatch instructions to shed load via hotline calls. The percentage of the total requirement that is to be shed by each transmission provider is based on the transmission provider's previous year peak load, as reported to ERCOT.[131] Under ERCOT's Nodal Operating Guides, transmission providers have 30 minutes to shed their required share of load if the curtailment is implemented remotely by SCADA system, and one hour if implemented by dispatch of personnel into the field to manually disconnect feeders.[132]

Load Shed Program Design

Each transmission provider in ERCOT is responsible for determining how load will be shed in order to meet its load shed obligation.[133] The larger transmission providers interviewed by the task force make use of automated systems for shedding load. All transmission providers interviewed pre-designated feeders or blocks that are available for manual load shed. Transmission providers generally take into account the following factors in setting up their load shed system:

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[130] Based on TRE data supplied to the task force. (This number does not include Greenville, for which comparable data was not available. Adding 8.8 MW for Greenville would bring the total to 4956.7 MW).

[131] See ERCOT Nodal Operating Guides: Emergency Operation § 4.5.3(5) (July 1, 2011), *available at* http://www.ercot.com/mktrules/guides/noperating/cur.

[132] *Id.* at § 4.5.3(7)(a)-(b). These time frames do not apply if the load shed directive exceeds 1000 MW, as was the case for ERCOT's last load shed instruction on Feb. 2, 2011. *Id*. at § 4.5.3(7)(c).

[133] Actual implementation of load shedding is carried out at the distribution level, which may be done through a separate division of the transmission provider or through a separate, affiliated entity (*e.g.*, a member distribution cooperative of a generation and transmission cooperative). This extra layer of communication appears to have caused some delay in the initiation of the load shed process in at least some cases.

1. Minimizing customer disruptions through target outage rotation periods. Transmission providers interviewed utilize a load-shed scheme with a targeted rotation period between 15 minutes at the low end and 30-45 minutes at the high end. During the February 2 event, transmission providers reported difficulties maintaining a short (15-minute) rotation period over the course of the morning, as ERCOT raised their load shed obligation to the highest levels most transmission providers had experienced. Transmission providers reported having to go through their rotation schedule multiple times, and some transmission providers expressed concern that a limited number of customer groups had to carry a disproportionate amount of the load-shed burden.[134]

2. Avoidance of feeders or lines reserved for under-frequency load shedding (UFLS) requirements. All transmission providers interviewed indicated that UFLS blocks[135] are not generally included as available feeders for manual load shedding under their load shed procedures. However, one transmission provider discovered during the February 2 load shed event that some lines designated as available for manual load shed were also designated for UFLS. Except for this one overlap in blocks, the transmission providers interviewed were able to fully meet their load-shedding obligations while maintaining the required 25 percent of load reserved for UFLS. There were no reported instances of automatic under-frequency trips during the February 2 event.

3. Exemptions for critical customers. Transmission providers utilize a variety of approaches for identifying critical customers or loads that are either exempt from rolling outages or are given a higher priority for preservation of service. Customers that typically receive some form of exemption or higher priority include hospitals, airports, and

[134] TRE Report at 41; materials provided to the task force by transmission operators.

[135] Distribution service providers in ERCOT are required to set up relays to automatically trip load as frequency falls, as follows: (1) at 59.3 Hz, a minimum of 5 percent of load must trip; (2) at 58.9 Hz, an additional 10 percent of load must trip; and (3) at 58.5 HZ, an additional 10 percent of load must trip, *i.e.*, the distribution service providers must have at least 25 percent of its load available for UFLS. (This is independent of any manual load shedding directives.) ERCOT Nodal Operating Guides Section 2: System operations and Control Requirements at 2.6.1(1) and (2). Some transmission providers use these same blocks of load for automatic under-voltage protection. (Note that NERC uses the term "distribution provider" to describe this type of entity. This report will use the term "distribution service provider" throughout to avoid confusion.)

other facilities that may affect public safety, such as police stations.[136] Some transmission providers interviewed indicated that they have a process for checking with gas customers for possible critical loads, such as gas compressor facilities without backup generation. But most acknowledged that the process for identifying "critical" gas facilities could be better standardized or otherwise improved.

4. Exemption of large loads and networks needed for system stability. Major downtown areas are generally exempted from the load shed plan, as cutting off service to these heavily networked systems could affect system stability. Large, high-voltage industrial loads are also generally not available for manual load shedding due to system stability concerns.[137]

After taking into account UFLS blocks, critical/exempt customers, and other load that is not appropriate for manual load shedding, the interviewed transmission providers indicated that they had between 30 percent and 70 percent of their total load available for manual load shedding.

Experience on February 2, 2011

The transmission providers' overall load shed response (in MW) was beyond the minimum required by ERCOT and was adequate to protect system frequency.

Most of the larger transmission providers interviewed were able to shed load within a few minutes of receiving each ERCOT directive, and utilized some form of automated system for shedding load. These systems were designed to

[136] The State of Texas also requires transmission providers and distribution service providers to provide notification of interruptions or suspensions of service under certain conditions (set out in their retail delivery tariffs) to customers that meet the criteria for designation as a Critical Load Public Safety Customer (hospitals, police stations, fire stations, and critical water and wastewater facilities), Critical Load Industrial Customer, Chronic Condition Residential Customer, or Critical Care Residential Customer. 16 TEX. ADMIN. CODE § 25.497 (2011).

[137] Some of these high-voltage industrial loads may be under contract as Emergency Interruptible Load Service (EILS) or providing ancillary services (RRS) as Non-Controllable Load Resources (NCLR). *See* TRE Report at 42-44. In such case, those resources would be (and were) called upon by ERCOT through the relevant QSE (at 5:49 for EILS and at 5:20 for NCLR), something that is not communicated to or controlled by the transmission providers or distribution service providers.

look at actual load on the feeders in real time, and were designed to rotate customer blocks by restoring service feeder-by-feeder as the pre-determined rotation period expired. These systems were also designed to ensure that the total curtailment obligation is maintained or exceeded at all times, by restoring a given feeder only *after* another feeder or feeders with off-setting load have been dropped in the next block. At least one of the automated systems in use during the event was designed to take into account cold load pickup prior to restoration of feeders,[138] and therefore may have generated a greater reported level of over-shedding for limited periods of time during the rotation process.[139]

Other transmission and distribution service providers used less sophisticated methods for shedding load during the event, including having a dispatcher record load amounts prior to dropping a given block to calculate the total amount to be reported to ERCOT as having been shed, and using color-coded circuit maps to select lines to be shed.

All but four transmission providers were able to meet or exceed their load shed obligations within 30 minutes of each oral dispatch instruction from ERCOT. Three of the four transmission providers did meet their full load shed obligations at a later point in time. The fourth transmission provider contended that it had not received the dispatch instruction.

Effect of Load Shed on Gas Delivery or Supply

At approximately 8:00 AM on February 2, ERCOT notified all transmission providers that gas companies were reporting low gas pressures, and requested that they confirm that no gas company feeds were included in their

[138] Cold load pickup is a phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. *Cold Load Pickup Issues: A Report to the Line Protection Subcommittee of the Power System Relay Committee of the IEEE Power Engineering Society*, May 16, 2008, § 2.1, at 3, *available at* http://www.pes-psrc.org/Reports/Cold_Load_Pickup_Issues_Report.pdf .

[139] One transmission provider's automated system includes an expectation of a 60 percent increase in load on any feeder coming off of its pre-determined outage period, and therefore requires that feeders in the next block must cover the expected increase before the first feeder can be restored. That transmission provider did report peak load shed amounts well above its requirement (about 49 percent over the required amount at one point), but attributed the reported over-shedding to several factors in addition to the cold load pickup assumptions used, including (1) restoration failure of a certain percentage of breakers; and (2) loads that did not come back on-line until manually re-set, including certain gas compressors.

outage rotation feeders.[140] At 9:25 AM, as part of its third directive to restore 500 MW of load, ERCOT requested that transmission providers serving west Texas concentrate their restoration efforts in that region due to concerns about the impact of the outages on gas compressor facilities. At 10:45 AM, ERCOT notified some transmission providers that gas compressor stations in two west Texas counties were still without power, and requested that service be restored to those counties as soon as possible.[141] In addition, some transmission providers reported additional requests from ERCOT about restoring power to specific gas facilities or regions, but noted that ERCOT did not appear to have reliable or current information as to which transmission or distribution service provider was providing electric service to those facilities.

The task force found that transmission providers currently have only limited information on overall system conditions in ERCOT, and in real-time can typically see nothing more than ERCOT's responsive reserve (PRC) levels and the status of generators connected to the transmission provider's own system. Many transmission providers indicated that they could perform better with respect to load shedding, particularly in increasing staffing and providing notice to the public, if they are able to get information about deteriorating system conditions from ERCOT earlier in the process.

Some transmission providers indicated they are already working on improvements to their public notification protocols, and believe that certain sensitive loads (including loads with back-up generation) could have benefitted from earlier notification of potential outages.

The task force also found that transmission providers with annual training programs, particularly those that require use of hands-on simulations or drills, tended to perform well during the February 2 load shedding event. Transmission providers with less frequent training, or that fail to simulate expected conditions during a load shed event, tended to have more problems with timely implementation of the required curtailment. Automated systems for shedding load may be helpful for larger transmission providers, but do not appear to be necessary

[140] One transmission provider reported that, upon receiving ERCOT's notice, it restored power to facilities believed to be compression facilities; these were later determined to be regulator stations, for which restoration of power would not affect pipeline pressure.

[141] ERCOT directed one transmission provider to restore power to five specific counties in north/central Texas due to concerns about affected gas facilities, which restoration could only be done by working outside the automated outage rotation system to identify each feeder or circuit serving those counties.

for successful implementation of a load shed program under ERCOT's current time requirements for implementation.

Price Effects of the Cold Weather Event

As discussed in the section of this report entitled "The Electric and Natural Gas Industries," ERCOT is an energy-only market. This type of market relies on scarcity pricing to provide price signals for the addition of needed resources. ERCOT transitioned from a zonal market to a nodal market in December 2010, and as part of its preparation for that transition, adopted rules in 2006 that included a Scarcity Pricing Mechanism that relaxed the then-existing system-wide cap of $1,000 per MWh. ERCOT did this by gradually increasing the cap in accordance with a defined schedule to $1,500 per MWh on March 1, 2007, to $2,250 per MWh on March 1, 2008, and finally to $3,000 per MWh on February 1, 2011, two months after the implementation of the nodal market and, as it happened, on the day before the severe weather impacts caused ERCOT to shed load.[142]

The rapidly dwindling supply of generation on February 2 created a scarcity event and, not surprisingly, caused prices to spike. By 4:55 AM, prices had reached a sustained level of $3,000 per MWh.[143]

These high prices, coupled with the fact they occurred the day after the price cap had been raised to $3,000 per MWh, fueled speculation that market manipulation may have been a factor. Such speculation was probably exacerbated by certain instances of past high prices, as well as two studies finding the existence of market power in the ERCOT markets.

In 2001, prices rose to the $1,000 per MWh cap on the first day of operation of ERCOT's pilot zonal market.[144] During the winter storm of February 2003, high prices of $990 per MWh in the balancing market and $967 per MWh in the ancillary service market were later determined to have been partially caused by "hockey stick bidding."[145] According to two studies evaluating behavior in the

[142] Potomac Report at 15.

[143] *Id*. at 20.

[144] The Steering Committee of Cities Served by Oncor and the Texas Coalition for Affordable Power, The Story of ERCOT: The Grid Operator, Power Market & Prices under Texas Electric Deregulation, at 32 (Feb. 2011), available at http//tcaptx.com/downloads/THE-STORY-OF-ERCOT.pdf.

[145] Public Utility Commission of Texas, *Report to the 79th Texas Legislature: Scope of Competition in the Electric Market in Texas*, January 2005, at 32, *available at* http://www.puc. state. tx.us/industry/electric/reports/scope/2005/2005scope_elec.pdf. Hockey stick bidding

ERCOT balancing market, large firms were found to have exercised unilateral market power between 2001 and 2003.[146] And in March of 2008, two days after the market cap rose to $2,250 per MWh, prices hit the cap for three consecutive 15-minute intervals.[147]

Given these historical events, suspicions concerning the causes of the high prices on February 2 were understandable. The Executive Director of the PUCT directed the IMM for ERCOT, Potomac Economics, Ltd., to investigate whether there was any evidence of market manipulation or market power abuse.

In its April 21 report to the PUCT, the IMM concluded there had not been any market manipulation during the cold weather event on February 2. The IMM further concluded that the ERCOT real-time and day-ahead markets operated efficiently, and that the shortage conditions were properly accompanied by scarcity level pricing, a phenomenon consistent with ERCOT's energy-only market design.[148]

The IMM reached its conclusion by examining whether there had been any economic or physical withholding. The IMM's test for economic withholding was to determine whether energy had not been produced when the capacity would have been economic, given the prevailing price. Since all available capacity was being utilized when prices spiked, the IMM concluded there had been no economic withholding.[149] The IMM's test for physical withholding was to determine whether resources were made unavailable that were actually capable of providing energy and were economic at prevailing market prices. This determination

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involves offers of a small, expendable quantity of energy or capacity well in excess of its marginal cost, which can set the marginal clearing price at times of short-term demand when all offers must be accepted. See Daniel Hurlbut, Keith Rogas, and Shmuel Oren, *Protecting the Market from "Hockey Stick" Pricing: How the Public Utility Commission of Texas is Dealing with Potential Price Gouging*, THE ELEC. J., April 2004, at 26-27.

[146] Ali Hortacsu & Steven L. Puller, *Understanding Strategic Bidding: A Case Study of the Texas Electricity Spot Market* (June 2007), http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.73.9947&rep=rep1&type=pdf; Ramteen Sioshansi & Shmuel Oren, *How Good are Supply Function Equilibrium Models: An Empirical Analysis of the ERCOT Balancing Market*, 31(1) J. REG. ECON. 1 (2007).

[147] Eric S. Schubert, Shmuel Oren & Parviz Adib, *Achieving Resource Adequacy in Texas Via an Energy-Only Electricity Market*, in ELECTRICITY RESTRUCTURING: THE TEXAS STORY 70, 92 (L. Lynne Kiesling & Andrew N. Kleit, eds., AEI Press, 2009).

[148] Potomac Report at 1-2, 8.

[149] *Id*. at 8-9.

required a review of the causes of outages and derates. After conducting this review, the IMM found no evidence that the outages and derates were caused by anything other than the physical inability of the generators to produce power.[150]

The IMM observed that the scope of the outages and derates was widespread in geography, generating unit type, and by class of market participant.[151] It also observed that those market participants that were able to operate their generation fleet at greater than 90 percent availability during the morning of February 2 were financially successful that day, and the market participants affected by significant generation outages were unprofitable.[152] Furthermore, those market participants that lost significant generating capacity and were unprofitable on February 2 did not achieve gains on February 3 that significantly exceeded the previous day's losses, despite high day-ahead prices.[153] These findings suggested to the IMM that market participants had every incentive to offer their units' capacity into the market, had they been physically able to do so.

Based both on the IMM's study and on the task force's independent evaluation of the causes of the generator outages, there does not appear to be evidence that the high prices on February 2 were the result of market manipulation. Rather, they appear to be the natural result of scarcity pricing in an energy-only market.

Rio Grande Valley Event: February 3-4

In addition to the ERCOT-wide load shed on February 2, ERCOT experienced more localized difficulties on February 3 and February 4 that necessitated local load shedding. The area affected was the southernmost tip of Texas along the Rio Grande River, designated as the Lower Rio Grande Valley (LRGV).

The weather in the LRGV is typically mild. Temperatures in February for Brownsville, the largest city in the LRGV, average a high of 72 degrees and a low of 53 degrees. For February 2011 as a whole, Brownsville had a high of 90

[150] *Id*. at 12.

[151] *Id*. at 10.

[152] *Id*. at 14.

[153] *Id.*

degrees; on February 3, however, the high reached only 36 degrees, with a low of 28 degrees.[154]

Load in the LRGV generally exceeds available local generation, making the area dependent on imports. The Rio Grande Valley import capability consists of a group of five elements, three 138 kV and two 345 kV transmission lines, owned and operated by American Electric Power (AEP), that allow for the import of energy into the LRGV area. The Rio Grande Valley import limit is a contingency import limit based on the loss of either of the two series compensated 345 kV lines that transmit electricity into the LRGV. The contingency limit is 1200 MW, with economic redispatch occurring at 1100 MW. This limit was exceeded for short periods during the evening hours of February 2, and for over 30 consecutive hours beginning on February 3 and concluding on February 4.

Two types of events can trigger load shedding to prevent an uncontrolled loss of load: under-frequency and under-voltage. Under-frequency load shedding is designed to rebalance load and generation within an electrical island following a system disturbance. Under-voltage load shedding is designed to prevent local area voltage collapse. While the ERCOT-wide February 2 event was the result of under-frequency concerns, the issue in the LRGV was one of under-voltage. Had the entities in the LRGV not implemented manual load shedding on February 3, a subsequent contingency could have resulted in the activation of automatic under-voltage load shedding.

On February 3, the LRGV area hit an all-time winter peak demand of 2734 MW.[155] A total of 829 MW of local generation was on scheduled outage that day, and the picture was further complicated by the loss of the three Frontera units, totaling 486 MW. The two Frontera combustion turbines CTG-1 and CTG-2 tripped due to frozen control equipment pneumatics at 9:47 PM and 9:59 PM, respectively, followed by the steam turbine CTG-3 at 10:00 PM. The import limit of 1200 MW had already been exceeded, beginning at 6:23 AM. When the three Frontera units tripped in rapid succession, the import level rose to 2074 MW (172.8 percent of the limit of 1200 MW). Additionally, the bus voltages at some substations dipped to 91 percent to 93 percent of nominal, which is outside the normal AEP Texas operating voltage range of 95 percent to 105 percent nominal. (The automatic under-voltage load shedding system in the LRGV activates when the voltage declines to 90 percent for three seconds.)

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[154] Weather Underground, *Almanac for Brownsville*, http://www.wunderground.com/history/airport/KBRO/2011/2/3/Daily History.html.

[155] Texas Reliability Entity, *Event Analysis: February 3-4, 2011 Lower Rio Grande Valley Load Shed Category 2f.1 Event* at 4 (April 15, 2011) (LRGV Event Analysis Report).

The transmission providers for the LRGV area are AEP, Public Utilities Board of Brownsville (BPUB), and the South Texas Electric Cooperative (STEC). AEP had previously developed a procedure with ERCOT, STEC, and BPUB that specified the load allocation for any necessary manual load shed in the event of the loss of one of the 345 kV transmission lines. The entities decided to use that plan for this event, even though it was not caused by the loss of a line but rather by the loss of Rio Grande Valley generation. AEP initiated the load shedding and the three entities each manually shed their portion of the target 300 MW load shed, beginning the process at 10:06 PM on February 3.[156] The maximum actual load shed of 459.5 MW occurred at 10:59 PM. (Power was fully restored to most customers in the early morning hours of February 4.)

Approximately 115,000 customers were affected by the rolling blackouts, with AEP contributing 60 percent of the load shed obligation and BPUB and STEC each contributing 20 percent. The task force determined that load shedding was executed well by all three entities and the required levels of load shedding were reached within ERCOT's specified 30-minute period. The entities attempted to rotate the load shed through different circuits, but due to the size of the allotments of BPUB and STEC relative to their total load, as well as the number of critical loads on their systems, the rotation periods for each circuit of load shedding were longer than desired and more frequent than during the ERCOT-wide load shed of February 2.

Some of the transmission providers in the LRGV region expressed concerns about communications with ERCOT. AEP initiated the first phase of the load shed and then requested ERCOT to notify the other transmission providers to shed their portion, as opposed to ERCOT directing the simultaneous shedding of load. As a result, AEP proceeded alone for the first phase of the load shed. The transmission providers also observed that a public announcement made by ERCOT on February 3, advising customers that further outages appeared unlikely, did not accurately reflect the situation in the LRGV and complicated the conduct of their localized load shed.

The task force concluded that in order to prevent similar problems in the future, additional generation or transmission lines are needed to reinforce the LRGV area. This is in accord with ERCOT's Regional Planning Group analysis, which concluded that there is a need for transmission or market solutions in the LRGV to meet forecasted load beyond 2014.[157] AEP Service Company has

[156] LRGV Event Analysis Report at 20.

[157] *Lower Rio Grande Valley (LRGV) 345 kV Project Analysis*, ERCOT (May 13, 2011), http://www.ercot.com/content/meetings/rpg/keydocs/2011/0513/ERCOT_Lower_Rio_Grande_Valley_345_kV_Project_Analysis.pdf.

proposed a new 345 kV transmission line from the Laredo area into the LRGV; however, improvements at this time are in the early planning stages.

February 10, 2011

In analyzing the implications of the February 2 blackouts, it is instructive to compare that day with February 10, when ERCOT did not shed either firm or interruptible load despite setting a new winter peak.[158] Cold weather was again expected on that day, and actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12 degree wind chill. (This compares to a low on February 2 of 19 degrees with wind chill of 4 degrees; however, low temperatures during the earlier event were more persistent, remaining in the low twenties for four days with wind chills between 10 and 14 degrees.) The average high temperature in the ERCOT region on February 10 was over 42 degrees (compared to an average high between February 2 and February 5 that remained below freezing).

ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages. ERCOT reports that 11 units, totaling 2160 MW of generation, were forced offline at some point during the day. The biggest difference between February 2 and February 10 was the number of units forced offline on February 2 just during the early morning hours. The cumulative net outages on that morning exceeded 14,700 MW,[159] whereas for the entire day on February 10, only 2160 MW were forced offline. The equivalent total outages for the entire day of February 2 was 21,400 MW, a ten-fold difference.

The majority of the forced outages in ERCOT on February 2 were weather-related, while on February 10, few were weather-related (those few were the result of frozen valves, a frozen transmitter and automatic temperature cut-offs at some wind farms). Representative causes of forced outages on February 10 included control issues, a condensate pump that was out of service, the loss of a vacuum pump, a low head level in a cooling lake, frozen valves, low gas header pressure, and a boiler tube leak.

There appear to be three reasons ERCOT was not forced to shed load on February 10: repairs made and protective measures taken during the event of February 2 remained in place; the temperatures on February 10 were not quite as

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[158] The peak of 57,915 MW occurred at 7:15 AM.

[159] "Cumulative net outages" subtracts out those units that were successfully brought back online.

cold and the cold temperatures were of shorter duration; and the wind chill was, in the main, not as severe.

In interviews with the task force, generator operators mentioned that on or after the earlier event they had installed wind breaks, including tarps or enclosures, added portable heaters or heat lamps, repaired or added insulation, and repaired or added heat tracing. One generator changed its procedures for monitoring the reliability of its heat tracing. Some generators also continued their increased level of staffing to address freeze protection issues, and others changed elements of their control logic to prevent units from automatically tripping.

Some of the vulnerabilities identified and addressed the week before included re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals. At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing.

The storm on February 10 was concentrated in Oklahoma and northern Texas, unlike the more widespread storm of February 2. Temperatures by and large were somewhat less severe, especially during the day when they rose above freezing. A number of generator operators told the task force that the difference in temperatures and the shorter duration of the cold spell on February 10 were significant factors in the improved performance of their units.

Lastly, the wind chill in some areas was not as extreme on February 10 as during the preceding week. Some generator operators cited the lower wind speed as a significant factor in their improved performance, an assessment with which ERCOT concurred.[160]

Salt River Project

ERCOT was not the only entity in the Southwest that was forced to shed load during the storm of February 1 through February 5. SRP shed 300 MW of load on February 2, affecting 65,000 customers. However, only some of the generation losses leading to SRP's load shed were weather-related.

[160] Of special interest to wind units was the absence of precipitation that would ice their turbine blades. Several wind farm operators mentioned this absence as a factor in their improved performance.

SRP's problems began at 6:54 PM on February 1, when Unit 1 at the Navajo Generating Station (NGS) in Page, Arizona, tripped offline.[161] Page was experiencing colder than average temperatures, reaching a high of 36 degrees and a low of 17 degrees, and facing average wind speeds of 10 miles per hour. NGS Unit 1 tripped due to these freezing conditions when a sensing line leading to a waterwall pressure transmitter froze. The trip resulted in a loss of 330 MW of generation for the SRP balancing authority area.[162]

In response to the trip, SRP called on the SRSG for assistance and imported its allowed amount of 170 MW. It also deployed 80 MW of spinning reserves and curtailed 48 MW of interruptible load. At 8:10 PM, SRP restored the interruptible load.

To make up for the loss of NGS Unit 1, SRP's system operator scheduled Santan Generating Station (SGS) Unit 6, a 275 MW combined cycle unit (consisting of a combustion turbine and a steam turbine), to start at 5:00 AM on February 2 (it had not been included in SRP's day-ahead plan). Understanding that it might need additional generation on February 2, SRP also decided to keep SGS Unit 5, a 570 MW unit, online for the following day.

On February 2, SRP's difficulties resumed at 2:56 AM, when Coronado Generating Station (CGS) Unit 2, which is coal-fired, tripped offline due to a non-weather related mechanical problem with its coal pulverizers. Although the unit was running at only 130 MW at the time of the trip, it was scheduled for its full 389 MW output for the morning peak. The loss of CGS Unit 2 also tripped Coronado 500 kV breakers 945 and 948.

SRP lost another 75 MW at 3:20 AM, when Unit 4 at the Four Corners Power Plant (FC) tripped due to control valve problems (all 750 MW of the unit was lost, of which SRP has a ten percent share). The FC unit trip was weather-related and occasioned by frozen sensing lines. SRP dispatched SGS Units 1, 2, 5 and 6 to replace the loss of FC Unit 4 for the morning peak.

SRP was able to close the Coronado 500 kV breaker 945 at 4:21 AM, and brought Coronado 2 back online. Shortly thereafter, at 5:07 AM, SRP dispatched SGS Units 1 and 2 at 90 MW each to meet increasing system loads, and at 5:15 AM ramped SGS Unit 6 to 236 MW.

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[161] Details are based on information provided to the task force by SRP.

[162] NGS Unit 1 is a 750 MW unit that is owned by the Salt River Project, U.S. Bureau of Reclamation, Los Angeles Department of Power & Light, Arizona Public Service, NV Energy, Inc., and Tucson Electric Power. SRP has a 21.7 percent ownership in the unit. NGS Unit 2, discussed below, has the same ownership structure and total output.

At 5:18 AM, SRP dispatched duct firing on SGS Units 5&6.[163] A few minutes later, at 5:22 AM, the SGS Unit 6 steam turbine tripped, although the unit's combustion turbine was able to continue supplying generation. The steam unit had an output of 80 MW. At this time, SRP system operators told the generator operators at SGS that they needed the steam turbine back online as quickly as possible. The system operators were not aware, and were not advised by the generator operators, that in order to get the steam turbine back online, the combustion turbine would have to be ramped down significantly. Between 5:22 AM and 5:44 AM, as a result of the ramping down of the combustion turbine, the output of SGS Unit 6 was reduced from 159 MW to 15 MW.

SRP experienced a flurry of activity between 5:22 AM and 6:00 AM. After the loss of the SGS Unit 6 steam turbine, SRP dispatched the Mormon Flat Hydro (MFH) Unit 2 to come online at 50 MW, interrupted 38 MW of instantaneous interruptible load, and at 5:30 AM dispatched Horse Mesa Hydro (HMH) Units 1, 2 and 3, for a total of 30 MW additional generation. SRP's system operators also directed its merchant group to purchase 100 MW for the 7:00-8:00 AM hour. At 5:31 AM, SRP called on MFH Unit 1 for 10 MW, and also requested that a large interruptible customer drop 100 MW of 10-minute interruptible load. At this point SRP's reserves were diminishing, and SRP used the interruptible load to increase its spinning reserves.

At 5:39 AM, SRP was able to bring SGS Unit 2 online at 92 MW, and at 5:40 AM, SRP's merchant group called on another interruptible customer to drop 29 MW of contracted interruptible load in the 6:00-7:00 AM hour. However, Tucson Electric Power contacted SRP at the same time to report that it had lost Springerville Unit 3, which diminished SRP's available capacity by another 25 MW. At 5:44 AM, SRP determined that SGS Unit 6 would not be able to return to service, resulting in a total loss of 236 MW of capacity.

SRP was able to bring on SGS Unit 2 online at 40 MW at 5:45 AM, and SGS Unit 1 at 40 MW at 5:57 AM. At 6:00 AM on February 2, SRP system load was running at 3557 MW, which was 161 MW higher than its day-ahead schedule.

At 6:02 AM, SRP dispatched Units 4, 5, and 6 at the Agua Fria Generating Station (AFGS), at approximately 70 MW each, to recover reserves and meet forecasted load. SGS Unit 2 also reached full load of 100 MW at this time. Two minutes later SRP dispatched Kyrene Generating Station (KGS) Units 5 and 6, at 60 MW each. Unit 6 was brought online at 6:11 AM and Unit 5 at 6:14 AM. SRP

[163] Duct firing is a process involving additional burners being fired for a heat recovery steam generator (HRSG) to increase steam production and output. The output of the burners combines with the hot exhaust gas from the gas-fired turbines to create steam.

dispatched the 41 MW KGS Unit 4 at 6:08 AM and HMH Units 1, 2 & 3 at 10 MW each at 6:09 AM. At this point all available SRP generating units were dispatched, and SRP purchased an additional 100 MW to begin at 6:20 AM.

SRP issued a Capacity Alert at 6:17 AM. (A Capacity Alert is an internal alert telling operators in the balancing authority that SRP believes that if another unit were to trip, the balancing authority would have trouble recovering.) A Capacity Alert is a precursor to a NERC EEA-1.

Five minutes later, NGS Unit 2 tripped due to frozen waterwall pressure sensing lines. The trip resulted in the loss of 350 MW for the SRP balancing authority area, and constituted the event that triggered load shedding. In response to the NGS Unit 2 trip, SRP again called on SRSG for assistance and was supplied with 128 MW, 82 MW less than anticipated. EPE, a neighboring balancing authority experiencing its own difficulties, told SRP that it could not deliver the assistance it was obligated to provide under the SRSG Agreement.

Immediately after the NGS Unit 2 tripped at 6:22 AM, SRP's system operator determined, based on the information available to him, that the remaining reserve and emergency assistance was insufficient to recover SRP's ACE in a timely manner.[164] The operator concluded that 300 MW of firm load needed to be shed to insure stable operations of the bulk electric system should additional generation trip offline. The system operator contacted its reliability coordinator, WECC's LRCC (Loveland Reliability Coordination Center), to notify it of the impending load shed. At 6:24 AM LRCC directed SRP (as transmission provider) to shed 300 MW. At the same time, KGS Units 5 and 6 reached full load of 62 MW each, and SRP's merchant group purchased 190 MW for the 7:00-8:00 hour.

At 6:29 AM, SRP called on the last of its 10-minute interruptible load, curtailing 136 MW. At the same time, SRP's distribution service provider initiated its rotating load shed program. Once initiated, load shed is to take place within one minute; however, SRP's distribution service provider encountered problems, requiring five full minutes to initiate the sequence. At 6:31 AM, LRCC declared an EEA 3 for SRP, which was seven minutes after SRP had initiated the shedding of 300 MW of load.

SRP reports that the 300 MW load shed event affected approximately 65,000 customers.

[164] ACE, or area control error, refers to the instantaneous difference between a balancing authority's net actual and scheduled interchange with other balancing authorities, taking into account the effects of frequency bias and correction for meter error.

Immediately after the load shed was initiated, SRP's ACE returned to normal. At this time SRP also restored its reserves to meet its SRSG reserve requirement. At 6:34 AM, Springerville Unit 3 tripped offline due to high furnace pressure, cutting 75 MW of generation (although this did not affect SRP's operations).

AFGS Units 4, 5 and 6 remained online and ramping to full load, and at 6:34 AM SRP's system operator instructed the distribution service provider to restore 100 MW of firm load. However, instead of restoring only the 100 MW, the distribution service provider mistakenly restored all 300 MW of the load that was shed. At 6:45 AM, the distribution service provider realized its mistake and, without further instruction, shed 200 MW of the load that had been restored. Prior to the second load shed of 200 MW, SRP's ACE had returned to normal.

At 6:52 AM, KGS Unit 4 came online and began ramping to full load, and the system operator directed the restoration of another 100 MW of shed load. At 6:55 AM, SGS Unit 6 returned to service and a minute later the system operator directed that the final 100 MW of shed load be restored. By 6:57 AM, approximately a half-hour after the initial load shed, SRP was able to restore service to its customers.[165] At 7:05 AM, LRCC declared a return to an EEA 0 condition effective as of 6:59 AM.

El Paso Electric Company

During the cold weather event, EPE experienced forced outages of all but one generator in its El Paso area fleet. Because of the significant loss of its local generation (six out of seven operational units) and the resulting loss of dynamic reactive support, EPE was limited in the amount of generation that could be imported on its transmission system.[166]

With limited import capability and limited local generation, EPE had to operate its system in such a way as to prevent cascading due to voltage instability. It was therefore necessary for EPE to reduce loads in its service area by manual load reduction. Load shedding occurred four times between February 1 and

[165] Although SRP had directed that all load be restored at this time, some of the distribution service provider's breakers would not close, leaving 4000 customers without service until 9:43 AM.

[166] EPE utilizes WECC Path 47 to import power from Palo Verde and Four Corners. The capability of this path is limited by post-contingency voltages. EPE can also utilize the Eddy DC tie in New Mexico to help regulate the flows on Path 47 by importing up to approximately 200 MWs from Southwestern Public Service (SPS) to the East.

February 4, totaling up to approximately 1023 MW and affecting 253,000 customers. Two of the load shed events occurred on February 2, one on February 3 and one on February 4 (all due to voltage instability concerns).

The four-day sequence of events is set forth below.[167]

Tuesday, February 1, 2011

On February 1, an arctic air mass moved in across the Las Cruces and El Paso area. Temperatures hovered in the low 40s between midnight and 4:00 AM, but dropped as the wind changed direction. The temperature dipped below freezing at approximately 8:51 AM and then plummeted into the middle teens by the late evening hours. Maximum temperature for the day was 43 degrees and the minimum was 14 degrees.

As the colder air moved in, gusty winds picked up in the late evening, measuring up to 26 mph at the El Paso International Airport. These gusts, combined with air temperatures in the middle teens, produced wind chill values below zero. The peak wind gust reached on February 1 was 43 mph (during the 1:00 AM hour).

Timeline of Events

- At 6:34 PM, the Coyote-Dell City 115 kV line tripped (reportedly as a result of gunshot damage to a conductor).
- At 8:07 PM, the first of EPE's gas-fired generators, Newman No. 3, tripped (loss of 40 MW).[168]
- At 10:15 PM, Rio Grande No. 6 tripped (loss of 50 MW).
- At 10:15 PM, system controllers contacted LRCC, EPE's reliability coordinator, and advised it of the loss of local generation.
- At 10:52 PM, system controllers requested that interruptible loads be interrupted due to the extreme weather conditions and the loss of local generation.

[167] Details are based on information provided to the task force by EPE.

[168] The various causes of EPE's unit trips are discussed in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

- At 11:45 PM, the Copper Generator was brought online.

Wednesday, February 2, 2011

The air temperature continued to drop during the morning of February 2, falling from 13 degrees at 1:00 AM to 8 degrees by 8:00 AM. Temperatures moderated during the afternoon, reaching 15 degrees. On February 2, the maximum temperature was 15 degrees (45 degrees below normal) and the minimum temperature was 6 degrees.

The maximum temperature for the day was the coldest maximum (high) temperature ever recorded in El Paso, Texas. A few wind gusts up to 24-26 mph occurred around mid-day. This, combined with the frigid air temperatures, produced wind chill values of -9 to -10 degrees. The peak wind speed reached on February 2 was 26 mph.

Timeline of Events

- At 12:10 AM, Newman 5 GT3 tripped.
- At 12:26 AM, Newman 5 GT4 tripped.
- At 1:49 AM, Rio Grande No. 8 tripped.
- At 1:53 AM, system controllers contacted LRCC, which declared an EEA l.
- At 2:02 AM, EPE purchased power from SPS; the Eddy DC tie was opened and ramped to 100 MW.
- At 2:27 AM, a switching order was given by the system controller to synchronize PNM's Luna Energy Facility (Luna) to the grid, permitting the transmittal of power EPE had purchased from PNM.
- At 3:17 AM, Newman Generator No. 4 GT1 tripped.
- At 3:20 AM, Four Corners Unit No. 4 tripped.

- At 5:07 AM, the HVDC terminal at the Eddy DC Tie experienced a runback[169] from 100 MW to 48 MW.

- At 5:12 AM, system controllers again contacted LRCC, and the EEA level was heightened to EEA 2. This Alert advised other utilities that EPE was placing its load management procedures in effect due to its energy deficient condition. Actions taken pursuant to this Alert included public appeals to reduce demand, made through media announcements, and other demand-side management procedures.

- At 6:28 AM, the Coyote-Dell City 115 kV line was restored.

- At 7:12 AM, the Newman No. 4 steam turbine (ST) tripped, and the Newman-Butterfield 115 kV line opened at Newman (tripping the line).

- At 7:16 AM, the Newman No.4 GT2 unit tripped. With the loss of Newman No.4 GT2, the Copper unit was the only local unit remaining online that could supply dynamic reactive support (it was producing 55 MW of power).

- At 7:22 AM, system controllers initiated load shedding in order to balance load with generation and maintain voltage stability. Area load was at 982 MW at the time, and approximately 170 MW of firm load was shed.

- At 7:23 AM, EPE again contacted LRCC and EPE's EEA status was increased to an EEA 3. This alert advised other utilities that EPE had implemented firm load interruptions.

- At 7:55 AM, system controllers saw that Luna had lost approximately 130 MW of generation. Another 103 MW of load was shed, with load stabilizing at 710 MW.

- At 8:16 AM, Luna ramped up to 235 MW.

- At 9:51 AM, the combustion turbine portion of PNM's Afton combined cycle generator was placed online (the steam turbine portion of this generator experienced problems and remained unavailable throughout the

[169] "Runback" is a manually or automatically controlled decrease in output designed to protect against loss of thermal transfer capability or transient angle instability.

event). EPE made arrangements to obtain power from that unit on an hourly basis.

- At 12:17 PM, controlled load shedding ended, with load at 977 MW.
- At 12:19 PM, LRCC was contacted and EPE's EEA alert level was decreased to EEA 2.
- At 6:04 PM, the terminal at the Eddy DC tie tripped (opening the Amrad-Eddy 345 kV line).
- At 6:11 PM, load shedding resumed, and continued for approximately two hours and 45 minutes. Load shed amounts varied between 100 and 250 MW during this period.
- At 6:15 PM, EPE contacted LRCC, which again placed EPE under EEA 3 status.
- At 8:58 PM, load shedding terminated because of reduced load demand. EPE contacted LRCC, which changed the EEA alert level back to an EEA 2.
- At 11:04 PM, the Eddy DC tie (and the Amrad-Eddy 345 kV line) resumed operation. (According to SPS, operating agent for the DC Terminal, the tie had tripped due to loss of thyristors.[170])

Thursday, February 3, 2011

The lowest temperatures of the event were experienced in the El Paso area during the morning of February 3, 2011. Temperatures remained in the single digits from midnight through 10:00 AM, slowly climbed into the teens during the late morning, and reached a maximum of 18 degrees at 2:51 PM. The high temperature for the day was 18 degrees, and the low was 1 degree. (The high temperature was 43 degrees below normal, and the low was 34 degrees below normal). The peak wind speed reached on February 3 was 20 mph. The combination of frigid air temperatures and wind speeds produced wind chill values from midnight to 11:00 AM of -10 to -17 degrees.

[170] A thyristor is a semiconductor with an anode, a cathode and a gate. Thyristors have the ability to switch high voltages and withstand reverse voltages, and are used in switching applications, especially in AC circuits, for AC power control, and overvoltage protection for power supplies.

Timeline of Events

- At 3:45 PM, PNM's Afton CT tripped.
- At 4:23 PM, PNM put the Afton CT back online.
- At 5:00 PM, as the evening load increased, LRCC was contacted, and EPE's alert status was elevated to EEA 3.
- At 5:30 PM, controlled rotating load shedding resumed for just over five hours. During this period, the load shed amounts varied between 100 MW and 250 MW.
- At 6:52 PM, Newman 4 GT1 was brought online.
- At 7:20 PM, Newman 4 GT1 tripped.
- At 9:32 PM, Newman 4 GT1 returned online.
- At 10:30 PM, Newman 4 GT2 was brought online.
- At 10:30 PM, EPE terminated the controlled rotating load shedding.
- At 10:40 PM, LRCC lowered the EEA level to Alert Level 2.

Friday, February 4, 2011

On February 4, although skies were clear and winds relatively calm, temperatures were as low as 3 degrees during the early morning hours. By late morning, temperatures moderated, reaching the middle 20s by 12:00 PM. The temperature continued to rise during the afternoon, and the high for the day was 37 degrees. Winds, with speeds under 10 mph, were generally light and variable in direction. The low for the day was 3 degrees. (The maximum air temperature was 24 degrees below normal and the minimum air temperature was 32 degrees below normal).

Timeline of Events

- At 2:02 AM, Newman 4 GT2 tripped.
- At 2:04 AM, Newman 4 GT1 tripped.

- At 3:17 AM, PNM's Luna steam turbine tripped.
- At 3:23 AM, one Luna gas turbine dropped from 90 MW to 11 MW.
- At 3:51 AM, the Luna steam turbine was brought back online and slowly ramped up.
- At 6:30 AM, LRCC issued an EEA Level 3 for EPE. With Copper again as the only local unit online, controlled rotating load shedding of between 100 MW and 250 MW resumed.
- At 6:49 AM, Newman 4 GT2 was brought online.
- At 12:05 PM, the controlled rotating load shedding ended.
- At 12:12 PM, the RC changed EPE's alert status to an EEA Level 2.
- At 3:57 PM, Newman 5 GT4 unit was brought online and remained stable at 50 MW.
- At 5:12 PM, the Rio Grande 8 unit was brought online.

Due to the added generation, which provided the necessary dynamic reactive support, no controlled rotating load shedding was required for the Friday night peak load period or thereafter during the event.

Saturday, February 5, 2011

- At 4:07 PM, Newman 5 GT3 came online.
- At 4:30 PM, LRCC modified EPE's alert status to an EEA Level 1.

Sunday, February 6, 2011

- At 9:46 AM, LRCC decreased EPE's alert status to an EEA Level 0.

Public Service Company of New Mexico

PNM set a new record winter system demand during the February cold weather event and experienced outages on some of the generating units it owns,

co-owns, or from which it purchases power.[171] PNM was generally able to meet its system load requirements and also to provide energy assistance to another utility. On February 3, however, PNM was forced to implement a localized rolling blackout in the Alamagordo and Ruidoso areas in southern New Mexico, and experienced an outage in the town of Clayton in northeastern New Mexico.

In the Alamogordo and Ruidoso areas, the February 3 rolling blackout was implemented at 5:21 AM by the PNM Distribution Operations Center, as a result of a transmission line outage. The PNM Amrad to Alamogordo 115 kV transmission line locked out due to a failed conductor clamp, a condition that was apparently unrelated to the weather. As a result, the Las Cruces to Alamogordo 115 kV transmission line, owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), became overloaded and required load relief from PNM and Tri-State. PNM implemented its share of the load curtailment by sequential curtailment of two separate feeder lines. Approximately 20,207 customers were affected, with an estimated load loss of up to 22.1 MW. All circuits were fully restored at 8:08 AM.

The outage in Clayton began at 5:03 AM as a result of the outage of a Tri-State 69 kV transmission line that serves PNM's Van Buren substation, located in Clayton. A static wire, stretched by the extremely cold weather, snapped and fell on one of the phases of the line, interrupting service to the town. All service was restored at 6:54 AM. The estimated load lost was 3.7 MW.

Southwest Power Pool

SPP also experienced severe weather conditions over much of its footprint during the February cold weather event. However, none of its entities was forced to shed load. Three BAs within SPP declared varying levels of EEAs due to tripping or derating of generating resources or deficiencies in natural gas supply. In one instance, SPS requested an EEA 1 following the trip of a 250 MW gas-fired generating unit. SPS had all of its available resources in use and issued public appeals for energy conservation. In a second instance, Oklahoma Gas & Electric Company (OG&E) experienced multiple generation losses on February 2 and February 3, and requested four separate EEA 2 declarations during the week. It was unable to meet its energy commitments to the reserve sharing group run by SPP. In the last instance, Sunflower Electric Cooperative (Sunflower) requested an EEA 3 on February 2 following the loss and subsequent derating of a large coal

[171] Generating units affected, to a greater or lesser degree, included Four Corners Unit 4, Reeves Unit 1, Reeves Unit 3, Delta Person CT, Valencia, Afton, LGS Units 1 and 2, and Luna Unit 2.

generating unit. The failure to start of a gas-fired combustion turbine aggravated the situation, which continued until the afternoon of February 3. During this period, Sunflower was unable to meet its energy commitments to the SPP reserve sharing group. However, following declaration of the EEA 3, Sunflower obtained sufficient transmission service to purchase energy and was able to meet its own firm energy commitments, thereby avoiding the need to shed load.

In SPS's case, its purchases over the Blackwater Tie (a connection between the Western and Eastern Interconnections) were lost between 9:00 AM and 10:00 AM on February 2, due to capacity emergencies in the Western Interconnection. SPS replaced this purchase with a 100 MW purchase from Public Service Company of Colorado, importing it over the Lamar Tie (another one of the connections between the Western and Eastern Interconnections). SPS ultimately increased this purchase to 210 MW, and was later also able to make limited purchases through the Blackwater Tie.

Notwithstanding SPS's transactions over the ties, the majority of the purchases made by the energy-deficient utilities within SPP were made from other SPP entities. Thus, even if SPP had been separated from its neighbors by asynchronous ties, as is ERCOT, it probably would not have had to shed load during the February event. This suggests that the problems ERCOT experienced did not directly relate to its functionally separate interconnection status, but rather to the ability and preparedness of the generators within its footprint to operate as scheduled during the severe weather conditions.

B. Natural Gas

The extreme cold experienced in early February 2011, particularly on February 2 and February 3, caused widespread production declines. These reductions were typically the result of freeze-offs,[172] mostly at wellheads but also in nearby processing plants. To a lesser extent, other equipment reliability issues contributed to the problems, both at the wellhead and at processing and treating facilities. The rolling power blackouts in ERCOT also played a role in the Fort Worth Basin, as did customer curtailments in the Permian Basin. These supply reductions had adverse effects all the way down the delivery chain.[173]

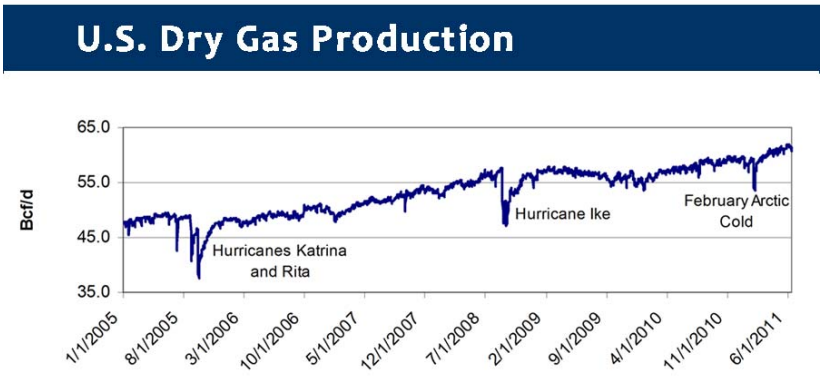
[172] A "freeze-off," as described earlier, occurs when water produced alongside the natural gas crystallizes or freezes, completely blocking off the flow and shutting down the well.

[173] Unless otherwise noted, the entity-specific data was obtained from materials submitted to the task force by producers, processing plants, pipelines, and LDCs.

This subsection summarizes the supply shortfalls resulting from production declines in the basins, discusses the resulting reduced gas volumes and pressures experienced by the pipelines, and ends with a detailed examination of the retail curtailments made by LDCs in the affected states of New Mexico, Arizona, Texas, and California.

Producing and Processing Facilities

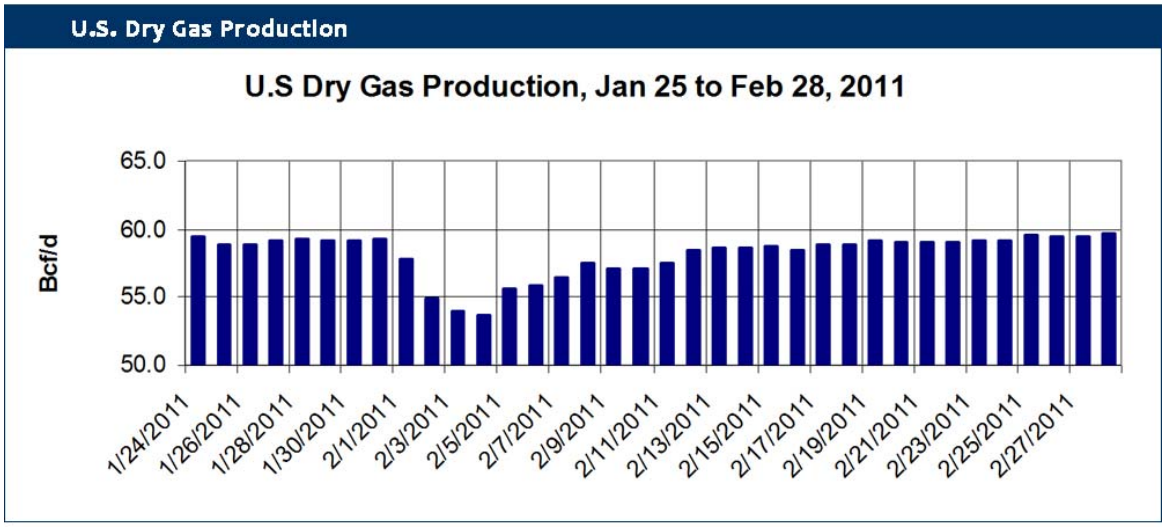
The reductions in supply experienced during the cold weather event were comparable in magnitude to production shut-ins during hurricanes. The following chart illustrates this point.



Source: Task Force chart based on Bentek data

Relative to average dry gas production of 59.22 Bcf per day on January 31, 2011, Bentek estimates that production in the first week of February declined by 5.55 Bcf per day, a reduction of 9.4 percent. The decline began on February 1 and reached its lowest level on February 4.[174]

[174] Data is based on task force analyses using supply and demand history from Bentek.



Source: Task Force chart based on Bentek data

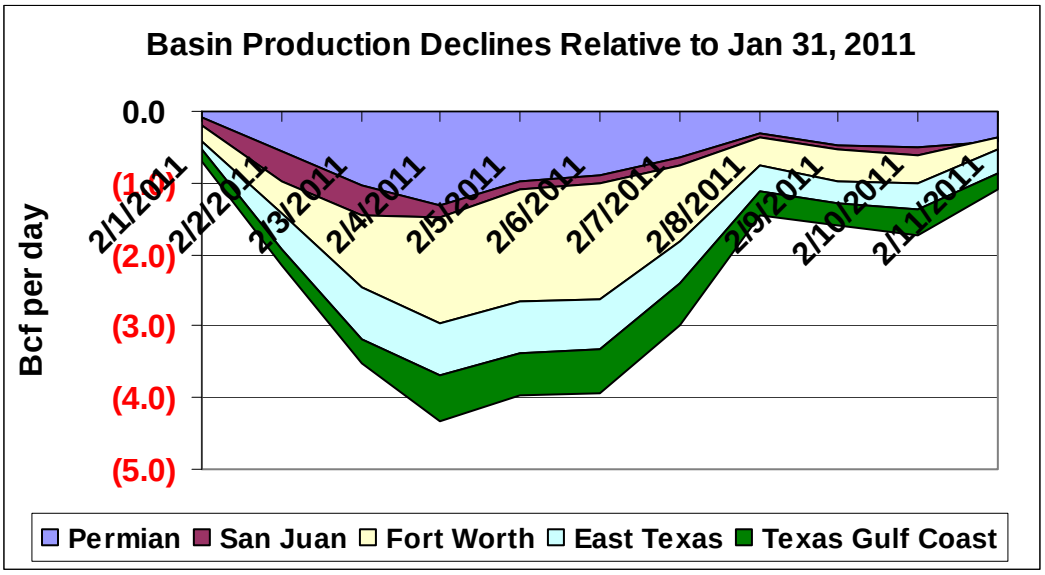
Of the 5.55 Bcf per day decline during the first week in February, 79 percent, or 4.36 Bcf per day, occurred in production basins in Texas and New Mexico (where production declined by 21 percent). Both the San Juan Basin in northern New Mexico and the Permian Basin in west Texas and southeastern New Mexico tend to experience production declines with low temperatures, and the February event was no exception. The declines in these basins, together with the large increases in demand, were almost exclusively responsible for the gas curtailments in Texas, New Mexico and Arizona.[175]

This weather event was so extreme that production freeze-offs were experienced not only in the San Juan and Permian Basins, but throughout Texas and as far south as the Gulf Coast. Based on scheduled pipeline receipts, the task force estimates that production in the Fort Worth Basin declined by 1.63 Bcf per day compared to the last week of January, 2011; East Texas Basin production declined by 0.72 Bcf per day; and Gulf Coast Basin production declined by 0.65 Bcf per day. [176] The shortfalls in these additional Texas basins, while not directly a cause of the natural gas curtailments, did contribute to fuel-related electric

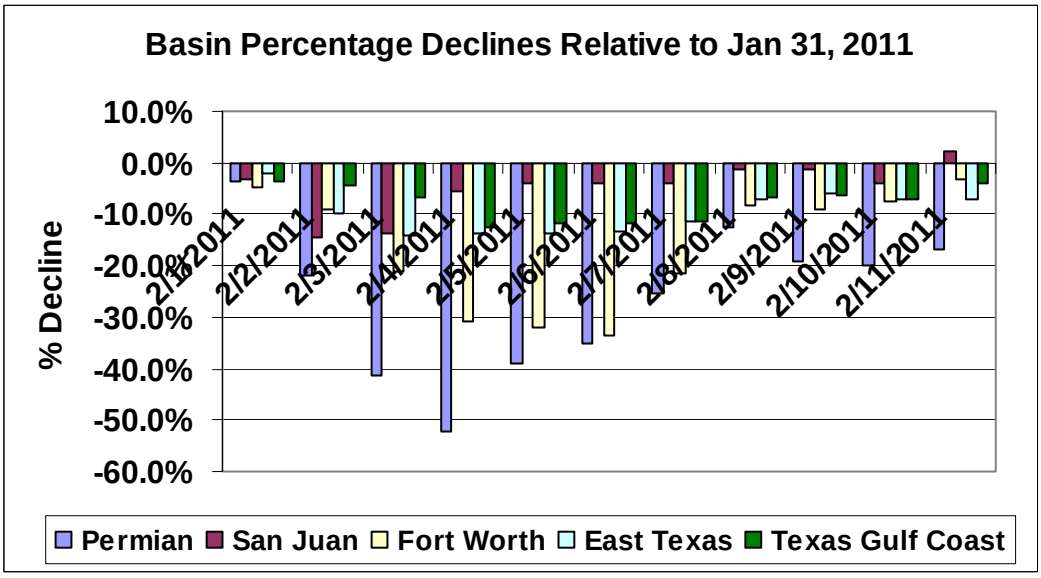
[175] Production declined by 0.43 Bcf per day in the San Juan Basin and by 1.31 Bcf in the Permian Basin, based on task force analyses of Bentek supporting data, pipeline receipts and flow data from El Paso and Transwestern.

[176] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); s*ee also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6; materials submitted to the task force by pipelines. Note that basin level production reductions may not be equal to the total February 4 reduction as not all basin level maximum reductions occurred on February 4.

generation failures in ERCOT. The following charts demonstrate absolute and percentage declines by production basin.



Source: Task Force chart based on Bentek data



Source: Task Force chart based on Bentek data

The causes of these production declines are examined in detail in the following section of this report, entitled "Causes of the Outages and Supply Disruptions."

Effects on the Pipelines and Storage Facilities

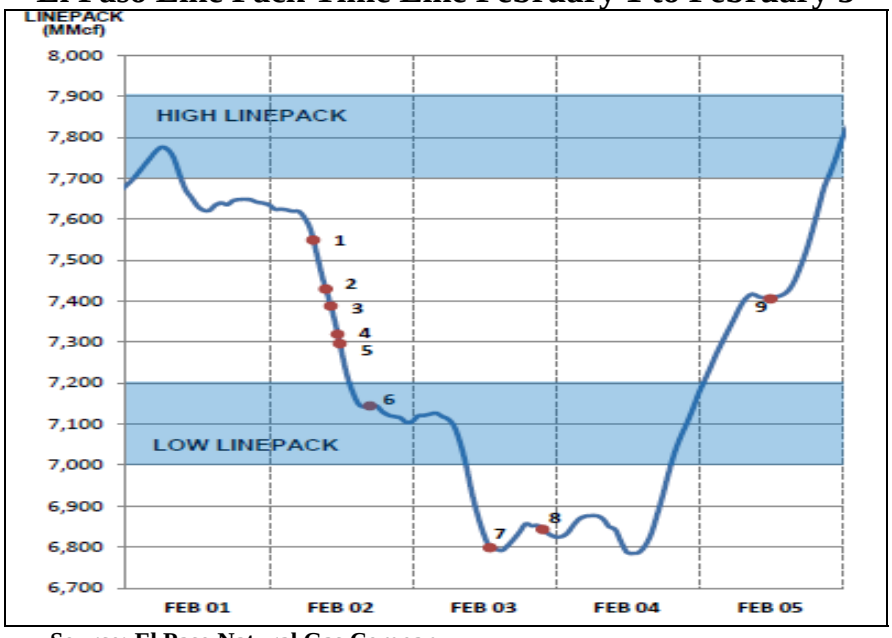
At the same time that gas supplies flowing into the pipelines were reduced, shippers requested increased volumes of gas. The reduced supply relative to higher deliveries (a situation known as a draft condition) resulted in lower line pressures and reduced line pack, which for most pipelines began on February 2.[177]

Between February 1 and February 4, pipelines responded to this draft condition through a variety of approaches. To the extent possible, deliveries to shippers were met by relying upon line pack. Pipelines with storage used increased withdrawals to build line pack. El Paso, for instance, used its Washington Ranch Storage Field to support its south system when gas supplies failed to arrive.

