Seismic Fragility of Natural Gas Transmission Pipelines and Wells

G&E Engineering Systems Inc.

November 14 2021 | Revision 4

ACKNOWLEDGEMENTS

The technical findings in this report would not have been possible without the efforts to study the performance of critical lifeline infrastructure by Mr. Le Val Lund (Los Angeles Department of Water and Power), Mr. Anshel Schiff (Precision Measurements), Mr. Alex Tang (L&T Consulting), Mr. Curtis Edwards (Poutney Consultants), Mr. Bruce Maison (East Bay Municipal Utilities District), Prof. Tom O'Rourke (Cornell University) and Prof. Mike O'Rourke (Rensselaer Polytechnic Institute).

A special acknowledgement to Prof. Kazuo Konagai (U. Tokyo) and Prof. Barry Davidson (U. Auckland) for their support over many years in the study of lifeline system performance in Japan and New Zealand.

The leadership of many PG&E people over the years has been instrumental to the understanding of the earthquake performance of critical gas and electric system infrastructure. PG&E's Geosciences, Gas Transmission and Gas Distribution teams have made contributions to the understanding of earthquake performance of gas pipelines, under the leadership of Mr. Jeff Bachhuber, Mr. Nozar Jahangir, Mr. Bill Horstman, Mr. Bronson Ingemansson and many others. Mr. Eric Fujisaki, Mr. Ed Matsuda and Mr. Brian Low have served as vice chairman, officers and members of the IEEE 693 committee; IEEE 693 is the industry-wide seismic guideline for high voltage power equipment, and is widely used by many utilities throughout the USA, Canada and the world. Their support for developing and implementing the SERA risk model for PG&E's gas and electric systems is gratefully acknowledged.

The seismic design of natural gas pipelines was documented in the 1984 seminal report, "Guidelines for the Seismic Design of Gas and Liquid Fuel Lifeline Systems", by Doug Nyman (Ed.). This report was the product of research and design efforts that supported the construction of the 800-mile long Trans Alaska Oil Pipeline from the north shore to Valdez. This report was written by members the Technical Council of Lifeline Earthquake Engineering (TCLEE). Over the years from the 1970s through 2014, the members of TCLEE developed and published more than 50 reports and guidelines on the seismic evaluation of lifeline infrastructure, including natural gas systems. Dr. Robert Kennedy (Structural Mechanics Consulting) developed many of the methods still used to quantify uncertainty and randomness in seismic hazards and performance of components. Mr. Pete McDonough was the chairman of TCLEE's Natural Gas and Liquid Fuels committee. Mr. Ron Eguchi and Mr. Doug Honegger have made many important contributions to risk models, codes and standards for gas pipelines. Our current state of knowledge reflects the efforts of the many members of TCLEE.

The California Energy Commission (CEC) sponsored G&E Engineering Systems to develop a consultant report on this topic, under grant PIR-18-003. This consultant report was published to the CEC on June 20 2020.

John Eidinger, November 2021

PREFACE

This report describes seismic fragility models for natural gas transmission pipelines and wells.

There are three classes of natural gas pipelines: high pressure transmission pipelines, medium pressure distribution pipelines and medium to low pressure service laterals. This report presents the empirical evidence of how each of these types of pipelines have performance in past earthquakes in California, as well as selected earthquakes in Japan, New Zealand and Alaska. The report compares the empirical evidence with the stress / strain quantitative limits in modern gas pipeline design codes and standards.

Two approaches are provided as to how to estimate the potential for damage of gas transmission pipes: a "repair rate per length" approach and a "strength of mechanics - finite element - strain limit" approach. The "repair rate per length" approach is best applicable to large lengths (preferably 100 miles or more) of gas transmission pipes including all their appurtenances. The "finite element" approach is best suited to examine a specific pipe that is exposed to specific seismic hazards and is the approach recommended for design and evaluation of important gas transmission pipes at specific locations.

The empirical record shows a variety of leaks in past earthquakes for gas transmission systems. For steel pipes with good quality welds and no corrosion, the majority of the leaks are to appurtenances and due to ground shaking. For steel pipes with potentially weak welds, with corrosion or other defects, there have been many major breaks and leaks to the main barrel of the pipe, due to both ground shaking and permanent ground deformations.

This report examines the records of gas pipe performance in 37 earthquakes (including foreshocks, aftershocks and sequences). These include 29 in California from 1906 to 2019, 5 in Japan from 1964 to 2018, 1 in New Zealand in 2010-2011, 1 in Alaska in 2018, 1 in Utah in 2020. Key trends include:

- In northern California, there has been a handful of leaks to gas transmission pipes. All are believed to have been in the "minor" category, requiring repair but without life safety implications or ignition / fire. There have been many leaks in gas distribution pipes and service laterals.

- In southern California, there have been dozens of failed gas transmission pipes; most of which were to pipes with potentially weak welds, corrosion or other defects. The vast majority of the failed pipes were installed pre-1930. One failed pipe released significant gas that led to a fire ignition that burned a few adjacent residential structures. There have been many leaks in gas distribution pipes and service laterals.

- For earthquakes that occurred in 1995 or later in Japan, New Zealand, Anchorage and Sal Lake City, as documented in this report, there have been no failures to gas transmission pipes, while there has been a range of damage to gas distribution system pipes. Older gas transmission pipes, with defects, had a high failure rate in the 1964 Niigata, Japan earthquake.

This report documents that the vast majority of all gas leaks identified post-earthquake have been in the gas distribution system. The CEC project excludes evaluations of gas distribution systems, including service laterals and customer-owned "in-structure" pipes and gas appliances. However, from a gas utility planning perspective, the post-earthquake repair efforts need to address all the damage and response issues, including repairs for transmission pipes, gas distribution mains, service laterals, as well as inspections of customer-owned gas pipes / appliances and corresponding re-light efforts. The empirical evidence indicates that the ratio of leaks in a modern gas system in a M 6 to M 7 earthquake might be: transmission (0 - 3%); distribution mains (3% - 30%); service laterals and meter sets (60% - 90%). In-house inspections and pilot light "relight" efforts can exceed the effort to repair all the transmission and distribution pipes and service laterals. G&E's SERA software can be used to help quantify the seismic performance of the entire gas system.

Most leaks in the transmission system, if the pipes all have good quality welds and have no corrosion, are likely to be minor leaks in appurtenances (including regulating stations, branch pipes, blow offs). For the main barrel of well-built steel transmission pipes, leaks are rarely, if ever, expected due to ground shaking; but leaks and major breaks can occur if the pipe is exposed to significant permanent ground deformations due to liquefaction, landslide or surface faulting.

The fragility models for "repair rate per length" forecast the number of repairs due to shaking, liquefaction, landslide and fault offset hazards. These fragility models are to be used with a geographically-described inventory of the main barrel of the transmission pipe, and imply a corresponding inventory of attached branch pipes and appurtenances associated with a gas transmission system.

The strength-of-materials / finite element approach shows that a well-built gas transmission pipe, with butt-welded girth joints, and without any branches or appurtenances, should essentially never fail due to ground shaking, but could exceed strain limits if exposed to excessive permanent ground deformations. An example is provided in this report that showed an actual pipe that failed when it was subjected to fault offset: the steel ripped open (failure of the pressure boundary), and the computed strains in the pipe were several times higher than the allowable strain limits.

Fragility formulations for natural gas wells are outlined. The models reflect the observations from a limited number of gas wells have been exposed to strong earthquakes in California.

The report includes recommendations for further research that will help better quantify the seismic fragility of gas system components.

ABSTRACT

The report describes the inventory of natural gas pipes and wells in California.

The report describes the performance of natural gas systems in 29 historic earthquakes in California and 8 historic earthquakes in Japan, New Zealand, Alaska and Utah.

The report describes the performance of a steel pipeline exposed to surface fault offset, using the finite element technique.

The report provides fragility models that are based on the empirical record as well as based on stresses and strains.

The report provides recommendations for further research.

Keywords: (Fragility, Seismic, Earthquake, Gas Transmission Pipelines, Wells)

Citation. Eidinger, John. 2021. *Seismic Fragility of Natural Gas Transmission Pipelines and Wells*. Prepared by G&E Engineering Systems Inc., G&E Report, Revision 4, dated November 14 2021.

ENDORSEMENTS

Nothing in this report should be considered as an endorsement of any particular product or company.

It is believed that the information contained in this report reasonably reflects what occurred (or did not occur) in various historic earthquakes in California and around the world. The author of this report has used that information to develop the fragility models in this report. The reader is cautioned that there is no doubt that this report does not contain all possible information, and the report may contain inaccuracies.

This report makes mention of major California, New Zealand, Japanese and other corporate and local government entities; some are listed on stock exchanges. While these entities shared information with the author of this report, the readers should know that none of these entities have endorsed the facts, conclusions or recommendations in this report.

Revisions. This report was last updated on November 14 2021. This includes updated information about the 2020 Magna M 5.7 earthquake; as well as various editorial changes.

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EXECUTIVE SUMMARY

This report describes seismic fragility models for natural gas transmission pipelines and gas wells in California.

The empirical record is presented of how natural gas pipes and wells have performed in 29 past earthquakes in California, from 1906 through 2019, as well as several additional earthquakes from Japan, New Zealand and Alaska.

Two approaches are provided as to how to estimate the fragility (potential for damage) of gas transmission pipes: a "repair rate per length" approach and a "strength of mechanics - finite element - strain limit approach". The "repair rate per length" approach is best applicable to large lengths (preferably 100 miles or more) of gas transmission pipes including all their appurtenances. The "finite element" approach is best suited to examine a specific pipe that is exposed to specific seismic hazards and is the approach recommended for design and evaluation of important transmission gas pipes at specific locations.

Fragility formulations for natural gas wells are outlined. In comparison to the large inventory of natural gas pipelines that have been exposed to strong earthquakes in California, there are only limited numbers of gas wells that have been exposed to strong earthquakes California.

It is intended that these fragility models be used by the California Energy Commission to evaluate the seismic response of gas transmission pipelines and wells in California. For a variety of reasons explained in the report, the fragility models in this report may not be applicable to natural gas systems in any other state of the United States or any other country.

The report includes recommendations for further research that will help better quantify the capability of gas system infrastructure to perform satisfactorily in earthquakes.

There are many uncertainties in performing seismic evaluations of natural gas pipelines and wells. This report outlines the uncertainties and provides suggestions as to how to quantify these in terms suitable for regional loss estimation.

Key Findings

The fragility of natural gas steel transmission pipelines varies significantly:

- If well-constructed, then these types of pipes commonly resist strong earthquakes without leaking gas. Gas leaks, should they occur, will most commonly be related to attached appurtenances. The main barrel of the pipe is nearly invulnerable to the effects of ground shaking. Even non-seismically-designed pipes have been shown to be able to sustain modest ground deformations, including fault offset up to a foot or more, without loss of the pressure boundary.

- If not well constructed, these types of pipes are especially vulnerable in strong earthquakes. They may fail (major loss of the pressure boundary) due to strong shaking, and they may fail due to modest ground deformations, including fault offset of about a foot or so.

In most large earthquakes in California, the number of repairs to natural gas pipelines may be approximately 0 - 3% (transmission system), 3 - 30% (distribution system), 60 - 90% (service laterals and riser / meter sets). While these percentage ranges are not absolute, they indicate that the majority of repairs will be to distribution mains and services.

The "strength of mechanics - finite element - strain limit approach" is the preferred approach to consider a specific pipe at a specific fault crossing zone (or liquefaction / landslide zone). In many cases such pipes will have no appurtenances / branch connections within or near the hazard zone. The strain limits described in this report for these pipes are consistent with "code" type approaches; meaning that if the strain limit is just reached, a well-constructed pipe without corrosion or other defects should be able to sustain the design-level imposed ground deformations with very high reliability. There is presently insufficient test or empirical data to quantify the chance of failure (loss of pressure boundary) if the imposed strains exceed the code-level limits; for one example provided in this report, when the computed strains were several times over the code-level limits, the pipe wrinkled and the steel tore open.

The term "leaking gas" means different things in different parts of the world. In California, and as adopted in this report, "leaking gas" means any leak that can be identified using gas sensing equipment that can identify methane leaks on the order of several parts per billion.

Three damage states (DS) are described for potentially damaged pipes: DS3 (major damage), DS2 (minor damage) and DS1 (pipe is not leaking, but has undergone nonlinear performance, and may be a candidate for replacement after the earthquake). DS3 includes leaks at high gas-to-air mixtures that pose significant potential for ignition, or located where rapid action is needed to limit the exposure to people. DS2 includes leaks at low gas-to-air mixtures that do not immediately have potential for ignition, or located where there is little or no exposure to people.

Older welded steel high pressure transmission pipes with poorly-constructed welds that are not at least as tough and ductile as the main barrel of the pipe, are significantly more vulnerable than modern steel pipelines constructed with high quality welds. In Southern California, dozens of such pipes (almost all built prior to 1930) have failed in past earthquakes; there is presently no evidence that indicates this has commonly occurred in Northern California.

CHAPTER 1: Introduction

1.1 Purpose of the Study

The purpose of this report is to developed fragility curves that can be used for seismic risk analysis of natural gas transmission pipes and gas wells in California.

1.2 Pipe Fragility Models

Fragility models are described for steel transmission pipes used in natural gas systems in California. The fragility models address damage to ground shaking (as measured by horizontal Peak Ground Velocity); liquefaction, landslide and fault offset (as measured by Permanent Ground Deformation).

The fragility models are outlined to allow 3 levels of loss estimation study: Level 1 (least pipe inventory and least seismic hazard definition); Level 2 (more inventory and more seismic hazard definition); and Level 3 (most pipe inventory information and most seismic hazard definition). All Levels 1, 2, 3 are geared towards forecast of pipe leaks per unit length of pipe, in relation to the level of ground hazard. The Level 1, 2, 3 models are used to forecast leaks on the main barrel of the pipe as well as to all related appurtenances.

Chapter 7 of this report provides an example of a Level 4 model, using finite element methods using nonlinear pipe and nonlinear soil elements. A Level 4 model is geared to quantifying the pipe strain (or stress) in relation to the level of applied ground hazard. Level 4 analyses are geared toward the evaluation, design and/or construction of gas pipelines to "code" type guidelines. If the forecast stress / strain in the pipe is less than a code-type allowable stress / strain, then the pipe is "qualified". By "qualified" it means the pipe is designed to meet the Standard of Practice for new steel gas transmission pipes built in 2020 in California. The probability that such a pipe will leak gas in a future earthquake depends, in part, upon how it was constructed, how the pipe has been loaded over its service life (internal pressure, external loads, etc.), and the accumulated effects of internal and external corrosion.

It would be convenient if simple-to-apply fragility models (Level 1, 2 or 3, per unit length) that exactly match the results from Level 4 approaches (for a specific pipe), it is not practical to derive Level 1, 2 or 3 fragility models that can exactly match every possibly installation / hazard configuration. In part, this reflects that the Level 1, 2, 3 fragility models are geared to forecast leaks for both the main barrel of the pipe as well as to all related appurtenances, whereas the Level 4 model is geared to qualify a specific pipe (usually without any appurtenances). If the user is interested in the seismic performance of a specific pipe installation to a specific level of seismic hazard, as for example a transmission pipe that delivers gas to an adjacent regulating station, including all the pipe and equipment at the regulating station, then the user should use the Level 4 approach using site-specific pipe and equipment inventory.

The fragility models described in this report are specific only to natural gas transmission pipes in California. The performance of natural gas pipes in other states of the United States (including Alaska, Utah, Washington, Oregon, etc.) and other counties (including Japan, New Zealand, China, Greece, Turkey, Israel) can vary widely as compared to those in California. The underlying reasons for this potential great disparity is that the type of pipe, quality of construction, corrosion protection systems, maintenance practices, subsurface conditions, and the definition as to what is a "gas leak" can vary throughout the world. In parts of the world where older cast iron gas pipes are still in use, there can be much higher reported damage and gas leakage than for a comparable earthquake in California. In parts of the world where gas leaks are identified primarily by smell, there can be lower reported damage and gas leakage than for a comparable earthquake in California.

1.3 Well Fragility Models

Fragility models are provide for natural gas wells. The fragilities address the more common damage modes, including: collapse of the well due to corrosion; collapse of the well due to liquefaction effects in the top 40 feet beneath grade; variation in gas pressure due to the impacts of the earthquake on the gas-bearing strata. Other failure modes are outlined, including faulting at depth (not quantified in this report) and damage to above ground components (a procedure to evaluate this process is described in this report).

1.4 Areas for Further Investigation

Based on the findings in this report, some areas for further research are recommended. These are described In Chapter 9 of this report. The new information from this research may indicate that updates of the fragility models in this report may be warranted.

1.5 Limitations and Certifications

The findings in this report are meant for earthquake and system planning purposes for natural gas system operators in the State of California.

The Level 1, 2, 3 fragility models in this report are *not applicable* to natural gas infrastructure in Oregon, Washington, Alaska, Utah or other high seismic areas of the United States, or in New Zealand, Japan, China, Greece, Turkey, Israel or other high seismic areas around the world. The Level 4 fragility approach is suitable for use in any locale.

The professional services have been performed using the degree of care and skill ordinarily exercised under similar circumstances by reputable engineers practicing in the field of seismic loss estimation for natural gas systems in California at this time. No other warranty, expressed or implied, is made as to the professional advice included in this report. Use of this information by other parties or for different purposes may not be appropriate and is entirely at those parties' responsibility and those parties agree to indemnify G&E for any such use.

The certification of this report requires that any person or Engineer of Record that uses information in this report for design or construction shall establish and suitably certify the following: local hazards; as-built conditions; mitigation concepts; site-specific analysis and design; cost estimates; in consideration of permit requirements. The Engineer of Record should confirm if mitigation scheme(s) are cost effective. If mitigation is not cost effective, then consider the "do-nothing" alternative and rely on emergency response.

1.6 Units

This report makes use of both customary English and SI units of measure. The academic and scientific communities preferentially uses SI units of measure, such as cm, meters, km. Essentially all the natural gas system operators in California have their entire pipe system designed and installed using "inches" as the unit of measure for diameter. As such, this report uses both SI units (generally for describing the hazards) and customary English units of measure (generally for describing pipe diameter or wall thickness).

This report does not convert pipe diameter sizes from inches to SI units. It is not proper to call an actual pipe built in California with outside diameter of 12.75 inches, as a 323.85 mm pipe. While the conversion is numerically accurate, there is no pipe vendor in the world that commonly sells a 323.85 mm pipe; even if they did sell such a pipe, it is unlikely that the actual outside diameter would have 5 significant digits of precision. Depending on context of the application, it is common to describe pipe diameter as either "nominal diameter", or sometimes as "inside diameter with pipe wall thickness", or sometimes "outside diameter with pipe wall thickness" or sometimes "average diameter with pipe wall thickness". To avoid introducing further confusion as to what is the true diameter / wall thickness of a pipe, without the extra possible mis-interpretation of conversion from inches to SI units, diameters of pipe constructed in California are always called out in terms of inches. In this report, for pipes constructed in Japan or New Zealand that were originally specified in SI units, the SI unit measurements are initially described and then converted to customary units.

The common conversions between the systems are as follows:

1 kip = 1,000 pounds

1 foot = 12 inches

1 inch = 25.4 mm = 2.54 cm

1 km = 3,280.84 feet

1 mile = 1.609347 kilometers

1 pound-force = 4.448 newtons

1 pound = 0.453592 kilogram

1 psi = 6.894757 kiloPascal (kPa). Absolute pressure is denoted as psia; the pressure of the atmosphere is 14.7 psia at sea level. Gauge pressure is denoted as psig; gauge pressure measures the pressure inside a pipe relative to the outside atmospheric pressure. In this report, unless otherwise noted, pressures that are listed as psi are relative to the outside (or psig), meaning that a pipe at 60 psi has internal gas pressure 60 psi higher than the outside air pressure.

1 kPa = 0.145038 psi

1 m = 1,000 mm = 100 cm

1 bar = 0.1 MegaPascal = 14.5038 psi

1 Dth = 10 therms = 1,000,000 BTUs

1 Dth = 1,000 cubic feet of gas with a heating value of 1000 BTU/cubic foot

1 Dth ~ 975 to 1,100 cubic feet of gas, depending on the heating value of the mix of various gases in the gas stream

1.7 Abbreviations

A	Area (inches^2)
AD	Average displacement across the fault (inches or meters)
ALA	American Lifelines Alliance
BCF	Billion Cubic Feet
BTU	British Thermal Unit
c	wave speed propagation speed (feet / sec)
cf	cubic feet
cm	centimeter
CEC	California Energy Commission
CNG	Compressed Natural Gas
CP	Cathodic Protection
D	Diameter (inches). ID or D_i for inside diameter. OD or D_o for outside diameter.
Dth	DekaTherm
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
FS	Factor of Safety
Ft	Feet
Fy	Yield stress of steel, ksi
Fu	Tensile strength of steel (ultimate stress), ksi
g	acceleration of gravity (= 32.2 feet / second / second)
G&E	G&E Engineering Systems Inc.
GB	Gigabyte
GHG	Greenhouse gas
GIS	Geographical Information System

GJ	GigaJoule
GMPE	Ground Motion Prediction Equation
HCA	High Consequence Area
in	Inch
ILI	In Line Inspection
IOU	Investor Owned Utility
Kip	kilo-point (1,000 pounds)
km	kilometer
ksi	kips per square inch
LDC	Local Distribution Company
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
m	meter
mm	millimeter
M	Magnitude (moment magnitude), or meter
MAOP	Maximum Allowable Operating Pressure (psi)
MCA	Moderate Consequence Area
Mcf	Thousand cubic feet
MD	Maximum Displacement across the fault (inches or m)
MW	Megawatt
p	pressure, psi
PHMSA	Pipeline and Hazardous Materials Safety Administration
psf	pounds per square foot
psi	pounds per square inch
p	pressure (psi)
PGA	Peak Ground Acceleration (measured in g)
PGD	Permanent Ground Displacement (measured in inches)
PGV	Peak Ground Velocity (measured in inches/second or cm/sec)
PG&E	Pacific Gas and Electric
R, r	Radius (inches)

RR	Repair Rate per 1,000 feet of pipe or per km of pipe
SAM	Seismic Anchor Motion
SDG&E	San Diego Gas and Electric
SERA	System Earthquake Risk Assessment (G&E software)
SMYS	Specified Minimum Yield Stress (psi)
t	Pipe wall thickness (inches)
VOC	Volatile Organic Compounds
Vs30	Average shear wave velocity of the top 30 meters below grade (m/sec)
ß	lognormal standard deviation
$ß_u$	lognormal standard deviation for uncertainty
$ß_r$	lognormal standard deviation for randomness
σ	Sigma. Represents the hoop stress in the pipe due to internal pressure
σ_a	Sigma.(allowable). Represents the allowable stress in the pipe

CHAPTER 2: General Approach

2.1 Introduction

Natural gas systems in California are a vital lifeline. Natural gas systems include a variety of components, including pipelines, wells, regulating stations, compressor stations, and facilities to inject odor and also adjust gas quality. To make the system work as a whole, there are also office and maintenance facilities. Various other systems are needed to make the natural gas system work as a whole, including power supplies, communication networks, transportation networks, and, of course, the people needed to make all of this work.

This report examines the seismic fragility of two of these components, namely pipelines and wells. The bulk of this report concentrates on gas pipelines, as this is by far the largest component of the overall gas system. The report also examines natural gas wells.

Natural gas is principally composed of Methane (CH_4). For brevity, this report uses the word "gas" to refer to natural gas. This report does not discuss gasoline (also commonly called "gas") or other liquid fuels (oil, kerosene, propane, etc.).

The damage and loss of gas system infrastructure in earthquakes will result in a number of consequences:

- Loss of fuel supply to major electric power plants
- Loss of gas needed for home heating and cooking
- Leaks in the gas pipeline system will result in release of methane (CH_4) into the environment; methane is a greenhouse gas
- Leaks of gas in a confined environment can displace enough air as to present a chance of suffocation. Odorizers are included in gas so that people can smell its presence, and take suitable action to open windows or leave the confined environment
- Gas, if combined sufficient concentrations with air, can ignite and become explosive. Ensuing fires can lead to property damage and injury / fatalities

A systematic seismic risk study should consider all the direct and indirect economic and other consequences of damage to the gas system. The general approach would be to examine the existing gas system in a scenario earthquake, and quantify all the consequences. This process is then repeated over many scenario earthquakes. Monte Carlo or other techniques can be used to examine variability risk due to repeats of the same scenario earthquake. The annual chance of each scenario earthquake can then be applied to the results, and the annualized losses due to all consequences can be quantified. Then, various mitigation schemes, with their related construction and operational costs, can be developed that might reduce these consequences. Then a benefit cost analysis can be performed to examine if the mitigation schemes are cost-effective. The cost-effectiveness test would also include the benefits accrued to daily operations, such as reduce ongoing maintenance costs and increased system reliability. Mitigation actions that are cost effective can then be included in the Rate Case, and then implemented in Long Term Capital and Operations and Maintenance Programs of the utility.

It is beyond the scope of this report to describe all the detailed steps in a systematic seismic risk study.

2.2 Loss Estimation Levels

This report outlines 4 levels of refinement for loss estimation for gas pipelines and wells. These are called:

- Level 1. Level 1 requires the least information about the inventory and hazards.
- Level 2. Level 2 requires additional information about the inventory and hazards.
- Level 3. Level 3 requires further information about the inventory and hazards.
- Level 4. Level 4 requires a level of information about the inventory and hazards that is suitable for design and construction of critical infrastructure at especially high hazard locations, such as major gas transmission pipes that cross active earthquake faults. This report addresses Level 4 by outlining the commonly acceptable levels of strain in natural gas pipes due to earthquakes, and describing the finite element modeling technique including pipe strain results from one real world example. This report is not intended to be a code or standard or guideline for design and construction.

This report describes the type of hazards (ground shaking, permanent ground deformations, etc.) that are needed for the loss estimation. Methods about how to calculate and quantify these hazards is not addressed in this report.

2.2.1 Level 1

The Level 1 methodology is performed as follows:

- Calculate the Peak Ground Velocity (PGV) throughout the study area for a Scenario earthquake. The study area might be a pressure zone, an entire service area, or the State of California as a whole. The choice of the Scenario earthquake and the study area is made by the user. PGV should be the maximum of two horizontal PGVs at a location.
- Obtain the inventory of gas transmission pipelines (and wells) in the study area. The inventory includes the spatial locations of the main transmission pipes (but no information about any appurtenances) / wells. For each pipe, the inventory should include the length of pipe (km), the nominal diameter of pipe (inches), the material and age of the pipe (modern steel with good construction, vintage steel with potential weak welds / corrosion or other defects).

The Level 1 methodology is geared to obtaining a first order loss estimation in a single scenario earthquake, due to the ground shaking hazard. Level 1 methodology is geared to providing a median estimate of gas transmission system performance in a single scenario earthquake. This may be adequate for initial planning efforts for issues such as emergency response. In areas of stable ground (i.e., no liquefaction, no landslide, no surface faulting), a Level 1 analysis may be adequate. In areas prone to ground failures (PGDs), a Level 1 analysis may significantly underestimate damage; in those areas, Level 2 or Level 3 refinements should be included in the loss estimation.

The advantages of Level 1 analysis is that it requires the least effort to obtain inventory information and the least effort to quantify the effects of ground failures. Ground shaking hazards are readily obtained from USGS ShakeMap software, either as planning scenarios of potential future earthquakes, or as near real-time maps of earthquakes that have actually occurred. The approach is simple and could be readily computed using Excel-based spreadsheets.

The fragility models for Level 1 analyses are as follows:

- Repair Rate of buried pipes as a function of PGV.

Level 1 analyses provide the following results:

- Estimate of total repairs to gas transmission pipes due to shaking caused by the Scenario earthquake. The estimates are median based (50% chance there are more and 50% chance there are fewer repairs.) The total repairs include leaks to the main barrel of the transmission pipe (rare) and appurtenances.

2.2.2 Level 2

The Level 2 methodology is performed as follows:

- Calculate the Peak Ground Velocity (PGV) throughout the study area for a Scenario earthquake. The study area might be a pressure zone, an entire service area, or the State of California as a whole. The choice of the study area is made by the user. Include a range of PGVs that reflect the uncertainty in ground motions at any single location. PGV should be the maximum of two horizontal PGVs at a location.

