

Southwest Kansas H₂S and Low Pressure Task Force

Interim Report to the Legislature

March 8, 2006

Acknowledgement

The Commission wishes to express its appreciation and acknowledge the tremendous effort put forth from the volunteer members of this group. Not only have they devoted their time and resources to this project, they have completed a tremendous amount of work in a very short amount of time to address complex energy supply issues.

Brian Moline, Chair
Michael Moffet, Commissioner
Robert Krehbiel, Commissioner

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Introduction

At the direction of members of the Kansas legislature, the Corporation Commission agreed to facilitate a working group in an effort to define the extent of Hugoton field operational issues that impact natural gas supply in rural areas of Southwest Kansas. The issues precipitated from the termination of gas supply to 110 consumers served from gas gathering pipelines in Southwest Kansas. The supply termination was based on concerns over the presence of Hydrogen Sulfide, (H₂S), in the gas stream as well as the problem of inadequate delivery pressure for this group of consumers.

The first meeting of the group was held on March 1, 2005. The meeting was attended by 66 stakeholders representing legislators, commissioners, gas gatherers, producers, gas transmission companies, gas distribution companies, agriculture and residential consumers, and various state agencies. After an extensive discussion from many different perspectives, a mission statement for the project was drafted by Commission Staff, (Staff). This statement is as follows:

1. Develop a clear technical understanding of the impact that H₂S and low pressure has on consumers of unprocessed natural gas within the Hugoton field area and investigate alternate means of providing natural gas service to these consumers.
2. Acquire input from interested parties on the legal, contractual, and public policy aspects that direct supply of natural gas to rural consumers in the Hugoton Field.

This working group, which has come to be known as the Southwest Kansas H₂S and Low Pressure Task Force, was divided into seven teams in order to address a multitude of broad ranging issues. The lists of topics to be addressed were developed by Staff with input from the discussion at the first Task Force meeting. This document is a compilation of the findings presented by each of the Task Force teams. In addition to the teams' findings, an additional conclusions section is included in this document which provides Staff's summary and recommendations of issues remaining to be resolved.

The seven task force teams and the goal of each team are listed as follows:

Team 1: *Data Acquisition*

Team 1 was given the assignment of gathering current data to accurately depict the extent of H₂S contamination and to obtain current values of the field working pressure. This team also obtained electronic versions of the maps required to be filed with the Commission under K.A.R. 82-3-801(a)(5).

Team 2: *Defining H₂S Contamination and Impact on Southwest Kansas*

Team 2 researched technical literature, state and federal regulations, and company operating policies to develop a recommendation regarding the threshold level of H₂S contamination within a gas stream serving consumers. Particular emphasis was placed on obtaining consensus on the H₂S contamination level that would place residential consumers at risk.

Team 3: *Summary Report on H₂S Awareness for the Public and Emergency Responders*

Team 3 was assigned the task of identifying broad groups of stakeholders that be impacted by H₂S contamination. After making this identification, Team 3 developed methods of delivering a consistent message to the public as well as emergency responders. The broad groups include: the energy industry (producer, gatherer, transmission, LDC); the general public; public officials; emergency responders; agricultural industry; and gas consumers in close proximity to gathering lines.

Team 4: *Gas Service Termination Practices*

Recognizing that consumers connected to gathering systems are at risk of losing gas supply, Team 4 was given the task of developing a best management practice that would minimize disruptions in energy supply to the affected consumer. The efforts of Team 4 also incorporated the requirements of House Bill 2263 passed during the 2005 legislative session.

Team 5: *Alternate Means of Supplying Natural Gas*

Team 5 investigated the feasibility of supplying processed natural gas to consumers that are now served by unprocessed gas from gathering systems. Construction of new infrastructure is contingent upon the amount of irrigation load that could be committed to using minimum volumes of natural gas. The team also focused on providing information on the location of pipelines that could assist entrepreneurs in developing alternate means of acquiring a supply of processed gas. Team 5 also provided research data on the impact of switching engines and residential use to alternative energy sources.

Team 6: *Regulatory and Industry Practices Regarding H₂S Contamination*

Team 6 investigated the applicability of regulating operations or practices based on the amount of H₂S contamination in a produced gas stream. Research was done reviewing the regulatory practices of other states as well as industry practices when dealing with H₂S contamination.

Team 7: *Policy and Legal Issues Associated with Consumers Connected to Gathering Systems*

Team 7 was convened to investigate the policy and legal issues associated with the mission of the task force. However, the work of this team was superseded by the Commission opening Docket 06-GIMG-400-GIG to investigate Commission policy regarding customers served directly or indirectly by gas gathering systems. Therefore, no report from Team 7 is included in this document. To review all filings and documents in the Commission docket, go to <http://www.kcc.state.ks.us/docket/docket.htm> and type in the above listed docket number in the search box.

Executive Summary of Task Force Findings

The data collected by the Task Force shows that H₂S contamination is widespread throughout the gas producing regions of Southwest Kansas. Attachment 1-1 is a H₂S concentration map of the area using the data collected by Team 1. The vast majority of samples taken indicated a concentration level of less than 30 parts per million (ppm) of H₂S in the gas stream. However, it must be noted that many wells in the Hugoton field are treated for H₂S on a regular basis. It is unknown if the reported values were measured before or after treating to remove H₂S. It is the opinion of the task force that the readings are most likely taken after the gas was treated to remove H₂S. Therefore, the only reliable conclusion that can be drawn from the H₂S data is that it can be controlled during the gas production operations. At this time, the actual H₂S contamination level of the producing reservoirs can not be determined with any accuracy.

The task force focused on the consequences of low system pressure, the presence of H₂S, and the effects of low pressure and H₂S on the supply of natural gas to consumers connected directly to gas gathering systems or wellhead sources of supply. The data collection effort identified at least 900 consumers that fit this category. This gas supply is typically used to power pumps for irrigation wells. To a lesser extent, this source of gas provides energy to residential homeowners, gas production company offices, and commercial users such as feedlots. Gas supplied from wellheads and gathering systems is unprocessed. That is, it has not been sufficiently conditioned to remove undesirable constituents from the gas stream, and it does not meet the specifications of pipeline quality gas that is typically delivered to gas consumers. The task force recognizes the best solution to providing gas to these consumers would be supplying them with pipeline quality gas. However, the low density of customers in this rural area, the high commodity price of natural gas, the low commodity price of agricultural products, and the unknown supply of irrigation water combine to make the expansion of a gas distribution infrastructure a high risk economic venture. Section V of this report provides examples of expansion projects that have been completed within the last 10 years. The task force also developed extensive maps of the existing gas gathering infrastructure with the expectation that a portion of gathering lines can be eventually used to provide processed gas to consumers.

H₂S has long been known as a toxic gas. The primary means of the toxic effects from H₂S on humans is through inhalation. As a contaminant of natural gas, human exposure to H₂S occurs only when the gas is released to the atmosphere. Therefore, the primary means of controlling H₂S exposure is through preventing any leaks from gas piping. Because H₂S is corrosive to metals under certain conditions, the task force researched the minimum concentration at which H₂S could become corrosive to metal piping. Should the H₂S contaminated gas breach the integrity of the piping system, the next level of concern is the location of the leak in relation to the environment of the persons placed at risk. For example, a release of H₂S contaminated gas in a confined enclosure such as the basement of a home or the offices of a compressor building would place the occupants at a higher risk than a release in open air adjacent to an irrigation pump. The task force reviewed various studies to determine the level of H₂S contamination that will result in

metal corrosion and reviewed studies dealing with health effects of H₂S in ambient air. The findings of the task force recommended a very conservative value for H₂S in gas of .001 psia partial pressure to be considered in combination with a .03 ppm H₂S concentration in ambient air as the threshold values of H₂S that should be considered a risk the general public. Section II of the report titled, "Defining H₂S Contamination" gives complete details of the reasoning behind this determination.

Once the level of H₂S has crossed the risk threshold, it is necessary to manage the operations of the gas deliverability system to minimize the consequences of the perceived risk. The task force considers education of the public and emergency responders to be the first step necessary in managing this risk. To that end, Section III of the report titled, "Public Awareness of the Risks of H₂S", provides recommended messages and identifies public organizations that can be used to provide information on H₂S to the public. If it becomes necessary to disconnect a consumer from gas supplied by a gas gathering system, Section IV of the report includes recommended management practices to coordinate the disconnection process and supply alternate supplies of energy.

Kansas has no laws that regulate the release of H₂S from oil or gas production operations. The task force researched activities of nearby states and industry best practices in dealing with H₂S. This research indicates the operators of the majority of wells in Southwest Kansas currently follow the industry H₂S management practices published in the American Petroleum Institute's Recommended Practice RP55. As noted earlier, the low H₂S contamination levels reported in Section I of the report do not indicate a need for regulatory action to protect public or workplace safety. Rather, the task force is recommending additional sampling for H₂S before treatment and the results reported to the KCC. The task force suggests the measurements can readily be accomplished when the operator conducts annual gas quality measurements as typically required in gas purchase contracts. If the reported data indicates H₂S concentrations are consistently found at levels of 100 ppm or greater, the task force recommends regulations protecting public safety from H₂S be considered for promulgation at that time.

Section I

Team 1 – Data Acquisition

Background

On March 1, 2005, the Kansas Corporation Commission held a meeting to “facilitate a working group in an effort to define the extent of Hugoton field operational issues that impact the natural gas supply in rural areas of Southwestern Kansas.” From this meeting, Team 1 was ask to acquire data concerning this issue from operators and gas gatherers from their wells and systems. The KCC identified and sent 271 letter requests for well information on wells and gathering systems that had sold gas as reported to the Kansas Department of Revenue (KDOR) in the 10 counties in southwestern Kansas within the past two years. As of September 2005, the KCC has received responses from a total of 254 operators and gas gatherers. This represents 93.7 % compliance rate. The data received was divided into sampling information from gas well operators and sampling information from gas gatherers. The first set combines records from 149 operators representing 11,499 wells. In all, 19 gatherers that submitted data representing approximately 15,364 individual sampling data points. Due to late submissions, these data sets are still subject to change.

Analysis

Staff has identified and listed certain areas of H₂S concentrations and the respective gathering system working pressures, as well as certain producing formations that may contain H₂S. This data will is represented graphically by the regional maps attached as Attachment 1-1 and 1-2. Analyses of other trends are depicted in the following attachments:

Attachment 1-3) All wells as reported by the operators with the H₂S concentration range; Of the wells that reported sampling for H₂S, very few sampling points had H₂S above 30 ppm.

Attachment 1-4) All sampling points as reported by the gas gatherers with the H₂S concentration range;

Attachment 1-5) All wells as reported by the operator with the H₂S concentration range from all producing formations or groups;

Attachment 1-6) Wells as reported by the operator with the H₂S concentration range from the Chase Group, Council Grove Group and Topeka Formation;

Attachment 1-7) Wells as reported by the operator with the H₂S concentration range from the Marmaton, Morrow, Keyes, Chester, and Mississippian formations;

Summary

The following tables illustrate the range of H₂S sampling as submitted by the operators and gas gatherers:

Data Source	Reported H ₂ S Concentration , (ppm)	Number of Sampling Points	% of Sampling Points
Gas Gatherers	0	4,558	35%
Gas Gatherers	1<ppm<30	8,190	63%
Gas Gatherers	31<ppm<500	161	1.2%
Gas Gatherers	Total	12,909	
Producing Wells	0	4,919	53%
Producing Wells	1<ppm<30	4,275	46%
Producing Wells	31<ppm<50	76	0.8%
Producing Wells	51<ppm<99	33	0.4%
Producing Wells	100<ppm<1,550	47	0.5%
Producing Wells*	Total	9350	

* At least 719 of the total wells reported are under some form of H₂S treatment.

Based on the data provided, very few of the sampling points have H₂S contamination above 30 ppm. Section II of this report discussed the risks associated with a contaminant level of 30 ppm. It must be noted that many wells in the Hugoton field are treated for H₂S on a regular basis. It is unknown if the reported values were measured before or after treating to remove H₂S. It is the opinion of Team 1 that the data collected did not adequately reflect the effect of removing H₂S from the gas stream through treatment and that the readings obtained through the data collection process are most likely taken after the gas was treated to remove H₂S. Therefore, the only reliable conclusion that can be drawn from the H₂S data is that it can be controlled during the gas production operations. Although the attachments indicate H₂S is not a severe problem in the producing reservoirs of Southwest Kansas, the task force was unable to determine the actual H₂S contamination level of the producing reservoirs with any level of accuracy.

Section II

Team 2 – Defining the H₂S Contamination and Impact on Southwest Kansas

Purpose

The purpose of this document is to capture and set forth information collected and developed in regard to understanding the problem of hydrogen sulfide (H₂S) contamination in the gathering and transmission pipeline systems of Southwest Kansas. This document was prepared by a working group comprised of energy and energy-related industry professionals and private citizens under the direction of the Kansas Corporation Commission (KCC). On March 1, 2005, the KCC commissioned six work groups to investigate, define, and understand the problem of increased presence and concentration of H₂S in natural gas production and operations, and the potential impact to unprocessed gas consumers.

This document will present information on the following topics:

- Typical pipeline gas quality specifications
- H₂S corrosive levels in piping systems
- H₂S corrosive levels in irrigation engines

Industry gas quality specification and Corrosive levels of H₂S

The current industry standard for hydrogen sulfide (H₂S) gas quality for gathering and transmission pipeline systems varies by individual system and ranges from 4 ppm to 16 ppm (parts per million). Responsibility for monitoring and enforcement of these gas quality specifications rests with the gathering, transmission, and local distribution system operators. Maximum H₂S levels allowed will vary by operator and contract constraints¹. Of the Kansas gathering companies researched, four companies have maximum H₂S levels of 4 ppm and two have maximum levels of 16 ppm². Attachment II-1 gives examples of tariff provisions for maximum H₂S content for interstate (transmission) and gathering pipelines.

¹ For further information, see Interstate Natural Gas - Quality Specifications & Interchangeability, Mr. Joseph Wardzinski, Senior Associate, Dr. Michelle Michot Foss, Executive Director and Mr. Fisoye Delano, Senior Researcher, University of Houston, Institute for Energy Law and Enterprise.

² Pioneer, Regency Gas, Anadarko Gathering, and OneOk have maximum levels of 4 ppm. Duke Energy Field Services and WGP-KHC, LLC have maximum levels of 16 ppm.

Corrosive levels of H₂S on metallic piping in wet gas systems

The purpose of this section is to determine, if possible, the threshold level of H₂S in natural gas and at what point it becomes corrosive to steel, and other commonly used metallic materials. Much literature has been written on H₂S and its effects on internal corrosion of steel pipelines in wet gas gathering systems and will aid in this effort.

Perhaps the best way to start is to discuss where hydrogen sulfide is found, how it occurs, and why it is corrosive. H₂S gas occurs naturally in crude petroleum, natural gas, volcanic gases, and hot springs. H₂S is a flammable, corrosive, colorless gas with a characteristic odor of rotten eggs. In addition to naturally occurring H₂S, another cause is sulfate reducing bacteria (SRB's) which is a group of anaerobic bacteria (does not require oxygen).

When H₂S is dissolved in water, it forms a weak acid which promotes corrosion (i.e., the consumption of the base material) and hydrogen stress cracking. The most common types of corrosion where H₂S is present consist of pitting, blistering, embrittlement, fatigue, and cracking. The severity of the corrosion due to H₂S is determined by factors such as oxygen and carbon dioxide (CO₂) levels, temperature, gas velocity, pH levels less than 6.5 (acidic), presence of water (conductive electrolyte), internal/external stresses, concentration (parts per million or partial pressure levels). The combination of CO₂ and H₂S is more corrosive than H₂S alone, and can be considered very corrosive when combined with even minute quantities of oxygen. Hydrogen induced cracking (HIC) attacks steel on an atomic level where hydrogen is absorbed into the metal. Areas which are subjected to stress are extremely vulnerable to HIC, and corrosion.