El Paso

The effect of the draft conditions on El Paso's line pack is depicted in the following graph (the numbered dots reference various occurrences on El Paso's system during the cold weather event):

El Paso Line Pack Time Line February 1 to February 5



Source: El Paso Natural Gas Company

[177] Generally by February 4, line pressures and line pack began rising again, as the previous day's scheduled receipts were received into the system. By February 5, line pack grew to a level above that prevailing on February 1.

El Paso system demand increased from 3,416 MDth[178] on January 31 to 3,675 MDth on February 2. For the same period, supply from all sources, including pipeline interconnects, decreased from 3,264 MDth to 3,040 MDth. As supply decreased and demand increased, El Paso used line pack to attempt to maintain deliveries. As a result, line pack fell from almost 7.8 Bcf on February 1 to approximately 6.8 Bcf at 2:00 PM on February 3.

As line pack fell, pipeline pressure on the western edge of the system dropped below 600 pounds per square inch gauge (psig). Pressure on the east side of the system had already dropped below 600 psig, as of 12:00 noon on the previous day. At 10:51 PM on February 3, El Paso issued a low pressure force majeure announcement, suspending its contract obligations and declaring that operating pressure on portions of its system could not sustain contract levels.

Pipeline Communications

Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2011)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFO) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition.) OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also

(cont'd)

[178] "MDth" is a thousand dekatherms.

limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

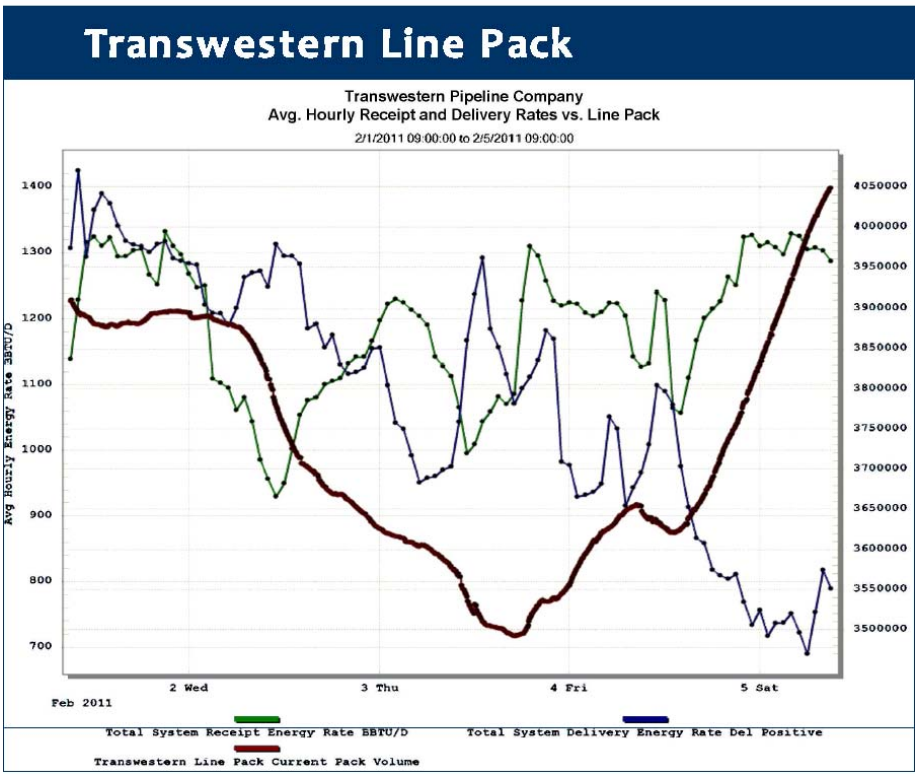
Based on data responses to task force inquiries, the number of companies making use of these various communications and directives for weather-related reasons in the Southwest during the first week of February is as follows:

Type of Pipeline	Number of Data Responses	Number of Companies With a Critical Notice	Number of Companies With an OFO	Number of Companies Declaring Force Majeure
Interstate	24	6	3	1
Intrastate	21	5	5	3

El Paso Natural Gas issued a force majeure declaration on February 3, stating that it had experienced system operating pressure on portions of its mainline and some laterals that could not sustain contract levels. The other interstate pipeline most affected by the supply shortfalls, Transwestern, did not declare a low pressure force majeure.

Transwestern

The effect of the draft conditions on Transwestern's line pack is depicted in the following graph.



Source: Transwestern Pipeline Company, LLC

Scheduled deliveries on Transwestern from January 31 to February 2 increased from 1,426 MDth to 1,526 MDth. Supplies dropped by approximately 400 MDth by midday on February 2; however, Transwestern continued to make scheduled deliveries from line pack. Accordingly, line pack decreased from 3.9 Bcf on February 1 to a low of 3.5 Bcf on February 3. Transwestern, unlike El Paso, did not declare a low pressure force majeure.[179]

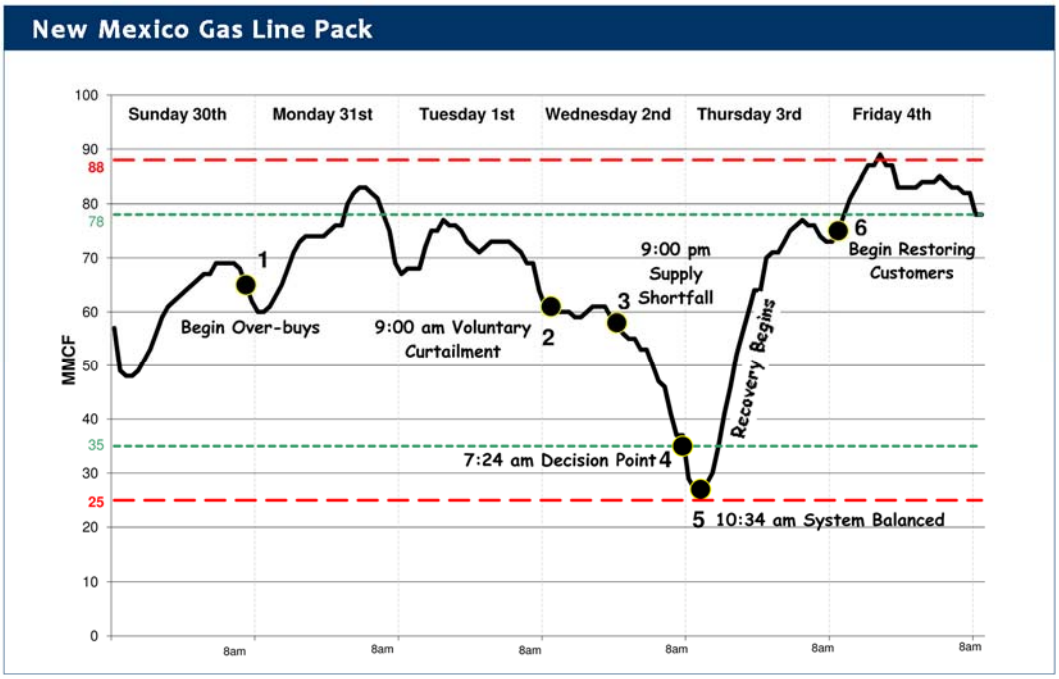
New Mexico Gas Company

NMGC also experienced significant line pack problems on its distribution system. On January 31, NMGC bought additional supply for its north segment and its south/remotes segment, for delivery on the following day. On February 2,

[179] By midday on February 3, pressures and line pack were beginning to increase, and on February 4, NMGC's line pack was over 4 Bcf.

NMGC contacted 39 large industrial and commercial customers, requesting them to reduce or curtail their gas usage. By 9:00 PM on February 2, NMGC reported to supplying pipelines that pre-ordered gas was not being delivered as scheduled.

The effect of events on NMGC's line pack is depicted in the following graph.



Source: New Mexico Gas Company

The vast majority of the shortages experienced on NMGC's north segment on February 2 and 3 was attributable to supply failures at the Transwestern Rio Puerco and El Paso's Wingate interconnection points. An NMGC representative has stated that the failure of Transwestern to deliver scheduled flows of 127,454 MMBtu on February 2 and 146,438 MMBtu on February 3 "was devastating to NMGC and its customers."[180]

Transwestern responded by observing that it scheduled much greater volumes of gas at Rio Puerco than NMGC historically flowed (and equal to the amount nominated by NMGC and other shippers to the point). NMGC was unable to flow all of the scheduled volumes, suggesting there were difficulties on NMGC's system in taking away the gas from the Rio Puerco delivery point. On February 2,

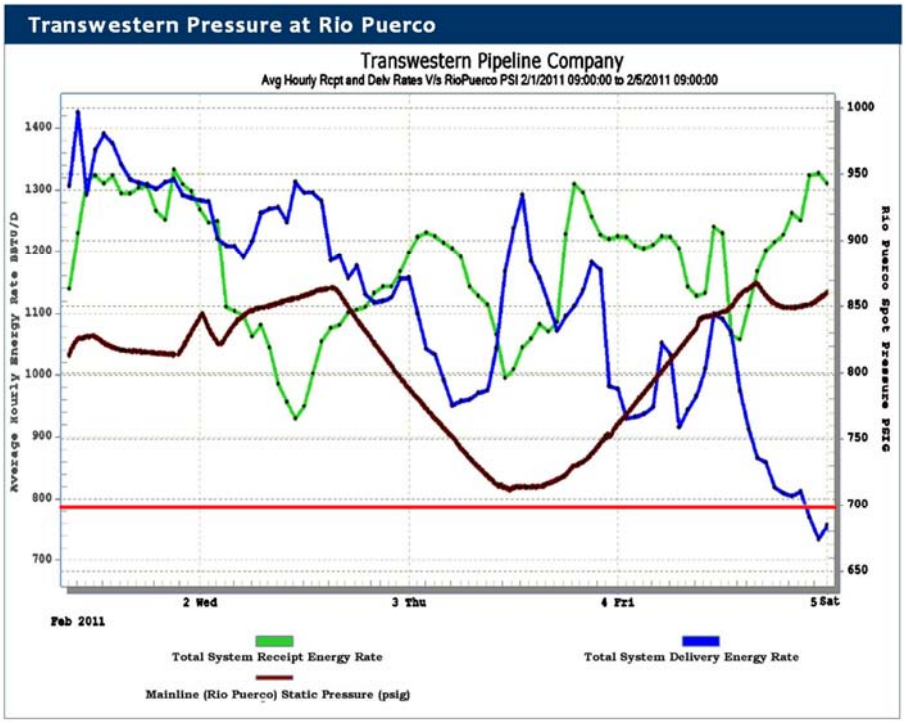
[180] Transcript of Testimony of Tommy Sanders at 13, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Mar. 17, 2011) (No. 11-0039-UT).

for example, Transwestern scheduled 305,000 MMBtu/d and NMGC took 182,000; on Feb. 3 Transwestern scheduled delivery of 298,000 MMBtu/d at Rio Puerco, and NMGC took 128,000.

NMGC also reported lower pipeline pressure than those on which it typically relies. On an average winter day in the north segment, pressure ranges from 800 to 900 pounds per square inch atmosphere (psia) at Rio Puerco. The average pressures were lower during the week of January 31 and, from February 1 to February 4, the loss of pressure caused NMGC to experience significant pressure losses on its own system. For example, the interstate pipeline pressure at NMGC's interconnection at Rio Puerco fell to a low of 724 psia from a normal operating pressure of 850 psia.

Notwithstanding this decline in pressure, Transwestern's contractual obligation with respect to pressures at Rio Puerco (as opposed to its typical operating pressures) is 700 psia, and Transwestern reports that pressure never fell below that obligation.

The following chart provided by Transwestern depicts the pressure at Rio Puerco (fluctuating brown line) relative to contractually obligated pressure (non-fluctuating red line), total receipts (green line) and deliveries (blue line) on the Transwestern system. According to the chart, pressure did not fall below the contractual obligation of 700 psia.



Source: Transwestern Pipeline Company, LLC

Coordination Among Pipelines to Address Supply Problems

Flows between and among pipelines through redirected supplies and incremental transactions at least partially alleviated supply shortage conditions during the first week of February, 2011. These flows were the result of active coordination among the involved counterparties to address shortfalls. The redirection of gas came too late to avoid the curtailments in New Mexico and Arizona that occurred on February 2 and February 3. However, in the Texas intrastate markets, the increased purchases of gas at pipeline interconnects was an important factor in maintaining pressure in the Dallas-Fort Worth area and also served to move gas east to west in response to reduced supply at Waha.

Changes in gas deliveries do not occur instantly. Operation Balancing Agreements (OBA) contractually specify how gas imbalances between flows and scheduled amounts are to be managed. (Interstate pipelines are obligated by FERC regulations to have OBAs at interconnects with other interstate pipelines and with intrastate pipelines). These agreements enabled counterparties to make operational changes and revise nominations.

Chevron Keystone Storage Facility

In addition to the pipelines, at least one storage facility experienced weather-related difficulties. These difficulties, however, stemmed not from freeze-offs upstream, but from the rolling blackouts on ERCOT's system and from the facility's own operational problems.

The Chevron Keystone Storage Facility (Keystone), which has interconnections with El Paso, Transwestern, and Northern Natural Gas Company, was affected by two rolling blackouts on February 2, at 6:30 AM and 10:00 AM. It was shut down completely for six hours (from 6:30 AM to 9:30 AM and again from 10:00 AM to 1:00 PM).

Keystone remained at less than 100 percent capacity through February 6, due to line and equipment freeze-offs. Keystone declared force majeure at 9:00 AM on February 2. As a result, during the period February 2 through February 4, Keystone was unable to deliver 100 percent of nominated volumes to its three interconnecting pipelines. Keystone lifted the force majeure effective 9:00 AM on February 7.

Keystone's difficulties did not meaningfully contribute to the curtailments of natural gas customers, but they did affect supplies to gas-fired generators of EPE and SRP. (The failures of EPE's generating units stemmed from other causes,[181] so they would not have been able to utilize the gas in any event; SRP was able to obtain gas from another source.) In order to estimate reduced output per customer, the task force prepared the following table, which compares customer scheduled deliveries with contractual withdrawal rights for the Keystone storage facility. It appears that on the coldest day, February 2, shortfalls were most significant not for NMGC, but for EPE, SRP and the two marketers Sequent and Tenaska.

Keystone Storage Scheduled Deliveries Relative to Contractual Rights

Total (MMbtu)	WD Rights	Scheduled Deliveries	2-Feb	3-Feb	4-Feb
Arizona Electric Power	(6,000)		-	(1,687)	(6,000)
Atmos Energy	(20,000)		(5,096)	(2,009)	(20,000)
BP Energy Company	(17,000)		(2,500)	(7,706)	(17,000)
El Paso Electric	(26,000)		-	(12,730)	(26,000)
New Mexico Gas	(140,000)		(140,000)	(140,000)	(52,510)
Salt River Project	(35,000)		(11,667)	(24,791)	(35,000)
Sequent Energy	(27,000)		(4,793)	(19,125)	(27,000)
Tenaska Marketing	(55,500)		(14,718)	(24,112)	(55,500)
Total	(326,500)	-	(178,774)	(232,160)	(239,010)

Natural Gas Curtailments to Retail Customers

The retail customer is the last link in the natural gas delivery chain, taking gas for home or business consumption from LDCs. LDCs receive their gas from interstate or intrastate pipelines at a delivery point called the "citygate." They distribute the gas through a large network of increasingly smaller diameter pipes to homes and businesses in the distribution area. LDC distribution networks operate at much lower pressures than transportation pipelines, but must maintain certain minimum pressures in order to deliver gas to end users. Some large LDCs use compressors to help maintain minimum delivery pressure, but others rely solely on pressure supplied by the upstream pipelines.[182]

When receipt pressures from the pipelines fall, or when consumer demand for gas exceeds the volume being delivered to the citygate, gas pressure within the LDC network will decline correspondingly. In such instances, LDCs must reduce

[181] The causes of the generating unit outages experienced by EPE are described in the following section of the report, entitled "Causes of the Outages and Supply Disruptions."

[182] NaturalGas.Org, *Natural Gas Distribution*, http://www.naturalgas.org/naturalgas/distribution.asp.

the amount of gas being consumed to prevent pressures from falling to the point where the entire system could fail. LDCs typically do this by first seeking voluntary curtailment from large users. If voluntary curtailment fails to stabilize gas pressure in the system, they will further reduce consumption by cutting off sections of the network, usually beginning with remote sections that would be the first to fail under strained conditions.[183]

State Regulation of Curtailment

Arizona, New Mexico, Texas, and California all regulate curtailments by LDCs in their states, but generally grant LDCs a great deal of discretion in determining how curtailments are implemented.

In Arizona, for example, the Arizona Administrative Code directs utilities to file, as a part of their general tariffs, a procedural plan for handling severe supply shortages or curtailments.[184] The definitions of customer classes and the priority of curtailment are left to the utilities. Southwest Gas's Arizona curtailment rule places residential and other human needs customers at the highest service priority. Electrical generators are classified below that, at priority 2 or 3, depending on the amount of gas they consume.

New Mexico also requires LDCs to create and file a list of customer classifications prioritizing curtailments during a system emergency, but does not prescribe how customers should be ranked.[185] NMGC Original Rule 21 sets forth the company's curtailment priorities, assigning the highest priority to residential and other human needs end users, including suppliers of service to human needs customers.[186] Under the NMGC plan, electrical generators fall within this highest priority category. Zia gives the highest curtailment priority to residential and small commercial or industrial customers.[187]

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[183] Transcript of Testimony of Timothy A. Martinez at 15, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers, NMPRC (Apr. 20, 2011) (No. 11-00039-UT).

[184] ARIZ. ADMIN. CODE § 14-2-308(H) (2010).

[185] N.M. CODE R. § 17.10.660.10(E)(1) (2011).

[186] N.M. Gas Co., Original Rule No. 21 IV (2009), *available at* https://www.nmgco.com/Regs/Rule21.pdf.

[187] Zia Natural Gas Co., Second Revised Rule 21 (C) (1997).

In Texas, state law provides that the highest priority of service should be given to "residences, hospitals, schools, churches, and other human needs customers," but LDCs have the authority to set their own priorities, which override the general provisions if the TRC approves the LDC's plan. The TRC-approved plan of Atmos Energy, for example, classifies electric generators several levels below residential customers.[188] Texas Gas Service's curtailment plan gives top priority to residential customers, ranking all commercial and industrial users below them.[189]

The California Public Utility Commission allows LDCs to set curtailment priorities, subject to PUC approval, and it has specifically declined to mandate priority service for electric generators.[190] Both San Diego Gas & Electric Company (SDG&E) and SoCalGas assign the highest priority of service to all residential customers and to small core commercial customers (including some electric generators) that use less than 20,800 therms per month.[191]

Restoration of Gas Service Following a Curtailment

Restoration of gas service to residences following curtailment is a lengthy process that must be performed by trained, qualified personnel. The first step is to shut off each individual gas meter. The LDC's distribution lines and lines from the meters to homes must then be purged of air and re-pressurized with gas. Once this is done, workers visit each home, inspect gas appliances for safety, open meter valves, relight pilot lights, and confirm that the appliances are operating safely. This can only be done when the customer is home, and if workers find that any appliances are not operating properly, service cannot be restored to that home until repairs have been made.

[188] *In re Curtailment Program of Lone Star Gas Co.*, Order No. 496, Docket No. 496 (Texas Railroad Comm'n Oct. 15, 1973).

[189] Curtailments, El Paso Texas Gas Service Area Gas Tariff, Third Revised, § 14.2.

[190] Pub. Util. Comm'n of Cal., Opinion Declining to Provide Service Priorities to Electric Generators in the Event of a natural Gas Shortage, No. 01-12-019 (2001), available at http://docs.cpuc.ca.gov/published/Graphics/11821.pdf.

[191] Annual Notice, San Diego Gas & Electric, Information on Natural Gas Services and Programs (Feb. 26, 2010) (on file with author); *Continuity of Service and Interruption of Delivery Rule 23(B),* SOUTHERN CALIFORNIA GAS CO. at 1, http://www.socalgas.com/documents/business/23.pdf. A therm is 100 MMBtu.

The February 2011 Curtailments

From February 2 through February 4, 2011, LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas. Areas affected included the cities of El Paso, in Texas (863 customers) Tucson (14,620) and Sierra Vista (4,596) in Arizona, and Hobbs (406), Ruidoso (50), Alamogordo (2,385), Silver City (290), Tularosa (1,445), La Luz (475), Taos (8,505), Red River (557), Questa (548), Española (12,367), Bernalillo (3,172), and Placitas (1,114) in New Mexico.

The New Mexico Curtailments and Outages

Zia Natural Gas Company

The city of Hobbs, in southeastern New Mexico, was the first to experience gas outages. Its LDC, Zia Natural Gas Company, receives gas from DCP Raptor Pipeline, LLC, (DCP) an intrastate pipeline that receives its supply from processing plant tailgates and wellheads. Zia serves approximately 11,000 retail customers in the Hobbs area.

On February 1, 2011, DCP fell behind for a two-hour period on deliveries to Zia because of wellhead freeze-offs and other supplier issues. However, the pipeline made arrangements with the Northern Natural Gas (NNG) pipeline to reverse the flow of gas at a DCP/NNG interconnect near Hobbs, making additional supplies available. Thus, according to both Zia and DCP, DCP's temporary supply shortage did not adversely affect customers in Hobbs.

At approximately 3:00 AM on February 2, an electrical blackout affected approximately 2,065 homes in the northeast area of Hobbs.[192] Zia was not notified of the blackout until approximately 7:30 AM, but at 5:55 AM, the company received a low pressure alarm from a regulator station on the northeast end of the system. Personnel sent to the site reported that pressure was well below normal levels, and Zia immediately contacted DCP, which informed them that a plant had gone out of service due to a cold weather-related mechanical failure and that DCP was attempting to address the problem. The DCP plant in question did not return to service until February 6.

Zia reported that it was able to continue supplying gas to all its customers in Hobbs until approximately 7:30 AM that day, when electric power was restored. At that point, there was a surge in demand as gas appliances that had been unable

[192] SPS is the city's electrical supplier.

to operate without electricity simultaneously came back in service. Almost immediately, Zia began receiving calls from customers reporting that they had no gas or very low gas pressure. In all, 406 customers called in to report supply problems.

Zia believes the reason for the outages was the sudden surge in demand when electric power came back online, coupled with the low line pressures that resulted from the DCP plant outage. That morning, Zia began the process of relighting the primarily residential customers that were affected, and the company was able to restore all gas service by 10:00 PM the same day.

Zia customers in the Ruidoso, New Mexico area also lost gas service as a result of the cold weather events. During the early morning hours of February 3, the Ruidoso area experienced power outages that lasted until 8:00 AM. At the same time, receipt pressures from El Paso were declining.

At approximately 7:30 AM, Zia began receiving complaints of no gas or low gas pressure. Personnel sent to the area reported extremely low pressures, and did what they could to boost flow by bypassing regulator stations. Through a local radio station that was operating on backup power, the company asked the community to cut back on gas use. Pressures were critically low through most of the morning but began to rise just before noon. However, when electrical power was restored, there was a surge in demand that further strained the system. A total of 50 customers at the far reaches of the distribution system lost gas service that day, but their service was fully restored by the end of the working day.

According to Zia, it has no industrial or large load single customers; almost all of its customers are residential or small commercial users. Thus, it was not possible for Zia to reduce demand by curtailing large commercial accounts. Zia believes the Ruidoso outages were caused by high demand on the system, combined with low supply pressures and the surge in demand that occurred when power was restored.

New Mexico Gas Company

NMGC serves more than 500,000 retail customers in towns, pueblos, cities and rural areas throughout New Mexico. NMGC's distribution system is divided into two areas: (1) the north segment, serving the Albuquerque metropolitan area and communities to the north; and (2) the south/remotes segment, consisting of (a) the southeast system, which serves the towns of Roswell, Artesia, Carlsbad, Lovington, Eunice, and surrounding areas, and (b) remote locations, including Alamogordo, Silver City, Clovis, Portales, Tucumcari, Hatch, and Truth or Consequences. The north and the south/remotes segments are served by the

Transwestern and EL Paso interstate pipelines and by other third-party pipelines. The remote locations that lost gas service during the period in question were supplied solely by El Paso.

NMGC: The North Segment

On February 2, 2011, NMGC personnel monitoring the company's north segment, which serves the Albuquerque metropolitan area and communities to the north, noted that gas volumes at the company's receipt points with El Paso and Transwestern were not increasing, indicating that much of the company's nominated gas was not being received. However, although line pack was decreasing, the system was still operating within sustainable limits. Based on additional gas purchases made during the day, the company expected pressures at receipt points to increase at 9:00 PM that night and at 8:00 AM the following morning.

As a precautionary measure, the company began telephoning large commercial users on the morning of February 2, seeking voluntary reductions of gas consumption. NMGC employees, working from a list of the company's 200 largest customers, placed phone calls or sent emails to points of contact on the list. Customers were informed that the company was expecting a gas shortage and that cutting back on gas usage was necessary to maintain service to home, hospitals, and other top priority consumers.

In some instances, large customers agreed to reduce their gas use, either by switching to alternative fuel supplies, lowering thermostats, or shutting down equipment or manufacturing processes. However, some of the customers (approximately 10 percent of those contacted) indicated that they could not or would not reduce their usage.

One of the large customers NMGC contacted was PNM, which operates two gas-fired generating plants in the Albuquerque area. Contacted at 9:42 AM on February 2, PNM responded by stating that no curtailment options were available to it, and that the plants would be increasing their gas consumption to meet power generation requirements.

In other instances, NMGC was unable to reach a point of contact for its large customers and could only leave messages requesting cutbacks or return calls. NMGC estimates that it was ultimately able to contact 30 percent of the top 200 users to request voluntary curtailment.

NMGC was expecting the supply problems to improve at 9:00 PM on February 2, because of the extra gas it had purchased. When line pressure did not

improve at that time, due to the inability of suppliers to put the purchased gas on the system, the company began contacting other pipelines and suppliers in an effort to purchase more gas.

During the early morning hours of February 3, NMGC personnel monitoring line pressure on the north segment, from both the company's gas control center and field locations, believed the system would have enough gas to meet the anticipated morning demand, based on the amount of gas that had been used the previous day. However, beginning at 7:12 AM, the demand for gas rose to unprecedented levels, even though temperatures were only slightly higher than the day before.[193]

Even at this point, however, the company concluded that if pressures at receipt points began to rise at 8:00 AM, as expected based on the additional gas that had been purchased, they would be able to meet the increased demands on the system.

However, pressures continued to decline at 8:00 AM, leading NMGC to conclude that it was in immediate danger of losing the entire system and that they must immediately reduce demand by cutting off sections of the system. At around this time, the company also began receiving reports of no gas or low gas pressure in the Albuquerque area, further indicating that its system was near collapse.

Because NMGC needed to act quickly, and because the distribution systems in the larger metropolitan areas of Santa Fe and Albuquerque were not configured so as to allow curtailment of large numbers of customers by closing just a few valves, the company decided to curtail the areas served by the Taos mainline, which runs from the company's north-south mainline at Otowi junction, located approximately 80 miles north of Albuquerque. That line serves the communities of Española, Dixon, Taos, Questa, and Red River. The Otowi Junction valve was closed at 8:37 AM, cutting off service to those communities.

The company also curtailed two additional communities just north of Albuquerque by closing two valves that supplied the town of Bernalillo at 8:55 AM and 9:14 AM, and by closing one valve to the town of Placitas at 9:29 AM.

[193] NMGC told the task force that although temperatures were slightly warmer on the morning of February 3, compared to the previous morning, demand was nevertheless higher, despite NMGC's efforts to seek voluntary curtailment from large users, and despite appeals through the media for residential customers to conserve gas. NMGC does not know the reason for the increased demand.

If pressures continued to decline, the next step anticipated by NMGC was curtailing sections of the Albuquerque metropolitan area. Curtailment options in that area were limited, however, because of the lack of shut off valves capable of curtailing a large block of customers at one time. The company nevertheless prepared for curtailments by sending a crew with a backhoe to two sections of pipeline that served 2,000 customers, with the intention of digging up the pipes and pinching them off.[194]

At 9:20 AM, following discussions between NMGC and PNM about system conditions, PNM decided to switch its Delta Person (Cobisa) power plant from gas to backup fuel oil. PNM was unable to make the changeover because of a faulty valve, and as a result the plant went out of service and did not draw gas from the system for the duration of the cold weather event.

By 10:30 AM, pressure on the north segment had stabilized and had begun to increase. The restoration process was already underway at that point, as NMGC teams began shutting off meter valves to individual customers so that the lines could be purged and recharged.

NMGC: The South/Remotes Segment

On February 2, line pressure on El Paso's delivery pipeline to NMGC's south/remotes segment steadily declined, dropping below contract pressure[195] at approximately 10:00 AM. As the day progressed, NMGC personnel monitored line conditions and began considering the possibility that if conditions worsened, they would have to curtail certain areas.

At approximately 3:00 PM, NMGC started calling large customers on the south segment to ask them to voluntarily reduce their gas consumption. Some of the larger customers, such as Western New Mexico University, Silver City School System, and the Alamogordo School System, agreed to reduce usage, but two other large users -- Holloman Air Force Base and the White Sands Missile Range -- could not be reached that day, reportedly because the bases were closed because of the weather conditions and the contact persons were not present. (Holloman Air Force Base was successfully contacted the following day at approximately 1:00 AM, and agreed to reduce its usage at that time.)

[194] Transcript of Testimony of Doug Arney at 4, In the Matter of an Investigation into New Mexico Gas Co.'s Curtailments of Gas Deliveries to New Mexico Consumers,, NMPRC (Mar. 17, 2011) (No. 11-00039-UT).

[195] Contract pressure is the minimum gas pressure, measured in pounds per square inch, that a pipeline agrees to provide to a customer at a given delivery point.

Shortly before 5:00 PM on February 2, NMGC received notice from El Paso that line pressure was not expected to improve during the next 24 hours.

At 1:50 AM on February 3, NMGC began cutting off service to schools and non-essential government buildings in Alamogordo. At 2:36 AM, seeing that conditions were continuing to deteriorate, the company declared a system emergency on the south segment.

At 3:00 AM, NMGC cut off service to the communities of Tularosa and La Luz, which are located at the end of the NMGC distribution pipeline that serves Alamogordo. Line pressures continued to decline, however, and at 5:05 AM, the company shut off one section of Alamogordo. At 6:00 AM, the Alamogordo area experienced an electrical blackout. When electricity was restored at 8:00 AM, the resulting surge in demand for gas caused pressure to drop to zero on the southern part of the Alamogordo system, forcing NMGC to cut off that section as well. In all, more than 4,300 customers lost gas service in Alamogordo, Tularosa and La Luz, out of a customer base of approximately 15,000. By 9:25 AM, pressures in the Alamogordo area began to stabilize, and by 3:00 PM that day, the company began restoring service to curtailed areas.

Another community on the NMGC south/remotes segment that lost a portion of its gas service on February 3 was Silver City. According to NMGC, the Silver City distribution network lacked the capacity to meet the unprecedented demand for gas on February 2 and February 3, due to system limitations. NMGC stated that in 2007, it determined that the system's maximum operating pressure should be reduced from 40 psi to 30 psi for safety reasons. With that limitation, the system could not transport the volumes demanded by customers.

Although two large users in that area, the Silver City Consolidated School District and Western New Mexico University, agreed to curtail gas use on February 2, mitigating demand on the system to some extent, pressure continued to drop. NMGC curtailed a section of Silver City at approximately 6:00 AM the following day, February 3, in order to avoid total collapse of the system. Pressure began to recover by 11:00 AM, and restoration efforts began shortly thereafter. A total of 271 out of approximately 9,200 customers in the area lost gas service due to the curtailments.

NMGC has informed the task force that it is in the process of making improvements to the Silver City distribution system that should allow it to meet peak loads of the sort that occurred during the February event.

Restoration of Service

Closing individual gas meters, which is the first stage of restoring service, began shortly after NMGC cut off service on the morning of February 3. In some areas, NMGC personnel began shutting off meters within minutes of the curtailment. As restoration efforts got underway, the company sought additional help through its mutual assistance agreements with the American Gas Association and the Southern Gas Association, whereby member LDCs agree to help each other in emergency situations. That morning, NMGC asked other member LDCs by email and by conference call to send personnel to help them restore service in the affected areas. Out-of-state LDCs responded by sending qualified service personnel, who began to arrive the following day. NMGC also sought help from other New Mexico LDCs, and hired local contractors and plumbers to help restore service. Police, fire department, and National Guard personnel all eventually played roles in the effort to restore service.

Relighting continued through the weekend and into the following week, with a workforce of more than 700 persons participating. Service was restored to some areas as early as February 5, but the statewide relighting effort was not substantially completed until the following week, on February 10.

The Arizona Curtailments and Outages

Southwest Gas, a multistate LDC whose service areas include the cities of Tucson and Sierra Vista in Arizona, was forced to curtail service to parts of those cities on February 3 due to low pressures at receipt points with El Paso. After El Paso declared a system-wide Critical Operating Condition at 11:52 AM on February 2, due to declining line pack and drop offs in gas supply, Southwest Gas's management met at 1:00 PM to plan for increased monitoring of the distribution systems. Shortly thereafter, at about 2:00 PM, the company started calling large commercial customers to alert them to possible curtailments.

At 10:00 PM, as conditions on the El Paso pipeline continued to deteriorate, Southwest Gas concluded that it might be necessary to cut off some customers in order to preserve system operability. When pressures on the Sierra Vista system reached a critical stage at approximately 3:30 AM on February 3, the company identified several sections of the system that should be shut down to reduce demand. At approximately 6:30 AM, crews began closing valves in Sierra Vista and Tucson. Out of a total of 17,801 customers in Sierra Vista, 4,596 were shut off; out of a total of 279,362 customers in Tucson, 14,620 were shut off.

Starting at approximately 5:00 AM on February 3, the company began curtailing several large commercial customers, including an electric power plant in

Tucson. Other commercial users voluntarily curtailed or reduced their use throughout the day.

By 8:30 AM, pressures began to stabilize and recover, and the restoration process was initiated. Southwest Gas brought in 130 employees from other divisions in California, Nevada, and Central Arizona to help with the relighting process, and service was fully restored on the afternoon of February 7, 2011.

The Texas Curtailments and Outages

Texas Gas Service (TGS) serves several communities in Texas, with a total of 616,462 residential, commercial, and transportation customers. The City of El Paso is one of those communities, and during the week in question it was the only city in Texas to experience gas curtailments, with 863 residential customers (out of approximately 231,000) losing service.

Gas is delivered to TGS by the El Paso and ONEOK WesTex Transmission, L.L.C. (ONEOK WesTex) pipelines. Beginning around February 2, TGS received cuts from its suppliers and had to make alternative arrangements to obtain gas for the anticipated cold weather demand, including buying compressed natural gas (CNG) for expedited delivery by tanker truck from Arizona. The company also experienced low delivery pressures from El Paso later that week. However, those factors were not responsible for the service disruptions that occurred. According to TGS, the El Paso system experienced unprecedented demand during the winter event, as much as 41 percent higher than the previous historical peak.[196] The company's distribution system was simply unable to handle that much volume.

Beginning on February 2, at approximately 8:00 AM, residential customers began reporting low pressures. Shortly thereafter, customers in low pressure areas of the system began losing service. TGS responded to each reported outage, and in some instances service was restored the same day. A total of 863 customers lost service during an approximately 24 hour period. Service was fully restored by February 5. The restoration process was hampered by icy road conditions, and by the fact that TGS workers could not restore service when customers were not at home.

In order to alleviate pressure on the system during the period of peak demand, TGS asked ten large transportation customers to reduce consumption at

[196] On February 3, 2011, TGS delivered 258,853 MMBtu to its customers in El Paso. The previous peak at that location was 184,088 MMBtu, in January 2007.

approximately 10:00 AM on February 3. The company also restricted service to 36 commercial customers in areas that were experiencing low pressure, and on February 3, extended a gas main to boost pressures in one of the affected areas. In addition, TGS used two CNG tankers to help deal with low pressure issues. One was used to maintain service to a hospital, and the other was deployed to assist in the restoration process in one of the affected neighborhoods.

TGS plans to make additional system improvements to increase delivery capacity by extending gas mains in several areas that experienced low pressures during the period in question. The cost of these improvements is expected to total more than $1.7 million and the company estimates that they will be completed by September 30, 2011.

The California Curtailments

SoCalGas and SDG&E are separate utility companies, both owned by Sempra Energy. SoCalGas serves approximately 20 million customers in Central and Southern California; SDG&E serves approximately 3.4 million customers in Orange and San Diego Counties, California. SoCalGas operates the natural gas transportation systems of both companies.[197]

Beginning on January 31, 2011, SoCalGas monitored weather developments in the Southwest and was aware of the supply problems that had developed because of the severe cold weather. The company responded to supply shortfalls by increasing withdrawals from on-system storage and by purchasing operational gas to support the southern system, which cannot be served by storage gas. Delivery shortfalls were highest on February 2 and February 3. SoCalGas estimates that the net cost of the operational gas it purchased was $3.81 million, representing the purchase price of the gas less the price at which SoCalGas was later able to sell it.

On the morning of February 3, the company issued a curtailment advisory to non-core (lower priority) customers, informing them that curtailments could occur. At 1:15 PM, due to the continuing severe weather and its effect on production, the company declared a system emergency and curtailed transmission service on its southern system for all interruptible and some firm non-core customers by limiting the amounts they could withdraw from the system.

SoCalGas curtailed 19 interruptible retail non-core and electric generator customers, and 40 firm non-core and electric generator customers. SDG&E

[197] Sempra Energy, *Our Companies*, http://www.sempra.com/companies/companies.htm.

curtailed all its interruptible load and all its firm service to three electric generator customers. SoCalGas reported that its non-core customers and electric generator customers generally complied with curtailment limits during the emergency. When the CAISO informed the two companies that approximately 500 MW of total generation was needed from two of the curtailed electric generators in order to ensure reliable grid operations, SoCalGas and SDG&E adjusted the curtailments so that the two plants could provide the necessary generation.

Resumption of Production

Weather conditions moderated slightly in the Southwest on February 3 and improved further on February 4, rising above freezing for the first time in days. Although production did not return to pre-event levels for several weeks, consumer demand slackened with the warmer weather, and line pack and system pressure rose steadily on the interstate pipelines. As a result, El Paso issued a warning of a system pack condition on February 5, and declared a system -wide Strained Operating Condition for high line pack February 6, 2011.[198]

Impacts of the Event on Natural Gas Prices

Gas prices responded to the winter weather and associated freeze-offs, although the increases were short-lived and not exceptionally dramatic. Some points in the midcontinent and southwest regions did post increases of approximately two dollars to three dollars per MMBtu, which were gains of 40 to 60 percent relative to February 1. West Texas prices were particularly strong with a basis at Waha of $2.60 relative to Henry Hub.[199] Southern California prices at Ehrenberg and Needles also traded higher by $1.77, reflecting upstream supply shortfalls.

The price gains in east Texas and south Texas were more muted, despite the freeze-offs extending to the Gulf Coast, and limited to $0.50 to $0.60 per MMBtu. The Houston Ship Channel, however, had an increase of almost $1.57.

The NYMEX (New York Mercantile Exchange) futures contract was flat to declining for the week. Cash prices at Henry Hub increased by only $0.29.

Most gains were gone by February 5, at which time warmer weather had returned. Prices on February 8 actually traded below those of February 1.

[198] Production figures from Bentek, supporting documentation for *Deep Freeze Disrupts U.S. Gas, Power, Processing* (Feb. 8, 2011); information provided to the task force by pipelines.

[199] Basis is the price differential between, in this case, Henry Hub and Waha.

The following table shows spot prices at a variety of locations for February 1 to February 8.[200] Daily closing prices are also listed for the NYMEX March gas futures contract, which is based on delivery at Henry Hub. The NYMEX price was relatively unaffected by the spot price increases during February 1 to February 8, suggesting that traders viewed the increases as a temporary, weather-related event.

Spot Prices

Flow Date	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb
Waha	$ 4.47	$ 4.79	$ 5.80	$ 7.30	$ 4.76	$ 4.76	$ 4.76	$ 4.25
El Paso-Permian	$ 4.40	$ 4.75	$ 5.74	$ 7.23	$ 4.86	$ 4.86	$ 4.86	$ 4.19
Transwestern-San Juan	$ 4.35	$ 4.66	$ 5.73	$ 6.40	$ 4.49	$ 4.49	$ 4.49	$ 4.11
El Paso-San Juan	$ 4.30	$ 4.51	$ 5.77	$ 6.52	$ 4.51	$ 4.51	$ 4.51	$ 4.10
East Texas, Carthage Hub	$ 4.36	$ 4.42	$ 4.63	$ 4.89	$ 4.49	$ 4.49	$ 4.49	$ 4.28
Houston Ship Channel	$ 4.40	$ 4.37	$ 4.61	$ 5.91	$ 4.43	$ 4.43	$ 4.43	$ 4.29
South Texas, Tennessee Zone 0	$ 4.38	$ 4.39	$ 4.62	$ 5.03	$ 4.40	$ 4.40	$ 4.40	$ 4.28
Oneok Oklahoma	$ 4.49	$ 5.31	$ 7.06	$ 6.28	$ 4.59	$ 4.59	$ 4.59	$ 4.40
SoCal Gas	$ 4.40	$ 4.50	$ 5.47	$ 6.17	$ 4.52	$ 4.52	$ 4.52	$ 4.22
Henry Hub	$ 4.42	$ 4.43	$ 4.55	$ 4.70	$ 4.48	$ 4.48	$ 4.48	$ 4.33
NYMEX Contract	$ 4.42	$ 4.35	$ 4.43	$ 4.34	$ 4.31	$ 4.31	$ 4.31	$ 4.10

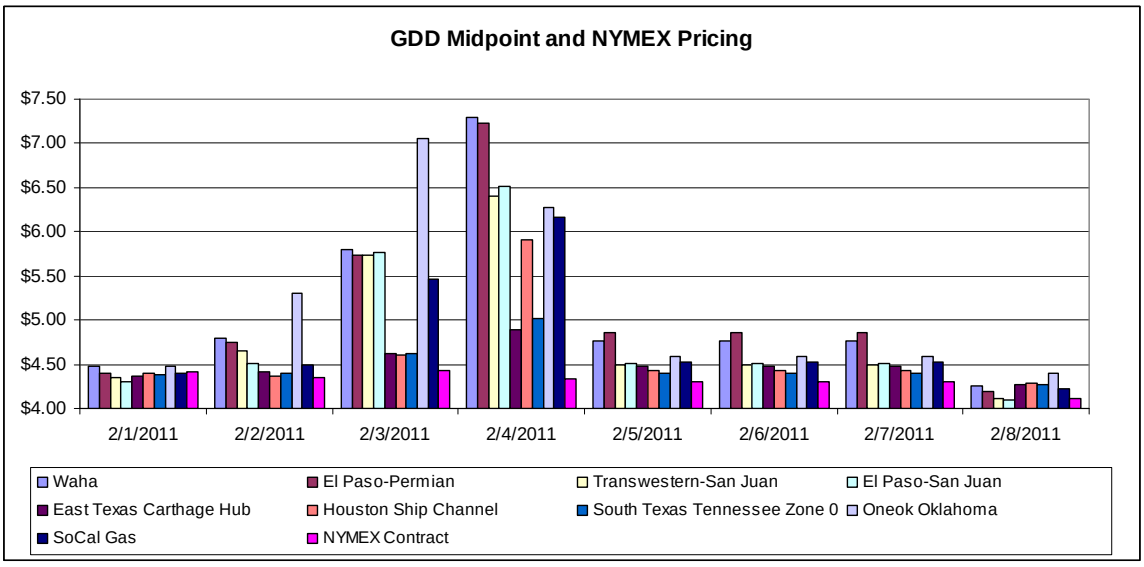
The following table shows the basis for the same locations relative to cash prices at Henry Hub.

Basis

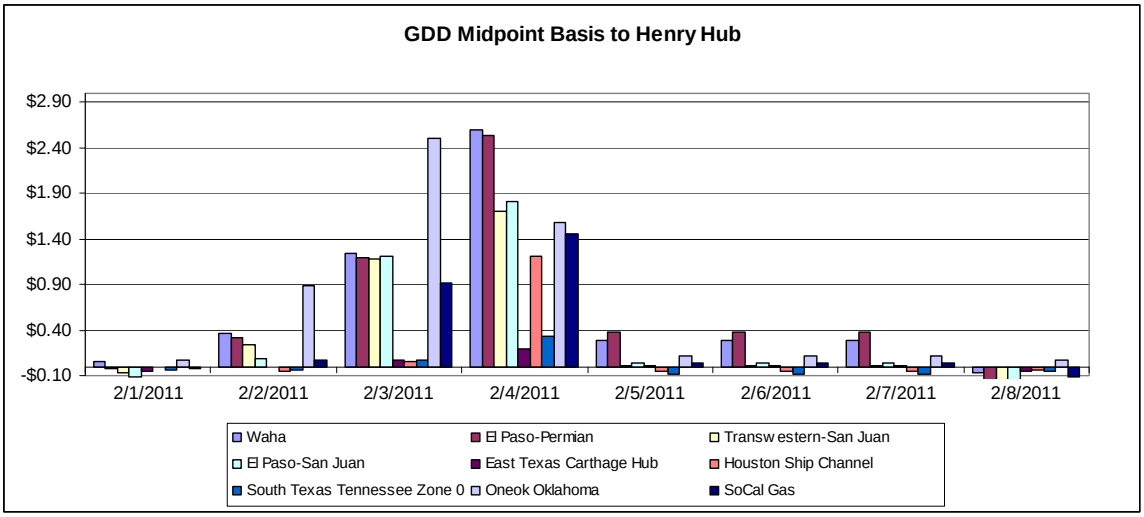
Flow Date	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb
Waha	$ 0.05	$ 0.37	$ 1.25	$ 2.60	$ 0.29	$ 0.29	$ 0.29	$ (0.08)
El Paso-Permian	$ (0.02)	$ 0.32	$ 1.19	$ 2.53	$ 0.38	$ 0.38	$ 0.38	$ (0.14)
Transwestern-San Juan	$ (0.07)	$ 0.24	$ 1.18	$ 1.70	$ 0.02	$ 0.02	$ 0.02	$ (0.22)
El Paso-San Juan	$ (0.12)	$ 0.08	$ 1.22	$ 1.82	$ 0.04	$ 0.04	$ 0.04	$ (0.23)
East Texas Carthage Hub	$ (0.05)	$ 0.01)	$ 0.08	$ 0.19	$ 0.01	$ 0.01	$ 0.01	$ (0.05)
Houston Ship Channel	$ (0.01)	$ (0.06)	$ 0.06	$ 1.21	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.04)
South Texas Tennessee Zone 0	$ (0.04)	$ (0.04)	$ 0.07	$ 0.33	$ (0.08)	$ (0.08)	$ (0.08)	$ (0.05)
Oneok Oklahoma	$ 0.07	$ 0.88	$ 2.51	$ 1.58	$ 0.12	$ 0.12	$ 0.12	$ 0.07
SoCal Gas	$ (0.02)	$ 0.08	$ 0.92	$ 1.47	$ 0.04	$ 0.04	$ 0.04	$ (0.11)

[200] *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 1, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 2, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 3, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 4, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 5, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 6, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 7, 2011, at 1-2.; *Daily price survey ($/MMBtu)*, Platts Gas Daily, Feb. 8, 2011, at 1-2. Reprinted with permission of Platts.

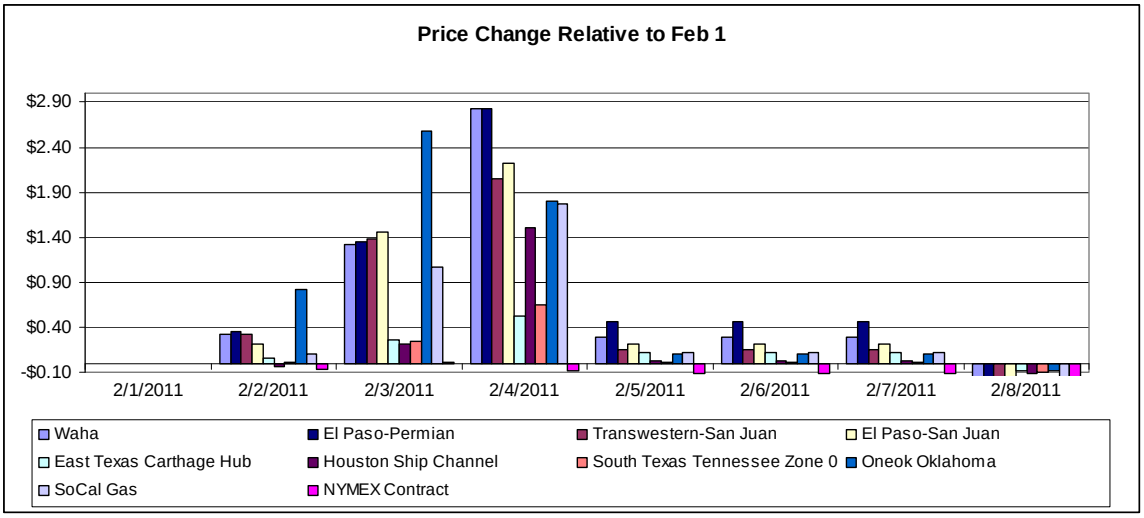
The following three charts show the absolute prices, basis, and price change of natural gas during the week of the event.



Source: Task Force analysis based on Platts data



Source: Task Force analysis based on Platts data



Source: Task Force analysis based on Platts data

The causes of the electric generator failures and the natural gas shortfalls described above are examined in the following section of this report, entitled "Causes of the Outages and Supply Disruptions."

VI. Causes of the Outages and Supply Disruptions

The precipitating cause of the rolling blackouts experienced in Texas and Arizona during the February 2011 cold weather event was the large number of electric generator outages. The principal cause of the gas service curtailments experienced in several southwestern states was the production declines in the supply of natural gas, which led to volume and pressure reductions in the pipelines. The task force has analyzed in detail the causes of these outages and declines, and found that the majority of them were directly or indirectly related to the weather, particularly so with respect to production declines in the gas supply. This section of the report describes in detail those causes, both weather and non-weather-related.

While the storm itself was an uncontrollable event of force majeure, the question arises as to whether the facilities affected should have been better prepared to withstand the severe weather. Was the cold spell so unprecedented that the entities responsible for those facilities could not reasonably be expected to have taken preventative actions? Or did entities fail to take into account lessons that could have been learned from past cold weather events in the Southwest? These questions are addressed in the next section of this report, entitled "Prior Cold Weather Events."

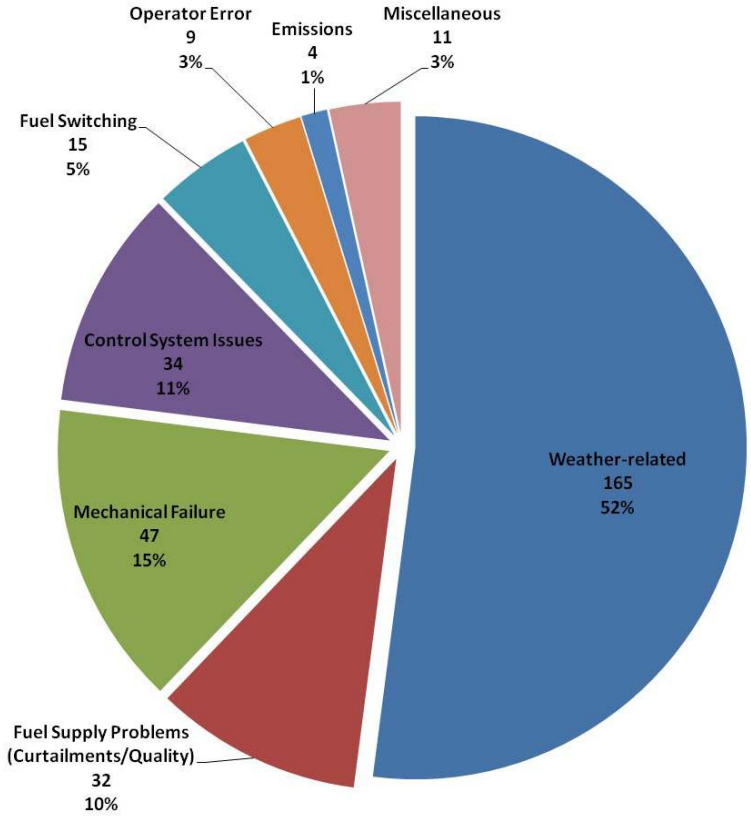
A. Electric

The rolling blackouts that utilities implemented during the cold weather event, which centered in Texas (ERCOT, EPE) and Arizona (SRP), were almost entirely the result of trips, derates, and failures to start of the generating units in those regions. The localized blackouts experienced by PNM in New Mexico, however, were caused by transmission trips. Units in Oklahoma and Kansas also experienced generator outages, but these did not result in blackouts.

The task force has analyzed these various generator outages to determine their underlying causes. By far, the most common cause of the outages was the cold weather, most commonly when sensing lines froze and caused automatic or manual unit trips. There were also several outages that were due to operator error or non-weather-related equipment failures. In a lesser number of cases, an interruption in the supply of natural gas prevented gas-fired units from providing power.

The following two charts[201] and supporting table depict the various causes of the trips, derates, and failures to start[202] for generating units throughout the Southwest, both by number of units and by MWhs.

Southwest - Number of Units Tripped, Derated, and Failed to Start - Feb. 1 - 5, 2011

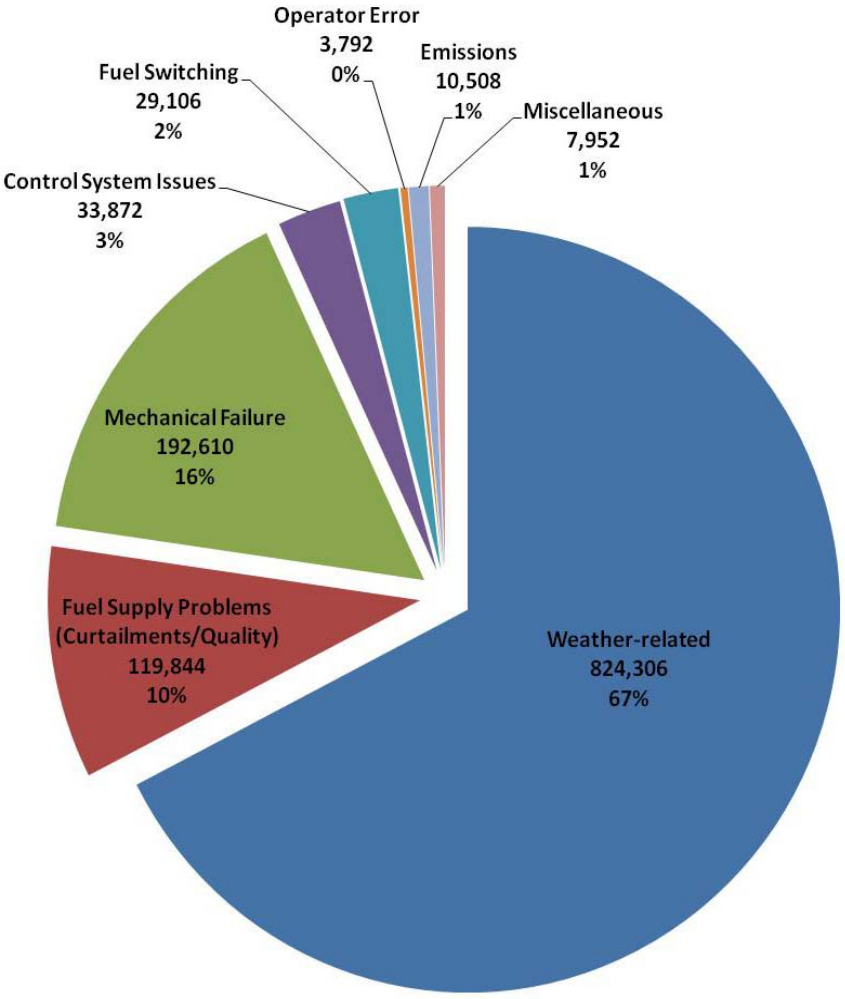


Total Entries in Pie Chart:	317
Total Number of Units Forced Out, Derated, or Failed to Start:	268

[201] Data includes generation in Texas (ERCOT and non-ERCOT), New Mexico, Arizona, and SPP. Units on the first chart are counted more than once if they failed multiple times from different causes (75 units failed on more than one occasion during the event); however, they are only counted once per cause. Data used in the preparation of this chart are drawn from materials submitted to the task force by balancing authorities and generators. Data throughout the section are drawn from materials submitted by transmission operators, generators, producers, processing plants, and pipelines.

[202] Trips totaled 167 units (30,376 MW), derates totaled 57 units (5024 MW), and failures to start totaled 44 units (4743 MW).