- Calculate the Permanent Ground Deformations (PGD) throughout the study area for a Scenario earthquake. The PGDs are computed due to liquefaction, landslide and surface faulting hazards.

- For liquefaction and landslide PGDs, quantify the maximum PGD in the hazard zone. The PGD is the PGD at the ground surface above the pipe.

- For fault offset PGDs, include the maximum PGD across the fault zone. This should include the accumulated creep, the co-seismic slip, and afterslip. The PGD is assumed to be applied in a "knife edge" pattern over a width of 1 foot.

- Obtain the inventory of gas pipelines (and wells) in the study area. The inventory should include the spatial locations of the pipes / wells. For each pipe, the inventory should include the length of pipe (km), the nominal diameter of pipe (inches), the material and age of the pipe (modern steel with good construction, vintage steel with potential weak welds / corrosion or other defects), and the Diameter-to-wall thickness (D/t) ratio.

The fragility models for Level 2 analyses are as follows:

- Repair Rate of buried pipes as a function of PGV. These are the same as used for Level 1 analyses.

- Repair Rate of buried pipes as a function of PGD for pipes that traverse liquefaction and landslide zones.

- Repairs of buried pipes as a function of PGD for pipes that traverse fault offset zones.

Level 2 analyses provide the following results:

- Estimate of total repairs to gas transmission pipes due to shaking, liquefaction, landslide and surface faulting caused by the Scenario earthquake. The estimates are median based (50% chance there are more and 50% chance there are fewer repairs.) The total repairs include leaks to the main barrel of the transmission pipe (rare) and appurtenances.

2.2.3 Level 3

The Level 3 methodology introduces additional parameters into the loss estimation. Level 3 analyses are intended to reduce some of the uncertainty as to locations where pipe damage is more likely to occur.

- Calculate the Peak Ground Velocity (PGV) throughout the study area for a Scenario earthquake. The study area might be a pressure zone, an entire service area, or the State of California as a whole. The choice of the study area is made by the user. Include a range of PGVs that reflect the uncertainty in ground motions at any single location. PGV should be the maximum of two horizontal PGVs at a location.

- Spatial variation in PGV in a single scenario earthquake is computed.

- Calculate the Permanent Ground Deformations (PGD) throughout the study area for a Scenario earthquake. The PGDs are computed due to liquefaction, landslide and surface faulting hazards.

- For liquefaction PGDs, include the type and direction(s) of PGD. Most liquefaction PGDs manifest themselves as settlements. In some areas, liquefaction PGDs also manifest themselves as lateral spreads. The direction of lateral spread in relation of the pipeline is important for pipeline performance. PGDs that are normal to the pipeline direction (like settlements or lateral spreads at 90° to the pipe direction) are much less damaging to well made gas pipelines (butt welded steel, fusion welded plastic) than PGDs that are parallel to the pipe direction. Describe the PGDs at the surface level as well as at the springline depth of the pipe; if the pipe is buried below the level of PGD, it will not be subjected to the additional stress / strains that are caused by the PGD.

- For landslide PGDs, include the direction of the PGD. This can be assumed as normal to the downslope direction of the landslide.

- For fault offset PGDs, include the accumulated creep, the co-seismic slip, and afterslip, and rate of PGD over prescribed widths through the offset zone. Include the direction of the PGDs. Factor in the PGDs due to strike slip, normal, reverse thrust and oblique offset movements. Include PGDs for faults that move sympathetically. Include probabilities that offset PGDs can occur at locations somewhat distant from the locations of mapped fault traces.

- The Level 3 hazards may be used in combination with Level 4 finite element-type approaches to compute the stresses and strains in a specific pipe.

- Obtain the inventory of gas pipelines (and wells) in the study area. The inventory should include the spatial locations of the pipes / wells. For each pipe, the inventory should include the length of pipe (km), the nominal diameter of pipe (inches), the material and age of the pipe (modern steel with good construction, vintage steel with potential weak welds / corrosion or other defects), and the Diameter-to-wall thickness (D/t) ratio. Include repair history for the pipe. Include soil corrosivity and pipe corrosion protection characteristics. Address accuracy of spatial location of the pipe. Subdivide the pipe length geometry into a suitable number of subs-segments such that the length of pipe that traverses liquefaction and landside zones matches the actual boundaries of these zones; subsegments could also be set to match lay sheet (fabrication sheet) part numbers.

For individual pipelines at a specific location, Level 3 hazard quantification coupled with Level 4 pipe analyses should be used. Level 1, 2 and 3 fragility models (repair rate per length) are not applicable to individual pipelines at specific locations.

Some users may wish to quantify "annualized" or "return period" loss estimations. For example, the PGVs and PGDs could be quantified as a "475 year", "975 year" or some other return period that corresponds to common code-type approaches for buildings. However, the user should be aware that these types of "return period" computations are essentially *meaningless* for spatially large gas system networks, and there is no meaning to a loss estimation for a gas network for a spatially large gas network "exposed" to a "2,475 year" code-based earthquake in a single analysis.

The user may also quantify the annual chance of occurrence for each scenario earthquake. For example, a Hayward M 6.8 event on the south segment of the Hayward fault might be assigned an annual chance of about 0.01 (1%). The assignment of annual chances is commonly done in Hazard models, for example computed for 0.2 M intervals; thus, the 0.01 value would be interpreted as a 1% annual chance of a M 6.7 to 6.9 event on the south segment of the Hayward fault. The level of refinement in this can be considerable, as a M 6.8 event on this fault that propagates to the northwest will result in different PGVs and PGDs than a M 6.8 event on this event that propagates to the southeast. The user may wish to examine multiple scenarios to allow the study of the effects of multiple epicenters and propagation directions. The approaches to quantify the uncertainties in the ground motions will vary depending on the approach taken, generally with larger $ß_u$ if directivity and propagation direction is not specifically modeled, and smaller $ß_u$ if directivity and propagation direction is specifically modeled.

2.2.4 Level 4

The Level 4 methodology is the approach that would be used to evaluate critical pipes at high hazard locations, and to then develop suitable design and construction approaches. Level 4 approaches are outlined in industry guidelines, codes and standards such as ALA (2005), PRCI (2009). Section 7 of this report provides an example of a Level 4 analysis for a specific steel pipe that underwent about 10 feet of fault offset. Level 4 analyses are geared towards providing levels of stress / strain in a pipe for a given set of hazards. The level of detail in the hazard description should be established by competent professionals and reflect the site specific conditions. Depending on the intent of the effort, Level 1, 2 or 3 characterizations of the hazards may be sufficient.

2.3 Length, Location, Number of Pipes, Storage of Pipe Data

2.3.1 Length and Location and Attributes of Pipes

The digitized length of pipe segments might initially established by using data derived from GIS datasets, such as ".shp" files used in common GIS software such as ArcGIS or QGIS. Before using this GIS information, the approach taken to originally create the GIS datafiles should be assessed.

Over the past 2 decades or so, many utilities have converted paper drawings to GIS-based datasets. It is not uncommon to create the GIS dataset with the intention of creating system-wide maps at large scale, suitable for planning projects, as well as to create maps that can be used in the field by crews to locate pipes. Unless the pipes are "pot holed" or located using magnetic or other means, the lines on the GIS datasets should never be assumed to represent the true location of the pipes. This is one of the reasons that pot-holing and field marking of pipe locations is always a good practice and often required before digging.

In the GIS creation, while the level of spatial accuracy might not be perfect, but it might be good enough for map making and initial estimated locations of the buried pipes. The length of each digitized pipe segment might be controlled by changes in pipe attributes (pipe diameter, pipe material), branch connections with other pipes, etc. It is not uncommon to have pipe segment lengths in GIS datasets as short at 10 feet (or less), or as long as 3,000 feet (or more). Some utilities set the length of each segment to reflect part numbers of pipes delivered by the fabricator; but this practice is uncommon.

The accuracy of GIS datasets in California can be roughly described as follows:

- Transmission pipes. Horizontal alignment of GIS lines can be ± 1 foot (quite accurate). This reflects that each transmission pipe has been potholed or located using magnetic or other means. Vertical alignment is roughly known, with most segments known to have either shallow burial (2 to 5 feet) or deep burial (over 5 feet). At stream and river crossings, GIS data for vertical and horizontal data should only be used as first order estimates, and the actual locations (such as for Level 4 analysis) should always be based on original plans and profiles. For construction, the locations should be verified in the field.

- Distribution pipes. Horizontal alignment of GIS lines is commonly ± 3 foot but could occasionally be more. Sometimes, the horizontal accuracy will be ± 1 foot, but not uncommonly, the pipe might have been re-routed during construction. This reflects that most distribution pipes have not been potholed or located using magnetic or other means.

- Service Laterals. The small pipe (generally 1-inch diameter or smaller) from the distribution main to the customer's meter is often constructed by third parties (not by the utility). The utilities may have reasonably good spatial location of where the lateral is tapped into the distribution main, and the type of the meter set, but no data as to where the lateral is located. Most laterals are constructed by third parties using the Green Book set of pre-approved drawings for service laterals. As such, the spatial location of laterals is nearly never known with accuracy, and the actual style of construction also has uncertainty. While a GIS dataset might indicate that the service lateral is "steel" or "plastic", there may be variations in materials over the length of the lateral. The support of the meter can be provided by the pipes (the riser pipe and the pipe leading into the customer's structure), and may be supplemented by informal blocking (CMUs, stacks of wood shims under the meter, etc.). Some meters might be located inside closets within buildings. From a seismic perspective, much of historic repair work has been to laterals and risers. The location and type of laterals can be established by field verification efforts, but as there are millions of laterals, the cost to obtain this information is high.

- Most GIS datasets have attributes assigned to each pipe. These attributes often might include year of construction, diameter, pipe material, etc. It is common that many pipes in the GIS dataset will have missing attributes. It might be that most missing attributes are most common for the oldest-installed pipes. In some cases, the owner of the gas system might have purchased the system from another company, and the old records were not transferred to the new company (or perhaps the old records were never very detailed). From a seismic analysis perspective, the usual practice is to evaluate pipes with missing attributes as having "default" fragility models, where the "default" fragility model reflects a rather vulnerable style (often an older type) of construction. The intent of using default fragilities is to bias the results to be a bit conservative (more earthquake vulnerability, larger loss estimates etc.), but if the "missing attribute" situation represents only a few percent of all pipes, then this approach might be prudent.

2.3.2 Number of Pipes, Medians and 84th Percentiles

In designing the loss estimation desktop software, the number of pipe segments in the model needs to be considered.

For a large utility the size of PG&E or SoCalGas, the total number of segments in the GIS datasets might be on the order of:

- Transmission Pipes. 200,000 segments, for about 10,000 km of pipe.

- Distribution Pipes. 1,000,000 segments, for about 100,000 km of pipe.

- Service Lateral Pipes. 4,000,000 laterals, for about 40,000 km of pipe.

If the user wishes to perform a seismic analysis of all pipe in a large gas utility, then the seismic hazards and pipe performance may need to be computed at millions of locations, for each scenario, and for each hazard.

There are four seismic hazards that need to be considered. The ground shaking seismic hazard can usually be computed at the mid-point along the length of the digitized pipe segment.

- Shaking. The level of shaking does not vary much over a 100-foot length. But, if the pipe segment length is 2,000 to 5,000 feet or so, there will be material variation of shaking over that length, and the variation of shaking over such a long segment might be important.

- Liquefaction. Typical liquefaction zones are on the order of 10s of feet to 100s of feet wide. Lateral spreads can vary tremendously over distances of 10s to 100s of feet. Pipe segments that transition into / out of liquefaction zones will be difficult to analyze accurately using the basic GIS segment data; more accurate models (Level 4 finite element type) can better accommodate these situations. For performing Level 2 or 3 analyses, it is recommended that the pipe segment lengths in the initial dataset be sub-divided into sub-segments so that each sub-segment is either "in" or "out" of a liquefaction zone.

- Landslide. Typical landslide zones are on the order of 10s of feet to 100s of feet wide. Downslope movements can vary tremendously over distances of 10s to 100s of feet. Pipe segments that transition into / out of landslide zones will be difficult to analyze accurately using the basic GIS data; more accurate models (Level 4 finite element type) can better accommodate these situations. For performing Level 2 or 3 analyses, it is recommended that the pipe segment lengths in the initial dataset be sub-divided into sub-segments so that each sub-segment is either "in" or "out" of a landslide zone.

- Surface faulting. Typical fault offset zones are commonly on the order of 10s of feet wide. Fault offset PGDs (amount and relative direction and angle to the pipe) will vary tremendously through the fault offset zone. Pipe segments that transition into / out of fault offset zones can be analyzed using basic GIS data, on a "per-crossing" basis, and not on a "per km" basis. More accurate models (Level 4 finite element type) can better accommodate these situations.

For a specific pipe, in a particular scenario, the assignment of liquefaction, landslide and surface faulting hazard characteristics can be done "by hand", by visually examining the pipe alignment and mapped hazard zones. For a large system with 100,000s to 1,000,000s of pipe segments, automated GIS-based techniques can be used to overlay the hazards with the pipes. These spatial-type computations (point-in-polygon, line intersection, etc.) are well documented in the literature and optimized computer code to perform these computations is well established. If the pipe and hazard datasets are "static" (not changing) then such computations can be done one time, and the results stored for later processing. On a modern desktop PC using latest i9 Intel (or similar) chips, these computations can take hours to days to run. If one considers that the utility is constantly adding and deleting pipes, as the system is constantly being renewed and extended, then the software should ideally have the capability to incrementally assign the hazards for each pipe as it is added; and also to track which pipes have been abandoned. Tracking abandoned pipes is especially useful for doing historic analyses of the response to pipes in historic earthquakes.

Allowing that a system-wide analysis might have a large number of segments (on the order of 1,000,000 or more), the seismic analysis approaches suggests that for pipes that have over-prediction of seismic hazards (PGA, PGV, PGD, etc.) and thus over-prediction of damage using fragility models, will be offset by other pipes that are correspondingly under-predicted. When considering a large number of pipes, using median pipeline fragility and median hazards might provide a level of accuracy that might be acceptable for purposes of emergency response, where the primary concern will be the total level of damage, and the total level of emergency response crews and time needed to make repairs.

If the user is interested in the performance of a single pipe and wishes to have high confidence in the results, then Level 4 analyses are recommended.

If the user is interested in the performance of a single pipe, the use of the fragility models for Level 1, 2 or 3 are not suitable for any purpose beyond preliminary loss estimation. The fragility curves described in this report do not incorporate all the possible variables / attributes that might be specific to a single pipe. It is possible to do analyses that include a treatment of uncertainties and randomness for each seismic hazard at a single site, but lacking the full details of a single pipe and how it is constructed and attached to adjacent pipes and equipment, the pipe fragility models provided in this report for Level 1, 2, 3 analyses may not be suitable.

As a compromise between accuracy and computation time, a convenient approach is to compute, for each pipe in a large sample size, the hazards at the 84^{th} non-exceedance level, and to use the median pipe capacity. This will provide a reasonable forecast for planning purposes of the near upper bound vulnerability of each pipe. Since it is never possible for all pipes in a large geographic network to be exposed to the 84^{th} percentile hazard motions in a single scenario, a convenient approach to establish the 84^{th} percentile performance of the entire network can be done using spatial variability hazard modeling techniques.

2.3.3 Storage

If one further subdivides the pipes into smaller segments, say each segment no longer than 80 feet, with an average segment length of 40 feet, then the number of segments will be larger. Say for example, the utility has 10,000 km of transmission pipe, then with a maximum pipe segment length of 80 feet, and an average of 40 feet, then the number of segments would be: 10,000 km * 3280.84 feet / km / 40 feet / segment = 0.82 million.

For designing the computer program to evaluate all this information, each segment of pipe might have many attributes. Assuming that character fields are 1 byte (1 byte = 8 bits) per character and real number fields are 8 bytes per number, and integer fields are 4 bytes per number, then storage issues are as follows:

- Geometry Data. 4 to 20 x,y vertices representing pipe location. Say each vertice has a x, y, point (exclude elevation z), to be stored internally as Real*8, and stored in both geographic (latitude / longitude) and projected (eastings, northings) units. Storage required = 8 vertices * 4 * 8 = 256 bytes.

- Attribute Data. The typical utility database will have about 100 or more attributes per pipe segment. These attributes can include: year of installation (4 bytes); material (16 bytes); nominal diameter (8 bytes); wall thickness (8 bytes); class; objectID (8 bytes); Series (8 bytes); Route Name (32 bytes); Status (active, inactive, etc.) (16 bytes); Installation Month (4 bytes); Installation Date (4 bytes), Segment Length (8 bytes).

- Exposure (population density) (8 bytes); Owner (16 bytes); Pipe depth (16 bytes); type (16 bytes); D/t Ratio (8 bytes); MAOP (8 bytes); SMYS (8 bytes); Station numbers (begin / end (32 bytes); ILI-Piggable (4 bytes); Mileposts (begin / end (32 bytes); liquefaction hazard data (100 bytes); slope (16 bytes); nearest stream / open face (40 bytes); depth to water table (8 bytes); Height from pipe to bottom of open nearest open face (8 bytes); liquefaction susceptibility (16 bytes); other landslide characteristics (100 bytes); Factor of Safety (dry and wet conditions (16 bytes); Ky (dry and wet conditions) (16 bytes); depth of the landslide mass (8 bytes); distance of pipe to landslide (8 bytes); landslide susceptibility (16 bytes); NEHRP soil classification (4 bytes); Vs30 (8 bytes); list of fault segments that the pipe crosses or is near to (120 bytes); fault offset susceptibility (16 bytes). Storage required: 764 bytes.

- Results (per scenario). Name of scenario (32 bytes). Magnitude (8 bytes). Computer run ID (32 bytes). PGA, PGV, pLiq, pSlide (winter), pSlide (summer), PGDs for each hazard, Repair chance, Repair type, Repairs due to shaking, Repairs due to liquefaction, Repairs landslide, Repairs due to offset, variability information. About 20 fields * 8 bytes = 160 bytes. If Monte Carlo simulations are done, then the results need to be tracked for each simulation, so if there are 1000 simulations, brute-force storage of all intermediate results is 1000 * 160 bytes / simulation) = 160,000 bytes.

Assuming no Monte Carlo simulations, then storage per pipe segment is about: 256 + 764 + 160 = 1120 bytes / segment. If there are 0.82 million segments, then storage required is about 0.92 billion bytes (~1 GB). If one tracks 100 different scenarios to cover a range of possible earthquakes, then the storage is: 0.82 million * (256 + 764 + (160 * 100)) = 14 GB.

While it is not the purpose of this report to develop the software and database schema, it is important to understand that database design, storage of data and computation time will all be important factors in the desktop software. With judicious tracking of attribute data, and excluding service laterals from independent analysis, then a 14 GB database to track 100 scenarios is a target database size. The software must be 64-bit and run in a 64-bit operating system environment (Windows 32 bit operating systems can limit file sizes to 2 GB). Excel-based spreadsheet-type computations will not be practical if there are over 1,000,000 rows of information (Excel is limited to ~1,000,000 rows).

CHAPTER 3: Inventory

3.1 Overview

Figure 3-1 shows a map with the service areas of the major natural gas system operators in California. The red lines are mapped Quaternary faults in California and Nevada. Some of the mapped faults are active (movement in the last 11,000 years), and some are potentially active (movement in the last 1,600,000 years) and some are inactive. Figure 3-1 shows that all the gas system operators in California are exposed to earthquake hazards.

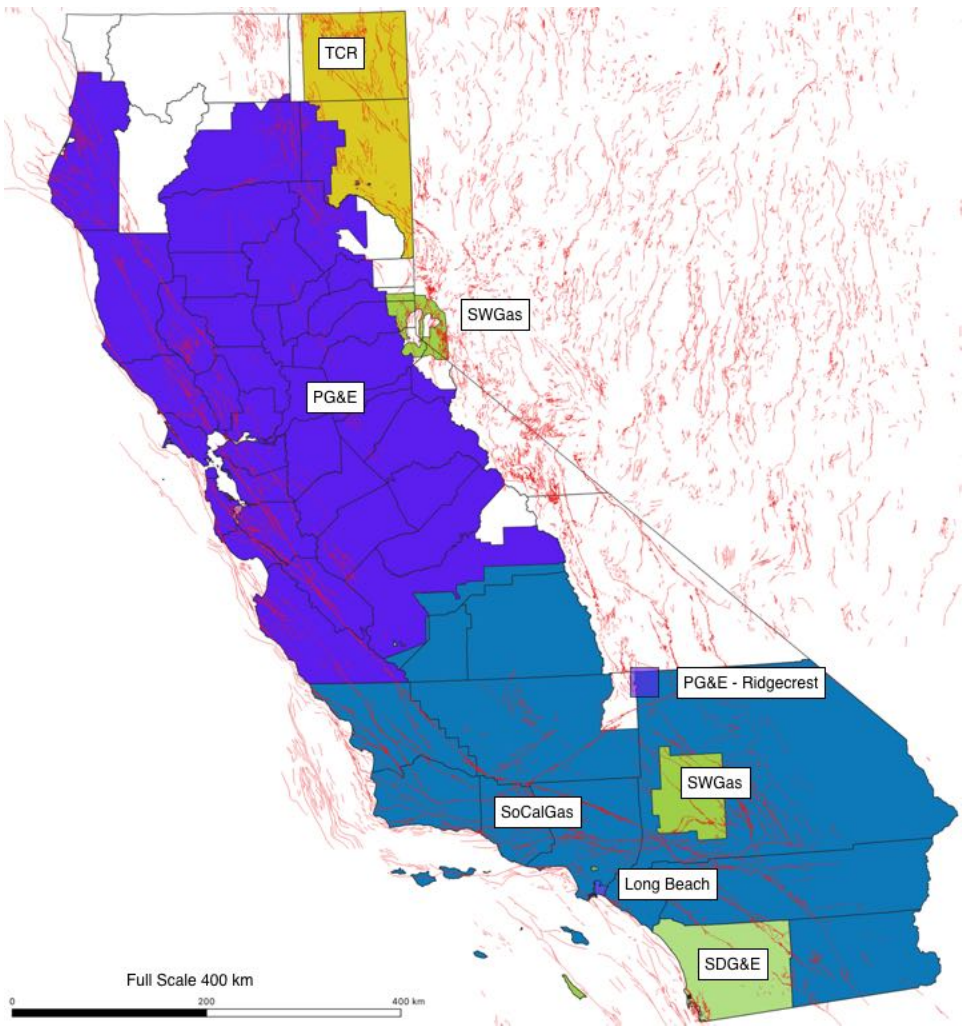


Figure 3-1: Natural Gas Systems in California

Figure 3-2 shows the natural gas transmission pipes in California. The data was derived from PennWell natural gas pipeline geospatial data and historical maps provided by the CEC. The data represents the pipeline transmission system in California as of about 2011 – 2012 (San Diego as of 2018). Figure 3-2 does not show gas distribution pipes or service laterals.

Table 3-1. Gas System Operators in California

Provider	Abbreviation	Type	Transmission Pipe Length, km
Pacific Gas and Electric	PG&E	IOU	10,358
Southern California Gas	SoCalGas	IOU	6,490
San Diego Gas and Electric	SDG&E	IOU	937
Southwest Gas Corp	SWGas	IOU	41
Tuscarora	TCR	IOU	303
Palo Alto		LDC	0
Coalinga		LDC	0
Vernon		LDC	10
Susanville		LDC	0
Long Beach Gas & Oil		LDC	0
Total			18,139

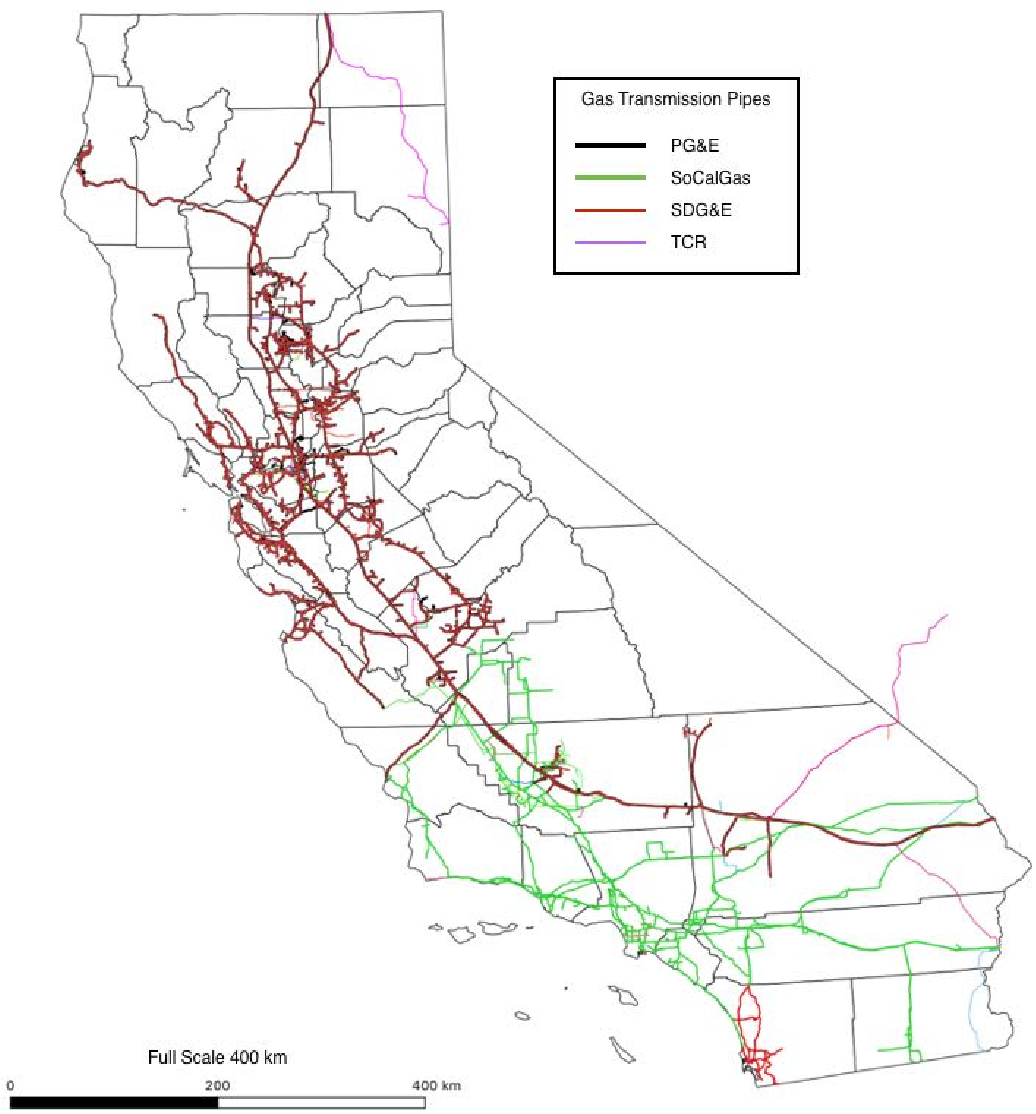


Figure 3-2: Natural Gas Transmission Pipes in California

Table 3-1 lists the primary gas system operators in California. Table 3-1 lists both the Investor Owned Utilities (IOUs) and Local Distribution Companies (LDCs). The IOUs also operate distribution systems that deliver gas to end users including residential, commercial and industrial customers. Table 3-2 lists other gas transmission system operators in California. The pipeline lengths in Tables 3-1 and 3-2 are derived from the geospatial data in Figure 3-2 or from other public sources.

Table 3-2. Other Gas System Operators in California

Operators	Transmission Pipe Length, km
Aera Energy	2
BP West Coast	32
California Gas	54
Chevron	668
Calpine	223
City of Redding	8
Conoco Phillips	8
Dick Brown	20
El Paso	150
Ex El	23
Exxon Mobil	9
Freeport Morgan Oil and Gas	25
Gill Ranch Storage	36
Kern River	537
Lodi Gas	71
Macpherson Oil Company	10
Midway Subset	6
Mojave Pipeline	748
Naftex Operating Company	10
North Baja Pipeline	132
Occidential of Elk Hills Inc.	38
PXP	12
Questar Pipeline Company	52
Ruby Pipeline & El Paso Corp.	1,102
Seneca	6
Silicon Valley Power	8
SMUD	122
Standard Pacific	55
Tesoro SoCal Pipeline Co	4
Thums	7
Venoco	57
Wild Goose	41

Total	4,276

While this report is geared to developing seismic analysis methods applicable to the three largest IOUs in California (PG&E, SoCalGas, SDG&E), the approaches may also be applicable to the various LDCs and other gas system operators.