- **General Corrosion**

Iron sulfide is formed as a byproduct from hydrogen sulfide corrosion reactions. In a dry gas system, free of oxygen and chloride salts, the iron sulfide actually forms a protective layer of black powder or scale inside the pipe. Although, this protective layer can be damaged by liquids in the pipeline, which in turn allows localized corrosion to occur because the iron sulfide is cathodic to the steel. However, according to this review, H₂S concentrations as low as 1 ppm can be corrosive under the right conditions. An atmospheric partial pressure (where partial pressure is defined as the pressure exerted by an individual gas in a gas mixture) of .001 psia or greater is considered corrosive according to the information reviewed. This is approximately equivalent to 34 ppm of H₂S when the line pressure is at 15 psig; a common delivery pressure for residential and agricultural users. See attachment II-2 for a more detailed relationship of ppm and partial pressure and additional information on corrosion of steel in the presence of various gases.

Similar to other forms of corrosion, corrosion associated with H₂S is an electro-chemical process. For corrosion to occur certain conditions must be present:

1. There must be an anode (That which corrodes)
2. There must be a cathode (That which is protected by the anode being consumed)

3. There must be a metallic or electrically conductive path (To connect the anode and cathode, in this case the pipe)
4. There must be an electrolyte (Water in the line)
5. There must be a difference in potential between the anode and cathode (Driving force)

In addition to electro-chemical corrosion, H₂S may react with certain types of metals to cause flaking which can damage appliances. For that reason, Copper or brass house piping should be replaced and avoided when H₂S is present in levels at or above 0.3 grains (4.92 ppm) per 100 standard cubic feet of gas as required in The National Fuel Gas Code - 5.6.3.2 (2002 edition). Galvanized steel piping should also be avoided due to similar flaking problems.

- **Hydrogen Induced Corrosion**

Another form of corrosion caused by H₂S is hydrogen induced corrosion, often called embrittlement, or sulfide stress cracking. In this situation atomic hydrogen is released by the reaction of H₂S with the base metal, and diffuses into the matrix structure of the metal. Atoms of hydrogen recombine in the matrix to form molecular hydrogen (H₂). This is a much larger molecule which becomes trapped in the molecular structure of the steel. The result is the “holes” in the metal matrix which allow it to flex and absorb stress, are slowly “filled-in”. This eliminates the “flex” and tightens or stresses the matrix to the point it becomes brittle (i.e., embrittlement). Eventually the metal (pipe) will fail as it is unable to handle the stresses of operations.

Attachment II-3 shows a graph which depicts the H₂S contamination levels and the total system pressure where hydrogen induced corrosion, or sulfide stress cracking occurs. Below a total system pressure of approximately 4.4 bar absolute, or 65 psia, this type of corrosion is not a concern. However, as the metal matrix becomes stressed, it also becomes more susceptible to general corrosion, or attack or dissolution of the base material.

Level at which H₂S becomes corrosive to irrigation engines

The availability in the public forum of any specific information on H₂S corrosion of gas fueled engines is very limited. Rather the topic, and the permissible level of H₂S is more an individual determination dependent on the application and desired performance. However, in order to obtain an insight into this issue, two industrial sources were contacted for their opinions and practices. The first contact was a gas compression engineering, fabrication, and rental firm; Compression Systems, Inc. (CSI). The second contact was one of the large engine manufacturers; Caterpillar, Inc.

1. Mr. Jim Holt, a design engineer with CSI in Oklahoma City, was contacted for his opinion. CSI designs, builds, sells, and rents engine/compressor packages. Jim indicated that if the application is a new engine on a new package, a situation in which CSI has a

considerable investment, they typically will not allow over 50 ppm H₂S in the fuel gas (on a continuous basis). However, if it is older rental equipment where the initial investment has been recovered, they may allow up to 100 ppm of H₂S in the fuel gas. Mr. Holt was informed that the pipelines at issue have an H₂S specification of 4 ppm, with the possibility of having higher concentrations. In this situation, Mr. Holt indicated that he would not be concerned in the slightest about using that gas in engines.

2. Mr. Bob Gonzales, the Petroleum Market Development Manager for Caterpillar, Inc. was asked what standards Caterpillar has for using H₂S contaminated fuels as the engine fuel source, and if they have any specific studies on the additional corrosion or maintenance requirements for varying levels of H₂S in fuel gas. On the latter, Mr. Gonzales confirmed that Caterpillar had not conducted, nor participated in any such study. However, Mr. Gonzales was able to provide a PDF copy of their Fuel System Manual for engines (attached below) which touches on H₂S contamination on pages 12 & 13. Attachment II-4 is an excerpt from this manual and shows that Caterpillar considers H₂S levels of 10ppm or below to be "sweet" for combustion purposes, and should not be considered any different than a standard fuel. Above this level various precautions and maintenance activities are recommended dependent upon the application.

Conclusions

1. Acceptable levels of H₂S in the gas stream to prevent corrosion hazards to piping and equipment:

The actions and reactions of H₂S in a pipeline environment are extremely complicated processes. Levels reviewed by the work group of H₂S partial pressures where corrosion is a concern ranged from 0.001psia to 0.05psia.

The purpose of this document was to examine how H₂S levels affect not only gathering and transmission pipeline systems, but more importantly, end-users of unprocessed gas, such as domestic and irrigation users. In the latter situations, the level of periodic inspection and maintenance will be very low, far below that of industrial applications. Therefore, a very conservative approach is suggested to insure appropriate levels of safety and continued operation.

For the purposes of this review, considering all of the variables involved, a conservative approach was taken and it is suggested and put forward for consideration that H₂S levels down to 0.001 atmospheric partial pressure be considered corrosive, although the combination of CO₂ and H₂S is more corrosive than H₂S alone, and can be considered very corrosive when combined with even minute quantities of oxygen. Concentration of H₂S or its corresponding partial pressure is only one of many potential factors that impact corrosivity of a given gas stream. However, the time to failure will vary by application and can become very long depending on the circumstances. In the case of a residence, the life of the in-home piping system should not be reduced below 20 years (or the expected occupancy) by the corrosivity of the fuel; however we found no long term studies of the affects of elevated H₂S levels being used in home appliances.

In an attempt to further define and support a suggested minimum H₂S corrosion threshold level, and verify the levels reviewed above for the Hugoton field, it is suggested that an attempt be made to gather relevant documentation related to historical leakage due to internal corrosion. Additional references describing corrosion due H₂S contamination are contained in Attachment II-5.

2. Levels at which H₂S and its combustion product sulfur dioxide become toxic in residences:

Different agencies have determined the exposure guidelines for H₂S. While the general limits are on the same order of magnitude, the exact permissible exposure limits have been revised over time, and may be different. Currently, both the National Institute for Occupational Safety and Health (NIOSH) and the Occupational Safety and Health Administration have set a reoccurring exposure limit (REL) of 10ppm hydrogen sulfide (H₂S) concentrations which exceeded the 10-minute NIOSH ceiling limit of 10 ppm and the 10-minute OSHA PEL of 20 ppm.

The Occupational Safety and Health Administration (OSHA) permissible exposure limit (PEL) for hydrogen sulfide of 10 ppm is set 10 times lower than the revised "immediately dangerous to life and health" level of 100 ppm set by the National Institute for Occupational Safety and Health (NIOSH).

The principal route of exposure to hydrogen sulfide is inhalation. Like carbon monoxide and the cyanides, hydrogen sulfide is classified as a chemical asphyxiant. Exposures to this gas can interfere with cellular respiration and cause death if an individual's cells are deprived of oxygen (biochemical suffocation). At low concentrations (i.e., < 10 ppm), hydrogen sulfide causes irritation of the eyes, mucous membranes, and upper respiratory system. When exposed to higher concentrations (10-50 ppm), persons tend to experience mild eye and upper respiratory irritation, headaches, and dizziness. Concentrations from about 50-200 ppm can cause severe eye and respiratory tract irritation, acute conjunctivitis, lacrimation, and difficulty breathing, as well as a sudden loss of consciousness.

3. Acceptable levels of H₂S in ambient air to prevent safety hazards to health, combustion products (Sulfur Dioxide):

The following information is provided as reference material. This includes ambient air quality standards and workplace standards. It should be noted the Kansas Department of Health and Environment has no statutory or regulatory authority to establish indoor air quality standards for the venues that are the focus of the Kansas Corporation Commission study on Hydrogen Sulfide in the Southwest Kansas Gas Supply. If such standards are established for this purpose, it is believed the concurrent monitoring and response efforts that must also be developed would present serious administrative and implementation difficulties. These include factors such as monitoring device location, maintenance and calibration. In addition, training in the proper use and response to high readings would be required.

Attachment II-6, Table A is a listing of hydrogen sulfide ambient air quality standards used by several states. These have been developed to address certain industries such as confined animal feeding operations and refineries. Many of the standards allow for a certain number of exceedances before a violation of the standard is considered to have occurred. Workplace standards for hydrogen sulfide are listed in Attachment II-6, Table B. It is important to understand these do not pertain to residential exposure situations. These only pertain to the workplace time exposure for healthy adults. These do not cover the more sensitive population such as the elderly, the very young and those with illness. It must also be considered that a person spends much more time at home than at the workplace.

Attachment II-6, Table C lists the federal ambient air quality standards for sulfur dioxide. The federal standards include 24-hour maximum and annual mean concentration thresholds. These do not cover the more sensitive population such as the elderly, the very young and those with illness. A serious secondary concern with sulfur dioxide is the formation of sulfuric acid in furnaces and vents. Higher efficiency furnaces have lower exhaust gas temperatures which would increase the likelihood of condensation of sulfur dioxide, and the resultant corrosion problems.

4. Dispersion model

The links listed here are for a simple model that might be used to determine how significant a problem could be if a leak occurred at an irrigation pump engine. The ALOHA model can predict how a cloud of gas might disperse in the atmosphere after a release. The model can predict rates of chemical release from broken gas lines, leaking tanks and evaporating puddles and can model the dispersion of both neutrally-buoyant and heavier-than-air gases. It should be noted that these dispersion models consider dispersion of pure substances, not mixtures of gases. There is discussion in API RP-55 that the radius of exposure is significantly overstated when considering a mixture of natural gas and hydrogen sulfide because of density differences. Attachment II-7 is a simplistic chart that shows the effects of air dilution on H₂S concentrations if 100% mixing occurs. The Lower Explosive Limit for natural gas occurs at a gas concentration of 5% gas in air.

<http://www.epa.gov/ceppo/comeo/marplot.htm>

<http://www.epa.gov/ceppo/comeo/aloha.htm>

Summary

This working group was charged with evaluating at what concentration hydrogen sulfide and sulfur dioxide become toxic in venues such as residences or near irrigation pump engines.

Hydrogen sulfide and its combustion by-product, sulfur dioxide, are highly toxic gases that can kill or cause serious injury if inhaled and can burn the skin and also the eyes and

other moist body organs. Hydrogen sulfide is heavier than air so it tends to concentrate at the bottom of poorly ventilated spaces. The principal route of exposure to these gases is inhalation. It is believed the concurrent monitoring and response efforts that would need to be developed to monitor concentrations in the venues focused on by the KCC study would present serious administrative and implementation difficulties. Therefore, one must approach this in a conservative manner to be protective.

For the purposes of this review, considering all of the variables involved, a conservative approach was taken. The working group puts forth for consideration the following:

- That the natural gas supply have a hydrogen sulfide concentration such that should a leak occur and the natural gas is released from containment within a residence, that the resulting hydrogen sulfide concentration in the air not exceed 0.03 ppm which is a Standard established by several nearby states for the Recommended Exposure Limit. At this concentration the health effects would most likely consist of eye irritation.
- That the natural gas supply have a hydrogen sulfide concentration such that should a leak occur and the natural gas is released from containment within an enclosed structure other than a residence, that the resulting hydrogen sulfide concentration in the air not exceed 0.20 ppm which is a standard established by a nearby state for the recommended exposure limit.
- That the natural gas supply have a hydrogen sulfide concentration such that should a leak occur and the natural gas is released from containment at an irrigation pump engine site, that the resulting hydrogen sulfide concentration in the air not exceed 10 ppm for a 10 minute exposure time which is a Federal Standard for the Recommended Exposure Limit.
- That the natural gas supply have a hydrogen sulfide concentration such that should a leak occur and the natural gas is released from containment at an oil or gas site, that the resulting hydrogen sulfide concentration in the air not exceed 10 ppm for a time weighted average which is a Federal Standard for the Recommended Exposure Limit.
- That the natural gas supply have a hydrogen sulfide concentration such that combustion results in a sulfur dioxide concentration in the air not exceeding 0.14 ppm, which is a Federal Standard for the 24-hour maximum.

It must be noted that the federal workplace standards do not cover the more sensitive population such as the elderly, the very young and those with illness and that a person spends significantly more time at home than at the workplace.

Disclaimer

The information, conclusions and suggestions developed and set forth in this document were obtained with best efforts in good faith by a working committee comprised of individuals from a cross section of the hydrocarbon industry and public section. While every effort has been taken to insure the accuracy of the content, the reader is warned, and strongly advised that the opinions and recommendations do not represent an endorsement by any individual(s), organization(s), agency(ies) or company(ies), nor is any warranty expressed or implied for any use, application, or interpretation of this material.

Section III

Team 3 – Summary Report on H₂S Awareness for the Public and Emergency Responders

Objective

Our goal was to develop a communication plan for public and emergency responders' H₂S education. After several discussions regarding the scope of the objective, we narrowed our focus to the short-term strategy of providing information to end users of unprocessed natural gas and training to emergency first responders.

Outcome

End-Users

H₂S Awareness Letter (See Attachment III-1) –

- A template H₂S awareness letter was developed for use by utilities, producers, gatherers, pipeline companies, distributors or any other entity providing unprocessed natural gas to end users.
- The letter directs consumers to the KCC website for more detailed information.
- A list of questions was prepared in anticipation of consumer inquiries following receipt of the letter.
- The team recommends that the KCC provide the template letter to such entities and request an annual consumer notification.
- The team recommends that the KCC request a copy of the annual communication piece and a list of customers receiving the information.

Emergency First Responders

- The team recommends that the KCC contact Kansas One Call and ask that H₂S information be provided during annual training sessions for emergency responders and excavators.

Other Identified Stakeholders

The following groups were identified as possible candidates for H₂S communications. It is noted if training is provided or can be accessed, or if a communication venue exists. The task force has provided presentations on the hazards of H₂S to the following groups: Southwest Kansas Royalty Owners Association; Kansas Association of Counties; Kansas Independent Oil and Gas Association; the Measurement and Pipeline Institute Seminar; and the Kansas Legislative Policy group.

The team recommends general information on the hazards of H₂S should be made available through one reference point. The KCC website is considered the optimal source for providing information and/or links that could be utilized for communications or presentations.

Other Identified Stakeholders

- Consumers in close proximity to pipelines or wells within city limits
- Oil & Gas Industry
 - Major companies provide H₂S training.
 - Independent companies, oil field workers and service industry can access
 - Gas Measurement & Compressor Institutes, Liberal
 - Technical colleges
 - Energy Training Council (www.energytrainingcouncil.org)
 - Other possible communication venues
 - KIOGA
 - Kansas Petroleum Council
- Agricultural Industry – Possible communication venues
 - KSU Extension offices/meetings
 - SW Kansas Irrigators Association
 - SW Kansas Royalty Owners' Association (Leo Haynos met with this group)
 - Kansas Livestock Association, Feedlot Services section
 - Kansas Farm Bureau
 - Ground Water Management District Meetings
- Governmental entities
 - Legislative – Representatives, Senators, Staff
 - Local officials – City, County
 - League of Kansas Municipalities
 - Kansas Legislative Policy Group
 - Kansas Association of Counties

Section IV

Team 4 – Gas Service Termination Practices

Gas consumers connected to gathering lines are dependent on the production system for their supply of gas. As such, the supply is affected by reservoir depletion or, in the case of H₂S, by contamination of the supply. Unless a distribution network is available, this supply configuration will eventually result in gas service no longer being available to the consumer. At that time, gas service to the consumer will be terminated by the company providing the service. Team 4 was given the task of developing a best management practice that would minimize disruptions in energy supply to a customer that is affected by termination of service.

Recognizing every company has unique business practices, Team #4 decided to design a generic flow diagram for suppliers to follow after the determination and documentation was in place to terminate the supply of gas to the end use customer. The flow diagram, (See Attachment 4-1), assumes there is no way to continue to supply gas safely from a gathering or production system. The following is a brief narrative for each step of the flow diagram.

1. Determination has been made that gas supply must be terminated

If supply is terminated because of H₂S contamination, Section 2 of this report provides detailed information that may be considered regarding the health hazards and corrosive levels of H₂S. The supplier may use this information when they meet with the customer to discuss service termination.