Southwest – MWh[203] of Generation Unavailable - Feb. 1 - 5, 2011



Total MWh in Pie Chart*: 1.2 Million
Total MWh of Load Served in affected Southwest Areas: 6.7 Million
Generation unavailable as a percentage of Total MW-hours Load Served: 18%
*Total time period is 106 hours (Midnight going into Feb. 1 through 10 AM Feb. 5)

[203] Megawatt hours were used for this chart to give an indication of the time impact of the outages, derates, and failures to start. (From an operator's perspective, a smaller unit out for a longer time might have a greater impact than a larger unit out for a short time, depending on the circumstances.) To capture this time factor, each instance of unavailable capacity was multiplied by the associated duration of the particular outage or derate and the results were summed.

Supporting Table (Southwest):

Cause	# of Unique Units	MWh
Total Frozen Sensing lines:	89	432,897
Frozen - Drum level sensing lines	48	150,000
Frozen - Other Sensing lines	41	282,896
Frozen Equipment (General)	21	153,393
Frozen Water lines	14	80,091
Frozen Valves	12	20,603
Blade Icing (Wind Turbines)	10	53,989
Low Temperature Limits (Wind Turbines)	17	80,389
Transmission Loss	2	2,944
Fuel Supply Problems (Curtailments/Quality)	32	119,844
Mechanical Failure	47	192,610
Control System Issues	34	33,872
Operator Error	9	3,792
Emissions	4	10,508
Fuel Switching	15	29,106
Miscellaneous	11	7,952

The large percentage of weather-related outages speaks in part to the design and construction of generating facilities in the Southwest. Unlike facilities in cold climates, generating stations in the Southwest are typically designed and constructed so that their boilers, turbines, and other auxiliary systems are exposed to ambient weather conditions. This design prevents heat build-up from occurring in the hot summer months. A more detailed discussion of generating plant design is contained in the appendix entitled "Power Plant Design for Ambient Weather Conditions."

Sub-freezing temperatures can have adverse operational effects on generating stations if systems containing water do not have sufficient freeze protection, if pneumatic air systems do not have sufficient air drying capacity or freeze protection, or if equipment lubricants are not maintained above prescribed minimum temperatures. Generators with exposed elements typically employ a combination of heat tracing, insulation, wind breaks or enclosures, and heat sources to prevent freezing and to maintain minimum lubricant temperatures. Frozen sensing lines were a particular problem during the February cold weather event, when many generators automatically tripped offline due to faulty readings

from transmitters whose sensing lines froze (most notably steam drum[204] level transmitters).

A detailed examination of the causes of the generator outages experienced within ERCOT, SRP and EPE during the February event, both weather and non-weather-related, is set forth below.

Generation Outages in ERCOT

As a preliminary matter, the task force categorized by age and fuel type the ERCOT units that failed, to determine whether there was any statistical indication that older units or units of a given fuel type were more prone to developing problems. With respect to age, no strong correlation was found. The failure percentage of units with in-service dates before 1981 (19 percent) was actually less than their percentage contribution to the ERCOT fleet as a whole (22 percent).[205] The failure of units with recent in-service dates (between 2001 and 2010) represented 55 percent of the failures, which was slightly more than their contribution to the fleet as a whole (48 percent).

The results are more equivocal with respect to type of unit, where a more significant correlation was found with respect to combined cycle units. Otherwise, however, no significant correlation was found between failure and type of unit. Of ERCOT's combined cycle units, 48 percent failed, compared to their 35 percent of the total. For wind units, 16 percent failed, compared to their 15 percent of total units. For simple cycle units, 21 percent failed, compared to their 20 percent of total units. For gas-steam and coal units, the percentage that failed exactly matched their percentage contribution of total units (13 percent and 7 percent, respectively). Nuclear facilities account for only 1 percent of the total fleet, and no nuclear units failed.[206]

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[204] Steam drums are used in boilers (excluding once-through supercritical boilers) to take in a mixture of steam and water coming from the boiler's waterwall tubes. The drum separates the steam from the water by gravity and mechanical separation (such as baffles). The water level in the drum is controlled to keep water in the waterwall tubes and to prevent water carrying over into the steam section of the boiler. The drum also functions to remove solids from the steam.

[205] This statistic and those immediately following are based on number of units, rather than on capacity. (Coal units, for instance, have a larger capacity contribution to the fleet as a whole than seven percent, which is their percentage contribution based on number of units.)

[206] The totals do not add up to 100 percent because certain other facilities have not been taken into account, such as hydro facilities and storage facilities.

For purposes of further analysis, the task force sorted by unit[207] the ERCOT generator trips, derates, and failures to start into three broad categories: weather-related, non-weather-related, and fuel supply. (The weather-related category considers only failures directly related to the weather; problems of insufficient fuel supply as well as outages and derates resulting from fuel switching, although indirectly related to the weather, are listed separately.) Direct weather-related causes accounted for 52 percent of the total failures, non-weather-related causes for 40 percent, and problems with fuel supply for nine percent.[208] Sub- categories within these major groupings, as well as specific examples of the various types of failures, are provided below.

ERCOT Weather-Related Outages and Derates

The task force identified the various specific causes for the trips, derates, or failed starts in ERCOT between February 1 and February 5 that were due directly to the cold weather.[209] (Some of the other failures experienced by ERCOT generators, such as reduced supplies of natural gas, were indirectly related to the weather.) The task force has identified the specific causes of these weather-related failures, by number of units and number of MWs:

Cause	No. of Units Lost	MW Lost
Frozen Sensing Lines (Total)	68	15,255
Frozen Drum Level Sensing Lines	(43)	(9438)
Frozen Other Sensing Lines	(25)	(5817)
Frozen Equipment (General)	13	2942
Frozen Water Lines	12	1072
Frozen Valves	8	1501
Blade Icing (Wind Turbines)	10	709
Low Temperature Limits (Wind Turbines)	17	1237
Transmission Loss	2	89
Total Weather-Related	**130**	**22,805**

[207] A unit that failed multiple times for different reasons is counted under each separate reason; if it failed multiple times for the same reason, it is counted once. That convention applies as well to the three charts detailing ERCOT's weather, non-weather, and fuel failures.

[208] Numbers add up to slightly higher than 100 percent due to rounding.

[209] The weather effects stemmed not only from the prolonged cold, but from high wind chill factors. Although typically thought of as applying to living beings, wind chill also more quickly cools inanimate objects, such as water pipes, bringing them down to the current air temperature. Wind also causes the loss of radiant heat, which otherwise can protect equipment from freezing. This phenomenon is discussed at more length in the appendix entitled "Impact of Wind Chill."

A sample of the ERCOT generating units that experienced weather-related failures, categorized by the specific cause of failure, provides some insight into the variety of concerns with which the generator operators had to contend during the event, and illustrates the complexity of the protections needed for generating plant systems.

- **Frozen Sensing Lines:** Instrumentation provides operational data necessary to monitor and control the generator's systems. Typically, sensing lines containing a standing water column sense changes in pressure and a transducer produces an electronic signal that is transmitted to instrumentation or controls. In sub-freezing temperatures, if freeze protection is not employed on critical unit systems, the water in the sensing lines freezes, causing faulty signals and subsequent unit trips or derates. During the February event, frozen sensing lines were the leading cause of outages, with steam drum sensing lines being the most prevalent (43 units tripped from this cause alone).

  - ✓ JK Spruce Unit 2, a 785 MW coal unit, tripped due to frozen sensing lines that caused a false high water level reading in the steam drum.

  - ✓ Ingleside Cogeneration lost two units due to frozen sensing lines. The lines were heat traced, but the ground fault interrupter breakers protecting the heat trace circuits tripped, resulting in a loss of 176 MW.

  - ✓ Another unit tripped due to frozen sensing lines on feedwater heater level controls. The freezing caused a high condensate level in a feedwater heater, which in turn incorrectly initiated a trip of the unit.

  - ✓ Non-drum sensing line failures included a unit whose vacuum system became erratic when the sensing line to the auxiliary steam pressure indication froze. Another unit tripped when the sensing lines to the rotor air cooler level transmitters froze.

Sensing Lines and Frozen Transmitters

There were many reports of frozen transmitters causing generating units to be forced offline during the cold weather event. In almost all cases, it was not the transmitters themselves that froze, but rather sensing lines filled with standing (non-flowing) water routed between the transmitters and the points the sensing lines are measuring.

(cont'd)

Transmitters

The transmitter assemblies perform three distinct functions. First, they detect the difference in pressure between two water lines, typically with a diaphragm-type sensor that deflects in the direction of, or towards, the lower pressure. Second, they serve as transducers that translate the pressure difference into an electrical signal. Third, they boost or otherwise process the signal for transmitting to the plant's control room, generally using electronics.

Differential Pressure Measurement

The technique of measuring the pressure difference (differential pressure) between two sensing lines filled with water has widespread application throughout power plants, especially in steam-powered generating units. This is due to the fact that differential pressure can be used to provide not just a measure of pressure itself, but also of water levels and flow rates. Significant applications include the following:

- **Pressure Measurement**
  - Between a boiler feedwater pump and the steam drum
- **Water Level Measurement**
  - In feedwater heater tanks
  - In the deaerator tank
  - In the steam drum
- **Water Flow Measurement**
  - Feedwater flow
  - Generator stator cooling water flow

Water Level Measurement

Differential pressure can be used to measure water level by virtue of the force of gravity, which results in greater pressure as the water level increases. This is akin to the hydraulic head resulting from water in an open reservoir, which is a measure of water pressure compared against standard atmospheric pressure. The method needs to be modified, however, to account for the fact that the space within a tank above the water is pressurized. Hence the use of differential pressure measurement, with one sensing line connected to the bottom of the tank to sense the water pressure, and the other to the top of the tank to sense the water vapor or steam pressure. The line at the top of the tank is known as the reference line. Even though the reference line connects to the top of the tank, which is above the water level, it will itself still fill up with water because the vapor/steam condenses in the line due to the much cooler ambient air temperature external to the tank.

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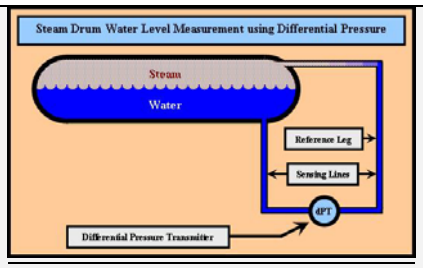

Water Flow Measurement

Differential pressure can be used to measure water flow by virtue of Bernoulli's principle: an increase in the speed of a flowing fluid is accompanied by a decrease in pressure. This increase in speed can be forced by placing a constriction such as an orifice plate or nozzle inside a pipeline, reducing its effective diameter. In order for the rate of flow in gallons per minute, for example, to remain the same, the velocity of the fluid must increase to make up for the fact that it is travelling through a smaller opening. This phenomenon is known as the Venturi effect. The higher velocity translates into lower pressure by Bernoulli's principle. Thus, measuring the differential pressure on either side of the constriction provides a measure of the rate of flow through the pipeline.

For exact flow measurement, the design and dimensions of the constriction are critical. In some cases, however, the concern lies more with changes in flow rate, indicative of blockages in the piping or overall flow path. This concern is important when strainers are used to filter out undesired particles from the fluid, especially in generator stator cooling systems. The strainers provide constriction to the water flow, resulting in a pressure difference. When the strainers are clogged, the pressure difference increases.

Steam flow can also be measured using the Venturi effect. But in that case, long sensing lines are not needed, as pressure immediately on either side of the orifice plate or nozzle is measured.

The Freezing Problem

Since differential pressure measurement requires gauging the difference in pressure between two separate sensing lines, if the water in either or both of those lines freezes, the measurement will be false. When a sensing line is plugged with ice, it cannot convey the intended water pressure to the transmitter location.

The fact that the water in the sensing lines is not flowing makes freezing all the more likely, and emphasizes the need for proper freeze protection methods such as insulation and heat tracing. Some sensing lines must run long distances through areas exposed to outdoor ambient air, which significantly exacerbates the risk of false readings.

- **Frozen Equipment (General):** Many other critical systems besides sensing lines experienced problems from the low temperatures. These included emissions systems, feedwater systems, control air systems, lubricating oil systems, and the like. Emissions systems sometimes rely on water, which is susceptible to freezing. Control air systems contain moisture-laden air; if the moisture is not removed, freezing can occur. Changes in the viscosity and properties of lubricants that are not kept at specified temperatures can adversely affect the operation of equipment.

  - ✓ Two units at one plant were derated when the NOx water storage tank lines froze.

  - ✓ At a City of Garland unit, 78 MW were lost from a draft fan failure, which was caused by frozen damper controls and a resulting low air flow trip.

  - ✓ A wind facility lost six units when lubricating oil fell below the minimum operating temperature and automatically tripped the units.

- **Frozen Water Lines:** The condensate and boiler feedwater systems of steam-cycle generating units (coal, conventional gas, and combined cycle) utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are susceptible to freezing, absent freeze protection measures. (This is especially true if the unit is offline at the onset of freezing temperatures.)
  .

  - ✓ One facility lost a 160 MW unit when air compressor drains froze. Another unit was shut down because of high boiler "superheat" temperature when its superheat spray lines froze.

- **Frozen Valves:** The operation of valves can become sluggish when exposed to severe cold weather. Depending on the particular application of these components, sluggish valves can cause instability in the boiler or turbine controls, which can eventually lead to a unit trip.

  - ✓ Kiowa Power Partners attempted to free up a frozen valve and, in the process, shut the valve completely, cutting off steam to the turbine and tripping 307 MW of capacity.

  - ✓ Another generating unit experienced a frozen valve on a fuel gas temperature controller, which caused gas temperatures to become

erratic. A bypass valve on another unit's fuel gas temperature controller froze, preventing the unit from reaching full capacity for a period of time.

- **Blade Icing:** Blade icing caused problems for wind generators. Precipitation and condensation during cold weather can cause layers of ice to form on turbine blades, causing potential balancing, bearing, and other equipment problems (as well as safety problems resulting from "ice throws").

  - ✓ Turkey Track Wind Energy lost 27 turbines and 40.5 MW of capacity during the event due to blade icing problems.

- **Low Temperature Limits:** Wind turbines are typically designed to operate within a designated range of temperatures, and have an automatic shutdown feature to protect their components if the range is exceeded. Although manufacturers offer a "cold weather package"[210] that allows a turbine to continue operating in colder temperatures, it does not appear that the package is used in the Southwest.

  - ✓ McAdoo Wind Energy suffered outages of 90 of its 100 turbines when the turbines, designed to shut down when the temperature drops below five degrees, performed as expected. Although McAdoo's turbines restarted automatically when the temperatures rose above the shutdown point, other units, such as Bull Creek Wind, did not come back online as temperatures rose.

- **Transmission Loss:** Generators can also be affected by external outages of transmission facilities.

  - ✓ At one generating plant, cold grease in a breaker appears to have caused slow clearing of the breaker, tripping six units.

[210] Press Release, General Electric, GE Energy's 2.5xl Wind Turbine Now Offers Extreme Cold Weather Capabilities for Challenging Applications in North America and Europe (Sept. 21, 2009), *available at* http://www.genewscenter.com/content/Detail.aspx?ReleaseID=8415& NewsAreaID=2.

ERCOT Non-Weather-Related Outages and Derates

While the majority of the ERCOT generator failures during the February event were weather-related, other causes also played a part. This is not surprising, as on any given day generating units can and do experience problems. To determine whether the amount of non-weather-related failures during the February cold weather event was typical, the task force reviewed ERCOT's 2010 daily forced outage data. During that year, forced outages ranged from 900 MW to 6300 MW per day, averaging 3200 MW per day or 16,000 MW for a five-day period. Therefore, the task force concluded that the 14,386 MW of non-weather-related failures experienced by ERCOT generators between February 1 and February 5, 2011 were comparable to what might be expected over a normal five-day period.

The causes (other than fuel supply) of the non-weather-related outages between February 1 and February 5 included difficulties with mechanical equipment, control equipment, operator error, emissions limitations, and fuel switching failures. The task force identified six general categories of non-weather-related causes of generator trips, derates, and failed starts over these five days:

Cause	No. of Units Lost	MW Lost
Mechanical Failure	37	7588
Control System Issues	28	3624
Fuel Switching	12	909
Operator Error	9	980
Emissions	3	358
Miscellaneous	11	927
Total Non-Weather-Related	**100**	**14,386**

Representative problems within these categories are discussed below.

- **Mechanical Failure**: A number of generators experienced mechanical equipment problems that were not related to the cold weather. For instance, several had combustion turbines trip due to high exhaust temperature spreads, which is an indicator of internal problems with the combustion turbine (or with the thermocouple[211]). Another common combustion turbine problem encountered during the event was high blade path

[211] Thermocouples are used to measure process temperatures and consist of two dissimilar metal wires soldered together at the tip, which produce an electrical current in response to temperature changes. Thermocouples can fall out of calibration over time or fail suddenly due to broken wires or damaged lead wire insulation.

spread,[212] which resulted in several more trips. Other trips, derates, and failures to start resulted from such problems as boiler and heat recovery steam generator leaks, plugged suction strainers on condensate pumps, improper boiler feed water pump oil pressure, gas pressure regulation issues (which were mainly resolved by the pipelines), and an assortment of gas turbine tuning issues.

- ✓ Greens Bayou CT 81 (54 MW) tripped due to a high combustible gas alarm, which was triggered by a leak in a coupling.

- ✓ San Miguel Unit 1 (395 MW) tripped due to a waterwall tube leak.

- **Control System Issues:** A prominent problem with control equipment appears to have been failed thermocouples. Control parameters, logic, and dynamics probes also resulted in several trips. Other problems included, but were not limited to, malfunctioning flame detectors and sheared air register pins,[213] loose wiring, a failed speed sensor, broken control linkages and faulty flow meter switches.

  - ✓ Deer Park CT 1 (195.5 MW) tripped due to a blade path temperature spread resulting from a failed sensor in the plant's distribution control system logic.

  - ✓ One facility experienced problems with its 46 relay,[214] which caused an outage. Another unit had a false indication of a ground fault on a generator rotor, which prompted the operator to take the unit offline.

- **Fuel Switching:** ERCOT has approximately 90 generating units with fuel switching capabilities, permitting them to switch from natural gas to an alternate fuel when natural gas is in short supply. (Generators may wish to switch fuel for other reasons as well, such as economics.) During the February event, 20 units attempted to switch from natural gas to their

[212] Blade path spread is a measurement, utilizing thermocouples, designed to identify turbine exhaust temperatures. A temperature spread beyond allowable limits will initiate an alarm or a trip. However, the alarm or trip can also be triggered by a defective thermocouple, rather than by actual fuel problems or air cooling problems.

[213] The failed flame detectors and air register pins caused burners inside the boiler to malfunction.

[214] A 46 relay (negative sequence relay) is used to detect unbalanced load on a generator that may cause excessive rotor heating and result in significant damage to the generator.

alternate fuel, with 15 units managing the switch successfully. The other units encountered various failures in their switching equipment. Derates also resulted from fuel switching.

- ✓ The Decker CT 2 (54 MW) tripped when attempting to burn fuel oil.
- ✓ The GEUS steam plant was derated by 5 MW due to operating on fuel oil.

- **Operator Error:** Several generators experienced minor problems associated with operator error. In some cases, the problems arose when operators switched control systems from automatic to manual mode. In other cases, generators tripped as the result of improper maintenance procedures.
  - ✓ A flameout of the boiler at one unit forced the burner valves to close but left the main gas trip valve open. In attempting to close the trip switch before restarting the unit, an operator selected the trip switch for the second unit, putting the second unit out of service.
  - ✓ An operator noticed that the fuel forwarding system for two units were operating in the incorrect mode. In attempting to rectify this situation, the operator correctly selected the automatic mode for one pump (it was operating in manual), but mistakenly selected "lagging" instead of "leading." This caused both units to give low pressure alarms and trip offline.
  - ✓ Hydraulic oil heaters at a generating unit had been left unplugged since the summer of 2009 (they had been unplugged at that time to avoid overheating). During the February event, trips resulted from low hydraulic oil temperatures.

- **Emissions:** At approximately 12:00 PM on February 2, ERCOT informed generators that the Texas Commission on Environmental Quality (TCEQ) was temporarily waiving air permit requirements that were preventing some generators from operating at full capacity during the emergency. (Although ERCOT characterized the action as a waiver, the TCEQ actually stated that it was exercising enforcement discretion.) This decision had little effect on the situation within ERCOT, as it was not announced until after half of the shed load had been restored.
  - ✓ Prior to issuance of the notice, Calpine's Clear Lake facility, which consists of three combustion turbines and two heat recovery steam

generators, was forced to manually shut down its GT102 and GT104 turbines in order to avoid exceeding NOx Limits.

- ✓ On February 3, another Calpine unit, Freestone Unit GT4, was derated so as not to exceed its NOx permit limits.

- **Miscellaneous:** A variety of other problems was also experienced, such as the following:

  - ✓ **Switchyard Equipment Problems:** Some generators encountered switchyard problems that led to units failing during the event. One entity was unable to start certain units because a standby transformer was not energized.

  - ✓ **Low Frequency Related Issues:** Two facilities reported frequency-related issues as causes for their units tripping. One facility's three generators tripped as a result of a low frequency turbine protection relay operating improperly. At another facility, the decline in frequency during the event caused the turbine control system to initiate an increase in fuel pressure to increase turbine speed, but it overshot its set point.

ERCOT Gas Supply Outages and Derates

Fuel supply problems did not significantly contribute to the amount of unavailable generating capacity in ERCOT during the first week in February. The outages and derates from inadequate fuel supply totaled 1282 MW from February 1 through February 5. (For comparison, the overall net generating capacity reduction in ERCOT peaked at 14,702 MW on the morning of February 2.) The fuel supply problems also did not occur all at the same time. The following table summarizes generation capacity reductions in ERCOT due to fuel curtailment and fuel quality problems.

Generator	Trip Time	Unit	Gen MW	MW Reduction	Pipeline (s)
Bosque Power Company	2/2 9:26 AM	Bosque Power: Unit 1, Unit 2, Unit 3, and Unit 4	597	154	Enterprise Texas Pipeline, Markwest Lateral
Calpine	2/4 7:55 AM	Corpus Christi: GT1, GT2, and ST1	516	174	South Cross CCNG Transmission
City of Austin (Austin Energy)	2/2 7:30 AM	Decker : Unit 2	450	100	Enterprise Texas Pipeline / Atmos Texas Pipeline
Power Resources	2/2 5:14 PM	Cal Energy: Unit 1	212	7	ONEOK WesTex Transmission
Luminant	2/1 10:00 AM	Lake Hubbard: Unit 1	441	174	Atmos-Texas Pipeline
GEUS	2/1 9:00AM	GEUS Steam Plant	112	112	Atmos-Texas Pipeline
Exelon	2/1 7:30 PM 2/2 11:00 AM 2/2 3:00 PM 2/2 6:00 PM	Mountain Creek: Unit 6, Unit 7, and Unit 8	808	476 396 476 396	Atmos-Texas Pipeline and Energy Transfer Fuel
Frontera Generation	2/2 8:16 AM	Frontera: Unit 1, Unit 2, and Unit 3	485	85	Kinder Morgan Tejas

- **Bosque Power Company:** MarkWest PNG Utility operates an intrastate, 30-mile, 18 inch diameter lateral in Hill, Johnson, and Bosque Counties, Texas. The lateral has an operating pressure of approximately 700 psi, and has no compressor stations. Gas is transported from Enterprise Texas Pipeline, a second intrastate pipeline, to the Bosque County Power Plant, the only electric generation facility served by the pipeline.

Bosque Power Company's QSE, EDF Trading North America (EDF), manages all transportation and gas supply purchases, nominations, and scheduling, including capacity on the Enterprise Texas Pipeline. EDF has only interruptible capacity on the Enterprise Texas Pipeline. The majority of its receipt points are in Waha and West Texas.

The power plant's units are programmed to automatically shut down if pipeline pressure drops below a certain point. On February 2, gas pressure steadily dropped to near the automatic shut down point. To mitigate the effects of lower gas pressures, the plant began reducing energy output on all four of its units.

MarkWest informed the task force that there are no compressors on their pipeline, and therefore the declining pressure was likely a gas supply issue. The pipeline had no capacity constraints.

- **Calpine:** The Calpine Corpus Christi facility is supported by one pipeline system, the Southcross CCNG Transmission pipeline (Southcross). Calpine Energy Services (CES), a subsidiary of Calpine Corporation, is an energy marketer that arranges for natural gas supplies for generation facilities owned by Calpine, including the Corpus Christi facility.

  On February 3 and 4, CES delivered gas into Southcross at four separate locations. However, at approximately 7:55 AM on February 4, the Calpine units tripped off line due to declining pipeline pressure on the Southcross system. The pressure on Southcross fell below the minimum delivery pressure obligation of 560 psig that is stated in both of CES's firm and interruptible agreements. Southcross reported that the low pressures on its system were due to supply freeze-offs that reduced expected deliveries into its system.

  Calpine was able to restart one of its units in less than one hour and run the facility at a derated level. Later in the day on February 4, once Southcross restored its line pack pressures, Calpine successfully brought all units back online.

- **City of Austin (Austin Energy):** The city of Austin has firm capacity on the Enterprise Texas Pipeline and is connected to the Atmos Pipeline-Texas (Atmos), both intrastate pipelines. Under the terms of the city's agreement with Atmos, its capacity rights are reduced when freezing weather is forecasted, pursuant to a specific formula in the contract. Most of the gas supply for the transportation is from Waha.

The plant did not experience curtailments. However, given the limitations on Atmos, usage was limited on February 2. Austin Energy exceeded its contractual hourly take on Enterprise Texas Pipeline and was requested by Enterprise to reduce flows to the hourly take (this is referred to as "back on rate"). This reduction caused a 100 MW derate of the Decker unit.

- **Power Resources:** Power Resources' Cal Energy Plant ramped down one hour early due to low gas pressure on its supplying pipeline, ONEOK WesTex, an intrastate pipeline located primarily in west Texas and the Texas panhandle.

  ONEOK WesTex states that it did not interrupt service but did experience operational difficulties and supply reductions. Beginning on February 1, increased gas usage by towns and power plants reduced the pipeline pressure, and several interconnecting gas processing plants also experienced supply difficulties. Normal operating pressures were restored by the afternoon of February 2.

- **Luminant and GEUS:** These plants are connected to the Atmos system, which traverses the Fort Worth, Permian, and East Texas Basins, all of which experienced supply losses due to freeze-offs.

  Transportation for power generation feeding off Atmos is only offered as an interruptible service, and is subject to electric generation restrictions, called "Tier 3 restrictions." Atmos instituted Tier 3 restrictions beginning at 9:00 AM on February 1, restricting gas flow to zero for the GEUS steam units and for Luminant's Lake Hubbard generating station. On February 2, increased demand resulted in continued loss of line pack and declining pressures at citygate points in Dallas-Fort Worth. Additionally, suppliers experienced well freeze-offs and equipment problems.

  On the morning of February 2, ERCOT initiated rolling blackouts to maintain the grid. The TRC contacted Atmos at approximately 10:00 AM to ask if additional volumes could be delivered to the Lake Ray Hubbard Electric Generating Station to assist with electric grid issues. Atmos explained to the TRC that such action would result in the loss of service to firm residential and commercial customers served by LDCs located to the north of the electric generation station on the pipeline system, and that therefore such deliveries could not be made to an interruptible customer.

- **Exelon:** Exelon has a firm gas transportation contract with Energy Transfer Fuel (ET Fuel) for the Handley Generating Station and an

interruptible gas transportation contract with Atmos for Handley Generating Station and Mountain Creek Station. Atmos implemented a Tier 3 restriction during the extreme weather event, which limited hourly flow to both the Handley and Mountain Creek stations.

The fuel curtailments at Handley did not affect operations until Unit 3 was called on the evening of February 2. Gas supply during the day was enough to allow Units 4 and 5 to run at full load. When Unit 3 was brought on line, it fuel switched Unit 4 to run partially on oil to allow Units 3 and 5 to increase output. Mountain Creek Units 6 and 7 ran at minimum load due to fuel restrictions. Mountain Creek Unit 8 ran at full load (but did have other non-gas related derates that affected output).

- **Frontera Generation:** The Frontera Generation plant is on the Kinder Morgan network of pipelines (collectively, KM Texas Pipes). The KM Texas Pipes receive natural gas from producing fields in south Texas, east Texas, the Gulf Coast, the Gulf of Mexico, and the Permian Basin. They also own or control gas storage capacity.

  Frontera has firm transportation service with deferred account service. "Deferred account service" is a balancing service that enables a shipper to acquire supply during low demand and deliver it to the KM Texas Pipes for future redelivery during peak demand, subject to contractual limits on hourly, daily, and total quantities.

  During the morning of February 2, the KM Texas Pipes contacted those customers that were taking more than their firm contractual rights, including both of the Frontera plants, requesting they stay within their contractual rights because pipeline pressures were falling and putting all firm services at risk. Later that day, ERCOT, along with the TRC, advised the KM Texas Pipes that ERCOT had declared an emergency condition. ERCOT then advised the KM Texas Pipes that the power grid in the Rio Grande Valley was in a critical state. ERCOT and the TRC requested the KM Texas Pipes to allow the Frontera electric generating plant to pull supplies in excess of their firm contractual rights. The KM Texas Pipes complied with this request.

Generation Outages in Salt River Project

The SRP balancing authority suffered several generator outages during the cold weather event, which severely affected its ability to serve load. On February 1 and 2, SRP lost a total of seven units. The failures of three of them were related to weather. On February 1, SRP lost Unit 1 at its Navajo Generating Station due

to a frozen transmitter sensing line, reducing generation capacity by 330 MW. On February 2, SRP lost additional generation due to weather-related problems: it lost 75 MW, its 10 percent share, from Unit 4 at Four Corners Generating Station (operated by Arizona Public Service Company), which failed due to a frozen sensing line that served the throttle pressure transmitter; and it lost Unit 2 at Navajo Generation Station, which tripped due to frozen waterwall pressure transmitter sensing lines.

SRP also suffered generation losses from the trips of four units on February 2, due to non-weather related issues: Coronado Generating Station Unit 2 , which experienced a mechanical problem with a coal pulverizer, losing peak load of 389 MW; the combustion turbine and the steam turbine units at Santan Generation Station Unit 6, which suffered an internal mechanical failure on the heat recovery steam generator and an accompanying runback of the combustion turbine; Springerville Unit 3 (operated by Tucson Electric Power), which developed high furnace pressure, causing a loss to SRP of its 75 MW share of the plant's 400 MW.

Generation Outages in El Paso Electric

The EPE balancing authority shed approximately 623 MW of firm load over the course of the February event, due to the loss of 646 MW of local generation. Unlike SRP, almost all of EPE's's outages were due to the cold weather.

On February 1, EPE lost its Newman Unit 3 because of frozen condensation on the fresh air inlet, and lost Rio Grande Unit 6 because of a frozen gas transmitter. The loss of these units resulted in a 152 MW reduction of capacity.[215]

On February 2, EPE lost 495 MW of capacity from its Newman and Rio Grande plants. Newman Gas Turbines 1 and 2 at Newman Unit 4, each with a capacity of 73 MW, tripped due to faulty drum level readings resulting from the cold weather. Gas Turbines 3 and 4 at Newman Unit 5, each with a 70 MW capacity, also tripped due to frozen drum level instrumentation sensing lines. Newman Unit 4 Steam Turbine, a 64 MW unit, tripped on February 2 due to frozen instrumentation associated with the condenser vacuum. Finally, EPE lost Rio Grande Unit 8, a 145 MW unit, due to frozen transmitter sensing lines that caused a low gas pressure signal.

[215] The Newman plant is not enclosed; the Rio Grande plant is enclosed.

El Paso attempted to bring its units back online on February 3 and February 4, with limited success. Newman Unit 4's GTs were restarted, only to trip on subsequent occasions for similar weather-related issues. (Luna and Afton, PNM remote generating facilities from which EPE was receiving energy, also experienced outages on February 3 and February 4.)

During the event, two EPE units, Newman Unit 1 and Rio Grande Unit 7, were offline and EPE tried to bring them online to assist with the shortages. Both units, however, failed to start due to frozen components and, in the case of Newman Unit 1, frozen drum drain lines and transmitter.

B. Natural Gas

Most of the natural gas supply problems experienced in the Southwest during the cold weather event were caused by freeze-offs, principally at the wellhead or, to a lesser degree, at nearby processing plants. Other equipment failures also played a role, as did the rolling blackouts and customer curtailments in the ERCOT region.

In order to analyze the causes of the supply shortfalls, the task force reviewed daily shortfalls at receipt points on pipelines. Most of these receipt points were at processing plants. The following table summarizes the information received from 13 processing companies, which overwhelmingly pointed to upstream supply outages as the major cause of the reduced volumes. (The second column is the maximum estimated production shortfall by basin; the third column is the percentage of shortfall of the processing plants that provided information; the final column lists the causes of the shortfalls.)

Processing Plant Outages Relative to Daily Production Shortfalls

BASIN	MAXIMUM DAILY PRODUCTION OUTAGE	PROCESSING RESPONSES AS A % OF THE DAILY OUTAGE	CAUSES
Permian	1.31 Bcf on Feb 4	0.44 Bcf (34%)	85% Upstream Supply Freeze-offs, 15% Mechanical/Electricity Outages
San Juan	.43 Bcf on Feb 2 and Feb 3	0.21 Bcf (52%)	Upstream Supply Freeze-offs, Minimal Amount due to Mechanical
Fort Worth	1.63 Bcf on Feb 6	0.17 (11%)	Upstream Supply Freeze-offs, Minimal Amount due to Mechanical
East Texas	.72 Bcf on Feb 3 and Feb 5	NA	NA
Gulf Coast	.65 Bcf on Feb 4	NA	NA

The task force further explored these upstream production outages by surveying 15 of the larger producers in the San Juan, Permian, Fort Worth, East Texas, and Gulf Coast Basins. These producers accounted for almost 40 percent of the total production for the five basins, with the highest percentages from the Fort Worth, San Juan, and Permian Basins.

For February 1 to February 5, an estimated 14.8 Bcf of production was lost from these five basins due to weather-related reasons. Of that amount, the surveyed producers lost 7.1 Bcf, equal to 48 percent of the total.

These production losses occurred for a variety of reasons. Some of the most common occurrences reported to the task force included:

- Freeze-offs (in some circumstances winterization was only designed for temperatures in the 20s),
- Icy roads that hampered logistics such as hauling away water produced by treatment equipment, and
- Rolling blackouts and customer curtailments.

Rolling blackouts were a problem particularly in the Fort Worth Basin, where they caused outages of compressors on gathering lines. In the Permian Basin, deployment of Load Resources by ERCOT during the event caused disruption to electric pumping units. According to information received from the

surveyed producers, 27 percent of the outages in the Fort Worth Basin were due to the rolling blackouts, and 29 percent of the outages in the Permian Basin were due to rolling blackouts or the curtailment of interruptible load.

The following table itemizes the reasons stated by these 15 producers for the supply shortfalls (the check marks indicate how many separate producers submitted information for each category):

	Permian	San Juan	Fort Worth	East Texas	Texas Gulf
Rolling Black Outs/ Curtailed Load	✓✓✓✓		✓✓		
Icy Roads	✓✓✓✓	✓	✓✓✓✓✓✓	✓✓	
Freezing of Compressors		✓✓	✓✓✓	✓✓	✓✓
Freezing Meters		✓			✓
Wellhead Freeze-offs	✓✓✓✓✓	✓✓	✓✓✓	✓✓✓✓✓	✓✓✓✓
Processing Facility Shut-in	✓	✓	✓	✓	
Ice Plugs in Gathering Lines	✓				
Frozen Salt Water Disposal Facilities	✓				

A basin-by-basin description of the gas production declines, and the resulting reduction in flows, follows.[216]

Permian Basin

The Permian Basin suffered production losses from February 1 through February 5 of 3.98 Bcf, with a maximum daily decline of 1.31 Bcf on February 4. The reasons provided for these declines are based on information received from

[216] The information is drawn from materials provided to the task force by producers and processing plants.

processors representing 34 percent of the maximum daily outage and producers representing 28 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso, Transwestern, Northern Natural Gas Company, and Enterprise Texas pipelines that had reductions exceeding 20,000 MMBtus per day, and thirteen processing plant points that had reductions of approximately 0.6 Bcf per day.

The receipt points on the El Paso pipeline with flow declines exceeding 20,000 MMBtus per day from February 1 to February 3 are all processing plant/gathering locations. They include Enterprise Waha (reduction of 120,681 MMBtus per day); Southern Union Jal#3 (reduction of 35,966 MMBtus per day); DCP Midstream GPS Eunice, reduction of 32,055 MMBtus per day; DCP Midstream Goldsmith Plant (reduction of 29,562 MMBtus per day); Southern Union Keystone (reduction of 28,515 MMBtus per day); Versado Gas Processors Texaco Eunice (reduction of 26,407 MMBtus per day); DCP Midstream Pegasus (reduction of 23,475 MMBtus per day); and Versado Gas Processors, Warren Monument (reduction of 21,460 MMBtus per day).

Transwestern's supply shortfalls in the Permian Basin were modest, relative to El Paso's, and were most significant at the Frontier Maljamar Gas Plant (reduction of 33,000 MMBtus per day) and at the Agave producer gathering connection (reduction of 44,000 MMBtu per day). Northern Natural processing plant receipt points with large reductions were the Atlas Midkiff Plant (reduction of 63,997 MMBtus per day) and the DCP Linam Ranch Plant (reductions of 106, 406 MMBtus per day). Finally, on Enterprise Texas Pipeline, the Crockett Gas Plant had a production shortfall of 34,376 MMBtus per day.[217]

Explanations varied for the reductions from the processing plants located in the Permian Basin.[218] The largest supply reduction to El Paso was the Enterprise Waha treating plant, which has a capacity of 280 MMcf per day. Enterprise reported that volumes delivered to the Waha Treating Plant decreased from 120 MMcf per day to approximately 40 MMcf per day, due to gas supply freeze-offs on February 2 and February 3. The plant's GE turbine then went down on

[217] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); *See also Market Alert: Deep Freeze Disrupts U.S. Gas, Power, Processing*, Bentek Energy LLC, Feb. 8, 2011, at 2-6.

[218] The task force received materials from a number of processing plants located in the basin. The material cited represents a sampling of data from those materials.

February 3, due to high discharge pressure when El Paso closed its valve at the plant tailgate (because of a high dew point in the gas stream).

On February 2, DCP's Linam Ranch plant in east New Mexico experienced freezing air ducts, resulting in a modest reduction to El Paso of 4,865 MMBtu per day from February 1 to February 3 (the reduction is 24,092 when measured from January 31). The plant then experienced a delay returning to service because of gas supply shortages from well freeze-offs, resulting in a lack of gas to restart the plant. The plant returned to normal operations on February 6 and supply returned to normal levels on February 7. Reductions in volume at three other DCP plants, Goldsmith, Pegasus, and Eunice, were the result of supply shortages from wellhead freeze-offs. Goldsmith and Pegasus experienced rolling blackouts that resulted in only brief outages, with gas being at the time either processed at the plants or delivered directly into pipelines.

Four DCP Texas processing plants were impacted by the rolling blackouts on February 2, but only one of them had resulting operational problems. The power outage caused the cooling water used for compression at the Roberts Ranch Plant in west Texas to freeze, leading to a plant shut down. (The plant was back in service on February 5.) The remaining plants did not experience any operational issues from the power outages. When the brief power outages occurred, the upstream gas bypassed the plants and was delivered without being processed.

Southern Union operates the Keystone and Jal #3 plants that together flowed reduced volumes of 64,481 MMBtu per day to El Paso. Southern Union reported that it experienced major property damage and significant financial losses due to freezing and failure of wells, pipes, and other facilities. The weather event ultimately resulted in the cessation of operations at many plants and field facilities, with corresponding reductions in deliveries to downstream pipelines. Some of Southern Union's issues were a direct result of rolling power outages at the Keystone facility at 7:25 AM and 9:05 AM on February 2, lasting 34 and 30 minutes, respectively.

Producer Declines in the Permian Basin

Producers representing a customary production level of approximately 0.75 Bcf per day[219] (approximately 30 percent of total basin production), reported production losses for the period February 1 through February 5 of 1.1 Bcf,

[219] This number represents the producers' usual production level, absent reductions experienced during the event.

estimated to be approximately 28 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Power disruptions to electric motors on pumping units (29 percent of the total losses, or 0.32 Bcf),
- Icy roads,
- Ice plugs in gathering lines,
- Freeze-offs, and
- Downtime at processing plant.

Occidental Energy Marketing reports that on February 2, because of its status as a Load Resource on ERCOT's system, electric service to its production facilities were interrupted when ERCOT deployed it as a Load Resource. This interruption resulted in significant production losses. Power began to be restored approximately 1.5 hours after the disruption occurred.

ConocoPhillips Company reports that a significant percentage of its production losses in the Permian Basin were attributable to rolling blackouts that knocked out processing plants and pumps and lifts. The majority of its Permian Basin production comes from oil wells that rely on electric pumps and lifts to maintain oil flow. When the pumps failed, the natural reservoir pressures were unable to sustain flow, the oil congealed, and the wells and flow lines froze.

San Juan Basin

The San Juan Basin suffered production losses from February 1 through February 5 of 1.3 Bcf, with a maximum daily decline of 0.43 Bcf on February 3 and February 4. The reasons provided for these declines are based on information received from processors representing 52 percent of the maximum daily outage and producers representing 71 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The task force reviewed receipt points on El Paso and Transwestern that had reductions exceeding 20,000 MMBtus per day, and eight processing plant receipt points with a reduction of approximately 0.35 Bcf per day (when netted against increased flows elsewhere).

Receipt points off of El Paso that had flow reductions exceeding 20,000 MMBtus per day are the BP Florida River Plant, with a reduction of 155,691 MMBtus per day, and two Williams Field Services processing plant/gathering locations; Milagro, with a reduction of 66,764 MMBtus per day, and #37, with a reduction of 24,047 MMBtus per day. Transwestern's most significant supply

shortfalls in the San Juan Basin for February 1 through February 3 were the William FS Kutz Plant, with reductions of 36,000 MMBtus per day, the Red Cedar Arkansas Loop gathering facility, with a reduction of 33,000 MMBtus per day, the Valverde Gas Plant, with a reduction of 48,000 MMBtus per day, and the Enterprise Chaco Plant, with a reduction of 87,000 MMBtus per day. These reductions were partially offset by increased flow of 100,000 MMBtus per day from the Williams FS Ignacio Plant.

Williams Fields Services reported that they had no operational problems, and the reduced volumes at Milagro and Kutz were due to upstream production shut-ins. With regard to the Chaco Plant, Enterprise reported it was operating at less than full capacity during the first week of February primarily because: (i) gas supplies were limited, (ii) ConocoPhillips moved approximately 100 MMcfd[220] from Chaco to their own San Juan processing plant on February 1, and (iii) winter production shut-ins occurred. In addition, the plant tripped on February 2 due to a hazardous gas supply alarm, and Enterprise's attempts to restart it were impeded by the combination of the lower volumes being nominated by producers and the cold weather experienced at the time.

Producer Declines in the San Juan Basin

Producers representing a customary production level of 2.0 Bcf per day (approximately 67 percent of total basin production), reported production losses for February 1 through February 5 of 0.9 Bcf, estimated to be approximately 71 percent of the total basin production losses for the five days.

None of the producers cited power outages as a cause of production losses. The losses were attributed to the following:

- Problems with compressor units,
- Freezing of wellhead meters,
- Cold weather, Freeze-offs,
- Icy roads, and
- Downtime at a processing plant.

Fort Worth Basin

The Fort Worth Basin suffered production losses from February 1 through February 5 of 4.7 Bcf and a maximum daily decline of 1.63 Bcf on February 6. The reasons provided for these declines are based on information received from

[220] MMcfd is a million cubic feet per day.

processors representing 11 percent of the maximum daily outage and producers representing 80 percent of the cumulative losses.

Reduced Flows at Processing Plant Pipeline Receipt Points

The Fort Worth Basin experienced supply reductions of almost 1.3 Bcf per day. Energy Transfer Fuel (ET Fuel) and Crosstex North Texas Pipeline (Crosstex) both receive gas from the Fort Worth Basin, and experienced reduced receipts.

ET Fuel had reduced receipts of 0.35 Bcf per day from January 31 through February 4. The largest reductions on the system occurred at the following receipt points: Chesapeake Energy production, with a reduction of 71,314 MMBtus per day; EOG Resources production, 127,418 MMBtus per day; Quicksilver Gathering, reduction of 69,675 MMBtus per day; and an ET Fuel processing plant, reduction of 61,668 MMBtu per day.[221]

Crosstex had a flow reduction estimated at 0.14 Bcf per day. The reduced volumes were due largely to the weather-related shut-down of the Silver Creek processing plant. Primarily due to freeze-offs, production at the plant declined by approximately 110,000 MMBtus per day from a normal flow rate of 185,000 MMBtus per day, to a five day average of 75,000 MMBtus per day on the outlet.

Atmos reported that intermittent supply reductions from nominated volumes were 0.13-0.17 Bcf per day.

The Energy Transfer Corporation Texas (ETC Texas) Godley area plant in north Texas experienced weather related difficulties on February 1 when one of its amine systems froze. ETC Texas was able to flow amine again on February 5. From February 1 through February 5, the inlet volume of the Godley Processing Plant decreased by 100 MMcfd, due to the loss of third party production from freeze-offs.

Producer Declines in the Fort Worth Basin

Producers representing a customary production level of 3.3 Bcf per day (approximately 69 percent of total basin production), reported production losses from February 1 through February 5 of 3.8 Bcf, estimated to be approximately 80

[221] Staff's analysis based on supporting data, display reports and data warehouse on file with Bentek (unpublished); pipeline scheduled volumes.

percent of the total basin production losses for the five days. The losses were attributed to the following:

- Rolling blackouts primarily affecting compressors on gathering lines (27 percent, or at least 1.0 Bcf),
- Icy roads, and
- Freeze-offs.

One large producer in the basin reported production losses for the period February 1 through February 5 as a result of electrical compression being shut down on a gathering system in the Dallas/Ft. Worth area. After power was restored, production was slow to return to standard rates. It therefore appears likely that a significant percentage of the lost production even after February 2 was due to the loss of power during the rolling blackouts.

East Texas

Producers representing a customary production level of 1.2 Bcf per day (approximately 24 percent of total basin production), reported production losses from February 1 through February 5 of 0.9 Bcf, estimated to be approximately 33 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Equipment freeze-offs,
- Icy roads,
- Downtime at processing plants,
- Freezing of equipment, and
- Wellhead freeze-offs.

Gulf Coast

Producers representing customary production level of 0.7 Bcf per day from February 1 through February 5 (approximately 14 percent of total basin production), reported production losses from February 1 through February 5 of 0.36 Bcf, estimated to be approximately 18 percent of the total basin production losses for the five days. The losses were attributed to the following:

- Compressors freezing,
- Frozen meters, and
- Freeze-offs.

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VII. Prior Cold Weather Events

The arctic cold front that descended on the Southwest during the first week of February 2011 was indisputably severe. Many cities in Texas and New Mexico experienced a 50 degree drop in temperature over an eighteen-hour period. Temperatures dropped to the low teens in Texas and below zero in New Mexico. Much of north Texas experienced record setting sleet and snow, totaling up to seven inches. Exacerbating the effects of the cold temperatures were accompanying sustained winds of 30-40 mph, with gusts as high as 51 mph.

The 2011 winter weather event has been determined by at least one weather service to be a one in 10 year occurrence for some regions of Texas, in terms of low temperatures and duration.[222] Adding the sustained winds to these low temperatures, the resultant convective heat loss (wind speed plus ambient temperature) for some generators was estimated to approach a one in 25 year severity. Specifically in El Paso, only four prior recorded cold weather events approached 2011 in severity, making the storm the worst weather event in the El Paso area in 49 years.[223]

This cold weather event was thus unusual in terms of temperature, wind, and duration. It was not, however, entirely without precedent. The Southwest experienced other cold weather events in 1983, 1989, 2003, 2006, 2008, and 2010. In fact, two of those years, 1983 and 1989, had lower temperatures than 2011.[224] But only in l989 were the severity, geographical expanse, and duration of cold temperatures and high winds comparable to the February 2011 event.

In most of those prior years, utilities avoided any significant outages or curtailments. In other years, however, that was not the case. This section examines pertinent prior winter weather events to determine if there were lessons that could have been learned that might have prevented or ameliorated the service disruptions experienced in 2011.

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[222] Key Document, Severe Weather Readiness Workshop Formerly Generation Weatherization Workshop, Winter Weather Readiness for Texas Generators, (June 8, 2011), http://www.ercot.com/calendar/2011/06/20110608-OTHER (citing Weatherbank, Inc).

[223] Forensic Weather Consultants, LLC, Forensic Weather Investigation of the Weather Conditions and Air Temperatures for the Period 1911-2011 (100 Years) in El Paso, Texas, May 12, 2011, at 1.

[224] Based on data from the National Weather Service.

A. Electric

The two prior cold weather events of most significance for the ERCOT region occurred in 2003 and 1989; generators experienced weather-related outages in both of those years, and rolling blackouts were implemented in 1989. The winter of 1989 in particular resembles that of 2011, both in the severity of the weather and in loss of load.

These two events are described below, beginning with the most recent.

2003 Event

On Friday, February 21, 2003, weather forecasts predicted a cold front over a large part of Texas. The front moved in earlier and was more severe than projected. Statewide, temperatures ranged from 15 to 27 degrees below normal. On Monday, February 24, with freezing temperatures as far south as San Antonio, the demand for electricity reached 42,029 MW, exceeding ERCOT's forecast by 4218 MW, or 11 percent. Owners of gas-fired generating units were short on gas and tried to acquire more gas on the intraday market. At the same time, the demand for gas increased as a result of heating needs.

System Events

By 6:00 PM on February 24, ERCOT issued a Market Alert to increase available energy and capacity, and ordered all Reliability Must Run (RMR) units raised to maximum output levels. Temperatures remained below freezing in Austin and Dallas into Tuesday. By 7:30 AM on Tuesday, ERCOT issued a Market Advisory requesting more bids. At the same time, gas companies informed customers that they were activating tariff provisions to curtail gas for purposes other than "human need." At the request of three QSEs, the ERCOT Chief Operating Officer signed affidavits stating that gas needed for electric generation met the qualification of human need.

At 9:08 AM on February 25, gas curtailment to a power plant caused three units to trip, resulting in the loss of 745 MW of generation. System frequency dropped to 59.81 Hz and could not be restored. The ERCOT system control error (SCE) was -1,500 MW and increasing. At 12:01 PM, ERCOT declared Emergency Electric Curtailment Plan (EECP) Step 1 (EECP was the predecessor to today's Emergency Energy Alerts). Step 1, invoked when reserves fall below 2300 MW, entailed instructing all available generation to come on line, and securing emergency power from neighboring electrical grids through the DC ties.

The EECP Step 1 succeeded in rebalancing the system within 30 minutes. Step 1 remained in effect for about seven hours and 30 minutes.[225]

Gas Supply Problems

Generator owners reported to the PUCT that they had problems acquiring natural gas to run their gas-fired units. Natural gas was suddenly in short supply, but equally significant was the fact that the structure of the natural gas market limited the way generators were able to respond to fuel shortages in real time. Specifically this involved the following:

- **Depleted reserves:** The amount of gas in storage declined rapidly starting in November 2002, faster than the usual drawdown over the winter period, dropping from a five year high to a five year low in just four months.

- **Timeline for gas nominations:** Natural gas trading closed for the weekend, meaning that fuel for Monday must be procured on Friday, thereby not allowing leeway for late changes in the forecast.

- **Fuel shortages and curtailments:** Delivery constraints reduced the fuel supply to some plants, forcing their electric generating capacities to be derated.

- **Lack of on-site storage:** Natural gas pipeline companies have the bulk of their storage underground, but most of the former vertically integrated electric utilities had their own gas storage facilities. Independent power producers generally do not have their own gas storage; in a deregulated environment, most believe it is uneconomical to maintain it.

In 2003, almost three-quarters of the installed electric generating capacity was fueled by natural gas. Of those units, 16 percent had dual fuel capability, the other fuel being oil. Many units switched from gas to oil on February 24 and February 25, but most had to be derated in the process, and some experienced operating problems. Of the total of 5500 MW of capacity that was lost due to gas curtailments, ERCOT estimated that only 3200 MW was regained on back-up fuel oil, yielding a net loss of 2300 MW.

[225] Prices spiked to $990 per MWh on February 24 and February 25, 2003, as the result of hockey stick bidding. For a discussion of this phenomenon, see the earlier section of this report entitled "The Event: Load Shed and Curtailments."

PUCT Recommendations

The Market Oversight Division of the PUCT investigated the 2003 cold weather event and issued a number of recommendations.[226] Notable among these are the following:

- Stricter enforcement of Resource Plan accuracy.
- Improved weather and electric demand forecasting.
- Consider providing financial incentives for fuel oil inventories to be maintained for use by dual fueled units.
- Curtailment prioritization – development of a joint curtailment methodology for natural gas and electricity production.
- ERCOT should communicate with both QSEs and Transmission / Distribution Service Providers in the future when the power system is under stress.

Consequences

Following the 2003 generating unit outages, ERCOT revised its Protocols to establish Resource Plan performance metrics. These were put in place in 2004. The February 2003 event ultimately became an impetus for the establishing of Emergency Interruptible Load Service in ERCOT.

1989 Event

Beginning on Thursday, December 21, 1989, an arctic air mass descended on Texas for three days, delivering some of the coldest temperatures ever recorded in the state over a one hundred year period. Temperatures bottomed out at 7 degrees in Houston, -1 in Dallas, and -7 in Abilene. As a result of the cold weather, the demand on the ERCOT power system peaked at 38,300 MW, an 11 percent increase over the previous winter's peak and 18 percent above the projected peak for the winter of 1989-1990. This load level was equivalent to 93 percent of the summer peak demand.[227]

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[226] Julie Gauldin, Richard Greffe, David Hurlbut & Danielle Jaussaud, Pub. Util. Comm'n of Tex., Market and Reliability Issues Related to the Extreme Weather Event on February 24-26, 2003, 29 (May 19, 2003), *available at* http://puc.state.tx.us/industry/electric/reports/ERCOT_annual_reports/special/weather_event.pdf (PUCT 2003 Report).

[227] Elec. Reliability Council of Texas, *ERCOT Emergency Operation: December 21-23, 1989* (Undated), at 5 (ERCOT Emergency Operation).

The high demand, combined with weather-related forced outages of generating units and the curtailment of natural gas fuel supplies, resulted in the need for ERCOT to shed firm load system-wide for the first time in its history or the history of its predecessor.[228] Although there were two subsequent years in which ERCOT shed load during hot weather spells,[229] the 1989 event remained the only cold weather-related load shed event until February 2011.[230]

The 1989 event predated deregulation of the electric utility business in Texas, which began in 2002. Utility companies were therefore still vertically integrated and owned and operated generation, transmission, and distribution in their franchise service territories.

System Events

On Wednesday, December 20, 1989, a severe cold weather alert was declared for north Texas, effective the following morning; by 6:00 PM on Thursday, all of ERCOT's territory had been placed under severe alert. The temperature was 21 degrees in Dallas and 41 in Houston at that time. Gas curtailments were experienced starting on December 21, and continued for several days thereafter. These resulted in a considerable number of generators switching to or increasing their mix of fuel oil.

On Friday, December 22, ERCOT was unable to maintain minimum required operating reserve levels, due to record-high loads and a large number of generating units being forced offline. The frequency dropped below 59.95 Hz at 8:30 AM, and ERCOT ordered the start up of all available units. Those local control centers experiencing generation deficiencies also shed interruptible loads and minimized their own internal loads such as mining operations and station

[228] ERCOT's predecessor was Texas Interconnected Systems, formed in 1941. *Id.* at 1.

[229] In May 2003, the loss of two nuclear-powered generating units tripped automatic UFLS relays, resulting in the shedding of 1549 MW of firm load; service was restored within three hours and 30 minutes. In April 2006, an early season heat wave and the loss of four generating units caused ERCOT to shed 1000 MW of firm load via rolling blackouts; service was restored within one hour and 45 minutes.

[230] For the Houston area, which was the hardest hit in Texas, it was the first shedding of firm load in the history of the Houston Lighting and Power Company, dating back to the energizing of its first lighting load in 1882. *See* Bill Beck, At Your Service: An Illustrated History of Houston Lighting & Power Company (Houston Lighting & Power Company, 1st ed.1990) at 409; *see also* A Brief history of CenterPoint Energy, 1880-1889, CenterPoint Energy, http://www.centerpointenergy.com/about/companyoverview/companyhistory/timeline/23b55aef7af66210VgnVCM10000026a10d0aRCRD/ (last visited Aug. 3, 2011.

lighting. Utilities made public appeals for customers to voluntarily reduce consumption.

At 10:00 AM on December 22, ERCOT's load peaked at 38,300 MW. At this point, the online generating capacity was 39,800 MW, or 1500 MW greater than the load. Within two hours, decreasing load and the restoration of some generating units that had been forced offline earlier succeeded in bringing reserves back up to acceptable levels. Thus, the record-setting peak load period was met without the need to shed firm load.

However, temperatures continued to drop overnight Friday into Saturday, December 23, when they reached minimums of -7, -1, and 7 degrees in Abilene, Dallas, and Houston, respectively, with wind chill factors down to -35 degrees.

Up until midnight Friday night, approximately 3000 MW of generation was offline due to weather-related problems. The system also suffered 1500 MW of capacity reduction on account of units switching from natural gas to fuel oil. Between midnight and 7:00 AM on the following morning, an additional 4700 MW of generation was forced offline due to weather-related problems. It was also difficult getting power from outside ERCOT. West Texas Utilities offered 220 MW of emergency power to Houston Lighting and Power Company (HL&P), to be delivered over the North Tie, but then had to withdraw the offer due to unspecified technical problems.