The three largest IOUs in California are PG&E, SoCalGas and SDG&E. IOUs are under the jurisdiction of the California Public Utilities Commission (CPUC) for rate making. TCR is an interstate gas pipeline system that is a subsidiary of TC Energy Corporation. TCR operates a gas transmission pipeline in northeast California.

There are several smaller natural gas providers in California. These include: Long Beach Gas & Oil, City of Coalinga, City of Palo Alto, Island Energy (formerly Mare Island Naval Shipyard), City of Susanville, City of Vernon. These municipal-owned distribution systems are also called Local Distribution Companies (LDC). These LDCs operate within the broader PG&E or SoCalGas service areas, and the PG&E and SoCalGas transmission systems delivers gas to those LDCs.

In Northern California, Southwest Gas Corp serves smaller communities near Lake Tahoe. In Southern California, Southwest Gas Corp serves the area near Victorville, Big Bear, Barstow. Outside of California, Southwest Gas Corp provides service in Arizona and Nevada. Company-wide, Southwest Gas has over 2 million customers.

Today (2020), about 85% of the natural gas supply for California comes from the American Southwest, the Rocky Mountain States and Canada, with the remaining 15% coming from in-state sources, both on shore and offshore.

Historically, gas has been used in California since the late 1800s. At the time of the 1906 earthquake, gas was widely used in San Francisco, then the largest population center of California; as well as smaller communities in southern California. Prior to the late 1920s, gas supply was from so-called "manufactured gas", where gas was created from the heating of coal. Beginning about 1918, large natural gas fields were discovered in Kern County, and this gas was cleaner burning and less expensive than manufactured gas. In the 1920s, PG&E and SoCalGas built steel transmission pipes from the Kern County area to deliver that gas to their gas distribution systems in San Francisco and California.

After the second world war, California's population growth resulted in increased demand for natural gas, and this required additional supplies for natural gas. A 1,000-mile pipeline running from Texas and New Mexico was constructed to deliver gas to the Los Angeles area. By 1951, PG&E constructed its first 34-inch gas transmission line (then called Line 300) to deliver gas from the California-Arizona border to the San Francisco Bay area. PG&E's 1951-vintage 34-inch line 300 welded steel gas pipeline was exposed to both fault offset and strong ground motion in the 1952 Taft earthquake. The 1952 Taft earthquake also exposed many SoCalGas steel pipelines to strong ground motions. Chapter 6.2 discusses the performance of both PG&E's and SoCalGas gas transmission pipelines in that earthquake.

The 1920s-vintage gas transmission pipes were constructed using welded steel pipes. It is now (2020) generally recognized that welded steel pipe constructed in the early 1920s in California did not always have consistent high quality welds, as reliable welding techniques were not yet then widely in place. For example, EBMUD (the largest water system operator in Northern California) constructed its first steel 48-inch aqueduct (Mokelumne No. 1) in 1923, intending it to be a welded steel pipe; but during construction of this pipe in 1923, EBMUD found that the actual welds were not sufficiently reliable (failure to pass hydrostatic tests, etc.), and during construction EBMUD switched from welded steel pipe to riveted steel pipe.

This issue of the reliability of welds in pre-1930 welded steel pipe becomes especially important in context of seismic issues, and in this report, chapters on the 1952 Taft earthquake and 1971 San Fernando earthquake both highlight that vintage (pre-1930) welded steel pipe in the SoCalGas system have had very high failure rates. Today (2020), PG&E, SoCalGas and SDG&E all recognize that their oldest welded steel pipes (generally pre-1930, but extending to about 1946) are considered to be potentially less reliable in earthquakes, and should be tagged as being higher priority candidates for early replacement. This report provides fragility models for these older welded steel transmission pipes which can be used to help quantify the seismic risk and thus provide input to developing quantified cost effectiveness strategies for possible replacement of these older pipes.

3.2 Components

Natural gas systems include many components. This report examines the historical earthquake record for the following components:

- Transmission Pipes
- Distribution Pipes
- Service Laterals
- Wells

The are many other components of the gas system, including gas storage fields, compressor stations, regulators, etc. This report does not provide any seismic assessment of these components.

Components in the gas system are sometimes similar to components in water systems. For example, water system include transmission pipes, distribution pipes, service laterals and wells. While there are some similarities between gas and water components, there are also many differences. In California, these differences include:

- Most welded water steel transmission pipelines use different types of welded joints than welded gas steel pipelines.
- Water transmission and distribution pipes are often made of materials that are not used in modern gas systems. For example, water system pipes include steel, concrete cylinder, prestressed concrete, ductile iron PVC, cast iron, asbestos cement; whereas gas system pipe are almost entirely steel or MDPE.

- Water systems commonly operate at pressures of 100 psi to 150 psi. Gas transmission systems commonly operate at pressures of 400 psi to 2,000 psi.

- Modern water pipes commonly use cement linings to reflect the effects of water chemistry and smoothness requirements suitable for water systems. Gas pipes never have cement linings.

- Most gas transmission steel pipes use impressed current as part of the corrosion protection system. Very few water steel pipes use impressed current.

- Wells used to supply water systems often (except for artesian wells) use pumps (submersible or shaft-driven) to lift water from underground aquifers to the surface level. Wells used to supply gas systems do not use pumps as the pressure of the gas in the gas-bearing strata is often sufficient to lift the gas to the surface.

For these and other reasons, the seismic performance of water systems and gas systems can be different. The reader is cautioned not to apply the gas system seismic performance and fragility information in this report for water systems, or vice-versa.

3.2.1 Transmission Pipes

Throughout this report, unless otherwise noted, the term "diameter" refers to a pipe's "nominal" diameter. The actual inside and outside diameters of pipes differ from the nominal diameter, reflecting the wall thickness of the pipe (t). Table 3-3 compares Nominal Diameter as well as Inside and Outside diameter and wall thickness for common steel transmission pipes. The actual t for specific pipes varies from those listed in Table 3-3, recognizing different Maximum Allowable Operating Pressures (MAOP) and class of various reaches of pipe.

Table 3-3. Steel Transmission Pipe Sizes

Nominal Diameter (Inches)	Inside Diameter (Inches)	Outside Diameter (Inches)	Wall t (inches)	Schedule
2	2.067	2.375	0.154	40
3	3.068	3.500	0.216	40
4	4.026	4.500	0.237	40
6	6.065	6.625	0.280	40
8	7.981	8.625	0.322	40
10	10.020	10.750	0.365	40
12	12.000	12.750	0.375	40
16	15.000	16.000	0.500	40
18	16.88	18.000	0.562	40
20	18.81	20.000	0.594	40
22	21.00	22.000	0.500	XS
24	22.63	24.000	0.688	40
26	25.000	26.000	0.500	XS
30	28.750	30.000	0.625	30
32	30.624	32.000	0.688	40
34	32.624	34.000	0.688	40
36	34.500	36.000	0.75	40
42	40.500	42.000	0.75	40

The actual pipe thickness chosen for a specific transmission pipe would normally be specified to be thick enough to withstand actual internal operating pressures with a minimum factor of safety of between 1.39 to 2.5 against yield in the hoop direction. The Specified Minimum Yield Stress (SMYS) of new steel pipe is commonly X42 (Fy = 42,000 psi) or higher, but the grade of steel for older pipe might have been A36 (Fy = 36,000 psi); A53 (Fy = 30,000 psi) or possibly even lower grades in the oldest pipes. It is believed that the lowest grade steel in the California's gas transmission pipe network has (Fy ~ 28,000 psi), for pipes dating back to the 1920s; although it is possible that a very few of the oldest pipes have Fy as low as 25,000 psi. The highest grade steel pipe commonly used in transmission system pipes is X70 (Fy = 70,000 psi).

If the user (the seismic analyst, etc.) has only the spatial location of steel pipe, and one does not have access or the resources to study original construction documents, then one might assume the pipe has Fy

= 42,000 psi, being one of the more common steel materials. But for situations where more accurate analyses are warranted, clearly the user should research the actual steel material properties.

When transmission pipe is designed, one of the key parameters is to select the wall thickness, t. The minimum thickness t for design is based on the pipe diameter, internal operating pressure, the steel material Fy, and the desired factor of safety. Per 49CFR 192.111, the minimum factors of safety for the allowable hoop stress (σ_a) for steel transmission gas pipe are:

- Class 1. σ_a = 0.72 Fy, or F.S. = 1/0.72 = 1.39
- Class 2. σ_a = 0.60 Fy, or F.S. = 1/0.60 = 1.67
- Class 3. σ_a = 0.50 Fy, or F.S. = 1/0.50 = 2.0
- Class 4. σ_a = 0.40 Fy, or F.S. = 1/0.40 = 2.5

The selection of Class rating from 1 to 4 varies based on where the pipe is located. Class 3 and 4 pipe are generally located in urban areas with high population density, and the required F.S. is 2.0 or higher. Class 1 and 2 pipe are generally located in rural areas with low population density, and the required F.S. is 1.67 or 1.39.

Table 3-4 shows the nominal hoop stresses at internal pressures of either 400 psi (or 800 psi), as well as the pressures needed to reach the minimum specified yield stress assuming grade X42 steel (Fy = 42 ksi) and the pipe wall thicknesses listed in Table 3-3 (calculated assuming hoop stress = pressure * radius (mean) / thickness). Various approaches are taken as defining what is the value of "radius": the inside radius, the mean radius or the outside radius. For thin-walled pipes (D/t > 40), the most common approach is to use the mean radius (average of inside radius and outside radius). For thick-walled pipes with D/t ≤ 20, the thin-walled cylinder equations lose some accuracy, and stresses will vary from the inside face of the pipe to the outside face of the pipe; for the pipe diameters listed in Table 3-3, thick-wall theory results in less than 0.1% higher hoop stress for pipes with diameter ≥ 10 inches. The thick-wall versus thin-wall differences in computed hoop stress are not material for purposes of the seismic considerations presented in this report.

$$\sigma = {}^{pr}/_{t}$$

Table 3-4. Hoop Stress and Internal Pressures

Nominal Diameter	Hoop Stress, psi @ 400 psi (mean r)	Hoop Stress, psi @ 800 psi	Internal Pressure (psi) to reach Fy = 42 ksi	Internal Pressure (psi) to reach F.S. = 2 assuming Fy = 42 ksi
2	2,884	5,769	5,824	2,912
3	3,041	6,081	5,525	2,762
4	3,597	7,195	4,670	2,335
6	4,532	9,064	3,707	1,853
8	5,157	10,314	3,258	1,629
10	5,690	11,381	2,952	1,476
12	6,600	13,200	2,545	1,273
16	6,200	12,400	2,710	1,355
18	6,207	12,414	2,707	1,353
20	6,533	13,067	2,571	1,286
22 (sch XS)	8,600	17,200	1,953	977
24	6,778	13,557	2,478	1,239
26 (sch XS)	10,200	20,400	1,647	824
30 (sch 30)	9,400	18,800	1,787	894
32	9,102	18,205	1,846	923
34	9,684	19,367	1,735	867
36	9,400	18,800	1,787	894
42	11,000	22,000	1,527	764

The actual operating pressure within the transmission pipes varies throughout the transmission system. The transmission system operator assigned a MAOP (Maximum Allowable Operating Pressure) for transmission pipes. Table 3-4 shows the internal pressures needed to reach nominal yield in the hoop direction, assuming grade X42 steel; and the actual operating pressures to maintain a nominal Factor of Safety of 2 on hoop pressure (Class 3 pipe).

The actual stresses in a pipe in Table 3-4 exclude many other contributors to stress. Other stresses and stress risers occur when there are:

- Axial stresses. Internal pressure will always result in hoop stress. For buried pipes near bends and closed valves, and all above ground pipes, the internal pressure also acts on the opposing faces of the pipe at elbows, resulting in longitudinal stresses in the pipe. For an ideal pipe situation (pipe not confined by soil), the longitudinal stresses will be 1/2 the hoop stresses. For buried pipes, the longitudinal stresses will drop at distance away from a bend as the longitudinal forces are reacted by restraint by the adjacent backfill in the pipe trench.

- Temperature stresses. For buried pipe, when the temperature of the steel differs from the temperature of the surrounding soil, longitudinal thermal tension (soil colder than the steel) or compression (soil hotter than the steel) stresses will occur, as long as the pipe does not slip through the soil. Differing temperatures of the internal gas will also induce stress in the pipe. The chance of pipe failure during extended coldest snaps is higher than otherwise, reflecting that cold soils induce higher tensile stresses in the steel.

- Corrosion, such that the actual wall t is less than the original wall t. This can manifest itself as patches of rust, pin holes or other defects (all thinning) on the outside or inside surface of the steel pipe. This report is not meant to be a primer on corrosion, but it is worthwhile to summarize some of the more common corrosion issues for steel gas pipes:

  - Pits. Pits are indentations on the outside or inside of a pipe. Pin-hole leaks in water steel pipes (and gas pipes) have been observed after earthquakes, where the earthquake-induced increase in stress in the pipe wall overcomes the residual strength at the pit location, allowing gas to shoot out in a thin stream. Post-earthquake leaks in gas pipes due to pitting have also been observed (for example, see discussion for the 1933 Long Beach earthquake, and 1952 Taft earthquake Sections 6.20 and 6.2, respectively).

  - Pits can show striations and undercutting features that are often associated with microbial corrosion, and manifest itself with increased chloride concentration. Chlorides can result from certain types of microbial activity. Microbes include sulfate-reducing, acid-reducing, general aerobic and anaerobic.

  - Dissolved O_2 in an electrolyte can cause pitting by creating concentration cells.

  - CO_2 is soluble in water and will form carbonic acid, which is corrosive to carbon steel.

  - When dissolved in water, H_2S forms a weak acid that can corrode carbon steel. In combination with dissolved O_2, it can cause pitting.

  - pH. A pH level of 7 is neutral, below 7 is acidic, and above 7 is basic. Water can occur in the pipe either as a part of the gas constituents, or from ground water sources. Water is denser than gas or hydrocarbon liquids that may be present in a gas pipe, so it will tend to form in pools at low points in the pipe. It is generally desirable to have a pH level inside a steel pipe that is somewhat basic, as that will tend to form an internal barrier on the inside of the steel pipe that is resistant to corrosion. When constituents in the pipe result in a pH less than 7, the acidic environment inside the pipe allows cells to form, where ions from one part of the pipe move to another; the loss of ions manifests itself as rust / pits, wall thinning. Dissolved CO_2, H_2S in water tend to lower the pH level below 7.

  - By maintaining the quality of the natural gas in the pipes, internal corrosion can be controlled. Monitoring the actual makeup (quality) of the gas and liquids in the pipe is also useful. A variety of facilities in gas transmission systems are geared to controlling and monitoring gas quality. It is beyond the scope of this report to address any of the corrosion control and monitoring aspects; other than to note that earthquakes will induce incrementally higher stresses in the pipelines, and any pipe that has already undergone wall thinning will be subject to an increased chance of failure (leak, etc.) in the earthquake; and that it is practically difficult to have perfect knowledge of all wall t at all locations at all times; intermittent corrosion checks can identify wall t at selected locations at selected times.

- External corrosion can occur whenever the surface of a steel pipe is in contact with the surrounding soil. This can occur in coated pipes, whenever there is a pin-hole or other type of defect in the coating system (plastic tape wrap, etc.). Defects can occur due to damage of the coating system during installation. If the exposed steel pipe is in soil that is corrosive in nature, a corrosion cell will be set up, and the steel will thin / rust over time. The common methods to protect steel pipe in corrosive soils is to add sacrificial anodes (zinc or magnesium), which will preferentially lose ions and thus protect the steel; or to impress a current into the steel, which changes its potential for corrosion. Impressed current is used for corrosion protection of most gas transmission pipes.

- Monitoring the status of corrosion is a never ending process. Once a pipe is known to have defects, then the implied Factor of Safety on hoop stress yield is reduced; there are various code cases (ASME B31.8g) that provide guidance as to what an acceptable residual F.S. is on pressure, for various types of wall defects.

- Flaws (cracks in the steel, defects at welds). The stress across a flaw is nominally zero, and the stress at the tips of the flaw are substantially increased to reflect the lack of load carrying ability across the flaw. Fracture toughness procedures can be used to compute the stress intensity at the tips of the flaw, and if the actual stress intensity at the tip is less than the toughness of the steel, the flaw should not propagate (get larger); if the stress intensity at the tip exceeds the fracture toughness, the flaw will propagate until either it reaches equilibrium, or the internal pressure can no longer be sustained and the crack propagates until the pipe leaks (minor release of internal gas and the pipe can continue to be functional) or breaks (major release of internal gas and the pipe no longer functions).

- Branch connections. At branch locations, there is an opening in the main pipe to allow gas to flow to the branch pipe. The geometry of the opening and the style of welds of the branch pipe (or reinforcement of the opening) to the main pipe (rarely as threaded connections for larger diameter gas pipes) result in stresses risers in both the main pipe and the branch pipe. WRC 107 and similar documents provide methods to compute the state of stress at the main pipe / branch connection, due to all six directions of loading (two shears and axial load, two bending moments and torque).

- Welds. For full penetration welds (for example common longitudinal seam welds made in the shop or girth welds made in the field), the nominal stress in the weld is the same as the stress in the main barrel of the pipe. The weld material is usually specified to have strength equal to or greater than the SMYS of the main barrel of the pipe.

- If the weld is partial penetration, then the stress in the weld will exceed the stress in the main barrel of the pipe. Standard gas pipe design calls for full penetration welds for all field and shop made longitudinal seam and field-made girth joints. However, failure of steel pipes especially in PGD zones has not been uncommon in earthquakes around the world for cases where actual girth welds were made with partial penetration welds; this reflects that the limited-strength girth weld is first to yield once the pipe becomes highly loaded, and the weld cannot sustain the imposed high strains sufficiently to accommodate the impacts from the PGDs.

- If the weld is a fillet weld, there is commonly about a 2.1 times increase for the highest stress in the weld as compared to the stress in the main barrel of the pipe. Fillet welds are commonly used for girth joint joinery of steel pressure pipes used for water service, but rarely (if ever) used for girth joint joinery of gas pipes. Fillet welds may be present at branch connections.

- Common external loads (soil weight and vehicle loading).

- Unusual configurations (concrete encasements used to carry especially high external loads, such as under railroad tracks; or for scour protection under creeks).

- Unplanned impacts ("hits" caused by digging by third parties, etc.)

- Pressure pipes on saddles within casing pipes with an empty annulus. Casing pipes are often installed under highways or railroad crossings, to allow for future installation of pipes through the casing pipe. The casing pipe is designed to carry the external soil pressure loads from overhead vehicle loading as well as soil loads. When pressure pipes are installed in these situations, it is common to push / pull the new pressure pipe through the casing pipe, leaving the annulus between the pressure pipe and casing pipe unfilled, with the new pressure pipe supported on sliding support saddles within the casing pipe. Sometimes the annulus is filled with concrete.

- Above ground pipes. Above ground pipes are exposed to stresses due to external and internal temperature changes; earthquakes; ground settlements; wind; seismic anchor motions; etc.

- Chemical interaction with gas / impurities inside the pipe that result in changes in steel properties.

- Fatigue (Earthquake). All steels have a fatigue life, whereby with a sufficient number of tension / compression stress cycles, the steel will fail. At very low ranges of stress (like under 2 ksi), steel can often take millions of cycles before the steel reaches its fatigue life (rupture and loss of pressure boundary). At very high levels of stress (with yielding), it might take only a few cycles for the steel to fail (rupture and loss of pressure boundary). The normal operating environment for the gas transmission system results in relatively few high stress cycles, and fatigue failures are thought to be rare. Under earthquake conditions, fatigue-related failures can occur when the steel stress is high enough to exceed yield. Acceptable strain limits under seismic loading reflect that most types of seismic loads that result in yield (such as fault offset / landslide / liquefaction) have one load cycle (the soil moves and yields the steel, then the soil stops moving); but a pipe that has already been yielded has taken up some if its seismic capacity. If the actual strain in a pipe is +4% under seismic for a one-time loading (like fault offset), then the strained pipe will have less margin to accept future fault offsets and ongoing operational loadings. The fragility and design of pipes to accommodate seismic loads considers that the ALA (2005) and PRCI (2009) allowable tensile strains (generally set at about +4%) are intended to provide reasonable margin for a one-time loading; if a pipe is designed to accommodate multiple earthquakes over its lifetime, then a lower allowable strain (say +2%) might be suitable. It is noted that the nominal breaking strain of reasonably tough (high Charpy capacity) virgin ductile steel for one time loading is often +20% to +30% strain; and the selection of +4% is intended by the authors of various ALA, PRCI (and similar) guidelines was established to provide some margin of the pipe to accept larger than assumed seismic loads; aging of the pipe and allowance for some amount (unspecified) of defects (imperfect welds, etc.). In other words, if an aged pipe (say 50+ years old) is actually exposed to an earthquake that induces +4% strain (such as due to fault offset), it is intended that at this level of strain, the chance that the pipe will not lose its pressure integrity is about 95% or higher. In practice, the actual failure of steel pipes at fault crossings has usually been caused by local buckling (wrinkling) of the steel shell, resulting in high local bending-induced strains in the steel, leading to rupture once these strains reach 20% or higher. High pressure steel gas pipes have D/t ratios commonly in the range of 50 or so, and the allowable compression strain limit of 1.76 t/D would be -1.76% for a lower pressure pipe (D/t = 100) or -3.52% for a higher pressure pipe (D/t = 50). It is noted that lower pressure water pipe (D/t commonly 150 or so) has had many observed wrinkling failures in past earthquakes. It is important to recognize that the +4% strain limit in guidelines are for those primary strains computed due to primary tension and bending of the entire pipe cross section; with a concurrent check that primary strains are kept below a local buckling (wrinkling) limit. Some newer design concepts ("pre-buckled pipe") being considered at fault crossings explicitly rely on very high local bending strains within the buckle in order to accommodate the fault offset (PGD) motions, and test data showing "no leak" in the wrinkles also have strains well in excess of 4%. As long as the pipe designer checks for fatigue under high strain conditions, it may be that these high strains in the buckles (well in excess of 4%) might be satisfactory (no rupture in the single event). Conceptually, the approaches for stainless steel bellows can be extended adopted for these "pre-buckled pipe" design approaches, as long as the pipe retains suitable margin under the design-basis seismic event and is not prone to excessive fatigue-related failures under normal operating conditions.

- Seismic Anchor Motions (SAMs) where pipes that are attached to components (regulating station configurations, well heads, pile-to-non-pile support conditions, etc.) are exposed to motions at the points where the pipe is anchored (attached) to the external component. SAMs can occur in earthquakes, but also due to soil compaction, frost heave, dry / wet cycles for expansive soils and other situations. SAMs are an important consideration for service line connections to structures; in particular mobile homes (manufactured housing); older wooden structures on weak "cripple wall" or other form of soft stories; and similar conditions where the gas pipe entering the structure undergoes considerable motions either due to the structure shifting on its foundation; falling off its foundation (such as unanchored mobile homes); or partial collapse of the structure. "Flexible hoses" are sometimes installed between the meter and mobile homes.

- Earthquakes. Pipes will have incremental stresses due to earthquake loading. This includes stresses due to inertial shaking (can be especially high for above ground pipes), ground vibration (applicable to all buried pipe), and permanent ground deformations (PGDs) due to liquefaction, landslide, surface faulting or other less common effects (soil compaction, lurching, etc.). Guidelines such as ALA (2005) provide allowable stresses / strains for earthquake loading on steel pipes. At present, there are no equivalent guidelines on allowable earthquake-induced stresses / strains for many other types of pipes, such as HDPE, MDPE, Copper, various other types of plastic, etc. although there is an ever-increasing wealth of empirical evidence and limited tests that capture the apparent seismic toughness or weaknesses of these other kinds of pipe materials. The most common of these other pipe materials in gas distribution system is MDPE. Some older plastic pipes might be subject to premature cracking when exposed to especially high stresses / strains.

3.2.2 Distribution Pipes

Table 3-5 provides the length of distribution gas pipes in the three large IOU gas systems in California. This data is based on available information from the PHMSA, and reflects inventory data through about June 30 2018. In this table, CP means Cathodic Protection. As of 2019, PG&E reports there is no longer any Cast Iron pipe in its distribution system. Tables 3-6, 3-7, 3-8 provide further breakdowns by material, diameter and decade of installation.

Table 3-5. Distribution Mains (Miles)

Type of Pipe	PG&E	SoCalGas	SDG&E
Steel, No CP, Bare	4	3,239	0
Steel, No CP, Coated	319	4,616	0
Steel, CP, Bare	28	0	0
Steel, CP, Coated	19,487	18,216	3,571
Plastic	23,172	24,886	4,596
Cast Iron	58	0	0
Copper	0.03	0	0
Total	43,067	50,957	8,167

Table 3-6. Steel Distribution Mains (Miles)

Steel Pipe, by Diameter	PG&E	SoCalGas	SDG&E
Unknown	18	0	0
< 2 inch	12,727	13,905	2,594
2 - 4	5,117	6,671	500
4 - 6	1,708	3,702	333
8 - 12	154	1,113	104
> 12	113	680	40
Total	19,837	26,071	3,571

Table 3-7. Plastic Distribution Mains (Miles)

Plastic Pipe, by Diameter	PG&E	SoCalGas	SDG&E
Unknown	3	0	0
< 2 inch	17,977	19,291	3,455
2 - 4	4,300	4,886	1,064
4 - 6	892	709	77
8 - 12	0.05	0	0
> 12	0	0	0
Total	23,172	24,886	4,596

Table 3-8. Decade of Installation, Distribution Mains (Miles)

Decade	PG&E	SoCalGas	SDG&E
Unknown	268	0	0
≤1939	1,446	2,299	183
1940 - 1949	3,044	2,919	272
1950 - 1959	6,156	8,249	1,150
1960 - 1969	6,608	7,047	1,105
1970 - 1979	6,347	7,040	1,464
1980 - 1989	5,978	9,539	1,541
1990 - 1999	5,590	5,496	1,045
2000 - 2009	5,296	6,317	1,011
2010 - 2019	2,303	2,051	396
Total	43,067	50,957	8,167

The oldest gas distribution pipes in PG&E's system now in service is believed to date to about 1920; none of PG&E's 1906-vintage pipes (see Section 6.1 for performance in the 1906 earthquake) are thought to remain in service. Since 2009, about a third to half of distribution pipe installed by PG&E per year reflects replacements of older distribution pipe, and the remainder for new subdivisions and new customers.

Nearly all distribution pipe operates at pressures of about 60 psi or lower. The operating pressures of plastic distribution pipes commonly found in California (operating pressures up to 60 psi) are estimated as follows:

- < 40 psi. 6%
- 40 to 49 psi. 15%
- 50 to 54 psi. 36%.
- 55 to 60 psi. 43%.

In distribution systems, the term "high pressure" refers to pipes operated at pressures from 20 psi to 60 psi; "semi-high pressure" for pipes operated < 20 psi; and "low pressure" for pipes operated at < 2 psi.

Nearly all new distribution pipe currently being installed (2020) is plastic pipe.

In a few instances, new gas distribution pipes have been installed by threading them through older cast iron pipes. This approach was adopted in the renewal of gas pipes in the San Francisco Marina District after the 1989 Loma Prieta earthquake. This style of construction helps reduce the cost of installation, reduces the need cut trenches into city streets, and is generally results in fewer disruptions to local residents. Available inventory information may not show where this style of construction has been adopted. From a seismic perspective, it remains uncertain if this style of plastic pipe is as-good-as, or perhaps not as-good-as, as plastic pipe installed by direct burial, in that the sharp edges of the burst-open original cast iron (or other) pipe remain a potential hazard.

Modern distribution systems in California include two basic kinds of pipes: steel and plastic. Most steel pipe was installed pre-1975, and most plastic pipe was installed post-1970. The age attribute for steel pipe can yield some insight as to whether it is more or less susceptible to corrosion-related aging effects; if the attributes are available (see Table 3-5), then steel pipes with the attribute "no CP, Bare" and located in soils with Rho < 750 cm (highly corrosive environment) are most susceptible to corrosion-related weakening over time. Exterior coating systems for steel pipe have evolved over time, with older pipes using coal tar or asphalt enamel coatings, and newer pipes commonly being tape wrapped and cathodically protected. The effectiveness of the coating system as well as use of impressed current cathodic protection systems against age-related corrosion is a consideration, and the oldest steel pipes that are located in bay muds, clayey soils, volcanic soils, high ground water conditions, might be the most susceptible to weakening due to pin holes and other corrosion-age-related effects.