2. Supplier verifies end user and affected parties

Many times the occupant of the resident is not the property owner. The supplier will need to verify through courthouse records or other legal documentation the actual owner of the property. Both the property occupant and the owner(s), (if different from the occupant), should be notified as part of the termination process.

3. Supplier makes diligent effort to contact end user

The supplier should obtain the current address from the county assessor's office, or other means, and locate the physical address and phone number of the affected parties. This effort should be documented for record.

4. Supplier meets with end user / affected parties to explain termination

This meeting should be in person if at all possible. Section 3 of this report provides examples of written correspondence that provides educational information for the end user about the H₂S / Low Pressure concern and why termination is necessary. Attachment 4-2 is a list of county official contacts who can explain the code requirements for any and all conversions to an alternative energy source.

5. Supplier makes formal notification in writing to end user / affected parties

This step should include a certified letter of notification to the end user / affected parties for the record. If there is going to be any offer of assistance for conversion to an alternate energy source, from the supplier, it should be documented in this letter. The communication should also take into consideration response time, alternative fuel sources available, and the time of the year. If the end user/affected party is connected to a gathering system subject to KCC jurisdiction, the notification must inform the end user/affected parties of their right to appeal the termination to the KCC as per the requirements of House Bill 2263.

6. Decision is made by end user (Accepts)

End User accepts alternative energy source and alternative is implemented with documentation of conversion. The meter is removed by the supplier and supplier databases are updated.

7. Decision made by end use (Declines)

End User declines alternative energy source or options from supplier. Supplier sends certified final disconnect notice to end user. The end user has the option to pursue other options that may be available to them. This could include negotiation, arbitration, legal action, or in some cases, appeal to the KCC under the requirements of House Bill 2263. This bill was passed during the 2005 legislative session. It provides consumers connected to KCC jurisdictional gas gathering systems the right to appeal to the Commission to determine the reasonableness of non-contract related curtailments that would adversely affect end users.

Section V

Team 5 – Alternate Means of Supplying Natural Gas

Summary

Team 5 is investigating the potential of supplying processed natural gas to consumers that are now served by unprocessed gas from gathering systems. We quickly reached the conclusion that building systems for limited residential load is not feasible so the effort has focused on the potential of serving irrigation load. It should be noted that any residential load in the area of irrigation systems will benefit from the availability of natural gas. Even with irrigation load, a certain density of consumers per mile of pipeline is required to make the project economically feasible. There will be some irrigation consumers that will no longer be able to use natural gas should the gathering system be unable to serve their needs. To meet that contingency, Team 5 also researched the impact of switching engines and residential use to alternative energy sources. The categories for our discussion can be summarized as follows:

- Processed gas mapping effort
- Efficiency & feasibility of extending gas distribution systems
- Interstate transmission line taps
- Comparison of alternative energy sources

Processed Gas Mapping Effort

KCC has acquired electronic mapping information on the majority of gas lines in Southwest Kansas. The lines are divided into gas gathering lines, processed gas lines, and transmission lines. The processed gas lines include gas distribution lines as well as processed gas lines operated by gathering systems as fuel supply for their facilities. Interstate transmission lines are also included in the database. In order to facilitate an expansion of the processed gas infrastructure, the database also includes the location of consumers that are connected to supplies of unprocessed gas. The task force is working with the Kansas Water Office to acquire information on the location of all natural gas powered irrigation motors. This data should become available in the spring of 2006. While this data is in the possession of the KCC, Staff has not developed appropriate protocols for the dissemination of this information. Therefore, this information is not available over the internet. Availability at this time is considered on a case by case basis.

Efficiency & Feasibility of Extending Distribution Systems to Serve Irrigation Load

The primary factors related to gas distribution extensions is cost of the extension and density of customers. Factors affecting the economic feasibility of an extension are unique for each expansion project. Often the entity proposing the expansion will

negotiate the terms of the project with the consumers to be connected to the supply system. The Rural Gas Self Help Rule, (K.S.A. 66-2101 et seq.) allows individuals, competing public utilities, and other entities to openly compete with certificated public utilities serving irrigation customers connected to gathering systems. The open competition provided by Self Help as well as the recently constructed infrastructure database will provide opportunity and tools for entrepreneurs to expand the gas infrastructure in this area. The following is a survey conducted by the task force regarding the feasibility of recent expansion projects:

Considerations on Feasibility:

Did you need a certain number of wells to make it work?

Southwest Kansas Irrigation Association, (SWKI): Not necessarily, but I don't know of any under 10 wells, and they were all spaced closely together.

Midwest Energy, (MWE): If connecting to an interstate pipeline, the expense of a tap is such that a significant number of wells need to be connected to warrant the investment. It will take at least 20 wells using the tap cost that I have seen. The concentration of wells is also an important issue. We have had very small groups of wells that we have connected, but we had a distribution system to build from.

Did you consider rate of return or years to payout in building the system?

SWKI: The farmers paid for them, so I can't speak for them. But all of them were scheduled to physically pay off the loans in 7-10 years, through operating costs.

MWE: We consider both rate of return and years to payout. We have built systems where the customers paid for construction costs up front, and designed a rate that fit those customers. We have also built systems that are built with our existing tariff system. We use our economic model to determine if there are any customer contributions to construction costs required.

Do you have any rule of thumb cost estimates you would recommend in trying to reach this decision?

SWKI: I would say that if you have at least 15-20 wells in a system, and they need an average of 1 mile line/irrigation well or less, it is probably feasible. A system totally for domestic use would not be feasible at all. Our average cost/irrigation well connection ran around \$10,000-\$12,000 per well, depending on the circumstances of the system. I'm sure that number would probably go up by 10-20%, if the systems were to be built now.

Did you forecast the cost of gas in comparison to cost of diesel when making the decision?

SWKI: We looked at it, and it looked like gas was going to be the cheaper option, plus the hassle of hauling diesel to each well is a daunting task, not to mention the environmental liability from diesel spills. One method of comparison can be developed by multiplying the diesel cost by 5.7 to come up with the equal gas cost. I think diesel is about \$1.80 per gallon now, so that would equate with \$10.26 natural gas.

MWE: Yes, but both fuels were much lower at the time. Natural gas was less expensive, and the irrigation wells were already set up with natural gas motors. Relative fuel costs are considered in any project evaluation.

Were all of the above left up to the individual farmer in deciding if he should participate?

SWKI: All the farmers had to decide whether or not they wanted to participate. Some did, some didn't, but I think most all the ones that did are glad they did now. A few that didn't have come back to us, and gotten on the systems now. A few (for various reasons, mostly cessation of irrigation due to loss of water) have dropped off the systems.

MWE: On our Finney County project, we worked with a group of customers, who we continue to work with, in setting up the whole plan and facility. That saved us in having the farmers sell the program to their neighbors, and it reduced our right of way costs for the system, because the participants knew those costs would be passed on.

Based on your knowledge of the systems, do you think any of them have a capability of expansion?

SWKI: Most of them have some capability of expansion, if the expansion is in the right location. However, if you are talking about adding on to the end of lines, most were pretty closely designed, & wouldn't be able to be extended from that point. It would have to be added on to at the pipeline taps, in most places. This would still save some infrastructure costs (regulation, metering, cost of getting gas contracts, etc., plus operation costs), but it wouldn't be free (or even cheap)!

MWE: Our physical distribution piping systems could expand in most if not all of our systems. We would have to look at them on a case by case basis, and it would depend where we need to expand each individual system. The evaluation of any expansion must be done with caution noting; (1) gas price volatility; (2) Relative fuel costs; (3) Other issues effecting agricultural production in Southwest Kansas such as water issues, all fuel costs are high and conversion to dryland will become an option which will make the payout difficult, government agricultural programs, environmental issues, timing of the conversion (once it is converted it will probably stay with that fuel), timing of the need to convert (natural gas and electric systems take a considerable amount of time to build)

Description of Existing Projects Developed by Midwest Energy:

Grant County Irrigation Project

The Grant County Irrigation Project was built to bring pipeline quality natural gas to irrigation engines and other loads that previously burned unprocessed natural gas from wellheads or gas gathering systems. The systems geographic area is mostly in Grant County and portions of Haskell County. The majority of the farmers represented in the group were being served by gathering system gas that was characterized by declining gas pressures. The farmers needed a new and more reliable source of natural gas to fuel their irrigation pumps.

Before its Kansas LDC operations were purchased by Midwest Energy in 1998, K N Energy met with these potential irrigation customers and created a project that did not have any upfront costs. Costs would be billed after the project was completed and customers were connected to the new distribution system. The irrigation customers were then charged a construction fee that was added to their bills in a per MMBtu charge. The more natural gas used, the more construction charges paid. The construction charge fee was added to bills for a period of five (5) years from the date construction was complete. The irrigation customers connected to the system but did not use very much gas, and there is still not much use on this system when compared to Midwest's other irrigation systems. The irrigation customers were only required to connect. There was no required commitment to use natural gas. Obviously this arrangement gives the affected customers access to reliable gas supplies, but it results in significant under-collection of capital costs from project beneficiaries. Their improvements are being subsidized by other customers. This outcome is what led Midwest Energy to develop the approach used for the Finney County Irrigation Project.

Statistics of Grant County Irrigation Project

- Over 300 irrigation wells connected
- Installed over 62 miles of pipe of which over 15 was high pressure steel
- One mainline transmission tap
- Charged customers an additional 32 cents per MMBtu used for construction for a period of five (5) years
- Customers only required to connect to system no usage requirement
- Started project in 1997 finished in 1998

Finney County Irrigation Project

The Finney/Kearny County Irrigation Project was built to bring pipeline quality natural gas to irrigation engines and other loads that previously burned unprocessed natural gas from wellheads or gas gathering systems. The system's geographic area is mostly in Finney and Kearny Counties and to a lesser extent, portions of Grant and Haskell Counties. The Finney County customers (which includes customers represented by the Kearny County Gas Irrigators Association or KCGI) are a group of irrigation customers

that had aggregated together with the intention of building their own gas distribution system. The majority of the farmers represented in the group were being served by gathering system gas that was characterized by declining gas pressures. In short, the farmers needed a new and more reliable source of natural gas to fuel their irrigation pumps.

Initially, the group decided to form a nonprofit natural gas public utility and received a Certificate of Convenience and Necessity (Docket 99-KCGG-031-COC) to build the distribution system. Later, KCGI engaged Midwest to build and operate the distribution system for them, while Midwest would retain ownership. The affected Customers recognized that a significant investment in facilities was needed. They did not object to paying for the facilities they needed, nor for associated costs of administration, operations and maintenance. However during negotiations, the Customers made it clear that if they paid construction charges for the system that served them, they did not also want to “pay regular rates forever.” That is, if they paid the full capital cost of their incremental system, they did not also want to pay average capital recovery costs attributable to other portions of Midwest Energy’s distribution system that did not serve them. To resolve the problem, a large group of Customers and Midwest Energy reached agreement on a project that in scope far exceeded what would normally be covered by a distribution main extension policy. The Company received KCC approval for Rate Schedules FCI and FCIP2 applicable to this special rate area.

Statistics of Finney County Irrigation Project

- Over 800 irrigation wells connected
- Installed over 141 miles of pipe of which over 20 was high pressure steel
- Two mainline transmission taps
- Charged customers close to \$6,000 per irrigated quarter of land connected to project
- Started project in 1999 finished in 2000

Garden City Irrigation Project

The Garden City Irrigation Project was built to bring pipeline quality natural gas to irrigation engines and other loads that previously burned unprocessed natural gas from wellheads or gas gathering systems. The systems geographic area is in Finney County north and west of Garden City. The majority of the farmers represented in the group were being served by gathering system gas that was characterized by declining gas pressures. The farmers needed a new and more reliable source of natural gas to fuel their irrigation pumps.

Midwest Energy met with groups of these potential irrigation customers, and created a project that did not have any upfront costs. Costs would be covered after the project was completed and customers were connected to the new distribution system, by requiring

minimum usage amounts and payment of standard irrigation rates. These features result in the customers paying for the improvements made to serve them. The irrigation customers connected to the system and continued to use similar amounts of natural gas as they had in prior years.

Statistics on Garden City Irrigation Project

- Over 200 irrigation wells connected
- Installed over 37 miles of pipe of which over 11 was high pressure steel
- One mainline transmission tap
- Required a minimum consumption for five (5) years to pay for construction
- Customers paid tariff rate with no construction charges
- Started project in 2001 finished in 2002

Continued Irrigation connections

Midwest Energy has continued to connect irrigation and convert irrigation customers served by gathering gas systems. The majority of these connections have been on a small scale where four irrigation wells or less have been tied to our distribution systems. Midwest employees are always aware of these customers and have worked towards converting our gathering system customers to processed gas lines. The process usually involves meeting with a small group of irrigators and developing a cost share approach to bringing the customer a better and more reliable natural gas product. Other entities have been involved in the process such as gas gathering companies. “Front Street” is an excellent example of this process. In the last several years Front Street and Midwest have worked together to convert customers from Front Street’s gathering systems to Midwest’s distribution systems. Midwest and Front Street cost share the construction costs and convert the customers to Midwest’s distribution facilities. Midwest Energy calculates the amount of cost it can absorb with its line extension economic analysis. This process has converted some commercial and irrigation customers and over 60 homes to Midwest’s distribution systems. This process has worked well and Midwest has discussed this arrangement with other gathering and production companies.

At this time fuel costs for irrigation engines make any large project difficult at best. Large projects will need to be paid with up front charges, or minimum use requirements. Future irrigation practices makes paying for the project with open-ended usage charges very difficult. Irrigators are looking at all types of fuels to power their irrigation motors and do not want to be locked into a long term commitment. Farming practices also will be important as reduced use of water occurs. This is good, but it makes economic planning for irrigation projects difficult if not impossible. The basis for determining minimum use requirements or up-front charges is the Company’s economic model. This model utilizes net cash flows from a particular project to determine its economic viability.

Line Extension Tariffs

Midwest published tariffs can be accessed at the following sites:

<http://www.mwenergy.com/PDFs/FCI.pdf> Finney County Project Tariff
http://www.mwenergy.com/PDFs/NGT&C_Sec_08.pdf Line Extension Policy

Aquila published tariffs can be accessed in Section 8 of the following site:

<https://networks.aquila.com/online/content/global/rates/ks/KsGRules.pdf>

Interstate Transmission Line Taps

Access to interstate transmission lines are subject to the Federal Energy Regulatory Commission (FERC) jurisdiction. The following outlines FERC policy regarding access to transmission lines:

As established in the following court case: Panhandle Eastern Pipe Line Co. v. FERC, 196 F.3d 1273 (D.C.Cir. 1999) And delineated by Order of FERC, issued on April 12, 2000, found in: 91 FERC 61,037

- Interstate pipelines are a possible alternate source of natural gas which meets transmission quality specifications along with adequate pressure.
- To initiate service from a pipeline, a request for service must be made to the pipeline including information such as hourly/daily volumes, pressure required and delivery location in order for the pipeline to estimate cost for an interconnect and time required to begin service.
- FERC Policy related to Interstate pipeline interconnections is that a pipeline must allow an interconnect if the following are met:
 - Customer must bear the cost of the construction or build the interconnect to the pipeline's specifications.
 - The interconnect must not adversely affect the pipeline's operations.
 - The interconnect and resulting transportation must not diminish service to the pipeline's existing customers.
 - The interconnect must not cause the pipeline to be in violation of any environmental or safety laws.
 - The interconnect must not cause the pipeline to be in violation of its right-of-way agreements or any other contractual obligation.
 - The cost of an interconnect will be determined by the pipeline at the time the request for the interconnect is made.

When considering an interstate tap, the pipeline considers the following:

- Cost to tap the pipeline with side valve.
- Cost of a plot of land for the meter setting.

- Cost of a meter setting, including a building, electronic flow measurement, and power and communication connection costs.
- Costs for flow control and overpressure protection, if required.
- Income tax gross up on the costs of the interconnect that are to be reimbursed to the pipeline.