By 5:36 AM on Saturday, December 23, the frequency had again dropped below 59.95 Hz, and over the course of the next hour and a half it hovered between 59.79 and 59.92 Hz, indicating the system was in difficulty. Interruptible loads were shed during the early morning hours. At 7:49 AM, ERCOT directed the utilities that were generation deficient to shed firm load.

HL&P had already begun shedding firm load, and increased its load shed to 1000 MW. Lower Colorado River Authority and the City Public Service of San Antonio shed 60 and 150 MW of firm load, respectively.

This firm load shedding, combined with some internal and external power transfers, succeeded in restoring the frequency to 60 Hz, re-stabilizing the system. Around 10:20 AM, however, seven generating units producing a combined 1275 MW were all forced offline nearly simultaneously, causing the frequency to plummet to 59.65 Hz. ERCOT was then forced to invoke system-wide load shedding, beginning with 500 MW, allocated among the utilities. Within ten minutes, the frequency had recovered and the system was stable once again.

As the midday Saturday load declined (typical for a weekend midday), much of the firm load that had been shed was able to be restored within only 30 minutes. The load shed directive was terminated slightly more than two hours later, when reserves increased to acceptable levels.

Accounts vary regarding the amount of total firm load that was shed. The PUCT reported a total load shed of 1710 MW.[231]

Generation Outages, Derates and Failures to Start

The following table presents a summary of the causes of the outages, derates, and failures to start experienced in ERCOT during the 1989 cold weather event.

Number of Units	Capacity	Cause
34	11,623 MW	Frozen Instrumentation
6	1385 MW	Paralyzed or Dead Fish Clogging Water Intakes
9	1051 MW	Other, Cold Weather-related
7	1246 MW	Non-weather-related
56	**15,305 MW**	**Subtotal**
Not Available	1500 MW	Gas curtailment impact (oil burning derate)
56+	**16,805 MW**	**Total**

[231] *See* Pub. Util. Comm'n of Tex., Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989 (Nov. 1990), at 14 (PUCT 1989 Report); ERCOT Emergency Operation at 6.

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Virtually all types of generating units encountered problems, whether viewed from the perspective of fuel type or unit type, suggesting that the problems could not be attributed to a particular fuel or unit design. The breakdown is as follows:

- Sorted by **Fuel Type:**
  - Coal: 8 units; 4669 MW
  - Natural Gas: 29 units; 3881 MW
  - Distillate Oil: 1 unit; 257 MW
  - Dual Fuel – Gas & Oil: 15 units; 4418 MW
  - Dual Fuel – Coal & Gas: 1 unit; 670 MW
  - Nuclear: 1 unit; 1250 MW *
  - Petroleum Coke: 1 unit; 160 MW

    *This unit was forced off line the previous weekend due to the failure of an expansion joint in a steam condenser. An attempt was made to start it up during the December 21-23 cold spell, but that failed due to equipment freeze-ups.

- Sorted by **Unit Type:**
  - Conventional Steam Turbine Generators: 32 units; 13,298 MW
  - Simple Cycle Gas Turbines: 7 units; 235 MW
  - Combined Cycle Units: 17 units; 1772 MW

PUCT Recommendations

The PUCT staff investigated the cold weather event of 1989 and issued a report the following year that evaluated the causes of the generator outages and made recommendations. Because the circumstances of the event, and the causes of the outages, are so similar to those of the 2011 event, it is worth reproducing those recommendations verbatim:[232]

- All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.

- All utilities should implement procedures requiring a timely annual (each Fall) review of unit equipment and procedures to ensure readiness for cold weather operations.

[232] PUCT 1989 Report at 7.

- All utilities should ensure that procedures are implemented to correct defective freeze protection equipment prior to the onset of cold weather.

- All utilities should maintain insulation integrity and heat tracing systems in proper working order. Generating unit control systems and equipment essential to cold weather operations should be included in a correctly managed preventive maintenance program.

- Additional training programs for plant personnel on the emergency cold weather procedures, including periodic drills, should be implemented by each responsible utility.

- PUC Engineering Staff should modify procedures for power plant CCN [Certificates of Convenience and Necessity] reviews to include a specific review for plant reliability under adverse weather conditions. Of special interest would be the selection of proper design temperature ranges for the power plant site.

The PUCT identified inoperative or inadequate heat tracing systems and inadequate insulation on instrumentation sensing lines as the most common technical equipment problems encountered during the freeze. (These problems also featured prominently in the failure of many generators during the February 2011 event.) Many of the PUCT's recommendations involve weatherization improvements it advised the generators to make, including ensuring the working operation of freeze protection equipment, insulation, and heat tracing systems; instituting preventative maintenance for cold weather equipment; and implementing adequate training for extreme conditions.

The report concluded that "the near complete loss of the ERCOT grid brings an awareness that, even in Texas, plant operators must prepare for cold weather emergencies...this awareness of and attention to cold weather problems must be continued."[233]

Comparison of 1989 and 2011 Events

A summary of the statistics for the 1989 event and the 2011 event show how similar they were. Weather conditions and system events for each year are set forth below.

[233] *Id.*

Comparison Table: Basic Information

	December 21-23, 1989	February 1-2, 2011
Min. Temps & Wind Chills in Dallas Area	Temperature: -1 degrees F Wind Chill: -12 degrees F	Temperature: 13 degrees F Wind Chill: -6 degrees F
Peak System Load	38,300 MW	56,334 MW
Net Generating Capacity Reduction	11,809 MW 31% of peak load	14,702 MW 26% of peak load
Gross Generating Capacity Reduction	56+ units 16,805 MW	193 units 29,729 MW
Firm Load Shed	1710 MW 4.5% of peak load	4900 MW 8.7% of peak load
Overall Duration of Firm Load Shedding	5 hours, 47 minutes	7 hours, 24 minutes

The following table compares the causes of the outages, derates, and failures to start for each year.

Comparison Table: Generator Problems

	December 21-23, 1989	February 1-2, 2011
Frozen Instrumentation	34 units 11,623 MW	61 units 13,924 MW
Fish Clogging Water Intakes	6 units 1385 MW	None reported
Other Cold Weather-related	9 units 1051 MW	54 units 6365 MW
Non-weather-related	7 units 1246 MW	63 units 7905 MW
Gas Curtailment Impact	No. of units not specified 1500 MW	15 units 1534 MW
Weather-related % of Gross Capacity Reduction in MW	**84 % ***	**68 % ***
Frozen Instr. % of Gross Capacity Reduction in MW	**69 %**	**47 %**

* Does not count gas curtailments as weather-related.

Despite the recommendations issued by the PUCT in its report on the 1989 event, the majority of the problems generators experienced in 2011 resulted from failures of the very same type of equipment that failed in the earlier event. And in many cases, these failures were experienced by the same generators. Of the over 56 units and 16,805 MW of generating capacity that became unavailable during the December 1989 event, 43 units (representing 13,606 MW of capacity) are still in service in 2011. And 26 of those units, representing 5654 MW of capacity, experienced problems again during the February 2011 cold weather event.

The failures of these repeating units alone eroded a large share of ERCOT's reserve margin going into the morning of February 2, 2011, putting the entire system in jeopardy. Weighing the shedding of 4000 MW of firm load in February 2011 against the 5654 MW of generation capacity that experienced problems in both the December 1989 and February 2011 events, it can be argued that had three-quarters of that capacity not failed again in 2011, the February 2011 blackouts would not have happened. [234]

In its 1989 report, the PUCT commented that "whether the corrective actions being implemented [by the generators in the wake of the event] are sufficient to prevent future freeze-off related power plant failures, only direct experience with another deep freeze will ascertain."[235] Texas has now had that second event, and the answer is clearly that the corrective actions were not adequate, or were not maintained. Generators were not required to institute cold weather preparedness, and efforts in that regard lapsed with the passage of time. It is also possible that new ownership or new plant personnel lacked the historical perspective to make these efforts a priority, at least in the absence of externally imposed requirements.

The task force considered whether cost alone could have been the driving factor in the failure to maintain adequate winterization, and believes it to be unlikely. Based on current industry data, the task force estimates that for conventional gas-fired units and combined cycle units, the capital cost of upgrading basic equipment such as insulation and heat tracing could range from $50,000 to $500,000, depending on the age and condition of the materials, the original design temperature of the unit, and any change in the design temperature.[236] (However, if significant plant components needed to be upgraded

[234] The number of units that tripped, had derates, or failed to start was much larger in 2011 than in 1989. This is primarily a matter of scale. The number of generating units in ERCOT increased from 323 in 1989 to 550 in 2011. However, the increase in the number of units does not correlate exactly with the increase in generating capacity from 54,000 MW to 84,400 MW (using full wind power nameplate capacity, i.e., not adjusted) because of the large increase in combined cycle natural-gas fired plants since 1989 and the introduction of wind power. Combined cycle plants have multiple, and smaller, generating units than conventional steam-turbine plants. Wind power installations vary widely in size from tens of megawatts to hundreds of megawatts, adding greatly to the unit count, but less so to the actual capacity. With so many more, and smaller, units on line in 2011, it is not surprising that the number of trips, derates, and failures to start were greater than in 1989.

[235] PUCT 1989 Report at 6.

[236] *See* Black and Veatch Corp., *Cold Weather Protection Assessment for El Paso Electric Company (Rev. 1)*, at 6-4 and 6-7. In the event an independent engineering analysis is commissioned, and based on current industry estimates, the costs for such an analysis for a gas-fired unit could range from $25,000 to $150,000, depending on the type of unit.

or replaced, the cost could be significantly higher. For instance, if cooling towers had freezing problems, the addition of a cooling tower bypass or variable speed tower fan motor might be needed; such costs could range from $150,000 to $500,000.[237])

Texas has recently enacted legislation to deal with the problem of inadequate winterization by generators. A bill was introduced in the Texas legislature following the February 2011 blackouts, with provisions directing the PUCT to prepare a weather emergency preparedness report, to review the emergency operations plans on file, and to recommend improvements to the plans to ensure electric service reliability. In introducing the bill, State Senator Glenn Hegar stated: "What I don't want, is another storm and another report someone puts on the shelf for 21 years and nobody looks at."[238]

After a Senate Committee hearing, the bill was amended and unanimously adopted by the Texas Senate.[239] The House unanimously passed the bill on May 23, and the bill was signed into law by Governor Richard Perry on June 17, 2011.

B. Natural Gas

Gas production suffered declines in each of the six prior years identified by the task force as having had severe cold weather, and in 1989 and 2003, the declines led to gas curtailments that caused outages or derates to a number of gas-fired electric generators. While some winterization has been put in place by producers and processing plants, production declines occur with each successive severe cold weather event, including the event of February 2011. It may well be that producers have limited market incentives to pay for more elaborate winterization, as they will likely lose less money from short periods of non-production than they would expend on preventing freeze-offs at each of the many wells a producer typically owns.

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[237] *Id.*

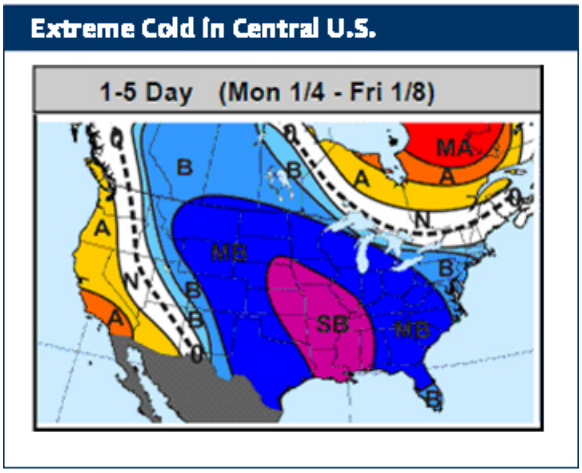
[238] Eric Dexheimer, *February Power Blackouts Across Texas echoed 1989 Failures, State Report Shows,* Austin American-Statesman, Apr. 10, 2011, http://www.statesman.com/news/local/ february-power-blackouts-across-texas-echoed-1989-failures-1390558.html?view AsSinglePage=true.

[239] SB 1133, 82 Leg., Reg. Sess. (TX 2011) *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133E.pdf#navpanes=0. The bill would also allow the PUCT to require entities to update their emergency operations plans and to adopt rules relating to implementation of the bill.

Gas production declines in these prior extreme cold weather years are presented below, beginning with the most recent.

January 2010

In 2010, an ongoing cold spell led to wellhead and gathering line freeze-offs in the Rockies, San Juan and other southwestern producing basins. About 0.5 Bcfd[240] was lost in the Rockies and another 1.0 Bcfd was lost from the Southwest and shale basins. From January 21 through January 28, Northern Natural Gas and Southwest Gas issued low line pack alerts. High temperatures in every city in the area were above freezing during the month, and low temperatures fell only to the low 20s in a few cities on a few days.



[Color legend: N is normal, B is below normal, MB is much below normal, and SB is strong below normal.]

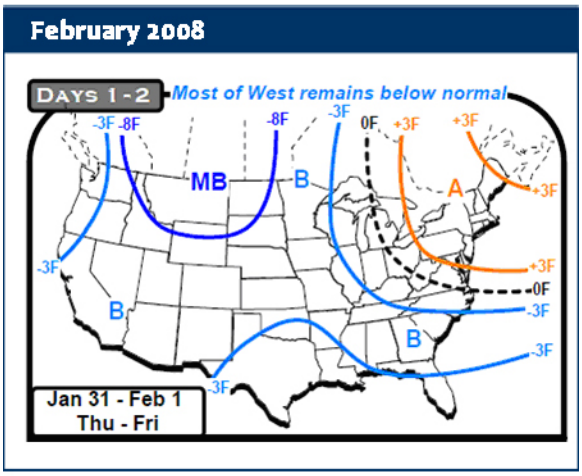
February 2008

There was widespread cold weather during late January and early February 2008 in the Rockies, Midwest, and Northeast. El Paso, Southwest Gas, Mississippi River Transmission (MRT), Natural Gas Pipeline Company of America (NGPL), ANR, Northern Natural Gas, and Kern River issued low line pack warnings, and receipts at the Opal[241] processing plant in Wyoming fell due to

[240] Production data in this section is drawn from Bentek, Supply and Demand Daily report.

[241] The Opal processing plant is a major source of output for Rockies production. Major interstate pipelines transport output from that plant to regional markets and markets in the East, the Pacific Northwest, California and the desert Southwest.

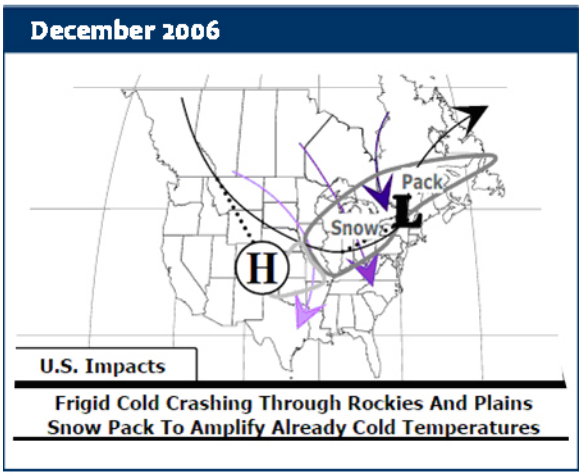
wellhead and gathering line freeze-offs in the region. Rockies production was off between 0.5 and 1.0 Bcfd over a 10-day period. Southwest regional production also fell by about 0.5 Bcfd during that time.



Source: MDA EarthSat, 1-5 Day Outlook, January 31, 2008

December 2006

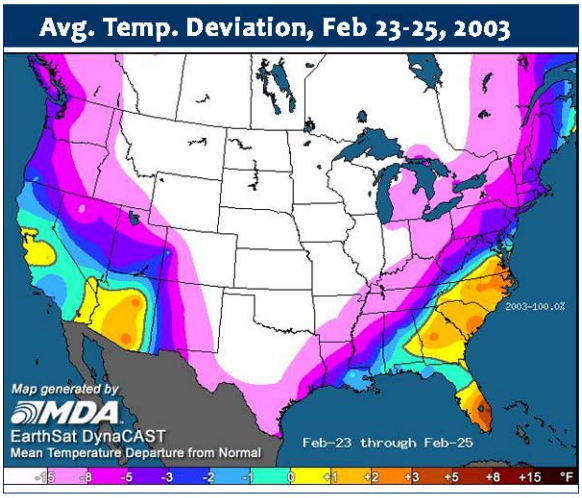
During the first few days of December 2006, unseasonably cold air accompanied by a good deal of snow covered much of the Rockies, the Great Plains and the Midwest. The Midwest and Chicago took the brunt of the frigid temperatures. Lows were in the single digits with a wind chill of -12 degrees. For two days, wellhead freeze-offs caused midcontinent production to fall almost 1 Bcfd, while Rockies and Texas/Louisiana production each were off about 0.5 Bcfd. Temperatures in Midland and El Paso dipped into the low teens for a short time. The short cold snap set off a flurry of operational warnings and alerts; El Paso issued a system operating condition flow order, and Southwest Gas, MRT, NGPL, Kern River, and Transwestern issued low line pack warnings.



Source: MDA EarthSat, Friday December 1, 2006.

February 2003

Overall, the winter of 2002/2003 was the third coldest of the most recent 11 winter periods. The winter began with record inventories (at that time) of gas in underground storage. But by April, over 2.5 Tcf (trillion cubic feet) was withdrawn, also a record at the time. Regional and national natural gas storage inventories were at record lows when compared to many metrics. During the period from February 23 through February 25, a shot of very cold air swept out of the Rockies and through the Midwest. It brought wind chills of -50˚ to portions of Wyoming and Colorado and lows below zero in Chicago. Gathering system and wellhead freeze-offs were reported in the Permian Basin and the midcontinent and Rockies regions, and NGPL issued an operational flow order. Midland and Dallas temperatures fell below freezing, although only for a short time. El Paso and Transwestern did issue low line pack alerts that were quickly lifted. As noted earlier, in ERCOT there were gas curtailments to electric generators, estimated by ERCOT to have resulted in a loss of 5500 MW of capacity.



Source: MDA EarthSat

In a May 19, 2003 report on the 2003 cold weather event, the PUCT observed that the gas supply shortages experienced by electric generators in Texas were due in part to an unusually steep decline in storage volumes in the months preceding the event. Those depleted storage reserves during a time of increased demand made it difficult for generators to obtain adequate gas supply, although only one supplier, the TXU Lone Star Pipeline (now Atmos Pipeline-Texas), actually curtailed industrial customers. The PUCT also noted that newly independent power producers, unlike the old vertically integrated utilities, tended not to have their own storage facilities, a factor that contributed to the supply shortage.[242]

[242] PUCT 2003 Report at 12-16.

The 2003 PUCT report recommended that the PUCT and the TRC collaborate on developing a joint curtailment methodology for natural gas and electricity.[243] According to industry observers at the time, the recommendation was aimed at coordinating electrical generation needs with gas supply, to ensure that supply was being used where it was most needed during shortages. However, the agencies reportedly were unable to develop a policy and the project died.[244]

December 1989

December 1989 was described at the time by the National Weather Service as the coldest December ever recorded for the combined northeast, central, and southeast regions of the United States. The freeze of December 21 through December 25 caused severe problems for Texas electric utilities, as described earlier in the discussion on electric prior cold weather events. Record and near record low temperatures occurred across the state. For Dallas, it was the coldest and second coldest days in the last 38 years; for Midland, the third and fifth coldest days; for San Antonio, the first and fourth. Houston and Brownsville each had two days among the top five coldest. Wind chill factors in Houston fell to -5 degrees, and in Dallas and Midland, to -12 degrees and -14 degrees, respectively.

While the gas supply situation was more precarious in the Northeast, the Gulf Coast supply regions, Texas and the Southwest were not without their problems. United States productive capacity had not been tested by a prolonged cold snap for more than a decade. Major processing plants[245], refineries and petrochemical plants in the Gulf Coast region shut down. Supply problems occurred in the Gulf of Mexico, Kansas, Texas, Oklahoma, Arkansas, and Louisiana. High winds prevented crews from reaching offshore production platforms that froze off. A major gathering operation in Oklahoma saw 40 percent of its supply frozen off. Producer respondents to a 1991 AGA study said that 10 percent of their production was affected by the cold temperatures.[246]

Most major interstate pipelines accessing Gulf supply experienced some kind of problem. Texas Eastern Transmission Corporation (TETCO) suspended all interruptible transportation deliveries and reduced firm deliveries by 0.5

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[243] *Id.* at 16.

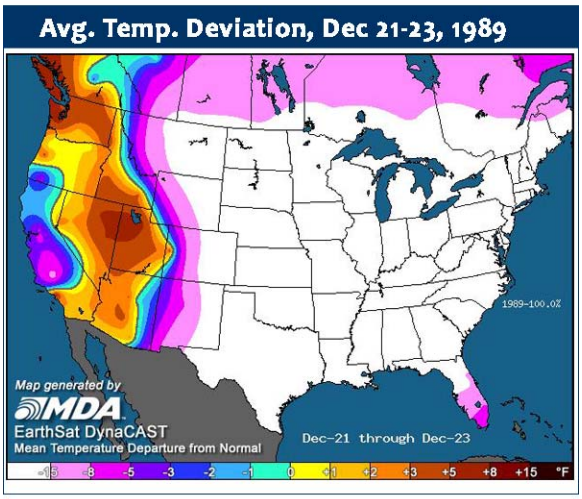
[244] Drawn from materials submitted to the task force by a pipeline company.

[245] Conoco Inc. lost its 1 Bcfd Grand Chenier processing plant in coastal Louisiana due to gas supply and plant operational problems.

[246] Foster Natural Gas Report No. 1845 (Oct. 3, 1991) at 20.

Bcfd.[247] Trunkline and NGPL also suspended interruptible transportation services. Transco curtailed firm service between 22 percent and 50 percent.[248]

In ERCOT there were gas curtailments to electric generators, tabulated earlier in the section on prior electric cold weather events.



Source: MDA EarthSat

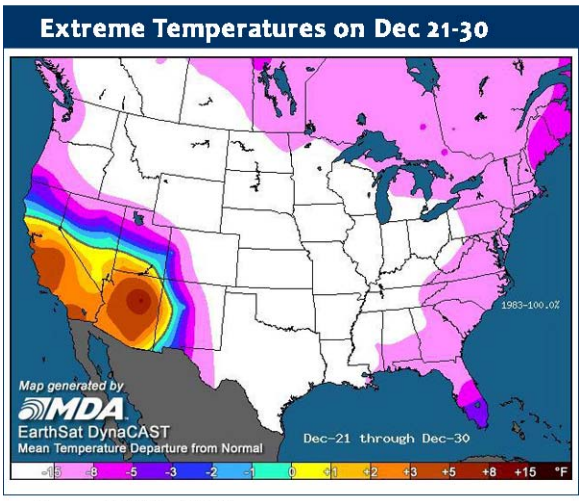
December 1983

At the end of December 1983, a nine-day stretch of cold weather in Texas resulted in a 3 Bcfd shortfall in supply. Demand was met by massive withdrawals from storage and fuel switching by generators. Refinery operable capacity fell over 72 percent during the week, due to gas supply curtailments. The TRC said that if schools and factories had not been closed for the Christmas holiday, deliveries to high priority customers would have been curtailed. Producers behind Valero Energy reported well freeze-offs, accounting for a 43 percent drop in supply.[249]

[247] TETCO reported a field supply shortfall of 1 Bcfd from its normal of 1.9 Bcfd.

[248] See Rick Hagar, Winter Hits U.S. Industry, Strains Gas Supply, OIL & GAS J., Jan. 1, 1990, at 28; see also Rick Hager, U.S. Gas Industry Ponders Lessons Learned from Severe Winter, OIL & GAS J., Mar. 5, 1990, at 17.

[249] See Rick Hagar, TRC Chairman Downgrades Size of Gas Surplus in U.S., OIL & GAS J., Feb. 27, 1984, at 47.



Source: MDA EarthSat

An examination of these prior years reveals that production declines are common during cold weather events. However, only in limited circumstances did they lead to curtailment of natural gas customers, including curtailment of gas-fired electric generators.

The production declines raise the question as to why producers did not improve their winterization preparations to withstand these not uncommon cold snaps. The reason most likely comes to one of cost (as well as to the lack of regulation requiring it). A study performed for the task force by the Gas Technology Institute[250] has estimated that capital costs for winterization could vary from as little as $2,800 to more than $30,000 per well, depending on the degree of cold weather protection required and other variable factors such as gas flow rates, pressures, existing winterization, and the like. In addition to these capital costs, the cost of maintenance and operational supplies such as methanol (antifreeze) could add up to several thousand dollars per year for each well. (These costs include costs associated with protecting field processing, such as separating water from the gas, as well as the flow lines to the separating facilities.)[251] Since it is not uncommon for the larger producers to have hundreds of wells in a given basin, these costs would quickly mount up. Such costs need to be accounted for in some fashion if mandatory weatherization were to be considered by regulatory or legislative bodies (as would the costs that would be incurred by electric generators to meet comparable requirements.)

[250] This report is included as an appendix, entitled "GTI: Impact of Cold Weather on Gas Production."

[251] Kent F. Perry, Gas Technology Institute, *Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During Early February, 2011* (June 2011) at 33.

Producers suggest that even improved winterization of the wells would not prevent a significant portion of production declines, since other problems, such as icy roads that prohibit hauling off water (which, if not done, shuts down the well), are also commonly encountered.

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VIII. Electric and Natural Gas Interdependencies

The February 2011 cold weather event highlights the interdependency of electricity and natural gas, an interdependency that has grown in recent years. Natural gas has become an increasingly popular fuel choice for electric generators. Concurrently, compressors used in the production and transportation of natural gas have come to rely increasingly on electricity for their power source, rather than natural gas.

The reason for the increased popularity of gas-fired electric generation is one of economics. Natural gas prices have fallen due to increased gas production, beginning in 2008 when producers developed the technology to drill the Barnett Shale. Just prior to 2008, average daily marketed production was about 55.5 Bcf per day. Spot prices at the Henry Hub during 2007 averaged almost $7.00 per MMBtu. Shale production accounted for perhaps five percent of total United States production, and offshore production comprised approximately 15 percent.

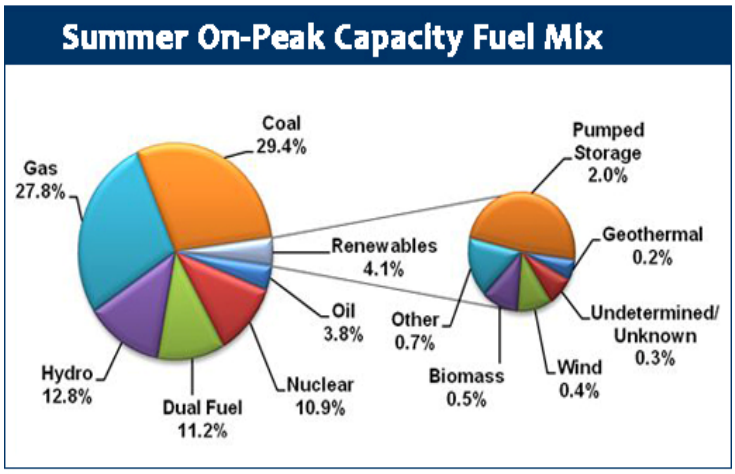
But by the end of 2008, average daily production had grown to over 59.3 Bcf per day. In the ensuing years, producers applied the lessons learned in the Barnett Shale to other basins, most notably the Fayetteville, Haynesville and Marcellus Shales, with notable results. Thus far in 2011, gas production is averaging almost 62.8 Bcf per day (and recently topped 64 Bcf per day), while average daily spot prices at the Henry Hub have fallen to $4.27 per MMBtu. Offshore production in 2010 accounted for only 10 percent of total United States production, and analysts estimate that shale production alone now accounts for 25 percent of total production.

At the same time, gathering companies, as well as pipelines and LDCs located in urban areas, have increasingly turned to electric-powered compressors. Gathering companies prefer electric-powered compressors because they can fit in smaller spaces than gas-fired compressors, and the companies do not need as much compressive power as the large pipelines. For pipelines and LDCs in urban areas, environmental restrictions relating to noise and air quality, as well as the ready availability of electricity, tip the scales in favor of electricity over natural gas. The large pipelines favor gas-fired compressors, because the gas is readily available to them and they have large horsepower demands.

The following chart depicts the mix of generation available for United States electricity needs in the summer of 2010, by fuel type.[252] It shows that 27.8

[252] NERC 2010 Summer Reliability Assessment (May 2010) at 10, http://www.nerc.com/files/2010%20Summer%20Reliability%20Assessment.pdf.

percent of all generation uses gas as the fuel source, and an additional 11.2 percent is dual-fueled (mostly gas and diesel oil).



Source: NERC's Summer Reliability Assessment, May 2010

The Southwest relies heavily on gas-fired generation to meet its peak capacity needs. In ERCOT, approximately 57 percent of the available on-peak summer and winter capability is from gas-fired generation (with 40 percent solely gas-fired and 17 percent having dual-fuel capability with gas as the primary fuel).[253] In the SPP region, 50 percent of the summer and winter on-peak capability is from gas-fired generation, and in WECC, 41 percent.

In New Mexico, gas-fired generating units consume approximately 70,102 MMcf annually, representing approximately one percent of total national consumption of gas used in the utility sector.[254] In Texas, gas-fired generating units consume approximately 1,387,421 MMcf of natural gas annually, representing approximately 20.2 percent of total national consumption of gas used in the utility sector.[255] And in Arizona, gas-fired generating units consume approximately 261,904 MMcf of natural gas annually, representing approximately 3.8 percent of total national consumption of gas used in the utility sector.[256]

[253] Based on data provided by ERCOT.

[254] EIA, Natural Gas Annual 2009, at 128-129 (Table 58), http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html.

[255] *Id.* at 152-153 (Table 70).

[256] *Id.* at 70-71 (Table 29).

Interdependency Effects During the February Event

The task force examined data from numerous electric and gas entities to gauge the severity that shortfalls in one commodity had on the other during the February event. Materials received from natural gas producers indicate that the rolling blackouts (or customer curtailments) in ERCOT were a significant cause, from 29 to 27 percent respectively, of production shortfalls in the Permian and Fort Worth Basins. For pipelines and LDCs, however, the effects of the rolling blackouts were negligible.[257]

Gas shortfalls caused problems for some generators in Texas, although not nearly to the extent as did direct weather-related causes such as equipment failure from below-freezing temperatures. In ERCOT, as detailed in the section of this report entitled "Causes of the Outages and Supply Disruptions," the outages and derates from inadequate gas supply during the cold weather event totaled 1282 MW, compared to a peak net capacity reduction of 14,702 MW. While gas supply to SRP and EPE was compromised due to problems at the Chevron Keystone Storage Facility, EPE's generating units failed for other reasons, and SRP was able to obtain gas from other sources. However, during the 2003 cold weather event, there were significant gas curtailments to electric generators in Texas, which affected generating capacity. Gas curtailments also caused a loss of generating capacity in 1989, although to a lesser extent.

The task force was cognizant of the possibility that gas shortages may have been a less significant factor only because so many generators were forced offline for other reasons, and thus unable to take the gas (as was the case with EPE). The task force attempted to answer the question of whether there would have been adequate gas supplies to ERCOT had its failed gas-fired generators been able to take the gas. To do so, the task force tallied and compared the MWs forced offline, the amount of gas demand the generators would have imposed on suppliers had they been capable of running, and the capacity of the gas supply system at the time.

The task force determined that 5256 MW of generation in ERCOT could have imposed demands on the gas supply system had the generating units not experienced trips, derates, or failures to start. This number represents the total 5556 MW of the 55 gas-fired generating units in ERCOT, reduced by 300 MW for those generating units connected to a single pipeline that had pressure or gas

[257] An exception for LDCs supplying gas is the surge effect experienced when electricity is restored after an outage, which places instant and simultaneous demand on gas equipment and systems. This effect is described in the section of this report entitled "The Event: Outages and Curtailments."

quality problems (making it unlikely the generating units could have received gas even if they had had no operational difficulties). Each unit was assumed to have a 9,000 Btu/kWh heat rate. In the aggregate, these units would have added a maximum additional gas demand of approximately 1.1 Bcf per day.

Adding this additional hypothetical demand to the actual peak demand of 12.5 Bcf per day[258] would have imposed total demand on the system of 13.6 Bcf. Supply in January was running at 17.7 Bcf per day; these volumes declined during the first week of February. On February 2, the worst day from the standpoint of ERCOT, supply declined to 16.35 Bcf per day. On February 4, when production volumes hit their lowest point for the week, supply declined to 14.08 Bcf per day.

A comparison of these supply and demand numbers shows that total demand (actual demand plus hypothetical demand) would still have been below the available supply during the February cold weather event, particularly so on February 2, the day rolling blackouts were implemented. The task force's analysis therefore indicates there would have been adequate gas to supply the generators in ERCOT that failed for other reasons.[259] This conclusion was confirmed by knowledgeable industry observers, who were of the opinion that the Texas supply of gas would have been adequate had the generators not experienced weatherization problems.

Fuel Switching

A not insignificant amount of gas-fired generation in the Southwest has fuel switching capability. In ERCOT, 16 percent of total generation can fuel switch; in SPP, it is seven percent. Within WECC, of those generating units that are directly connected to El Paso, Northern Natural Gas, or ONEOK WesTex, 38 have fuel switching capability.

Fuel switching enables a simple or combined cycle generating turbine to alternate between fuel sources, typically natural gas and some type of fuel oil.

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[258] The actual demand listed is a worst case scenario, because the calculation was derived by adding together the peak demand of each of the three major pipelines in Texas serving gas-fired generating units. A more realistic number would probably be demand of approximately 12 Bcf per day or less.

[259] The excess gas was sold out of state, but had the generators in ERCOT been able to use it, they could have gotten it. Since gas prices rose modestly in the region during the event, the shippers would very likely have redirected the gas to Texas to take advantage of the higher prices, had the generators been able to accept it. This would be true whether or not the contracts were interruptible, since a shipper could adjust its purchases and sales to take advantage of the pricing differential.

Fuel switching can be as simple as a control room operator pushing a button which automatically switches to oil, or as complicated as having to remove gas injectors and install oil injectors in every position around the boiler, a process that can take days rather than minutes.

It is common for units that switch to an alternate fuel type to experience a capacity derate, since normally each unit is designed to most efficiently burn a particular fuel.

The choice to perform fuel switching is primarily based on three factors: 1) cost, 2) environmental restrictions, and 3) the availability of natural gas. Running the generating unit on alternate fuels, such as fuel oil, may cost up to twice as much on a MW basis.[260] And environmental and air quality control restrictions, which vary by state, may limit the number of hours per year a generator is allowed to run on fuel oil.

Fuel switching capability was a more desirable option in the past, when the relative prices of gas and oil fluctuated, making one or the other more economical at any given time. Given the decline in natural gas prices, this option has become less valuable.

During the February event, 20 generating units in ERCOT attempted to switch fuels, with 15 managing it successfully.[261] (This echoed ERCOT's experience during the 2003 cold weather event, when a number of units that attempted to switch fuels were unable to do so, and those that did switch experienced derates of capacity.[262]) SRP has nine units capable of switching, and EPE has three units capable of switching. None was asked to switch during the event, as the units either failed for other reasons or were able to obtain adequate gas supply. In SPP, of the three representative entities the task force examined, eight generating units have fuel switching capabilities; four attempted to switch during the event and ultimately succeeded, although half had initial difficulties.

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[260] Based on information supplied to the task force by an LDC.

[261] A majority of the units that attempted to switch fuels but were unable to do so experienced a mechanical failure of some sort in the switching equipment, which could have been due to the cold temperatures, inadequate maintenance, lack of regular testing, or the infrequent use of the alternate fuel in normal operations.

[262] PUCT 2003 Report at 17. The PUCT recommended that providing financial incentives for fuel oil inventories, to be maintained for use by dual-fueled generating units, should be considered.

Fuel switching raises a number of questions, such as: whether generators that have the capability to switch fuels should be required to maintain their alternate fuel equipment and stockpile an adequate supply of the alternate fuel, whether subsidies or incentives should be instituted to compensate for such requirements or to add fuel switching capabilities to those units that do not currently have it, and whether units that can switch fuels should be paid to do so in order to preserve gas supplies for residential consumers. These are issues that can be most fruitfully addressed in forums involving representatives of both the electric and natural gas industries operating in the region, as well as the regulatory bodies overseeing them.

Communications

In 2004, NERC released a report entitled "Gas/Electricity Interdependencies and Recommendations," which summarized the findings of its Gas/Electricity Interdependency Task Force (GEITF). The GEITF held a series of meetings with representatives of both the electric and gas industries and prepared a list of recommendations for NERC's consideration. The GEITF reported that a recurring theme expressed by gas industry participants was concern about communications between pipeline operators and entities other than the pipeline's contractual customers. While the pipelines communicate with the LDCs serving a generator or with the generator itself, they do not communicate with a regional reliability coordinator, apparently due to confidentiality restrictions. The GEITF recommended that NERC, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

Communication failures between gas and electric entities did not seem to play a role during the February 2011 event (although there were complaints of communication issues between shippers and pipelines). Nonetheless, the electric and gas industries might consider revisiting the GEITF recommendations to see if procedures should be developed for communications between pipelines and reliability coordinators.[263]

[263] NERC plans to conduct an electric/gas interdependency study in 2011 to reevaluate the GEITF recommendations. The study will analyze whether procedures should be developed for communications between the electric and gas industries.

IX. Key Findings and Recommendations

The facts that came to light in the course of the joint inquiry conducted by the staffs of FERC and NERC, as well as the conclusions drawn from them, have been presented throughout the body of this report. Because the matters examined are complex and detailed, this section presents in summary form the task force's key findings. It also presents recommendations that the task force believes, if implemented, could significantly contribute to preventing a recurrence of the rolling blackouts and natural gas curtailments experienced in the Southwest during the February 2011 cold weather event.

A. The Electric Industry

Key Findings -- Electric

- During the February event, temperatures were considerably lower (15 degrees plus) than average winter temperatures, and represented the longest sustained cold spell in 25 years. Steady winds also accelerated equipment heat loss. However, such a cold spell was not unprecedented. The Southwest also experienced temperatures considerably below average, accompanied by generation outages, in December 1989. Less extreme cold weather events occurred in 2003 and 2010. Many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment.

- While load forecasts fell short of actual load, the forecasts were not a factor in the loss of load. ERCOT manually increased its February 1 and February 2 forecasts by 4000 MW to factor in wind chill, and had established sufficient reserves to accommodate both forecasted load and the actual load that transpired. The reason blackouts had to be initiated was that over 29,000 MW of generation that was committed in the day-ahead market or held in reserve either tripped, was derated, or failed to start. This was the largest loss of generation in ERCOT's history, including during the prior cold weather load shed event in December 1989 and the two hot weather load shed events in 2003 and 2006. While units of all types (except nuclear generating units) tripped, derated, or failed to start in 2011, in ERCOT, gas combined cycle units had the highest percentage of failures, compared to their percentage of the total fuel mix.

- ERCOT and the generators within ERCOT could better coordinate generator scheduled outages, both in terms of the total amount of scheduled outages at a given time and their location. A substantial amount of generation (11,566 MW) was on scheduled outage going into the cold weather event. ERCOT's current Protocols provide that requests for scheduled outages submitted earlier than eight days before the outage is to begin are automatically approved, unless they would violate a Reliability Standard.

- ERCOT's fast action in initiating rolling blackouts prevented more widespread and less controlled ERCOT-wide blackouts. Had ERCOT not initiated manual load shedding, its under-frequency load shedding relays would have instantaneously dropped approximately 2600 MW (five percent of system load), a loss that could have created further system disturbances and resulting generation outages. Load shedding by the transmission and distribution operators in ERCOT's footprint was generally carried out in a timely and effective manner.

- Transmission operators and distribution providers generally did not identify natural gas facilities such as gathering facilities, processing plants or compressor stations as critical and essential loads.

- Balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when temperatures dropped.

- The lack of any state, regional or Reliability Standards that directly require generators to perform winterization left winter-readiness dependent on plant or corporate choices. While Reliability Standard EOP-001 R.4 and R.5 refer to winterization as a consideration in emergency plans, these requirements apply only to balancing authorities, transmission owners, and transmission operators.

- Generators were generally reactive as opposed to being proactive in their approach to winterization and preparedness. The single largest problem during the cold weather event was the freezing of instrumentation and equipment. Many generators failed to adequately prepare for winter, including the following: failed or inadequate heat traces, missing or inadequate wind breaks, inadequate insulation and lagging (metal covering for insulation), failure to have or to maintain heating elements and heat lamps in instrument cabinets, failure to train

operators and maintenance personnel on winter preparations, lack of fuel switching training and drills, and failure to ensure adequate fuel.

- Gas curtailment and gas pressure issues did not contribute significantly to the amount of unavailable generating capacity in ERCOT during the event. The outages, derates, and failures to start from inadequate fuel supply totaled 1282 MW from February 1 through February 5, as compared to an overall peak net generating capacity reduction of 14,702 MW.

Recommendations -- Electric

PLANNING AND RESERVES

1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generation Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer peak season.

The large number of generating units that failed to start, tripped offline or had to be derated during the February event demonstrates that the generators did not adequately anticipate the full impact of the extended cold weather and high winds. While plant personnel and system operators, in the main, performed admirably during the event, more thorough preparation for cold weather could have prevented many of the weather-related outages.

Capacity margins going into the winter of 2010/2011, for both ERCOT and the southwest regions of WECC, were adequate on paper. (ERCOT reported a 57 percent margin above forecasted winter peak demand, and the southwest regions of WECC projected a 105.7 percent margin.) But those margins did not take into account whether many of the units counted would be capable of running during the severe cold weather that materialized in February.

While the probability of a winter event in the predominantly summer peaking Southwest appears to be low, shedding load in the winter places lives and property at risk. The task force recommends that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season.

2. Planning authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon.

Both ERCOT and the Southwest regions of WECC undertake planning studies to ensure that sufficient reserves are available to meet seasonal peak loads. However, the forecasted peak demand in the winter assessments for 2010/2011 was not as high as that actually experienced in early February.

Planners should undertake a sensitivity study, using the 2011 actual conditions as a possible extreme scenario, that reflects expected limits on available generation. These limits would include those due to planned outages, limited operations during periods of extreme cold weather, ambient temperature operating limitations, and any likely loss of fuel sources.

This sensitivity study should be used by operational planners to identify various system stress points, and by Reliability Coordinators, Balancing Authorities, and Transmission Operators to improve and refine strategies to preserve the reliability of the bulk power system during an extended cold weather event. These strategies should include procedures relating to utilization of generators with fuel switching capabilities and implementing early start-ups for generators with long start-up times.

3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.

This recommendation is designed to ensure that Balancing Authorities take into account transmission constraints, other demands on reserve sharing resources, the possibility that more than one reserve sharing group member might experience simultaneous emergencies, and other factors that might affect the availability or deliverability of reserves. ERCOT is currently considering a similar recommendation, which was presented to its Board of Directors in March, 2011.

4. ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage, consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria.

ERCOT's Protocols provide that it may not forbid an outage request submitted more than eight days prior to the scheduled outage, unless the outage would keep ERCOT from meeting applicable Reliability Standards or Protocol requirements. The Protocols further limit review of outage requests made earlier

than eight days before the outage to the following three things: load forecast, other known outages of both generation and transmission, and the results of a contingency analysis to indicate whether the outages would cause overloads or voltage problems.

The task force recommends that ERCOT consider lengthening the period for which ERCOT may deny an outage request, assuming the conditions for doing so are met. (ERCOT is presently considering a Protocol revision to give itself the authority to deny an outage request that is not scheduled more than 90 days prior to the outage date, a revision which the task force supports.) In addition, ERCOT should consider giving itself the authority to cancel previously approved outages in cases of approaching extreme weather conditions, even up to the time of the event itself. In making this evaluation, ERCOT should take into account the costs that would be imposed on the generator as well as the practical difficulties of returning it to service if plant components are disassembled, as well as the generator's need to perform maintenance at some point while also avoiding the high demand summer season.

In addition to the criteria for outage evaluation currently provided in the Protocols, the task force recommends that ERCOT take into consideration the potential loss of units based on weather conditions beyond their design limits, and the effects likely to result from the totality of scheduled and proposed outages.

In furtherance of these criteria, ERCOT should:

- Have available to it the design temperatures of all generation resources.
- Take into consideration as an extreme weather event approaches which plants will not be available based on their design temperature limits.
- Consider increasing reserve levels during extreme weather events.
- Commit, for purposes of serving load and being counted as reserves, only those plants whose temperature design limits fall within the forecasted temperature range.
- Determine, prior to approving an outage, if the combination of previously approved scheduled outages with the proposed scheduled outages might cause reliability problems.

5. ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to utilize pre-operational warming prior to anticipated severe cold weather, and (iii) allow

it to verify with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.

ERCOT data on forced outages during the 50 coldest days between 2005-2011 show a correlation between low temperatures and forced outages. This was demonstrated not only by the February 2011 event but also by the 1989 event; in both cases, extremely low temperatures led to the loss of large amounts of generation and the implementation of rolling blackouts.

Increasing the amount of responsive reserves going into a cold weather event would compensate for the probability that a number of generating units might fail, and would provide better response to system instability in the event of such losses.

Additionally, pre-operational warming would help prevent freezing and identify other operational problems. Running a unit prior to the start of extreme cold weather would utilize the unit's own radiant heat to help prevent freezing. And starting it up would permit correction of any problems that otherwise would not be noticed until the unit was called upon for performance.

While pre-operational warming has considerable value, issues of whether or how generators are to be compensated for taking such actions at ERCOT's direction would need to be addressed.

COORDINATION WITH GENERATOR OWNERS/OPERATORS

6. Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.

Sixteen percent of ERCOT's generation capacity is listed as having fuel switching capabilities. During the February cold weather event, a quarter of the 20 units that attempted to switch fuel were unsuccessful. If a unit represents itself as having fuel switching capability, verification of the adequacy of its capability would provide useful information to the Balancing Authority or Transmission Operator as to the availability of that unit in the event of natural gas curtailments.

Fuel switching verification might consist of the following:

- Documented time required to switch equipment,
- Documented unit capacity while on alternate fuel,
- Operator training and experience,

- Fuel switching equipment problems, and
- Boiler and combustion control adjustments needed to operate on alternate fuel.

7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions.

The task force determined that a combination of scheduled and forced outages of ERCOT's black start units would have put ERCOT's ability to restore the system in jeopardy, had an uncontrolled blackout not been averted by the implementation of load shedding. Balancing Authorities and Transmission Operators should take steps to ensure the availability and reliability of their black start units during adverse weather and emergency conditions, particularly to prevent a gap in this function before 2013, when the provisions of Reliability Standard EOP-005-2 on System Restoration from Blackstart Resources becomes mandatory. These steps should ideally include auditing Generator Owner/Operators, random testing of black start units during temperature extremes (both hot and cold), determining the ambient operating temperature limitations of the black start units, evaluating the effects of extreme temperatures on implementation of the entity's black start plan; and ensuring that operators are trained to start the black start units during extreme weather conditions. ERCOT is presently considering Protocol revisions that would provide for unannounced testing of black start units and "claw back" payments for black start units that fail testing or fail to perform.

8. Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.

In order to ascertain actual capabilities during extreme weather conditions, Balancing Authorities and Reliability Coordinators should require Generator Owner/Operators to provide accurate ambient temperature design operating limits for each generating unit that is included in its portfolio (including the accelerated cooling effect of wind), and update them as necessary. These limits should take into account all temperature-affected generator, turbine, and boiler equipment, and associated ancillary equipment and controls.

The Balancing Authorities should take steps to verify that Generator Owner/Operators comply with this requirement, and should prepare for the winter season by developing a catalog of individual generating unit temperature limitations. These should be used to determine if forecasted temperatures place a particular generating unit in a high risk category.

Lastly, Balancing Authorities and Reliability Coordinators should consider the feasibility of counting on a generating unit whose rating falls below forecasted weather conditions, and should consider whether to take into account weather-related design specifications in ranking units in the supply stack during critical weather events.

9. Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.

Balancing Authorities are permitted to request a forecast of real output capability under Reliability Standard TOP-002-02 R15. Doing so would allow operators to make proactive decisions prior to the onset of cold weather, including but not limited to:

- Requesting cancellation of planned outages,
- Directing advanced fuel switching,
- Directing startup of units with startup times greater than one day,
- Requesting startup of seasonally mothballed units, and
- Making advance requests for conservation.

In the case of ERCOT, which does not own the generators in its footprint, consideration needs to be given to ensuring that there is an adequate cost recovery mechanism in place for reliability measures taken by the generators at ERCOT's direction.

10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages.

Some generators experienced derates during the event due to emission limitations. The Texas Commission on Environmental Quality (TCEQ) exercised enforcement discretion with respect to its emission restrictions during the event; however, this action, which was taken after the TCEQ received requests during the event itself, did not come in time to prevent all the emissions-related derates that

occurred on February 2. It is recommended that ERCOT work out procedures in advance with the TCEQ for the exercise of its enforcement discretion in the case of severe weather events, and have an internal procedure in place that delegates specific ERCOT personnel as responsible for contacting the TCEQ and other environmental regulatory bodies during the early stages of an event, in order to inform them of the significance of the situation.

WINTERIZATION

11. States in the Southwest should examine whether Generator/Operators ought to be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate.

The task force determined during its inquiry that certain generators were better prepared than others to respond to the February cold weather event. In many cases the entities that performed well had emergency operations or winterization plans in place to provide direction to employees on how to keep their units operating. Although the implementation of a winterization plan cannot guarantee that a unit will not succumb to cold weather conditions, it can reduce the likelihood of unit trips, derates and failed starts.

The state of Texas has provided a starting point for such legislation with SB 1133, which was signed into law on June 17, 2011. This statute incorporates two important components: (1) mandatory reporting of emergency operations procedures, and (2) independent review by the PUCT.

In addition to the matters covered in the Texas statute, the task force recommends that planning take into account not only forecasts but also historical weather patterns, so that the required procedures accommodate unusually severe events. Statutes should ideally direct utility commissions to develop best winterization practices for its state, and make winterization plans mandatory. Lastly, it is recommended that legislatures consider granting utility commissions the authority to impose penalties for non-compliance, as well as to require senior management to acknowledgement that they have reviewed the winterization plans for their generating unit, that the plans are an accurate representation of the winterization work completed, and that they are appropriate for the unit in light of seasonal weather conditions.

NERC staff has concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability. Accordingly, NERC intends to submit a Standard Authorization Request, the first

step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations.

Plant Design

12. Consideration should be given to designing all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed.

The ideal time to prepare a generating unit to withstand cold temperatures is in the design stage. For that reason, the low temperatures and wind chills that can occur during the occasional severe storm should be incorporated in the design process.

13. The temperature design parameters of existing generating units should be assessed.

The task force found that for existing generating units, it is often not known with any specificity at what temperature the unit will be able to operate, or to what temperature heat tracing and insulation can prevent the water or moisture in its critical components from freezing. For that reason, Generator Owner/Operators should conduct engineering analyses to ascertain each unit's operating parameters, and then take appropriate steps to ensure that each unit will be able to achieve the optimum level of performance of which it is capable.

The task force recommends the following:

- Each Generator Owner/Operator should obtain or perform a comprehensive engineering analysis to identify potential freezing problems or other cold weather operational issues. The analysis should identify components/systems that have the potential to: initiate an automatic unit trip, prevent successful unit start-up, initiate automatic unit runback schemes and/or cause partial outages, adversely affect environmental controls that could cause full or partial outages, adversely affect the delivery of fuel to the units, or cause other operational problems such as slowed valve/damper operation.

- If a Generator Owner/Operator does not have accurate information about the ambient temperature to which an existing unit was designed, or if extensive modifications have been made since the unit was designed (including changes to plant site), it should obtain an engineering analysis

regarding the lowest ambient temperatures at which the unit can reliably operate (including wind chill considerations).

- Each Generator Owner/Operator should ensure that its heat tracing, insulation, lagging and wind breaks are designed to maintain water temperature (in those lines with standing water) at or above 40 degrees when ambient temperature, taking into account the accelerated heat loss due to wind, falls below freezing.

- Each Generator Owner/Operator should determine the duration that it can maintain water, air, or fluid systems above freezing when offline, and have contingency plans for periods of freezing temperatures exceeding this duration.

Maintenance/inspections generally

14. Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis.

The task force found a number of inadequacies in generating units' preparations for winter performance. These included a lack of accountability and senior management review, lack of an adequate inspection and maintenance program, and failure to perform engineering analyses to determine the correct capability needed for their protection equipment.

The task force recommends the following:

- Each Generator Owner/Operator's senior management should establish policies that make winter preparation a priority each fall, establish personnel accountability and audit procedures, and reinforce the policies annually.

- Each Generator Owner/Operator should develop a winter preventative maintenance program for its freeze protection elements, which should specify inspection and testing intervals both before and during the winter. At the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance, in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season.

- Each Generator Owner/Operator should prioritize repairs identified by the inspection and testing program, so that repairs necessary for

the proper functioning of freeze protection systems will be completed before the following winter.

- Each Generator Owner/Operator should use the recommended comprehensive engineering analysis, combined with previous lessons learned, to prepare and update a winter preparation checklist. Generator Owner/Operators should update checklists annually, using the previous winter's lessons learned and industry best practices.

Specific Freeze Protection Maintenance Items

The task force found that many generating units tripped, were derated, or failed to start as a result of problems associated with a failure to install and maintain adequate freeze protection systems and equipment. Based on these findings, on an examination of freeze protection systems of many of the affected generating units, and in some cases on standards issued by the Institute of Electrical and Electronics Engineers, the task force has prepared a number of recommendations designed to prevent a repeat of the spotty generator performance experienced during the February cold weather event. Of course, specific actions should conform to best industry practices at the time improvements are made, as well as to the requirements of any mandatory winterization standards imposed by regulatory or legislative bodies.

Heat tracing

15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the power supply to all heat trace circuits, including all breakers and fuses.

- Each Generator Owner/Operator should, before each winter begins and before forecasted freezing weather, inspect the continuity of all heat trace circuits, check the integrity of all connections in the heat trace circuits, and ensure that all insulation on heat traces is intact. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could cause grounds.

- Each Generator Owner/Operator should, before each winter begins, inspect, test, and maintain all heat trace controls or monitoring devices for proper

operation, including but not limited to thermostats, local and remote alarms, lights, and monitoring cabinet heaters.

- Each Generator Owner/Operator should, before each winter begins, test the amperage and voltage for its heat tracing circuits and calculate whether the circuits are producing the output specified in the design criteria, and maintain or repair the circuits as needed.

- Each Generator Owner/Operator should be aware of the intended useful life of its heat tracing equipment and should plan for its replacement in accordance with the manufacturer's recommendations.

Thermal Insulation

16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins, inspect all accessible thermal insulation and verify that there are no cuts, tears, or holes in the insulation, or evidence of degradation.

- Each Generator Owner/Operator should require visual inspection of thermal insulation for damage after repairs or maintenance have been conducted in the vicinity of the insulation.

- Each Generator Owner/Operator should ensure that valves and connections are insulated to the same temperature specifications as the piping connected to it.

- Each Generator Owner/Operator should be aware of the intended useful life of the insulation of water lines and should plan for its replacement in accordance with the manufacturer's recommendations.

Use of Wind breaks/enclosures

17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed.

Specifically, the task force recommends:

- A separate engineering assessment should be performed for each generating unit to determine the proper placement of temporary and/or permanent wind breaks or enclosures to protect and prevent freezing of critical and vulnerable elements during extreme weather.

- Temporary wind breaks should be designed to withstand high winds, and should be fabricated and installed before extreme weather begins.

- Generator Owner/Operators should take into account the fact that sustained winds and/or low temperatures can result in heat loss and freezing even in enclosed or semi-enclosed areas.

Training

18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.

Operator training should include awareness of the capabilities and limitations of the freeze protection monitoring system, proper methods to check insulation integrity and the reliability and output of heat tracing, and prioritization of repair orders when problems are discovered.

Other Generator Owner/Operator Actions

19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner.

Specifically, the task force recommends:

- Each Generator Owner/Operator should maintain a sufficient inventory of supplies at each generating unit necessary for extreme weather preparations and operations.

- Each Generator Owner/Operator should place thermometers in rooms containing equipment sensitive to cold and in freeze protection enclosures to ensure that temperature is being maintained above freezing and to determine the need for additional heaters or other freeze protection devices.

- During extreme cold weather events, each Generator Owner/Operator should schedule additional personnel for around-the-clock coverage.

- Each Generator Owner/Operator should evaluate whether it has sufficient electrical circuits and capacity to operate portable heaters, and perform preventive maintenance on all portable heaters prior to cold weather.

- Each Generator Owner/Operator should drain any non-critical service water lines in anticipation of severe cold weather.

Transmission Facilities

20. Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions.

Transmission Operators reported several incidents of unplanned outages during the February 2011 event as a result of circuit breaker trips, transformer trips, and other transmission line issues. Although these outages did not generally contribute materially to any transmission limitations, some transmission breaker outages did lead to the loss of generating units. Many breaker trips were the result of low air in the breaker, low sulfur hexa-fluoride (SF_6) gas pressure, failed or inadequate heaters, bad contacts, and gas leaks.

Specifically, the task force recommends:

- Transmission Owner/Operators should ensure that the SF_6 gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold, and also perform annual maintenance that tests SF_6 breaker heaters and supporting circuitry to assure that they are functional.

- Transmission Owner/Operators should maintain the operation of power transformers in cold temperatures by checking heaters in the control cabinets, verifying that main tank oil levels are appropriate for the actual oil temperature, checking bushing oil levels, and checking the nitrogen pressure if necessary.

- Transmission Owner/Operators should determine the ambient temperature to which their equipment, including fire protection systems, is protected (taking into account the accelerated cooling effect of wind), and ensure that temperature requirements are met during operations.