3.2.3 Service Laterals

Service laterals take gas from the distribution main to the customer meter. The meter is commonly located outside and immediately adjacent to the customer's structure, although there are some cases where the meter is located in closets or other utility rooms.

Table 3-9 provides the service laterals in the IOU systems for California. Table 3-10 provides further breakdowns by decade of installation.

Table 3-9. Pipe Service Laterals Inventory (Count)

Type of Lateral	PG&E	SoCalGas	SDG&E
Steel, No CP, Bare	7	129	0
Steel, No CP, Coated	11,238	842,049	0
Steel, CP, Bare	320	23	0
Steel, CP, Coated	1,165,555	732,221	266,806
Plastic	2,386,862	2,907,790	380,608
Cast Iron	26	0	0
Copper	1,018	0	0
Total	3,565,026	4,482,212	647,414

Table 3-10. Decade of Installation, Service Laterals (Count)

Decade	PG&E	SoCalGas	SDG&E
Unknown	471,136	0	0
≤1939	27,191	56,745	4,939
1940 - 1949	101,111	122,146	23,653
1950 - 1959	370,761	53,167	104,831
1960 - 1969	345,807	582,605	84,240
1970 - 1979	473,778	691,072	126,964
1980 - 1989	482,298	1,059,500	11,937
1990 - 1999	515,711	523,552	76,100
2000 - 2009	487,660	593,695	69,257
2010 - 2019	289,573	259,730	38,093
Total	3,565,026	4,482,212	647,414

Generally, service laterals are installed following the provisions of the Green Book (ref. Green Book), often by third party contractors. Generally, there are no drawings showing the actual location and length and style of construction of service laterals.

A service lateral is normally installed in a straight line at a right angle to the distribution main, traversing from the main to the meter. Commonly, the service lateral pipe is installed by direct burial, with about 2.5 to 3 feet of cover. Offsets, diagonal runs and bends should be avoided wherever possible. Where avoidable, the service lateral should not be installed under driveways or customer-paved areas.

Depending on the configuration of a customer's property, there can be many exceptions with regards to alignment.

At the end of the lateral, there will commonly be a riser pipe up to the meter set. Gas pipe from the meter set into the customer's structure is called "house lines"; except where specifically mentioned, this report does not address seismic issues related to house lines or the customer's gas appliances.

Depending upon the utility's approach in developing its GIS, a service lateral could be geocoded using a proxy pipe length, extending from the distribution main in the street to a point within the property. This is called a "proxy" geometry. The most common diameter of service laterals are 0.5-inch to 1.25-inch.

3.3 Types of Pipe

3.3.1 Transmission Pipes

PG&E, SoCalGas and SDG&E all use steel pipe for almost all gas transmission pipelines. This reflects that in California, most gas transmission pipes operate at 400 psi or much higher pressures. Carbon steel is the most cost effective material to construct pipes that operate at pressures of 400 to 2,000+ psi. Plastic can be used for gas pipes up to about 24-inch diameter that operate at pressures up to 100 psi or so; but more commonly, plastic pipes are limited to gas pipes with diameter up to about 8 inches or so.

In other parts of the world, gas systems might be fed by LNG sourced at a terminal located at an ocean port. A "transmission pipe" in those places might operate at pressures of 60 psi or less. Therefore, a "transmission pipe" in Japan might be a relatively thin-walled steel pipe operating at low pressure as compared to a "transmission pipe" in California operating at 400 psi or higher. The terminal facility at a port location will include tank storage and other related facilities.

Steel pipe is manufactured in one of several ways:

- ERW Steel Pipe. Flat rectangular sheets are cut. The long edges of the sheet are then rolled upwards, forming a semi-circle. Two semi-circles are then joined using longitudinal seam welds to form a pipe. High frequency electrical current is passed between the edges, causing them to melt and fuse together. The longitudinal Electric Resistance Welding (ERW) weld seam cannot be seen or felt.

- DSAW Steel Pipe. The longitudinal welds are made using Double Submerged Arc Welds (DSAW). This process leaves behind an obvious bead. DSAW welding is commonly used for both straight and spiral welds. DSAW welded steel pipe was first commonly used in the 1940s. DSAW steel pipes remain commonly used for steel pipes used in water systems.

- Prior to the 1970s, low frequency current was used. Low-frequency ERW welds are considered to be more prone to corrosion and seam failure than high frequency ERW.

- Helical welded pipe. The pipe is made from coils of steel that are formed in a helix arrangement. In the shop, full penetration welds are made along the helical coils.

- Seamless pipe (SMLS). Seamless pipe begins as a solid cylindrical hunk of steel called a billet. While still hot, the billet is pierced through the center with a mandrel. The steel is then rolled and stretched to form a pipe with the desired length, diameter and wall thickness.

Both ERW and SMLS pipe can have the same strength. Potential weaknesses in ERW occur if the welds are not made to specifications. Potential weaknesses in SMLS occur if the rolling process results in uneven wall thickness. Reflecting a concern for weld quality-related issues, SMLS pipe is often specified for high pressure gas pipe. ERW pipe is generally less expensive to produce than SMLS pipe.

Once placed in the field, both ERW and SMLS pipe must be connected to adjacent pieces using girth welds. For gas pipes, girth welds are almost always full penetration welds.

For water pipes in the USA, girth welds are most often specified using single fillet or double fillet welds. For full penetration welds, if made to specifications, girth welds are as strong in tension or compression as the main barrel of the pipe. For single- or double-lap fillet welds, even if properly made, the welded joint is generally weaker than the main barrel of the pipe, especially in compression, owing to the geometric offset that will always induce high bending that leads to premature wrinkling of the pipe. Girth joints made using fillet welds are not thought to be used in gas transmission pipes in California.

The common steel materials for gas transmission pipes used are: A53 Grade B, A106 Grades B, C, X42, X52, X60, X65 and X70. A53 and A106 are most often used for lower pressure (up to 200 psi) water pipes. The lowest strength steels in gas transmission systems in California might have Fy about 25 ksi to 30 ksi; the highest grades might have Fy up to 70 ksi.

Girth joints for gas transmission pipes should always be welded full penetration. In earthquakes, steel pipes can fail due to joint failure (failure of girth welds) (possible); wrinkling with leak (possible); wrinkling without leak (possible); pin hole failures due to dynamic stress loading (where the pipe has thinned due to corrosion); damage to appurtenances (common); failure of shop made welds (especially helical and DSAW pipes if those welds were of low quality (possible).

There may also be shop-made joints made as part of the fabrication process. For steel pipe, shop-made joints are usually made with electric-arc automatic welding machines, and are always specified to be full thickness welds. These welds might be spiral (if the pipe is fabricated using sheet metal that is spun off a helical coil) or longitudinal (if the pipe is fabricated using two semi-circular sheets). Heavy wall ($t > 0.5$ inch or so) steel pipe might be longitudinal seam-welded. It is generally assumed that these shop-made welds are always as strong as, or stronger, than the pipe. However, unless Quality Control is good, there can be no assurance that the shop-made welds are in fact as strong as the pipe; and there have been observed instances of welded steel pipe failures due to poor shop-made welds. For seismic analyses (Level 1, 2, 3) it is assumed that the end user will not take the effort to review Quality Control records from original construction, and therefore the assessment of pipe weaknesses owing to these types of defects must be speculative. The empirical data provided in this report reflects actual Quality Control for actual pipes; not all of which can be assumed to have been perfect.

Quality Control. Owing to the importance of welding, this paragraph provides several cautions to the user. Many academic-oriented studies simply assume welding is "perfect"; but reality can be different. The user is cautioned that unless both factory-made and field-made welds are verified as being as assumed in the design, then any seismic analysis for a specific pipe that has deficient welds might lead to *incorrect results; with potential serious life safety consequences*. The user is cautioned that the usual treatment of uncertainty in the literature does not provide especially satisfactory guidance as to how to consider the potential range of pipeline performance in future earthquakes. The user is cautioned that if the user is designing a new steel pipe to cross a PGD zone (like a fault), that the specifications on welding, including Quality Control in both the factory and field, should be carefully considered, and issues like "x-ray" and "visual inspection" and whether the contractor or the owner should perform weld inspections, are all important to meeting the goal of installing a seismically-reliable pipe.

The force at which the local buckle (wrinkle) occurs will depend on the pipe wall thickness and pipe diameter, as well as the out-of-roundness of the pipe, as well as local imperfections. Once buckled, incremental compressive axial movement of the pipe tends to be accommodated by an increasing bulge at the buckle, leading to high internal strains in buckle. The buckle then often fails by rupture and split of the steel barrel, where the combined effects of hoop strain plus local bending strain exceeds the rupture capability of the steel. The direction of the split in such a case will often be parallel to the long axis of the pipe.

Butt welds. The two ends of the steel pipe are prepared to accommodate a full-thickness groove weld made in the field. This welded joint, if well made using an electrode as strong or stronger than the main pipe steel material, should be able to accommodate the full tensile capacity of the pipe. If "backing plates" are tack welded to the inside of the pipe to allow for easier fit-up, the final full penetration weld may not be as strong as the pipe; even a small tack welded backing plate can cause a stress / strain riser.

Early vintage steel transmission mains in the SDG&E gas system used coal tar asphaltic wrap as the first exterior coating layer for purposes of corrosion protection. Over time, the early generation pipe wrap degrades and disbands from the pipe, causing any cathodic protection current to leave the pipe around the disbanded coating thereby not providing adequate protection. Ultimately, this lack of corrosion protection can lead to corrosion and an increasing rate of leaks. In 2019, SDG&E targeted replacement of 7.4 miles of such pipe, and intends to continue this program while monitoring performance to review the benefits (reduced leaks, etc.) and risk reduction (Sempra 2019).

Early vintage steel pipes (transmission and distribution) were installed with pipeline oil drips at low points of high volume pipes in gas systems to collect and purge unwanted liquids from the transmission main (Sempra 2019). For example, these details were included in pipes in downtown San Diego when coal gasification was used and liquids were traditionally found in the system. Since liquids are no longer an issue for the SDG&E gas pipeline system, oil drips are obsolete. Oil drips remain a vulnerability, for a number of reasons:

- They may not be located with precision on pipeline drawings, meaning that there can be extra risk of excavation damage.

- They create a discontinuity and a stress riser on the main pipe. This results in increased stress during seismic events, leading to a higher potential of damage.

Early vintage pipes in the SDG&E system included mechanical couplings (Dresser and similar) to joint pipes. This type of coupling is a known weakness in earthquakes, as the coupling can take nominally no axial seismic forces, and has limited (generally less than 1 inch axial or 2° rotation) movement capability before leaking. Over time, the rubber gaskets in such couplings can degrade. Continuous welded pipelines with a single coupling after a long reach of welded connections are particularly sensitive to excessive pull-out or push-in movements at the coupling owing to travelling seismic waves (demands can exceed several inches under strong shaking), leading to leak and failure. In San Diego, such couplings can be found in both high pressure transmission pipe and medium pressure distribution pipe.

3.3.2 Distribution Pipes

Plastic pipe in gas systems in California is the now the most common type of distribution pipe. Most distribution pipe installed post ~1970 that operates under 60 psi is plastic pipe. Nearly all the plastic pipe can be classified as Medium Density Polyethylene Pipe (MDPE).

Plastic pipe is further subdivided into several types. For example, plastic pipe is produced by companies such as Dupont, Nipak, Phillips Driscopipe, Plexco and CSR/PolyPipe. There is a variety of types of plastic pipe, and the following list is not meant to be exhaustive:

- 2406. This 4-digit number likely refers to the resin used to manufacture the pipes. The first digit ("2") refers to the resin designation of the plastic (the higher this number, the denser the material). The second digit ("4") refers to the crack resistance of the plastic. The third and fourth digits ("06") refers to the hydrostatic design strength at 73°F (in psi) of the pipe (not the yield or ultimate strength), for example 06 = 600 psi, 08 = 800 psi, 10 = 1,000 psi. ASTM D3350 Standard Specification for Polyethylene Plastics Pipe and Fittings Materials) provides further details.

- 2708. Commonly installed 2013 – 2019. It is used extensively in natural gas service and distribution lines.

- 3408. HDPE pipe made using resin PE3408.

- TR-418. TR-418 is a Medium Density Polyethylene pipe (MDPE). It has high molecular weight, specially designed as a pressure pipe. The pipe is considered to have good mechanical properties, excellent resistance to ultraviolet radiation and thermal aging, and very high environmental stress cracking resistance. It is marketed as having a long useful life. Its appearance is yellow. Commonly installed 1984 – 2014.

- AA. This is also called Aldyl A Polyethylene (PE) Gas pipe. Aldyl A is a trademarked name referring to PE pipe manufactured by Dupont chemical company using Dupont's Alathon polymer resin. Commonly installed 1972 – 1989. Industry experience has identified that Aldyl A pipe that had been manufactured between 1970 and 1972 sometimes has low ductile inner wall characteristics that resulted from excessive temperature settings during the extrusion process (Haine, 2014). These pipes are predisposed to initiate cracks faster on the inner wall. Aldyl A pipes made of Alathon 5043 resin with LDIW characteristics have a median projected time to failure only $1/10^{th}$ that of Aldyl A pipes made of Alathon 5043 resin that have no LDIW (low ductile inner wall, caused by excessive temperature settings during the extrusion process) characteristics. In 1983, DuPont changed the resin formulation to resin 5046-C; this new resin offered an order of magnitude improvement in resistance to slow crack growth and long term performance over 5043. In 1988, the resin was changed to 5046-U, offering yet another ten-fold increase in median time to failure over its predecessor. In 1992, the resin was changed to 5046-O, offering yet another three-fold improvements in median time to failure over its predecessor.

Plastic pipes can fail by one of several failure modes:

- Rapid Crack Propagation, such as from a sharp blow on the pipe. Not thought to be an issue under earthquake loading.

- Ductile Rupture. This can occur when a pipe is over-pressurized over a prolonged period of time; or possible under earthquake loading if the pipe is exposed to PGDs that result in high strains. Over-pressurization might occur due to failure of a pressure regulating device or incorrect operating procedures.

- Slow Crack Growth. This is characterized by crack initiation and propagation that can occur over many years at relatively low loads below the yield point of the material. These failures are characterized by brittle (slit) fracture surfaces that exhibit very little ductile deformations. Under earthquake loading, this failure mode is most likely (if at all – few or none have been documented to yet occur) at zones exposed to PGDs (fault offset, liquefaction, landslide); but also conceivable under high shaking. The external earthquake stresses could allow a small defect to grow in response to the stress, possibly leading to rupture. Other external stresses can also lead to such failures, such as due to impingement points on rocky soil; frost heave; pipe bending beyond recommended curvature; different expansion / contraction rates of dissimilar materials between a fitting and the pipe body; stress imposed on the pipe by tree roots; stresses created when a fitting is fused by heat to the pipe body; dents and gouges; etc. It has been suggested that much of plastic pipes manufactured from the 1960s through the early 1980s might be susceptible to brittle-like cracking (by slow crack growth) and manufacturers might have over-rated the strength and resistance to brittle-like cracking of their plastic pipeline products.

- Rupture of the girth joint. This failure mode is due to improper installation rather than a material defect.

- Third party damage (TPD). Not an issue in earthquakes, but a pipe that has some TPD that was insufficient to fail at the time, might be weakened to the point that failure could occur under earthquake loads.

Prior to 1933, piping in some of California's IOU gas distribution systems included steel pipe joined together with threaded couplings. This style of pipe has been recognized as being particularly vulnerable to damage in earthquakes.

There remains a lot of steel distribution pipe in California's gas distribution systems.

Cast iron pipe was commonly used in gas distribution systems in California in the early 20th century. There were many cast iron gas pipe failures in the 1906 earthquake (see Section 6.1). Today (2020), it is believed that all cast iron gas pipe has been replaced with more modern pipes in California.

3.4 Underground Gas Storage

PG&E and SoCalGas and a number of other agencies operate underground gas storage facilities in California. SDG&E has no underground gas storage facilities.

Table 3-11 lists the underground gas storage fields in California, along with the storage volumes of each field (in billions of cubic feet, BCF), and the amount of gas withdrawn or injected in 2018. Table 3-12 lists the number of wells at each storage field, and provides some statistics as to the approximate depth of the underground geologic formation and the maximum pressure at the top of observation wells. Source data is from PHMSA.

Table 3-11. Underground Gas Storage Facilities (2018)

Facility	Operator	Latitude	Longitude	Working Gas Capacity BCF	Base Gas Capacity BCF	Total Gas Capacity BCF	Vol With-drawn BCF	Vol Injected BCF
Los Medanos	PG&E	38.02347	-122.00376	17.95	11.19	29.14	14.01	7.11
McDonald Isl	PG&E	37.99096	-121.47647	82	54.57	136.57	31.85	22.06
Pleasant Creek	PG&E	38.54552	-122.00211	2.25	5.08	7.33	1.35	1.32
Aliso Canyon	SoCalGas	34.30911	-118.55263	86.2	81.52	167.72	1.36	11.85
Honor Rancho	SoCalGas	34.44743	-118.5869	27	20.99	47.99	27.48	23.15
La Goleta	SoCalGas	34.4213	-119.8196	21.5	24.59	46.09	9.67	9.22
Playa del Rey	SoCalGas	33.96272	-118.43803	2.4	4.46	6.86	3.79	3.39
Wild Goose	Wild Goose	39.348	-121.81706	75	11	86	46.44	28.1
Kirby Hills Domengine	Lodi Gas	38.15996	-121.90573	5.37	1.93	7.3	3.45	1.52
Kirby Hills Domengine	Lodi Gas	38.19739	-121.27042	7.51	3.59	11.1	8.13	6.04
Kirby Hills Wagenet	Lodi Gas	38.15996	-121.90573	10.18	2.52	12.7	7.92	3.41
Lodi Midland	Lodi Gas	38.19739	-121.27042	4.88	4.22	9.1	4.91	3.2
Gill Ranch	Gill Ranch	36.7922	-120.2544	20	3.5	23.5	14.97	4.44
CVGS Colusa	Central Valley	39.38628	-122.03145	9.6	1.4	11	1.88	10.37

Table 3-12. Underground Gas Storage Facilities (2018)

Facility	Operator	# Injection / Withdraw Wells	# Observation Wells	Max Depth Ft	Min Depth Ft	Max Pressure psi
Los Medanos	PG&E	19	1	4000	3700	1600
McDonald Isl	PG&E	81	7	5315	5150	2070
Pleasant Creek	PG&E	7	0	2975	2675	1250
Aliso Canyon	SoCalGas	74	4	9646	6797	1876
Honor Rancho	SoCalGas	35	0	11253	8784	3473
La Goleta	SoCalGas	18	3	4455	3734	1808
Playa del Rey	SoCalGas	22	17	6729	5729	1475
Wild Goose	Wild Goose	17	4	3040	2490	1510
Kirby Hills Domengine	Lodi Gas	9	2	2500	1900	1129
Kirby Hills Wagenet	Lodi Gas	9	3	5900	4200	2140
Kirby Hills Domengine	Lodi Gas	9	2	2375	2220	1321
Lodi Midland	Lodi Gas	8	5	2640	2470	1326
Gill Ranch	Gill Ranch	12	7	6231	5683	3244
CVGS Colusa	Central Valley	8	5	2600	1980	1436

Storage of each facility is divided into two parts: Top (or working) gas, and Cushion gas.

- McDonald Island. Maximum daily delivery capacity 1,455,540 Dth.
- Los Medanos. Maximum daily delivery capacity 331,500 Dth.
- Pleasant Creek. Maximum daily delivery capacity 63,240 Dth.
- Gill Ranch (operated by others). Maximum daily delivery capacity 97,410 Dth, or 95,500 Mcf (PG&E portion), or 382,000 Mcf (total capacity).

Gas delivered and withdrawn to/from storage varies seasonally. For example, Figure 3-3 shows the quantity of dekatherms storage and withdrawn for each month in 2017 from PG&E's underground gas storage fields. The monthly rate of withdrawals is up to 16 to 18 million dekatherms, peaking in the colder months (December, January). The monthly rate of injection is about 6 to 9 million dekatherms, peaking in the spring months (March, April, May, June) when both residential heating and power plant gas usage is lowest. In 2017, the date of peak withdrawal was January 6, with 1,372,668 Mcf withdrawn on that date.

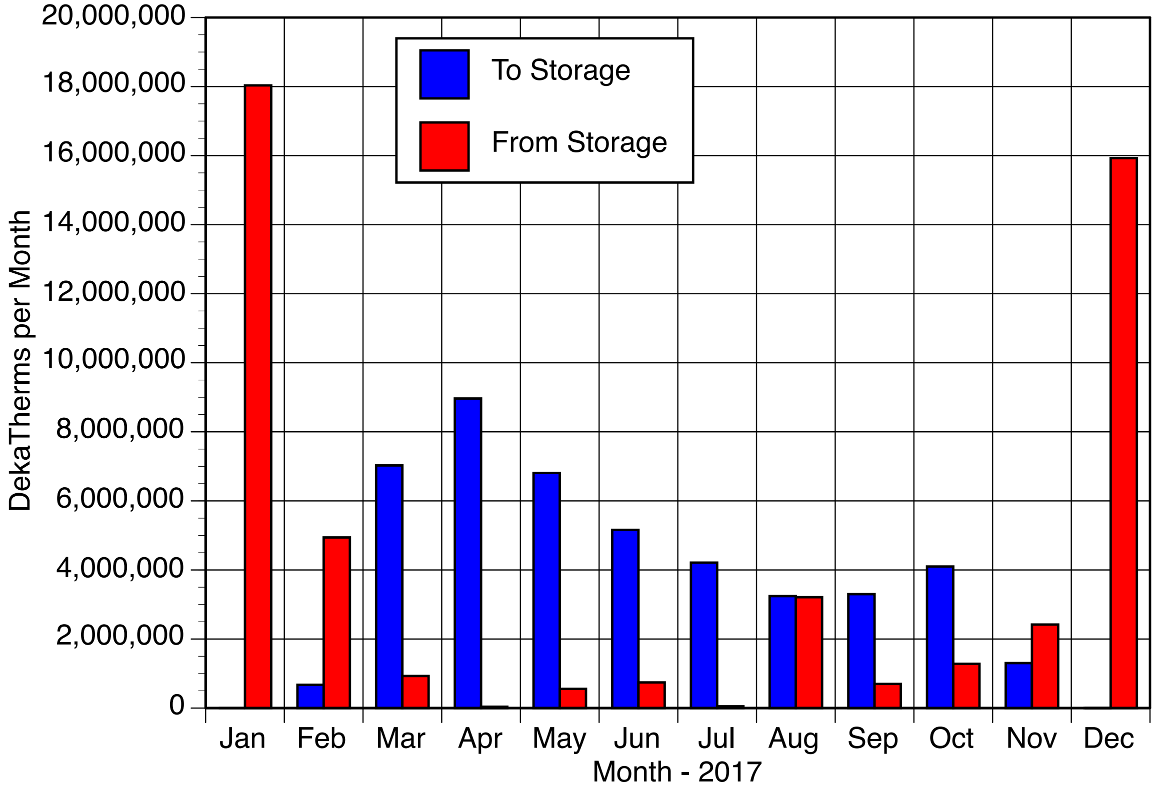


Figure 3-3. Gas Stored and Withdrawn from Storage, 2017, PG&E

3.5 Other Aspects of the Gas System

Section 3.5 outlines other aspects of gas systems. The report addresses only a portion of a gas system's assets, namely pipelines and wells. A complete seismic loss estimation model for an entire gas system would need to include many other components, including compressor stations, measuring and regulating equipment, structures, purification equipment, office and maintenance facilities, emergency response capability, operational strategies, etc., none of which are addressed in this report.

Gas production in the USA has grown significantly from 1992 through 2010, during which time the number of producing gas wells increased by 76 percent. About 11,000 new wells were drilled annually from 1992 to 2010, on average. According to the 2011 EPA fact sheet, the US had nearly 1.1 million producing gas wells in 2009.

Figure 3-4 shows the estimated amount of natural gas production and supply in the entire United States. The trend shows about 20 trillion cubic feet produced (and used) per year in recent years, and projected to rise about 1% per year through 2025. California uses about 12% of the US total.

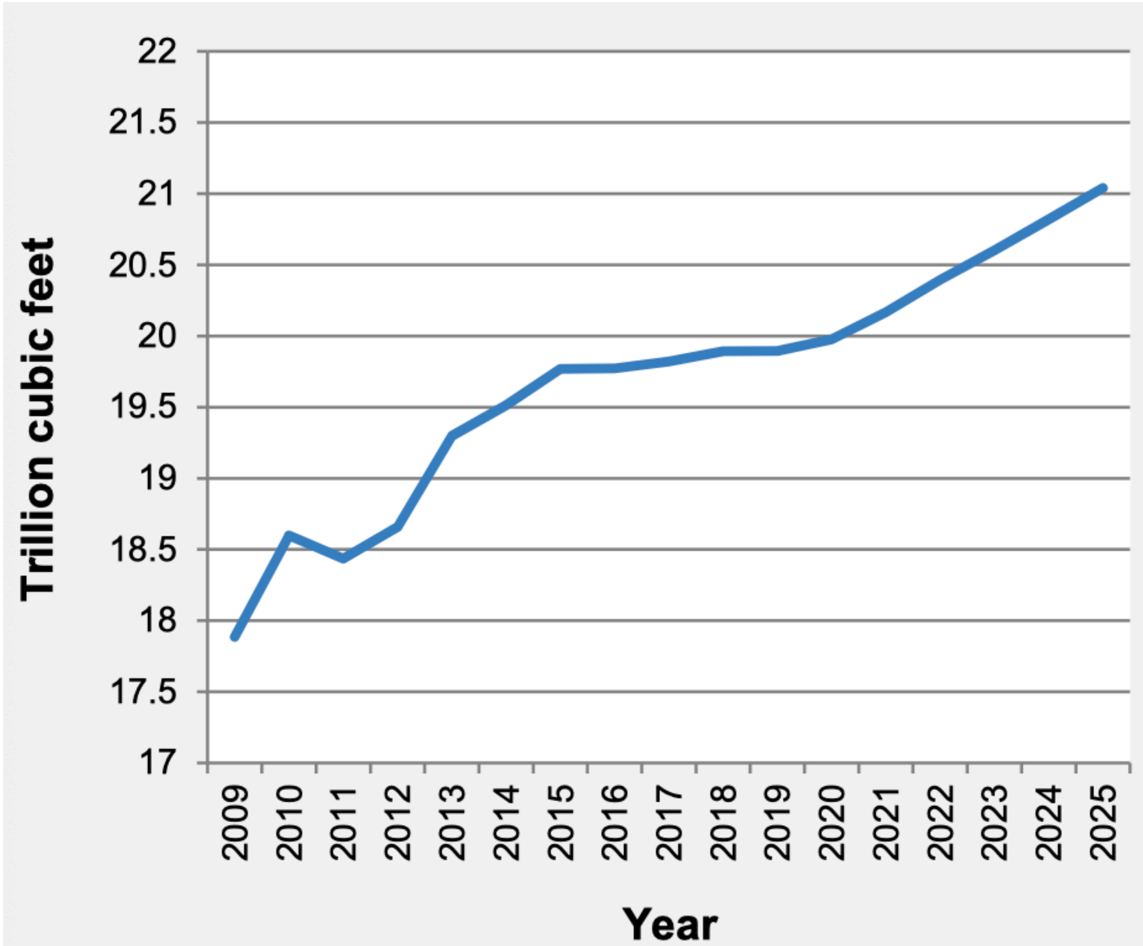


Figure 3-4: Natural Gas Production and Supply, All of United States, 2009-2025 (ref. EPA 2013)

In California, the breakdown of demand for natural gas was as follows (2012): residential (20.8%), commercial (8.6%), industrial (14.5%), mining (9.4%), electricity generation (45.6%), agriculture and other (1.1%) (ref. http://ecdms.energy.ca.gov, http://energyalmanac.ca.gov/electricity/web_qfer).