The cost of the interconnect is dependent on the volume and delivery pressure of the gas to be delivered to the customer. (Customer could be a single irrigator, an LDC or a self-help distribution system.) A “ballpark” estimate of interconnect costs for different size interconnects are:

- Meter setting for a single irrigation well = \$20,000
- A 2” meter setting with flow control and overpressure protection = \$185,350 up to \$525,000
- A 4” meter setting with flow control and overpressure protection = \$236,300 up to \$632,000

These cost estimates have an estimated accuracy of +/- 25% and depend on which pipeline is doing the cost estimate based upon that pipeline’s construction specifications. The customer may be able to save costs by doing some of the construction on the meter setting to the pipeline’s specification. If a customer chooses to connect to an interstate pipeline, the customer will need to locate a gas supply on the pipeline, arrange for transportation and nominate the supply for delivery or contract with a marketer to provide these functions. The matrix attached as Attachment V-1 provides an itemized estimate for constructing a tap. Attachment V-2 provides an example application for a tap service.

Comparison of Alternative Energy Sources

Irrigation Power Comparison

As noted above, choice of fuel is driven by economic decisions. The following table provides an example of fuel calculation prepared by Kansas State University Agriculture Extension service. This spreadsheet can be accessed at:

<http://www.oznet.ksu.edu/irrigate/Software/Irrsoftware.htm>

An example of the spreadsheet input is attached as Attachment V-3

Section VI

Team 6 – Regulatory and Industry Practices Regarding H₂S Contamination

Background

Team 6 investigated the applicability of regulating operations or practices based on the amount of H₂S contamination in a produced gas stream. Research was done reviewing the regulatory practices of other states as well as industry practices when dealing with H₂S contamination. During the course of the taskforce effort Team 6 responsibilities developed into three general tasks associated with the determination of further actions relative to the presence of H₂S at wells and gathering systems in and around the area of the Hugoton Field in southwestern Kansas. Those general tasks were:

(A) should operators of wells and gathering systems sample and report to the Kansas Corporation Commission (KCC) H₂S levels at wells and gathering points on an annual basis;

(B) should field rules specific to H₂S levels and concerning monitoring and safety be applied to exploration and production and gathering system operations; and

(C) should continuous monitoring of H₂S levels at wellheads and on gathering systems be required or expanded.

A record of the positions developed by Team 6 on specific issues related to the general tasks are included in this report as Attachment VI-1. As noted in Attachment VI-1, Team 6 realized that any final comment or recommendation with respect to a number of the general tasks and subsets of those tasks would be highly dependent on the findings of the data acquisition team, Team 1. For example, if the data acquisition had determined that elevated H₂S levels were primarily a problem associated with the shallower gas reservoirs of the Hugoton and Panoma Fields, then monitoring and reporting requirements would be established through the Basic Proration Orders (BPO) in place for those fields. If the data indicated a more widespread distribution of H₂S contributions to the gas supply, then requirements under state wide general rules would be more appropriate.

Final Comments / Recommendations – General Tasks A, B, & C

(A) Should operators of wells and gathering systems sample and report to the Kansas Corporation Commission (KCC) H₂S levels at wells and gathering points on an annual basis?

Sampling and testing for H₂S on annual basis would of course provide additional data with respect to the current levels of H₂S and any trends associated with increases in those levels by area or by specific reservoir. This is of particular interest to Commission staff as a review of the H₂S data gathered through the data acquisition phase of this taskforce shows some troublesome data gaps and a relatively low incident of H₂S levels in wells at or above those determined to be at a level which would be considered deleterious under Team 2 designation of approximately 30 ppm (.001 partial pressure at 20 psi) and even less wells with a reported H₂S level in excess of 100 ppm which has been established as a benchmark for implementation of certain regulatory standards in neighboring producing states (Texas, Oklahoma, and Colorado). However, the lack of consistency in reporting treated versus untreated levels and the relatively large data set with no reported values (2,154 wells or 18.7% of the well data set) suggests that additional tests and reporting H₂S levels would be useful to the Commission in its final determinations with respect to these matters. Team 6 suggests that if the Commission determines that additional test be conducted with respect to H₂S levels that such testing be conducted as part of routine sampling and tests conducted in conjunction with gas quality sampling required under existing gas contracts. It is further recommended that if such additional sampling and testing is conducted that the reporting of this test data be made in a uniform manner and in an electronic format. Such sampling and testing should be annualized only if trends indicate increased levels of H₂S and such annual sampling is warranted to track such trends in wells with histories of elevated H₂S levels.

With regard to whether those samples should be taken with annual testing associated with gas testing in the prorated fields Team 6 would suggest that the current data set indicates that some of the highest H₂S levels are in reservoirs or areas not under proration and therefore not subject to annual testing unless the well's allowable is above 250 MCF/day. Therefore limiting any sampling to prorated fields may not identify the most serious threats to the gathering system integrity or public safety.

(B) Should field rules specific to H₂S levels and concerning monitoring and safety be applied to exploration and production and gathering system operations?

If additional sampling and testing as recommended under Task A indicates a widespread impact of H₂S at levels that are typically regulated under Railroad Commission of Texas Rule 36 or API Recommended Practice 55, the Commission should develop area specific H₂S regulations for oil and gas exploration and production activities. These activities would include gas gathering systems. Team 6 recommends that any regulation development effort undertaken should be done through the Commission's Oil and Gas Advisory Committee and should rely on existing benchmark regulatory formats which producers and gas gathering system operators have a level of experience. Examples of the regulatory formats from adjacent states are included with this report as Attachments VI-2 and VI-3.

(C) Should continuous monitoring of H₂S levels at wellheads and on gathering systems be required or expanded?

There was a broad range of opinion within Team 6 concerning the necessity of additional continuous monitoring of H₂S levels within the study area. Expansion of continuous monitoring of H₂S could provide benefits with respect to gathering system integrity and public safety. The cost of such monitoring systems is a primary concern as well as at what point location such monitoring systems should be deployed (wells, gathering systems, user taps). Clearly as the number of continuous monitoring points increase the cost of such monitoring increases. There is a need to integrate current H₂S data sets with gathering system mapping, well location data, and tap locations so that the cost / benefit of any expansion of continuous monitoring with respect to the gathering system integrity and public safety can be evaluated.

Southwest Kansas H₂S and Low Pressure Task Force Conclusion

In conclusion, Staff believes additional data must be collected from the producers and gas gatherers in order to predict the severity and extent of H₂S contamination in southwest Kansas. It is also apparent to Staff that the task force was unable to reach a conclusion as to what amount of H₂S could be allowed in delivery of gas to consumers. The following paragraphs summarize Staff's recommendations regarding further data collection and provide additional suggestions that may be used to determine the acceptable risk associated with H₂S contamination.

As noted in the selection of the name for the task force, Staff recognized two apparent problems in serving gas consumers connected directly to gas gathering systems. The most immediate problem needing addressed is the safety of consuming natural gas that is contaminated with H₂S. The second problem is the supply of natural gas for these consumers. While not a direct threat to public safety, the low pressure and limited future supplies of gas will have a significant financial impact on them. The task force first attempted to establish the extent of these problems by undertaking an extensive data collection campaign of H₂S levels, well operating pressure, and location of gas consumers in the Hugoton field area. Although 26,000 sample points were obtained, Staff has low confidence that the reported H₂S concentrations represent the H₂S concentrations in the reservoir. We are also uncertain that we have identified the majority of the consumers connected to gas gathering systems. The most recent wellhead operating pressure data confirms the ongoing trend of pressure depletion in the area. However, it offers no reliable forecast of remaining supply for connected consumers. This analysis leads Staff to recommend the following:

- Producers should be required to provide current measurements of H₂S concentration from each individual well. The measurement should be taken upstream of any treatment for H₂S removal. Producers should be given up to 12 months to complete the data acquisition. In order to trend H₂S contamination over time, producers should repeat the data acquisition every five years.
- Producers and gas gatherers should be required to provide the addresses/locations of all consumer taps that are supplied with unprocessed gas. This should include company offices or equipment that consume unprocessed gas.
- By June of 2007, Staff should supply an addendum to this report that incorporates the results from the second round of data collection.
- Any person providing unprocessed natural gas to public utilities should be required to communicate with the public utility on the availability of future unprocessed gas supplies by November of each year.
- Consumers of unprocessed natural gas should be encouraged to be aware of the inevitable depletion of their current supply. In doing so, they should consider the

possibilities of processed gas availability or what alternative energy supply is most suited to their consumption patterns.

Staff Commentary on Defining a Level of H₂S that Should be Allowed in the Unprocessed Gas Provided for Consumption

Team 2 provided extensive research into the health effects and the corrosiveness of H₂S. Their research indicates there are no available studies that directly address the potential risks of consuming natural gas contaminated with H₂S. Rather, all studies involved research on the corrosiveness of H₂S on metallic piping or the health effects of inhaling H₂S. Team 2 was able to reach a conclusion for each of these independent scenarios; however, they could not reach a conclusion regarding the potential risk to consumption of this type of gas stream.

Staff suggests that the potential risk associated with the consumption of contaminated gas can be inferred using conventional risk assessment techniques. Risk may be defined as the probability of a loss occurring and the magnitude or consequence of the loss. Risk increases whenever the probability of the loss increases or the consequences of the loss increase. Staff believes the contractual limits placed on the amount of H₂S allowed in gas transmission lines is an example of risk management practiced by the operators of gas transmission lines. In this case, the operators are establishing the level of risk from corrosion they are willing to undertake by limiting the amount of H₂S they will allow in their transmission system. As shown in Attachment II-1, the levels of H₂S allowed by transmission contracts vary from 4 ppm to 16 ppm.

For the purposes of discussion, the following paragraphs portray an approach that can be used to assess the risks of the inhalation of H₂S as a hazard of concern. Using a simplistic approach of risk assessment, Staff believes the risk of the inhalation hazard from consuming gas contaminated with H₂S can be assessed by considering the following contributing factors:

1. High levels of H₂S must exist in the producing reservoir;
2. The treatment for H₂S in the production operations must fail;
3. The gas piping transporting the gas must fail; and
4. Release area must be confined to limit the effects of dilution with ambient air.

It should be noted, that the above listed factors are not independent. That is, the failure modes must occur sequentially in order for the inhalation risk to occur. By assigning various levels of probability to the four possible contributors, an overall level of risk can be developed.

High levels of H₂S must exist in the producing reservoir

Staff is uncertain of the extent of H₂S concentrations in the gas producing reservoirs in the Hugoton area. If the untreated gas has H₂S levels that correspond to a partial pressure

above .001 psia, the probability of the first contributing factor should be considered as relatively high. Because we have low confidence that the data collected represents H₂S levels in untreated gas, Staff assumes a risk assessment model would consider this factor as having a high chance of occurring.

The treatment for H₂S in the production operations must fail

As demonstrated in the data acquisition phase of the report, H₂S can be successfully removed from the gas stream using a variety of treatment techniques. The amount of H₂S left in the gas stream is dependent on the conditions of the contract between the producer and the operator of the gas gathering system that transports the gas. This safeguard is only as good as the vigilance of the operator in maintaining the treatment technique, and the vigilance of the gas gathering system in verifying that contract specifications are being met. Sporadic high readings in the sampling data indicate that on occasion treatment techniques fail. The large number of wells, limited manpower, and remote distances make monitoring the treating facilities for compliance with contract specifications a difficult, if not impossible, undertaking. As a rule, gathering system operators in Southwest Kansas do not use electronic monitors to continuously monitor for H₂S in their gathering systems. This practice makes any chance of a rapid response to H₂S treatment failure unlikely. Unless the current operating practices are expanded to include a more rigorous means of monitoring operations, Staff believes the second of the above listed contributing factors have a relatively high probability of occurring.

The gas piping transporting the gas must fail

The third contributing factor deals with the integrity of the piping that transports the natural gas. If gas contaminated with H₂S is not allowed to leak from the gas piping, there is no path to allow the H₂S to become an inhalation risk. Although there are several ways by which a pipe could begin to leak, corrosion is considered the most likely method that would result in unplanned consequences. Because H₂S is corrosive to metallic piping, the possibility exists that high concentrations of H₂S could result in pipeline leaks as well as leaks in house piping. Although over 100 residential consumers of unprocessed gas were removed from service last year, Staff notes there was no evidence of internal corrosion of the piping reported by those removing the facilities. This corroborates the Team 2 finding that corrosion of steel pipe will not occur below .001 partial pressure. Given the low pressure of residential gas supply and supply to irrigation engines, Staff believes the probability of a corrosion leak occurring on fuel piping would be very low at the H₂S levels currently present in the southwest Kansas gathering systems.

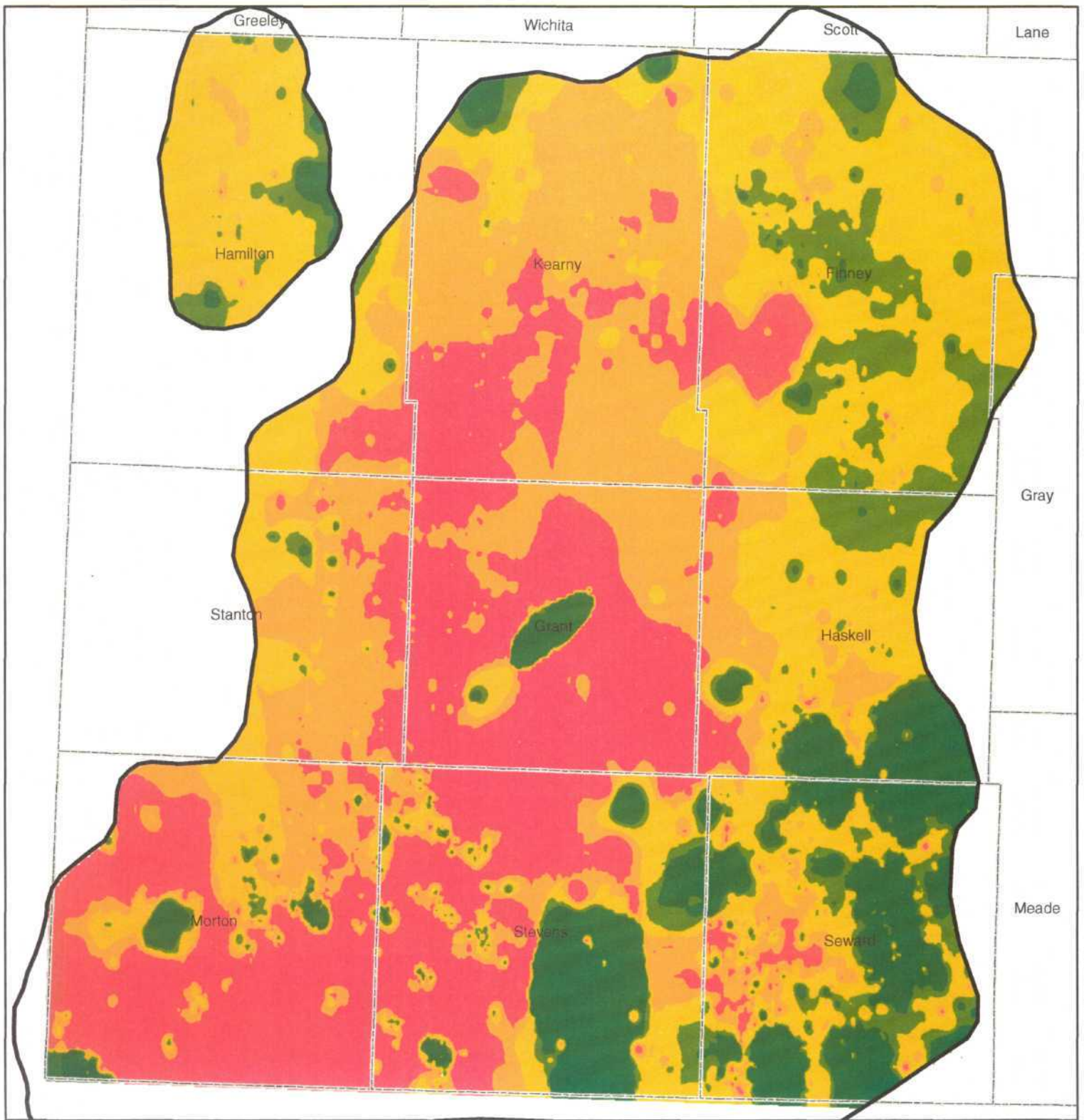
Release area must be confined to limit the effects of dilution with ambient air

Should a leak occur, the location of the leak must be considered to evaluate potential consequences. Of highest concern would be the potential leak in a basement of a residence. Although the probability of the leak occurring may be low, the probability of

the leaking gas being an inhalation risk is relatively high. On the other hand, a leak at an irrigation engine in the open air would have a much lower risk of H₂S inhalation.