COMMUNICATIONS

21. Balancing Authorities should improve communications during extreme cold weather events with Transmission Owner/Operators, Distribution Providers, and other market participants.

During the February event, ERCOT communicated with Transmission Owners and Transmission Service Providers (an ERCOT-specific term) concerning the initiation of load shedding and the subsequent restoration of service. These communications appear to have been made in accordance with applicable ERCOT Operating Guidelines and Reliability Standards. However, ERCOT and several of its Transmission Service Providers that were responsible for curtailing firm load suggested areas for improvement in communications.

Transmission Service Providers are dependent on ERCOT for much of their information on ERCOT-wide system conditions, as they do not have information regarding generator trips beyond those on their own systems, and can only track ERCOT-wide system status by monitoring ERCOT's posted Physical Response Capability levels or monitoring frequency levels. Some of these Transmission Service Providers suggested that ERCOT should have communicated concerns about deteriorating conditions much earlier than it did.

A task force appointed by ERCOT's Board of Directors to look into the February 2 rolling blackouts concluded that there was a need for earlier dissemination of operational information to Transmission Service Providers and Distribution Service Providers (an ERCOT-specific term) during the period leading up to a possible emergency, a conclusion with which this task force agrees.

22. ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service.

Some ERCOT Transmission Service Providers expressed concern that they have virtually no information regarding loads on their own systems that may be deployed by ERCOT as Load Resources or Emergency Interruptible Load Service resources. These loads contract directly with ERCOT, and the Transmission Service Provider does not receive information about their status. When these loads are shed by ERCOT without prior notification to the Transmission Service Providers and Distribution Service Providers, they have the potential to cause localized imbalances in line flows, voltages, and other system parameters that may be problematic.

The task force suggests that ERCOT share information about the status of these loads with Transmission Service Providers on a daily basis, and study the effects of the loss of large blocks of these loads on the transmission grid.

23. WECC should review its Reliability Coordinator procedures for providing notice to Transmission Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency), and consider whether modification of those procedures is needed to expedite the notice process.

The Task Force observed a lag in communicating a declared system emergency in WECC. In one instance, a Reliability Coordinator did not issue an EEA 3 declaration until seven minutes after the decision had been made to do so; the delayed declaration appeared to have been the first official notice by the Reliability Coordinator to other WECC entities of the seriousness of the generation failures on the system of the Balancing Authority in question.

24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.

The task force's review of incidents during the event, as well as of operating procedures and protocols in place at the time, indicated that critical employees such as operators had numerous responsibilities that, while manageable in non-emergency situations, could prove impossible to meet during the often-compressed time frame of an emergency situation. In at least one instance, overloading a single on-call operations representative appears to have led to a delay in making emergency power purchases.

LOAD SHEDDING

25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.

Keeping gas production facilities in service is critical to maintaining an adequate supply of natural gas, particularly in the Southwest where there is a relatively small amount of underground gas storage. And keeping electric-

powered compressors running can be important in maintaining adequate pressure in gas transmission lines.

The task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.

26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

The task force found that at least one Transmission Operator in WECC experienced a minor delay in initiating its load shedding sequence, due to problems notifying the concerned Distribution Provider. Another Transmission Operator experienced delay in executing its load shedding because the individual operators had never shed load before and had not had recent drills. These incidents underscore the necessity of adequate training in load shedding procedures.

B. The Natural Gas Industry

Key Findings -- Natural Gas

- Extreme low temperatures and winter storm conditions resulted in widespread wellhead, gathering system, and processing plant freeze-offs and hampered repair and restoration efforts, reducing the flow of gas in production basins in Texas and New Mexico by between 4 Bcf and 5 Bcf per day, or approximately 20 percent, a much greater extent than has occurred in the past.

- The prolonged cold caused production shortfalls in the San Juan and Permian Basins, the main supply areas for the LDCs that eventually curtailed service to customers in New Mexico, Arizona, and Texas.

- Wellhead freeze-offs normally occur several times a winter in the San Juan Basin but are not common in the Permian Basin, which is the supply source that LDCs in the Southwest region typically rely upon when cold weather threatens production in the San Juan Basin.

- Electrical outages contributed to the cold weather problems faced by gas producers, processors, and storage facilities in the Permian and Fort Worth Basins, with producers being more significantly affected by the blackouts; however, based on information obtained from a sampling of producers and

processing plants in the region, the task force concluded that the effect of electric blackouts on supply shortages was less important than the effect of freezing temperatures.

- Although producers in the New Mexico and Texas production areas implemented some winterization measures such as methanol injection, production was nevertheless severely affected by the unusually cold weather and icy road conditions, which prevented crews from responding to wells and equipment that were shut in.

- The extreme cold weather also created an unprecedented demand for gas, which further strained the ability of the LDCs and pipelines to maintain sufficient operating pressure.

- The combination of dramatically reduced supply and unprecedented high demand was the cause of most of the gas outages and shortages that occurred in the region.

- Low delivery pressures from the El Paso Natural Gas interstate pipeline, caused by supply shortages, contributed to gas outages in Arizona and southern New Mexico.

- Some local distribution systems were unable to deliver the unprecedented volume of gas demanded by residential customers.

- No evidence was found that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages.

- The pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls.

- Additional gas storage capacity in Arizona and New Mexico could have prevented many of the outages that occurred by making additional supply available during the periods of peak demand. Natural gas storage is a key component of the natural gas grid that helps maintain reliability of gas supplies during periods of high demand. Storage can help LDCs maintain adequate supply during periods of heavy demand by supplementing pipeline capacity, and can serve as backup supply in case of interruptions in wellhead production. Additional gas storage capacity in the downstream market areas closer to demand centers in Arizona and New Mexico could

have prevented most of the outages that occurred by making additional supply available in a more timely manner during peak demand periods.

Recommendations – Natural Gas

1. Lawmakers in Texas and New Mexico, working with their state regulators and all sectors of the natural gas industry, should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.

The Texas and New Mexico production basins experienced unusually sharp declines due to the prolonged freezing weather of early February 2011. Although these areas typically experience occasional freeze-offs during periods of sub-freezing weather, and although natural gas producers and processors in those regions employ some winterization techniques, to a significant degree those measures were inadequate to meet consumer demand during this event. Production difficulties were compounded by icy road conditions, which disrupted routine maintenance and delayed repairs.

Some industry representatives stated that producers and processors already have strong economic incentives to keep gas flowing at all times, and that increased winterization would not have prevented many of the shortfalls that occurred in the Southwest production basins in early February 2011. Others stated that the levels of winterization typically employed in these areas are designed to deal with less severe, more typical winter weather conditions, and that additional winterization could protect the system from the effects of unusually harsh weather. Many expressed the view that along with increased reliance upon natural gas for energy, steps should be taken to improve the reliability of gas supply during extreme cold weather events.

Whether the adoption of uniform winterization standards for natural gas facilities is the right way to meet the goal of increased reliability is a complex question. Among the issues that need to be resolved are the following:

- Determining the costs of increased winterization and balancing those costs against the need for increased reliability,
- Determining who should ultimately bear the costs of additional winterization, and whether ratemakers would be willing to pass the costs of increased reliability along to consumers,
- Determining whether it is practical to design for very low temperatures, which may not recur for years or even decades,

- Ensuring that standards are uniformly applied, and determining whether state commissions would have adequate resources or authority to promulgate and enforce those standards, and
- Identifying possible incentives for industry that could improve the reliability of winter supply without government regulation.

Because the Commission does not have jurisdictional authority over this sector of the natural gas industry for these purposes, we recommend that state lawmakers and regulators in Texas and New Mexico investigate whether minimum standards for the winterization of gas production and processing facilities should be adopted, by way of legislation, regulation, or the adoption of voluntary industry practices, and whether such standards would be likely to effectively and reliably improve supply during extreme weather events.

2. The gas and electric sectors should work with state regulatory authorities to determine whether critical natural gas facilities can be exempted from rolling blackouts.

The natural gas industry depends in many instances on electric utilities for the power that helps move gas from the production fields to end users. Electric-powered instrumentation, compression, pumps, and processing equipment are essential links in that process, and in some instances, even the brief, temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service for long periods of time, especially where weather conditions delay access to those facilities. The resulting gas outages can contribute to electricity shortages by cutting off or reducing fuel supply to gas-fired generating plants.

Gas producers, processors, pipelines, storage providers, and LDCs should identify portions of their systems that are essential to the ongoing delivery of significant volumes of gas, and which are dependent upon purchased power to function reliably under emergency conditions. State regulatory authorities should work with the gas industry and electric transmission operators, balancing authorities and reliability coordinators to determine whether such facilities can be shielded from the effects of future rolling blackouts.

3. State utility commissions should work with LDCs to ensure that voluntary curtailment plans can reduce demand on the system as quickly and efficiently as possible when gas supplies are disrupted.

One tool available to LDCs faced with supply disruptions during periods of high consumer demand is the implementation of voluntary curtailment plans, which seek reductions or curtailment from large commercial users. State

regulators, who review and approve the voluntary curtailment plans of LDCs, should assess whether they are designed and implemented in a way that maximizes their potential effect in emergency situations.

Voluntary curtailment plans should include multiple points of contact for large customers and up to date, 24-hour contact information. Where appropriate, the plans should provide for pre-event planning, training, and customer education. Large customers should be contacted prior to emergencies and efforts should be made to explain the circumstances under which reductions or curtailments would be sought and to obtain advance commitments for possible reductions, giving LDCs a clearer idea of the amount of demand that can be reduced in an emergency. While voluntary curtailment does nothing to increase supply, in light of the importance of reducing demand when distribution systems are near collapse, regulators and the LDCs should ensure that planning for voluntary curtailments is as thorough and well-thought out as possible.

4. State utility commissions should work with balancing authorities, electrical generators, and LDCs to determine whether and under what circumstances residential gas customers should receive priority over electrical generating plants during a gas supply emergency.

Gas-fired generation provides much needed electrical power during a weather emergency, but also consumes large amounts of natural gas. Although restoring residential electricity service after a rolling blackout is a fairly simple process, restoring gas service after an outage is both labor-intensive and time-consuming.

State utility commissions should work with LDCs to identify situations where consumption by gas-fired generators could contribute to residential gas customer outages, and should consult with those generators and the relevant Balancing Authority to determine whether alternative power suppliers or fuel supplies could be used in emergency situations. The state commissions should also evaluate the relative importance, for human needs customers, of gas-fired generation and residential use, and should assess the relative impacts of curtailing generating plants versus gas supply to residences.

5. State utility commissions and LDCs should review the events of early February 2011 and determine whether distribution systems can be improved to increase flows during periods of high demand.

In some instances during the winter storm event, LDC distribution systems were unable to flow scheduled volumes, suggesting that downstream parties may not have had sufficient capacity or facilities to handle historically high demand.

Accordingly, state commissions and distribution companies should determine whether system enhancements can be made to improve volume handling capacity, such as additional distribution valving, looping, more compression, or reconfigured compression. Although such system improvements would probably not compensate for the level of supply shortfalls that occurred in early February 2011, they might allow LDCs to take higher volumes for longer periods of time.

6. State utility commissions should work with LDCs to determine whether the LDC distribution systems can be improved so that curtailments can be implemented, when necessary, in a way that improves the speed and efficiency of the restoration process.

The events of early February 2011 demonstrated that once operational pressures and line pack begin to fall beyond normal tolerances, little time may be available to evaluate, locate, and shut off portions of the pipeline systems of the LDCs to avoid system collapse. Regulators should work with LDCs, as part of the annual system review process, to determine whether the systems under their regulatory authority should be further sectionalized to provide more options when involuntary curtailments are necessary.

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ATTACHMENTS

Acronyms

Glossary

Appendices

Task Force Members

Legislative and Regulatory Responses by the States

Categories of NERC Registered Entities

Electricity: How it is Generated and Distributed

Power Plant Design for Ambient Weather Conditions

Impact of Wind Chill

Winterization for Generators

Natural Gas: Production and Distribution

Natural Gas Storage

Natural Gas Transportation Contracting Practices

GTI: Impact of Cold Weather on Gas Production

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Acronyms

AC	Alternating Current
ACE	Area Control Error
ANR	ANR Pipeline Company
Bcf	Billion Cubic Feet
Btu	British Thermal Unit
CFE	Comisión Federal de Electricidad
CNG	Compressed Natural Gas
COP	Current Operating Plan
DC	Direct Current
DC Tie	Direct Current Tie
EEA	Energy Emergency Alert
EILS	Emergency Interruptible Load Service
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
Hz	Hertz
IMM	Independent Market Monitor
ISO	Independent System Operator
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LRGV	Lower Rio Grande Valley
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MW	Megawatt
MWh	Megawatt Hour
NGL	Natural Gas Liquids
NMGC	New Mexico Gas Company
NERC	North American Electric Reliability Corporation
OCN	Operating Condition Notice
OFO	Operational Flow Order
PNM	Public Service Company of New Mexico

Acronyms

PRC	Physical Response Capability
PUCT	Public Utilities Commission of Texas
QSE	Qualified Scheduling Entity
RMR	Reliability Must Run
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SCADA	Supervisory Control and Data Acquisition
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TRE	Texas Reliability Entity, Inc.
TRC	Texas Railroad Commission
UFLS	Under-Frequency Load Shedding
WECC	Western Electricity Coordinating Council

Glossary

Active Power - Also known as real power, this is the rate at which work is performed or at which energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW) when referring to electricity. In the field of electric power, the terms “active power” or “real power” are often used in place of the term “power” alone to differentiate it from reactive power. (See Reactive Power)

Allocation of Capacity - A process by which capacity available in a pipeline is distributed to parties in the event requests for volume (*i.e.*, nominations) are in excess of the available space. Typically the allocation is based on service type, contract type and a company's tariff provisions.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Ancillary Services - The services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. These include, but are not limited to, voltage support, regulation, reserves, and black start capability.

Aquifer Storage - The storage of gas underground in porous and permeable rock stratum, the pore space of which was originally filled with water and in which the stored gas is confined by suitable structure, permeability barriers, and hydrostatic water pressure.

Area Control Error (ACE) - The instantaneous difference between a Balancing Authority’s net actual and scheduled interchange, plus the instantaneous difference between the interconnection’s actual frequency and scheduled frequency and a correction for meter error.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Glossary

Auto-Transformer - A power transformer with a single coil for each electrical phase, as opposed to a conventional transformer, which has two coils per phase. In an auto-transformer, the entire coil acts as the primary winding while a portion of the same coil acts as the secondary winding.

Automatic Generation Control (AGC) - A feature of a power system's centralized control system that automatically adjusts generation in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus its Frequency Bias.

Balancing (Natural Gas) - Equalizing a shipper's receipts and deliveries of gas on a transportation pipeline. Balancing may be accomplished daily, monthly or seasonally, with penalties generally assessed for excessive imbalances.

Balancing Authority (BA) - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports interconnection frequency in real time.

Base Load (Natural Gas) - A given volume of gas used by a LDC or other large user, remaining fairly constant over a period of time. Base load does not vary with heating degree-days.

Baseload Generating Units - Electric generating units which produce energy at a constant rate, usually at a low cost relative to other generating units available to the system. Baseload units are used to meet some or all of a given region's continuous energy demand on a seasonal or daily basis, including at minimum load levels, and tend to operate non-stop except for maintenance or forced outages.

Base Load Storage (Natural Gas) - Storage facilities capable of holding enough natural gas to satisfy long term seasonal demand requirements.

Blade - The component of a steam turbine that is acted upon by the flow of steam. Blades in steam turbines are also referred to as "buckets." Similarly, in gas, or combustion turbines, the blades are the components acted upon by the flow of the high pressure, high temperature gases produced in the combustor. In both steam turbines and combustion turbines, the blades are arranged in multiple stages of varying diameter, with many blades per stage. Modern wind turbines, in contrast, typically utilize only three long blades. The purpose of the blades is to extract energy from the motion of the propelling fluid (steam, combustion gases, or air) and convert it into rotational form by direct coupling to a common spinning shaft which is in turn used to drive a generator.

Glossary

Boiler - The component of a steam power plant in which water is heated and converted into steam.

British Thermal Unit (BTU) - the measurement of heat released by burning any material. The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density.

Bulk Electric System - The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not considered to be part of the bulk electric system.

Capacitor Bank - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Capacity Market - A market where Load Serving Entities purchase generating capacity (including adequate reserves) to cover their peak loads.

Capacity Release (Natural Gas) - A mechanism by which holders of firm interstate transportation capacity can relinquish their rights to utilize the firm capacity to other parties that are interested in obtaining the right to use that capacity for a specific price, for a given period of time and under a specifically identified set of conditions. The firm transportation rights may include transmission capacity and/or storage capacity.

Capacity-Short Charge - In ERCOT, a monetary charge to Qualified Scheduling Entities (QSEs) who cannot meet their resource commitments when a Reliability Unit Commitment (RUC) study (conducted periodically) determines there is insufficient generation to meet projected demand, and the costs associated with bringing the needed additional generation on-line cannot be fully recovered using energy revenue. The capacity-short charge is the mechanism for covering those costs. This is done on the basis of settlement intervals.

Centrifugal Compressor Unit(s) -Compressors that produce pressure by centrifugal force from rotation of a compressor wheel that translates kinetic energy

into pressure energy of the gas. Centrifugal compressors are commonly used in gas transmission systems due to their flexibility.

Charge - In physics, charge, also known as electric charge, electrical charge, or electrostatic charge is a characteristic of an object that expresses the extent to which it has more or fewer electrons than protons. A single electron carries an elementary charge of negative polarity, whereas a single proton carries the same, except of positive polarity. The unit of electrical charge is the coulomb (symbolized C) where 1 C is equal to 6.24×10^{18} elementary charges. It is not unusual for real-world objects to hold charges of many coulombs. When two objects having electric charges are brought into proximity with each other, an electrostatic force is manifested between them – attractive if the charges are of opposite polarity and repulsive if the charges are of the same polarity.

Circuit Breaker - In electrical power systems, circuit breakers are used to disconnect and reconnect transmission lines, transformers, generators, and other facilities from the power system or from each other. Circuit breakers trip to interrupt the flow of current when faults develop, de-energizing the faulted facility and isolating it from the system. They are also used to switch facilities in or out of service.

Citygate - The point at which a Local Distribution Company receives natural gas from an interstate or intrastate pipeline.

Cold Load Pickup - Phenomenon that takes place when a distribution circuit is re-energized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: 1) inrush current which reestablishes the magnetic fields in motors and transformers and the necessary temperatures in heating coils and incandescent lamp filaments and 2) loss of load diversity due to cyclic loads which normally cycle randomly with respect to one another, such as refrigerator compressors, all restarting at the same time. The inrush current may last up to several seconds while the loss of load diversity may persist for many minutes.

Combined Cycle Unit - This type of electric generating unit consists of one or more gas turbines, also referred to as combustion turbines, equipped with heat recovery steam generators to capture heat from their exhaust. Steam produced in the heat recovery steam generators then drives a steam turbine generator to produce additional electric power. A typical arrangement consists of two natural gas-fired combustion turbines combined with a single steam turbine, each driving its own electrical generator, for a total of three generators. The heat recovery aspect of combined cycle units increases the overall efficiency of electric power production.

Glossary

Comisión Federal de Electricidad (CFE) - A Mexican governmental entity that generates, transmits, distributes and sells electricity to more than 34.2 million customers, representing more than 100 million people annually. CFE interconnects to ERCOT via two high voltage DC (HVDC) ties and to WECC via AC transmission lines at the California border just south of San Diego.

Compressor or Compressor Units - Mechanical equipment that adds pressure to the natural gas stream to enable the flow of natural gas through a pipeline system.

Compressor Station - A permanent facility that houses compression equipment that supplies pressure to move natural gas through pipelines.

Condensate and Water Return Lines - Plumbing in a generating station that captures condensate and used water for recycling or re-use.

Condenser - In a steam turbine generating station, the condenser is a type of heat exchanger that cools the steam exiting the turbine to the point where it condenses into water, thereby recovering the high quality feed water for reuse. The cooling is accomplished using separate cooling water. Surface condensers use a shell and tube assembly wherein the cooling water is circulated in the tubes, and the steam and condensate are contained in the tank-like housing, or shell, that surrounds and encloses the tubes.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve Level - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. The Contingency Reserve Level is that level of reserves required for the reliable operation of an interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This

capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Contract Pressure (Natural Gas) - The maximum or minimum required operating pressure at a natural gas receipt or delivery point, as specified in the agreement between a pipeline and its customer.

Control Area - An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: 1) match, at all times, the power output of the generators within the electric power system(s) with the load in the electric power system(s); 2) maintain scheduled interchange with other Control Areas; 3) maintain the frequency of the electric power system(s); and 4) provide sufficient generating capacity to maintain operating reserves, all within reasonable limits in accordance with Good Utility Practice.

Controllable Load Resources (CLR) - In ERCOT, CLRs are a type of load resource capable of controllably reducing or increasing consumption under dispatch control (similar to automatic generation control or AGC) and able to immediately respond proportionally to frequency changes (similar to generator governor action) to provide the following ancillary services: Up and Down Regulation (URS & DRS), Responsive Reserve (RRS), and Non-Spinning Reserve (NSRS).

Cooling Tower - A structure and associated equipment intended to facilitate the evaporative cooling of water by contact with air. In steam turbine generating stations, cooling water is routed through the cooling tower for cooling after having absorbed heat in the condenser.

Cooling Water - In steam turbine generating stations, water that is used in the condenser to extract heat from steam exiting the turbine for the purpose of condensing that steam back to feed water. The feed water is then cycled back through the boiler to make steam again. The cooling water is generally taken from a nearby lake (often man-made for this purpose) or river and is distinctly separate from the feed water that is used to make steam and which must be specially treated to prevent corrosion. Electric generating stations use wholly separate cooling water systems to extract heat from the large copper conductors comprising the generator stator windings.

Cooling Water Intakes - The point at which industrial plants, including power plants, bring cooling water into their system from lakes, rivers, or other sources.

Broadly, the total physical structure and any associated constructed waterways used to withdraw cooling water.

Current (Electric) - The rate of flow of electrons in an electrical conductor. The symbol for current is “I” and the unit is the ampere, or amp, where one amp is defined as one coulomb of charge per second.

Current Operating Plan (COP) - In ERCOT, a plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the resources that it represents for each hour in the next seven operating days, including resource operational data, resource status, and ancillary service schedule.

Curtailment (Electric) - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Curtailment (Natural Gas) - A method to balance a utility's natural gas requirements with its natural gas supply. Customers are typically ranked by priority in the utility’s curtailment plan. A customer may be required to partially cut back or totally eliminate its take of gas depending on the severity of the shortfall between gas supply and demand and the customer's priority.

Day-Ahead Market - A daily, co-optimized market in the 24 hour period before the start of the next operating day for ancillary service capacity, certain congestion revenue rights, and forward financial energy transactions.

Day-Ahead RUC (DRUC) - In ERCOT, a Reliability Unit Commitment (RUC) process performed for the next operating day.

Decommitment Payment - In ERCOT, a payment made to a resource committed by the Reliability Unit Commitment (RUC) process if the directive to use that resource is cancelled prior to its scheduled start time.

Demand (Electric) - The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. The term “demand” is often used interchangeably with the term “load” with respect to electric power systems.

Depleted Oil and/or Gas Fields - Naturally occurring reservoirs that once held deposits of oil and gas, consisting of porous and permeable underground formations confined by impermeable rock or water barriers. The working gas requirement for this type of storage reservoir is generally about 50% of the total

reservoir capacity. Gas is typically withdrawn in the winter season and injected in the summer.

Derate (Electric Generator) - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Direct Current (DC) Tie - In electric power systems, the term "DC Tie" or, more correctly, "HVDC Tie" referring to high voltage DC, is used to describe a transmission-level facility that interconnects between two portions of a power system, two different power systems, or two different electric power interconnections. The DC Tie consists of: (1) a converter station to convert three phase AC power to DC; (2) a DC connection to a second converter station; and (3) a second converter station that reconverts the DC power back to three-phase AC. The DC connection between the two converter stations (step 2 above) may be either a long HVDC transmission line or, in the case of "back-to-back" converters at the same location, a simple set of bus bars. The power flow in DC ties is not free-flowing as it is in AC lines, but rather is controlled precisely by control systems on the converters. Unlike AC lines, DC ties can interconnect between asynchronous interconnections such as ERCOT, the Eastern Interconnection, and the Western Interconnection because concerns about frequency, phase angle, and voltage differences are rendered immaterial by the AC-to-DC-to-AC conversion process.

Distribution (Electric) - The function of distributing electric energy to retail customers, and all associated physical means of serving that function, including substations, low voltage distribution lines, transformers, etc.

Distribution Provider - As defined by NERC, a Registered Entity that provides and operates the "wires", *i.e.*, distribution lines, transformers, and associated facilities, between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider.

Distribution Service Provider - As defined by ERCOT, an entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

Electrical Energy - Electric power generated, transmitted, distributed, and consumed over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).

Electric Reliability Council of Texas, Inc. (ERCOT) - ERCOT is an Independent System Operator (ISO) that manages the flow of electric power to 23 million customers in Texas representing 85 percent of the state's electric load and 75 percent of its land area. ERCOT is registered with NERC to serve the following roles: Balancing Authority, Interchange Authority, Planning Authority, Reliability Coordinator, Resource Planner, and Transmission Service Provider. It is also jointly registered with other entities as a Transmission Operator**.**

Electric Reliability Organization (ERO) - The Energy Policy Act of 2005 required the creation of an independent Electric Reliability Organization (ERO) to be certified by FERC and tasked with developing and enforcing mandatory reliability standards applying to the bulk power system. (*See* Energy Policy Act of 2005, Pub. L. No. 109-58, section 102.)

Electromagnetic Induction - The creation of a voltage in a conductor due to a relative movement between the conductor and a magnetic field. Electromagnetic induction is the basic principle of operation of generators.

Emergency Interruptible Load Service (EILS) - In ERCOT, EILS is an emergency load reduction service designed to decrease the likelihood of the need for firm load shedding. It is provided by qualified loads that make themselves available for interruption in an electric grid emergency. Customers meeting EILS criteria may bid to provide the service through their Qualified Scheduling Entities (QSEs). EILS is called upon during an Energy Emergency Alert (EEA) Level 2B to assist in maintaining or restoring system frequency. EILS is not an Ancillary Service.

Energy - See Electrical Energy.

Energy Emergency Alert (EEA) - NERC Reliability Standard EOP-002-2.1 prescribes the use of an energy emergency alert (EEA) procedure when a load serving entity is unable to meet its customers' expected energy requirements. These energy emergencies are declared by the load serving entity's Reliability Coordinator, and are categorized by level of severity, *i.e.*, EEA1, 2, or 3, with level 3 being the most severe. ERCOT defines EEA as an orderly, predetermined procedure for maximizing use of available resources and, only if necessary, curtailing load during an emergency condition while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT system.

Energy Imbalance Service (EIS) - EIS is provided when a difference occurs between the scheduled and the actual delivery of energy to/from the transmission system over a single hour. The market participant must purchase this service from the transmission provider or make comparable alternate arrangements with another market participant who will purchase this service from the transmission provider.

Energy-only Market (Electric) - A market for electric energy that pays resources only for delivered energy and ancillary services, and does not pay for installed capacity (ICAP).

Energy-only Resource Adequacy Mechanism - A mechanism that allows real-time energy prices to rise in times of scarcity in order to provide incentives for investment in peaking as well as base-load generation.

E-Tag - Electronic Tagging, or e-Tag, is used to schedule an interchange transaction in a wholesale electricity markets. NERC and/or Regional Entities (such as WECC) collect all e-Tag data in near real-time to assist Reliability Coordinators in identifying transactions to be curtailed to relieve overload when transmission constraints occur. NERC defines an interchange transaction as "an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority area boundaries."

Export - In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Firm Service (Natural Gas) - Transportation service on a firm basis means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service.

Flow Line - Flow lines carry the fluids or natural gas from the wellhead to and in-between individual vessels in separation, treating, heating, dehydrating, compression, pumping or other processing equipment generally located at or near the well site.

Force Majeure - A superior force, "act of God" or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage - The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. This can be done automatically, as in the case of tripping, manually, as in the case of forced

shutdowns, or by withholding a generating unit, transmission line, or other equipment from returning to service due to unresolved problems.

Frequency - The rate, in terms of time, at which a periodic pattern repeats itself. In electric power systems, frequency is measured in cycles per second, or Hertz (Hz). The symbol is "F". The nominal, or base, frequency for power systems in North America is 60 Hz.

Frequency Bias - A weighting factor applied to the difference between the Interconnection's actual frequency and scheduled frequency during the calculation of a Balancing Authority's Area Control Error (ACE). The weighting factor determines how strongly a Balancing Authority will respond to deviations from the scheduled frequency. Larger Balancing Authorities will usually have a larger Frequency Bias.

Frequency Deviation - Broadly, a change in the frequency of an electrical interconnection. More typically, sudden changes that result in the frequency of the interconnection going outside the normal bounds of 59.95 Hz to 60.05 Hz due to the unexpected loss of a significant amount of generation or load.

Generation - The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Generator Operator - An entity that operates a generating unit or a fleet of generating units and performs the functions of supplying energy and interconnected operations services to a power system.

Generator Owner - An entity that owns and maintains a generating unit or a fleet of generating units.

Generator Runback - The intentional rapid reduction of the output level of an electric generating unit or an entire generating station, either manually or

automatically via plant controls, due to any of a variety of problems in the plant that limit the plant's capacity to generate power, or problems on the transmission system external to the plant which limit the capability of the system to accept the plant's power output.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric power industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing - The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hertz - The unit of frequency equal to one cycle per second.

Hockey Stick Bidding - A pricing strategy during a supply shortage whereby a trader offers to sell a small quantity of energy at a price well above marginal cost, in order to manipulate prices upward.

Hourly RUC (HRUC) - In ERCOT, any Reliability Unit Commitment (RUC) executed after the Day-Ahead RUC (DRUC).

Human Needs Customers - Customers such as residential users, hospitals, and nursing homes, who use natural gas for essential human needs.

Hydrate Crystals - Crystals of hydrates formed under certain pressure and temperature conditions by hydrates and water present in natural gas. Hydrate crystals can form when the temperature is above the melting temperature of ice and can block natural gas wells, gathering systems, and pipelines.

Import Limit - The maximum level of electric power that can flow into a power system or portion of a power system over a transmission path or paths without

violating facility thermal ratings, voltage ratings, transient stability limits, or voltage stability limits either in real-time or post contingency, *i.e.*, after the loss of a generator, transmission line, or other facility.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis. ISOs in the U.S. include the California ISO, ISO New England, the New York ISO, PJM, the Midwest ISO, and ERCOT. These ISOs dispatch generation in their respective geographic territories.

Induction Machine - A rotating electromagnetic machine using alternating current that may be a generator or a motor. When a generator, the induction machine's rotor is driven at a speed greater than synchronous speed. When a motor, the induction machine's rotor is driven at a speed less than synchronous speed. Induction generators are rarely used for large scale power generation. Induction motors, on the other hand, are the most common type of AC motor. Induction machines absorb reactive power and cannot be used to produce reactive power (as a synchronous machine can).

Insulator - A material with a high resistance to the flow of electric current. More broadly, mechanical supports and spacers constructed of insulating materials. Electrically speaking, an insulator is the opposite of a conductor.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interconnection - In North America, any one of the four major electric system networks – Eastern, Western, Quebec, and ERCOT. These operate asynchronously with respect to one another.

Interruptible Service - Service on an interruptible basis means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service and receives a lower priority than such other classes of service.

Interruptible Responsive Reserve - In ERCOT, Interruptible Responsive Reserve is provided by load resources that are automatically interrupted when system frequency decreases to 59.7 Hz. The total amount of Interruptible Responsive Reserve procured for a given hour is limited to one half of the Responsive Reserve Service required for that hour.

Inverter - A converter designed and operated to convert DC power to AC power. In power systems, inverter generally refers to high voltage DC (HVDC) converters.

Island (Electrical) - An electrically isolated portion of an interconnection.. The frequency in an electrical island must be maintained by balancing generation and load in order to sustain operation. Islands are frequently formed after major disturbances wherein multiple transmission lines trip, or during restoration following a major disturbance.

Joule-Thomson Effect - The cooling that occurs when a compressed gas is allowed to expand in such a way that no external work is done. The effect is approximately 7 degrees Fahrenheit per 100 psi for natural gas.

Lateral Line - A pipe in a gas distribution or transmission system that branches away from the central and primary part of the system.

Line Pack - Natural gas occupying all pressurized sections of the pipeline network. Introduction of new gas at a receipt point “packs” or adds pressure to the line. Removal of gas at a delivery point lowers the pressure (unpacks the line).

Line Trip - This refers to the automatic disconnection of a transmission line by its circuit breakers. Line trips are initiated by protective relays and are designed to protect the power system when a short circuit, or fault, occurs on a line by isolating the faulted line from the system.

Liquefied Natural Gas (LNG) - Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

Long Haul Pipeline - A transportation pipeline that transports natural gasa significant distance (hundreds of mile or more) from the production area.

Load - See Demand (Electric).

Load Acting as Resource (LaaR) - This term, discontinued by ERCOT when they transitioned from a Zonal Market to a Nodal Market on December 1, 2010, was replaced by the term Load Resource (see below).

Load Resource - In ERCOT, Load Resources provide ancillary services for either Responsive Reserve Service (RRS) or Non-Spinning Reserve Service (NSRS). There are two types of Load Resources – Controllable Load Resources (CLRs)

and Non-Controllable Load Resources (NCLRs). "Controllable" refers to the capability to control the load remotely from the ERCOT control center rather than solely at the end-use customer location (or by its Qualified Scheduling Entity (QSE)).

Load Service Entity - An entity that secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Load Shedding - The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence. (See Rolling Blackouts.)

Local Distribution Companies (LDC) - Any firm, other than a natural gas pipeline, engaged in the transportation or local distribution of natural gas and its sale to customers that consume the gas.

Magnetic Field - The invisible lines of force between the north and south poles of a magnet. A magnetic field is created when electric current flows through a conductor.

Make-Whole Charge - In ERCOT, a charge made to a Qualified Shedding Entity (QSE) for a resource to recapture all or part of the revenues received by a QSE that exceed the Make-Whole Payment for a resource (see below).

Make-Whole Payment - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource to reimburse it for allowable startup and minimum energy costs of a resource not recovered in energy revenue when a resource is committed by the Day-Ahead Market (DAM) or by a Reliability Unit Commitment (RUC).

Maximum Allowable Operating Pressure - The maximum operating pressure at which a pipeline system may be operated safely.

Mercaptans - A group of strong-smelling chemical compounds added to natural or LP gases as a safety measure, to warn of leaks.

Metering (Electric) - A meter is a device for measuring and displaying an electrical quantity. For example, meters are used to measure power flows, voltage, current, frequency, etc. The term "metering" generally refers to a group of meters

associated with a given facility, and the information from those meters transmitted to and displayed in a control room or control center.

Methanol - A light volatile flammable poisonous liquid alcohol used especially as a solvent, antifreeze, or denaturant for ethyl alcohol, and in the synthesis of other chemicals.

Nomination - A request for a physical quantity of natural gas under a specific purchase, sales or transportation agreement, or for all contracts at a specific point. A nomination will continue for specified number of days or until superseded by another service request for the same contract.

North American Energy Standards Board - A non-profit, private standards development organization established in January 2002 to develop voluntary standards and model business practices designed to promote more competitive and efficient natural gas and electric service.

Nodal Market (Electric) - Prices are assessed at points (*i.e.*, nodes) where electricity enters or leaves the grid. Transmission lines throughout the grid may be subject to congestion rents, which means generators may receive different prices based on how they contribute to or relieve congestion on the grid. ERCOT transitioned from a zonal to a nodal market on December 1, 2010. Their nodal market calculates transmission costs from the point of generation from roughly 4,000 delivery points. Nodal pricing is intended to provide a more detailed and accurate picture of transmission and generation than zonal pricing. ERCOT's nodal system reduces the time interval for which the market-clearing price is calculated to five minutes (from fifteen minutes in their former zonal market).

Non-Controllable Load Resources (NCLRs) - In ERCOT, these represent loads that provide selected Ancillary Services, but that do not have the capability of being switched or controlled directly from the EROCT control center. (Compare Controllable Load Resources)

Non-Spinning Reserve Service - In ERCOT, this refers to generation resources capable of being ramped to a specified output level within thirty minutes or load resources that are capable of being interrupted within thirty minutes. The generation resources must be capable of running at a specified output level for at least one hour, and the load resources must similarly be capable of remaining out of service for at least one hour.

Operating Condition Notice (OCN) - In ERCOT, this is the first of four possible levels of communication issued (by ERCOT) in anticipation of a possible emergency condition**.**

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Operational Balancing Agreement - A contract that specifies the procedures that will be used between two interconnected natural gas pipelines in order to manage variances or imbalances at major interconnect points.

Operational Flow Order (OFO) - A notice to natural gas pipeline users designed to protect the operational integrity of the pipeline. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage.

Outage - The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load - As defined by NERC, the highest hourly integrated Net Energy For Load (generation plus imports minus exports) within a Balancing Authority area occurring within a given period (*e.g.*, day, month, season, or year), or the highest instantaneous demand within the Balancing Authority area.

Peak Load Storage (Natural Gas) - Storage that provides high-deliverability of gas supplies to the market over short periods of time.

Peaking Unit or Peaking Power Plant - Peaking plants operate primarily during times when load or demand increases rapidly to a maximum level and remains there for only a short time, *e.g.*, on hot summer afternoons when air conditioning causes electricity usage to reach its highest level in the daily cycle. Peaking plants are often powered by natural gas, but they can also be powered by water at hydroelectric dams or by fuel oil. These plants can be brought online and taken offline quickly, in response to changing demand.

Phase (Electrical) - In AC power systems, power is generated, transmitted, and distributed using three virtually identical sets of (1) coil windings in generators and transformers, (2) conductors in overhead and underground transmission and distribution lines and busses, (3) electrical poles and contacts in circuit breakers and switches and (4) other power equipment such as capacitor banks, reactors, etc., known as phases, and often identified by the letters A, B, and C. The three individual phase windings of a typical generator stator are arranged so that they're evenly spread out around the circular / cylindrical design/construction, each oriented one third of a turn apart (120 degrees) from the other two. As the rotor spins, its magnetic field sweeps through each of these windings sequentially as it completes a single rotation. The voltage, current, and power associated with each phase are therefore separated in time from the other two phases by virtue of this sequence. This method is much more efficient than a single phase approach not only for generating power, but also for its transmission and distribution.

Physical Responsive Capability (PRC) - In ERCOT, this is defined as the total amount of system wide On-Line capability that has a high probability of being able to quickly respond to system disturbances. It can be made up of generation and load resources.

Pigging - The practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of natural gas in the pipeline.

Planning Reserve Margin - Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand through the planning horizon, which can range from the upcoming season to a ten-year period. It is calculated as the difference between resources and peak demand, divided by peak demand to arrive at a percentage figure.

Poles - The opposite ends of a magnet where the field is most concentrated, designated as the north and south poles. In a synchronous generator, the magnetic poles are established by DC current passing through the field winding on the rotor which is essentially the coil of an electromagnet. Separately, in AC electrical equipment, particularly in switches and circuit breakers, poles refer to the contact assemblies associated with a particular phase. For example, it is common to refer to pole A, B, or C of a three phase disconnect switch. (See Phase)

Potomac Economics, Ltd. - The Independent Market Monitor (IMM) for ERCOT.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Processing Plant - A surface installation designed to separate and recover natural gas liquids such as propane, butane, ethane, or natural gasoline from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods, and to control the quality of natural gas marketed or returned to oil or gas reservoirs for pressure maintenance, re-pressuring, or cycling.

Production Separator - An item of production equipment used to separate liquid components of the well stream from gaseous elements.

Qualified Scheduling Entity (QSE) - In ERCOT, a Market Participant that is qualified for communication with ERCOT for Resource Entities and Load Serving Entities (LSEs) and for settling payments and charges with ERCOT**.** QSEs submit schedules on behalf of Resource Entities or LSEs such as retail electric providers (REPs). QSEs must submit daily schedules for their bilateral transactions with total generation and demand and bid curves for zonal balancing up and balancing down energy. The schedules for generation and demand are required to be balanced so that supply equals demand. QSEs also bid for ancillary services.

Ramp or Ramp Rate (for Interchange Schedules) - The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.

Ramp or Ramp Rate (for Generator Output) - The rate, expressed in megawatts per minute, that a generator changes its output, or is expected to change its output.

Rating - The operational limits of a transmission system element under a set of specified conditions**.** In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar), and is also known as "imaginary power."

Reciprocating Compressor Unit(s) - Also known as "positive displacement" compressors, reciprocating compressors operate by trapping a certain volume of natural gas within the compressor and reducing the volume. The high-pressure gas is then released through the discharge valve into the pipeline. Piston-operated reciprocating compressors fall within the category of positive displacement compressors. These compressors have a fixed volume and are able to produce high compression ratios.

Rectifier - A converter designed and operated to convert AC power to DC power. Electrically speaking, rectifiers are the opposite of inverters. High voltage DC (HVDC) converter stations contain large numbers of high power rectifiers.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric transmission owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Regulation - The ability to maintain a quantity within acceptable limits. For example, frequency regulation is the control or regulation of the system frequency to within a tight bandwidth around 60 Hz. Voltage regulation is the control of a voltage level within a set bandwidth. In power systems operations, regulation often refers broadly to changing the output level of selected generators to match changes in system load.

Regulator, Pressure - A device that maintains the pressure in a fluid flow line, less than its inlet pressure within a constant band of pressures, regardless of the rate of flow in the line or the change in upstream pressure.

Relay Misoperation - Any unintentional operation of a protective relay when no fault or other abnormal condition has occurred.

Reliability Must Run (RMR) Unit - A unit that must run for operational or reliability reasons, regardless of economic considerations. ERCOT specifies that an RMR unit would not otherwise be operated unless it is necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria where market solutions do not exist.

Reliability Unit Commitment (RUC) - In ERCOT, a process to ensure that adequate resource capacity and ancillary service capacity are committed in the proper locations to serve the forecasted load. ERCOT conducts at least one Day-Ahead RUC (DRUC) and at least one Hourly RUC (HRUC) before each hour of the operating day, but additional RUCs are conducted when needed to evaluate and resolve reliability issues.

Reserve Sharing Group - A group whose members consist of two or more balancing authorities that collectively maintain, allocate, and supply operating reserves required for each balancing authority's use in recovering from contingencies within the group.

Resource Entity (RE) - In ERCOT, Resource Entities either own or control a generation resource or behave as a load resource that can comply with ERCOT instructions to reduce electricity usage or provide an ancillary service. Each RE must also be represented by a Qualified Scheduling Entity (QSE), which establishes a control interface with ERCOT.

Responsive Reserve Services (RRS) - As defined by ERCOT, an ancillary service that provides operating reserves that is intended to: (1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT transmission grid using primary frequency response and interruptible load, (2) help restore frequency to its scheduled value to return the system to normal, (3) provide energy or continued load interruption during the implementation of an Energy Emergency Alert (EEA), and (4) provide backup regulation. RRS can be provided by generation or by load resources having Interruptible Responsive Reserve capability.

Restoration - The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

Reticulated Pipelines - Natural gas pipelines with highly networked, web-like transmission lines, with many possible transportation paths for natural gas supplies to reach the desired marketplace.

Rolling Blackouts - Also known as rotating outages, these are controlled, temporary interruptions of service to customers, most commonly initiated by switching off selected distribution circuits intended to reduce load during times of capacity shortfalls due to significant forced outages of generation and/or transmission facilities. The service interruptions are transferred from one group (or block) of customers to another over time so that no one group bears the entire burden of the necessary reduction in load.

Rotor - The rotating component of a generator attached to the spinning shaft of the generator. In the large synchronous generators that are predominant in electric power systems, the rotor winding acts as an electromagnet that produces the magnetic field used to induce voltage in the stator windings.

RUC Clawback Charge - In ERCOT, money returned by a Qualified Scheduling Entity (QSE) to ERCOT for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are lower than those allowed by the prevailing RUC guaranteed payment.

RUC Make-Whole Payment - In ERCOT, a payment made to a Qualified Scheduling Entity (QSE) for a resource that was committed by the RUC process when the resource's start-up and minimum energy costs are less than revenues received.

Salt Cavern - An underground natural gas storage cavern which has been developed in a salt dome by the solution mining process.

Scarcity Pricing Mechanism - A pricing mechanism based on the idea that under scarcity conditions, generating units will receive higher compensation for producing electricity. The additional revenue is intended to provide an incentive for investment in new generation facilities, and to promote overall system reliability. Under this mechanism, when available supply falls below a predetermined threshold, the price of additional power rises significantly.

Scheduled Frequency - For power systems in North America, the scheduled frequency is normally 60.00 Hz. During periods of time error correction, which

may last several hours, the scheduled frequency in a given interconnection is set to 59.98 Hz to slow down clocks that use synchronous motors when they are running fast, and to 60.02 Hz to speed them up when they are running slow The fact that the clocks are running fast or slow is an indication that system frequency averaged slightly higher or lower than 60.00 Hz over a long duration, signaling the need for a correction.

Sine Wave - The graphical representation of a mathematical function that describes the smooth, symmetrical, and periodic variation of a quantity that oscillates in magnitude or amplitude. In AC electric power systems, the voltage and current are characterized by sine waves having a frequency of 60 Hz. These waveforms, starting from a zero baseline, traverse a path that increases to a crest (positive maximum), then falls back to zero, continues downward to a trough (equal but opposite to the crest, *i.e.*, in the negative direction), and back to zero in one-sixtieth of a second.

Sluicing/Service Water Systems - A system used to remove bottom ash from many coal-fired boilers.

Southwest Power Pool (SPP) - A Regional Transmission Organization serving members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas (non-ERCOT). SPP is connected to and is part of the Eastern Interconnection.

Southwest Reserve Sharing Group (SRSG) - A pool of electric load-serving entities in Arizona, New Mexico, Nevada, southern California, and El Paso, Texas that have entered into an agreement to share contingency reserves. SRSG is a NERC Registered Entity that administers certain requirements on behalf of its members related to disturbance control and emergency operations. SRSG is connected to and is part of the Western Interconnection.

Spinning Reserve - Unloaded generation capacity that is synchronized and available to serve additional demand.

Stability - The ability of an electric power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. Instances of instability are serious because they have the potential to cause widespread outages in the power system, and possibly even in the entire interconnection.

Static VAR Converter / Compensator (SVC) - A combination of shunt reactors and shunt capacitors whose switching is precisely controlled by power electronics

to automatically manage reactive power injections and withdrawals from the power system to help maintain proper transmission voltage.

Stator - The stationary component of a motor or generator surrounding but not making physical contact with the spinning rotor in the typical cylindrical design/construction.

Substation - A site that houses circuit breakers, disconnect switches, transformers, reactors, capacitors, and other equipment serving as an electrical hub in the power system, especially at interfaces between different voltage levels. The prefix "sub" distinguishes substations from generating stations. A central control house is often provided to house control and protective equipment.

Supervisory Control and Data Acquisition Systems (SCADA) - A system of remote control and telemetry used to monitor and control a power system or a natural gas transportation or distribution system.

Synchronize - The process of bringing two electrical systems together by closing a circuit breaker at an interface point when the voltages and frequencies are properly aligned. Also, when generators are brought on-line, they are said to be synchronized to the system.

Synchronous - To be in-step with a reference. The rotor of a synchronous machine, be it a motor or a generator, spins in unison with the power system in terms of frequency (see Synchronous Speed, below).

Synchronous Speed - The speed at which the rotor of a synchronous generator must rotate in order to stay in synchronism with the rotating magnetic field of the system. The synchronous speed is determined by the frequency of the power system and the number of magnetic poles in the rotor. For example, the synchronous speed of a two pole steam-turbine generator in a 60 Hz system is 3600 revolutions per minute (rpm), while the synchronous speed of a 24 pole hydro generator is only one-twelfth of that, or 300 rpm.

System (Electric Power) - A combination of generation, transmission, and distribution facilities, equipment, and components.

System Operator - An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

System Operating Limit (SOL) - The value of any of a number of electrical quantities such as real power flow (in MW), total power flow (real plus reactive) (in MVA), voltage (in kV), current (in amperes) or frequency (in Hz) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure that established reliability criteria are satisfied.

Telemetry - Equipment for measuring a quantity (amperes, volts, MW, etc.) and transmitting the result via a telecommunication system to a remote location for indication and/or recording.

Texas Reliability Entity (TRE) - Texas Reliability Entity, Inc. is authorized by NERC to develop, monitor, assess, and enforce compliance with NERC Reliability Standards within the geographic boundaries of the ERCOT region. In addition, TRE has been authorized by the Public Utility Commission of Texas (PUCT) and is permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides. TRE is independent of all users, owners, and operators of the bulk power system.

Thermal Insulation - Any material which slows down or retards the flow or transfer of heat.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transient Flow or Unsteady State Flow - The process which involves changes within the control volume with time.

Transmission - An interconnected group of lines and associated equipment operated at high voltage levels in the range of 100 kV to 765 kV in North America for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Operator - The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

Transmission Owner - The entity that owns and maintains transmission facilities, including, but not limited to, overhead and underground transmission lines, substations, transformers, circuit breakers, capacitor banks and busses.

Transmission Service Provider (TSP) - As defined by NERC, an entity that administers the transmission tariff and provides transmission service to transmission customers under applicable service agreements. ERCOT specifies that TSPs own or operate transmission facilities.

Treatment Plant - A plant designed primarily to remove undesirable impurities from natural gas to render the gas marketable. Examples of these impurities are water, water vapor, sulfur compounds, carbon dioxide, nitrogen and helium.

Turbine - A rotating mechanical device driven by the force of a working fluid. The working fluid is typically steam, water, combustion gases or, in the case of wind turbines, air.

Under Frequency Load Shedding (UFLS) - The automatic disconnection or tripping of customer load based on a decline in system frequency. The set points are predetermined. For example, a utility may trip 5% of their connected load if frequency falls below 59.3 Hz, an additional 10% if it falls below 58.9 Hz, and a final 10% if it falls below 58.5 Hz. The purpose of UFLS is to arrest the frequency decline accompanying major system disturbances generally involving the sudden loss of large amounts of generation or multiple transmission line tripping that results in the formation of an electrical island in which the remaining generation is inadequate to supply the load, thereby forestalling a complete system collapse.

Under Voltage Load Shedding (UVLS) - The tripping of customer load based on a decline in system voltage. For example, a utility may trip 5% of their connected load if voltage falls below 92% of nominal and an additional 10% of their load if voltage falls below 90% of nominal. The purpose of UVLS is typically to avoid a voltage collapse, but it can also be used to avoid overloading transmission facilities during contingency conditions when other transmission facilities trip or are forced out of service.

Unit Commitment - The process of selecting which generating units will be placed on line to serve the load and reserve requirements.

Verbal Dispatch Instruction - In ERCOT, a dispatch instruction issued by operators in the control center to a generating unit or units, load resource, or their Qualified Scheduling Entities (QSEs) orally over the telephone, as opposed to one issued in writing or issued automatically by a control system and delivered electronically via telecommunications.

Vertically Integrated Utility - An electric utility company or a federal, state, or municipal agency that owns and operates all aspects of the power system in its franchise service territory, *i.e.*, generation, transmission, and distribution. The ownership of certain facilities may be shared or held wholly by others, but the vertically integrated utility still controls the power system in the territory.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is "V" and units are volts or kilovolts (kV).

Well Freeze-offs - Natural gas flow blockages resulting from water vapor freezing or the formation of crystal hydrates in the gas stream.

Wellhead - The assembly of fittings, valves, and controls located at the surface and connected to the flow lines, tubing, and casing of the well so as to control the flow from the reservoir.

Wellhead Choke - Points at the wellhead where flow and pressure are primarily controlled.

Western Electricity Coordinating Council - The Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

Wheeling (Natural Gas) - The transportation of customer-owned gas by a transmission company for the customer at a pre-determined cost to the customer.

Windbreaks - Temporary or permanent structures intended to obstruct, or serve as a barrier against, the wind for the comfort and safety of people and/or the protection of property or equipment.

Wind Chill Factor - The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people to feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a

stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

Zonal Market - A market for electric energy divided into regional pricing zones. Generators within a zone receive the same price for the power they provide, and transmission lines crossing zonal boundaries are assessed additional costs due to market congestion when the power flowing through them reaches operational constraints.

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Appendix: Legislative and Regulatory Responses by the States

The natural gas and electricity shortages that occurred in the Southwest in early February 2011 seriously affected three states: Arizona, New Mexico and Texas.[1] Each state took different regulatory and legislative actions in response to the events. As part of its inquiry, the task force contacted state regulators and followed subsequent legislative and regulatory developments. The following section describes the actions taken by each state.

Arizona

In Arizona, approximately 19,000 customers in the Tucson and Sierra Vista areas lost gas service on February 3, 2011. Most of those customers had their service restored within four days.[2] The Arizona Corporation Commission (ACC), which among other things, regulates public utilities in the state, took the lead in reviewing the circumstances surrounding the gas outages.[3] One commissioner met with Southwest Gas Corporation representatives on February 3,[4] and another sent data requests to four impacted pipelines on February 16, 2011.[5]

On March 2, 2011 the ACC held an open meeting on the Southern Arizona gas outages, with witnesses from Southwest Gas Corporation and El Paso Natural Gas Company testifying. At the hearing, representatives from both companies stated that cold weather was the primary reason for the outage, as demand far outweighed supply during the record-low cold temperatures.

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[1] The task force contacted regulatory staff with the Public Service Commission of Nevada and the California Public Utilities Commission, who informed us that they did not experience a substantial, direct impact from the February 2011 gas supply shortages, and that no related inquiries or proceedings were underway in their states.

[2] *See* Alex Dalenberg, *ACC Meeting will Delve into SW Gas Outage, Arizona Daily Star* (Feb. 13, 2011).

[3] The Arizona legislature did not hold hearings or take any legislative actions in response to the outages.

[4] *See* Letter from Commissioner Barbara Burns to the Chairman and Commissioners of the Arizona Corporation Commission, Docket No. G-00000C-11-0081 (Feb. 11, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123284.pdf (last visited Aug. 5, 2011).

[5] *See* Letter from ACC Commissioner Sandra Kennedy to Southwest Gas Corporation; El Paso Natural Gas Company; UNS Gas, Inc.; and Transwestern Pipeline Company, LLC, Docket No. G-00000C-11-0081 (Feb. 7, 2011), *available at* http://images.edocket.azcc.gov/docketpdf/0000123172.pdf (last visited Aug. 5, 2011).

The ACC held two follow up meetings, on April 6, 2011 and April 7, 2011, to gather information from customers affected by the outages.[6] No further action has taken place in the ACC proceeding.

New Mexico

More than 30,000 customers lost gas service in New Mexico on February 2 and 3, 2011, some for as long as a week. Shortly thereafter, a New Mexico State Senator asked the state's Attorney General to look into the causes of the outages,[7] and the legislature announced that it would hold hearings. On February 11, 2011, a hearing was held before the full New Mexico Senate, which heard testimony from some of the individuals who lost gas service and from representatives of New Mexico Gas Company (NMGC), El Paso Natural Gas Company, and the New Mexico Public Regulation Commission (PRC).

On February 14, 2011, the New Mexico Senate directed the PRC to convene a task force to investigate how and why New Mexico consumers lost natural gas service and to make recommendations on how to prevent such loss of service in the future.[8]

On March 16, 2011, Governor Susana Martinez signed a bill[9] into law that created a state task force to investigate the causes of the outages and to make recommendations on how to prevent similar outages in the future.[10] As of the date of this report, the report from the Natural Gas Emergency Investigation Legislative Task Force is pending.

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[6] *See Tucson Residents Tell Commissioners About Freezing Nights and No Natural Gas Service, Associated Press*, (Apr. 8, 2011).

[7] *See State Senator Carlos Cisneros, Senator Calls on AG to Immediately Investigate Gas Outage* (Feb. 8, 2011), *available at* http://www.democracyfornewmexico.com/democracy_for_new_mexico/2011/02/sen-carlos-cisneros-requests-immediate-investigation-into-gas-outage-by-ag.html (last visited Aug. 5, 2011).

[8] SM 30 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/SM030.pdf (last visited Aug. 5, 2011).

[9] HB 452 (Engrossed), 2011 Regular Session (NM, 2011), *available at* http://www.nmlegis.gov/Sessions/11%20Regular/final/HB0452.pdf (last visited Aug. 5, 2011).

[10] *See* House Executive Message No. 2 (Mar. 16, 2011) *available at* http://www.governor.state.nm.us/uploads/FileLinks/7bbb779a53dd4071933247333d38f22c/House%20Executive%20Message%202.pdf (last visited Aug. 5, 2011).

Appendix: Legislative and Regulatory Responses by the States

The United States Senate Committee on Energy and Natural Resources held a field hearing in New Mexico on February 21, 2011 to receive testimony regarding the natural gas service disruptions in New Mexico and the reliability of regional energy infrastructure.[11] The Committee heard testimony from three different panels, and sent follow up questions to the Federal Energy Regulatory Commission.

The PRC opened its investigation into the outages on February 11, 2011.[12] In its order opening the inquiry, the PRC directed NMGC, Public Service Company of New Mexico, El Paso Electric Company, and Southwestern Public Service Company to provide testimony responding to specific questions within 30 days of the order.[13]

At the same time, the PRC also initiated a non-docketed proceeding entitled the NMPRC Informal Task Force Investigation into Severe Weather Cascading Events. The Informal Task Force, which included representatives of several New Mexico utilities,[14] PRC staff, the state Attorney General's Office, several municipalities, and the general public, was charged with developing a summary of the weather event, identifying the causes, determining how to mitigate the impact of future events, and reviewing the policies and rules of the PRC and other New Mexico agencies.[15]

On May 3, 4, and 5, 2011, the PRC held hearings on the outages, hearing testimony from gas company representatives and other parties, including

[11] *See* Recent Natural Gas Service Disruptions in New Mexico and Reliability of Regional Energy Infrastructure before the Senate Energy and Natural Resources Committee, 112th Congress (Feb. 21, 2011) *available at* http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=169bb12f-e360-3d3f-378c-4a762ddf0b56 (last visited Aug. 5, 2011).