Natural gas (methane, CH_4) is considered to be a greenhouse gas (GHG). GHGs are considered to be a pollutant to the atmosphere. A perfectly "leak-tight" system will allow no venting / release / leakage of methane into the air. Natural gas distribution systems are estimated to account for 6% of methane emissions from US Natural gas infrastructure (the remaining from processing and transmission) (ref. 2014 Inventory of U.S. Greenhouse Gas Emissions and Sinks. Available online at: http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf). About half these emissions are estimated to be from gas mains and services, in particular those made from cast iron pipe or non-cathodically-protected steel pipe.

Production involves the extraction of oil and gas from underground formations and initial separation of crude oil and gas from other components in the hydrocarbon stream coming from the ground. These activities are commonly referred to as upstream activities.

Downstream activities include the transportation of natural gas by transmission and distribution pipes to the end customer.

It would be ideal if a natural gas transmission and distribution system would not vent any natural gas into the atmosphere. Venting sources include pneumatic devices, dehydration processes, gas sweetening processes, compressors, tanks, well testing. "Fugitive" sources include equipment leaks through valves, connectors, flanges, compressor seals, related equipment, and leaking pipes (transmission, distribution, service laterals).

In rural areas, natural gas can be distributed by truck to end user customers, where the gas is generally stored in small tanks. This report does not address this infrastructure (trucked distribution system or local storage tanks).

The demand for natural gas is greatly affected by temperature. On cold days, use of natural gas by residential and commercial customers can be as much as 7 times greater than on warm days because of increased use of gas for space heating. To fully satisfy this increased high-priority demand, gas is withdrawn from storage in certain service areas, or peaking supplies can be purchased from suppliers. If necessary, service to interruptible lower-priority customers may be curtailed to provide the needed delivery system capacity.

PG&E, SoCalGas and SDG&E acquire and arrange for delivery of natural gas to its system in sufficient quantities to meet its customers' needs. A natural gas procurement objective is to ensure that adequate supplies of natural gas are available at a reasonable cost. California acquires natural gas from a wide variety of sources with a mix of purchase provisions, which includes spot market and firm supplies. The purchases may have terms from one day to several years. This report is not focused on the procurement of natural gas supply, other than to reflect that the use of underground storage facilities is important both in terms of meeting peak demands as well as to serve as a buffer to store gas purchased at less volatile (and presumed lower) cost than to rely on more volatile spot market purchases.

Gas quantities are commonly described in terms of dekatherms (system-wide scale) or therms (residential customer scale). A typical small residential customer might use about 500 therms per month. A dekatherm (dth) is a unit of energy used primarily to measure natural gas, developed in about 1972. A dekatherm is equal to 10 therms or 1,000,000 British Thermal Units (BTUs) or 1.055 Gigajoules (GJ). A dekatherm is about 1,000 cubic feet of gas if measured by volume.

Equating energy (therms) with volume (cubic feet) is not precise, as the amount of energy content of gas varies from well to well. A dekatherm is exactly one thousand cubic feet (Mcf) of natural gas with a heating value of 1000 BTU/cf.

Natural gas is a mixture of gases, and contains about 80% methane (CH_4). Natural gas's heating value varies from about 975 BTU/cf to 1,100 BTU/cf depending on the mix of different gases in the gas stream. Billing to customers is done by therm, rather than by cubic feet, as customers are buying heat (therms); if billed by volume (cubic feet), then a rate adjustment from $/Mcf to therms is done in order to assure all customers receive the same amount of heat per dollar.

Small residential customers occasionally have the ability to switch between energy sources (electricity or gas) for space heating and similar uses. Switching between energy sources is not often done except at the time a decision is made to purchase or replace the equipment at its end of life (furnaces, water heaters, dryers, ovens, cooktop elements, etc.).

Large commercial customers (large commercial, industrial, electric generation) often have the ability to switch to alternate energy sources. The IOUs remain competitive for these customers through the use of negotiated transportation contract rates (subject to conditions of State tariffs), special long term contracts with electric generation and cogeneration customers, and other tariff programs.

Gas operations are subject to inherent risks such as from gas leaks, fires, natural disasters, catastrophic accidents, explosions, pipeline ruptures and other hazards. Consequences may cause unforeseen interruptions, personal injury and/or property damage. All gas systems are subject to damage from third parties due to construction activities, vandalism or acts of terrorism. These incidents can lead to severe business interruptions, significant decreases in revenue, environmental pollution, personal injury or death, damage to System Operator's and Other's properties and other costs or claims to / against the System Operator.

Chapter 4: Seismic Hazards

There are five primary hazards induced by earthquakes:

- Ground Shaking
- Surface faulting
- Liquefaction
- Landslide
- Tsunami Inundation

To varying extents, gas system facilities in California are exposed to all of these hazards.

4.1 Scenario Earthquakes and Probabilistic Earthquakes

A "Scenario Earthquake" is defined as an earthquake having an epicenter on a known fault (or location for an unknown fault), a magnitude, and a direction of propagation. Throughout this report, magnitude (M) is meant to be moment magnitude, unless otherwise specified.

For example, a scenario earthquake could be a M 6.8 event on the north segment of the Hayward fault, with epicenter at midpoint along the digitized length of the fault, and propagation equally away from the epicenter towards the northwest and southeast along the fault.

If the hazard models include methods to quantify the variation in motions due to directivity-related issues, then the choice of epicenter and propagation direction is important. If the hazard models exclude directivity-related issues, then the choice of epicenter and propagation direction is not important.

A "Probabilistic Earthquake" is defined as a level of shaking at a specific location with non-exceedance over a defined return period.

For example, the user might be interested in the response of a pipe for a "475 year", "975 year" or "2,475 year" earthquake.

The common way to compute "Probabilistic Earthquakes" is to sum up all the possible scenario earthquakes (all magnitudes over all faults), assigning each an annual probability of occurrence. Practically, this summation is often done using increments of magnitude in 0.2M increments. For example, the contribution to overall hazard from Hayward north fault segment might be computed as the sum of various scenario events with M = 5.0 (for 4.9-5.1), 5.2 (for 5.1 - 5.3), etc. all the way up to M = 7.4 or so. This process is repeated for all known faults, and for unknown faults / sources, and different weights can be assigned to consider a range of different understandings of the earthquake source mechanisms, annual chance of occurrence, etc.

The largest IOU gas systems in California cover service areas as large as 50,000 square miles or more. It is always *incorrect* to apply a code-based probabilistic earthquake hazard motions (like a 2,475 year earthquake) over the entire gas system inventory; there is no practical meaning to the results, other than saying the loss estimation forecast for individual pipes (or wells) represents the likely non-exceedance results over a 2,475 year time frame. No single earthquake can ever produce the 2,475-year hazard map included in current codes over a large geographic area.

The best way to perform loss estimation for a large gas system (such as PG&E, SoCalGas, SDG&E) is to evaluate the system, as a whole, for a range of specific scenario earthquakes. For PG&E, this might include ~100 different scenarios, to cover all the major active faults in the PG&E service area and a suite of variable M events on some of the more important faults. For SoCalGas, this might include a similar number of scenarios. For SDG&E, this might include 5 to 15 different scenarios. For the smaller IOUs or LDCs, possibly a handful of scenarios will be sufficient to understand the seismic risk.

In selecting scenarios, the utility might be interested in the performance of its gas system due to a range of earthquakes. Examples below are given for the three large IOUs or large LDCs:

- A Maximum earthquake on an active fault. For example, M 8.0 on the northern San Andreas fault (PG&E); or a M 7.7 on the San Jacinto fault (SoCalGas); or a M 7.5 on the Rose Canyon / Silver Strand fault (SDG&E). There are many definitions as to what is a "Maximum" earthquake; herein, a Maximum earthquake is defined as the near upper bound magnitude that is possible on a known fault; return periods are commonly 500 to 5,000 years or so.

- A Probable earthquake. For example, a M 6.8 on the south segment of the Hayward fault (PG&E); a M 7.0 on the San Jacinto fault (SoCalGas); or a M 6.9 on the Elsinore fault (SDG&E). Return periods might be 50 to 200 years or so.

- A major Historic earthquake. For example, a M 7.8 on the northern San Andreas fault, to represent a repeat of the 1906 Great San Francisco earthquake (PG&E); a M 6.4 on the Newport Inglewood fault to represent a repeat of the 1933 Long Beach earthquake (SoCalGas, Long Beach); or a M 7.2 on the Laguna Salada fault to represent a repeat of the 2010 El Major - Cucapah earthquake.

- Any recent earthquake. In California, there can be dozens to hundreds of M 3 to 5 earthquakes every year. Gas utilities want to be able to quickly assess their gas systems to any (or all) of these events, even those events that are non-damaging. Understanding the performance of gas system infrastructure in non-damaging events helps to establish empirical-based fragility models, at least at lower ground motion levels.

Depending in the scenario earthquake, the approaches to address uncertainties and randomness in the hazards will vary. For example:

- User specified scenario. The full range of uncertainties can be considered, possibly including intra-event and inter-event issues; directivity issues; 1D versus 3D basin effect issues, etc.

- ShakeMap "real" earthquake. By "real" earthquake, it is meant that a ShakeMap was been computed for an event that just took place, with the ShakeMap often available within 5 to 10 minutes of the actual earthquake. ShakeMap factors in the recorded motions from strong motion instruments, and then uses attenuation models and averaging / extrapolation to create a shaking map that covers an entire area. At locations with actual recordings, the uncertainty in ground motion is essentially nil (it is recorded); at locations distance from instruments, the uncertainty can be considerable. ShakeMaps are created a "grid points"; the assumed properties of that grid point (Vs30, etc.) may not match the properties throughout the area represented by that grid point; and the local utility may have better site specific data for that area than was assumed in the development of the ShakeMap. For grid points represented by two (or more) instruments, there is necessarily an averaging process between the instruments in order to set the unique motions for that grid point. For these and other issues, the uncertainty in the motions presented in a ShakeMap should generally be considered a median-based estimate, with at least ±50% uncertainty. For small-ish earthquakes (M ~ 5) in more rural areas of California, there may be only a single instrument near the epicentral area, and "back-calculation" of the motions right atop the epicenter from that instrument have been known to result in ShakeMap forecasts of very high motions that might not have existed. For large-ish earthquakes (M ~ 7) near smaller communities, the lack of any instruments in the community might lead to strong bias downwards (ShakeMap under-reporting the motions in that community by perhaps a factor of 2). Thus, while ShakeMaps provide useful first order (5 to 10 minutes after event) estimates of ground shaking motions, the ShakeMaps should not ever be assumed to represent "ground truth": they are just estimates.

4.2 Hazard Variables

Loss estimation requires a range of quantified seismic hazard parameters in order to assess the seismic performance of gas pipelines. The following are the hazard variables that should be computed for each scenario. Some of these variables need only be computed for more detailed Level 2, 3 or 4 analyses.

4.2.1. Shaking, Liquefaction, Landslide and Surface Faulting Hazards

- PGA. Peak ground acceleration, g. This should be horizontal PGA. Vertical PGA is not needed for any of the Level 1, 2, 3 fragility models, but should be computed for Level 4 models. PGA can be defined as median for a single horizontal direction; median for the maximum of two horizontal directions; median for the maximum horizontal motion in any direction. A range of PGA should be computed, reflecting the various approaches taken to consider uncertainties; the 84^{th} percentile non-exceedance level PGA is a convenient way to quantify uncertainty using a single value. PGAs should reflect the surface level value, in consideration of the local subsurface conditions.

- PGV. Peak ground velocity, cm/sec. This should be horizontal PGV. Vertical PGV is not needed for any of the Level 1, 2, 3 fragility models, but should be computed for Level 4 models. PGV can be defined as median for a single horizontal direction; median for the maximum of two horizontal directions; median for the maximum horizontal motion in any direction. A range of PGV should be computed, reflecting the various approaches taken to consider uncertainties;, the 84^{th} percentile non-exceedance level PGV is a convenient way to quantify uncertainty using a single value. PGVs should reflect the surface level value, in consideration of the local subsurface conditions.

- Vs30, Z1, Z2.5, hSeis, W, Dip. These variables (and others) are needed in many modern Ground Motion Prediction Equations (GMPEs). It is beyond the scope of this report to quantify these variables, but a few comments are appropriate:

    - hSeis. The user should be able to define the top of rupture. If hSeis = 0 km, this means that the scenario earthquake is assumed to cause rupture (if M is large enough) up to the ground surface, and thus pipes can be exposed to offset.

    - Dip. The dip angle of buried faults is needed to define the hanging wall and foot wall of non-vertical faults. Vertical faults (like San Andreas) have Dip = 90°. For shallow faults (say Dip < 20°), it is commonly thought that the rupture near the surface will be much steeper than the average dip at depth. For Level 3 and 4 analyses, the direction of offset relative to the pipe is important, so a "near surface rupture Dip angle" might be suitable for purposes of that computation, perhaps defaulting to ~70°. The sign of the Dip angle is important in that the characterization of the fault rupture plane needs to be done in three dimensions, so if using only a surface line representing the fault plus a (unsigned) dip angle, is insufficient to define if the fault dips to the north / east / south / west. For lesser-studied faults, the dip angle is often speculative.

- Basin parameters Z1, Z2.5, Time Histories, c. The Z1 and Z2.5 parameters reflect the depth to very stiff basin layers beneath a site. Very loosely, these parameters might be indicative of whether a specific site is exposed to potential 3D basin effects. Modern GMPEs do not provide guidance as to whether (or not) basin effects might be important at a site. Modern GMPEs also do not provide direct guidance as to whether a site is exposed to vertically propagating shear waves, P-waves or surface waves, nor the direction these waves are moving. The parameter "c" represents the apparent wave propagation speed. Time Histories for points along a pipeline, especially for pipes exposed to basin effects, are a suitable approach for Level 4 analyses.

- The following provides some guidance on selecting c. However, it is noted that well-constructed welded steel gas transmission pipes should respond elastically to travelling waves due to either P or S waves in most conceivable conditions. Only slow moving R waves might pose a material risk of inducing stresses (strains) high enough to exceed yield or the compressive wrinkling limits for (D/t < 100) steel gas transmission pipes.

    - Three important types of waves occur in earthquakes: P, S and R (compression, shear and Rayleigh waves, respectively). P waves are the first to arrive and travel the fastest; they typically travel at speeds of about 14 km / sec through the base of the Earth's mantle. S waves travel slower than P waves; they typically travel at speeds of up to 8 km / sec through the base of Earth's mantle. R waves are the slowest of all seismic wave types; they typically travel at speeds of about 1 to 5 km / sec, and are important for pipes located in soil conditions.

- The lower the assumed c, the higher the pipe stress. A common situation is that while a code-based seismic hazard map or a site-specific hazard study might provide PGV, neither code nor most studies describe c.

- For pipes not exposed to basin edge effects, and located in firm soils, a default value for c can be assumed.

- ALA (2005) suggests c = 13,000 feet per second for common soil conditions and assuming ground strain is computed using Eq 7-3 with $\kappa = 1$. ALA (2005) notes that this is a simplified approach, and should be refined for sites with special characteristics.

- Hall and Kennedy (1981) suggested using c (for design using Eq 7-3 with $\kappa = 2$) with conservative default values (conservative meaning to have the intent of forecasting higher stresses in the buried pipe) of 4,000 feet per second (rock or permafrost); 3,500 feet per second (massive gravel deposits); 3,000 feet per second (sand or competent soils); or slightly lower values for sites underlain by deep deposits of silt and clay deposits. The condition of surface waves is not directly addressed.

- Newmark (1980) suggested using c (for design using Eq 7-3 with $\kappa = 2$) of 3,000 feet per second (competent rock); 2,500 feet per second (moderately competent materials); 1,500 to 2,000 feet per second (quite incompetent materials that have very large depth on the order of 1,000 feet or more). The condition of surface waves is not directly addressed.

- For pipes exposed to edge basin effects, a portion of all ground motion energy might be due to reflected waves, and surface wave (Rayleigh wave) conditions might dominate. In these cases, a lower value of c might be appropriate.

- In Level 4 analyses, propagating time histories can be applied to a buried pipe and the effects of all waves and pipe alignment changes can be directly quantified. For Level 1 and 2 analyses, basin edge effects can be ignored. For Level 3 analyses, pipes exposed to basin effects can be assigned a user-defined value, perhaps conservatively set in the range of c = 1,200 to 1,500 feet per second. Edge basin effects on buried water pipes have been documented as being an important contributor to pipe damage in the 1995 Mexico Earthquake, the 2017 Mexico City earthquake, and may also have been a factor in damaging buried gas pipes in the 1971 San Fernando, 1994 Northridge and possibly the 1952 Taft earthquakes. The lower the c, the more the relative displacement between two locations on a pipe will be. While seismic-vibration-caused stresses are believed to rarely (if ever) result in failure of well-built welded steel gas transmission pipes (without couplings), the empirical record (see Section 6) shows many leaks in gas distribution and service lateral pipes in areas that were exposed only to ground shaking (and with no permanent ground deformations due to liquefaction, landslide of surface faulting). More research is needed as to how to accurately forecast the conditions where slow moving surface waves might induce high-enough stresses as to lead to leaks in gas system pipes, including branch connections, at locations where pipes enter vaults, or other conditions that lead to rapid changes in pipe / soil stiffness (encasements, couplings, etc).

- For pipes with vertical bends (vertical bends are needed to accommodate changes in terrain), the computed stress in the pipe at the bend at the top of the hill in firm soils conditions (using Level 4 methods) might be about twice that in the pipe at a distance away from the bend.

- pLiq. This is the probability that liquefaction will be triggered at a location, given the scenario earthquake.

- PGDv | Liq. This is the vertical direction permanent ground deformation (inches) that occurs at the surface, given liquefaction occurs. For Level 2 and 3 analyses, compute this at the depth of the springline of the buried pipe.

- PGDh | Liq. This is the horizontal direction permanent ground deformation (inches) that occurs at the surface, given liquefaction occurs. For Level 2 and 3 analyses, compute this at the depth of the springline of the buried pipe.

- PGD | Liq. = sqrt(PGDv^2 + PGDh^2).

- pPGD = pLiq * PGD | liq. This is a probabilistic forecast of the amount of PGD at a point. It is useful for making certain kinds of liquefaction hazard maps; but it is not used for pipe fragility models or pipe damage forecasts. Pipe damage fragility models use PGD | Liq, and the probability the pipe is damaged due to liquefaction is times pLiq.

- pSlideSummer. This is the probability that a landslide will be triggered at a location, given the scenario earthquake, assuming summer time (ground not saturated) conditions. Summer-time conditions means that there is a much lower chance that landslides will be triggered. In coastal California, summer time conditions usually exist from about early April to late December April each year, depending on the rain conditions for that year. For calibration in historic earthquakes, summer time conditions are the most common.

- pSlideWinter (pSlide). This is the probability that a landslide will be triggered at a location, given the scenario earthquake, assuming winter time (ground saturated) conditions. Winter-time conditions means that there is a much greater chance that landslides will be triggered. In coastal California, winter time conditions usually exist from about late December to early April each winter season, depending on the rain conditions for that year. For planning purposes, winter conditions are often assumed.

- PGD | Slide. This is the downslope direction permanent ground deformation (inches) that occurs at the surface, given a landslide occurs. This is the maximum PGD for a slide mass as a whole.

- pSlidePGD = pSlide * PGD | slide.

- pOffset. This is the probability that a pipe is exposed to fault offset PGD given the scenario earthquake. This value should factor in whether (or not) the pipe crosses the mapped trace of an active fault; whether (or not) the pipe crosses the mapped trace of a nearby fault (active or potentially active) that can have sympathetic offset given the offset of the primary active fault; and whether the pipe is exposed to offset event though it does not intersect mapped faults, given the uncertainties in the mapping of surface faults. For Level 3 and Level 4 analyses, factor in the spatial location of the pipe to end points of the fault rupture, and the chance of offset, and the amount of offset diminishes rapidly near the ends of rupture. For Level 3 and 4 analyses, include propagation direction, as the chance of offset and the amount of offset increases at locations along the propagation direction.

- AD. Average displacement of surface fault offset anywhere along the main fault rupture. Also, AD84 (84^{th} percentile). AD is a measure for evaluating the performance of a large inventory of pipes exposed to surface fault offset. AD is commonly forecast as the sum of primary and secondary fault offset across the main fault rupture; AD will be a fraction of the main fault offset for nearby faults that have activated sympathetic movements, commonly in the range of 0% to 15% of the main fault offset for sympathetic faults located within a few km of the main fault. AD should include co-seismic slip (the offset that occurs within a few seconds of the earthquake) and afterslip (the offset that can occur within a few days / weeks after the earthquake. For Level 2 analysis, assume AD is applied as a knife edge offset to the pipe. For Level 2 analysis. Assume AD is distributed over a fault zone, with default 85% applied as a knife edge offset, and the remaining over the width of the zone. For Level 3 analysis, provide the direction of the AD relative to the direction of the pipe, reflecting the style of offset (right lateral, left lateral, normal, reverse, oblique) and the direction of the pipe. For Level 4 analysis, have a qualified geologist describe a suite of offset patterns (directions, amounts) that could occur in future earthquakes and select a suitable design criteria that reflects the importance of the pipe, the nearby occupancy, and network considerations.

- MD. Maximum displacement of surface fault offset anywhere along the fault rupture. MD values are commonly used for design of new pipes across faults (Level 4). Using MD to estimate the likely damage to existing pipes in historic earthquakes will generally result n overestimates of actual damage.

- Creep. Some faults exhibit ongoing creep. Pipelines are exposed to both creep and co-seismic slip and afterslip. For design (Level 4), the total offset design should include creep + co-seismic slip + afterslip. The stiffness of soils surrounding buried pipe may be lower under slow creep motions than under sudden co-seismic offsets. It is thought that pipes can sustain creep offsets somewhat better than co-seismic offsets; this refinement can be considered in Level 4 analyses.

4.2.2. Tsunami Hazards

For most gas transmission pipelines in California, tsunami hazards are non-existent.

There are a few locales where tsunami hazards are important. Coastline areas in the port area of Crescent City had tsunami inundation in the 1964 Alaska earthquake, resulting in fatalities. Coastline areas near Santa Cruz were impacted by the 2011 Great Tohoku earthquake, resulting in damage to boats and dock facilities. Any offshore earthquake near the coast of California that might include material vertical slip at the ocean floor (as for example, possibly the San Gregorio fault under Monterey Bay), or any earthquake that induces underwater landslides, can trigger tsunamis that will inundate the coastline areas.

With respect to gas pipe infrastructure, inundation poses two hazards. Both these hazards caused damage to pipelines in the 2011 Great Tohoku earthquake:

- Gas pipes hanging underneath bridges at the mouths of rivers / creeks. These pipes can be impacted by high velocity waves, damaging the pipes; the bridges themselves can fail due to inundation and related wave forces.

- Buried gas pipes near shoreline areas (port areas) can become exposed due to scour effects during inundation and retreat of high speed water. Few if any of these pipes have been designed with scour protection. Loss of soil support around the pipe can lead to unintended imposed PGDs on the pipe.

Given the very small inventory of gas pipelines that might be exposed to tsunamis, this report provides no fragility models for these situations. A Level 4 approach should be adopted for any gas pipelines that might be exposed to tsunami hazards.

Chapter 5: Historic Repairs to Gas Pipes

5.1 Pipe Leaks - Distribution Pipes

Gas system operators in the United States provide an annual report to the Pipeline and Hazardous Materials Safety Administration (PHMSA) as to the number of leaks in their gas systems. The data in Tables 5-1 to 5-3 was accessed at http://www.phmsa.dot.gov/pipeline/library/data-stats/raw-data. This data reflects information for the year starting July 1 and ending June 30.

There were no significant earthquakes ($M \geq 6.5$) in the PG&E, SoCalGas or SDG&E service areas during the 2018 reporting period.

Table 5-1. Total Leaks and Hazardous Leaks in 2018 (PG&E)

Cause of Leak	Mains - Total	Mains - Hazardous	Services - Total	Services - Hazardous
Corrosion Failure	1221	390	3046	2201
Natural Force Damage	86	61	294	187
Excavation Damage	268	264	1487	1470
Other Outside Force Damage	13	13	233	216
Pipe, Weld or Joint Failure	92	57	1375	859
Equipment Failure	262	166	10973	1116
Incorrect Operation	510	244	2792	1591
Other Cause	85	28	1415	358
Total	2537	1223	21615	7998

Table 5-2. Total Leaks and Hazardous Leaks in 2018 (SoCalGas)

Cause of Leak	Mains - Total	Mains - Hazardous	Services - Total	Services - Hazardous
Corrosion Failure	2682	405	8045	2268
Natural Force Damage	109	57	934	392
Excavation Damage	439	430	2958	2925
Other Outside Force Damage	4	1	664	420
Pipe, Weld or Joint Failure	1134	258	4938	723
Equipment Failure	203	8	16104	1013
Incorrect Operation	320	162	4398	388
Other Cause	56	11	431	70
Total	4947	1332	38472	8199

Table 5-3. Total Leaks and Hazardous Leaks in 2018 (SDG&E)

Cause of Leak	Mains - Total	Mains - Hazardous	Services - Total	Services - Hazardous
Corrosion Failure	114	87	816	385
Natural Force Damage	15	12	186	153
Excavation Damage	69	69	333	331
Other Outside Force Damage	1	1	48	23
Pipe, Weld or Joint Failure	69	45	339	76
Equipment Failure	33	8	1122	63
Incorrect Operation	48	40	101	45
Other Cause	14	11	62	53
Total	363	273	3007	1129

The "background leak rate" for the three systems is listed in Table 5-4 and is based on the data in Tables 5-1 to 5-3 and Table 3-5.

Table 5-4. Leak Rates

Items	PG&E	SoCalGas	SDG&E
Mains - Leaks	2537	4947	363
Services - Leaks	21615	38472	3007
Distribution Main Length - miles	43067	50957	8167
Leaks / Mile / Year (Mains)	0.059	0.097	0.044
Lakes / Mile / Year (Mains + Services)	0.561	0.852	0.413

5.2 Cause of Leaks - Transmission and Distribution Pipes

Table 5-5 provides a range of the more common causes for leaks to gas transmission pipes. The "Percentage of repairs" reflects the expected range of all repairs throughout a gas transmission system in a typical year. The "WROF" category range includes earthquake damage from minor earthquakes.

Transmission leaks include leaks on transmission mains, up distribution pipes. Typically, this includes the pipeline between a compressor station up to a distribution regulator station; or the pipeline between a compressor station and up to the outlet of a farm tap; or leaks at compressor stations or storage facilities.

Table 5-5. Causes of Leaks, Transmission System

Leak Category	Percentage of repairs (Range)	Notes
Construction	2 - 10%	
Equipment	50 - 80%	Appurtenances, valves
External Corrosion	5 - 15%	
Incorrect Operation	< 1%	
Internal Corrosion	2 - 5%	CO_2, sulfur, water, other chemicals
Manufacturing	< 1%	
SSWC and SCC	< 1%	Stress corrosion cracking and selective seam weld corrosion
TPD	3 - 10%	Third Party Damage
WROF	< 2%	Weather-related or Outside Forces. Outside forces can be ground movement, flooding, cold weather, lightning, landslide, earthquake
Other	< 1%	

Table 5-5 shows that the majority of leaks in a gas transmission system are due to damage to appurtenances and valves. Very few historic leaks have been attributed to earthquakes. Section 6 of this report examines the damage patterns in actual historic earthquakes. A few percent of total can be due to third party damage (contractors that accidently dug up and damaged a buried gas pipe, etc.); the remainder reflect various weaknesses in pipes. From an earthquake perspective, all the leak causes could manifest themselves in future earthquakes, as any pipe that is predisposed to weaknesses (due to ongoing age-related effects, corrosion, manufacturing, etc.) is likely to be more vulnerable to leak in earthquakes owing to the additional imposed stresses on the pipe. Even Third Party Damage is possible after earthquakes, as there will be a lot of repair work by third parties to water pipes, sewers, storm drains, and other underground infrastructure, resulting in an increased chance of accidental third party damage to gas pipes during the reconstruction / repair efforts by others post-earthquake.

Table 5-6 provides a range of the more common causes for leaks to gas distribution pipes and service laterals that are common in California. The values highlighted in yellow are for the more common leak causes (potentially over 1% of all leaks).