Using a risk assessment approach, it may be possible to quantify the threshold at which the H₂S content in a gathering line would present an unacceptable risk to the gas consumers. Staff recommends an operator contemplating termination of service to a consumer connected to the gathering system utilize this approach to evaluate the appropriateness of such service termination for health or safety reasons.

Attachments



/HS Pressure Final.mxd

- Working Pressure**
- 0.77-15
 - 16-30
 - 31-60
 - 61-80
 - 81-2000

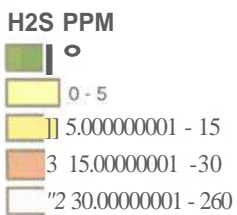
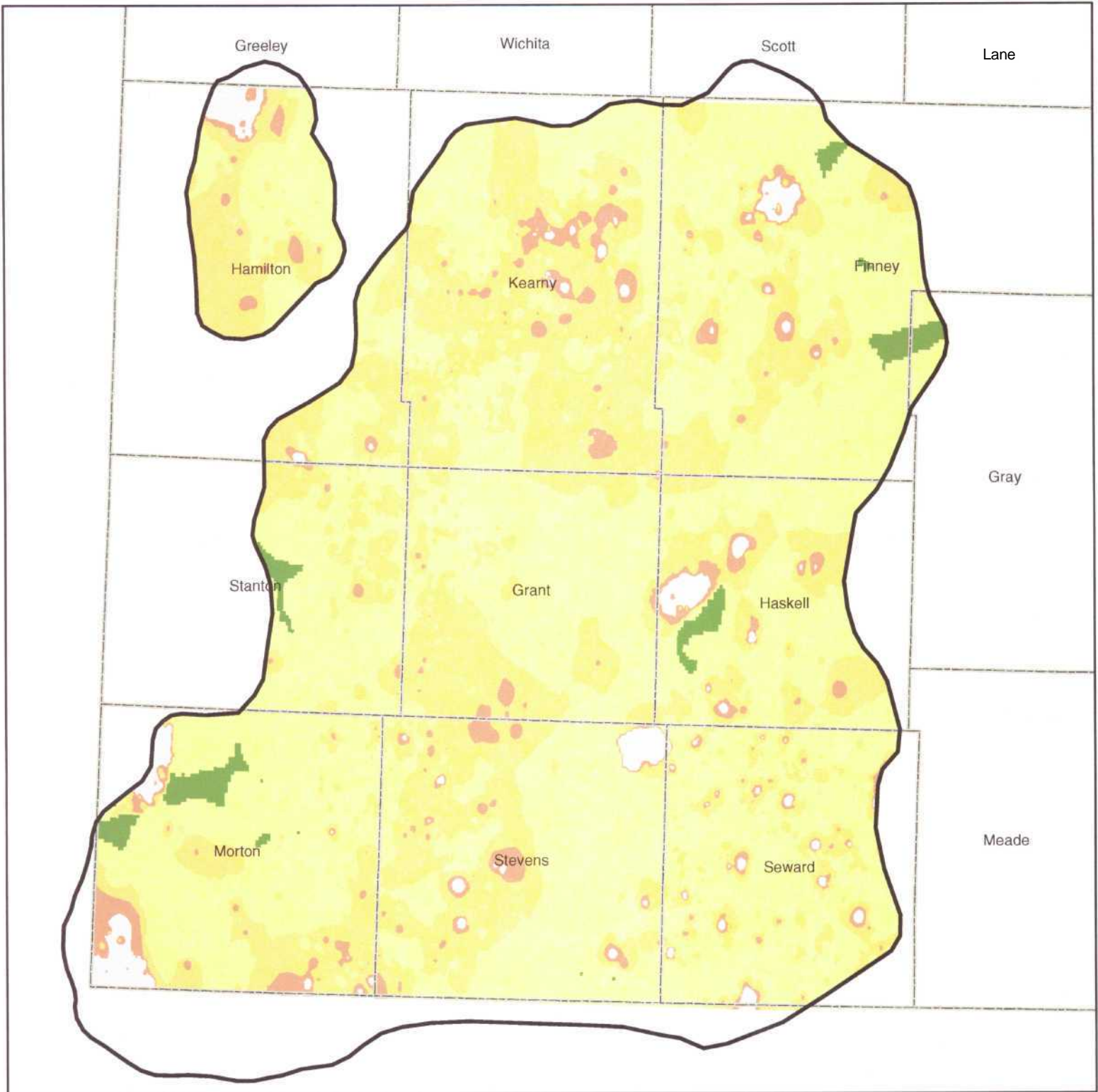
Wellhead Working Pressure

Pressure readings from
1/04 to 7/05



**KANSAS
CORPORATION
COMMISSION**
9 September 2005

Study Area with Estimated H2S PPM



KANSAS
CORPORATION
COMMISSION
9 September 2005

Attachment II-1

Samples of tariff provision for Hydrogen sulphide content for interstate pipelines

Allowed Hydrogen Sulphide levels

Tennessee Gas Pipeline	16 parts per million
Texas Gas Transmission, LLC	16 parts per million
Portland Natural Gas Transmission	4 parts per million
Algonquin Gas Transmission LLC	16 parts per million
Enbridge Pipeline LLC	16 parts per million
Southern Star Central Gas Pipeline, Inc.	4 parts per million
East Tennessee Natural Gas Company	4 parts per million
Columbia Gas Transmission Corporation	4 parts per million
Western Gas Interstate Company	4 parts per million
Viking Gas Transmission Company	16 parts per million
Kern River Gas Transmission Company	4 parts per million
Texas Eastern Transmission, L.P.	8 parts per million
Vector Pipeline L.P.	4 parts per million
CenterPoint Energy Gas Transmission Company	4 parts per million
El Paso Natural Gas	4 parts per million
Panhandle Eastern Pipeline Co	16 parts per million
Midwestern Gas Transmission Company	4 parts per million
Northern Border Pipeline Company	6 parts per million
Colorado Interstate Gas Company	4 parts per million
TransColorado Gas Transmission Company	4 parts per million
Trailblazer Pipeline Company	16 parts per million
Northern Natural Gas Company	4 parts per million
Kinder Morgan	4 parts per million
Mid West Gas	4 parts per million

Tennessee Gas Pipeline

“shall not contain more than twenty grains of total sulphur nor more than one grain of hydrogen sulphide per one hundred cubic feet”

Texas Gas Transmission, LLC

“Not contain more than one (1) grain of hydrogen sulfide, nor more than twenty (20) grains of total sulphur, per one hundred (100) standard cubic feet of gas.”

Portland Natural Gas Transmission

“Sulfur/Hydrogen Sulfide – Not more than twenty (20) grains of total sulfur nor more than one-fourth (1/4) grain of hydrogen sulfide per one hundred (100) Cubic Feet”

Algonquin Gas Transmission LLC

“ Shall contain less than one grain of hydrogen sulphide per 100 cubic feet volume as measured by methods in accordance with accepted industry practice as”

Enbridge Pipeline LLC

“ Shall contain less than one grain of hydrogen sulfide per one hundred (100) cubic feet of gas”

Southern Star Central Gas Pipeline, Inc.

“Hydrogen Sulfide and Total Sulfur: The gas shall contain not more than one quarter (1/4) grain of hydrogen sulfide per one hundred (100) cubic feet and not more than twenty grains total sulfur per one hundred (100) cubic feet.”

East Tennessee Natural Gas Company

“All gas shall contain no more than twenty (20) grains of total sulphur, nor more than one fourth (1/4) of one grain of hydrogen sulphide per one hundred (100) cubic feet as determined by methods to be mutually agreed upon.”

Columbia Gas Transmission Corporation

“ shall not contain more than twenty five hundredths (0.25) grains of hydrogen sulphide per one hundred (100) Cubic fee of gas”

Western Gas Interstate Company

“all gas shall not contain more than five grains of total sulphur, nor more than one fourth (1/4) of one grain of hydrogen sulphide per one hundred (100 cubic feet”

Viking Gas Transmission Company

“Hydrogen Sulphide

The gas shall not contain more than one (1) of hydrogen sulphide per one hundred (100) cubic feet.”

Kern River Gas Transmission Company

“will contain not more than 0.25 grain of hydrogen sulfide per 100 cubic feet of gas (the gas will not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products)”

Texas Eastern Transmission, L.P.

“Hydrogen Sulfide

The gas shall not contain more than one-half (0.5) grain (8 ppm) of hydrogen sulfide per one-hundred (100) cubic feet.”

Vector Pipeline L.P.

“Shall contain no more than ¼ grain of hydrogen sulphide per 100 cubic feet of gas”

CenterPoint Energy Gas Transmission Company

“shall contain less than one fourth (1/4) grain of hydrogen sulfide per hundred cubic feet of Gas volume”

El Paso Natural Gas

“Hydrogen Sulfide

The gas shall not contain more than one-quarter (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet”

Panhandle Eastern Pipeline Co.

“1.0 grain of hydrogen sulphide and 20 grains of total sulphur (reduced by sulphur caused by odorization equipment) per 100 cubic feet”

Midwestern Gas Transmission Company

“ All gas shall not contain more than twenty (20) grains of total sulphur and not more than one fourth (1/4) of one grain of hydrogen sulphide per hundred (100) cubic feet”

Northern Border Pipeline Company

“The gas shall not contain more than 0.3 grains of hydrogen sulphide per Ccf.”

Colorado Interstate Gas Company

“such Gas shall not contain more than:
.25 grain of hydrogen sulphide per 100 cubic feet.”

TransColorado Gas Transmission Company

“Hydrogen sulfide – The gas shall not contain more than one-quarter (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet.”

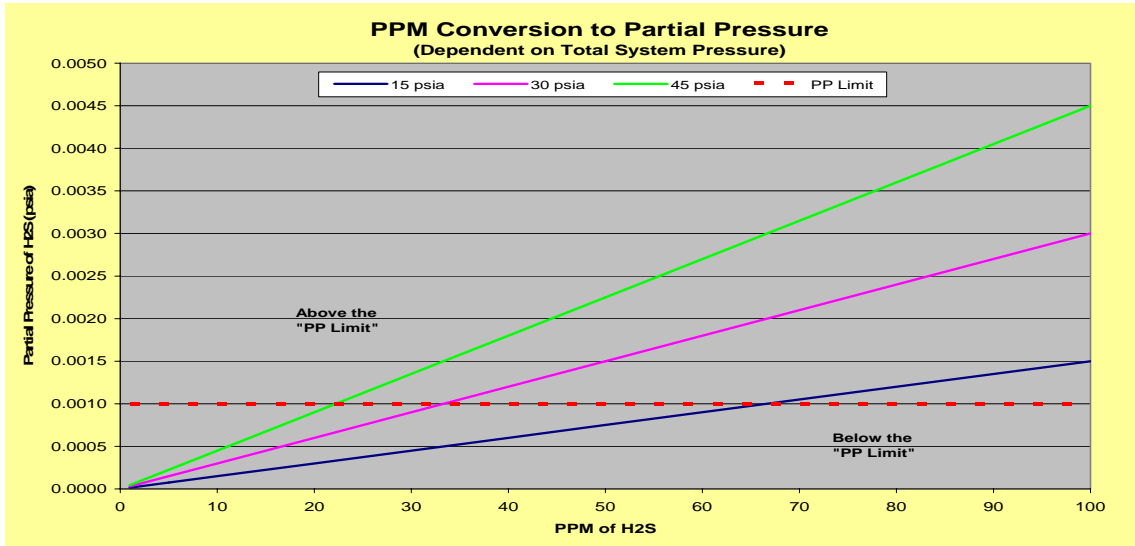
Trailblazer Pipeline Company

“ Shall not contain more than one (1) grain of hydrogen sulfide per one hundred (100) cubic feed of gas, as determined by methods prescribed in “ Standards of Gas Service, Circular of the National Bureau of Standards of Gas Service,” No. 405 page 134 (1934 edition)”

Northern Natural Gas Company

“Hydrogen sulfide – less than or equal to ¼ grain/Ccf”

Attachment II-2



See attachment below for other partial pressures other than those listed above:

The numbers shown in the grid are the "partial pressures" of H₂S, given the pressure (psia) and the ppm H₂S.

Atmospheric pressure =	14.7								
PSIA =	10	13.3	15	20	30	40	100	200	500
PSIG =	-4.7	-1.4	0.3	5.3	15.3	25.3	85.3	185.3	485.3
1 ppm H ₂ S	0.00001	0.0000133	0.000015	0.00002	0.00003	0.00004	0.0001	0.0002	0.0005
2 ppm H ₂ S	0.00002	0.0000266	0.00003	0.00004	0.00006	0.00008	0.0002	0.0004	0.001
4 ppm H ₂ S	0.00004	0.0000532	0.00006	0.00008	0.00012	0.00016	0.0004	0.0008	0.002
8 ppm H ₂ S	0.00008	0.0001064	0.00012	0.00016	0.00024	0.00032	0.0008	0.0016	0.004
16 ppm H ₂ S	0.00016	0.0002128	0.00024	0.00032	0.00048	0.00064	0.0016	0.0032	0.008
50 ppm H ₂ S	0.0005	0.000665	0.00075	0.001	0.0015	0.002	0.005	0.01	0.025
100 ppm H ₂ S	0.001	0.00133	0.0015	0.002	0.003	0.004	0.01	0.02	0.05
200 ppm H ₂ S	0.002	0.00266	0.003	0.004	0.006	0.008	0.02	0.04	0.1
500 ppm H ₂ S	0.005	0.00665	0.0075	0.01	0.015	0.02	0.05	0.1	0.25

Conversion Rates:

1 bar_{absolute} = 14.5psia

16.4 ppm = 1grain

.061 x ppm = grains

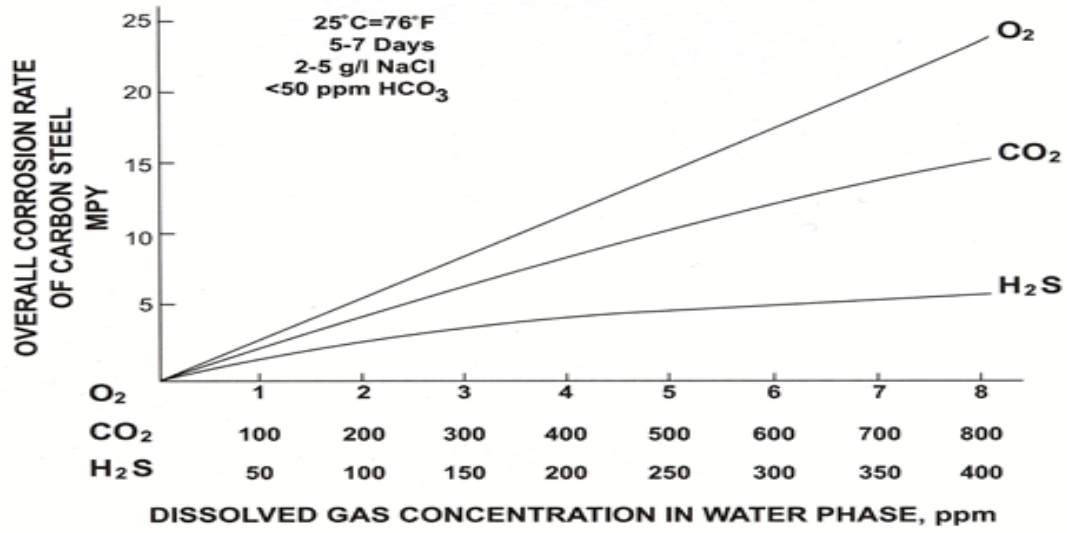
10,000 ppm = 1%

Pounds per Square Inch Absolute (PSIA) = Pounds per Square Inch Gauge (PSIG) + Atmospheric pressure in Pounds per Square Inch (PSIA = PSIG + Atmospheric Pressure)

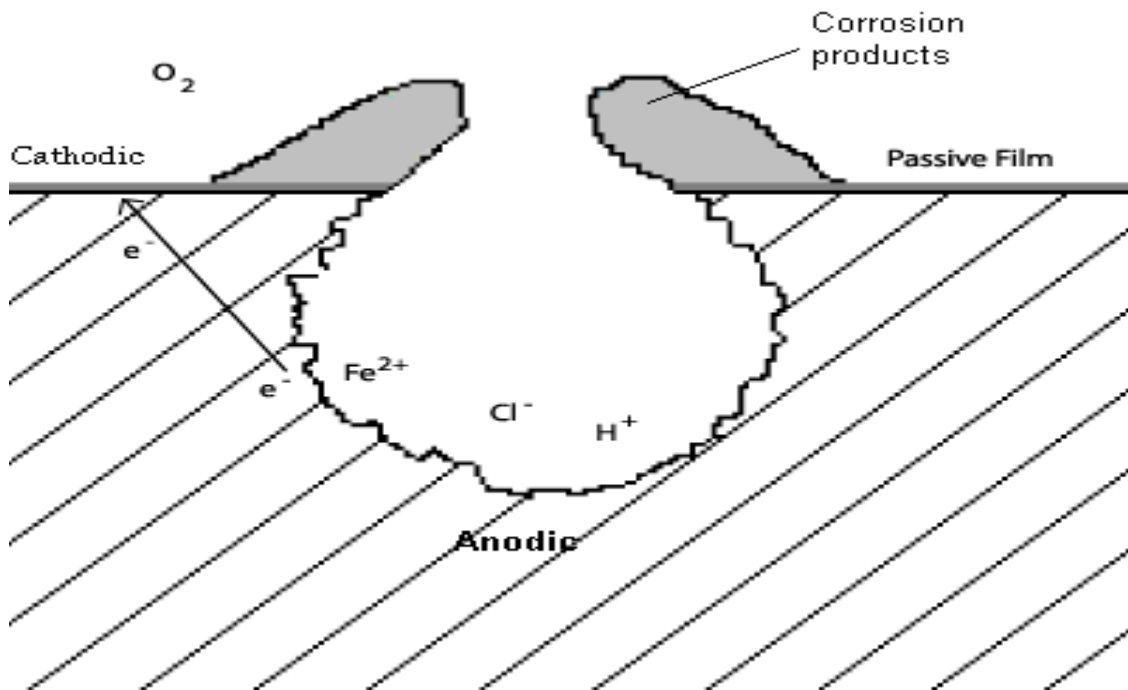
Example: If atmospheric pressure is 14.7psi then, 30 psia = 15.3psig + 14.7 atmospheric pressure

Corrosion rates of steel versus oxygen, carbon dioxide, and hydrogen sulfide. For the chart shown below, please note that 400 ppm is the maximum H₂S that can be dissolved in water.