[12] *See* Press Release, Public Regulation Commission, NMPRC initiates investigation into Natural Gas Delivery Failure (Feb. 10, 2011), *available at* http://www.nmprc.state.nm.us/news/pdf/2011-02-10-gasinvestigation.pdf (last visited Aug. 5, 2011).

[13] In the Matter of an Investigation into New Mexico Gas Company's Curtailments of Gas Deliveries to New Mexico Consumers, Order Initiating Investigation and Setting Hearing, New Mexico Public Regulation Commission, Case No. 11-00039-UT (Feb. 15, 2011), *available at* http://164.64.85.108/infodocs/ 2011/2/PRS20156381DOC.PDF (last visited Aug. 5, 2011).

[14] The utilities are Public Service Company of New Mexico, Southwestern Public Service Company, El Paso Electric Company, NMGC, Zia Natural Gas Company, and Raton Natural Gas Company.

[15] February 2011 Severe Cold Weather Investigations & Status, Presentation before the Natural Gas Emergency Investigation Legislative Task Force (July 25, 2011) at pp. 1-2.

representatives of the affected municipalities. Since then, the parties have submitted additional written testimony and briefs to the PRC. As of the date of this report, the PRC's investigation is still pending.

Texas

With several million consumers affected by electrical blackouts, the State of Texas was severely impacted by the extreme weather events of early February. Two regulatory agencies in Texas have jurisdiction over the industries in question – the Public Utilities Commission of Texas (PUCT) (which has primary jurisdiction over the electrical power industry) and the Texas Railroad Commission (TRC), whose jurisdiction includes the natural gas industry.

The PUCT reacted at once to the electric outages, asking the state's independent energy market monitor on February 4, 2011 to investigate whether power generators, pipeline companies or others broke market rules.[16]

The PUCT also directed the Texas Reliability Entity, Inc. (TRE) to investigate the Electric Reliability Council of Texas (ERCOT) Energy Emergency Alert Level 3 that occurred on February 2, 2011. At the same time, the PUCT asked El Paso Electric Company to investigate and report back on the weather-related issues surrounding this event.

On February 8, 2011, the TRC held the first state hearing on the outages. One of the witnesses, the TRE, addressed the impact of the rolling blackouts on natural gas service.[17]

On February 15, 2011, the Texas Senate's Committee on Natural Resources and Committee on Business and Commerce jointly convened a hearing to discuss the causes of the rolling blackouts.[18] The hearing included testimony from the PUCT, the TRC, the Texas Commission on Environmental Quality, ERCOT, and the Office of Public Utility Counsel. The House Committee on State Affairs also held a hearing on the causes of the rolling blackouts on February 17, 2011.

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[16] *See* Rebecca Smith, *Texas to Probe Rolling Blackouts, Wall Street Journal* (Feb. 7, 2011).

[17] *See* Press Release: Railroad Commission Emergency posted item to be discussed at 1:30 P.M today, Texas Railroad Commission (Feb. 8, 2011), *available at* http://www.rrc.state.tx.us/pressreleases/2011/020811.php (last visited Aug. 5, 2011).

[18] *See* Chris Tomlinson, *Texas Senate Investigates Power Outages, The Associated Press* (Feb. 16, 2011).

Prompted by the hearings, the legislature enacted a bill to address the perceived causes of the rolling blackout.[19] On June 17, 2011, that bill was signed into law.[20]

The law directs the PUCT to prepare a "weather emergency preparedness report on power generation weatherization preparedness." [21] Under the law, the PUCT must review the emergency operations plans it currently has on file,[22] determine the Texas electricity grid's ability to operate continuously during extreme weather events in the upcoming year, consider the upcoming year's forecasted weather patterns, and recommend improvements to emergency operations plans to ensure electric service reliability.[23] In addition, the law permits the PUCT to require entities to update their emergency operations plan when it does not contain information sufficient to determine whether that entity can perform during adverse weather. The law also permits the PUCT to adopt rules implementing the legislation.[24]

On April 21, 2011, the Independent Market Monitor reported that "there was no evidence of market manipulation or market power abuse" within the ERCOT region.[25] The Independent Market Monitor similarly determined "that the ERCOT real-time and day-ahead wholesale markets operated efficiently and the outcomes are consistent with the ERCOT energy-only wholesale market design."[26]

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[19] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[20] Another bill was introduced which would have required the PUCT to develop a process for obtaining emergency reserve power generation capacity, but it was not considered during the legislative session. HB 1986, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/ HB01986I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[21] SB 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[22] P.U.C. Subst. R. 25.53(c)(2) (TX, 2011).

[23] S.B. 1133, 82 Leg., Reg. Sess. (TX, 2011), *available at* http://www.capitol.state.tx.us/tlodocs/82R/billtext/pdf/SB01133I.pdf#navpanes=0 (last visited Aug. 5, 2011).

[24] *Id.*

[25] Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011, Potomac Economics LTD. (April 21, 2011), *available at* http://www.puc.state.tx.us/files/IMM_Report_Events_020211.pdf at 2 (last visited Aug. 5, 2011).

[26] *Id.*

On May 13, 2011, the TRE issued a report on whether ERCOT Protocols and Operating Guides were followed during the period leading up to the Energy Emergency Alert event.[27] The TRE concluded that event "was caused by either insufficient or ineffective preparation of generating facilities for prolonged freezing weather."[28] The report went on to find that "ERCOT Market Participants committed potential violations of the ERCOT Protocols and Operating Guides in connection with the event."[29] The TRE will conduct additional investigations as necessary and forward information to the PUCT for further action, as appropriate.[30]

Also, on May 13, 2011, PUCT staff issued a report on El Paso Electric Company's activities during the weather event.[31] PUCT staff did not identify any violations of the Public Utility Regulatory Act or the PUCT's Substantive Rules.[32] The report, however, did conclude that "designed cold weather tolerances of El Paso Electric Company's current generation equipment and/or weatherization preparation were inadequate to prevent failures in the conditions during the event timeframe."[33]

[27] Protocol and Operating Guide Compliance Report of the ERCOT Emergency Alert (EEA) Level 3 on February 2, 2011, Texas Reliability Entity, Inc. (May 13, 2011), *available at* http://www.puc.state.tx.us/files/TX_RE_EEA_Protocol_Comp_Report.pdf (last visited Aug. 5, 2011).

[28] *Id.* at 1.

[29] *Id*.

[30] *Id.*

[31] Report on El Paso Electric Company Weather-Related Issues in February 2011, Staff of the Public Utilities Commission of Texas (May 2011), *available at* http://www.puc.state.tx.us/files/EPE_Report_05-13-11.pdf (last visited Aug. 5, 2011).

[32] *Id.* at 4.

[33] *Id.* at 1.

Appendix: Categories of NERC Registered Entities

All entities that fall within one or more of the following categories must register with NERC. Many entities carry out multiple roles and therefore have multiple registrations.

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within BA area, and supports interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Appendix: Categories of NERC Registered Entities

Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.

Appendix: Categories of NERC Registered Entities

Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

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Appendix: Electricity - How It Is Generated and Distributed

Electricity is one of the most widely used forms of energy in the industrialized world. According to the U.S Energy Information Administration, in 2009 the U.S. electric utility net generation was 2,372,776 gigawatt hours. Table 1 shows the share of net electricity generation by energy source in the United States.

Energy Source	Net Generation (%)
Coal	44.5
Nuclear	20.2
Natural Gas	23.3
Hydro	6.8
Oil (Petroleum) and other	1.6
Renewables	3.6

Table 1: Share of net electricity generation in 2009 in the U.S. (Source: U.S. Energy Information Administration)

Electric power is produced at generating stations and transmitted via transformers, transmission lines, switching devices and protection and control equipment for delivery to end users. The electric power system as shown in figure 1 is an integrated system made up of generation, transmission and distribution subsystems.

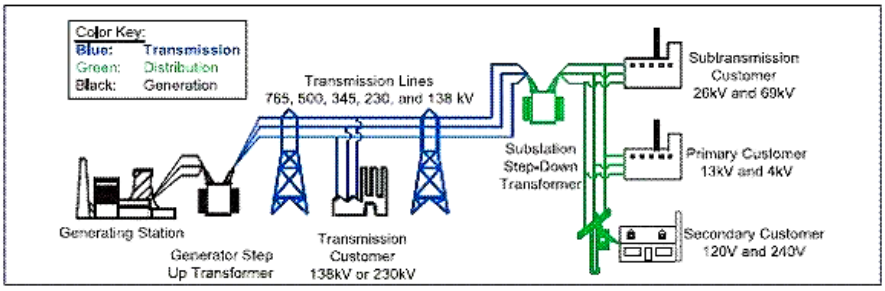

Figure 1 – Basic structure of the electric system (NERC)

Generation

Generating plants produce electricity by burning fuels such as oil, coal, natural gas, or lignite to create steam that drives a turbine, which in turn drives a turbine generator shaft. In a coal-fired plant (figure 2), coal is ground by pulverizers into fine powder, mixed with pre-heated air and injected into a combustor, where it is ignited. The hot combustion gas rises through the boiler and heats water that enters the steam generator. The partially vaporized water enters the steam drum, where steam is separated from the water. The remaining

water cycles through the boiler again, and through tubes lining the furnace walls. The steam is passed through another section of the boiler known as the superheater, where the temperatures are increased to well above boiling.

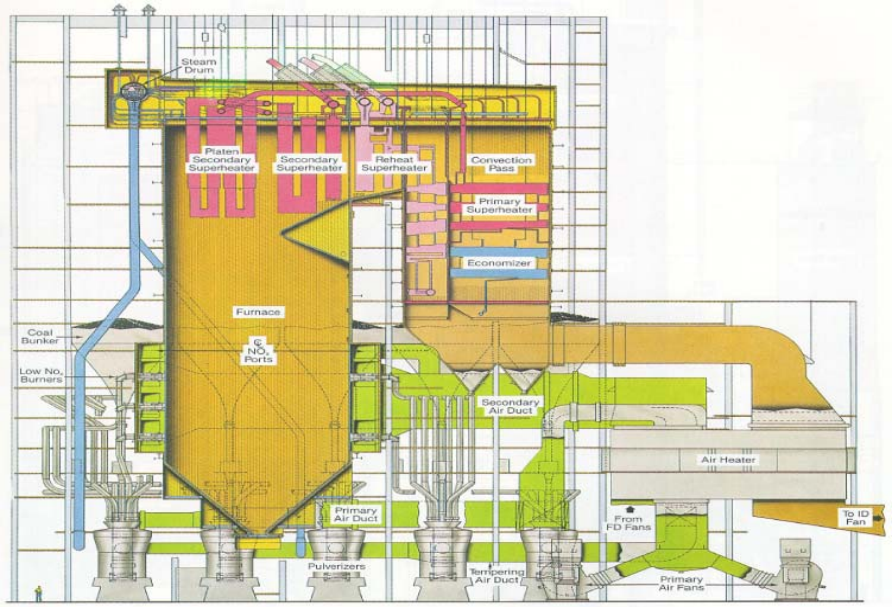

Figure 2 – Typical drum-type coal/lignite boiler plant
(PJM Generation Basics)

The superheated steam, now at very high pressure, passes through a high pressure turbine (shown in figure 3), causing the turbine to spin and turning the shaft of an electrical generator. After passing through the high pressure turbine, the steam is piped back to the boiler to be reheated, then enters an intermediate pressure turbine and low pressure turbine before it passes through a condenser, where the steam is converted back to water, which is usually cycled back to the steam generator for reuse. The mechanical energy generated by the spinning generator shaft is converted to electrical energy for delivery to the electric power system.

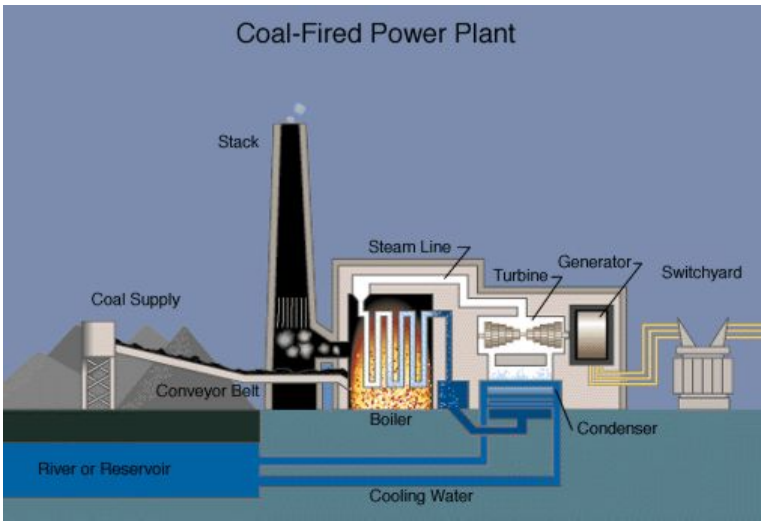

Figure 3: Typical coal burning generating plant with cooling tower (Department of Energy)

In nuclear generating stations, steam is also used to drive a turbine. However, the energy required to produce the steam is derived from nuclear fission, typically fueled by uranium.

Wind turbines use blades to collect the energy of the wind. As wind blows, it flows over the blades, causing them to turn. The blades are connected to a gear box with a drive shaft that turns an electric generator to produce electricity.

In hydroelectric plants, the gravitational force of water flowing downhill drives the turbine generator shaft (as shown in figure 4). The mechanical energy of the spinning shaft is then converted to electrical energy.

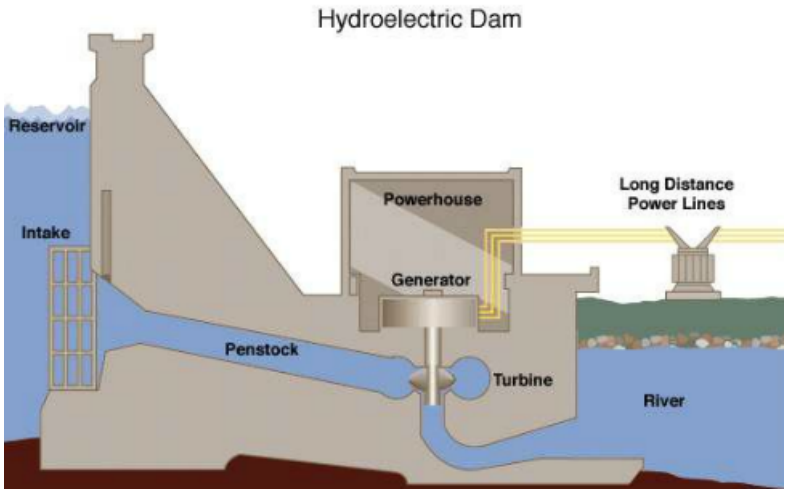

Figure 4: Typical hydroelectric generator
(Energy Information Administration)

Electric energy can also be produced by simple cycle or combined cycle combustion turbines or internal combustion engines, which usually burn natural gas or fuel oil. The combustion turbine drives an electric generator to produce electricity. One advantage of combustion turbines is that they can be started quickly, making them suitable for emergencies and during peak periods, when demand for electricity is at its highest.

A combined cycle combustion turbine is shown in figure 5. Note: a simple cycle combustion turbine plant does not include a heat recovery steam generator (HRSG), steam turbine, and a second generator as depicted in figure 5.

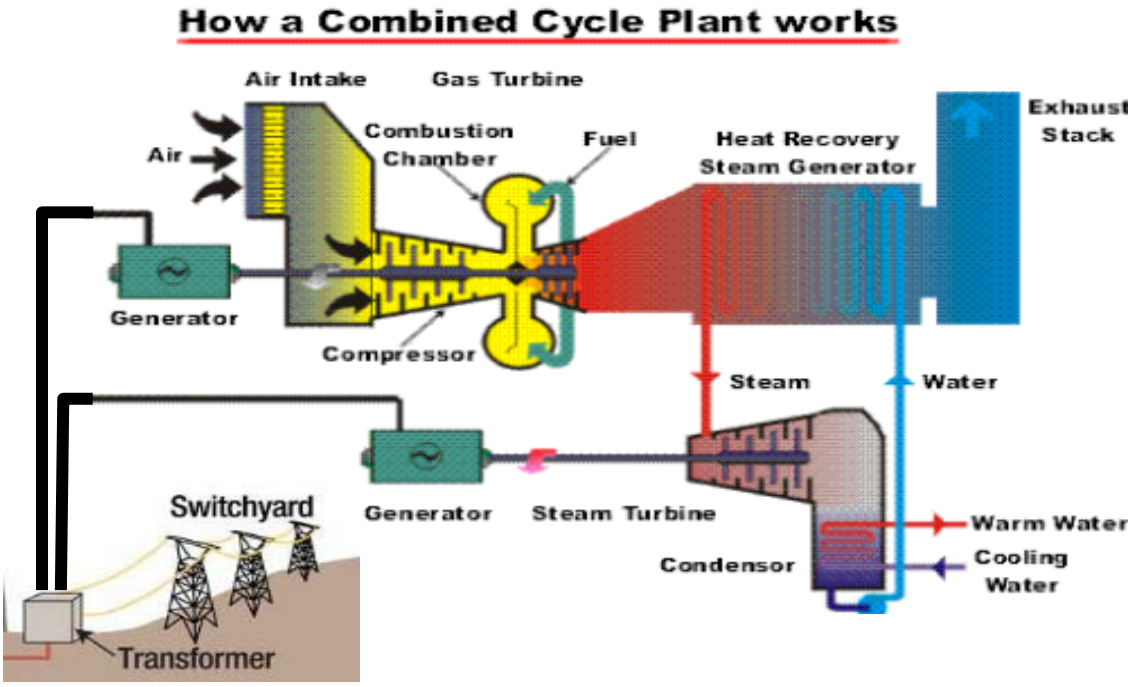

Figure 5: Combined cycle turbine generator with steam generator and HRSG (Washington State University)

Conversion of Mechanical Energy to Electrical Energy

A generator works on the principle of electromagnetic induction, discovered by scientist Michael Faraday between 1831 and 1832. Faraday discovered that the flow of electric charges could be induced in a coil of wire by passing a magnet through the coil. This movement creates a voltage difference between the two ends of the wire or electrical conductor, which in turn causes the electric charges to flow, thus generating electric current.

Every modern generator consists of two main components: the rotor (the moving part) and the stator (the stationary part). In an AC generator, the rotor spins inside the stator. A mechanical device is used to spin or turn the rotor. With every rotation, the changing magnetic field creates a current in the stator windings. A generator does not actually make electrical energy. Instead, it uses mechanical energy supplied to it to cause the movement of electric charges present in the wire of the stator windings, thereby generating an electric current that is supplied to the grid. A generator is akin to a water pump, which causes the flow of water but does not actually create the water flowing through it.

Most large power generators are three-phase generators and have three windings (A, B and C phases), one winding for each phase. In a three-phase

generator, a rotor rotates at the center of the three windings creating the changing magnetic field. Each one of the winding sets produces a voltage. Each phase voltage has a 120º phase angle separation from the other two phase voltages as shown in figure 6. The waveform of the induced voltages is a sine wave (also shown in figure 6) in which each phase voltage periodically reverses direction. The current produced from this generator is known as alternating current (AC).

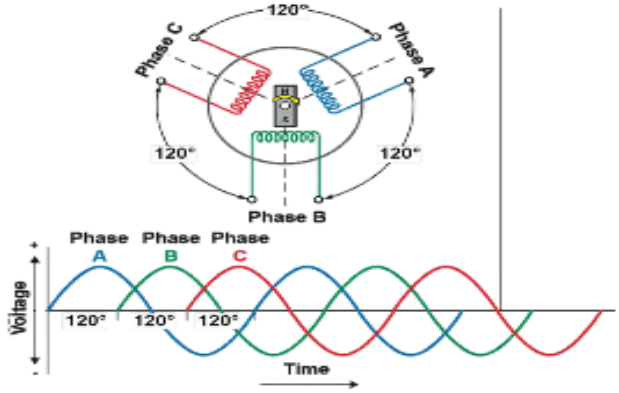

Figure 6: Three-phase generator diagram & waveform
(Electric Power Research Institute)

Figure 7: Three-phase power generator
(Electric Power Research Institute)

There are two general types of AC generator: synchronous and asynchronous. The terms synchronous and asynchronous refer to the relationship between the generator rotor's speed of rotation and the power system speed. Power system speed (or synchronous speed) is the speed of rotation of the AC electrical system to which the generator is connected. When a generator is connected to the power system, the rotating magnetic field of the generator is synchronized with the rotating magnetic field that already exists in the three-phase system. An AC generator can be designed to rotate in-step, or in synchronism,

with the power system's rotating field. This type of AC generator is called a synchronous machine. Most utility power generators and most large motors are synchronous machines.

An AC generator's rotor can also be designed to rotate slower or faster than synchronous speed. This type of machine is called an asynchronous machine. Most small AC motors are asynchronous machines. Induction machines – alternating current machines in which power is supplied to the rotor by means of electromagnetic induction – are the most common type of asynchronous machines. Most wind turbines use induction generators.

Synchronous machines are the most common type of generator used for large-scale power production, and can be used to produce both active[1] and reactive power[2]. This is in contrast to conventional induction machines, which cannot produce reactive power, only active power. The latest design for wind turbine generators, however, includes sophisticated power electronic interfaces and controls that allow these units to inject or absorb reactive power from the grid, as well as providing frequency response, inertial response, etc.

Transmission

Electricity from generators is stepped up to higher voltages by means of a generator step-up transformer for transportation in bulk over transmission lines. Operating the transmission lines at high voltage (100,000 to 765,000 volts) reduces electricity losses from conductor heating and allows power to be transported economically over long distances. The higher the voltage, the lower the current flow needed to transmit the same amount of power. Since losses are related to high current flow, lowering the current lowers the losses. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power grid. Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics, along paths of least resistance. When power arrives near a load center, it is stepped down to lower voltages by means of step-down transformers, usually located at substations throughout the system. These substations contain other equipment such as communication, control, protection

[1] Active Power is the useful or working energy supplied by a power source. It is used to perform work such as lighting a room or heating a building or turning a motor shaft.

[2] Reactive Power is used to support the magnetic and electric fields necessary to operate power system equipment. Reactive power is never consumed by the power system and is stored in the electrical and magnetic fields that exist in the system.

and metering equipment. The Bulk Power System (BPS) is predominantly an AC system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another.

Three-phase AC power is normally transmitted by overhead AC circuits, which consist of aluminum conductors with a reinforcing steel core suspended from metal towers by porcelain insulators, as shown in figure 8. Underground transmission circuits can also be used, but are used less frequently than overhead circuits due to the costs involved, as well as the associated reduction in current carrying capacity. Transmission cables installed underground must be insulated, increasing cost and limiting the current carrying capability of the system.

High Voltage Direct Current (HVDC) systems are usually employed for special purposes, including the transmission of large blocks of power from remote sources to load centers or interconnection to systems that operate at different frequencies. A DC transmission system consists of a two conductor line connecting two AC systems. A rectifier at one end of the line converts the AC voltage to a constant DC value and an inverter at the other end reconverts the DC into AC.

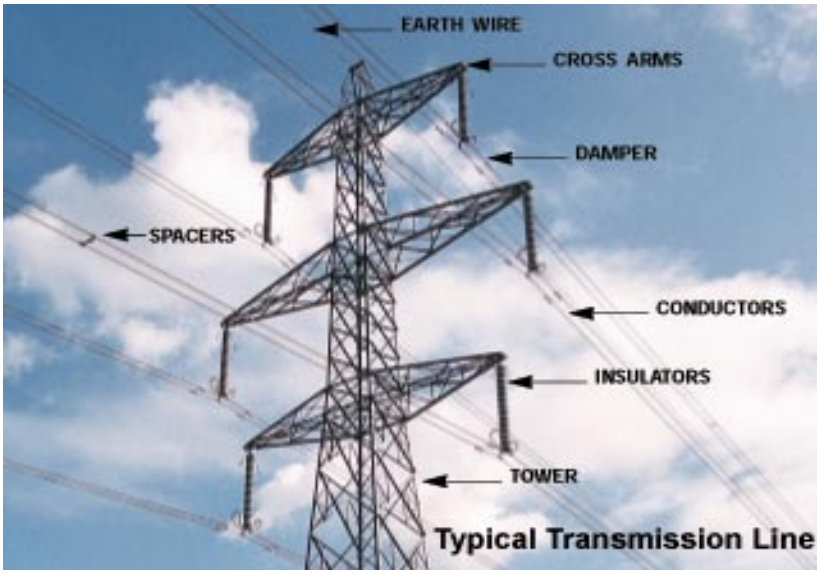

Figure 8: Transmission tower (National Grid)

While the power system is commonly referred to as “the grid,” there are actually three distinct power grids or interconnections in the United States. Figure 9 shows the various interconnections. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western

third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a small part of Mexico near the California border. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small DC ties. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads. The frequency at which the various interconnects were designed to operate is 60 Hz.

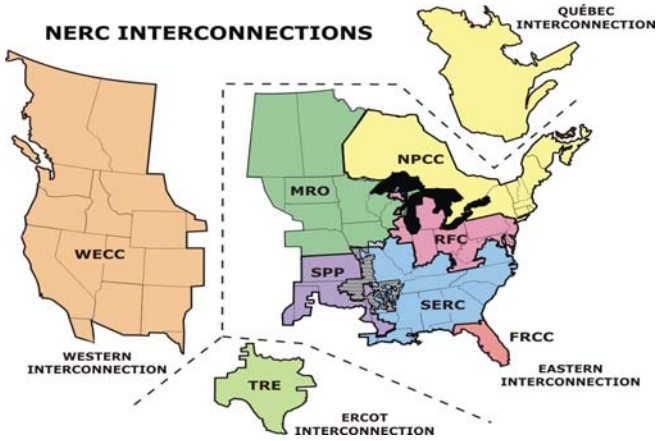

Figure 9: North American interconnections (NERC)

System Frequency

If the total demand from customers is not in balance with the available generation, the electrical frequency of an entire interconnection will deviate from 60 Hz. The target frequency is referred to as the scheduled frequency. When the actual frequency deviates from the scheduled frequency, a frequency deviation has occurred. For example, if the scheduled frequency is 60 Hz but the actual frequency is 59.95 Hz then a -0.05 Hz frequency deviation has occurred. When the supply of generation to the transmission system is inadequate, the frequency falls below 60 Hz. When too much generation is supplied to the transmission system, the frequency rises above 60 Hz. Individual power systems within an interconnection work together to maintain the frequency within a narrow band around the 60 Hz nominal frequency.

Under normal conditions, the power system frequency in a large interconnection (such as the Eastern Interconnection) varies approximately ±0.03 Hz from the scheduled value. If the scheduled frequency is 60 Hz, the normal range is 59.97 to 60.03. These variations are normal and constantly occur due to the varying nature of the interconnection's load. However, large downward, or negative, frequency deviations can trigger automatic load shedding schemes in most areas, designed to reestablish the necessary balance between generation and

load. Depending on the region, automatic under-frequency load shedding usually begins when the frequency declines to levels of 59.3 to 59.7 Hz. Distribution loads are typically shed in various size blocks before generating units start to trip.

System Voltage

The maintenance of voltage within a narrow range is critical to utility customers. Transmission voltage fluctuations of more than ten percent can affect the overall stability of the transmission system. Entities that experience sustained voltage fluctuations equal to or greater than ten percent must file a report with NERC.[3] Capacitor banks, Static VAR Compensators, load tap changing transformers, phase shifters, and voltage regulators are used to control system voltage. Low voltage conditions are usually caused by the loss of critical transmission or generation facilities and may result in the overload of adjacent circuits, which could require bringing power in over tie lines.

Load Balancing

An electric power system must have enough generating capacity to supply expected peak load demand plus a reserve margin to accommodate forced outages of generating units. Operating reserves also are necessary to regulate and respond to unanticipated events such as load forecast errors.

Large frequency deviations from the scheduled value occur when there is a significant mismatch between total load demand and total generation. The frequency rise or decay will in most cases be halted by the action of the speed governors on generators which respond to frequency changes and automatically adjust generation to meet demand. Governor action is supplemented by the Automatic Generation Control (AGC) system which over a period of several minutes brings the frequency and interchange (energy transfers that cross Balancing Authority boundaries) back to schedule.

AGC can be a very effective tool during system restoration. The primary function of AGC is to make continuous and automatic adjustments to the output of selected generators in a way that meets load demand and the established interchange schedule at the desired operating frequency. AGC software is normally designed to control a defined portion (within the Balancing Authority boundaries) of the interconnected system. To accomplish the AGC control function, control parameters are continuously monitored. The control parameters

[3] Reliability Standard EOP-004-1 (Disturbance Reporting).

consist of an actual frequency reading and all tie-line MW flows to neighboring Balancing Authority areas. These control parameters are selected and normally fixed for the portion of the system being controlled. A key assumption to the typical AGC control strategy is that the power system is operating in an interconnected mode.

Distribution

Some larger industrial and commercial customers take service at intermediate voltage levels (4,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts. Residential customers receive power via overhead or pad mounted transformers supplied by distribution feeders from substations. The transformers step down the voltage from a typical voltage of 13,000 volts to 120/240 volts. The lines carrying the power to a business or residence usually terminate at an electric meter owned and maintained by the distribution company. The meter records the energy consumed by the end user and is read periodically by the distribution company to monitor energy usage and for billing purposes.

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Appendix: Power Plant Design for Ambient Weather Conditions

Geographic location and the corresponding ambient weather conditions, including expected temperatures and wind speed, have a direct impact on the preferred design for generating facilities. In the northern regions of the United States, most generating plants (especially steam-cycle plants) are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiated from boilers, other generation equipment, and supplemental heaters can generally maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling purposes during the hot weather months.

Enclosed coal fired power plant in the northeastern United States (Allegheny Energy)[1]

In the southern and other warm weather regions of the U.S., generating plants are designed and constructed without enclosed building structures, with the boilers, turbine/generators, and other ancillary systems exposed to the weather, in order to avoid excessive heat build up. For the colder months, when temperatures may fall below freezing, generation owners and operators undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, temporary heating, and temporary wind breaks (to prevent heat loss from normal operations and from supplemental heating sources).

[1] *Available at* http://www.industcards.com/st-coal-usa-wv.htm (last visited Aug. 10, 2011).

Non-enclosed coal fired power plant in the southern United States (Luminant)[2]

Common Freezing Problems

Some power plant components and systems are susceptible to freezing. Any power station system that uses water, air (which can contain moisture), or rotating machinery (which uses lubricating oil) can develop operational problems or trip off-line as a result of sub-freezing temperatures, unless adequate cold weather protection is in place.

- Instrumentation - Instrumentation provides operational data necessary for process monitoring and control systems. Freezing often may occur not in the instrumentation itself, but in the sensing lines that run from piping, pressure vessels, and tanks that contain water or steam. The sensing lines are filled with a static water column that, if frozen, will send incorrect data, possibly resulting in unit trips, load rejection, unit runback schemes, or incorrect operator actions. Critical instrumentation sensing lines that are susceptible to freezing include lines used to monitor boiler steam drum water level, deaerator pressure, feedwater heater water levels, and various critical cooling water flows (generator, turbine oil cooling, etc.).

- Feedwater systems - The condensate and boiler feedwater systems for steam-cycle generation units utilize water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves contained in these systems are all susceptible to freezing. This is especially true of generation units that are not in operation at the onset of freezing temperatures, due to static water in the feedwater systems. In addition, the reverse osmosis

[2] *Available at* http://www.powermag.com/environmental/Luminants-Oak-Grove-Power-Plant-Earns-POWER-s-Highest-Honor_2877_p2.html (last visited Aug. 10, 2011).

equipment, demineralizers, filters, and storage tanks often found in condensate make-up water systems are susceptible to freezing.

Cooling Water Systems

- Cooling Water Intakes - Steam cycle power plants require large quantities of cooling water, often supplied by rivers or lakes. Water drawn from a river or lake is filtered through trash racks and circulating water screens to remove tree branches, debris, and fish. When temperatures drop below freezing, ice can clog racks and screens, limiting the flow of cooling water. Water intakes can also become clogged by fish kills during extreme cold weather, as happened in Texas in 1989.

- Cooling Towers - Cooling towers lower the temperature of water used in the cooling process so that it can be reused (reducing the amount of water taken from lakes and rivers) or discharged at lower temperatures. Cooling towers use mechanically induced draft or natural draft designs. Mechanical cooling towers (box) have fans mounted on the top to draw air through the water as it falls over trays to remove the heat gained in the steam condenser. Natural draft cooling towers are of the familiar, hyperbolic design that can be seen at many large coal and nuclear power plants. During extended periods of freezing temperatures, ice can accumulate on the trays in the towers and affect operations or damage the unit.

- Equipment Cooling Water - Various equipment and systems in power plants require cooling water to stay operational. These include turbine lubricating oil coolers, generator/hydrogen coolers, pump and fan bearings, and air compressors. Freezing of the piping, valves, and instrumentation sensing lines in these systems can cause derates or outages.

- Sluicing/Service Water Systems - Sluicing water is used to remove bottom ash from coal-fired boilers. Icing problems in the bottom ash removal system can interfere with ash removal and may lead to derates or outages. Service water is used for various wash down systems and fire protection systems. Loss of service water due to freezing should not affect unit capacity, but could affect equipment protection systems.

- Wastewater Systems - Various power plant systems that use water can create waste streams that must be treated for contaminants before re-use or discharge. Those systems include boiler blowdown, cooling tower blowdown, various cooling systems, bottom ash sluicing water, and service water systems.

Freezing of valves and piping on these systems can result in the accumulation of wastewater, which could affect other systems.

Emission Reduction Systems

- Sulfur Dioxide Removal Systems - Among the methods available to reduce and remove sulfur dioxide from emission flue gas on coal plants, the predominant technology has been use of wet lime or limestone scrubbers. Lime or limestone contains calcium oxide, which when mixed (slaked) with water forms calcium hydroxide. Calcium hydroxide is sprayed through the flue gas to produce a chemical reaction to form calcium sulfite or sulfate (gypsum). As the waste product is processed, it contains less and less water, which is then reused in the scrubber. The scrubbing and waste processes require many runs of piping and instrument/control locations, many of which are susceptible to freezing. Freezing problems on piping runs or sensing lines could cause scrubber chemistry problems, tank overflows, etc., which could lead to derates or unit shutdowns if the plant is unable to stay within permitted emission limits.

- Nitrogen Oxides Reduction Systems - As with sulfur dioxide systems, numerous technologies are available to reduce nitrogen oxides in fossil fuel plants. Many of these technologies use water in the emissions reduction process. These systems are susceptible to freezing that can lead to failure in the emissions reduction process, resulting in derates or unit shutdowns.

Control Air Systems, Control Drives, Valve Actuators, Valves

- Freezing in Control Air Systems - Air is compressed and used to operate pneumatic control valves, boiler damper control drives, and various other pneumatic controls in the plant. Moisture in the air can condense and accumulate in lines, air receivers, and component control mechanisms. If moisture is not removed (through use of air dryers and air receiver blow-downs), these pneumatic controls can freeze and cause equipment controls to malfunction or fail, which can in turn cause a unit shutdown or limit the unit's output.

- Sluggish Valve Operation - When exposed to severe cold weather, the operation of valves and control valves can become sluggish. This can lead to instability in boiler or turbine controls and ultimately lead to a unit trip.

- Lubricating Oil - Various types and grades of lubricating oil and grease are used in power plants on rotating machinery and other moving parts. As the temperature decreases, the lubricating properties and viscosity of these oils change, possibly affecting operation of the equipment.

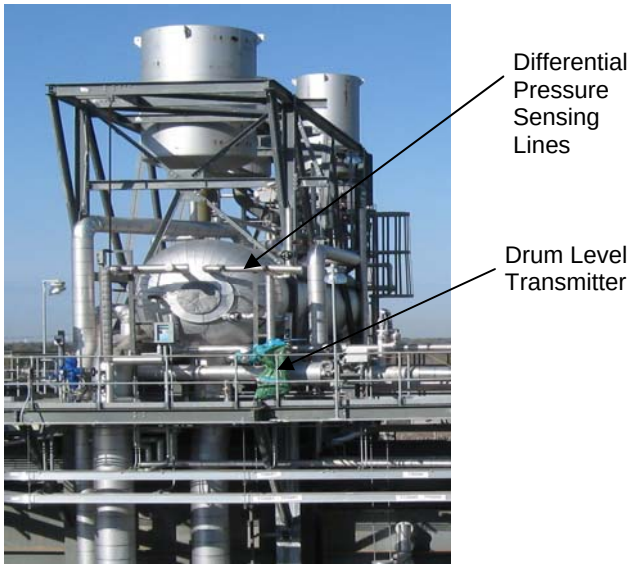
Fuel

- Coal - Severe cold weather can limit or prevent the transfer of coal into a plant. Coal in Texas (lignite) typically contains between 30 and 40% moisture. When temperatures are low enough to freeze moisture in the coal, the coal may slide on conveyor belts or block belt transfer points, chutes, and crushers, limiting supply.

- Natural Gas Supply - Freezing weather can cause gas valves to malfunction, adversely affecting gas supply to the units.

- Fuel Oil - During cold and freezing weather, fuel oil supplies in storage can gel without the appropriate additives. Gelled fuel oil can affect pump and burner performance, which in turn affects the unit's output. Some types of fuel oil must be heated before they can be used in cold weather.

Steam Drum Level Measurements



One of the most critical measurements made on a drum type steam boiler is the water level in the main drum. Too high a water level can result in water being

injected into the boiler tubes or steam turbine, damaging the boiler tube or turbine blade. Too low a water level or no water can result in overheating the drum or boiler tubes, leading to drum or boiler tube damage.

The steam drum in a southern plant can be located outside, near or at the top of the boiler. During the February 2011 cold weather event many of the plants had problems with freezing in the drum level water level regulating system.

A typical drum level measurement system works by maintaining the differential pressure between the steam side and water side of the drum to a constant value. The drum level transmitter monitors and regulates this differential pressure by controlling the amount of water being added or removed from the drum. On a normal drum, the water level is controlled to approximately plus or minus 2 inches of the desired level.

Appendix: Impact of Wind Chill

Wind Chill Factor

The term "Wind Chill Factor," is often used to explain the additional heat loss people experience through convection cooling when exposed to the wind. Whenever there is a temperature difference at a surface, *e.g.*, the difference between normal body temperature and ambient air at a lower temperature on the surface of human skin, heat is conducted across the surface from the warmer body to the cooler air. In the process, the layer of air on the surface is warmed and forms a thermal boundary which tends to slow the rate of heat loss. Wind accelerates the heat loss by literally sweeping away that boundary layer and replacing it, continuously, with air at the ambient temperature. This acceleration of heat loss caused by the wind makes people feel that the air temperature is colder than it actually is. This feeling is quantified by assigning a stationary air temperature, known as the Wind Chill Temperature, which yields an equivalent perception of cold.

The polar explorer and geographer Paul Siple first used the term "wind chill" in 1939. During the second expedition of Admiral Richard Byrd, Siple and his partner Charles Passel conducted experiments at Little America, Antarctica, to determine the time required to freeze water in plastic vials exposed outside in the wind. They developed a formula for relating heat loss to wind speed and air temperature, expressed in units of atmospheric cooling-watts per square meter. Later, the formula was modified to allow computation of a wind chill equivalent temperature.

Wind Chill Temperature is only defined for ambient temperatures at or below 50 degrees Fahrenheit and wind speeds above 3 mph. Bright sunshine may increase the wind chill temperature by 10 to 18 degrees.

Wind Chill Effect on Inanimate Objects

The Wind Chill Factor, per se, applies only to human beings and animals. The only effect wind chill has on inanimate objects, such as car radiators and water pipes, is to more quickly cool objects to the current air temperature. Objects will not cool below the actual air temperature. For example, when the temperature outside is -5 degrees and the Wind Chill Temperature is -31 degrees, a car's radiator will not get any colder than -5 degrees. Similarly, if the ambient temperature is above freezing, stationary water in piping exposed to the wind will not freeze, no matter how strongly the wind may blow.

Appendix: Impact of Wind Chill

Wind Chill Effect on Industrial Plants

Industrial plants, including electric generating stations, can nevertheless be affected by the accelerated rate of heat loss, or cooling, caused by air movement. During the hot summer months, this cooling effect can help prevent temperatures from exceeding equipment operating limits. For this reason, many plants in warmer climates are of an open-air design, without walls or enclosures. In the winter, however, the enhanced cooling from the unimpeded flow of air can cause freezing problems.

On cold days when the outside temperature drops below freezing, sustained high winds can quickly and continuously remove the heat radiating from boiler walls, steam drums, steam lines, and other equipment in an electric generating station, causing ambient temperatures to drop below freezing in spite of the heat being produced by the facility. If stationary water lines, such as those used for differential pressure measurement, are exposed to the wind under those conditions, they can freeze if they lack adequate freeze protection such as heat tracing and insulation. Wind screens and enclosures can slow the rate of heat loss caused by high winds, while at the same time acting to contain heat supplied by supplemental space heaters at critical locations.

Wind Chill Effect on Electric Demand or Load

The accelerated cooling effect of the wind affects buildings and homes throughout the community, and can significantly increase demand for electric power. In particular, buildings that are not well insulated, with frequently opened doors or drafty windows, can experience higher rates of heat loss on windy days, increasing the demand for heating energy.

During the February 2011 weather event, ERCOT engineers and operators concluded, based on archived historical data, that the forecasted wind speeds would significantly increase the load on the system. They therefore increased the conventional load forecast by 4000 MW to account for the added load created by high winds combined, with low temperatures.

Appendix: Winterization for Generators

Extreme cold weather can cause generators to fail for many reasons, including the failure or absence of heat tracing on key components, missing or inadequate wind breaks, inadequate insulation, lack of supplemental heating devices, human error, or inadequate training, maintenance, or preparation. As discussed below, effective winterization programs incorporate both physical components and operational processes to protect generating plants from freezing weather.

Physical Components of Winterization

Physical freeze protection is accomplished by three primary components:

- Heat tracing – the application of a heat source to pipes, lines, and other equipment that must be kept above freezing;
- Thermal insulation – the application of insulation material to inhibit the dissipation of heat from a surface; and
- Windbreaks – temporary or permanent structures erected to protect components from wind.

Generators use other temporary measures to prevent freezing in plants, including installing space heaters, draining non-essential water lines, and placing small heat lamps in cabinets.

Heat Tracing

Types of Heat Tracing Cable

Electric heat tracing involves the application of heat to the outside of pipes or other lines to maintain proper operating temperature. A heat tracing system is typically made up of the following: (i) heat tracing cable wound around the pipe; (ii) a thermostat that measures ambient air temperature; (iii) thermal insulation; and (iv) a power source. The failure of any of these components can result in frozen instrumentation.

There are five main types of heat trace cable. "Self-regulating" cable automatically increases power to produce additional heat as the temperature falls. It can be used on metal or plastic components for freeze protection, temperature maintenance, and foundation heating, and is typically found on sensing lines and other ancillary components. However, it cannot be used on surfaces that have high surface temperatures.

"Power-limiting" heat tracing is similar to self-regulating heat tracing in that it increases power and heat as temperatures drop, and decreases power as temperatures rise. It is specifically designed to produce high temperatures and to be used on high surface temperature fixtures.

"Parallel constant watt" heat tracing cable consists of a continuous series of short, independent heating circuits that maintain a consistent output of heat for up to several hundred feet. One benefit of this type of cable is that if one of the independent circuits fails, the rest of the cable will continue to operate. However, the length of the cable is limited, based upon the distance between the circuits, making it impractical for certain situations.

A "series constant watt" heat tracing cable is designed specifically for components that need longer circuit length. These cables are made of high-resistance wire that is powered at a particular voltage to generate heat. However, a break anywhere along the cable will result in failure of the entire heat tracing installation.

Another common type is "mineral insulated" heat tracing cable, which is typically used to maintain high temperatures, or in locations where it will be exposed to high temperatures. Mineral insulated cable is also used to provide heat over long distances, and is often used to protect high temperature steam lines.

Power Supply

Each heat tracing cable must be connected to a power source. In a typical installation, several cables covering one component of a generating unit will be connected to a freeze protection electric panel that contains circuit breakers or fuses for the various circuits. Depending on the size and layout of the generating unit, it may have dozens of freeze protection panels. These panels are often equipped with visual displays that indicate when the system is energized and when the heat tracing is activated. Images 1 and 2 are examples of the inside and outside of a new freeze protection panel.

Figure 1: Freeze Protection Panel Interior

Figure 2: Freeze Protection Panel Exterior

As can be seen in the example above, lights on the front of the panel indicate the status of the freeze protection system. Such indicator lights must be regularly monitored and tested by plant employees, since control room personnel are not always able to monitor panels remotely.

The failure of a freeze protection panel during cold weather can cause heat trace cables connected to that panel to fail. Failure to properly maintain or inspect the panel can cause corroded connections to go unnoticed and go unrepaired, possibly resulting in a short circuit that shuts off power to other panels.

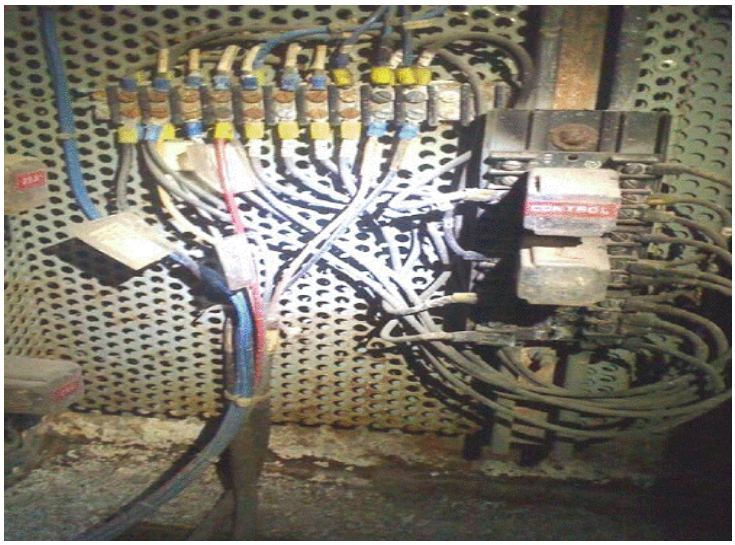


Figure 3: Corroded Freeze Protection Panel

Thermostats

Although the panel is always energized, heat tracing cables are turned on only when low temperatures call for freeze protection. Power to the cable is supplied either by a contactor (wherein two metal plates, usually separated, are pressed together to power the cables), or by a solid state controller. In most cases the system is turned on by a thermostat located at the panel. In some cases plants initiate freeze protection procedures at certain specific temperatures, and in some instances, the heat tracing must be turned on manually by plant personnel.

Thermal Insulation

A layer of thermal insulation is placed on top of the heat tracing that is installed on a pipe. This insulation is similar to home insulation, but is composed of different materials. A weatherproof skin is typically applied as an external layer to protect the insulation and heat trace from damage.

Figure 4: Insulated Piping with Heat Tracing

Thermal insulation plays a significant role in freeze protection, particularly in windy conditions, by preventing rapid heat loss. However, even small gaps in insulation have been known to result in frozen lines.

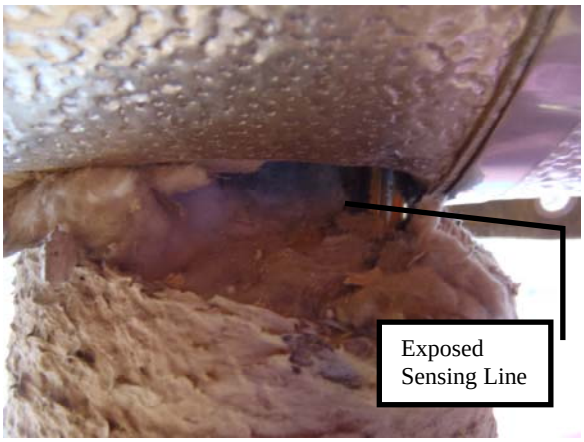


Figure 5: Gap in Insulation

In addition to the pipe itself, valves, flanges, traps and fittings should be insulated to the extent possible. Non-insulated valves, like those pictured below, can cause pipe to freeze if enough surface area is exposed to freezing wind conditions.

Figure 6: Exposed valves emerge from thermal insulation and are not heat traced

Windbreaks

The third major component to winterization is windbreaks. Windbreaks are temporary or permanent structures used to prevent wind from blowing directly over exposed components and dissipating heat at an increased rate.

Figure 7: Temporary windbreak created with scaffolding and tarpaulin

Other Winterization Efforts

In addition to the three major winterization techniques, generating stations sometimes use other freeze protection measures. These include keeping water flowing to reduce freezing, draining liquids from valves, purging drained lines of water with compressed air, and installing space heaters in enclosed areas to raise ambient air temperatures.

Winterization Processes

Although designing freeze protection systems for exposed areas is critical to cold weather operation, preparation for freezing conditions is equally important. In order to achieve good freeze protection, a generator must know what areas are likely to freeze, and must take steps to ensure that appropriate procedures are put in place. The following paragraphs describe some of the steps that can be taken to prepare for winter, and discuss how the proper use of checklists can help plant managers implement effective winterization measures.

Winter Preparation

Preparation for winter weather should begin well before its arrival, and many generator operators in Texas and the Southwest start their winterization programs in the fall of each year. These procedures include verifying that installed heat tracing is working, components are properly insulated, space heaters are operational, fuel switching can be initiated, and instrument systems are free of moisture. Many generators also verify that their inventory of freeze protection equipment – such as heat lamps, heat guns, propane torches, tarps, de-icing

material, fuel, insulation, sand, and extension cords – is adequate for the upcoming season. Timeliness is an important aspect of pre-winter preparation – it should begin early in the season so that there is time to make necessary repairs before cold weather hits.

In addition to pre-season preparation, generating stations typically have a set of procedures that are initiated whenever a winter storm is expected. Much of the work that is done before a storm arrives is similar to pre-season preparation. However, the pre-storm procedures may include calling in additional operators and maintenance personnel, moving motor vehicles into garages, draining non-essential water lines, and moving portable heaters into position.

As winter weather sets in, generating stations may adjust their operations to protect against freezing conditions. Such changes may include switching instrument air to nitrogen backup, warming up standby boilers every two hours, opening bypass valves on steam traps, and rotating pumps every two hours.

A critical component of winterization plans is the opportunity for post-winter critiques and reports on lessons learned. Applying lessons learned is sometimes done informally but some generators go further, requiring plant managers to conduct post-winter meetings to identify necessary improvements and to file written reports on the plant's performance during the winter season.

Checklists

In order to ensure that all of the plant-specific tasks are properly completed, many generator operators create checklists for plant personnel to follow. Although the form of such checklists may vary depending on the size of the plant and the types and locations of the generating units, effective checklists tend to have certain characteristics.

Good checklists are sufficiently detailed to allow plant operators and maintenance personnel to adequately prepare for and deal with cold weather events. For example, a checklist may specify who is responsible for assigning personnel to freeze protection duty, or may identify specific tasks triggered by different freeze alert levels.

A checklist can be broken down not only by task, but also by area and by individual components or areas to be checked. For example, the checklist can specify which particular lines should be drained and which vents should be closed.

Appendix: Winterization for Generators

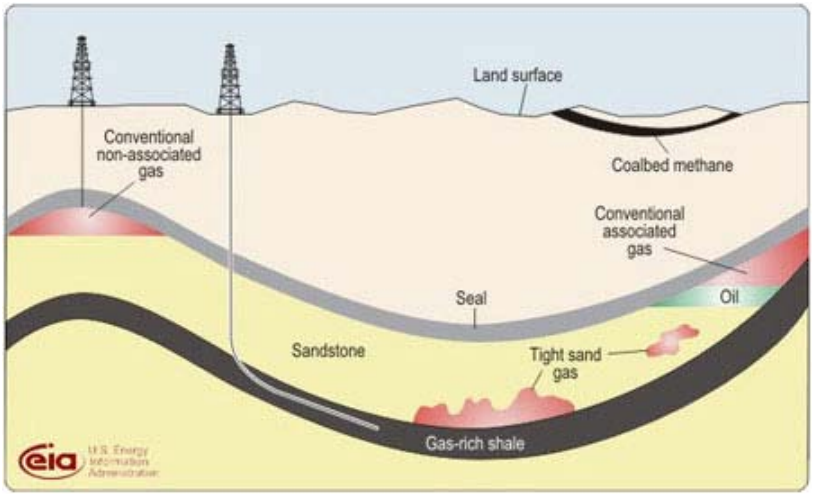
A list that is lacking in detail and that only includes general tasks such as turning off vent fans or checking boiler and duct air heater enclosures will not be effective. Plant employees might understand which components should be included in such general references, but non-specific descriptions are inadequate to ensure that all systems are identified and checked.

Checklists can also offer generating stations the ability to audit their performance in implementing winterization. A common feature of effective checklists is a requirement that employees initial and date the checklist for each task completed. Not only does this provide confirmation that the tasks were completed, but it also holds operators and maintenance staff accountable for their performance.

Appendix: Natural Gas – Production and Distribution

What Is Natural Gas?

Natural gas is a highly compressible, naturally occurring mixture of hydrocarbons, principally containing methane, that migrate upward through geological formations until the migration is halted by a physical barrier that allows the natural gas to accumulate in the small pore spaces within a geological formation, or reservoir. The physical barrier is a non-permeable formation that is known as a reservoir seal or caprock. The type of formation where the natural gas can accumulate, which can include sandstone, coal as well as shale, depends upon the location of deposition of the original organic material and the geologic formations that lie above. To access the natural gas that has accumulated within the reservoir, drilling companies will drill down to the formation using drilling rigs that punch into the formation using drill bits and long string pipes to bring the natural gas to the surface at the well site.



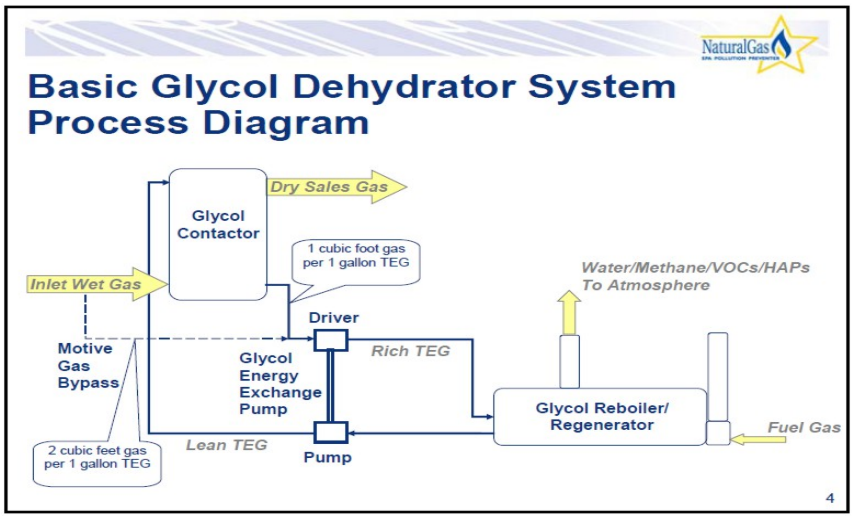
(Energy Information Administration)

While in the ground, the natural gas is under high pressure. When these formations are produced, the natural differential in pressure, between the high pressure in the formation and lower pressure at ground level, can provide the driving force to move the gas to the surface. The company in charge of producing the natural gas, by allowing the natural gas to flow from the subsurface formation up to the surface, will drill several wells to maximize its ability to produce the natural gas while maintaining the integrity of the reservoir within the geological formation to ensure a long and active production life.

As part of the natural gas stream that reaches the surface and is produced from the wellhead, there are many other gas constituents other than methane. Heavier hydrocarbons, such as ethane, propane, butane, and pentane plus, are also produced along with the methane-rich gas stream. After production, these heavy hydrocarbons or natural gas liquids (NGLs) can be removed through processing and sold separately from the natural gas. Other gases, such as hydrogen, carbon dioxide, nitrogen, oxygen, sulfur, and hydrogen sulfide, are also produced, and most of the gases will be removed from the

natural gas stream through the use of treating plants. Unlike NGLs, some of these gases are undesired impurities with little or no commercial value.

Another common byproduct of natural gas production is water. Just as natural gas can migrate through geologic formations and into reservoirs, water and crude oil can follow the same process. Water that accompanies natural gas is removed through the use of dehydration facilities located at or near the wellhead.[1] The water is then commonly injected back into the outer limits of the reservoir's geological formation to help produce additional natural gas from the reservoir by displacing the natural gas from the pore spaces within the geologic formation and push the natural gas toward the producing wells. Unless water is removed from the gas stream, it can freeze in the pipeline and stop the flow of gas from the wellhead.



(Environmental Protection Agency)

Over time, multiple wells are drilled into the formation in order to maximize production of natural gas in the reservoir. After each well is tested and examined by the production company, the wells are connected through a series of pipelines increasing in diameter as more gas is gathered and transported through the gathering pipeline.

[1] The dehydration of natural gas usually involves one of two processes – absorption or adsorption. Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface. The absorption process requires a chemical with an affinity for water, such as glycol, which is the most commonly used dehydration agent. After absorbing the water, the glycol falls out of solution to the bottom of the tank where the water-rich glycol is removed. The adsorption process is a physical-chemical process in which the gas is concentrated on a surface of a solid or liquid to remove the impurities. Natural Gas Supply Association, Processing Natural Gas, *available at* http://www.naturalgas.org/ naturalgas/processing_ng.asp (last visited Aug. 5, 2011); Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 262 (Elsevier 2006).