Table 5-6. Causes of Leaks, Distribution System

Leak Cause	Mains + Regulation	Service
Atmospheric Corrosion	<0.1%	3 - 5%
Cast Iron Fracture	<0.01%	<0.1%
Compression Coupling	<0.1%	0.2 - 0.5%
Construction Defect	0.5 - 2%	10 - 20%
Damage by Earth Movement	<0.2%	1 - 2%
Damage by Electrical Facility	<0.01%	<0.1%
Damage by Heavy Rain/Flood	<0.1%	<0.1%
Damage by Third Party (non-dig-in)	<0.1%	0.5 - 1%
Deliberate Acts/Vandalism	<0.01%	<0.1%
Dig-in/Excavation	0.2 - 1%	10 - 20%
Earthquake	<0.01%	<0.1%
Equipment Malfunction	<0.1%	0.2 - 0.5%
External Corrosion	1 - 2%	5 - 15%
Fire or Explosion	<0.01%	<0.1%
Incorrect Operation	<0.1%	0.2 - 1%
Internal Corrosion	<0.1%	0.2 - 0.5%
Leak	<0.01%	<0.1%
Lightning	<0.01%	<0.01
Material Failure	0.1 - 0.5%	2 - 5%
No/Deteriorated Pipe Dope	0.5 - 2%	25 - 50%
Other	0.5 - 2%	10 - 20%
Other Natural Forces	<0.1%	0.2 - 0.5%
Plastic Crack Failure	<0.1%	0.5 - 2%
Plastic Embrittlement	<0.1%	0.1 - 0.5%
Previously Damaged	<0.1%	0.1 - 0.5%
Rodent	<0.01%	<0.1%
Root Damage	<0.01%	<0.1%
Stress Corrosion Cracking	<0.01%	<0.1%
Unknown (Replaced Facility)	<0.1%	0.2 - 0.5%
Vehicle	<0.01%	0.1 - 0.5%
Weld Failure	<0.1%	0.2 - 0.5%
Total	4 - 7%	93 - 96%

Columns and rows in Tables 5-5 and 5-6 do not add up exactly owing to round off. With regards to causes "Damage by Earth Movement" and "Earthquake", the data in Tables 5-5 and 5-6 *do not* reflect the damage after actual earthquakes; see Section 6 for a more discussion of the actual repairs made after actual historical earthquakes.

Table 5-6 shows that the most common repair in distribution gas systems is "no / deteriorated pipe dope". Mostly, this reflects the detection of gas leakage along the riser pipe at the meter connection, where screwed fittings are used. Pipe "dope" reflects any thread lubricant, thread sealing compound or anaerobic chemical sealant that is used to make common pipe thread joints leak-tight. Over time, this material may deteriorate for a variety of reasons, basically age-related issues (embrittlement over time with UV light, atmospheric corrosion, etc.), mechanical loading, etc.; the typical repair would be to replace / add more pipe dope to again make a leak-tight connection.

Chapter 6: Damage in Historic Earthquakes

Table 6-1 summarizes the performance of gas pipe systems in 37 historic earthquakes.

Table 6-1. Historic Earthquakes

Sect.	Gas System(s)	Earthquake	M	Year	Trans (T) Dist (D) Service (S) repairs or leaks (see text for details)
6.1	PG&E	San Francisco	7.9	1906	Many gas leaks
6.2	PG&E SoCalGas	Kern County	7.3	1952	T: 2 stress-relieved pipes, D: 1 repair (PG&E) T: 5. (SoCalGas)
6.3	PG&E	Daly City	5.7	1957	T: 1 D: 2
6.4	PG&E	Greenville	5.8	1980	Some gas pipe leaks in Livermore
6.5	PG&E, Coalinga	Coalinga	6.3	1983	Some gas pipe leaks in Coalinga
6.6	PG&E	Morgan Hill	6.2	1984	T: 1 possible. D: none reported, data sparse.
6.7	PG&E	Ridgemark	5.4	1986	T, D: none reported
6.8	PG&E	Calaveras	5.6	1986	T: 0. D: possible.
6.9	PG&E	Fort Tejon	5.2	1988	T: 0. D: no data.
6.10	PG&E	Loma Prieta	6.9	1989	D+S: 600.
6.11	PG&E	Cape Mendocino	7.2	1992	D: some likely, no record available. T: no data.
6.12	PG&E	Salinas	5.1	1998	T: 1 possible. D: 0.
6.13	PG&E	Yountville	5.0	2000	D: possibly a few leaks. T: 0.
6.14	PG&E	San Simeon	6.5	2003	D: no inventory in area. T: 0.
6.15	PG&E	Alum Rock	5.6	2007	T: 1. D: 0.
6.16	PG&E	Eureka	6.5	2010	T: 1. D+S: 279.
6.17	PG&E	Napa	6.0	2014	T: 2 replaced pipes D+S: 263.
6.18	PG&E	Ridgecrest	6.4 7.1	2019	T: 2 replaced pipes D+S: 356.
6.19	None	Fort Tejon	7.9	1857	No gas system
6.20	Long Beach SoCalGas	Long Beach	6.4	1933	D: 119. S: 2,650 (LB) T: 0 (SoCalGas)
6.21	SoCalGas	San Fernando	6.7	1971	T: > 59. D: 181. S: 137.
6.22	SoCalGas	Santa Barbara	5.3	1978	No data.
6.23	SoCalGas	Imperial Valley	6.6	1979	T: 3 stress-relieved pipes
6.24	SoCalGas	Devers	5.9	1986	T: 0. D: 0.
6.25	SoCalGas	Whittier	6.1	1987	T: 0. D: 22. S: 3,000.
6.26	SoCalGas	Landers	7.3	1992	T: 0. D: 0.
6.27	SoCalGas	Big Bear	6.4	1992	T: 0. D: 1.
6.28	SoCalGas	Northridge	6.7	1994	T: 35. D: 123. S: 511.
6.29	SoCalGas	Hector Mine	7.1	1999	T: 0. D: 0.
6.30	Niigata	Niigata Japan	7.5	1964	T: some: D: some
6.31	Osaka Gas	Kobe	6.9	1995	T: 0. D: 196. S: 26,000.
6.32	RockGas	Christchurch	7.1	2010/11	T: no inventory. D: 3: S: 1
6.33	Multiple	Tohoku	9.0	2011	T: 0. D: 190
6.34	Saibu Gas	Kumamoto Japan	7.0	2016	T: 0. D:88. S: 832.
6.35	Kita Gas	Hokkaido Japan	6.7	2018	T: 0. D:0. S: 13

6.36	Enstar	Anchorage	7.1	2018	T: 0. D+S: 15.
6.37	Dominion	Magna Utah	5.7	2020	T: 0. D: 0. S: 391 + 113.

The lack of gas system damage in some of these historical earthquakes is good information, as that forms a baseline for establishing the level of shaking below which no gas system damage is expected.

The following sections briefly review the earthquake, highlight the associated geologic hazards, and describe the damage to the gas system.

6.1 San Francisco M 7.8 1906

The M 7.8 earthquake of April 18, 1906 occurred at 5:12 am Pacific Standard Time. This earthquake has also been called the great San Francisco earthquake. The magnitude of this earthquake has previously been reported as M_s 8.0 or M_s 8.3; some have more recently assigned this earthquake as having moment magnitude M_w 7.7, 7.8 or 7.9. The duration of strong ground shaking was about 45 to 60 seconds.

The causative fault was the San Andreas fault. Fault rupture occurred from just north of San Juan Batista (west of Hollister) to Cape Mendocino in the north. Figure 6.1-1 shows a map of the length of observed fault rupture and associated MMI intensities for this earthquake.

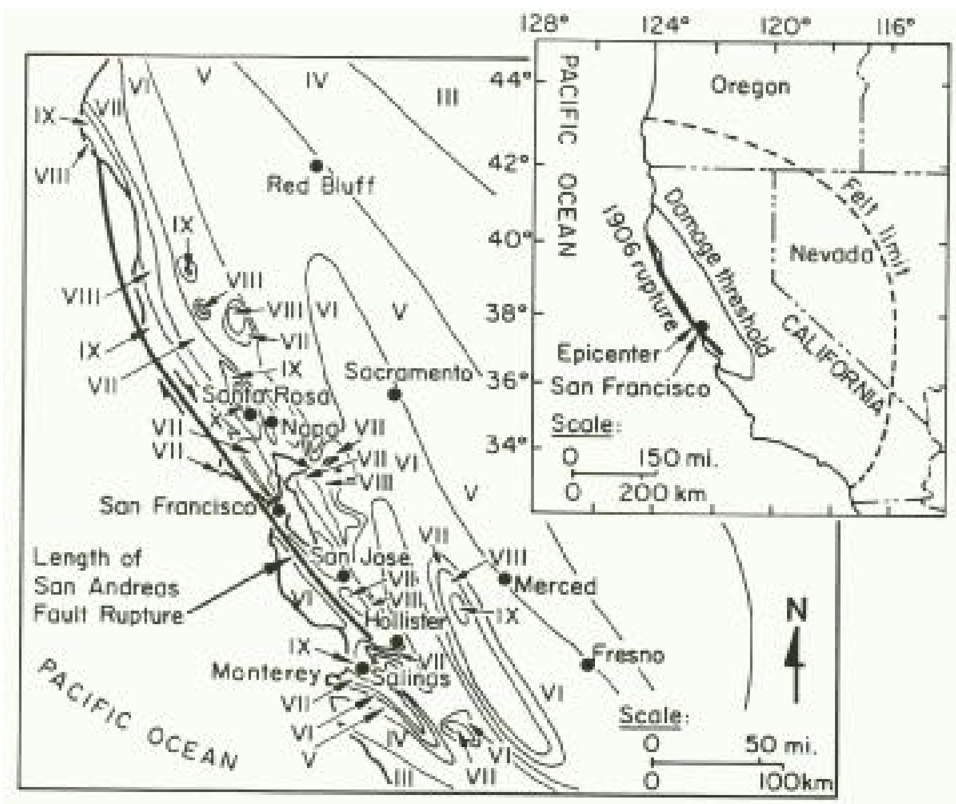


Figure 6.1-1. Map of 1906 San Francisco Earthquake (from O'Rourke and Hamada, 1992)

This earthquake exposed San Francisco to moderate to very strong ground shaking, including many zones with PGDs. The population in San Francisco was then about 400,000 people, about half of today's population. PG&E's gas system was heavily damaged in San Francisco.

Moderate to strong shaking also occurred in Oakland, Berkeley, Santa Rosa; the population of those areas in 1906 was much smaller than it is today. PG&E did not operate a gas system in those areas in 1906.

PG&E has just been formed (1905) at the time of the 1906 earthquake. The following is a brief history of gas and electric supply in San Francisco, up to 1906. It should be recognized that at this time, PG&E was primarily a manufacturer of gas, and then distributor of gas into the city; this gas was then burned primarily for lighting. PG&E, as well as several other competing companies, were then supplying electricity into the city for purpose of electric lighting. There were also competing gas companies.

The first gas works began in 1852, with a gas plant (south of Market) and 6.5 miles of pipe delivering gas to 237 customers. The gas was used for lighting. The system grew, merging with others, and by 1873, was called the San Francisco Gas Light Company.

In 1879, a municipal-owned electric lighting system was introduced. The first electric street light was erected in 1888, and an electric grid was gradually extended. Throughout this time frame, using electricity or gas to create light remained competing businesses.

In 1888, San Francisco Gas Light built the Potrero Gas Works, at the site of the modern Potrero substation. In 1891 the North Beach Gas Works (Figure 6.1-2) was completed.

Figure 6.1-2. Damage to SFG&E North Beach Gas Plant, San Francisco 1906

In 1896, San Francisco Gas and Electric was formed, merging with the Edison Light and Power Company. Several more gas and electric companies were merged into San Francisco Gas and Electric by 1903.

In 1905, San Francisco Gas and Electric and California Gas and Electric merged to form Pacific Gas and Electric (PG&E).

By the time of the earthquake at 5:13 am (local) April 18 1906, San Francisco was served by four competing gas systems. Gas was delivered by underground cast iron pipes, and then burned to create light. The four gas companies in operation c.1900 were:

- San Francisco Gas and Electric (predecessor to modern PG&E)
- Spreckels gas corporation. Gas manufactured at Potrero. Ultimately consolidated into PG&E in 1903.
- Pacific Gas Improvement Company (gas generated near Fillmore and Bay Streets). Ultimately consolidated into PG&E in 1903.
- Equitable Gas Light Company. Consolidated into SFG&E (PG&E) in 1903.

Immediately before the earthquake, SFG&E was supplying gas from several sources. Carbureted water gas was manufactured and distributed from the North Beach Station at the former Bay and Fillmore streets, supplying the north and west ends of the city. At Potrero, another carbureted gas plant was in operation. A new gas works at Martin Station (in Daly City) had recently begun to deliver small quantities of crude oil water gas to the city.

The following descriptions of the damage and repair efforts to the gas distribution system were described by Edward Jones, Gas Engineer of the San Francisco Gas and Electric Company, sometime after the earthquake.

The earthquake damaged the North Beach Station (Figures 6.1-2, 6.1-3), where liquefaction resulted in settlements locally on the order of 2 to 3 feet. A gas holder station and storehouse at Fifth and Tehama Streets were destroyed by the fire (this gas holder was located within Sullivan Marsh, and probably also subject to liquefaction). The gas plants at Potrero and Martin were subject only to ground shaking, and had little damage.

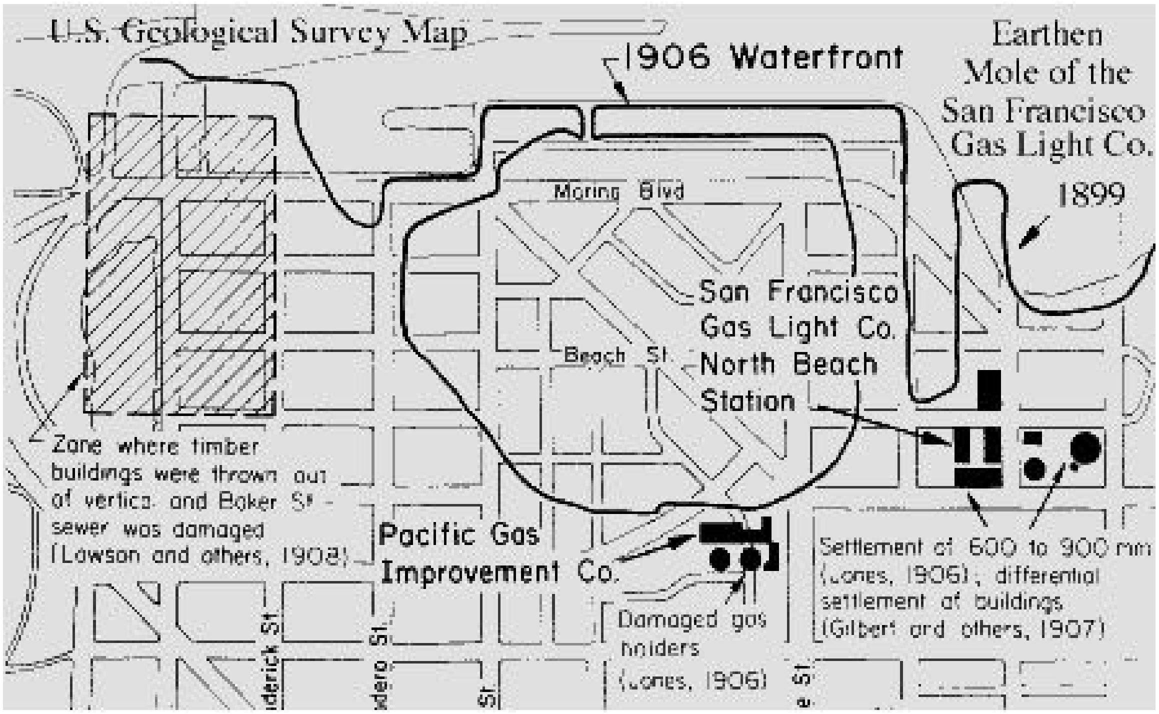


Figure 6.1-3. Locations of PGIC and SFG&E Gas Plants, San Francisco 1906

At Pacific Gas Improvement Co. (Figure 6.1-3), sometime before 7:00 am, the gas had been shut off at the inlet and outlet of the holders. Holder No. 3, with a capacity of 700,000 cubic feet, had slight damage; Holders 1 and 2, each with 325,000 cubic feet capacity, were so badly damaged that the gas escaped.

At the North Beach Station (Figure 6.1-3), the gas was shut off at the inlet of the meter, and the valves were closed at the inlet of the 2,000,000 cubic foot storage holder. The 24-inch outlet pipe connections of this holder were broken off between the holder and the outlet valves, so the holder could not be isolated and the gas leaked out. The valves on the damaged 24-inch pipe were closed, and this prevented gas coming from Potrero to leak out from this location. This report suggests that the 36-inch cast iron pipe that ran between the Potrero and North Beach stations was, in itself, largely undamaged by the earthquake at this point in time (it was later damaged by explosions). As a 36-inch cast iron pipe of the style of construction likely circa 1905 or so cannot take much PGD, this suggests that this 36-inch pipe alignment traversed stable soils.

The valves at the inlets and outlets of the two 600,000 cubic foot storage holders at Fifth and Tehama were closed immediately following the earthquake.

After the valves at the North Beach plant were closed, staff went to the Potrero plant and closed valves on pipes between the plant and the city. Tests showed that the 12-inch steel pipe from Martin to Potrero were leak tight. At 7:27 am on April 18, the Potrero plant outlet pipes were valved out, thus isolating the last supply of gas into the city.

On Wednesday, April 18, a repair crew began work to repair the 24-inch gas pipe at the junction of Van Ness and Vallejo Streets, where the street had settled 24 inches, breaking the main, and the pipe was pulled apart 18 inches.

On Wednesday, Thursday and Friday, April 18, 19, and 20, even as the fires spread to their ultimate extent, repair crews were repairing gas mains, with the two gas plants at Potrero and Martin repaired and readied for use.

During this repair time, it was needed to assign men to stand in food-lines, so that food could be obtained to feed the men working on the gas pipe repairs.

Between April 18 and 20, there were successive explosions in the underground gas pipes linking the Potrero and North Beach gas plants. On the 30-inch gas main (Figure 6.1-4), running from Potrero works on Kentucky row (now Third Street), Mariposa, Potrero Avenue, Tenth, Market, Fell to Van Ness Avenue, along Van Ness to Broadway, there were 21 explosions in Zone A (highlighted by the elongated oval). In nearly every case the explosion took place at a line drip or cross, where the main was weakest, and the earth around the main was thrown up, leaving openings of various sizes up to 12 foot wide and 30 feet long. Along the 24-inch main linking the two stations, there were as many as 40 breaks due to explosions. Fortunately, these explosions caused no damage to life or property (according to a PG&E worker; but other accounts suggest many injuries in the South of Market area).

Figure 6.1-4. Map Showing Gas 30"-24" Main, Potrero to North Beach, 1906

One possible reason for the gas explosions was that there remained many gas stoves in the city being used in the days after the earthquake, relying on the residual gas in the gas pipes. With damage to the gas pipes, air entered into the pipes, and the use of the gas stoves allowed ignitions / burning fuel to back up into the mains; the traveling wave of the burning fuel backup until it found a weak spot in the gas main.

The fire burned itself out by April 22. At that point, PG&E isolated all gas east of Van Ness, and used the gas from the Potrero plant, via the 30-inch main, to serve the un-damaged parts of the city west of Franklin (one block west of Van Ness). As there were not valves in every gas pipe, crews manually cut the pipes and plugged them, east of Van Ness. This was a large labor effort, as every pipe into the burned areas had to be plugged. This effort required a 500-man crew.

By April 30, the 30-inch main was repaired, and the pipes in the burned area were all isolated. The remainder of the city was ready to accept gas re-supply, but as the water system had not yet been repaired, the gas system was not turned on until May 7 (19 days post-earthquake). By that time, about 400 miles of gas mains were ready for use, with another 166 miles (in the fire burned area) cut off.

The gas pipes running east-to-west (generally in the fault-normal direction) were reported by PG&E to be invariably damaged with "pull aparts", while the gas mains running north-to-south (generally in the fault parallel direction) invariably were damaged by telescoping and buckling (with few exceptions). In modern review, these observations are viewed with skepticism, as for every "pull apart zone" there would need to be a "compression zone", for wave passage effects, and similarly for liquefaction effects.

It was suggested at the time that pipes on piles would be earthquake-resistant through zones of "made ground" (for example, former marshes). PG&E then had one such situation, where a gas pipe on Jackson Street between Drumm and David Streets, which is made land, the street main had been laid on a line of piles that went to hard pan. The pipe broke over each pile, 9 in number, and was not broken in the made ground where it was unsupported.

Most of the gas holders were damaged by twisting out of their guide frames, and there was damage to buildings:

- A foreman at the North Beach plant observed that waves of water sloshed out of the 2,000,000 cubic foot gas holder; the relief holder was similarly affected. These two holders were heavily framed with latticed girders, and did not leave their guides by the ground shaking. The yard around the tanks had settled around 2 to 3 feet.

- The storage holder at Townsend near Third Street was twisted around 2 feet from the guide rails.

- At Martin, the 1,500,000 cubic foot holder was twisted 5 feet on the lower section, 8 feet on the middle section, and 12 feet on the upper section.

- At Martin, the 4,000,000 cubic foot generator was moved 2.5 inches to the south; all connections were of steel, and no joints were broken.

- Some brick buildings of comparatively poor construction were unharmed. Other buildings of great strength with heavy footings on good foundations, where shaken to the ground.

In reviewing the gas pipe alignment in Figure 6.1-4 its alignment is shown along 10th Street through the South of Market area. There were also several water pipe breaks along 10th Street. Over the past decade, the author as well as various PG&E engineers have tried to locate a 1905-era map of PG&E's historic gas mains, to verify / validate the location of the historic 36-inch (variously 24-inch to 30-inch) gas pipe between Potrero and North Beach and other infrastructure; nobody yet has been able to find such a map. Considering these two inconsistent findings (36-inch gas main with no damage; much damage to adjacent water pipes), the assumed location of the gas main pipe in Figure 6.1-4 might not be correct.

6.2 Kern County M 7.3 1952

A M 7.3 earthquake occurred on 4:52 am July 21, 1952 (local time) on the White Wolf fault (variously reported as high as surface wave M 7.7). Prior to the earthquake, the White Wolf fault had not been a known to be an active earthquake fault, and had registered no known activity for the prior ~100 years (1850 – 1951).

The epicenter was on the White Wolf fault, near Wheeler Ridge, located south of Bakersfield. This fault has been characterized as being 52 km in length, striking N 43°E, variously reported as dipping about 62° to the southeast. The sense of fault rupture was left lateral reverse movement; primary movement was reverse, with lesser lateral displacement.

At the time of the 1952 earthquake, the first of PG&E's 34-inch gas transmission lines through this area had recently been constructed.

Depending on location along the rupture, surface rupture ranged from 1 to 3 feet of up movement (up on the south) to a several feet of left lateral movement. There were many aftershocks, with 7 registering M 5.5 or higher.

Surface fault rupture bisected the then-constructed 34-inch gas transmission line.

6.2.1 PG&E Gas System

At the time of the earthquake, the first of the 34-inch gas transmission lines had already been built.

Figure 6.2-1 shows a closeup of the White Wolf fault crossing location. This shows the current (2020) pipe alignments and names, and the mapped traces of the surface rupture of the White Wolf fault (red dashed lines). The main trace (northeastward strike) crosses the Line 300A 34-inch transmission line as shown in the main map.

About 200 meters to the northwest of the main trace crossing zone, there are presently various stubs and cross over pipes between modern-named Lines 300A and 300B. This includes two 24-inch cross over pipes, installed September 27 1952 and August 24 1954.

Most of the modern Lines 300A and 300B in this area is buried. However, there are ten above ground segments of the original 1950-vintage pipe that cross over local drainages; these are located mostly to the southeast of the fault crossing zone in the mountainous crossing of the Tehachapis. Each above ground segment is about 50 to 150 feet long. The newer (1953) Line 300B pipe is essentially entirely buried in this vicinity; both the original (300A) and newer (300B) pipes are above ground where they cross an open channel aqueduct near the town of Arvin.

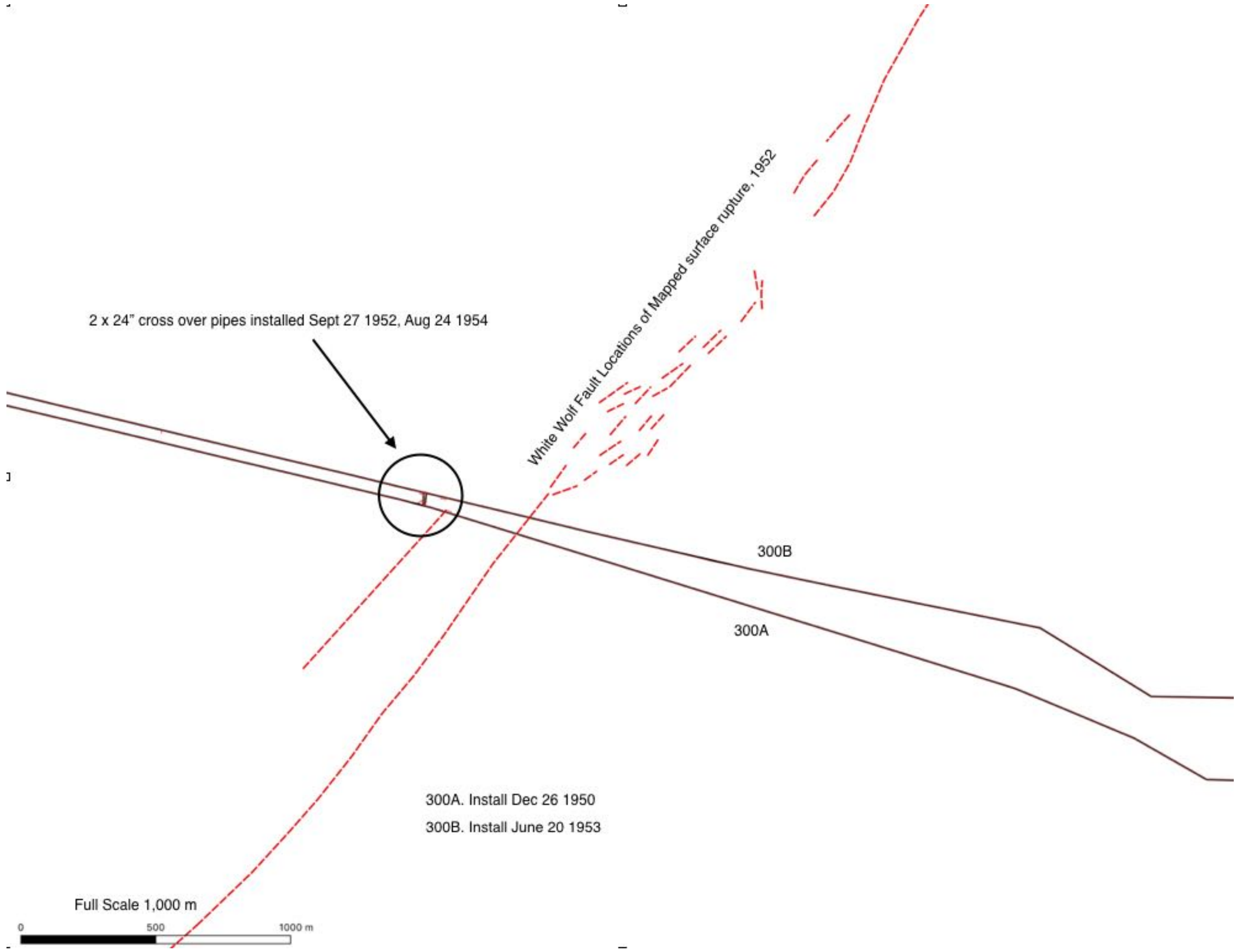


Figure 6.2-1. Gas Transmission Pipes (black lines) at the White Wolf Fault (red lines).

Mr. R. J. Lind of PG&E reported the following (1954):

- Line 300 crossed the main trace of the fault (Figure 6.2-1). The earthquake effects were noticeable for 43 miles along the Line 300 alignment.
- Personnel were dispatched along Line 300 to establish radio communications between the Hinkley and Kettleman compressor stations. Pipeline employees patrolled Line 300 on foot and by vehicle.
- Patrolmen found telephone wires wrapped around each other where cross arm constructed had been used. These were repaired by 12:35 pm July 21.
- The Patrolmen noted that there were many landslides / ground cracks near or crossing Line 300. No leakage or pipe damage to Line 300 was encountered.

- The buried portions of Line 300 had a cover of about 30 inches above the pipe. Therefore, visual inspection of the buried pipe itself was not feasible.