Note the different gas concentrations on the x axis (from NM WAIDS web site).

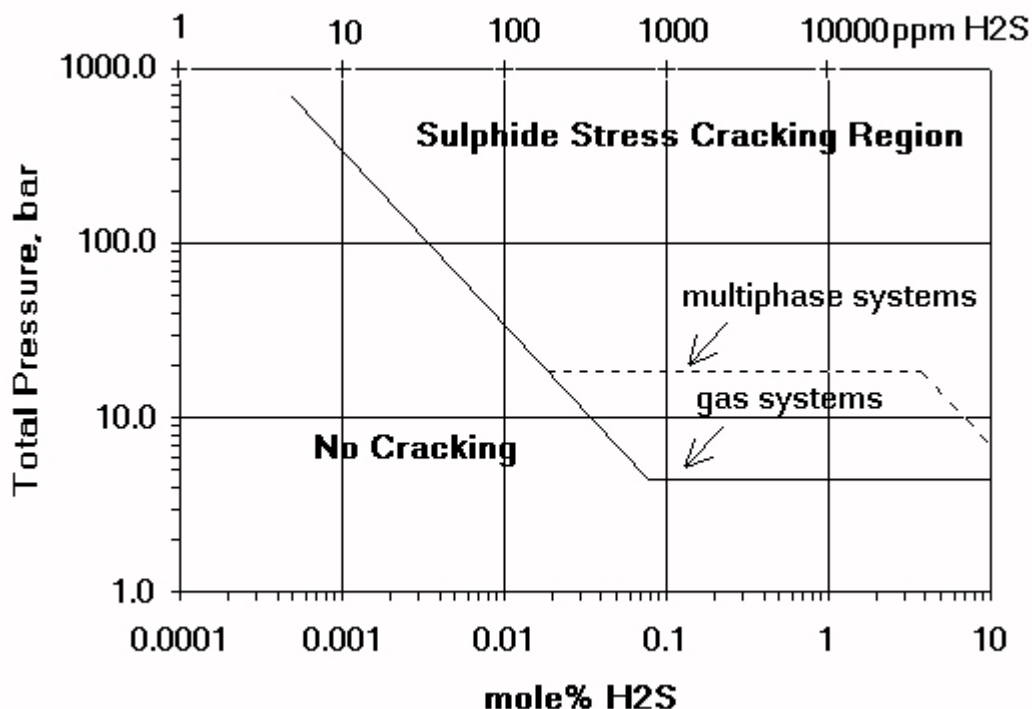


Typical pitting corrosion cell from NM WAIDS web site:



Attachment II-3

Chart from NACE (MR0175):



The **mole** (symbol: mol) is one of the seven [SI base units](#) and is commonly used in [chemistry](#). It measures the [amount of substance](#) of a [system](#) and is defined as the [amount of substance](#) that contains as many [elementary entities](#) as there are [atoms](#) in exactly 0.012 [kilogram](#) of [carbon-12](#). This quantity is known as [Avogadro's number](#) and is approximately $6.02214199 \times 10^{23}$.

When the mole is used, the elementary entities *must* be specified. Elementary entities may be:

- [atoms](#)
- [molecules](#)
- [ions](#)
- [electrons](#)
- other [particles](#)
- specified groups of such [particles](#)

A mole of [atoms](#) or [molecules](#) is also called a 'gram atom' or 'gram molecule'.

With a mole of a gas one means a mole of molecules.

Mole % to partial pressure conversion: $\text{Mole \%} \times \text{psia} = \text{partial pressure}$

Attachment II-4

Excerpts from:

CATERPILLAR

Gas Engines Application and Installation Guide

G3600–G3300

| Fuels & Fuel Systems

LEKQ7256 (Supersedes LEKQ2461) 10-97

Common Fuels

Natural Gas

The composition of natural gas as it leaves the well head varies from one area, or gas field, to another. In each instance, it is a mixture of gases composed mostly of methane (CH₄) with varying percentages of ethane (C₂H₆), propane (C₃H₈), butane (C₄H₁₀), and usually small amounts of helium (He), carbon dioxide (CO₂), nitrogen (N₂), and in some fields hydrogen sulfide (H₂S). Natural gas in its original state is often referred to as *field* gas, *well* head gas, or *wet* gas. In the gas industry, the designation *wet* or *dry* does not refer to the presence or absence of Water, but to the presence or absence of liquid hydrocarbons such as butane, pentane, etc. Before being marketed through the gas distribution pipelines, the *wet* ends are removed to provide what we often refer to as *dry* pipeline gas. The energy content of pipeline natural gas is determined by the molar or volume percentages of methane, ethane, and propane in the mixture. To obtain better understanding of natural gas, it is necessary to review the physical characteristics of the individual gases usually found in natural gas. Figure 1 shows some of the more important physical constants of component gases which are often found in gaseous fuel mixtures, including natural gas.

Figure 2 illustrates the variation in composition of natural gases from different fields. An analysis of a typical *dry* pipeline gas is also represented in Figure 2. These gas analyses will have more meaning after a more thorough study of the heat value and combustion characteristics of the various gases. Low heat value (LHV) of a gas is the high heat value less the heat used to vaporize the water formed by combustion. This applies whether the gas is a single hydrocarbon (or any other gas which forms water as a product of combustion) or a mixture of hydrocarbons.

The amount of heat (per unit volume) lost in vaporizing the water is different for different gases. This variable must be eliminated if the engine manufacturer is to provide reliable fuel consumption data. This explains why all engine manufacturers use low heat value for gaseous fuels.

Sour Gas

Sour gas generally refers to fuels containing a high concentration of sulfur compounds (above 10 ppm), primarily hydrogen sulfide (H₂S). Fuels such as field, digester, bio-mass, or landfill gas generally fall in this category. Sweet gases are fuels with low concentrations of sulfur compounds (below 10 ppm). Sweet gases can be used in an engine without any additional treatment or changes to the engine. However, sour gases require the appropriate operation parameters and maintenance schedule, outlined below. The maximum level of H₂S allowed under any circumstances is given by Figure 3.

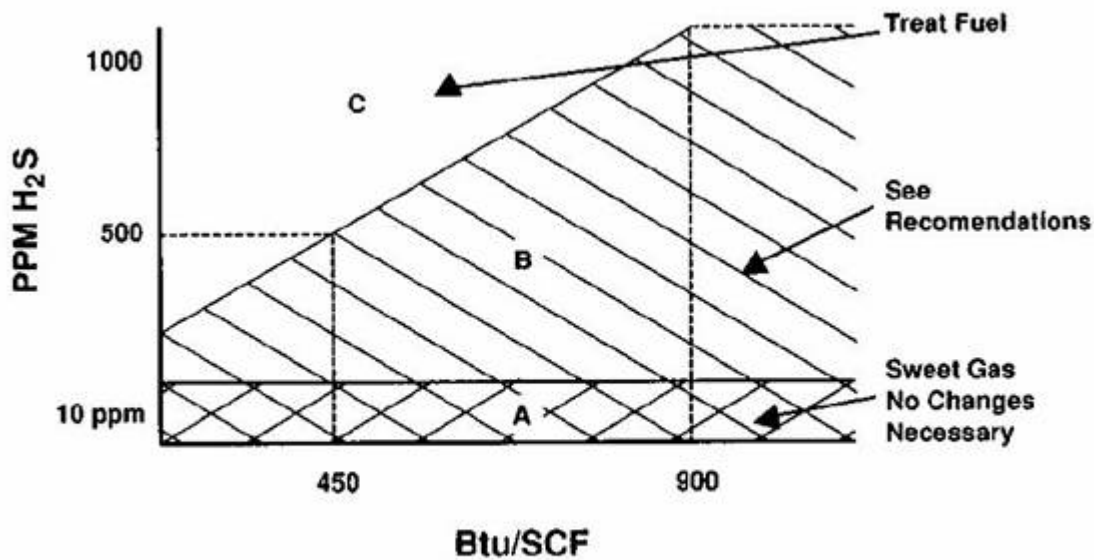


Figure 3.

Any fuel in the section “C” of the graph must be treated to remove the excess H₂S.

If gas with excessive sulfur levels is used as a fuel, sulfur compounds could be dissolved in the oil from blow-by gas and cause corrosive attack on internal engine components. The corrosion usually is caused by a direct H₂S attack of the bright metals within the engine, such as the oil cooler and bronze/brass bushings or bearings. This direct H₂S attack cannot be deterred by high TBN oils or controlled by oil analysis. There are various devices available to reduce H₂S in the fuel gas such as chemically active filters, reactive beds, and solutions. The performance of most of these devices deteriorates as the reactive chemicals are depleted. The device then requires servicing or replacing to maintain an effective level of H₂S removal. It is recommended that even though a fuel gas is scrubbed to pipeline level of H₂S, the precautions listed below should be taken for high sulfur fuels to protect against those intervals when the chemical scrubbers deteriorate and require servicing. Even brief intervals of operation with high sulfur fuel without precautions can damage the engine.

- Maintain the coolant outlet temperature between 96°C and 102°C (205°F and 215°F). Temperature rise across the engine should be no more than 15°F, and a 10°F rise is desirable. Water and sulfur oxides are formed during combustion and will condense on cylinder walls at low temperature. The higher jacket temperature will minimize the amount of condensation. Engines equipped with inlet control cooling systems will maintain outlet temperatures in the 96°C and 102°C (205°F and 215°F) range. Engines with outlet control cooling systems may require additional external controls to maintain 96°C and 102°C (205° to 215°F) outlet temperatures.
- Maintain the temperature of the oil in the sump high enough to prevent water from condensing in the oil. Normally, maintaining the jacket water outlet temperature at a minimum of 93°C (200°F) will accomplish this.
- Establish an oil analysis program to assure oil change periods are not extended beyond
- safe limits and that other problems are not overlooked. Caterpillar Dealers are capable of establishing and conducting such programs.
- A CD grade oil with less than 1% sulfated ash can be used instead of oils normally used in natural gas engines. CD oil has a higher TBN (which indicates its ability to neutralize

- acids formed from products of combustion of sulfur compounds) than normal gas engine oil.
- Where it is possible to start the engine on sweet gas, bring the engine up to operating temperature on sweet gas, then switch to sour gas reverse the procedure when shutting the engine down.

There is no known oil additive that can protect the internal bright metal engine components from H₂S attack. A positive crankcase ventilation has proven to successfully reduce the H₂S attack of internal engine components. The ventilation system should positively remove the fumes from the crankcase and allow filtered air to enter the crankcase to dilute the levels of H₂S. Guidelines for installing and sizing a system are given in the section on “Low Btu Engines”.

Attachment II-5

References on H₂S

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NACE. Corrosion Basics - An Introduction. , 1984.

Nathan, C. C., ed. Corrosion Inhibitors. Philadelphia: Betz Laboratories, Inc., 1981.

Treseder, R. S., and R. N. Tuttle. Corrosion Control in Oil and Gas Production. 1998 ed. Houston: CORUPDATE, Inc., 1998.

Srinivasan, S., and S. Tebbal. "Critical Factors in Predicting CO₂/H₂S Corrosion in Multiphase Systems." Pipeline Corrosion (2001): .

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"Metallic Corrosion and its Control." CorCon C.de Waard Materials and Corrosion Consultancy. CorCon. 09 Mar. 2005 <www.xs4all.nl>.

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"Useful Service Life Evaluation Testing of Copper Tubing for Gas Distribution System in California." Copper Applications in Metallurgy of Copper & Copper Alloys, and Plumbing. Feb. 2004. CDA. 01 Apr. 2005 <www.copper.org/innovations/2004/Feb2004/SoCalGas_Tst_Rslts.htm>.

Questions and Answers about Hydrogen Sulfide. Department of Environmental Quality. 24 Feb. 2005 <www.michigan.gov>.

NM WAIDS. 22 Feb. 2005 <http://octane.nmt.edu/waterquality.corrorsion/H₂S.htm>.

NACE - TPC 5 - Corrosion Control in Petroleum Production (): 10-19.