Depending upon the impurities in the natural gas stream, the pipeline will funnel the natural gas stream to processing and treatment plants. The treatment plants are used to remove impurities and other objectionable material usually before the natural gas stream is transported to the processing facilities.

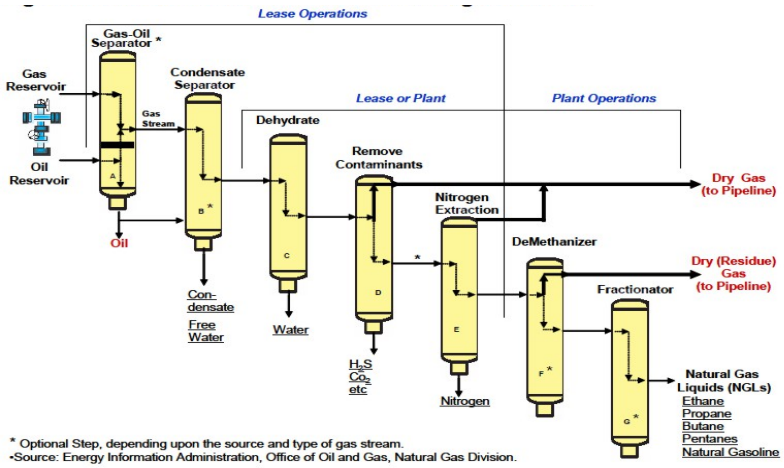
The natural gas stream often contains other contaminants that must be removed before the natural gas stream is delivered to downstream pipelines. Some of these contaminants are hydrogen sulfide, carbon dioxide and other sulfur-based impurities, which are sometime referred to as "acid gas."[2] When hydrogen sulfide combines with water in the natural gas stream, sulfuric acid forms. Similarly, carbon dioxide that combines with oxygen forms carbonic acid. These acid gases can cause damage which, if left unchecked, could lead to pipeline failure.[3]

The processing plants typically remove NGLs through a refrigeration process that involves a form of rapid cooling of the natural gas stream. Two types of this cooling process are mechanical refrigeration, as used in lean oil absorption, and turbo-expander or cryogenic process. The technology used will depend upon the age of the processing facilities as well as the desired result. Mechanical refrigeration is a process whereby the natural gas stream is chilled by a vapor compression refrigeration process, similar to the process used by a refrigerator or an air conditioner, but producing much colder temperatures. This is coupled with the use of glycol as an absorption fluid that combines with the NGLs and falls out of the gas stream. In the cryogenic process, the high pressure natural gas stream is rapidly expanded by decreasing the pressure. This process causes the gas stream to cool rapidly (Joule-Thomson Effect)[4] to temperatures that will cause the NGLs to move from a gaseous phase to a liquid phase. The NGLs fall out of the gas stream and are collected for sale and additional processing. The residual gas, from which the NGLs have been removed, is transferred to a downstream pipeline for transmission to end users. Both of the above processes are effective means for recovering NGLs and for reducing the possibility that NGLs will condense and fall out of the gas stream as liquids that could cause damage to downstream equipment.

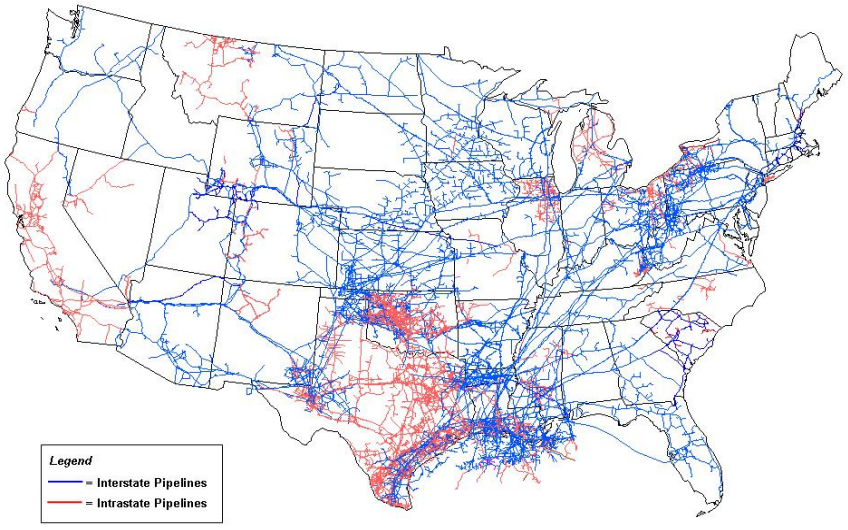
[2] Natural gas containing hydrogen sulfide is considered "sour" gas while natural gas without hydrogen sulfide is considered "sweet" gas. *Id*. at 261.

[3] Frøydis Eldevik, *Safe Pipeline Trasmission of CO2,* Pipeline & Gas J., April 2011, Vol. 238 No.4, p. 3, *available at* http://www.pipelineandgasjournal.com/safe-pipeline-transmission-co2?page=3 (last visited Aug. 5, 2011).

[4] Joule-Thomson Effect is the change in temperature or cooling effect resulting from the rapid expansion of pressurized natural gas through a valve.



After treating and processing, the natural gas can be transported to market centers by the intrastate and interstate pipeline system. This network is made up of more than 210 pipeline systems with over 305,000 miles of varying diameter pipeline, 1,400 compressor stations, and 400 underground storage facilities, all connecting the various natural gas production areas, both onshore and offshore, to multiple markets throughout the United States.[5]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Types of pipeline systems

The interstate pipelines can divided into two types of systems – long-haul and reticulated. Long-haul pipelines receive natural gas supplies from producers and

[5] U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas, available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

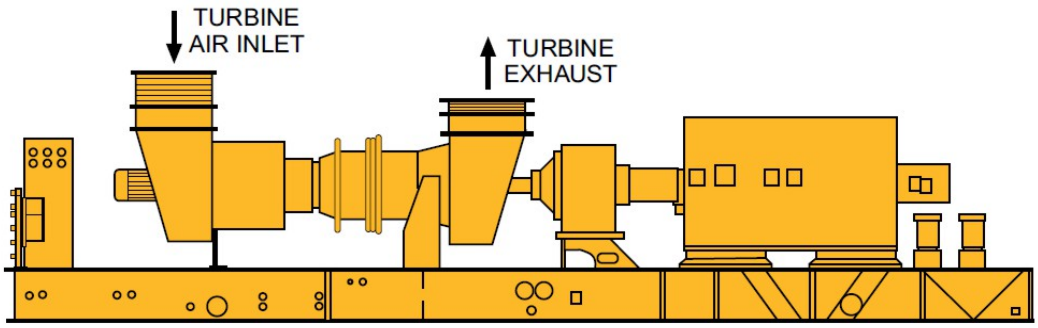
processors and transport it across hundreds of miles to market areas outside the production areas. Reticulated pipelines resemble a spider web that overlays both the supply areas and the market areas, and typically have multiple lines that can change direction of gas flow through the system, depending upon market needs.

Pipeline Design

A natural gas pipeline system can be as simple as a single diameter pipe receiving gas from one source and transporting it to a single delivery point, or as complex as a network of multiple diameter pipes covering hundreds of miles with compressor stations, storage facilities, and numerous receipt and delivery points. In order to move natural gas supplies from the supply areas to the market areas, a pipeline must be designed to transport the required volume of gas supplies, while maintaining system pressures along the length of the pipeline necessary to serve its shippers.

The design of all pipeline systems starts with the same basic idea, the need to transport a specific volume of natural gas from at least one supply source to a specific destination while maintaining contractual delivery pressure obligations. Due to frictional loss resulting from the gas flow, the pressure of the gas stream will decrease. Compressor stations are designed to re-pressurize the gas stream in order to overcome the pressure losses associated with movement of gas in a pipeline. Compressor stations are above-ground facilities where the pipeline connects with large individual compressor units through various smaller pipelines or "yard piping" as well as meter and regulation equipment. Compressors are mechanical devices that increase the pressure of the gas stream. After the gas stream has been re-pressurized, the gas re-enters the pipeline for further transmission to downstream markets. Compression facilities are needed along the length of the pipeline, and are typically placed at 40 to 60 mile intervals.

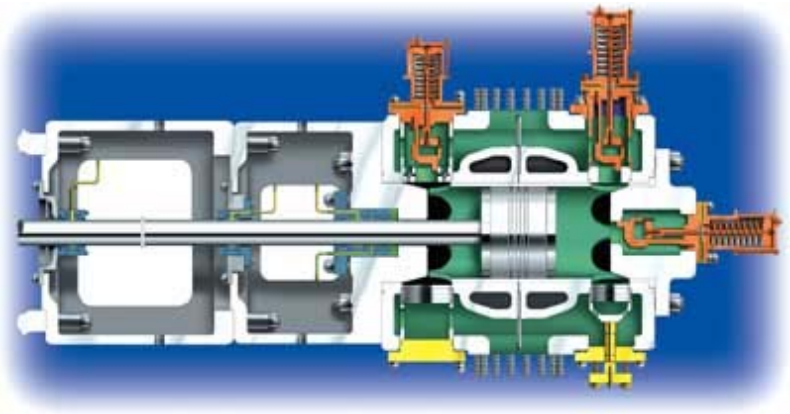
Compressors are split into two basic parts, the compressor and the driver, or motor. The motor, which can be fueled by electricity or gas-fired, powers the compressor unit that compresses the gas. The two types of compressors that are most commonly used by the interstate natural gas companies are centrifugal and physical displacement or reciprocating compressors. Centrifugal units are turbines that spin at high rates of speed to compress and accelerate the gas stream. These compressors are used to accommodate high flow rates at high pressures. Most interstate pipeline systems use centrifugal compressor units on their mainlines. The following is an illustration of a centrifugal compressor and gas-fired motor.



(Solar Turbines Incorporated (a Caterpillar Company))

The gas stream enters the inlet or suction side of the compressor unit, where it is forced through the rotating turbines at high speed and exits the compressor at the discharge side, moving back into the transmission pipeline. With gas-fired compressor motors, a small amount of natural gas is funneled from the gas stream at the suction side to provide fuel for the motor.

Reciprocating units increase the pressure of the gas stream by compressing or reducing the volume of the gas through the use of pistons within a cylinder similar to the pistons in a car engine. These compressors can be found on interstate pipelines' mainline systems, which need to compress gas volumes with greater pressure differentials. Storage facilities also utilize reciprocating compressors to inject gas supplies received from pipeline systems at pressures ranging from 500-1,000 psig, into storage caverns at pressures that can exceed 2,000 psig. Just like the motors used by gas-fired centrifugal compressors, a small amount of natural gas is taken from the gas stream to provide fuel.



Reciprocating Compressor Cylinder Assembly (machinerylubrication.com)[6]

[6] "Reciprocating Compressor Basics," *available at* http://www.machinerylubrication.com/Read/775/reciprocating-compressor (last visited Aug. 5, 2011).

Line pack

Line pack is the volume of gas in the pipeline at a given point in time. Pipeline operators use line pack to maintain system operating pressures while accommodating the system's highly variable load requirements.

Most gas supplies enter a pipeline system at a relatively even hourly rate, or about 1/24th of the total amount of gas per hour (4.17 percent per hour) for the entire day, also known as "steady-state" conditions.[7] On the demand side, deliveries rarely leave the system at an even hourly rate. Deliveries are not constant primarily due to variations in demand caused by inlet and outlet flow changes, non-performance of receipt or delivery points, scheduled or unscheduled maintenance, and compressor startups and shutdowns.[8] Flow conditions that vary over time are known as transient flow conditions. Depending upon the flexibility provided by the interstate pipeline within its tariff or contract with the customer, the hour rates for gas delivery could be 5 percent and even up to 8 percent per hour. These hour rates are equivalent to a 20 hour to a 12.5 hour day, or simply stated, the customer can take the entire scheduled and confirmed quantity of gas for the entire 24-hour gas day in as little as 20 to 12.5 hours. Managing these transient loads could not be done without actively managing system line pack.

In order to prepare for the upcoming gas day, the pipeline operator will increase system pressures by increasing the use of available compression horsepower at compressor stations strategically located along the pipeline system. The increase in pressure will allow the pipeline operator to "pack" the pipes with additional gas from other portions of the pipeline system located closer to the supply points. Further, depending upon demand forecasts for the upcoming gas day, customers will often increase their receipts in order to ensure that they will be able to meet their load requirements. Unlike electricity, which is added to the transmission lines instantaneously, natural gas must be physically moved through the pipeline from the supply areas to the market areas for delivery. Depending upon the length of the pipeline system, this physical transportation of gas from the supplier to the end user can take days. Most interstate pipeline systems move gas at speeds between 20 and 30 mph. If the pipeline has its origin in the Gulf of Mexico and the destination is the New York City market area, 1,500 miles away, the gas will need roughly two days to travel that distance

[7] Steady-state flow conditions exist when the gas volumes both received into and delivered out of the pipeline system are equal at every moment in time while the pipeline is operating at a constant pressure and temperature. For example, a pipeline is said to operate under steady-state conditions when 1/24th of the gas volumes are entering the system every hour while simultaneously 1/24th of the gas volumes are leaving the pipeline system every hour. Gas volumes going into the system must equal the gas volumes leaving the system to be considered steady-state conditions.

[8] Saeid Mokhatab, William A. Poe & James G. Speight, Handbook of Natural Gas Transmission and Processing 414 (Elsevier 2006).

at 30 mph. This is why it is critical for pipeline systems to receive gas supplies nominated, scheduled and confirmed in order to replace the system line pack in a timely manner.

Maximum Allowable Operating Pressure

The Maximum Allowable Operating Pressure (MAOP) is one of the many design assumptions that will limit either a pipeline's design capacity or peak day capacity. The MAOP, which represents the maximum pressure at which a pipeline may operate its system,[9] is an operational or safety-based constraint that protects the integrity of the pipeline system while defining an upper capacity limit. As such, the MAOP will act as a physical constraint[10] that the pipeline companies' system design engineers must address with each pipeline expansion project before the Commission.

When a pipeline company files an application to add a new service or to expand its existing facilities, it will look to the Commission's regulations (18 C.F.R. § 157.14(a)(7)-(9)(vi)) for guidance. Under these regulations, the pipeline company is required to provide to the Commission flow diagrams reflecting "Daily Design Capacity" and "Maximum Capabilities" for both its existing and proposed facilities. Currently, most of the interstate pipeline companies justify the need for facility augmentation through the use of a steady-state model of their respective systems while operating under design peak day flow conditions. These models are designed to meet the pipeline's firm contractual obligations while maintaining: (1) the volumetric requirements of its existing firm shippers; (2) the minimum contractual delivery pressure obligations; (3) controlling pressures located at critical points on their system; and (4) the full utilization of the existing available capacity through the use of all available compression horsepower along the path of the new service.

Implicit in the pipeline companies' design process is the need to maintain actual operating pressures at or below the MAOP in order to maximize throughput levels on their respective systems. From the design perspective, this is a relatively simple task. In most cases the pipeline's design capacity is based upon maximum utilization of compression facilities while transporting gas volumes between primary contractual

[9] In its November 14, 2002 comments in Docket No. PL02-9-000, the Office of Pipeline Safety (OPS) stated that the purpose of setting regulatory standards for determining pipeline MAOP is to "prevent pipeline failure that could result from excess operating pressure, startup and shutdown." OPS defines MAOP as the maximum pressure at which a pipeline or pipeline segment may operate. The Office of Pipeline Safety, Comments in Response to Open Forum at the Natural Gas Markets Conference Oct. 25, 2002, Docket No. PL02-9-000 at 4 (filed 11/14/2002); s*ee also* 49 C.F.R. § 192.3.

[10] Physical constraint, or pipeline bottleneck, is a point on a system where the existing facilities are inadequate to accommodate 100 percent of the flowing capacity of the upstream pipeline facilities.

receipt and delivery points. Under these specific design assumptions, maintaining operating pressures at or approaching the MAOP will ensure that existing shippers will receive their gas requirements.[11] However, as previously discussed, the changing load requirements and the capacity release market could potentially reduce the pipeline's ability to maintain optimum operating pressures to meet new demands on its system if the new loads are not proximate to the traditional markets. The potential impact of new markets could reduce the operational flexibility of the pipeline by reducing the operating pressure. If the pipeline cannot maintain historical operating pressures that are necessary to meet the requirements of its shippers, the throughput capacity of the pipeline will be reduced.

[11] Scheduled and unscheduled maintenance is not incorporated into the pipeline's design capacity. As a result, required maintenance will reduce the pipeline's ability maximize throughput capacity and could prevent the pipeline from meeting its firm contractual requirements.

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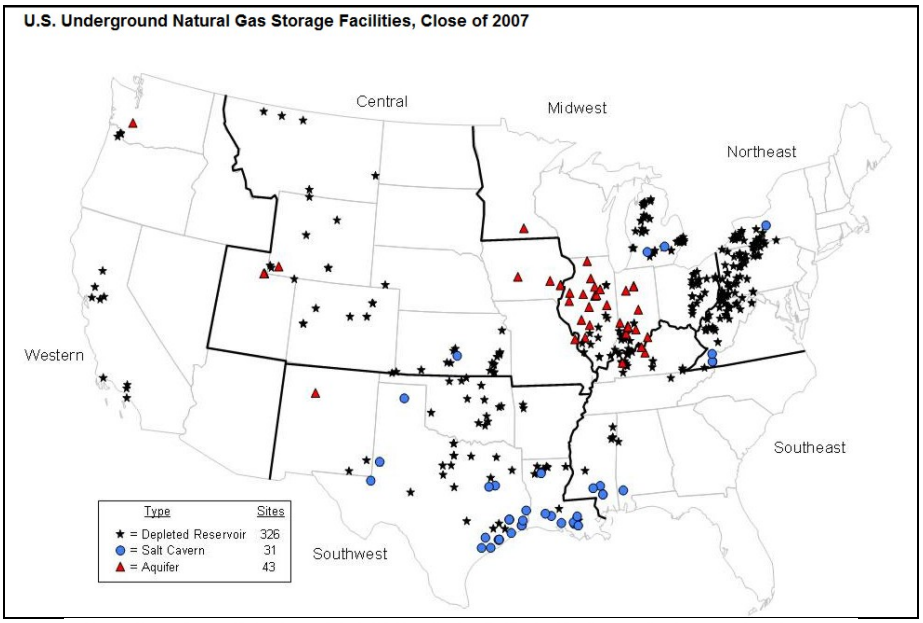
Appendix: Natural Gas Storage

Natural gas, like many other sources of energy, can be stored during periods of low use and called upon during periods of greatest demand. There are over 400 underground storage facilities, eight LNG import facilities and over 100 LNG peaking facilities located throughout the U.S.[1]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Base load vs. Peak load Storage Facilities

Storage facilities are designed to meet either base load or peak load requirements. Base load storage is designed to meet seasonal demand that exceeds the average deliverability of the pipeline system. Base load storage facilities have sufficient capacity to meet the long-term seasonal demand requirements for the pipeline's market areas. Historically, these storage facilities were used by the pipeline's customers to inject natural gas supplies into the storage facility during periods of low system use, such as the non-heating season (when gas prices are low), which typically runs from April 1 through October 31. These gas volumes were then withdrawn to meet base load requirements during the heating season, which usually runs from November 1 through March 31.[2]

[1] United States Energy Information Administration, *About U.S. Natural Gas Pipelines – Transporting Natural Gas, available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html (last visited July 20, 2011).

[2] This trend has changed in the last decade as newer and more efficient natural gas-fired electric generation facilities have replaced higher emission oil-burning facilities. As a result, more natural gas is needed during the spring and summer months to meet increased electrical demand for the summer cooling season. Now, instead of having one peak season, market areas served by some pipelines may have two peak periods, during both the summer and winter months.

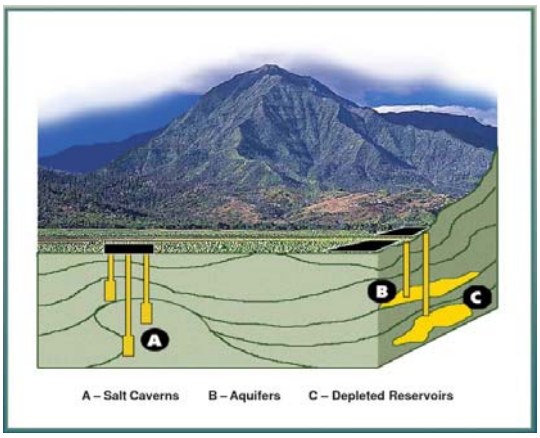
Base load storage facilities are usually large depleted oil or gas reservoirs that have relatively low withdrawal rates. They can provide a steady flow of natural gas and typically have turnover rates of once a year due in part to the length of time necessary to replenish the gas supplies. Depleted gas reservoirs are the most common type of base load storage facilities.

Peak load storage facilities, on the other hand, are designed to operate at high rates of withdrawal. These facilities are used to meet peak load requirements that can call for large amounts of gas over short periods of time. Peak load facilities are much smaller than base load facilities but can be quickly replenished – in some cases within days or weeks.

Different Types of Underground Storage Facilities

Three types of reservoirs or geological formations are used as underground storage facilities – aquifers, depleted reservoirs, and salt caverns. All of these formations must be developed or reworked in order to create the space necessary to provide the storage service. Natural gas is injected slowly into the formation through the use of compression facilities in order to build up the reservoir pressure necessary to allow the natural gas to flow freely from the storage facility directly into the downstream pipeline systems. Toward the end of the withdrawal season, when the prevailing reservoir pressures fall below the operating pressures of downstream pipeline systems, compression equipment that was used to inject gas volumes into storage is used to re-pressurize the gas stream so that gas from storage can be moved downstream into the pipeline systems.

Not all of the natural gas in storage facilities can be withdrawn. In order to maintain the integrity of the formation and to prevent migration of water into the reservoir, some natural gas must be left in the reservoir. This is typically called “base gas” or “cushion gas.” Similar to line pack in a natural gas pipeline, base gas is the volume of gas left in the reservoir to provide the pressure needed to extract the remaining gas. The gas that is withdrawn from the storage field is referred to as “working gas.” The amount of working gas within the reservoir represents the storage capacity of the facility.



Types of Underground Natural Gas Storage Facilities (FERC)

Depleted Reservoirs

Depleted gas reservoirs are the most commonly used formations for storage reservoirs. These formations are formerly producing gas reservoirs that have had all of the economically recoverable natural gas extracted, and which can be readily converted from production to storage. However, to maximize the usefulness of the facility, the reservoir should be located near a market area (for base load or peaking facilities) or a supply area, (to supplement supply when production is interrupted). The reservoir also must be located near a mainline pipeline facility. Most depleted gas reservoirs are located in production areas, leaving aquifers and salt caverns as the only option for storage development in other areas.

Aquifers

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. A porous rock formation has small spaces between the grains of rock where natural gas, oil and water can be found. A permeable formation is one where liquid can flow through small channels that connect the small pore spaces within the formation. Aquifers are the least desirable and most expensive types of natural gas storage facilities for the following reasons:

- The geological formations are not as well known as depleted reservoirs, which are explored during the development and production process. Accordingly, there is a significant cost associated with developing and studying the geological characteristics of an aquifer in order to determine its suitability as a storage reservoir.

- Aquifers do not have in place the facilities and equipment associated with a producing gas reservoir, such as extraction equipment, pipelines, dehydration facilities, and compressors. Aquifers may also produce large

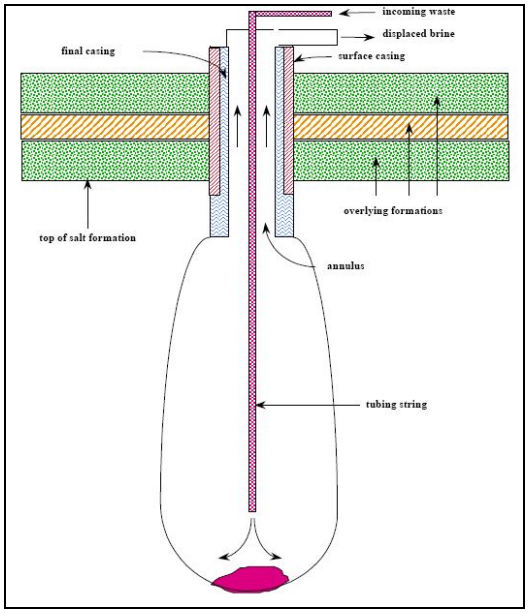
volumes of water as natural gas is withdrawn from storage, increasing costs.

- Development of an aquifer as a gas storage facility can take twice as long as development of a depleted reservoir facility.

Salt Caverns

A salt formation is a naturally occurring deposit of salt that may exist in two forms: salt domes and salt beds. Salt domes are formations that have migrated through sedimentary geological formations to form large domes of salt. These domes can be a mile wide and 30,000 feet thick. Salt domes most often used as salt caverns are generally found about 6,000 feet beneath the surface. Salt beds are not as thick or as deep – these formations are usually less than 1,000 feet thick and are less stable than salt domes, but both formations are well suited to natural gas storage.

Salt Cavern Underground NG Storage Reservoir
(Energy Information Administration)

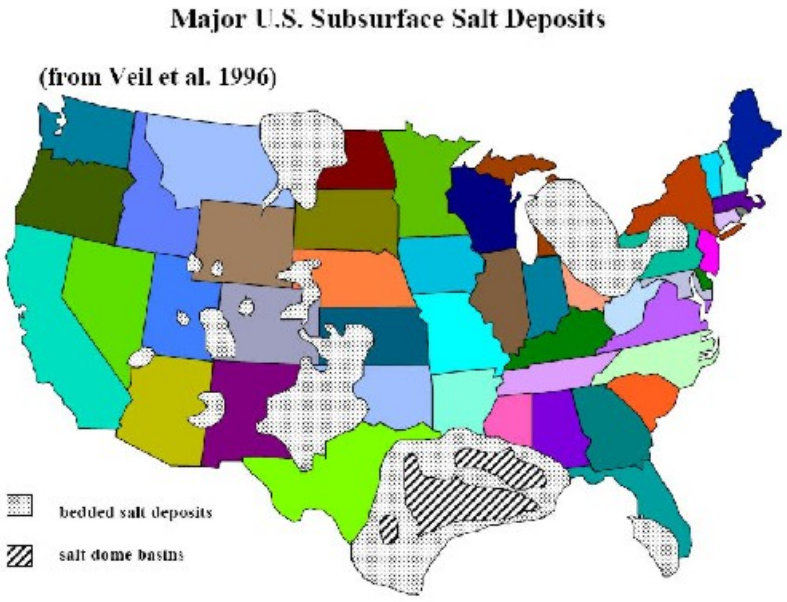


Salt Cavern Leaching
(Oregon National Laboratory)

Salt caverns are developed by drilling into the salt formation and circulating large amounts of water under high pressure to dissolve and extract the salt, leaving a large void. This process is known as "salt cavern leaching."[3] Once created, the salt cavern offers an underground vessel-like structure that can provide very high rates of delivery.

[3] Salt Cavern Storage, *What is Salt Cavern Storage? available at* http://www.saltcavernstorage.com/what-is-salt-cavern-storage.html (last visited July 20, 2011).

Salt caverns provide another operational benefit, in that they can operate with less base gas than depleted reservoirs and aquifers.



(Oregon National Laboratory)

Because salt cavern storage reservoirs are typically much smaller than depleted gas reservoirs, they cannot hold the volumes necessary to meet base load storage requirements. However, because the deliverability of the salt caverns is typically much higher, gas stored in these facilities can be more quickly withdrawn and replenished than gas stored in any other type of facility.

LNG and LNG Peak Shaving Facilities

Liquefied natural gas (LNG) is natural gas that is stored and transported in liquid form at -260 degrees Fahrenheit. In liquefied form, the gas volume is reduced by a factor of 610. This reduction in volume makes the transportation and storage of liquefied natural gas more practical.

In order to introduce LNG into the pipeline system, the LNG must be warmed and re-gasified. This is done at specially built re-gasifier terminals attached directly to the interstate pipeline grid or to LDC distribution systems.

LNG can also be produced on a much smaller scale at liquefaction facilities, which receive natural gas directly from the pipeline system, convert it to liquid form, and store it in above ground facilities until needed to meet peak load requirements. These facilities are referred to as “peak shaving” plants.

Appendix: Natural Gas Storage

LNG Peak shaving plant (Energy Information Administration)

Appendix: Natural Gas Transportation Contracting Practices

Interstate natural gas pipeline rates for transportation of natural gas may be based on distance transmitted (zone matrix) or on a "postage-stamp" basis, where all consumers pay the same rate regardless of distance transmitted. Natural gas pipelines' tariffs may contain rates based on a function of the volume reserved for a particular buyer (a set capacity charge) and a variable based on the pipeline volume actually consumed by the buyer (a commodity charge). Gas is sold by unit of energy, not by volume. Prices are usually stated in price per unit of energy, such as dollars per million British thermal units (Btu), rather than price per unit volume, such as dollars per thousand cubic feet (Mcf). Interstate natural gas transportation tariffs are often priced per thermal unit or energy unit, not on a volumetric basis.

The wholesale market is composed of both the natural gas commodity market and the transportation market. Since 1984, when FERC Order No. 436 was issued, large numbers of industrial customers, electric generators, and end use customers have been buying gas from parties other than the pipelines or LDCs. After the issuance of FERC Order No. 636 in 1992, the industry witnessed a dramatic growth in the use of marketers to provide gas, arrange transportation, or provide both services to LDCs, industrials, retail users, and electric generators.

Gas customers use marketers in a variety of ways. LDCs, which hold firm transportation rights on a single pipeline, can use the marketer to obtain and deliver gas to an interconnect point on that pipeline, and the LDC can use its firm transportation service to deliver that gas to its citygate delivery point. Other customers, such as industrials, may employ a marketer to acquire gas and interstate transportation service to deliver the gas to the industrial's citygate delivery point. Increasingly, marketers are offering additional services to customers such as asset management services, where the marketer manages capacity for LDCs, as well as providing price hedging, financing, and risk management services.

The transportation market also has developed to provide shippers with alternative means of acquiring capacity. Shippers can choose either short or long-term services from the pipeline or can acquire capacity from other shippers through the capacity release mechanism.

The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires capacity on interconnecting pipelines and schedules gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points not on a single pipeline company's system.

Nominations, Confirmations, and Scheduling

The North American Energy Standards Board (NAESB) is an independent, industry-supported entity whose primary purpose is to set business standards across the industry. The Commission's standards relating to nominating, confirming, and scheduling gas across the interstate pipeline system were developed by industry representatives in conjunction with NAESB. The nomination, confirmation, and scheduling processes control the movement of gas across the interstate pipeline system.

Nominations

A nomination is a request for service under any transportation agreement by a gas purchaser (referred to as the shipper) to transport gas from a specified receipt point to a specified delivery point over a specific time period. In short, a nomination is the request for space in a pipeline to ship gas. Pipelines use the nomination process to coordinate and reconcile gas from different shippers on their pipelines.

A shipper purchases capacity on a pipeline by entering into a service agreement with that pipeline. For example, a shipper may have a firm transportation agreement with Pipeline A for 100,000 dekatherms (DTH) per day of service. Since the agreement is firm in nature, as opposed to interruptible, the shipper pays for that full capacity whether it uses it or not, and has priority for that capacity on the pipeline.

On a given day, the shipper may not need the full 100,000 DTH of capacity, but might need, for instance, 75,000 DTH to meet its needs. The shipper will thus nominate 75,000 DTH for that day, and the pipeline can then schedule the unused 25,000 DTH of available pipeline capacity to another shipper as interruptible transportation.

The industry-standard gas day begins each day at 9:00 AM central time, and runs for 24 hours. In order to standardize nominations across the interstate pipeline system, FERC has implemented four time cycles where shippers may nominate gas (or change their nominations) over the course of each gas day. These nomination cycles follow the NAESB standards. While this is the minimum number of nomination cycles that a pipeline must have in its tariff, some pipelines offer more nomination options.

The first of the four standard nomination times is the "timely nomination cycle." Under the timely nomination cycle, shippers must make their nominations

by 11:30 AM the day before the gas is to flow. The pipeline will acknowledge receipt of the nomination by 11:45 AM and will issue its final confirmations by 3:30 PM and post scheduled quantities by 4:30 PM. Gas under the timely nomination cycle will flow at 9:00 AM the following morning, which is the beginning of the gas day.

The second nomination cycle – which also occurs prior to gas flow – is the "evening nomination cycle." Shippers must make their nominations for this cycle by 6:00 PM the day before gas flows, and the pipeline will acknowledge receipt of the nomination by 6:15 PM, issuing its final confirmations by 9:00 PM and posting scheduled quantities by 10:00 PM. Gas under the evening nomination cycle will flow at 9:00 AM the following morning. During the evening nomination cycle, the firm shipper can adjust his nomination to his full contractual capacity for the next day, taking precedence over, or "bumping," an interruptible shipper's nomination.

The two remaining cycles are known as intra-day nomination cycles, since they occur while gas is flowing during the same gas day. Under the intraday 1 nomination cycle, shippers must make their nominations by 10:00 AM on the gas day. The pipeline will acknowledge receipt by 10:15 AM, issue its final confirmations by 1:00 PM, and post scheduled quantities by 2:00 PM. Gas under the intraday 1 nomination cycle will flow at 5:00 PM on that gas day. The same bumping procedures apply to the intraday 1 nomination cycle. The intraday 1 nomination cycle is the first opportunity for shippers to adjust their gas flows during the gas day.

For the intraday 2 nomination cycle, shippers must make their nominations by 5:00 PM, and the pipeline will acknowledge receipt of the nomination by 5:15 PM, issue its final confirmations by 8:00 PM, and post scheduled quantities by 9:00 PM. Gas nominated under the intraday 2 nomination cycle flows at 9:00 PM on the same gas day.

Bumping rights do not apply to the intraday 2 nomination cycle. FERC implemented this no-bumping rule for the intraday 2 nomination cycle because shippers bumped this late in the gas day would be unlikely to be able to arrange alternative transportation.

Confirmations

Once a nomination is received by the pipeline or the party providing the requested service, the nomination must be confirmed. The confirmation process verifies that (a) the shipper agrees to supply the nominated quantity to the pipeline

for transportation, and (b) the pipeline agrees to transport the nominated quantity, based on the availability of capacity. The confirmation process provides a degree of assurance to the parties that gas will be delivered, and is also important for record keeping purposes.

Scheduling

For each nomination cycle, once the shippers nominate gas on a particular pipeline, it is the pipeline's responsibility to schedule the gas. Scheduling refers to the process by which nominations are consolidated by receipt point and by contract, and verified by upstream and downstream parties. If there is enough capacity to accommodate all nominations, then all nominated quantities will be scheduled. If the nominated capacity exceeds the available capacity on a pipeline, quantities will be allocated according to what is referred to as scheduling priorities. Shippers with a higher priority service will receive their capacity before shippers with a lower priority service.

Scheduling priorities for each pipeline are set forth in that pipeline's tariff. Although scheduling priority specifics may differ from pipeline to pipeline, all follow a general priority model. In general, primary firm shippers are given highest priority. Firm shippers are shippers that have entered into firm transportation agreements with pipelines. Firm shippers reserve a volume of capacity on a pipeline and pay for that capacity whether they use it or not. Each transportation agreement specifies a primary receipt and delivery point for service under the agreement. In some cases, the agreements may set forth multiple primary receipt and delivery points that can be used. When the shippers take service under the primary receipt and delivery points set forth in the agreement, they are considered primary firm shippers, and receive the highest priority of service.

In general, secondary firm shippers are given the second highest service priority. Under FERC policy, shippers may use receipt and/or delivery points for service other than the primary points set forth in their agreements, but only if capacity is available at those points. These alternate points are referred to as secondary points. In general, when a firm shipper takes service under secondary receipt and/or delivery points, that shipper no longer has the highest priority of service, but rather the second highest service priority. These secondary firm shippers get their gas scheduled after the primary firm shippers.

Interruptible shippers are generally given the third highest priority service. Interruptible service is service that is not guaranteed. Whereas firm shippers pay for the capacity whether they use it or not (and are given highest priority on that

capacity), interruptible shippers only pay for transportation capacity when it is used.

Pipelines implement various methods for allocating interruptible capacity. One method is to schedule interruptible nominations *pro rata*, whereby all shippers with interruptible capacity have a proportional share of their capacity scheduled. Another method is based on economic ranking, where shippers who pay more for their interruptible capacity receive priority over shippers who pay less. A particular pipeline's practices for scheduling interruptible capacity will be set forth in the priority provisions of its tariff.

Nominations and Scheduling on Intrastate Natural Gas Pipelines

The NAESB standards do not apply to intrastate pipelines, which follow their own scheduling practices. Only thirteen percent of the member companies of the Texas Pipeline Association that responded to an informal poll reported that they accept electronic nominations, and none indicated that they follow the NAESB standards.

In Texas, intrastate pipelines schedule gas transportation five days a week, with no weekend scheduling. Some intrastate pipelines do not schedule volumes at particular delivery points on their systems, but instead accept nominations from customers, typically LDCs, that can have hundreds of delivery points. These customers do not schedule volumes at a particular point, but submit a nomination that covers all of their points, with the right to obtain delivery at any of them.

The Commission requires major non-interstate pipelines to post scheduled volumes no later than 10:00 PM central time the day before gas is to flow. This deadline occurs after interstate natural gas pipelines are required to post their evening cycle schedule confirmations by receipt and delivery point.

Imbalances

A point imbalance is the difference between the volume of gas that is scheduled to flow at a receipt or delivery point, and the volume of gas that actually flows through the point (typically determined by meters). A transportation imbalance is the difference between net receipts under a specific agreement (total receipts minus any fuel receipts), and total deliveries made under a specific agreement. When an imbalance occurs on a pipeline system, the pipeline must resolve that imbalance to keep all parties whole. There is no single method pipelines use to handle system imbalances. Instead, each pipeline resolves

imbalances in accordance with the imbalance provisions set forth in its FERC NGA Gas Tariff.

Operational Balancing Agreements

An operational balancing agreement (OBA) is a contract between two physically interconnected parties specifying the procedures to be used in processing imbalances or differences in hourly flows between the parties. An OBA ensures that a shipper, once it has properly nominated and had its gas confirmed, will not be subjected to imbalance penalties resulting from the transfer of gas between the pipelines. In Order No. 587-G, the Commission adopted a requirement that each interstate pipeline enter into an Operational Balancing Agreement at all points of interconnection between its system and the system of another interstate or intrastate pipeline. That requirement is codified in section 284.12(b)(2)(i) of the Commission's regulations.

Impact of Cold Weather on Gas Production in the Texas and New Mexico Gas Production Regions of the United States During early February, 2011

Winterization Document

Prepared for Federal Energy Regulatory Commission

Prepared by Gas Technology Institute
Kent F. Perry

July, 2011

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Introduction

Colder-than-normal weather during the first week in February led to the biggest non-hurricane natural gas supply disruption in the United States since at least 2005.

Due to a combination of well freeze-offs (gas flow blockages resulting from water vapor freezing in the gas stream) and other temperature-related well failures, processing plant shutdowns, electric power outages, and pipeline operational issues, estimated daily natural gas production fell from about 62 billion cubic feet per day (Bcfd) to less than 57 Bcfd, a decrease of 8%. (Ref. 1)

The cold weather likely impacted thousands of natural gas wells in Texas and Louisiana, home to one-third of U.S. gas production. Because it rarely freezes in these southern U.S. latitudes gas wells aren't built to withstand the phenomenon called "well head freeze off." That's when the small amount of water produced alongside the natural gas crystallizes inside pipelines, completely blocking off the flow and shutting down the well.

In particular, along with the cold weather came severe icing conditions. Icy roads inhibited the movement of water hauling trucks in particular and the ability to access wellheads. The result was that fail safe switches on water and condensate storage tanks at wellheads and at compressor stations were activated. The fail safe switches are designed to shut down operations to prevent spills. (Ref. 2)

This report focuses on gas well winterization technology that is deployed in colder climates and discusses to what degree they might be applied to the impacted production areas (Texas and New Mexico) addressed with this study.

The Phenomena of Wellhead Freezing and Cold Weather Impact on Gas Production Operations

Freezing is a potential and serious problem starting at the production wellhead through the last point in the customer delivery system. The occurrence of freezing is continuously reduced each step of the way, but care must be taken at each and every step to assure smooth operational conditions and satisfied consumers at the end of the line. Freezing not only affects the wellhead and gas pipeline but is also a significant contributor to measurement errors, instrumentation upsets or failures and other regulation equipment that can be found at compressor stations, gas processing plants, regulator stations and other critical points of operation. (Ref. 3)

Many criteria can have an impact on the freezing issue including:

- Gas quality and composition
- Wellhead and wellbore design and configuration
- Piping designs, regulation or restriction points

- Instrument take-off points
- Other

Three areas will be reviewed as to the potential for freezing due to cold weather conditions:

1. The reservoir, wellbore and wellhead environment.
2. The gas well production facilities located at or near the wellhead.
3. The gas gathering system including compressor stations and gas processing plants.

Potential for Freezing - Within the Reservoir, Wellbore and Wellhead

Natural gas resides in geologic formations for time periods of millions of years (geologic time). Over this extended time period the gas becomes saturated with water. The volume of water that natural gas can carry as water vapor is a function of pressure, temperature and gas composition. Figure 1 is a schematic of a gas reservoir (Barnett shale in this example), its gas quality, reservoir conditions and gas flow pathway from the reservoir to the surface. The gas flows from the reservoir through perforations in the pipe (casing) and then up through the production tubing, through the wellhead and then to production facilities.

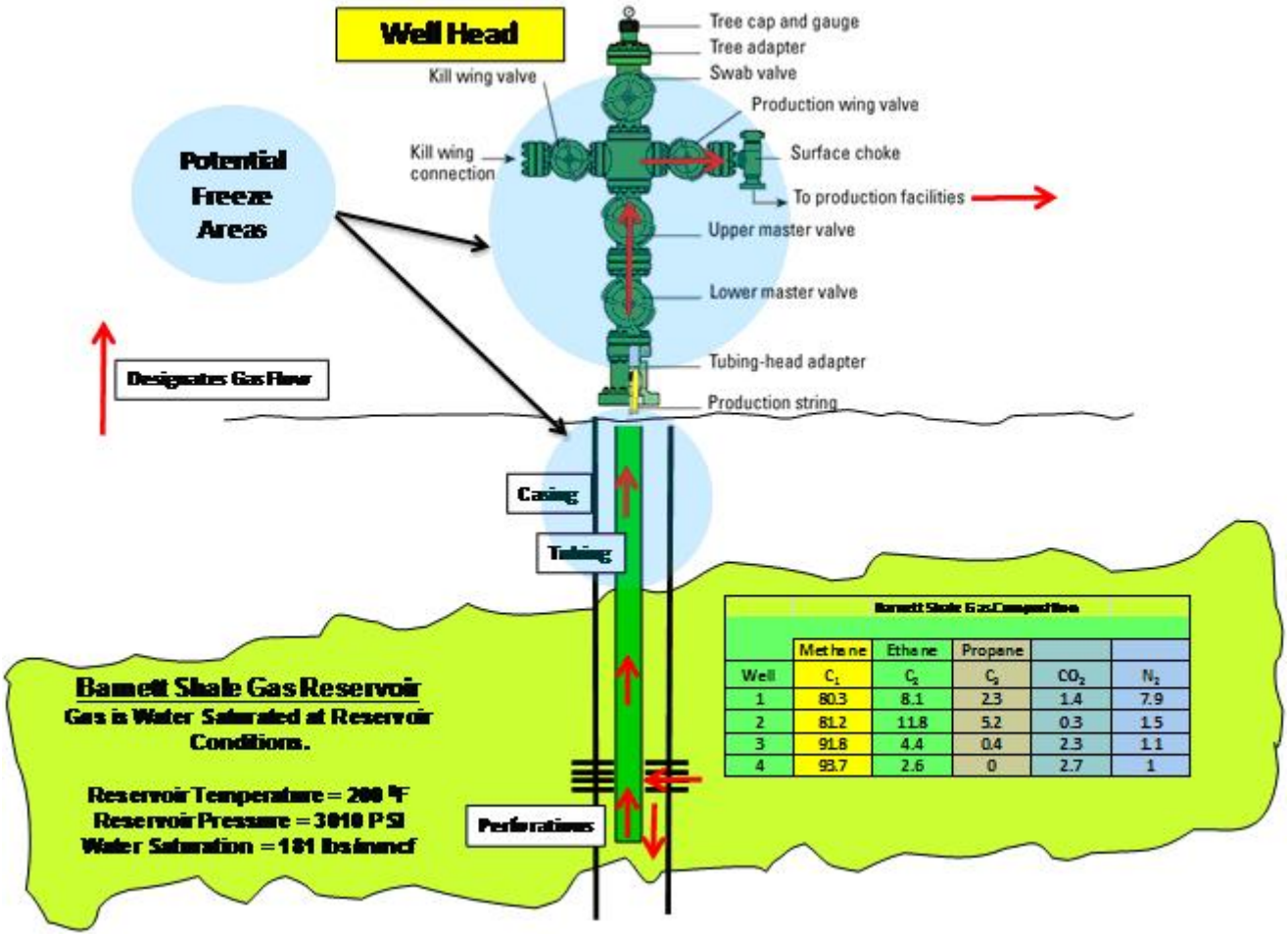

Figure 1 – Schematic of Gas Reservoir (Barnett Shale as example), wellbore and wellhead flow paths to Production Facilities, (Ref. 4&5) (Figure from GTI)

Under the Barnett example reservoir conditions the gas can hold as much as 181 lbs of water per mmcf of natural gas. For production operations, 7 lbs of gas per mmcf is considered to be dry gas, or at least dry enough for safe and efficient transportation of the gas without undo problems due to water fallout or freezing. Many natural gas compositions include not just methane CH_4 but also heavier hydrocarbons such as ethane and propane. In the Barnett example, the composition of well #2 contains over 11% ethane and 5% propane. The existence of these heavier hydrocarbons can facilitate the formation of hydrates (a combination of hydrocarbons and water that form ice under conditions well above freezing). Hydrates are discussed in more detail later but for this discussion can be thought of as ice capable of reduction or complete blockage of gas flow. (Ref. 4 &5)

As the gas flows up the production tubing and nears the surface it experiences a drop in pressure and can also be cooled by gas expansion (Joule Thompson effect) and exposure to cold ambient temperatures at the surface. The Joule-Thomson rule of temperature effect as a result of pressure reduction is such that temperature will decrease approximately 7 degrees Fahrenheit for every 100 psi

pressure reduction. As an example, if you can have gas flowing at 60 degrees Fahrenheit and 700 psi and you may have no evidence of freezing. If you pass through a flow choke and cut the pressure to 225 psi, the flowing temperature at the point of regulation will drop 33 degrees to approximately 27 degrees Fahrenheit. If the gas stream is saturated with water vapor and condensate, you will quickly experience freezing. The gas stream is the same, but conditions have changed and icing problems can impact your operations. (Ref. 3 &4)

The presence of ice or hydrates can not only shut off the pipeline, but can also alter measurement. If ice forms on the rim of the orifice plate, the flow measurement will be in error as a result of the reduced orifice diameter. If ice forms in the instrumentation supply lines, controllers will cease to function causing a loss of control of the system. Ice can block off sensing ports and other vital instrument readings. Once the ice begins to thaw, problems are still going to be present. On the initial start-up of a new or cold well, probes, intrusive instruments and orifice plates should have been removed from the pipeline. Large balls of ice traveling down the pipeline can do physical damage to the pipeline itself and to any object protruding into the pipeline such as sample probes, temperature probes, meters, orifice plates and similar intrusive devices. After the flowing stream has stabilized and temperature conditions are above the hydrate point, these items can be safely re-installed. (Ref. 3 &4)

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in Table 1. See also Figure 1.

Table 1 – Points of Freezing Potential in the Reservoir, Wellbore and Wellhead (Ref.4)

Point of Freezing Potential	Cause of Freezing	Solution
Near Surface Wellbore	As the natural gas travels from the reservoir to the surface, cooling can occur due to gas expansion and exposure to colder temperatures near the surface.	Methanol is injected into the flow stream at the wellhead. The flow of methanol is down the wellbore annulus and then is carried up the gas flow stream through the wellhead preventing freezing.
Wellhead including Wellhead Valves	At the wellhead a change in flow path size can change causing an increase in velocity and cooling. Well head also exposed to surface weather conditions.	Solution is as above, methanol injection. In some cases the wellhead can be completely enclosed in a small building or “hut”, insulated and heated, but methanol is the most practiced solution.
Wellhead Chokes	Wellhead chokes are points at the wellhead where flow and pressure is primarily controlled. Significant pressure	As above with methanol application. Also, wellhead design should consider choke points and avoid wherever

	drop often occurs and expansion cooling can be severe. This cooling combined with cold ambient temperatures can cause significant freezing issues.	possible.

Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead

The basic flow of natural gas from a wellhead through the processing equipment and to the gas sales distribution system is illustrated in Figure 2. Note that this is described as a typical configuration keeping in mind that variations to equipment placement and metering occur dependent upon the number of wells, their proximity to each other, well ownership and other factors.

Referencing Figure 2, when gas leaves the wellhead it sometimes flows through a line heater which will warm the gas, any gas condensate and water within the flow stream, mitigating freezing and facilitating the separation of these three phases. (Line heaters are not always deployed in warmer production climates unless large flow volumes requiring pre-heating before separation of phases are experienced). The flow stream next enters the production separator (sometimes described as a heater treater) where gravity, heat and flow through mesh material separate the gas condensate from gas and from water. The condensate and water flow to storage tanks through liquid meters in some cases, or alternatively volumes are measured directly within the storage tank. These liquids are marketed by truck or pipeline in the case of condensate and the water sent to disposal facilities by truck or pipeline dependent on volumes and distances.

The gas flow stream exits the top of the production separator and flows to the dehydration unit. It is noted that the gas, while free of liquid phase water and condensate at this stage, is still saturated with liquid vapors notably water. Gas flows into a dehydration unit for removal of water or dehydration of the gas, drying it to normally 7 lbs/mmcf or less allowing for transport without freezing and water fallout issues. The normal dehydration process utilizes glycol which absorbs the water from the gas leaving the hydrocarbons within the flow stream. The glycol when saturated with water is sent to a glycol reboiler that through application of heat boils off the water. The dry gas is now metered and flows to the gas gathering system. (Ref. 4&6)

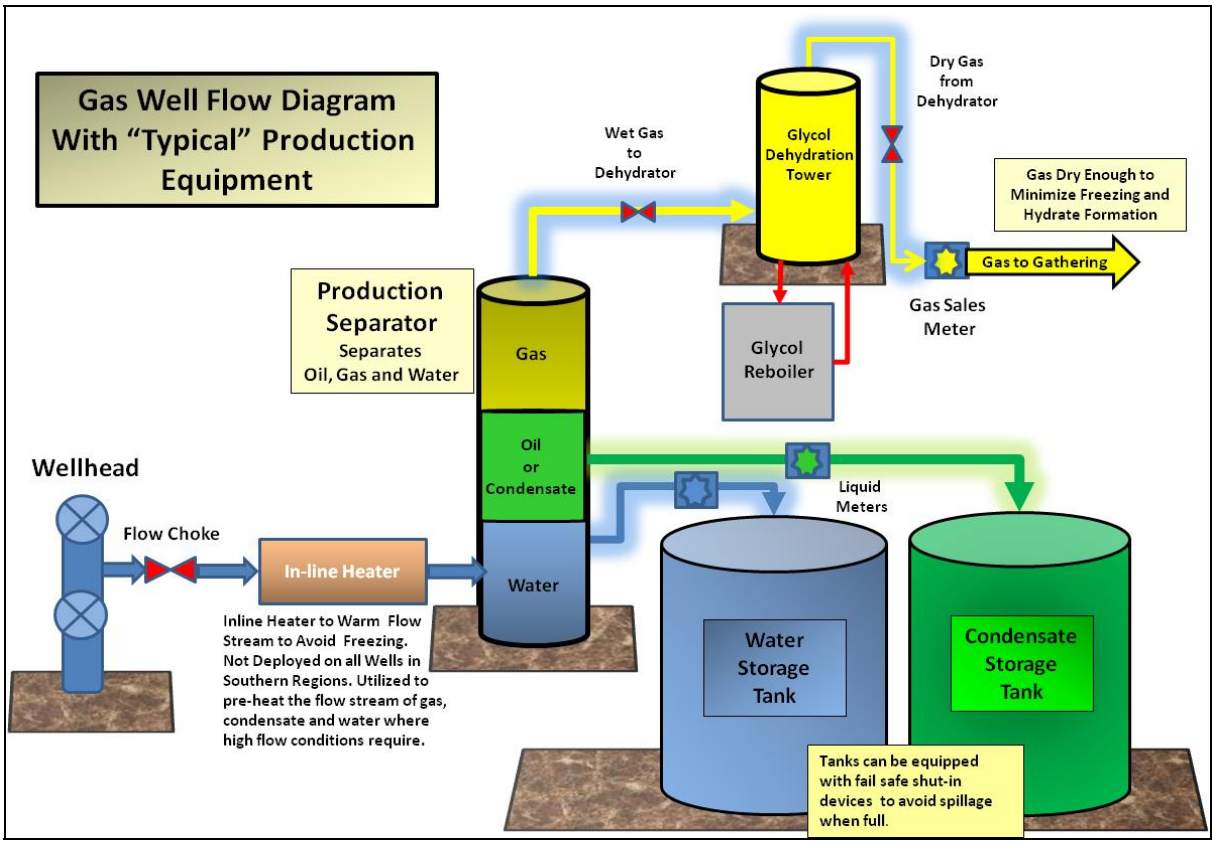

Figure 2 – Gas Well Producing Location with Typical Equipment for Gas Production Operations – Does not Include Gas Processing or Compressor Station. Production Equipment is Equipped with Fail Safe Devices to Shut-in Production to Avoid Spillage and Equipment Damage - (Ref. 4&6). (Figure from GTI)

The likely areas for icing and/or hydrate buildup and the typical solution for these problems as applied in cold weather climates are described in the following Table 2. See also Figure 2.

Table 2– Potential for Freezing – Gas Well Production Facilities Located at or Near the Wellhead. (Ref. 3, 4&6)

	Cause of Freezing	Solution Utilized in Colder Gas Production Regions
Flow lines from wellhead to line heater. If no line heater (common in warmer regions)	Exposure to low surface temperatures, gas has cooled due to expansion, gas contains water and heavier hydrocarbons which are prone to freezing or hydrate development.	Methanol injection, line heating, maintaining level flow lines to avoid liquid build-up, and limit choking points. Additional protection is usually required including insulating

then flow line to separator.		flow lines, wrapping with heat tape or glycol tubing under the insulation.
Production Separator	The production separator has equipment and instrumentation that can be impacted by cold weather. Gas, water and condensate flow throughout the unit. It is exposed to surface temperatures.	The unit is sometimes placed in a heated housing unit or hut. Alternatively, a cold weather version needs to be utilized. The cold weather unit is designed such that all piping and potential freeze instruments are internalized to the unit or insulated.
Gas Flow lines to Dehydration Facilities	If exposed these lines, which are still carrying water saturated gas and other hydrocarbons are prone to freezing and hydrate formation. This can take place in a particularly exposed portion of the line or at a bend or reduction in line size.	Sometimes these lines can be buried if it is some distance to the dehydration facility. This alone may not be adequate and insulation and heating may be required. A methanol injection point can be designed into the flow scheme if a particular area becomes a problem.
Flow Line to Sales Meter and Meter	The gas flowing to the sales meter has now been dried and is much less prone to freezing. The gas however can still be comprised of ethane and higher hydrocarbons as well as CO2 or N2 or other constituents. Depending on conditions of T & P Hydrates can still form despite dry (water content) gas.	Hydrate control can be achieved through application of heat, housing the meter and protecting from weather, methanol injection and other techniques described for managing wet gas freezing.
Condensate and Water Lines and Storage Tanks.	The lines to the storage tanks are at low pressures and the water is usually brine so freezing and hydrates are not as much of an issue. Depending on fluids and climate however some freezing can occur. If this takes place in the flow lines it can disrupt the separator causing production shut-in.	These lines can be insulated or in severe conditions heated with electric tape or glycol tubing. The tanks themselves do not normally present a problem.

Potential for Freezing - Gas Gathering System Including Compressor Stations and Gas Processing Plants.

After natural gas leaves the wellhead and wellhead production site it continues flow downstream through the natural gas system (Figure 3). Along the way, gas compression is required to maintain pressure and gas processing is applied to further dry the gas and remove heavy hydrocarbon components. Each is discussed further in this section.