- It was decided to lower the operating pressure in the pipe in the area affected by the earthquake, by reducing flow from 400,000 Mcf / day to 300,000 Mcf / day. This reflected concern that the buried pipe might have had some increase in stress / strain.

- The Line 300 pipe is described as 34-inch OD with t = 7/16" (0.438"). The pipe was fabricated using open hearth process with longitudinal seams made by the submerged arc process. Fy = 48 ksi with Fu = 65 ksi. MAOP = 790 psi, which correlates to hoop stress being 64 percent of yield stress. With the post-earthquake operational steps to reduce flow and pressure, the hoop stress was lowered from 31 ksi (790 psi internal pressure) to 17 ksi (450 psi internal pressure).

- Patrolmen were assigned to take pressure readings above and below the fault crossing zone at 15 minute intervals, 24 hours per day, with the objective of observing any unexplained decrease in pressure that might indicate pipe damage. None was identified.

- With the reduction of gas purchase, there was no need to boost pressure at the Hinkley Compressor Station, 94 miles upstream (west northwest) from the fault zone. There was no observed damage at the Hinkley Compressor Station.

- Surface ground cracks were observed along Line 300, immediately southeast of the town of Tehachapi. Several cracks traversed Line 300, and constant vigilance was maintained at these locations. Many open (above ground) spans were observed to be in possible jeopardy from large boulders on the upper sides of hills; one such multi-ton boulder had rolled down a hill and had come to rest about 100 feet from the pipeline alignment.

- A small diameter gauge and pressure-control line was distorted, strained and twisted at Pressure Limiting Station Four. These small diameter lines are for automatic operation of pressure-control valves, and would have been inoperative had they been ruptured.

- Surface offset was observed at milepost 254. Mr. Lind describes the pipe at the main crossing location as at the bottom of a hill with vertical angulation of about 16.75 degrees; the pipe accommodated this angle using both welding elbows and a wrinkle bend. Another less severe fault offset location was about 410 feet to the east. At a location about 200 feet south of the pipe, vertical offset was observed at about 18 inches; immediately north of the pipe, observed offset was about 5 inches.

- Repairs were made at Pressure Limiting Station Four, including relief of strain and realignment of the control lines.

- The buried pipe at the fault offset location was uncovered using a backhoe, initially for a length of about 160 feet of the offset location. Once uncovered, the pipe uplifted about 6.75 inches. The excavation was extended for 560 feet, and the line lifted 28.375 inches and was blocked in place.

The vertical movement occurred 30 feet below the fault and tapered off rapidly towards each end of the exposed line.

- It was considered to shut down the pipe and install a new pipe; but there were no good alternatives to supply gas during the shutdown. It was decided to keep the line in service until the new 34-inch "loop" line (300B) would be built and put in service in two years (1954).

- There was some movement of the above ground pipe saddles, on the order of an inch or so at some supports between the saddles and the pipe.

- A 0.75" Mueller welding tee connection was installed on the 34-inch line in order to supply SoCalGas with gas in case their Grapevine – Tehachapi main ruptured (see Section 6.2.2 below for further discussion of the impact to SoCalGas pipes in this earthquake). This connection never saw use and was removed at a later date.

- The 24-hour patrols were discontinued on July 29 1952. The 100,000 Mcf cut in flow was discontinued July 28 1952. A foot patrol along a 51-mile stretch observed no issues at the restored higher operating pressure.

- The parallel Line 300B 34-inch line was constructed and put in service on June 24 1953. Once that was done, the older 34-inch Line 300A was taken out of service and de-pressurized from MP 247 to 256. Repairs to the original line started July 1 1953. The steel pipe was cut open; during that process, a portion of the steel tore apart on its own, indicating that there was considerable pent-up stress in the steel due to the fault offset. The pipe separated 4 inches horizontally and 2 inches vertically. A total of about 20 inches of pipe were removed, and then a new pipe segment of 34-inch OD x 7/16 inch pipe was inserted with butt weld girth joints. Welding sleeves, 34-inch inside diameter x 7/8-inch, 10 inches wide, were placed around each end of the inserted piece and arc-welded into place. A similar process was done 19 feet downstream, resulting in a 1-inch opening; the following day, due to thermal changes overnight, the gap opened to 2.5 inches; a welding sleeve was installed over the gap, as above. The line was returned to service on July 4 1953. No post-event creep / movement in the fault zone was recorded.

6.2.2 Southern California Gas System

Mr. A. B. Newby described the damage to the SoCalGas pipeline system in the 1952 earthquake and nearby smaller 1954 earthquake in his report (1952). Figure 6.2-2 shows a map of the various SoCalGas facilities affected in the 1952 M 7.3 earthquake and the smaller January 12, 1954 M 5.9 earthquake in this area.

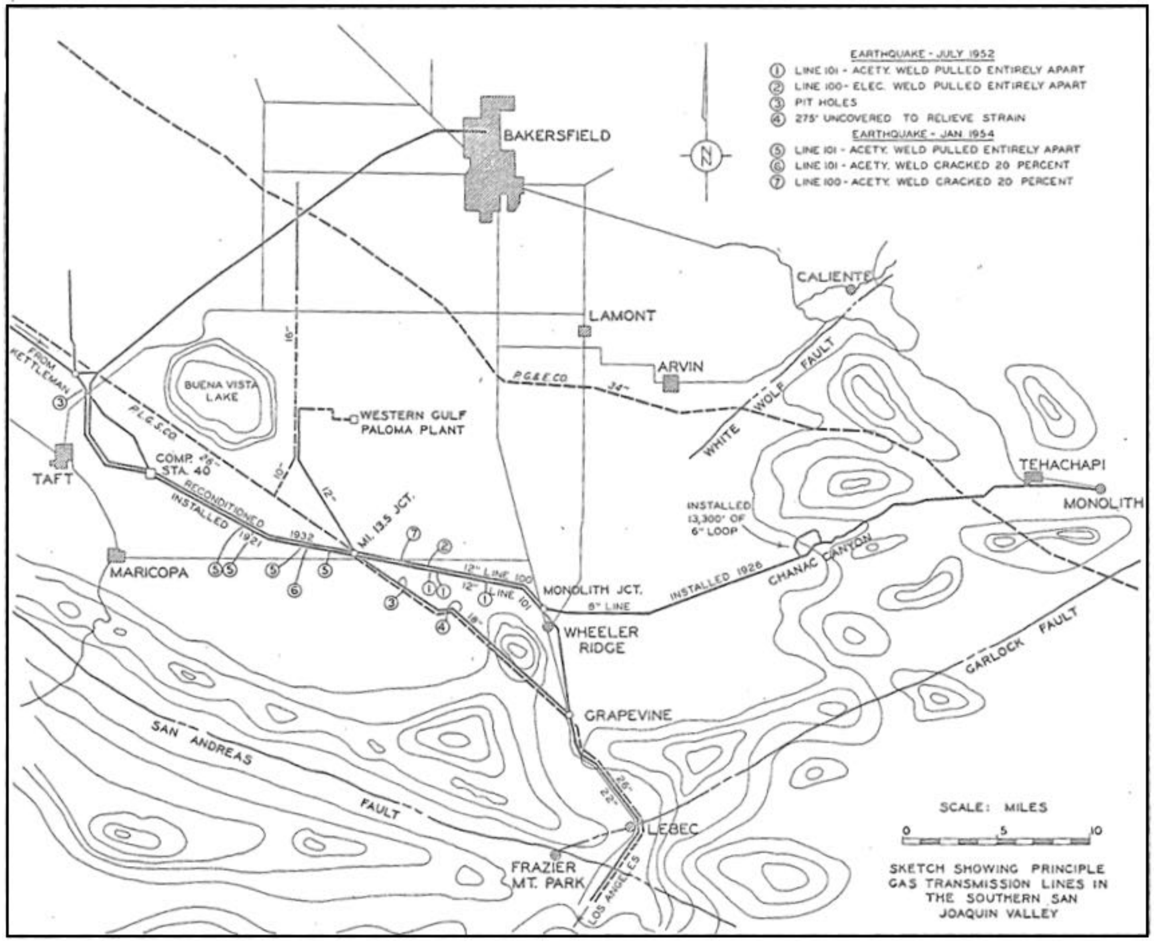


Figure 6.2-2. Gas Transmission Pipes, SoCalGas, 1952 White Wolf Earthquake (after Newby, 1954)

- The first order of business was to establish communications. Telephones worked for a few minutes, and then went dead shortly after the earthquake. We then relied on an emergency generator with short wave radio.

- Reports indicated Compressor station 40 and 43 and Standard Oil's gas plants and everything around Taft were okay. A report from the Western Gulf repressuring plant noted that there was a fire and there had been a large explosion there.

Reports suggested that everything was intact except between Mile 13.5 Junction and Monolith Junction (see Figure 6.2-2 for locations). In this reach:

- Both parallel 12-inch steel pipelines 100 and 101 were broken.

- At 3 locations, Line 101 had failed welds at locations marked "1". This pipe was built in 1921 with oxy-acetylene welds. The ends of the pipe were from 0.5 to 2 inches apart at the different breaks.

- Line 100 broke at one location, at the location marked "2". This line had been reconditioned in 1932, and electric welded using chill rings. At the break location, the weld evidently failed from compression and then from tension. The parallel Line 101 did not fail at this location. Photos suggest that Line 100 first wrinkled in compression, and then parted in tension.

- Both Lines 100 and 101 were repaired and put back in service by 8:45 pm July 21.

- Pit holes popped out on a 22-inch line near Taft and on a 18-inch line at Wheeler Ridge at the location marked "3". These leaks were from external corrosion.

- At location marked "4", 275 feet of 18-inch pipe was exposed to relieve stress/strain.

- The 18-inch Line 101 parted at 4 girth weld (oxy-acetylene) locations, marked "5"; at "6", another weld was cracked 20% around the circumference (1954 earthquake).

- The 12-inch Line 100 had a cracked girth weld 20% around the circumference (acetylene) at location "7" (1954 earthquake).

- The gas distribution system in the town of Tehachapi was intact and tight. The distribution system consisted of 2" screwed steel pipe installed in 1927, with later additions made using 2-inch and 3-inch welded steel pipe. The only damage was from a fallen brick wall that broke off a riser pipe at a meter. As a matter of precaution, 18 services were cut off at the main in the business area, where there was considerable damage to buildings. More work was involved to turn back on 200 customers who had turned off the gas at their homes.

- The 8-inch pipe from Monolith Junction to Tehachapi (35 miles) appeared to be tight and not leaking. Still, it was suspected the pipe had undergone fault offset. A patrol observed that where the line goes up a hog back from the bottom of Chanac Canyon to the top of Tehachapi mountains, it crossed cracks in the earth 4 inches wide and 2 inches of vertical slippage. This portion of the line is 6-inch acetylene welded, installed in 1926. The line had been installed as buried, but at two locations, it was observed to be above ground after the earthquake; at one location, it was above ground for 15 feet, and at the other location, 43 feet. An emergency tap to PG&E's line 300 (see Section 6.2.1) was installed to allow emergency cross tie supply to the town of Tehachapi, in case this pipe had to be taken out of service. A parallel 13,300 foot long pipe was installed, and the original pipe was kept in service without repair. The modern interpretation is that pipe going up the hog back was stressed by strong shaking in a manner that resulted in its up-thrust out of the soil.

For a number of years, some in the earthquake engineering community suggested that pipes constructed with oxy-acetylene welding method (generally pre-1930) versus those made with electric arc method (generally post-1930), where inherently weaker. This was based on the ~10-fold higher number of repairs per mile for the older-welded pipe. But, this trend should not be relied on, for the following reasons: both well-made oxy-acetylene and electric arc welds should have the same mechanical strength; even reflecting that oxy-acetylene welds might have a larger heat affected zone; the reports of failures from the 1971 San Fernando and 1994 Northridge earthquakes (see Sections 7.3 and 7.10) also reported that the failed oxy-acetylene welds had poor weld quality (O'Rourke and McCeffery, 1984). In the 1989 Loma Prieta earthquake, EBMUD suffered many failed electric-arc welded pipes along the south shore of Alameda Island, and again EBMUD reported that these pipes had been originally installed in the 1960s with defective welds. The underlying issue is that with welded steel pipe, that at locations where the pipe is heavily loaded due to ground shaking, if the main barrel longitudinal stresses get high (perhaps over 50% to 75% of yield), then a poorly-made welded connection might fail. The compression failure on Line 100 would suggest that this pipe, being at modest pressure, might have had D/t ratios in excess of 100 or so (actual t is unknown), and it is well established that if the main barrel compressive stresses exceed about 45% of yield, then for pipes with D/t >> 100, the joint can readily wrinkle in compression, if there is any out-of-round geometric offset at the girth joint, such as for joints made with fillet welds. The available SoCalGas information form the 1930s suggest that perhaps the joints had been made with interior backing plates and two belled joints, suggesting that such out-of-roundness geometry might have existed.

6.2.3 Impact on Oil and Gas Wells

The San Joaquin Valley near Bakersfield has a variety of oil fields. This chapter is written based on the report of Robert Johnston (1954). This information is provided in this report in recognition that California's gas systems include several natural gas wells fields. The vulnerabilities to natural gas wells include sanding; casing collapse; effects of corrosion; variations in gas pressures; impacts to well-head equipment and attached piping; power outages; etc. These vulnerabilities should be considered when factoring in the potential performance of gas well fields in future earthquakes.

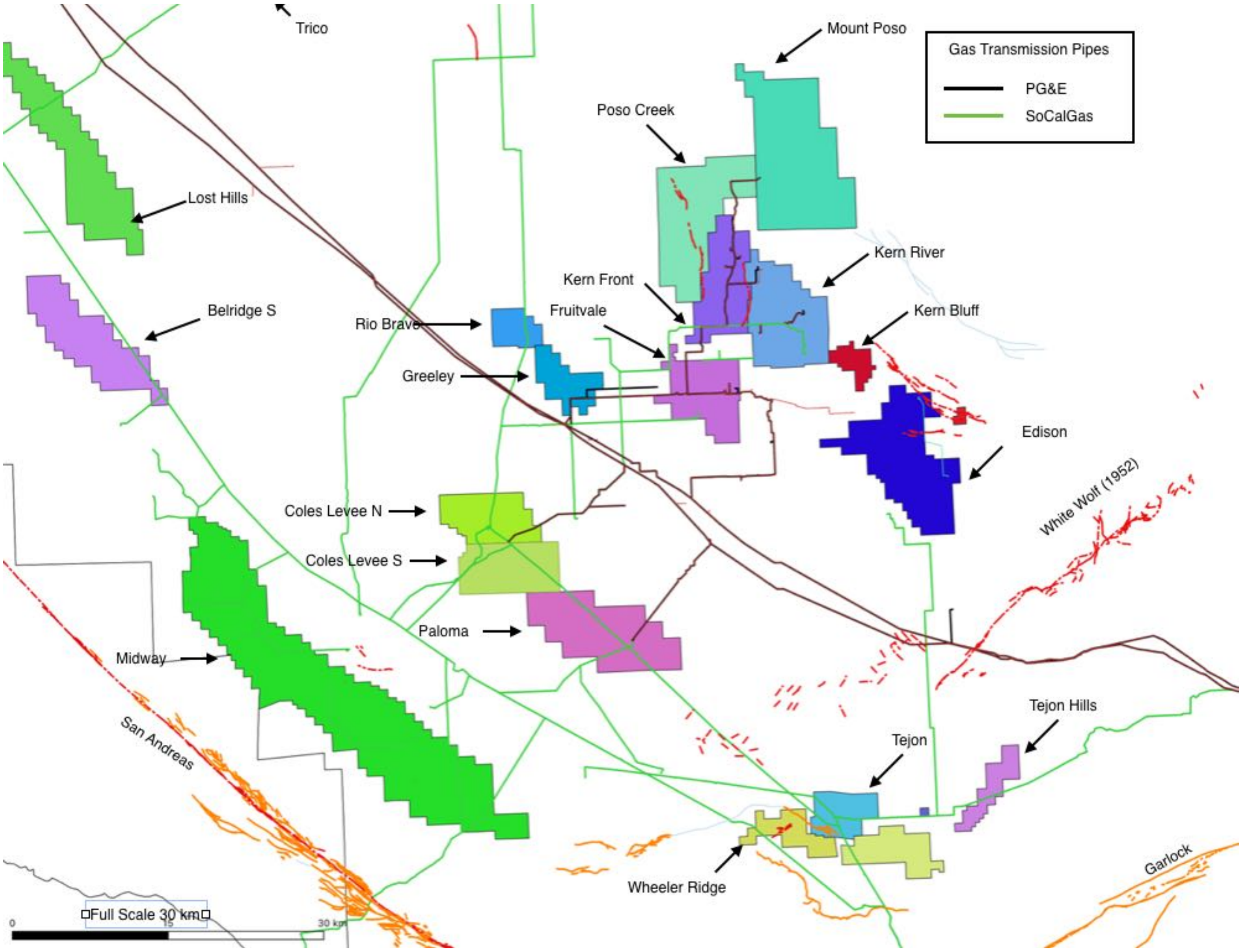


Figure 6.2-3. Well Fields, Near White Wolf Fault

Figure 6.2-3 shows the administrative boundaries of the gas well fields near the white Wolf fault rupture (red lines). The nearby Garlock and San Andreas faults (orange, red lines) are also shown. In the following paragraphs, the damage at gas wells is noted; the PGA levels are very approximate, factoring in attenuation functions; with the exception of one strong motion instrument in the town of Taft (PGA = 0.22g), there were no strong motion recordings in this earthquake.

The fields with the most noticeable effects of the earthquake were Tejon Hills (south of the fault, PGA ~0.3g), Kern River (northeast of Bakersfield, PGA ~ 0.15g) and Fruitvale (northwest of Bakersfield), PGA ~ 0.15g). In general, production variations consisted of a sharp rise in casing pressure, accompanied by a slight reduction in daily production of oil and water. Nearly all wells returned to normal production within a period of 2 to 3 weeks.

There was no evidence of actual fault movement detected in any of the wells, although there were a number of casing failures at shallow depths in the Tejon field.

At the Wheeler Ridge field (the field closest to the fault rupture, PGA ~ 0.4g), relatively little effect could be detected in any of the wells other than a slight settling of the sols at the well head, This ground slumping resulted in a great deal of pump trouble that was resolved with adjustment by mechanical means.

At the Tejon field (PGA ~ 0.3g), there was the greatest amount of damage to subsurface equipment. Several of the shallow wells were found with casing collapsed of tubing kinked. In 6 wells, the tubing could not be pulled and it was necessary to drill a new twin well in each case. Several of the wells showed an increase in pressure many times above normal in the first few days after the earthquake; there were instances where the casing pressure rose from 50 psi to 320 psi; from 30 psi to 300 psi; from 15 psi to 195 psi; the exact time at which the casing pressures reached their peak varied between wells; some showed highest reading 2 days after the earthquake; some 3 or 4 days after the earthquake. Within two weeks, the pressures declined slowly to about 20% below normal; followed by a long period of slow build up to normal. Variations in daily production of oil and gas were usually associated with variations in gas pressures. For example, in one small portion of the Tejon field, one well jumped from 20 barrels per day to 34 barrels per day, while a nearby well dropped from 54 barrels per day to 6 barrels per day. None of the wells with large production variations, or where casings collapsed, appeared to be associated with any fault rupture.

At the Kern River field (PGA ~ 0.15g), 150 wells were found to be sanded up. In spite of the amount of sand caving throughout the field, no wells were found to have casings collapsed or sheared. A temporary although slight increase in gas pressures was noted and accompanied by a minor drop in daily production. All wells returned to normal daily output over time.

At the Fruitvale field (PGA ~ 0.15g), there were large variations in gas pressures, although very few of the wells became sanded up. Several wells had casing pressures increase from about 150 psi to 800 psi, with a steady decline to below normal 2 weeks after the earthquake, then slowly rising to near normal 5 months after the earthquake.

At the Paloma, Greeley, Rio Bravo, Coles Levee and Trico fields (PGA ~0.1g to 0.2g), there were insignificant production changes. One casing collapsed at 9,000 feet depth at the South Coles Levee field; on pulling the casing, it was evident that the failure was largely due to previous corrosion and the earthquake merely caused final collapse. There were similar casing failures discovered where the pipe was found to have been corroded rather than sheared due to earth movement.

At the Midway-Sunset, South Belridge and Lost Hills fields (west side of San Joaquin Valley, as far north as Coalinga, PGA ~ 0.05g to 0.1g), numerous wells became sanded up as a result of the earthquake. Nearly all the wells returned to their previous normal capacity.

The oil and gas wells with the most fluctuations in pressure, bad sanding conditions, kinked tubing and casing collapse were those located in soft unconsolidated formations. None of the damage was associated with fault offsets at the surface or at depth.

6.3 Daly City M 5.7 1957

This earthquake occurred on March 22 1957 at 11:44 am local time. The epicenter of this earthquake was where the San Andreas fault goes offshore under the Pacific Ocean, southwest of Daly City.

The gas system had little damage in the 1957 earthquake. The available record indicates the following:

- There was a cracked weld on a 26-inch pipe near Alemany Blvd.
- There were two cast iron mains that were broken.
- In Hayward, there was gas leaking from a broken service line to a house.
- In Millsdale, San Jose, there was an overhead house line that broke at couplings; gas was turned off with no damage.
- There were 128 calls received by PG&E from customers about broken mains and services; in not all of these cases was PG&E able to find evidence of leaking gas.

6.4 Greenville M 5.8 1980

Two earthquakes occurred on the Greenville fault in January 1980:

- On January 24, 1980, 11 am local time, a M 5.8 (variously reported as M 5.5) occurred with epicenter about 12 km southeast of Mount Diablo, in the sparsely-populated hills north of Livermore. This event was followed within 2 minutes by M 5.2 and M 4.4 aftershocks. There was fault offset measured of about 1 to 2 cm.

- On January 26, 1980, 6:33 pm local time, a M 5.4 occurred with epicenter about 10 km northeast of the town of Livermore.

Both events occurred on the Greenville - Mount Diablo fault system. This is one of several active faults along the east side of the Coast Range. The largest historic earthquake along these faults was the M 6.8 event on April 19, 1892 in the Vacaville-Winters area.

There was damage in the town of Livermore. Interstate 580 near at Greenville Road near Altamont Pass was damaged due to about a foot of embankment settlement, and the highway was closed.

There were no leaks in PG&E's gas transmission or distribution systems reported near Livermore. However, California Division of Mines and Geology staff reported that "gas lines snapped" (1980).

Two of PG&E's gas compressor stations were shaken in these events. These stations are mounted on large concrete platforms supported on concrete piles, about 25 feet above the ground level. After the earthquakes, inspections revealed the only significant damage to be in the anchorage of a large hydrator tank where there was some spalling of concrete and elongated anchor bolts.

6.5 Coalinga M 6.3 1983

On May 2 1983, Monday 4:42 pm local time, a M 6.3 earthquake (variously reported up to M 6.5) occurred on a thrust fault southwest of Coalinga, California. There was about 0.5 meters of uplift, but no surface faulting was observed. On June 11 1983, an aftershock caused surface faulting about 12 km northwest of Coalinga. The earthquake triggered thousands of rock falls and rock slides as far as 34 km northwest and 14 km south of the epicenter (basically, in the hilly zones with PGA > 0.2g).

Prior the earthquake, there had been no knowledge of the causative fault. Since then, it has been recognized that there is a long belt of buried thrust faults along the western margin of the San Joaquin Valley, called the Great Valley sequence. Segment 13 is the segment that produced the 1983 earthquake.

The epicenter was about 15 km northeast of Coalinga. Coseismic uplift of as much as 45 cm was associated with the 1983 Coalinga earthquake.

The earthquake caused about $10 million in damage, injuring 94 people. Damage was severe in the town of Coalinga, where 1- and 2-story unreinforced brick buildings were heavily damaged or collapsed. 6 bridges had structural damage. The local water system was damaged, with many pipe leaks and breaks. There was temporary disruption of power service. There was various types of damage to the oil fields near Coalinga.

The population of the town of Coalinga was then about 7,000 people. The earthquake devastated the central business district, with many collapsed unreinforced masonry structures. Essentially all mobile homes in the community suffered significant damage, with many falling off their supports.

Gas System

PG&E delivers natural gas to Coalinga via its transmission system; the City of Coalinga owns and maintains the city-owned gas distribution system (LDC). Post-earthquake investigations reported that natural gas pipes in the LDC were damaged, and the gas system in Coalinga was shutoff for several days.

There here were no gas transmission pipe failures in the PG&E system.

Richard Bettinger and R. Knebel (EERI 1984) describe PG&E's efforts with respect to restoring gas service after the Coalinga earthquake, as follows:

- PG&E was requested by the City of Coalinga to provide assistance in restoring gas service after the earthquake.

- The City of Coalinga owned the gas distribution system. PG&E supplied gas at the southeast corner of the city. Inlet pressure to the PG&E regulator station was about 175 psi. Outlet pressure to the City distribution system was about 22 psi.

- The total length of pipe in the city system was about 24 miles, including 2, 3, 4 and 6-inch mains, of which 90% were steel and 10% were plastic. The oldest steel pipe dated to 1937, the newest plastic pipe to 1981. All steel pipe was cathodically protected.

- Gas pipes exposed at 35 locations during the restoration effort appeared to be in good condition, and there was no evidence of excessive corrosion. Steel pipe wrap (single and double) was observed to be in very good condition. There was no evidence of any disbanding or deterioration. Common depth of cover was between 2+ to 7 feet.

- Plastic pipe was Nipak TR 418.

- Service risers and meter sets in many cases were in alleys and were very exposed. More than 50% of the meter sets had old-style K regulators.

- Total number of customers was about 2,500.

- The Kettleman gas compressor station was about 20 miles southeast of the epicenter. The station operated throughout the earthquake. The only significant damage was failure of the telephone system, which led to loss of telemetering; minor sliding of piping relative to supports; falling of unanchored tabletop equipment and ceiling panels, cracking in single-story wood frame house walls.

- Coalinga-Nose Gas Dehydration Station. This station is located 3 miles southeast of the epicenter. It is a small dehydration station that had several tanks and a large heat exchanger. Several tanks slid on their pads. A tall odorant tank slid and was leaking, likely from a cracked pipe attachment. A few small unanchored tanks slid on their saddles. One pipe support bracket cracked at its bolt hole location. The heat exchanger on an unanchored skid slid. This station operated throughout the earthquake.

- Amador Gas Metering Station. This small station is about 3 miles east of the epicenter. It had one vertical tank with attached piping, and a small steel shed for instrumentation. The only damage was a small leak from a valve in an underground vault. The station was operating when inspected a day after the earthquake.

6.6 Morgan Hill M 6.2 1984

On April 24 1984, 1:15 pm local time, a M 6.2 earthquake occurred on the Calaveras fault, Central segment, east of Morgan Hill. The epicenter was near Mount Hamilton.

The rupture is estimated to have propagated over a 25 km section of the Calaveras fault. At Anderson Dam, there was an instrumental recording of PGA = 1.3g.

In Morgan Hill, a number of mobile homes slid off their foundations. In Santa Clara County, over 550 buildings were reported to have sustained at least minor damage.

Gas System

There was one transmission pipe leak reported on May 15 1984 near Watsonville, or 21 days after the earthquake. This leak might not have been (?) related to the earthquake.

6.7 Ridgemark M 5.6 1986

On January 26 1986, a M 5.6 earthquake occurred on the Calaveras fault. This event has been also variously called the Calaveras earthquake.

Gas System

There were no leaks reported in either the PG&E transmission or distribution system that could be attributed to this earthquake. It might be the case that the historic leak data is too sparse in order to provide reliable information about gas system leaks due to the 1986 Ridgemark earthquake.

6.8 Calaveras M 5.6 1986

On March 31 1986, a M 5.6 earthquake occurred on the Calaveras fault, Central segment.

Gas System

There were no transmission system pipe leaks reported. This is not to say that there were none; but just that the historic data is possibly incomplete for 1986.

There were about two dozen leaks in the PG&E distribution system in Salinas and Modesto in the weeks following the earthquake. The PGA levels in these communities might have been about PGA = 0.01g to 0.03g or so. The modest number of leaks in areas with small PGA levels (PGA ≤ 0.05g or so), suggests that the gas system at these levels of shaking have leak rates not significantly different from the background leak rate due to aging / corrosion and other non-seismic reasons.