National Fuel Gas Code. 2002 Edition

3. A Few Web Links for Information on Hydrogen Sulfide

- <http://www.atsdr.cdc.gov/toxprofiles/tp114.pdf>
- <http://www.atsdr.cdc.gov/tfacts114.html>

- [http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h₂s_monitoring.html#Sudden%20Release%20of%20H₂S](http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html#Sudden%20Release%20of%20H2S)
- <http://www.cdc.gov/niosh/idlh/7783064.html>
- <http://www.cdc.gov/niosh/ipcsneng/neng0165.html>
- <http://www.cdc.gov/niosh/rtecs/mx12b128.html>
- http://www.drthrasher.org/Toxicology_of_Hydrogen_Sulfide.html

Attachment II - 6

Ambient Air Quality Standards for Hydrogen Sulfide in Other States

State	Level	Time Duration
Texas	0.08 ppm 0.12 ppm	30-minute average
Minnesota	0.05 ppm 0.03 ppm	30-minute average, not to be exceeded over 2 times per year 30-minute average, not to be exceeded over 2 times in any 5 consecutive days
Missouri	0.05 ppm 0.03 ppm	30-minute average, not to be exceeded over 2 times per year 30-minute average, not to be exceeded over 2 times in any 5 consecutive days
Iowa	0.03 ppm	1-hour average, daily max not to be exceeded over 7 days per year
Nebraska	TRS 0.1 ppm 10 ppm	Hydrogen sulfide, methyl mercaptan, dimethyl sulfide, dimethyl disulfide 30-minute rolling average 1-minute maximum
Oklahoma	0.2 ppm	24-hour period

B. Federal Standards for Hydrogen Sulfide

National Institute for Occupational Safety and Health (NIOSH):

Recommended Exposure Limit (REL): 10 ppm, 10-minute ceiling
Immediately Dangerous to Life and Health (IDLH): 100 ppm

Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL):

20 ppm, 10-minute ceiling; 50 ppm, 10-minute max peak
Time Weighted Average (TWA): 10 ppm
Short-term Exposure Limit (STEL): 15 ppm

American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Value (TLV):

Time Weighted Average (TWA): 10 ppm
Short-term Exposure Limit (STEL): 15 ppm

C. Federal Ambient Air Quality Standard for Sulfur Dioxide

Level	Time Duration
0.14 ppm	24-hour maximum
0.03 ppm	Annual arithmetic mean

Attachment II-7

Concentration of natural gas vs. levels of H₂S in room air:

INPUT		OUTPUT		INPUT		OUTPUT		INPUT		OU TP UT
Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM		Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM		Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM
0.10%	4	0.004		0.30%	4	0.012		0.50%	4	0.02
	8	0.008			8	0.024			8	0.04
	12	0.012			12	0.036			12	0.06
	16	0.016			16	0.048			16	0.08
	20	0.02			20	0.06			20	0.1
	50	0.05			50	0.15			50	0.25
	75	0.075			75	0.225			75	0.375
	100	0.1			100	0.3			100	0.5
	200	0.2			200	0.6			200	1
	300	0.3			300	0.9			300	1.5
	400	0.4			400	1.2			400	2
	500	0.5			500	1.5			500	2.5
0.20%	4	0.008		0.40%	4	0.016		0.60%	4	0.024
	8	0.016			8	0.032			8	0.048
	12	0.024			12	0.048			12	0.072
	16	0.032			16	0.064			16	0.096
	20	0.04			20	0.08			20	0.12
	50	0.1			50	0.2			50	0.3
	75	0.15			75	0.3			75	0.45
	100	0.2			100	0.4			100	0.6
	200	0.4			200	0.8			200	1.2
	300	0.6			300	1.2			300	1.8
	400	0.8			400	1.6			400	2.4
	500	1			500	2			500	3

INPUT			OUTPUT			INPUT			OUTPUT			INPUT			OUTPUT		
Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM	Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM	Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM	Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM	Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM	Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM
0.70%	4	0.028	1.00%	4	0.04	4.00%	4	0.16	10.00%	4	0.4	20.00%	4	0.8			
	8	0.056		8	0.08		8	0.32		8	0.8		8	1.6			
	12	0.084		12	0.12		12	0.48		12	1.2		12	2.4			
	16	0.112		16	0.16		16	0.64		16	1.6		16	3.2			
	20	0.14		20	0.2		20	0.8		20	2		20	4			
	50	0.35		50	0.5		50	2		50	5		50	10			
	75	0.525		75	0.75		75	3		75	7.5		75	15			
	100	0.7		100	1		100	4		100	10		100	20			
	200	1.4		200	2		200	8		200	20		200	40			
	300	2.1		300	3		300	12		300	30		300	60			
	400	2.8		400	4		400	16		400	40		400	80			
	500	3.5		500	5		500	20		500	50		500	100			
0.80%	4	0.032	2.00%	4	0.08	5.00%	4	0.2	10.00%	8	0.4	20.00%	8	0.8			
	8	0.064		8	0.16		8	0.4		8	0.8		8	1.6			
	12	0.096		12	0.24		12	0.6		12	1.2		12	2.4			
	16	0.128		16	0.32		16	0.8		16	1.6		16	3.2			
	20	0.16		20	0.4		20	1		20	2		20	4			
	50	0.4		50	1		50	2.5		50	5		50	10			
	75	0.6		75	1.5		75	3.75		75	7.5		75	15			
	100	0.8		100	2		100	5		100	10		100	20			
	200	1.6		200	4		200	10		200	20		200	40			
	300	2.4		300	6		300	15		300	30		300	60			
	400	3.2		400	8		400	20		400	40		400	80			
	500	4		500	10		500	25		500	50		500	100			
0.90%	4	0.036	3.00%	4	0.12	10.00%	8	0.8	20.00%	12	1.2	30.00%	12	1.6			
	8	0.072		8	0.24		8	0.8		12	1.2		12	1.6			
	12	0.108		12	0.36		12	1.2		16	1.6		16	2			
	16	0.144		16	0.48		16	1.6		20	2		20	2			
	20	0.18		20	0.6		20	2		50	5		50	5			
	50	0.45		50	1.5		50	5		75	7.5		75	7.5			
	75	0.675		75	2.25		75	7.5		100	10		100	10			
	100	0.9		100	3		100	10		200	20		200	20			
	200	1.8		200	6		200	20		300	30		300	30			
	300	2.7		300	9		300	30		400	40		400	40			
	400	3.6		400	12		400	40		500	50		500	50			
	500	4.5		500	15		500	50									

INPUT	OUTPUT	
Percent Natural Gas in Air	H ₂ S in Gas Stream in PPM	H ₂ S in Air in PPM
20.00%	4	0.8
	8	1.6
	12	2.4
	16	3.2
	20	4
	50	10
	75	15
	100	20
	200	40
	300	60
	400	80
	500	100

Attachment III - 1

<Date>

<Name>

<Address>

<City, ST ZIP>

Dear Natural Gas Customer,

The safety of all of our customers and the general public is essential. That's why as part of a new safety education plan, we are sharing important information about unprocessed natural gas and how it could affect you, your family, or employees who may work with you at your home or business.

Unlike most residential and commercial customers who receive natural gas that has been processed before the gas enters a utility's distribution system, because of your location, you obtain natural gas directly from a gas gathering system. By "tapping" into a gathering line before the gas has been through a processing station, the gas could contain natural contaminants such as hydrogen sulfide (H₂S), a flammable, colorless gas. The chemical H₂S occurs naturally in petroleum and natural gas, and concentration levels vary.

At elevated concentrations, especially in confined spaces, H₂S could affect your health. While H₂S poisoning is rare, you should, however, be aware of the potential for health risks. If you come into contact with H₂S—at a residence, grain dryer, feedlot, irrigation system or other location fed by a natural gas gathering line tap—you need to know the signs and symptoms of hazardous H₂S levels and what to do in an emergency.

H₂S has a characteristic odor of rotten eggs; however, after brief exposure, the odor is no longer detectable. Physical symptoms vary, but may include the loss of smell, eye, throat or skin irritation, and respiratory problems. If you smell the rotten eggs odor or believe you have a physical symptom, **evacuate the area immediately and call 911.**

Trained experts should be consulted if you believe you have an unsafe condition. Local emergency officials or utility experts can assist you if you encounter a natural gas leak, or encounter the characteristics of H₂S.

For additional information, visit the H₂S information page of the Kansas Corporation Commission Web site at www.kcc.state.ks.us/pipeline/hugoton_h2s.htm. Or, contact us at 1-800-____ (utility phone number). Also, in the coming months, watch for more information about H₂S and natural gas safety.

Sincerely,

Utility Representative, Title

Utility Name

Attachment V-1

Interstate Transmission Pipeline

	BASE PRICE (STEP 1)	FLOW CONTROL PRICE (STEP 2)	FLOW CONTROL W/OPP PRICE (STEP 3)	SIDE VALVE PRICE (STEP 4)	
				LOW PRICE	HIGH PRICE
Single 2"	\$73,200.00	\$15,750.00	\$2,700.00	\$15,600.00	\$20,550.00
Single 3"	\$78,750.00	\$24,000.00	\$4,050.00	\$15,600.00	\$20,550.00
Dual 3"	\$104,250.00	\$24,000.00	\$4,050.00	\$16,950.00	\$21,600.00
Single 4"	\$85,950.00	\$31,050.00	\$5,550.00	\$16,950.00	\$21,600.00
Dual 4"	\$117,000.00	\$31,050.00	\$5,550.00	\$19,050.00	\$24,000.00

ADDITIONAL PRICE ADDERS

GAS QUALITY EQUIPMENT (STEP 5) (Receipt Meter Stations Only)

Add \$0.00 if none is required

Add \$600.00 if the volume is less than 2 MMSCF/D

Add \$4,050.00 if the volume is between 2 and 20 MMSCF/D

Add \$49,350.00 if the volume is greater than 20 MMSCF/D

OVERPRESSURE PROTECTION (OPP) (STEP 6)

Add \$0.00 if none is required

Add \$8,850.00 if the volume is less than 5 MMSCF/D

Add \$10,950.00 if the volume is between 5 and 15 MMSCF/D

Add \$15,150.00 if the volume is greater than 15 MMSCF/D

LOT ACQUISITION AND SITE PREPARATION (STEP 7)

\$18,000.00

TAXES (GROSS-UP) (STEP 8)

33% times the above steps

EXAMPLE:

A new single 2" delivery meter station with flow control and OPP which ties into the 26" Mainline No. 1 Line and will require a new lot.

Step 1	\$73,200.00	(single 2")
Step 2	\$15,750.00	(flow control)
Step 3	\$2,700.00	(flow control w/opp)
Step 4	\$20,550.00	(high price)
Step 5	\$0.00	(not applicable)
Step 6	\$8,850.00	(overpressure protection)
Step 7	\$18,000.00	(land)
Step 8	\$46,300.00	(taxes)
TOTAL	\$185,350.00	

NOTES:

Step 1 - Base Price is for a skid mounted meter run, electronic flow measurement (EFM), an 6' x 6' building, power and communication connection, heavy equipment usage, x-ray, company labor, transportation, expenses, and overhead.

Step 2 - Flow Control Price includes material, company labor, x-ray, heavy equipment, transportation, expenses, and overhead. Generally, flow control is required for deliveries to NON no-notice customers.

Step 3 - Flow Control with Overpressure Protection Price includes material, company labor, x-ray, heavy equipment, transportation, expenses, and overhead. Generally, flow control is required for deliveries to NON no-notice customers.

Step 4 - Side Valve Price is for material, company labor, x-ray, heavy equipment, transportation, expenses, and overhead of one side valve. The low price is for a side valve connecting to a small pipeline (4" to 12" pipeline). The high price is for a side valve connecting to a large pipeline (18" to 30" to 30" pipeline).

Step 5 - Gas Quality Equipment includes material, company labor, transportation, expenses, and overhead. \$600 is for an in-line probe for spot sampling, \$4,050 is for an electronic sampler, and \$49,350 is for a gas chromatograph.

Step 6 - Overpressure Protection includes material, company labor, x-ray, heavy equipment usage, transportation, expenses, and overhead. \$8,850 is for a 2" x 3" relief valve, \$10,950 is for a 3" x 4" relief valve, \$15,150 is for a 4" x 6" relief valve.

Step 7 - Lot acquisition and Site Preparation includes a standard 50' x 50' lot, survey, title search, environmental, fence, gravel, and small entrance way.

Step 8 - Generally, Taxes are included for delivery meter stations.

Attachment V-2

Application for Transmission Pipeline Tap Service



Gas Delivery Data Sheet for Kinder Morgan Interstate Gas Transmission LLC

Submit to: Richard Kaup, email: richard_kaup@kindermorgan.com,

Fax: (303) 763-3515, Office: (303) 763-3558

Date: _____ (MM/DD/YYYY) DELIVERY POINT REQUESTOR

Contact Name: _____ Phone: (____) _____ - _____ Ext. _____
Company: _____
=====
=====
Customer Name (End User): _____
Customer Type: _____ (click here to choose type)
Customer Contact: _____
Customer Phone number: (____) _____ - _____ Ext. _____
Address: _____
City: _____ State: ____ Zip: _____

LOCATION AND QUANTITY OF GAS TO BE DELIVERED (Attach map if available)

Section: __ Township: __ (Choose) Range: __ (Choose) County: _____ State: __
--



Current Supply from? (Company name): _____
Project / delivery point name: _____
Delivery requested (Volume) _____ mscf/D, Max / Min Hourly flow: _____ / _____ mscf/Hr
Delivery requested (Therms): _____ MMBtu/D, Max / Min Hourly: _____ / _____ MMBtu/Hr
Is the market seasonal? (Choose) If Yes, when is load? _____ (Months)
24 Hour/D operation? (Choose) If No, how many hours per day flow: __ (Hours)
Any future expansion plans? (describe) _____

REQUIRED DELIVERY PRESSURES / SPECIAL CONCERNS

Delivery pressures: _____ psig Desired _____ psig Maximum _____ psig Minimum
Transportation service type requested: (Choose)
Is Odorized gas acceptable? (Choose)
Critical gas quality circumstances? _____
Is standard pipeline quality gas acceptable? (Choose) If no, what are the exceptions: _____
Is telemetry access requested by customer? (Choose) Any other special items? _____
Is a non-interruptible design necessary (i.e. dual regulation, fail-safe, etc.) (Choose)

BUSINESS QUESTIONS

In-service date requested: _____ (MM/DD/YYYY)
Who is funding the construction? _____
Comments: _____

Submitted By: _____ Phone: (____) _____ - _____ Ext. _____

Attachment V-3

Irrigation Energy Cost Comparison

IRRIGATION ENERGY COST COMPARISON

Compares energy costs of irrigation pumping with different fuels at various prices and levels of performance. % NPPPC is percent of Nebraska Pumping Plant Performance Criteria.

INPUT VALUES FOR WHITE BOXES OR ACCEPT CURRENT VALUES

130 Acres	Electric:	0.110 \$/kWh	100	% NPPPC
18 Inch Application	Nat. Gas:	7.00 \$/mcf	100	% NPPPC
150 Feet Lift	Diesel:	1.60 \$/gal	100	% NPPPC
45 PSI Pressure	Propane:	1.10 \$/gal	100	% NPPPC

ALL OUTPUT IS LISTED IN THIS RED BOX

		----- Cost as percent of: -----			
	Energy Cost (\$)	Electric	Nat. Gas	Diesel	Propane
Electricity:	8449.67	100	110	97	78
Natural Gas:	7712.64	91	100	89	71
Diesel:	8701.62	103	113	100	80
Propane:	10853.34	128	141	125	100

whp-hr/kWh
 0.885 Electricity
 whp-hr/mcf
 61.7 Natural Gas
 12.5 whp-hr/gal Diesel
 whp-hr/gal
 6.89 Propane

This program was originally developed by David Pacey and Freddie Lamm, Kansas State University

Attachment VI-1

TEAM 6 DISCUSSION AND COMMENTS

During each of the meetings of the taskforce, Team 6 dealt with subsets of the three assigned primary tasks. The following is a list of the initial comments/recommendations of Team 6.

1. *If annual sampling and reporting is required should that sampling be part of the annual production testing requirements of the prorated fields (Hugoton and Panoma) or should the sampling be expanded to all wells or gathering systems within a given geographic area as identified by current data reports? Such a determination would be dependent on the findings of the data acquisition team.*
2. *Should notice to KCC and gas gathering operators be required when wells with a history of elevated H₂S levels undergo performance or stimulation treatments and are backflowed into a gathering system. The team found no specific field data available to confirm that such conditions were responsible for the expansion of H₂S problems within given gathering systems. However, KCC staff suggests that such notice should be considered further as a method of monitoring and controlling the expansion of increased H₂S levels in gathering systems.*
3. *Are there specific best management practices available that would be applicable to controlling the expansion of H₂S contamination in wells and are those best management practices readily available to operators of wells and systems in southwestern Kansas. No extensive or specific best management practices concerning performance or stimulation treatment operations for areas with H₂S contamination were identified as being readily available to operators. Gas gathering system operators and producers did acknowledge some internal operational procedures being utilized that did address such operations.*
4. *Should H₂S monitoring and safety rules for field operations (wells and gathering systems) be applied to only the prorated fields (Hugoton and Panoma) or should they apply to field operations within a given geographic area as identified by current data reports? Such a determination would be dependent on the findings of the data acquisition team.*
5. *What field rules for H₂S monitoring and safety are being utilized in adjoining oil and gas producing states? See Appendix A of Team 6 report for summary information on H₂S monitoring and safety regulations utilized in Texas, Oklahoma, and Arkansas as well as certain Bureau of Land Management requirements referenced in Colorado regulations. Railroad Commission of Texas Rule 36, which is the basis of Oklahoma and Arkansas H₂S regulation, is also included in this appendix.*
6. *In lieu of specific regulations are there recommended practices for oil and gas operations involving H₂S. Yes, American Petroleum Institute Recommended*

Practice 55 (Recommended Practice for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide) is an industry standard. Elements of this practice or Texas regulatory rule covering H₂S have been adopted in internal company procedures by a number of the larger producers and gas gathering operators in the taskforce study area.