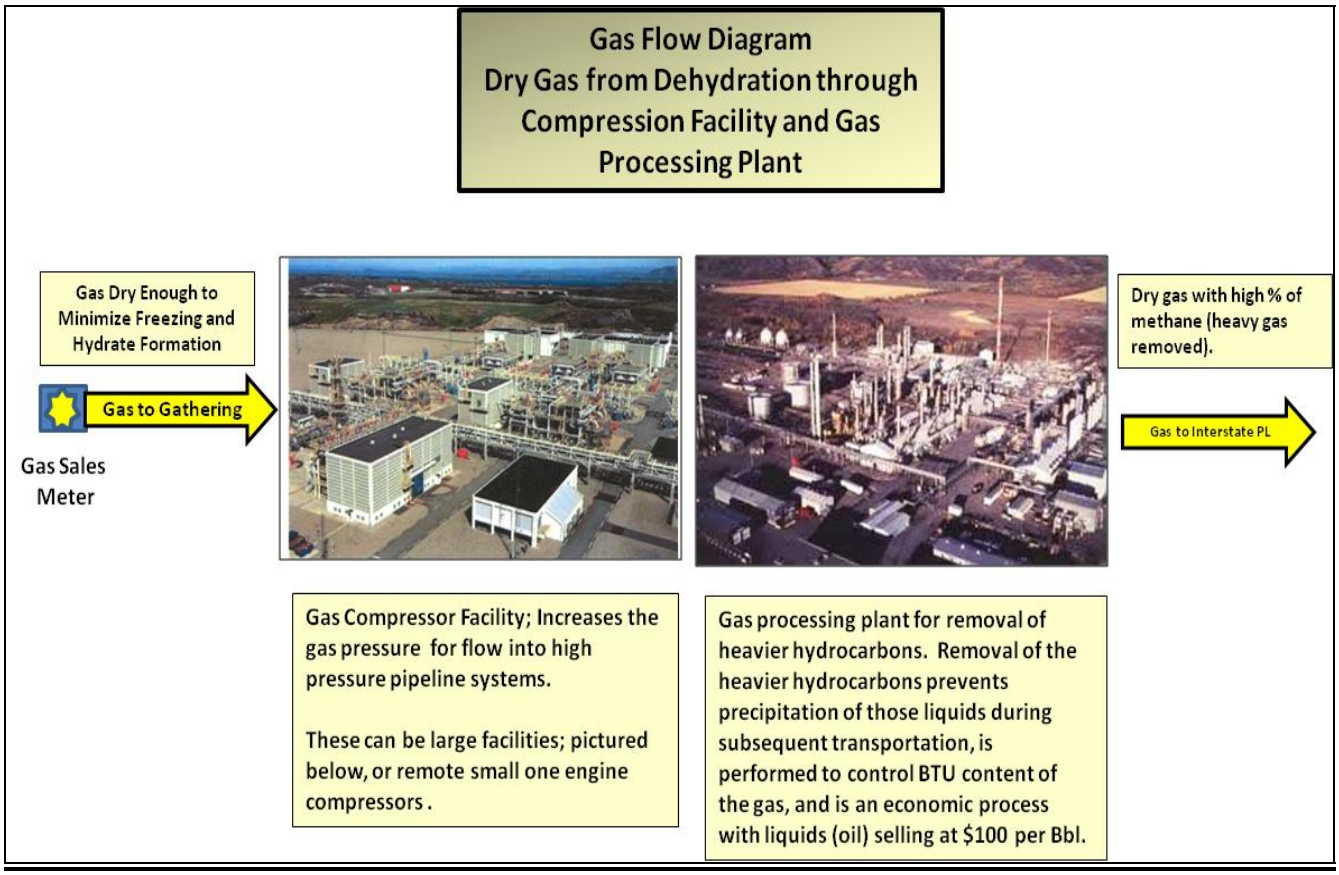

Figure 3 – Gas Flow Diagram – Dry Gas from Dehydration Facilities through Gas Compression and Gas Processing Plant. (Figure from GTI and ABB Oil and Gas and Duke Energy Canada)

Compression - After the natural gas stream leaves the dehydration facility it will at times flow through a compression facility or single compressor. The purpose of this is to boost the pressure of the gas such that it is able to flow into a sales line that is at higher pressure. The natural gas industry utilizes a large number and wide variety of compressors. Overall greater than 45,000 compressors are in place in the United States (Figure 4) (Ref. 7).

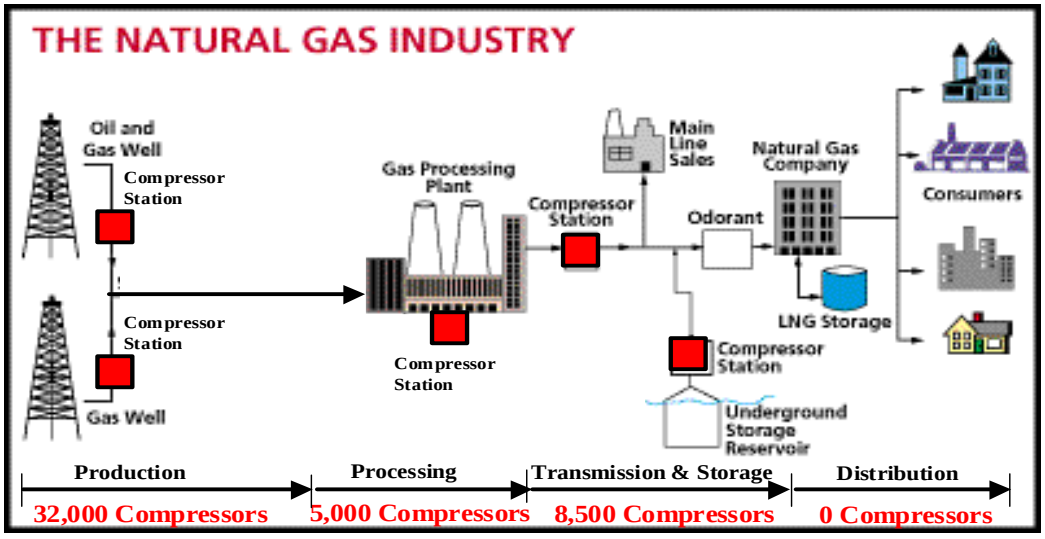

Figure 4 – Natural Gas Compressors in the U.S. Natural Gas System (Ref. 9) (Diagram from Wikimedia Commons)

Compression facilities range from small single compressors to large facilities handling large volumes of gas at aggregation points. The compression facilities within a producing gas field will change with time due to several factors:

- The drilling of new wells over time introduces increased gas volumes in a gas producing region.
- Existing wells will decline in gas production volumes over time reducing gas volumes.
- Gas flowing from the wellhead is initially at high pressure but then declines as gas is produced. This decline can be very rapid for the newer gas shale wells being developed, requiring compression facilities to be installed at appropriate points to keep wells flowing.
- The older well flow rates (at low pressure) will be reduced by the high pressure new wells in the absence of compression facilities. It is under these circumstances that new and sometimes remotely located compressors are installed.

The overall effect of these changing conditions is that compressors may need to installed, removed or resized based on the many factors impacting their size and number requirements.

The impact of cold weather on compressor stations can vary. Compressors stations all have safe guard instrumentation that senses temperature, pressures and flow rates. If pressure, as an example, gets too high or too low, the compressor will shut itself down to prevent expensive damage. These instrumentation processes can be impacted by cold weather. In colder climates, compressors can be housed to protect against any severe weather conditions (Figure 5). The majority of these compressors are fueled by natural gas as it is readily available due to it being the medium being compressed and transported. (Ref. 4, 7, 8)

Compressor stations take low pressure gas and increase the pressure significantly which is accompanied with temperature increases of the gas flow stream. Changes in pressure and temperature will cause additional liquids to drop out of the gas stream. The temperature and pressure conditions can vary considerably at these facilities. Some of the variables and conditions involved include:

- Pressure changes can occur; pressures can be dropped to manage the inlet pressure conditions to the compressor. High pressure and low pressure wells may be feeding the inlet side of the compressor. These well pressures are brought into balance at the inlet section of the compressor by dropping some well pressures to balance with the low pressure wells.
- The drop in pressure can cause gas cooling (Joule Thompson effect).
- Increasing pressure through the compression facility can cause gas heating.
- Temperatures and pressures are monitored throughout the compressor system and automatic shut down devices will be activated if they deviate from a defined range (too high or too low).
- Many of these changes can cause liquids (water and condensate) to condense from the gas stream and need to be removed and stored in nearby storage tanks.
- The storage tanks must be emptied on a regular schedule or fail safe shut-in devices will activate.

In urban areas (Dallas Ft. Worth as an example) electric compression is sometimes required due to noise limitations or emissions constraints. These facilities in particular are subject to any reduction in electric power due to weather or other conditions. There are some electric compression facilities in the Ft. Worth area but not in large enough numbers to have significant impact on gas production. (Ref. 4, 7, 8, 9)

Figure 5 - Fully enclosed, insulated and heated compressor; for cold weather environments. The unit offers metering, separation, and compression, all on one skid. (Photo Wikimedia Commons)

Larger compressor facilities are located at gas aggregation points where larger volumes of gas are compressed to higher pressures. These can be complex facilities with extensive piping, metering, and instrumentation. Cold weather can impact these facilities similar to smaller, more remote facilities. The incentive to weatherize however is greater at these locations due to the size and gas flow rates they address. There is an economic incentive as well as a reliability of service incentive to maintain flow at these aggregation points. The technology is readily available for winterization of these facilities and is commonly applied in colder regions of the country. As with the wellhead and production sites, the weatherization approach is a combination of heating important components via electric supply or warmed liquid flow (glycol), insulation of components, housing critical portions of the facility, injection of anti-freeze type chemicals (methanol), drying of the gas flow components, drying instrumentation gas via desiccants or other drying medium, or a combination of these techniques. (Ref. 4, 6)

Gas processing plants function to remove heavier hydrocarbons from the gas stream. These include ethane, propane, butane and others. There are three factors that drive the gas processing business:

1. The need to control gas heating value (BTU). Gas going into most end use functions (residential, commercial) requires gas within a certain BTU range which is often a narrow window around 1000 BTU/Ft^3 of gas.
2. For gas to be transported long distances through interstate pipeline systems it needs to be relatively free of heavier hydrocarbons. The heavier constituents will eventually precipitate during the pressure ups and downs encountered during long distance transportation. They then form liquids inside of the pipeline causing an unwanted pressure drop, freezing (through hydrate formation) or other interference.
3. With high oil prices, liquids are more valuable than natural gas. Therefore an economic incentive exists to remove the heavier hydrocarbons and sell into the liquids market as opposed to keeping them in the gas phase and selling based on BTU value alone.

These plants can be very complex (Figure 6) with extensive piping, processing units, regulators, instrumentation and other components. Many of these components can be impacted by weather conditions and to assure ongoing processing plant operation must be protected against weather. (Ref. 4, 10)

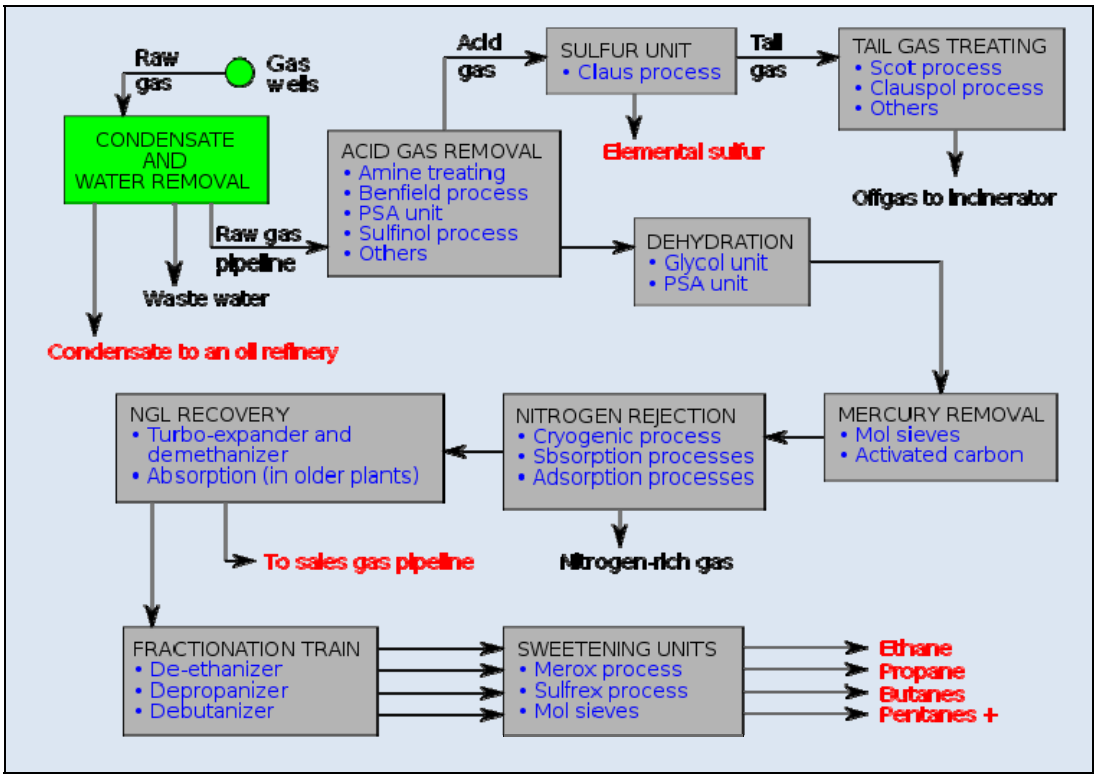

Figure 6 – Flowchart for a Gas Processing Facility – Illustrates the Complexity of the Process and the many Steps that can be Required. Levels of Complexity vary from Plant to Plant based on Need. (From ABB Oil and Gas).

Gas processing plants operate in cold weather climates along with other gas production facilities and as such, winterization equipment and processes are well known. It is a matter of frequency of events (cold weather) and the amount of time the facility is impacted, vs. the cost and time to winterize. Some processing plants have adequate piping and flow schematics to bypass some processes that might be impacted by cold weather. (Ref. 10)

Prevention of Wellbore, Wellhead and Production Facilities from Freezing – General Discussion and Description

There are several options for the prevention of freezing problems. Many of these are practiced on a regular basis in the colder regions of the country, to a lesser extent in the Mid-Continent region of the United State and not at all (in many cases) in Southern regions of the country. In order to correct freezing problems that occur under differing operational conditions, solutions must be designed for the particular needs of the location where the problem exists. Protection against freezing requires deployment of one or more mitigation techniques. Each of these techniques requires and investment in capital and operating expenses. The application of these techniques is usually determined by the

need or frequency of use along with the consequences (loss of production for a certain time period) of not utilizing.

In Southern regions of the United States, cold weather can be infrequent and when it does occur, can be limited in duration. A consequence is that the investment in freeze protection equipment and operations can be limited. The consequence to the producing life of a well can be minimal compared to the investment for cold weather operations in that lost production occurs for several days from a well with 20-30 years of operation life. On the other hand, if the level of impact is similar to the events of early February, 2011 and occurs on a more frequent basis, there can be a detrimental impact to the overall natural gas industry, as lack of reliability and accountability can result in loss of market. (Ref. 4)

Described below in general order of frequency of use are several techniques that can be applied to prevent freezing in gas operations:

1. **Methanol Injection to Prevent Freezing** - Methanol (an anti-freeze type solution) injection is a very common practice for freeze protection of wellbores and pipelines where wet gas flow occurs. Injection down the annulus of a wellbore by chemical injection pumps is utilized in production facilities in cold climates and in many gas storage operations where reliable, high flow rates in cold weather is required. The same technique can be practiced within a pipeline system and production facilities. The methanol is injected into the gas stream by chemical injection pumps or enters the pipeline by methanol drips and effectively lowers the freeze point of the gas. The amounts of methanol required can be calculated by using available tables for specific applications.

   A small volume methanol tower can also be fabricated allowing small volumes of gas to pass through the methanol for treatment. Because of the sensitive nature of many pneumatic controllers, this method is occasionally used to prevent freeze-ups in these devices and to prevent liquid migration into small orifices and passages. An additional filter is often used to ensure that the methanol is not carried over into the instrumentation. (Ref. 4, 11)

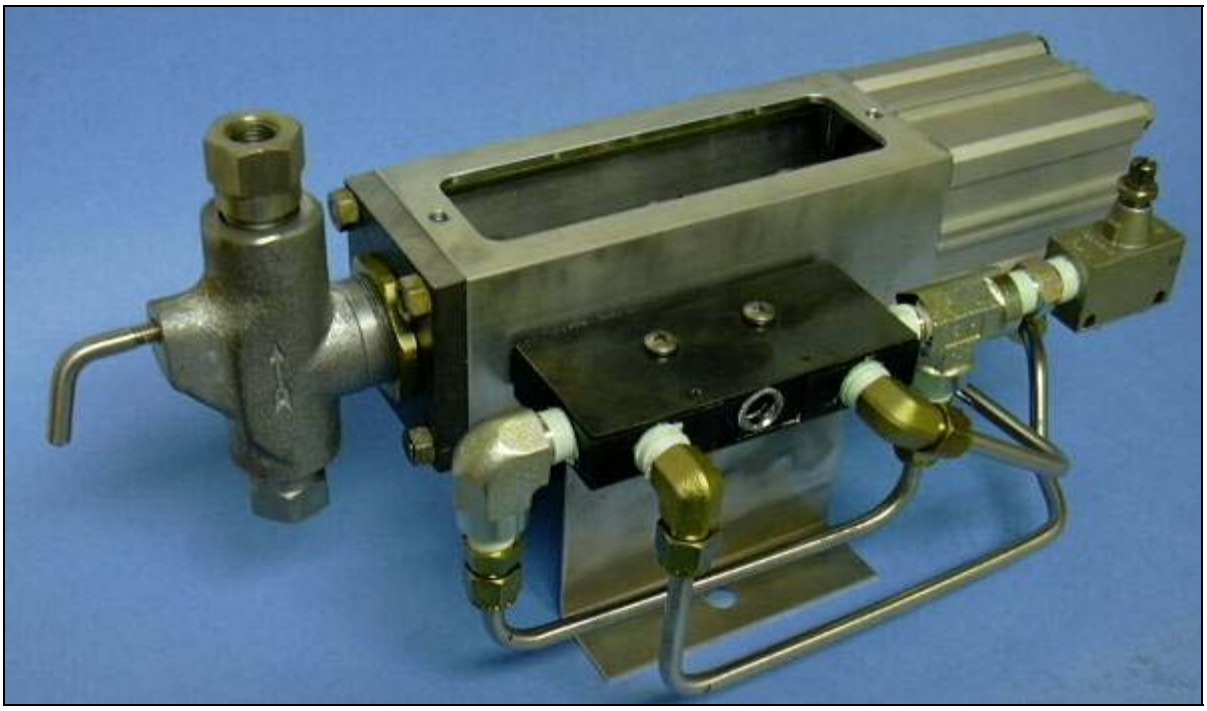

Figure 7 – Methanol Injection Pump Utilized to Inject Methanol into a Wellhead and/or Flow line to Prevent Freezing and Hydrate Buildup. Usually Located in Protected Housing on the Gas Well Location. (Ref. 11) (Photo Source ZKO Oilfield Industries; PTAC.org)

2. **Buildings or "Huts" to Enclose Production Equipment and other Weather Sensitive Equipment**
   Buildings are often constructed to house weather sensitive equipment in cold weather. This can be the preferred method for protecting production equipment and is widely applied in colder climates. The housing can be heated by catalytic heaters and can be insulated as needed for the extremes of weather conditions anticipated.

   Figure 8 is a typical setup for a Midwest Gas Storage Field (Manlove Gas Storage Field near Champaign, IL). The green fiberglass housing structure protects metering and other production equipment from freezing. Heating devices of various types can be utilized within the structure. Methanol chemical injection pumps are housed within the structure. During gas withdrawal operations (winter conditions) methanol is injected into the wellbore to prevent freezing. The wellhead itself is not enclosed. The wellhead is left open to allow for workover rigs to access the wellbore for any type of downhole maintenance required. Also, the heating of the wellhead may not preclude the formation of gas hydrates down in the wellbore some distance. This requires methanol injection as described in #1 above (Ref. 4, 12)

Figure 8 - Fiberglass Housing Surrounding Production Equipment at Gas Storage Field in Midwest United States (Ref. 12) (Photo credit Wikimedia Commons)

3. **Water Removal from the Gas Stream by Glycol Dehydration.** Gas dehydration is practiced on all natural gas flow systems to enable flow of gas without problems of hydrate formation, freezing, water drop out, corrosion and other issues. One of the most common methods of dehydration for large volumes of gas is glycol absorption. Gas passes through the glycol inside a vessel called a contactor (See Figure 2). The object is to remove the water to a point where the water vapor dew point of the gas will not be attained at the highest pressure and lowest temperature of the pipeline system. The glycol absorbs water and is then treated by circulating the glycol to a regenerator and distilling the water out of the glycol. The reconditioned glycol is returned to the contractor and the procedure is repeated. This process can reduce the water dew point to 60-70 degrees Fahrenheit. Colder climates frequently dictate a dehydration system in a natural gas system, but even warmer climates may require central dehydration due to pressure, temperature and gas composition. A producer can basically look at three dehydration options.
    a. Partial dehydration at the well head and later additional steps to meet contract specifications.
    b. Chemical injection at the well head with later dehydration at the central delivery point.
    c. Full and complete dehydration at each and every well head.

The glycol dehydration system is a low cost system with continuous operation and minimal pressure loss across the unit, thus making it a preferred approach in several areas of operation. The drawbacks can be glycol carry-over during surges, contamination by solid particles and inefficiency during fluctuating flow rates. (Ref. 4, 13)

4. **Heat Application for freeze protection** - Heat is a logical solution to freezing problems. It is also a costly approach to the problem for several reasons. Obviously, if the gas is never allowed to reach freezing temperatures, ice cannot form and will not be present. The water will likely not be removed, which remains an issue for operations and contracts, but the freezing is eliminated. The problems with heat are that it is expensive equipment to install, it requires additional fuel (energy and revenue) to produce the heat, and the heat will not remain effective as it travels down the pipeline and away from the heat source. Heat is also a potential hazard as it can provide an ignition point for the gas. Safety and special emphasis on proper application is a must when using a heat source. The most common application of heat for freeze protection is in a specific and direct situation, as in the case of a regulator valve body. The pressure drop at the regulator is the only problem point and therefore, can be the only specific location where freeze protection is required. There are multiple ways to apply heat from heating blankets, to catalytic heaters, to fuel line heaters, or in some cases, steam systems where they are properly designed, installed and maintained. Heat systems can be very effective for a localized freezing problem. Heat application coupled with insulation is a common technique for protecting flow lines in northern climates. (Figure 11). (Ref. 3)

Figure 9 – Gas Wellhead with Insulation on Flow line to Protect Freezing. (Photo Courtesy of ABB Oil and Gas)

5. **Combination of Techniques are Often Utilized –** A combination of winterization techniques are often required to fully protect a gas well production facility. Figure 10 illustrates a typical installation for a cold climate.

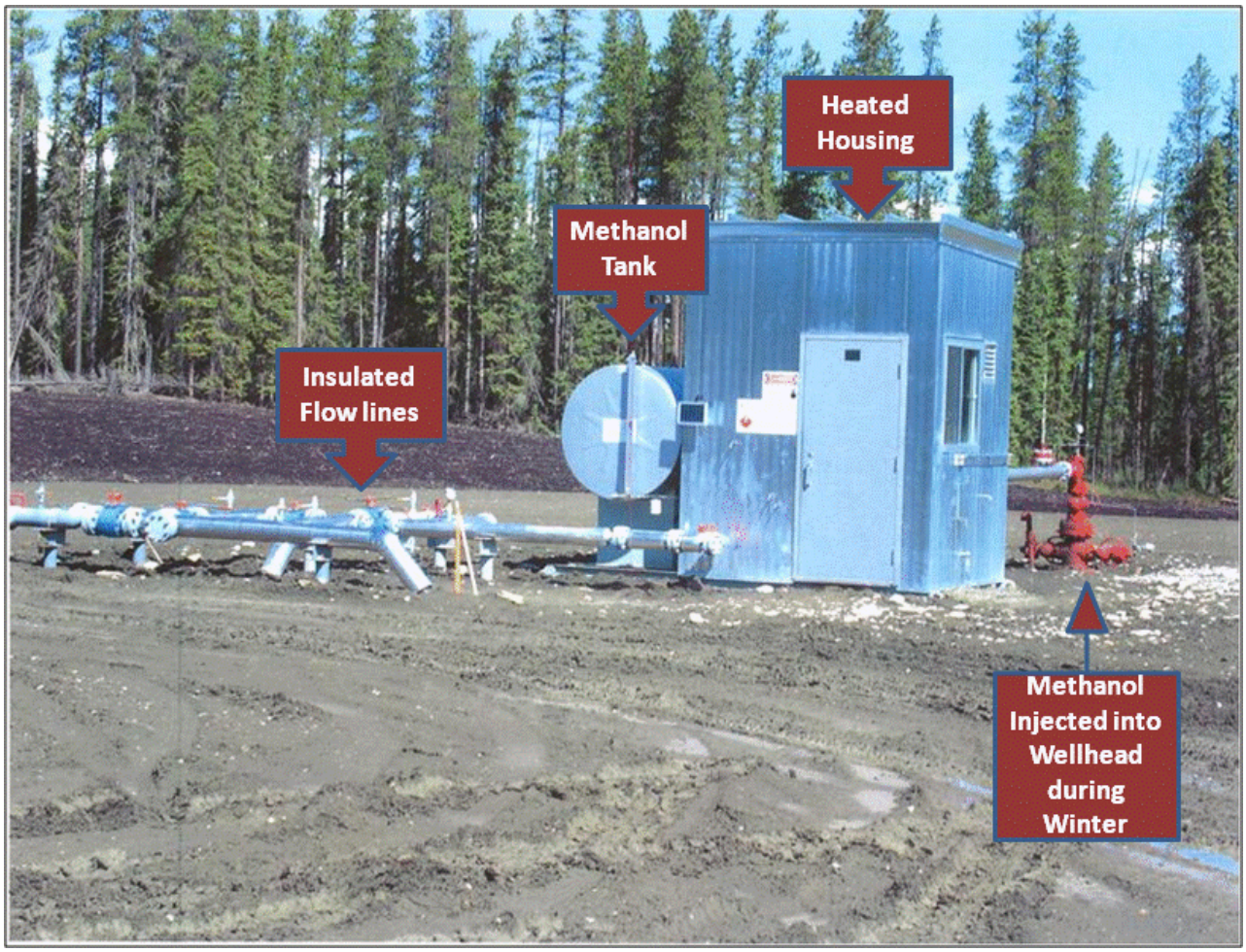

Figure 10 – Gas Production Wellhead and Production Equipment in Northern Region of United States Winterized for Cold Weather Operations. (Photo Source ZKO Oilfield Industries; PTAC.org and modified by GTI)

Referencing Figure 10, the following equipment and steps are practiced for flow assurance in cold weather climates:

- Flow lines are insulated.
- All wellheads are set up to inject Methanol which is done throughout the cold months.
- Assurance that flow lines are level, avoiding low spots where water can accumulate.
- Utilization of gas fired line heaters ahead of the production separators to keep all fluids warm enough to avoid freezing prior to separation of gas, gas condensate and water phases (See Figure 6).

- All flow lines beyond the production separator are insulated and heat traced. This is accomplished by electrical heat tape when electricity is available. Where there is no electric service, glycol tubes for circulating glycol are utilized to maintain flowing temperatures.
- Minimizing flow chokes is also practiced wherever feasible. Flow chokes are notorious Joule Thompson freeze points.
- Fiberglass huts over the wellheads are sometimes considered but difficult to accommodate due to impediments to accessing the wellbore for work-over and other considerations. (Ref. 3, 4, 6, 11)

6. **Pipeline Pigging** - Pigging in the maintenance of gas pipelines refers to the practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of the gas in the pipeline (Figure 11).

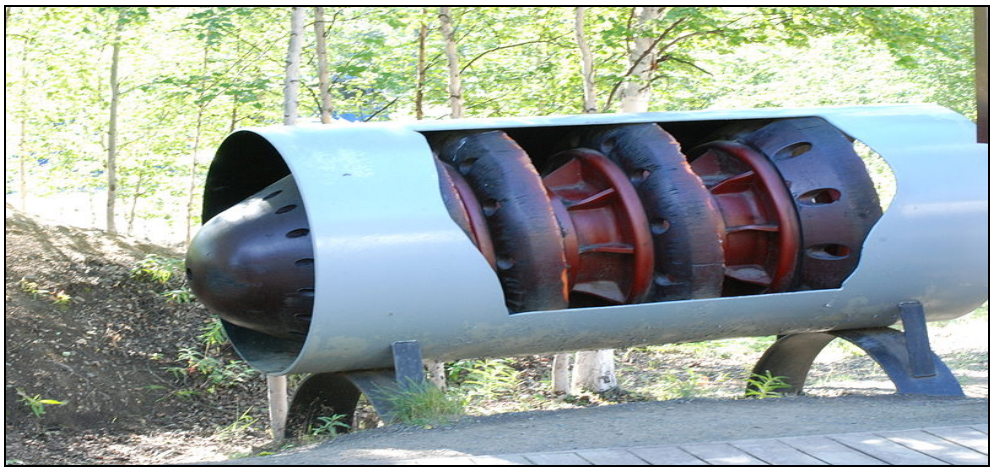

Figure 11 – Pipeline Pig Inside of Cut out Section of Pipeline (Photo Credit Wikimedia Commons).

These operations include but are not limited to cleaning and inspecting of the pipeline. This is accomplished by inserting the pig into a 'pig launcher. The launcher / launching station is then closed and the pressure of the product in the pipeline is used to push it along down the pipe until it reaches the receiving trap - the 'pig catcher' (Figure 12). (Ref. 14)

Figure 12 – Pipeline Pig Launch and Receiving Station (Photo credit Wikimedia Commons).

If the pipeline contains butterfly valves or other restrictions in line diameter the pipeline cannot be pigged. Pigging has been used for many years to clean larger diameter pipelines in the oil industry. Today, however, the use of smaller diameter pigging systems is now increasing in many areas to maintain pipeline flow integrity.

Pigs are also used in gas pipelines where they are used to clean the pipes, but also there are "smart pigs" used to measure pipe properties such as pipe thickness and corrosion. They usually do not interrupt production, though some natural gas can be lost when the pig is extracted. Most of the pigging operations are deployed in the gas gathering, transmission and distribution portions of the gas system as opposed to the wellhead production areas where pipeline configurations and sizes do not allow for pigging operations.

Pigging operations are conducted on a year around basis as needed to keep pipelines in working flow conditions. During cold weather their deployment can be increased due to additional liquids fallout and due to increased flow rates during cold weather. (Ref. 14)

7. **Practical Piping and Equipment Construction Considerations for Freeze Protection** - During the design phase of the piping and the instrumentation system, certain steps can be taken to reduce the negative effects of freezing problems. Piping configurations that would allow for liquid accumulation should be avoided if at all possible. Drainage should slope towards drain fittings located at low spots. Where possible, use ball valves and large diameter tubing for instrument feed lines and sensing lines. Avoid restrictions where flow will occur. Limit choking points. Tubing runs should slope back toward the pipeline and you should have a leak free

instrument system. Liquids, if they are present, will be drawn towards the leak. If you avoid creating traps and liquid drop out areas, your freezing problems will be minimized. (Ref. 3, 4).

8. **Other Water Removal Techniques for Cold Weather Protection, Especially for Instrumentation**
    a. **Solid Absorption -** A very efficient method of water removal is the dry bed or molecular sieve method. The gas is passed through large towers of solid particles and the molecular sieve absorbs the water very aggressively. Very dry gas over a wide range of flow rates can be attained by this method. Eventually, the sieve becomes saturated and must be regenerated. The stream must be switched to a second tower and hot gas is introduced to the original unit to evaporate the water and dry the sieve. Cool gas is then used to cool the desiccant and the tower is ready for re-use. This cycle is repeated until the desiccant has degenerated and is no longer effective. While this method produces very dry gas and has several positive operating characteristics, it is more costly than typical glycol systems and more complex to operate. If the gas contains heavier hydrocarbons they can sometimes interfere with the sieves.
    b. **Drip pots, coalescers and automatic liquid dumps can reduce freezing problems on instrumentation** - Occasional slugs of liquid can damage or even "shut in" many instrument supply systems. Where this slug potential exists or in cases where liquid is a severe problem in the gas supply used for instrumentation, drip pots and coalescers can effectively knockout or reduce the water and condensate in a small volume instrument supply system. If the problem is excessive, an automatic liquid dump designed for instrumentation can be extremely helpful. Whereas the drip pot requires routine manual draining, the automatic liquid dump will act as a drip pot collection vessel with a coalescer and as a result of an internal float assembly and pivot valve, will automatically release the collected liquid to a lower pressure point.
    c. **Instrument filters designed for freeze protection to control equipment** - Many instrument controllers and other sensitive measurement equipment powered by instrument gas supply need the highest level of clean and dry instrument supply that is attainable. In some cases a good linear polyethylene filter can provide adequate protection. But the most common solution for instrument supply gas is the filter dryer. These units are designed for high pressure applications with removable media cartridges. While various types of media are available from molecular sieve to special H2S removal media, most are equipped with a combination desiccant and charcoal filter cartridge. Coupled with providing extremely dry and fresh gas, the ancillary filtration elements in the cartridge provide for 2-4 micron protection as well. (Ref. 3, 4).

Natural gas systems, from mainstream pipeline flow to low pressure instrumentation, are subject to freezing conditions. Figure 10 is contrasted with Figure 13 where a non winterized location is illustrated.

Through careful planning and evaluation of a specific application, proper selection of available options, and a good routine maintenance program, this industry wide concern can be controlled and minimized. The cost of dealing with the aftermath can be more expensive than the preventative action that could have been taken.

Figure 13 - Typical wellhead in Warm Climate. (GTI) No methanol or other injection equipment for freeze mitigation. Flow line is elevated without insulation of other protection from cold weather. Tank battery and other production equipment are not protected from cold weather. (Ref. 4)

Alternatives to Cold Weather Control Techniques

Emissions of natural gas and other greenhouse gases are under increasing scrutiny as the concern about global warming continues to grow. Natural gas can be emitted to the atmosphere in many locations along the gas system. The gas industry has taken steps to mitigate these releases and continues to do so. Gas dehydration facilities are one step in the process where some gas is emitted. The dehydration step is required to remove water vapor from the gas stream to allow for safe and efficient transportation of the gas, and in particular to avoid gas line freeze-up when weather conditions turn cold.

One alternative to gas dehydration is the continuous injection of methanol into the system from the wellhead to a point of aggregation of the gas where it can be dried to pipeline specifications. This practice would eliminate the need for many individual dehydration facilities and thus the gas emissions. This is relevant when discussing flow assurance under cold weather conditions as well. The

injection of methanol could have the additional impact of avoiding freezing conditions within the gas flow system. This mechanism is practiced in the offshore environment where long pipelines transport oil, gas and water to onshore facilities for processing. Application of this technique onshore however, is often hampered by the many different mineral owners involved with each well. Each mineral owner has a royalty interest in the well allowing him a percentage of the revenue generated. This requires that a gas sales meter be installed to measure his appropriate share prior to mixing the flow volume with another well. Accurate gas measurement requires dry, liquid free gas leading to dehydration facilities at most wells. In the offshore environment there is only one royalty owner, the Federal Government. (Ref. 4, 11)

Discussion of Gas Hydrates Formation

Gas hydrate formation, also known as freezing, is a potentially serious problem in natural gas flow lines starting at the production well all the way through to the customer delivery system. The effective inhibition of hydrate formation, especially during cold weather, is essential for producers and transmission companies if they are to maintain a continuous supply of natural gas. Methods to control freezing range from removing water from the gas stream to lowering the water's dew point by injection of chemicals such as methanol.

Natural gas hydrates are ice-like substances that form through entrapment of hydrocarbon molecules inside the lattice of ice crystals. Hydrate crystals are formed under certain pressure and temperature conditions where the temperature may be above the melting temperature of ice. Many types of hydrates can form based on the presence of various gases. These include methane, ethane and propane hydrates, carbon dioxide and nitrogen hydrates and others.

Hydrates are very complex systems and their formation and dissolution remain a topic of ongoing research. They are known to exist in nature and form frequently within natural gas flow systems from the wellbore through the distribution systems for natural gas. They have been known to plug pipelines in the Gulf of Mexico for thousands of feet shutting in flow from multiple production platforms and significantly interrupting gas supply. In the Gulf of Mexico, where flow lines lay on the ocean floor in deep, cold water, and where the flow through the pipelines includes oil, gas and water prior to separation at onshore facilities; hydrate formation is a threat throughout the year. The solution to this problem is simply to inject methanol and other chemicals that inhibit hydrate development. This is performed as an ongoing operation and continues to be practiced. Research continues to better understand and control the formation of hydrates under these conditions, but today the application of methanol is the only effective solution. (Ref 4, 16)

Figure 14 – Hydrate Photos – Inset is the Water- Methane Hydrate Structure (Ref. 16, 17) (Photo Credits National Energy Technology Center (DOE) and Wikimedia Commons)

Figure 14 is comprised of two hydrate photos, one illustrating the melting of hydrates with the associated release of methane which has been ignited. It is through this phenomenon that the term "burning ice" is often used when describing hydrates. The smaller inset figure illustrates the hydrate cage formed by water and methane.

Methane hydrate, much like ice, is a material very much tied to its environment—it requires very specific conditions to form and be stable. Remove it from those conditions, and it will quickly dissociate into water and methane gas. A key area of basic hydrate research is the precise description of these conditions so that the potential for occurrence of hydrates in various localities can be adequately predicted and the response of that hydrate to intentional, unintentional, and/or natural changes in conditions can be assessed.

Figure 15 illustrates the combination of temperatures and pressures (the phase boundary) that describes hydrate formation conditions. When conditions move to the left across the boundary, hydrate formation will occur. Moving to the right across the boundary results in the dissociation (akin to melting) of the hydrate structure and the release of free water and methane.

In general, a combination of low temperature and high pressure is needed to support methane hydrate formation. Note that depending on the ambient pressure, methane hydrate can form at temperatures well above the freezing temperature for water; for example at 2500 psi pressure, the ice-like methane hydrate will form at 65 ^{o} F.

Heavier hydrocarbon gases and other gases such as carbon dioxide can form hydrates at higher temperatures and lower pressures than methane. Hydrates may form in wet natural gas streams containing high percentages ethane, propane, CO_2 and H_2S where no methane hydrate is formed.

Referring to Figure 15, note that the phase line for CO_2 and ethane are to the warm side of the methane phase boundary indicating that under a given pressure CO_2 and ethane hydrates form at higher temperatures. (Ref 4, 16, 17)

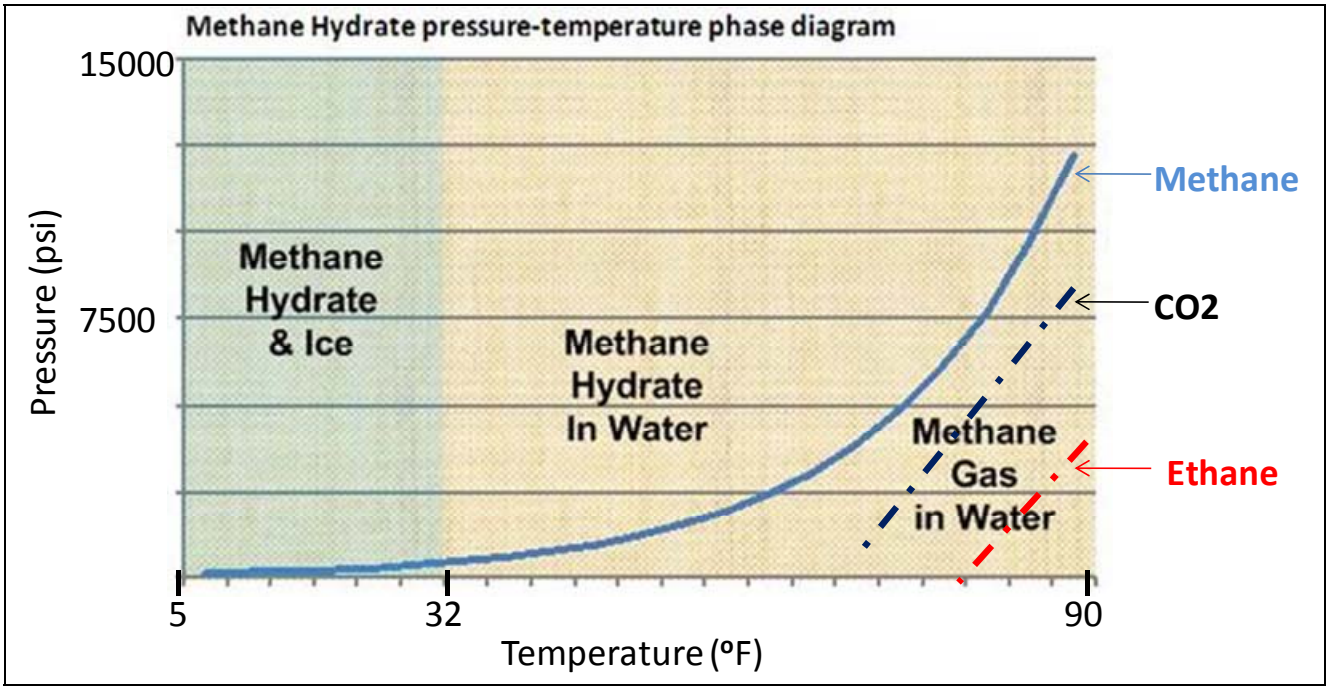

Figure 15 - Methane Hydrate Phase Diagram (Diagram Modified from Physical Chemical Characteristics of Natural Gas Hydrate).

The control of hydrates as previously discussed is accomplished in the same manner as for the control of icing conditions; application of heat, drying of the gas or chemical injection. With hydrates however it must be noted that they can form in somewhat dry gas especially if heavier hydrocarbons are present.

Gas Quality Considerations and Gas Processing

New technology has enabled the development of many new and significant shale gas plays in the United States including the Barnett, Marcellus, Eagle Ford, Fayetteville and others. The quality of the gas from these shale resources is different in each area requiring different approaches to production and gas processing. The volume of ethane, propane, carbon dioxide, nitrogen and other constituents vary considerably from play to play and can vary considerably within a single shale area such as the Barnett.

The gas processing industry has scrambled to keep up with the growth of the Barnett shale. Gas production has increased to 4 Bcf/day from near zero in 1999. Major gas processing plants have been constructed by Devon, Quicksilver, Enbridge and others. Most of the plants include compression, CO_2 treating with amine units, Cryogenic separation and fractionation. The process gas moves east toward Carthage, Texas where it can reach the Midwest markets via various hubs or it moves Southeast via the Transco or Florida gas pipeline. The gas processing plant typically process large volumes of gas. Within the Barnett region, plant capacities can range from 35 mmcf/day increasing to 1.0 bcf/day. Given the size of these plants, the volume of gas processed, the investment and sophisticated processes and equipment they are likely better able to withstand weather changes and disruptions due to rapid declines in temperature. When they do occur the problems can be identified and resolved. Unlike individual well locations the scale of these operations can justify winterization equipment and processes even for infrequent events. (Ref. 4, 5)

Table 3 – Barnett Shale Gas Compositions (Ref. 5) *Oil and Gas Journal*, March 9, 2009, Compositional Variety Complicates Processing Plans for U.S. Gas Shales.

Barnett Shale Gas Composition					
	Methane	Ethane	Propane		
Well	C_1	C_2	C_3	CO_2	N_2
1	80.3	8.1	2.3	1.4	7.9
2	81.2	11.8	5.2	0.3	1.5
3	91.8	4.4	0.4	2.3	1.1
4	93.7	2.6	0	2.7	1

Table 3 illustrates the gas composition from 4 wells from the Barnett shale producing area. As can be seen the compositions vary considerably. These changes and levels of gas constituents across the Barnett region have the following impact on gas production with respect to cold weather:

- The presence of the heavier hydrocarbons establishes a higher probability of hydrate formation even after the gas stream has been dried to 7 lbs/mmcf.

- There is the potential for liquids fallout with the heavier gases that may be accelerated during cold weather. This condensation may occur without hydrate formation.
- The heavier liquids provide an economic incentive along with high oil prices to establish gas processing plants to remove liquids.
- The presence of CO_2 and N_2 require that these waste gases be removed or blended with other gases to bring their percentage levels down to pipeline specifications.

In general the variation in gas composition adds complexity as compared to a dry gas producing region. The complexity consists of additional gas handling, processing, transportation, blending, metering and other operations that potentially can be impacted by cold weather. The exposure of this additional equipment to weather can impact the reliability of gas flow under conditions not normal for an area. (Ref. 4)

On the other hand, independent of the heavier hydrocarbons, gas shale production has all of the issues associated with water production and methane hydrate formation. There is the possibility that these conditions alone are enough to cause disruption during cold weather spells and as such the presence of heavier hydrocarbons may have limited additional impact. (Ref. 4)

What needs to be determined is the impact of cold weather on gas processing plants which are established solely for heavy gas removal. They being located at aggregation points can disrupt large volumes of gas flow when problems occur. Alternatively they are large complex facilities, located in a contained area (as compared to wellheads spread across many miles) which combines to provide both the incentive and opportunity for cold weather control technology.

Discussion of Cost Implications to Winterize Gas Wells – Per Well Cost and Per Field Cost

Recent technology development has enabled the recovery of gas from shale formations around the U.S. and now around the world. Unlike offshore platforms or large flow volume conventional gas wells, many wells are required to recover gas from low permeability gas fields. Gas well spacing requirements can reach down to one well per 10 or 20 acres in some cases. In the Barnett area typical spacing is one well per 40 acres and over time greater than 14,000 gas wells have been drilled over a 12 county area (Figure 10). This development took place in stages over a 10 year period as a better understanding of the full potential developed.

Another factor regarding gas fields with a large number of wells is the time required to respond to an event that impacts every wellhead. Within the time frame of the recent cold weather event it would have been impossible to attend to each of 14,000 wellheads, most at a different location to alleviate freezing and/or other cold weather issues. (Ref 4, 18)

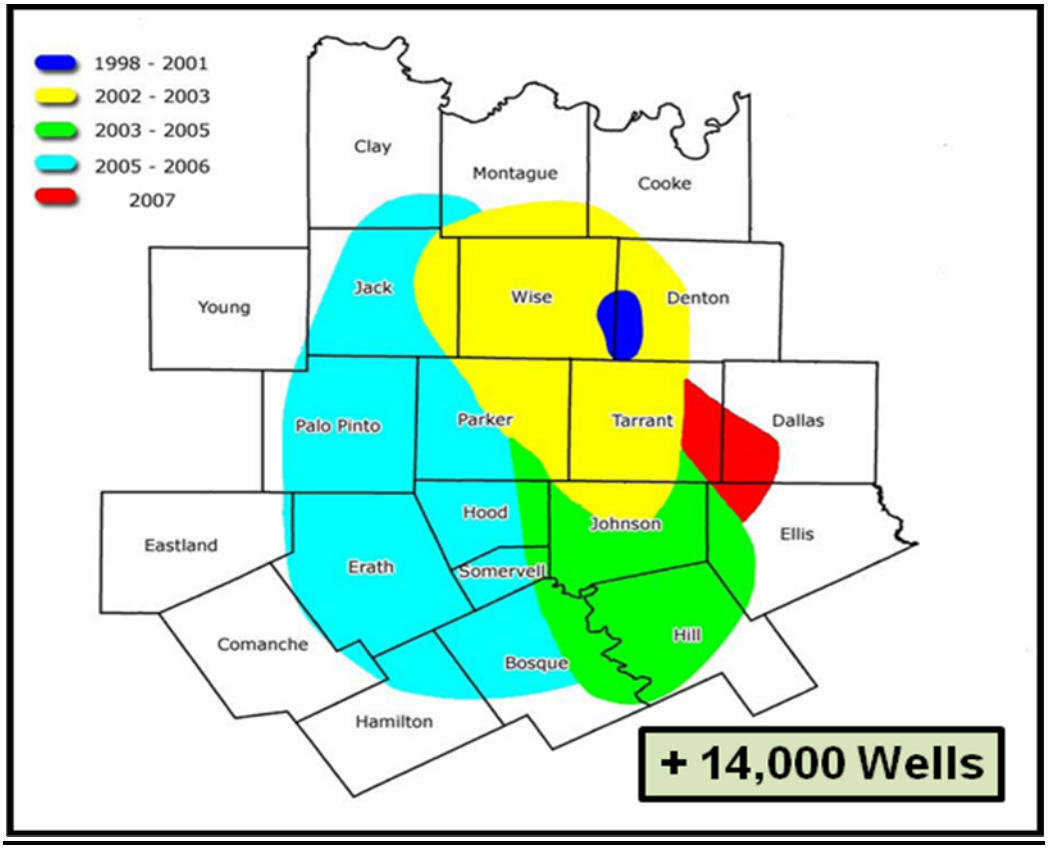

Figure 16 – Barnett Shale Gas Development Area near Dallas, TX, (Ref. 18) (Figure Courtesy Perryman Group – HART Unconventional Gas Conference).

The implications for cold weather flow assurance is that unlike the ability to winterize a large volume of gas flow at a single well location with a single investment, unconventional gas development requires winterization of many locations at practically the same capital expense.

Winterization of a gas well requires both capital expenditures and annual operating expense. Table 6 identifies the cost per well of these items.

In Northern regions of the country this equipment is normally part of the original well design and installed as a matter of necessity along with all other production equipment. On wells that can cost well in excess of $1 million each, these costs are not as significant as when compared to a retrofit after the well has been placed on production. This investment needs to be weighed against the impact and ramifications of the reduction in gas flow, power reductions and outages during this time period. (Ref 4, 19, 20)

Winterization cost of a wellhead or associated production equipment can varying considerably based on the size of facilities to be winterized, location, weather conditions, gas quality and other criteria.

Some approaches can be relatively simple with other facilities requiring more elaborate winterization equipment. Several scenarios based on conditions are described below with discussion of cost.

- **Case 1 - Cost Analysis for Simple Methanol Injection Pump and Hookup**

In some areas, possibly in many locations in the warmer climate production areas in Texas and New Mexico, a simple installation of a methanol injection system to be utilized during cold weather spells may be effective. Unlike northern climates where severe cold is experienced throughout the extended winter, the warmer production regions may not require significant equipment installation. If problem areas or key producing facilities are identified they may be protected with a simple investment.

A methanol injection and solar powered pump system can be installed for a capital cost of approximately $2,800 per installation. The systems are designed to reduce maintenance and operation expenses. Methanol costs are $12.00 per mmcf of gas throughput based on a treating ratio of 3 gallons of methanol per mmcf at a cost of $4.00 per gallon. Based on a well producing 1 mmcf per day of gas, methanol costs would equal $12 per day. On an annualized basis assuming methanol injection for 5 months the methanol cost equals $1800. Labor is estimated at $1000 per month or $5000 total. (Ref. 15)

Capital Cost = $2800 per installation.
Operating Cost for 5 months cold weather = $6800.

- **Case 2 - Cost Analysis for Building to Enclose Production Equipment**

In some cold weather climates the most efficient approach to winterization is to house the susceptible equipment in a small building or hut. This can sometimes save on more expensive approaches while at the same time protecting all equipment from year around weather conditions. These buildings can be heated with specialized heating equipment or in many cases can be warmed simply from the heat given off by the production equipment itself (assumes a heated production unit is within the building). In cold weather climates the design and construction of the production equipment includes the insulated housing, all of which is skid mounted for portability. When managed in this fashion the additional cost for winterization can be negligible compared to total well cost. Building cost can vary according to size requirements. This may be an option for critical equipment in the Texas, New Mexico producing regions.

Building cost = $2500 to $10,000

- **Case -3 - Cost Analysis for Equipment to Winterize Gas Wellhead in Very Cold Climate e.g., Canada (See Figure 10).**

In very cold production areas such as Canada, several winterization techniques need to be applied including methanol injection, line insulation, a small hut to protect chemical injection pumps small heaters, and methanol storage. The total cost of this installation is estimated at $34,425 per installation (see itemization below). (Ref. Table 10) Operating cost for a 5 month period is estimated at $6800 the same as Case 1.

Table 4 – Winterization Equipment Cost for a Gas Well Located in a Cold Climate

Equipment		Description		Cost
Winterized Production Unit - Net Cost for Winterization		Production unit winterized by internal piping and insulation.		$23,000
Timberline solar powered methanol pump w/solar panels				$2,800
Chemical Pump to Supply Chemical Inhibitors		Chemical Inhibitor Pump for Corrosion Protection		$1,350
Vent Gas Bottle to Supply Heater		System to Collect Vent Gas from Injection Pumps to Supply Heaters		$675
Methanol Tank		Stores Methanol		$1,000
Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft		Methanol Transfer		$500
Flow Line Insulation - $3/Ft - 100 Ft		Insulate Flow Line		$300
Flow Line Heat Tape - $4/Ft - 100 Ft		Provide Heat to Flow Line		$400
Fiberglass Hut for Enlcosing Production Equipment		Weather Protection		$1,500
Catalytic Heater for Location Housing		Heating for Hut		$500
Installation Cost - 2 men for 3 days at $50 per hour.		Labor		$2,400
Total Capital Cost per Well				**$34,425**

- **Case 4 - Cost Analysis for Equipment to Winterize Gas Wellhead Equipment Including Gas Production Unit**

In areas where a gas production unit is required to remove liquids (water or condensate or both) from the production stream a gas separator must be installed. The cost of a separator can vary based on

size which is dependent on the total flow volume to be handled by the separator. In warm weather climates the piping and instrumentation for the separator is installed externally to the unit as freezing is not an issue. For cold weather climates all of the piping needs to be internalized where heat from the production unit itself, in addition to insulation where required will prevent freezing. The additional design requirements, locating of piping and instrumentation in a confined space can add as much as $23,000 to the cost of a production unit. (Ref. 20) A less expensive option in some cases can be as described in Case 2 where all of the production equipment is housed in a small building or hut. These insulated buildings often require no additional heat beyond what is supplied by the heating unit in the production separator itself. (Ref 21)

- **Case 5 – Installation of Additional Storage Capacity at Critical Facilities**

During the recent cold weather spell in Texas and New Mexico many wells and compressor facilities were shut-in by automatic fail safe shut down devices that were triggered by tanks filling up with liquids. The fail safe shut-in devices protect against tank overflow and spillage. For critical facilities such as central compressor stations, gas processing plants or important well tank batteries, additional storage could be installed to allow for operations during bad weather conditions. Additional tanks are relatively inexpensive when compared to the impact of significant gas flow reductions.

Total Cost Discussion

The cost estimates for winterization can vary considerably based on the type of facility, the number of installations being considered, the degree of cold weather protection that is required, gas flow rates, pressures and other factors.

Simple weatherization such as for Case 1 above can be accomplished for an estimated $2800 capital cost and $6800 annual operating cost.

More comprehensive winter protection can increase the capital cost to over $11,000 per installation.

Winterization of production units, if required can add an additional $23,000 per installation depending on production unit size.

Overall, the cost of winterization, given the number of wells can be considerable. The simple table below illustrates cumulative capital cost with variable well counts and per well equipment costs.

Table 5 – Cumulative Cost for Winterizing Gas Wells – Variable Well Counts and Individual Well Equipment Cost.

			Well Count		
	10,000	20,000	30,000	40,000	50,000
Cost per Well			Cumulative Cost		
$2,500	$25,000,000	$50,000,000	$75,000,000	$100,000,000	$125,000,000
$10,000	$100,000,000	$200,000,000	$300,000,000	$400,000,000	$500,000,000
$20,000	$200,000,000	$400,000,000	$600,000,000	$800,000,000	$1,000,000,000
$35,000	$350,000,000	$700,000,000	$1,050,000,000	$1,400,000,000	$1,750,000,000

For 50,000 wells the total cost could vary from $125 million to $1.75 billion based on per well equipment needs. It may be that key compressor locations and gas processing facilities, if winterized or supplied with additional liquid storage tanks, could mitigate a significant percentage of the cold weather flow problem. The total number of these locations is likely to be much reduced from the number of wells noted in Table 5 above. If 1000 facilities of this type required a $10,000 investment each the total would equal $10 million, a much reduced number from those illustrated above.

Table 6 which follows itemizes capital cost and operating expenses for winterization of production facilities. The capital costs do not total within the spreadsheet as there is duplication of equipment in some cases.

Table 6 – Itemization of Capital and Operating Expenses for a Typical Gas Well – (Note, the Capital Costs Items Listed in the Table are not Totaled as Locations will require a Subset of these Items).

Gas Well Winterization Expenses						
Cold Weather Protection Equipment		**Description**		**Cost Per Well - Excludes Duplicate Applications**	**Source**	
Capital Cost						
Winterized Production Unit - Net Cost for Winterization		Production unit winterized by internal piping and insulation.		$23,000	Sivals Engineering, Odessa, Tx., Ref 20	
Methanol Injection Pump		High Pressure Pump to Inject Methanol		$1,648	ZKO Oilfield Industries, Ref. 11	
Timberline solar powered methanol pump w/solar panels				$2,800	Timberline Manufacturing, Ref. 22	
Chemical Pump to Supply Chemical Inhibitors		Chemical Inhibitor Pump for Corrosion Protection		$1,350	ZKO Oilfield Industries Ref. 11	
Vent Gas Bottle to Supply Heater		System to Collect Vent Gas from Injection Pumps to Supply Heaters		$675	ZKO Oilfield Industries Ref. 11	
Methanol Tank		Stores Methanol		$1,000	estimate	
Methanol Injection Tubing - High Pressure - $5/Ft - 100 Ft		Methanol Transfer		$500	Drillspot .com	
Flow Line Insulation - $3/Ft - 100 Ft		Insulate Flow Line		$300	Drillspot .com	
Flow Line Heat Tape - $4/Ft - 100 Ft		Provide Heat to Flow Line		$400	Drillspot .com	
Fiberglass Hut for Enlcosing Production Equipment		Weather Protection		$500	JW Williams Co. Casper, Wyoming, Ref. 21	
Catalytic Heater for Location Housing		Heating for Hut		$500	ZKO Oilfield Industries Ref. 11	
Installation Cost - 2 men for 3 days at $50 per hour.		Labor		$2,400	JW Williams Co. Casper, Wyoming, Ref. 21	
Operating Expense for Methanol Injection						
Methanol costs are $4.00 per gallon. Assume 10 gallons per day for 5 months. Methanol cost = 5 months * 30 days/mo.*10 gal/day * $4/gallon = $6000		Methanol Cost		$6,000	Timberline Manufacturing, Ref. 22	
Maintenance - Per Month - $200 @ 5 months				$1,000		
Total - Cost per Year				$7,000		

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