7. *What is the current level of continuous monitoring on the gas gathering systems in this study area?* Continuous monitoring for H₂S in the untreated gas stream on gathering systems is currently very limited on a per-mile of gathering line basis. Early indications from gas gathering operators indicated that as many as 6700 miles of gathering line within the study area of this report was served by as few as five continuous monitoring points that were capable of monitoring H₂S levels. While continuous monitoring for H₂S was limited it was determined that all gathering systems and the larger producers within the area did have systematic procedures for identifying elevated levels of H₂S at wells and in gathering systems on a non-continuous basis. The triggers for when such monitoring by sampling varied between individual well and gas gathering system operators.
8. *Where should additional continuous monitoring points be added?* Options would of course include individual wells, points on gas gathering systems, or at exit taps to gas users on the gathering systems. Beyond the point of placement the determination would be greatly dependent on the findings of the data acquisition team with regard to the extent of H₂S impacts across various systems and interconnects between well areas and gathering systems.
9. *What is the cost of such monitoring points and the elements that affect the costs associated with such continuous monitoring?* Costs associated with monitoring include initial installation, operation, and maintenance. Installation costs vary with type of system and size of installation. Early information from gas gathering operators suggested that costs ranged from a low of \$3000 - \$6000 for exit tap installations to more than \$25,000 for gathering line systems. Other costs associated with such monitoring points included costs for automated shut down capabilities.

Attachment VI-2

SUMMARY OF H₂S REGULATIONS AND BEST MANAGEMENT PRACTICES

- **Summary Information – H₂S Regulations (Texas, Oklahoma, and Arkansas)**
- **Summary Information - Oil and Gas Regulations in H₂S Areas on Federal Lands**
- **API Recommended Practice 55 – Personnel Safety Provisions and Public Alert Levels**
- **Texas Railroad Commission Rule 36 - Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas**

Summary Information (Texas, Oklahoma, Arkansas)

**Field Rules / Regulations
H2S Areas**

	Texas	Oklahoma	Arkansas
Applicability: Min. Conc. Exempt from Regulation Area of Application	<100 PPM Statewide	<100 PPM Statewide	<15 PPM @ Atmos. Cond., < 100 PPM in the gas stream Designated Areas
General Provisions: Tests:	ASIM D-2385-66, GPA Man. C-1, GPA Pub. 2265-69 colorimetric tubes for tests of vapor accum @ storage tanks	ASIM D-2385-81, Or as approved by the Comm	Not specified Industry accepted colorimetric tubes for tests of vapor accum @ storage tanks

**Field Rules / Regulations
Required R.O.E. Calculations**

	Texas	Oklahoma	Arkansas
General Provisions: R.O.E. (Ft) (Radius of Exposure)	Pasquill-Gifford 100 PPM & 500 PPM	Pasquill-Gifford or air dispersion models accepted by US EPA 100 PPM, 300 PPM & 500 PPM	Pasquill-Gifford 100 PPM & 500 PPM
Storage Tanks Min. Concen. subject to specific regulation	> 500 PPM	> 500 PPM	>100 PPM

	Texas	Oklahoma	Arkansas
Storage Tank Provisions R.O.E. (Radius of Exposure)	NO	NO	NO
Warning sign at Tankage	Yes, (Within 50 ft.)	Yes, (Within 50 ft.) –Design of sign specified or compatible with OSHA req.)	Yes, (Within 50 ft.)
Security at Tankage	Fencing required inside city limits, town sites or when tanks are exposed to public	Fencing required inside city limits, town sites or when tanks are exposed to public or other areas as deter. by Commission	Fencing required inside city limits, town sites or when tanks are exposed to public

Field Rules / Regulations H2S Areas

	Texas	Oklahoma	Arkansas
Contingency Plan: When Required	100 PPM ROE >50 ft. and includes a “public area” except a public road; 500 PPM ROE > 50 ft. and includes a public road, or 100 PPM ROE > 3000 ft.	Required for any site that could reasonably result in accidental exposure of the public to a concentration of H2S in excess of 300 PPM - (Reaction and Advanced Briefing Plans)	All operations subject to H2S provisions must prepare a written contingency plan. Plan initiated when H2S exceeds 15 ppm at any point of radius >100 ft from point of release or includes any public area
Training On-site Personnel	Yes	Yes	Yes

Regulations For H2S Areas On Federal Lands

BLM Onshore Order No. 6 (43 CFR 3160)

- Order is applicable when H2S Concentration in gas stream > 100 PPM
- **Potentially Hazardous Volume** = When 100 PPM ROE includes residence, school, church, park, school bus stop, place of business or public area where public could be expected to frequent, or a 500 PPM ROE that any Fed, State, Municipal road or highway
- **Public Protection Plans** - Requirements are similar to Texas RRC Rule 36 and based on intersection of ROE levels and various public places and roads.

API Recommended Practice 55 - Personnel Protection and Public Alert Levels

- **Personnel Safety Provisions** apply if work area concentration of H2S exceeds 10 ppm for 8 Hr. time weighted avg. (TWA) or 15 ppm for short term exposure level (STEL) -15 min. or the work area concentration of SO2 exceeds 2 ppm for 8 hr TWA & 5 ppm for STEL
- **Public Alert Level** – when atmospheric exposure > 30 ppm for H2S and 10 ppm for SO2

Attachment VI-3

Texas Administrative Code

RAILROAD COMMISSION OF TEXAS, OIL AND GAS DIVISION

Title 16 Part 1 Chapter 3

Rule §3.36

Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

(5) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can expect to be populated.

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colorimetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: $x = [(1.589) (\text{mole fraction } H_2S)(Q)]$ to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: $x = [(0.4546) (\text{mole fraction } H_2S)(Q)]$ to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard 253.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE

Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

(ii) Other materials and equipment (including materials and equipment used in drilling and workover operations) which are not included within the provision of clause (i) of this subparagraph may be used for hydrogen sulfide service provided:

(I) such materials and equipment are proved, as the result of advancements in technology or as the result of control and knowledge of operating conditions (such as temperature and moisture content), to be suitable for the use intended and where such usage is technologically acceptable as good engineering practice; and

(II) the commission has approved the use of said materials and equipments for the specific uses after written application.

(iii) Existing facilities (including materials in present common usage for drilling and workover operations in hydrogen sulfide areas) which are in operation prior to the effective date of this section, and where there has been no failure of existing equipment attributed to sulfide stress cracking, shall satisfy the requirements of this section.

(iv) In the event of a failure of any element of an existing system as the result of hydrogen sulfide stress cracking, the compliance status of the system shall be determined by the commission after the operator has submitted to the commission a detailed written report on the failure.

(7) All operations subject to subsection (a) of this section shall be subject to the additional control and equipment safety provision, paragraph (8) of this subsection, and the contingency plan provision, paragraph (9) of this subsection, if any of the following conditions apply:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road;

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(8) Control and equipment safety provision. Operators subject to this provision shall install safety devices and maintain them in an operable condition or shall establish safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. For intentional releases of a potentially hazardous volume of hydrogen sulfide gas, the gas must be flared unless permission to vent is obtained from the commission or its delegate. Venting will be allowed only upon a showing that the venting will not pose an unreasonable risk of harm to the public.

(9) Contingency plan provision.

(A) All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before hydrogen sulfide operations are begun.

(B) The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(C) The contingency plan shall be activated prior to an intentional release, or immediately upon the detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(D) Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

(E) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(F) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(G) The plan shall include a call list which shall include the following as they may be applicable:

(i) local supervisory personnel;

(ii) county sheriff;

(iii) Department of Public Safety;

(iv) city police;

(v) ambulance service;

(vi) hospital;

(vii) fire department;

(viii) doctors;

(ix) contractors for supplemental equipment;

(x) district Railroad Commission office;

(xi) the appropriate regional office of the Texas Commission on Environmental Quality or its successor agencies;

(xii) other public agencies.

(H) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(I) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the commission in accordance with subparagraph (L) of this paragraph.

(J) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(K) The plan shall include provisions for advance briefing of the public within an area of exposure. Such advance briefing shall include the following elements:

(i) the hazards and characteristics of hydrogen sulfide;

(ii) the necessity for an emergency action plan;

(iii) the possible sources of hydrogen sulfide within the area of exposure;

(iv) instructions for reporting a gas leak;

(v) the manner in which the public will be notified of an emergency;

(vi) steps to be taken in case of an emergency.

(L) In the event of a high density of population, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for

public notification, will be acceptable. The reaction plan option must be approved by the commission.

(M) The plan shall include additional support information, if applicable, such as:

- (i) location of evacuation routes;
- (ii) location of safety and life support equipment;
- (iii) location of hydrogen sulfide containing facilities;
- (iv) location of nearby telephones and/or other means of communication; and
- (v) special instructions for conditions at a particular installation such as local terrain and the effect of various weather conditions.

(N) The Railroad Commission District Office shall be notified as follows if the contingency plan is activated:

(i) 12 hours in advance of an intentional release or as soon as a decision is made to release if such decision could not reasonably have been made more than 12 hours prior to the release;

(ii) immediately in the case of an accidental release;

(iii) as soon as possible before or after an unplanned intentional release made in an emergency situation to prevent a possible uncontrolled release.

(O) The retention of the contingency plan shall be as follows.

(i) The plan shall be available for commission inspection at the location indicated on the certificate of compliance.

(ii) The plan shall be retained at the location which lends itself best to activation of the plan.

(P) In the event that, due to particular situations, a contingency plan cannot be developed consistent with the provisions of this paragraph, relating to the contingency plan, then the operator may develop an adjusted plan to fit the situation, and submit same with the certificate of compliance. Approval of the certificate of compliance so submitted will constitute approval of the contingency plan.

(Q) The plan shall be kept updated to insure its current applicability.

(10) Injection provision.

(A) Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this provision unless first approved by the commission after public hearing:

(i) where injection fluid is a gaseous mixture, or would be a gaseous mixture in the event of a release to the atmosphere, and where the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road; or, if the 500 ppm radius of exposure is in excess of 50 feet and includes any part of a public road; or if the 100 ppm radius of exposure is 3,000 feet or greater;

(ii) where the hydrogen sulfide content of the gas or gaseous mixture to be injected has been increased by a processing plant operation.

(B) Each project involving the injection of gas or gaseous mixtures containing hydrogen sulfide which does not require a public hearing prior to receiving commission approval specified in this provision shall nevertheless be subject to the other provisions of this section to the extent that such provisions are applicable to such project.

(11) In addition to any other requirements of this section, drilling and workover operations, and gasoline plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following.

(A) Protective breathing equipment shall be maintained in two or more locations at the site.

(B) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(C) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in concentrations that could be harmful shall be utilized at the site.

(12) Drilling provision. Drilling and workover operations where the 100 ppm radius of exposure includes a public area or is 3,000 feet or greater shall be subject to the following additional provisions.

(A) Protective breathing equipment shall be maintained at the well site and shall be sufficient to allow for well control operations.

(B) The operator shall provide a method of igniting the gas in the event of an uncontrollable emergency.

(C) The operator shall install a choke manifold, mud-gas separator, and flare line, and provide a suitable method for lighting the flare.

(D) Secondary remote control of blowout prevention and choke equipment to be located away from the rig floor at a safe distance from the wellhead.

(E) Drill stem testing of hydrogen sulfide zones is permitted only in daylight hours.

(F) The Railroad Commission district office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this provision.

(G) A certificate of compliance shall be required on each well subject to this provision even if well is located on certificated lease.

(H) Full compliance with all the requirements of this provision must be satisfied before the well is drilled to a depth that is within 1,000 feet of the hydrogen sulfide zone. Alternate depths may be approved in advance by the appropriate commission district office.

(I) API Publication RP-49 is referenced as a suggested guideline for drilling and workover of wells subject to this provision.

(J) Blowout preventers and well control systems shall be pressure tested at or near compliance depth or at depth of nearest bit change prior to reaching compliance depth. The appropriate Railroad Commission district office must be notified at least four hours prior to the test.

(13) Training requirement provision.

(A) Each operator whose operations contain hydrogen sulfide in excess of 100 ppm shall train its employees working in the affected areas in hydrogen sulfide safety.

(B) Each operator shall require all service companies working in affected areas to utilize only those service company personnel who have been trained in accordance with the provisions of subparagraphs (C) and (D) of this paragraph. Written certification to the operator by the service company that only those service company personnel who have been trained in accordance with the training requirement provision will be utilized in affected areas complies with this provision. For this provision, service company shall mean any company actually performing work at well sites, gasoline plant sites, or on pipelines, where such work could allow the escape of hydrogen sulfide gas.

(C) The training of all personnel working in the affected areas shall include the following elements:

- (i) hazards and characteristics of hydrogen sulfide;
 - (ii) safety precautions;
 - (iii) operation of safety equipment and life support system.
- (D) On-site supervisory personnel shall be additionally trained in the following:
- (i) effect of hydrogen sulfide on metal components in the system;
 - (ii) corrective action and shutdown procedures, and when drilling a well, blowout prevention, and well control procedures;
 - (iii) must have full knowledge of the requirements of the contingency plan, when such plan is required.

(E) Training schedules and course outlines shall be provided to the commission personnel upon request for the purpose of commission review to determine compliance with the provisions of subparagraphs (C) and (D) of this paragraph.

(14) Accident notification. Operators shall immediately notify the appropriate Railroad Commission District Office of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident.

(d) Reports required.

(1) Certificate of compliance provision. A certificate of compliance shall be submitted for operations subject to any provision of this section. The following shall apply to the certificate of compliance provision of the section.

(A) The certificate of compliance shall certify that operator has complied or will comply with applicable provisions of this section.

(B) The certificate of compliance shall be filed in triplicate in the commission district office where the operation is located.

(C) The certificate of compliance shall certify that existing operations subject to this section to be in compliance will be in compliance as specified in an attached schedule, or, for new or modified facilities, will be in compliance upon completion.

(D) An approved certificate of compliance will permit an operator to perform all activities described in the certificate without additional filing of approval; provided that, consistent with subsection (c)(12)(G) of this section, a certificate of compliance will be required on each well subject to the provisions of subsection (c)(12)(G) of this section.

(E) A new or amended certificate of compliance shall be required if there is a change in public exposure caused by public infringement of an existing radius of exposure resulting in a change in the applicable provisions of this section, not described by the existing certificate. The operator shall file the new or amended certificate within 30 days after such infringement.

(F) A new or amended certificate of compliance shall be required if there is modification of an existing operation or facility which increases the radius of exposure in a public area, or results in a change in the applicable provisions of this section not described by the existing certificate. The operator shall file the new or amended certificate at least 30 days prior to initiating the operation or construction.

(G) The operator shall file a certificate of compliance 30 days prior to commencement of a drilling or workover operation on wells where a certificate of compliance is required for that well by provisions of this section (wells drilled on noncertificated leases or wells with a 100 ppm radius of exposure greater than 3,000 feet).

(H) In case of extenuating circumstances, an operator may file a certificate of compliance with an attached written explanation for those cases where waiver of 30-day

prior filing is requested. In such cases, the approval of the certificate of compliance will constitute authority to proceed.

(I) The certificate of compliance shall be prepared and executed by a party who, through training and experience, is qualified to make such certification.

(J) The certificate of compliance will be in effect until conditions are altered in a manner that would require amending the "certificate." The operator shall notify the commission within 30 days following cessation or abandonment of operations in a certificated area.

(K) The certificate of compliance required by the provisions of this order for an existing system are due in the district office as soon as is reasonably possible, and no later than September 1, 1976, and as applicable for new or modified operations.

(L) A certificate of compliance may cover a single operation or multiple operations located in an area, a field, or a group of fields within a commission district. The description of the type of operation as indicated on the form must be sufficiently complete to the degree that it is obvious what element of an operation is to be covered by the certificate. All Railroad Commission identification numbers for each element of the system must be shown on the certificate and must be identified as to the type of operation.

(M) Certificates are nontransferable, and a new operator of a system or any acquired element of a system or operation shall be required to certificate that operation. Operator of a certificated system shall notify the commission in writing when the system or any operating part has been transferred to another operator. An amended certificate shall be required should any change occur that would add or delete a Railroad Commission identification number covered by the certificate.

(N) Each operator shall maintain a current master list of all his operations for which a certificate of compliance is in effect and shall submit such list for inspection upon request by the commission.

(2) Completion report provision.

(A) The operator shall report on the initial completion report for new oil or gas wells the hydrogen sulfide concentrations of the wellhead gas for all wells where the hydrogen sulfide concentration is equal to or exceeds 100 ppm.

(B) The drilling of a well in an area which would require the submission of a certificate of compliance (Form H-9) shall have noted on the drilling application (Form W-1) that such certification has been filed.

(3) Releases of, and accidents related to, hydrogen sulfide. The operator shall furnish a written report to the district office within ten days of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident, whether it be from an accidental or intentional release.

(e) Exception provision. Any application for exception to the provisions of this section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