6.9 Fort Tejon Ranch M 5.2 1988

This M 5.2 earthquake occurred on June 10, 1988. The epicenter was about 33 miles south-southeast of Bakersfield, possibly on the Garlock fault.

Gas System

This earthquake produced moderate levels of shaking along PG&E's Line 300A and 300B gas transmission mains. There were no leaks reported in the gas transmission system.

6.10 Loma Prieta M 6.9 1989

On October 17 1989, a M 6.9 earthquake (variously reported as M 7.0 or M 7.1) occurred near Mt. Loma Prieta. This earthquake was on a previously unknown thrust fault, just west of the San Andreas fault. The thrust motion was steeply inclined up towards the east, with a right lateral component.

There were many landslides record in the epicentral area. Liquefaction occurred as far away as San Francisco.

Figures 6.10-1 and 6.10-2 shows the gas transmission system (black lines), major and minor highways and county borders (light lines) and selected place names (green squares) in the San Francisco and Monterey Bay areas.

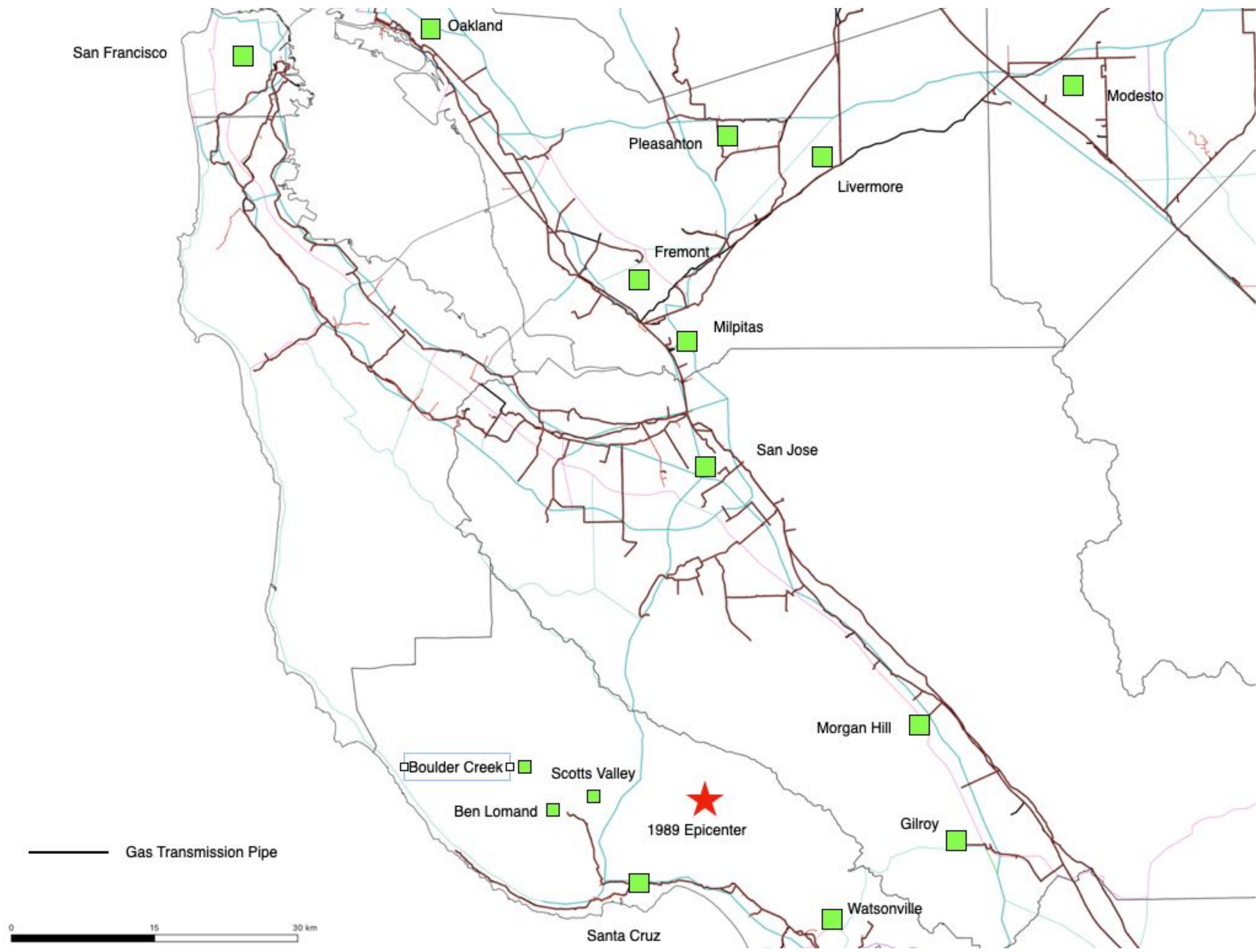


Figure 6.10-1. Loma Prieta, M 6.9, 1989 (San Francisco Bay Area)

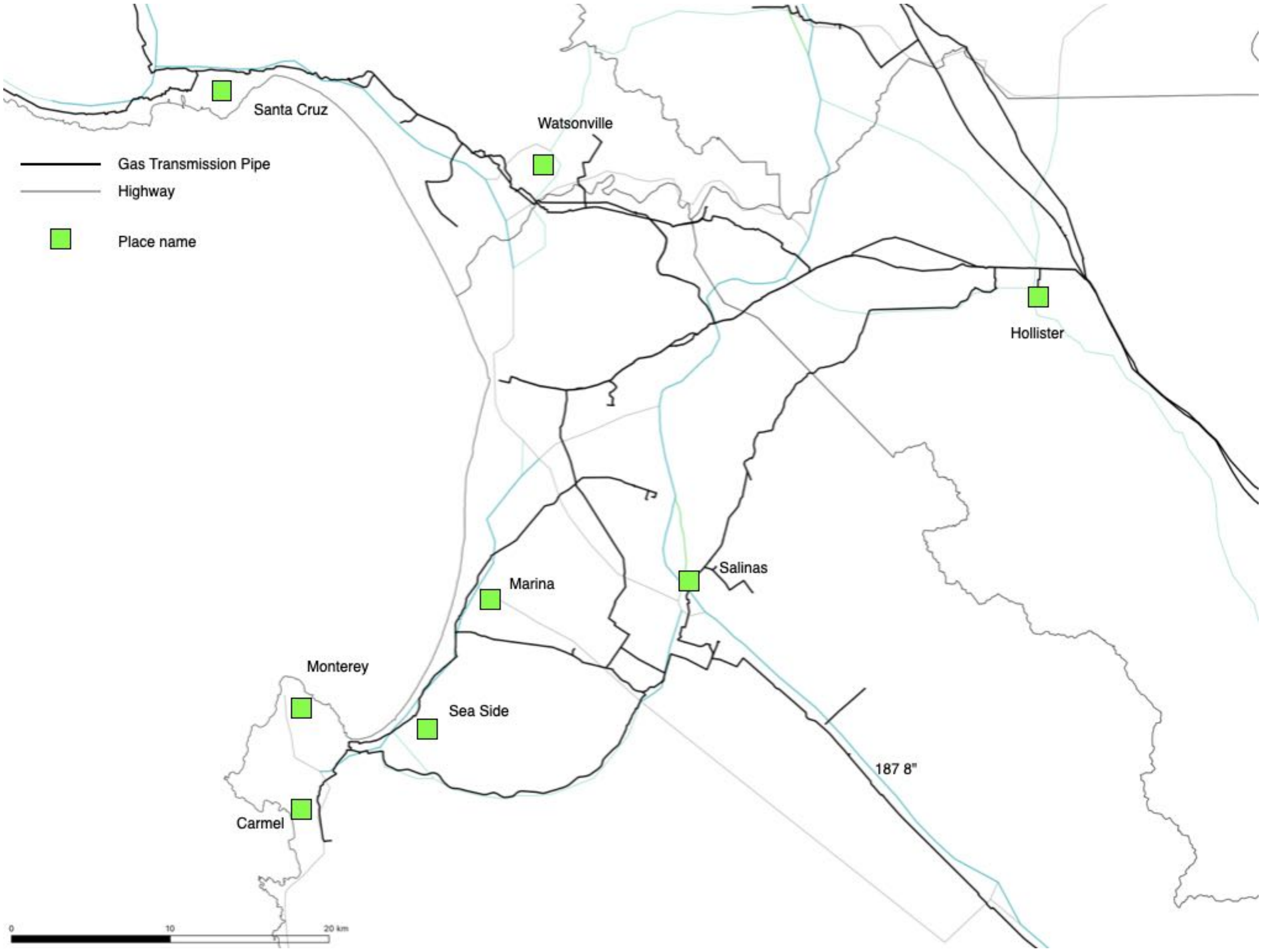


Figure 6.10-2. Loma Prieta, M 6.9, 1989 (Monterey Bay Area)

Gas System

Phillips (1990) and McDonough (1995) reported the following:

- The gas transmission system was virtually undamaged. There were no breaks reported in the PG&E gas transmission system following the earthquake.

- There were 2 leaks on a 6-inch (variously reported as 8-inch) steel distribution line in Hollister and a 8-inch (variously reported as 12-inch) steel line near Santa Cruz (built 1956). Both of these leaks were attributed to 1930-vintage oxy-acetylene welds; both pipes operated at about 60 psi. Both the leaks were repaired without affecting customer service. There was 1 leak off a 20-inch steel distribution line (60 psi) in Oakland, on 12th street; this pipe was installed in 1952; it may have been damaged due to ground deformations in the high liquefaction zone at the outlet of Lake Merritt.

- PG&E identified 156,355 customers who were without natural gas immediately after the earthquake. Most of these customers apparently shut off the valves at their gas meters, due to concern about possible gas leakage. The media initially broadcast messages urging people to do this. PG&E reported that the cost for re-lights after the earthquake was about $7 million. At the peak of the re-light effort, 1,183 servicemen were used, including those from SoCalGas, SDG&E, Mountain Fuel, Sierra Pacific, Northwest Natural Gas and Washington Natural Gas. This was accomplished in about 10 days.

- Over 20,000 leak calls were received within the first week after the earthquake. Many of these turned out to be false. In all, about 1,000 leaks were identified in the two week period following the earthquake, of which about 600 were identified as requiring immediate repair. Of these, about 87 were on distribution mains, one on a high pressure feeder main, and the remainder on service laterals to buildings.

- About 23% of the underground pipe leaks were identified as corrosion related, which may or may not have been initiated due to ground shaking. About 10% of the distribution main leaks and 12% of the service line leaks were on plastic pipe. About 11.4 miles of main (such as in the Marina area of San Francisco) and 1,700 service lines were replaced as part of the restoration.

- PG&E was able to restore gas service to nearly all areas (except the Marina District) within 10 days after the earthquake.

The number of earthquake-related repairs in the gas distribution system is estimated to be about the following:

  - Hollister. 35 - 45. This included a leak on a 12-inch steel pipe.
  - Santa Cruz. 90 - 100. This included a leak on a 8-inch steel pipe.
  - Watsonville. 30 - 40.
  - Oakland. 60 - 80. This included a leak on a 20-inch steel pipe.
  - Sacramento. 5 - 15.
  - San Francisco. 300 - 315.
  - Fremont. 5 - 10.
  - Modesto 5 - 10.
  - Total ~ 600 (variously reported as up to 1,000, systemwide)

Even in cities relatively distant from the epicenter, there were leaks in the distribution system.

Some of the leaks were due to earthquake effects (shaking, liquefaction, landslide), but most were likely due to aging, quality of construction or related issues. In either case, the leaking pipes were repaired, so they are counted as earthquake-related damage.

North of Santa Cruz, there were many landslides in the hilly areas around the small communities of Scotts Valley, Ben Lomand, Boulder Creek. The above repair data do not cover these areas; many people in more remote communities use propane and are not otherwise attached to the natural gas distribution system grid.

The estimated breakdown in the leaks in the distribution system is 30 - 40% occurring in the distribution main, 35 - 45% in the buried service laterals, and 20 - 30% in the riser pipes / meter sets. At the time of the earthquake, it is estimated that about 70% of distribution mains were steel and 30% of distribution pipe was plastic. Leaks on distribution mains were about 85% - 90% steel, and 5% - 15% plastic, and 2 - 5% (cast iron / copper).

After the earthquake, USGS published a report on the performance of the built environment (Honegger 1991). Figure 6.10-3 shows a map of 302 leaks in San Francisco. The boxes represent plats, and are about 1,700 feet long (north-south) and 1,100 feet wide (east-west).

- After the earthquake, PG&E elected to replace all the distribution gas pipe in the Marina District. This was done as an abundance of caution, and not only because there were gas leaks in that area. In modern thinking, this can be considered similar to the decision to replace non-leaking gas transmission pipes where they sustained fault offset (as done in Napa 2014, Ridgecrest 2019), reflecting that the liquefaction that occurred in the Marina District likely imposed stresses into the then-existing gas distribution pipes. Therefore, PG&E elected to do replacement of the old pipes with new pipes.

- The replacement process in the Marina District was done by inserting new plastic lines inside existing old low-pressure steel and cast iron pipes. The new plastic pipe operate at higher pressure than the original steel or cast iron pipes. The replaced pipes served 5,100 customers in the Marina District. On a smaller scale, similar replacements were done in Watsonville (serving 166 customers) and Los Gatos (serving 140 customers). The cost of these efforts was about $19 million.

- The leak data reported in Figure 6.10-3 was based on paper maps for the period October 17 – 31 1989, and reflect only leaks with noticeable odor. The 302 leaks in San Francisco reported in Figure 6.10-3 included:

    - 31 repairs to mains (3 steel, 27 cast iron, 1 plastic)

    - 271 repairs to service laterals (241 steel, 10 plastic, 20 copper)

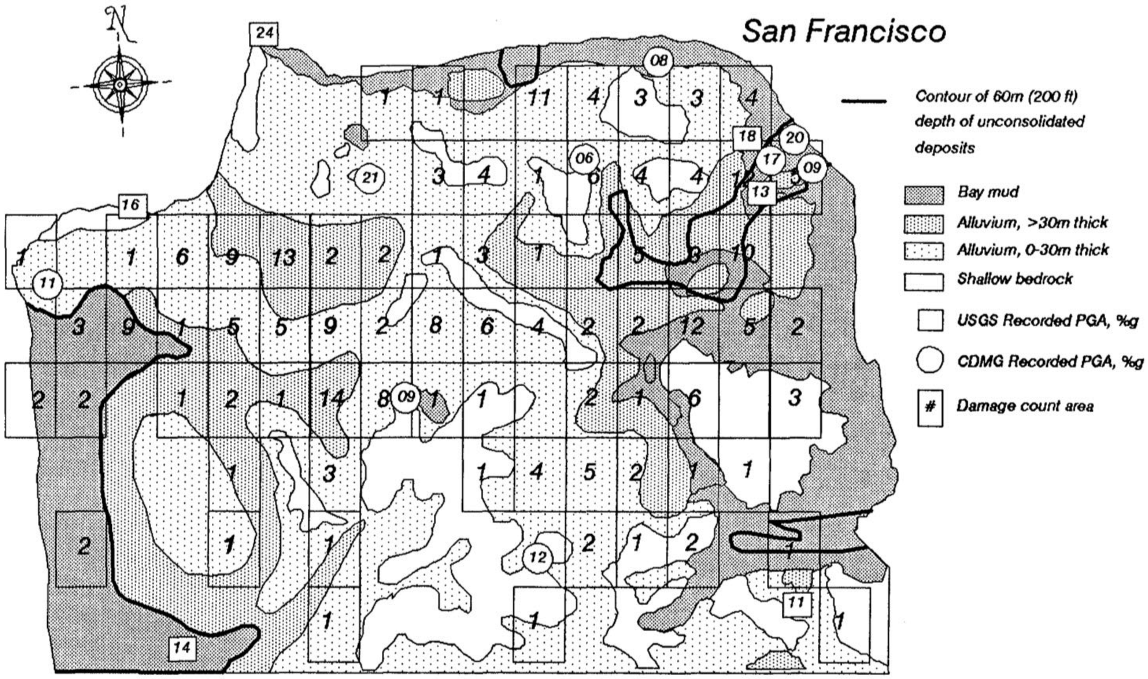


Figure 6.10-3. Location of Leak Repairs in Northern San Francisco

Notes for Figure 6.10-3: Horizontal PGA is shown in circles as percent g; the number of repairs in each plat box is shown in bold numbers; surface geology per CDMG. Map is after (Honegger 1991).

Table 6.10-1 provides a breakdown of the 302 leaks in San Francisco by material and by type of repair.

Table 6.10-1. Summary of Repairs in San Francisco

Type of Repair	Steel	Cast Iron	Copper	Plastic	Total	Pct Total
Bell joint damage	1	19	0	0	20	6.62
Weld damage	1	0	0	0	1	0.33
Replace pipe section	1	0	0	1	2	0.66
New clamp	5	5	0	0	10	3.31
Tighten clamp	94	2	8	3	107	35.43
Tighten pipe joint	45	0	0	0	45	14.90
Pipe-body damage	1	0	0	0	1	0.33
Other (permanent)	21	1	2	6	30	9.93
Other (temporary)	75	0	10	1	86	28.48
Total	244	27	20	11	292	
Percentage	80.79	8.94	6.62	3.64		

About 90% of the leaks in Figure 6.10-3 were on service laterals and about 10% on distribution mains.

- Most of the damage to distribution mains were to cast iron pipes (27 of 31 repairs, 87%), using bell-and-spigot joints.

- Much of the damage to service lines were to steel pipes, with most requiring only minor repair, like tightening of bolts, clamps, pipe joints (57%)

- Many of the other repairs reflect adjustments to the above ground steel riser pipe to the meter. This often involves tightening or adding pipe dope to make the pipe leak-tight.

6.11 Cape Mendocino M 7.2 1992

The Cape Mendocino earthquake sequence included three events. The largest event was a M 7.2 on April 25, 1999; followed by two M 6.5 and 6.6 events on April 26 1999. The sequence includes both interplate and intraplate activity associated with the Mendocino Triple Junction, the convergence of the Cascadia Subduction Zone, San Andreas Fault and the Mendocino Fracture Zone the converge near Cape Mendocino.

The largest nearby population center is Eureka, about 27,000 people, about 50 km to the north of the epicenters.

Population exposed to PGA > 0.3g was likely under 10,000 people, mostly in Fortuna, Rio Dell, Scotia, Petrolia, Ferndale.

These earthquakes triggered numerous landslides and caused widespread liquefaction in the Eel River Valley.

The M 7.2 event caused a number of wood frame houses to fall off their foundations in Scotia. In Rio Dell, across the Eel River from Scotia, glass store fronts along the main street were shattered. A power plant at a local lumber mill was damaged. Two lumber mills shut down for weeks.

Gas System

Figure 6.11-1 shows the gas transmission system near Eureka and Fortuna. Black lines represent gas transmission pipes and grey lines show the principal highways in the area. Green squares represent the larger population areas. The red star is the location of the April 25 1992 epicenter. A 12-inch transmission main delivers gas to the entire area.

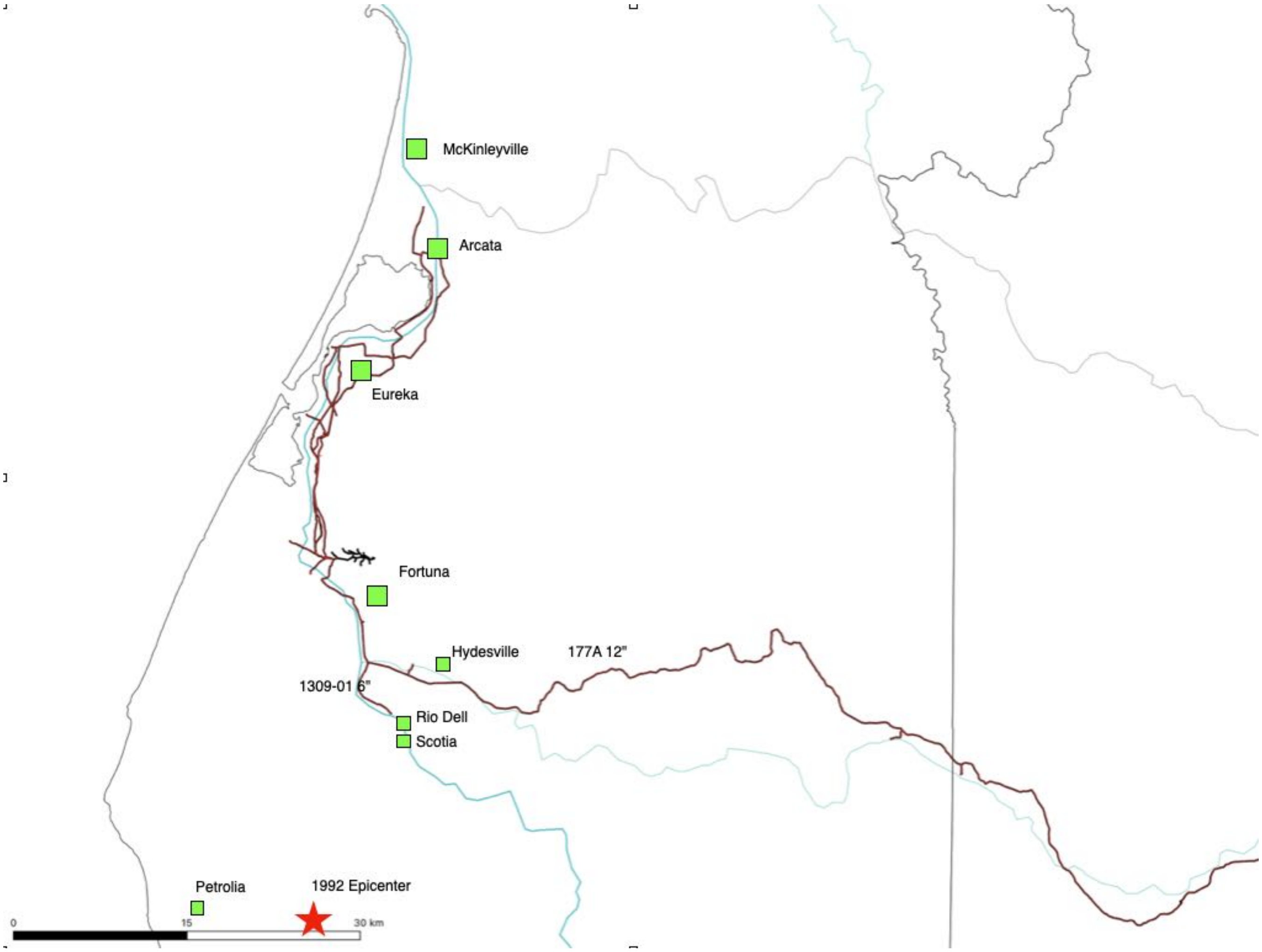


Figure 6.11-1. Gas System near Eureka, Fortuna

There were no reported leaks in the gas transmission system in the vicinity of Eureka / Eel River in 1992. This is not to say that there were no leaks, as the reporting of leaks in 1992 is perhaps incomplete.

The level of shaking in Eureka was modest, with PGA ~ 0.2g. In the 2010 Eureka earthquake, there were many leaks in the gas distribution near Eureka, see Section 6.16.

Overall, given the style of pipes and level of shaking, it is likely that there were some gas leaks in / near Fortuna / Hydesville / Rio Dell / Scotia in the 1992 earthquake. However, the leak data is not presently known.

6.12 Salinas M 5.1 1998

On August 12 1998, a M 5.1 earthquake occurred near Salinas.

Figure 6.12-1 shows the gas transmission and distribution systems near Salinas. Black lines represent gas transmission pipes. Green squares represent the larger population areas. The red star is the location of the August 12 1998 epicenter. Grey lines show major highways in the area.

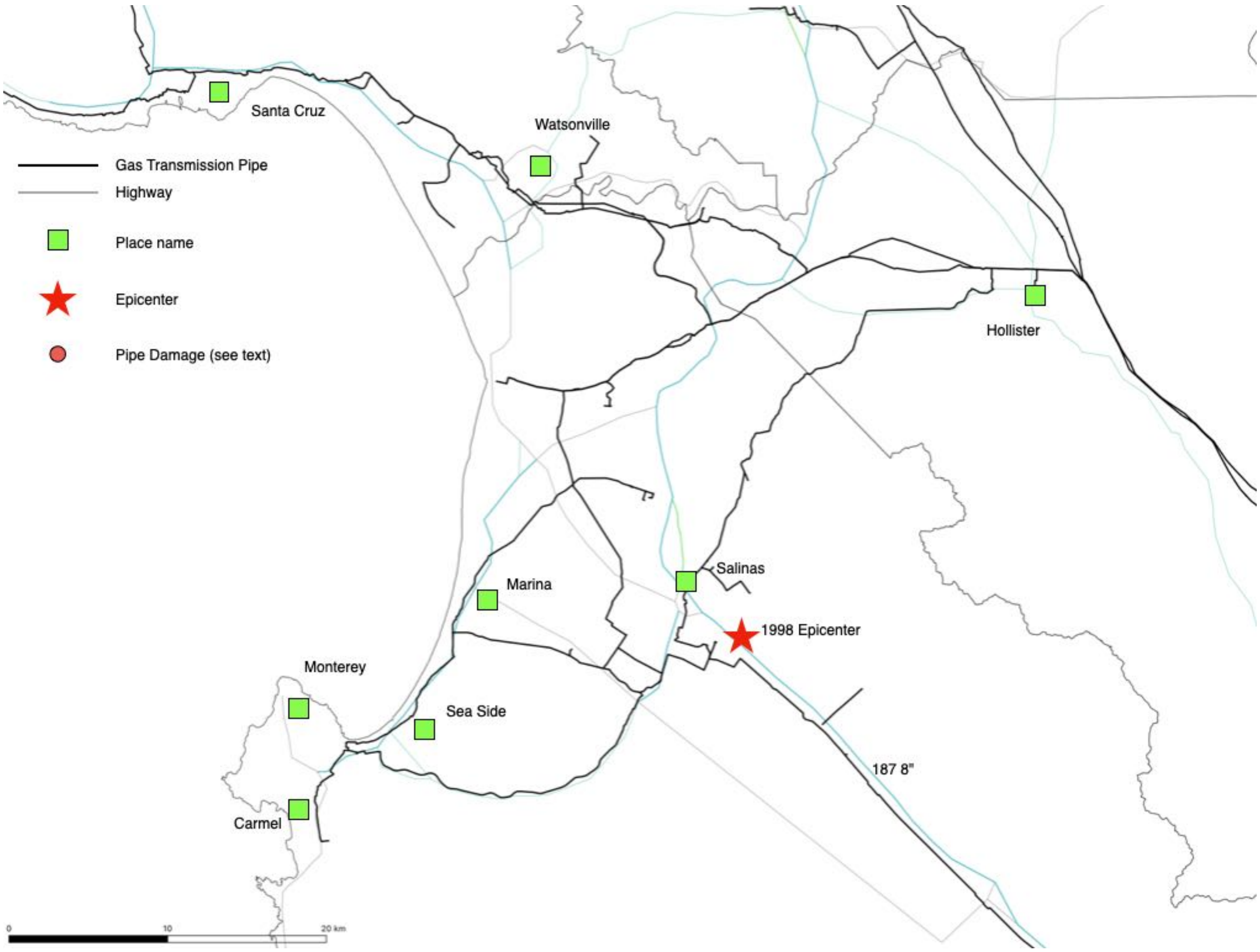


Figure 6.12-1. Gas Transmission and Distribution System Near Salinas

Gas System

There was 1 reported leak in the gas transmission system in the vicinity of Salinas. This occurred more than 3 weeks after the earthquake, near the red dot shown in Figure 6.12-1. The leak was on Line 187 (8-inch steel pipe), and the cause was described as TPD (Third Party Damage).

Given the delay in reporting the leak, and the modest level of shaking in the area, and the leak cause, this leak was most likely not caused by the earthquake.

There were likely a few leaks in the distribution pipes in the area, possibly concentrated in the communities around Monterey Bay (Salinas, Sea Side, Carmel, Watsonville, Santa Cruz, Hollister). The PGA levels in these communities were about PGA = 0.02g to 0.07g or so.

6.13 Yountville M 5.0 2000

On September 3 2000, a M 5.0 earthquake occurred near Yountville. The epicenter was northwest of Napa.

Figure 6.13-1 shows the gas system near Yountville. The gas transmission pipes are shown in black.

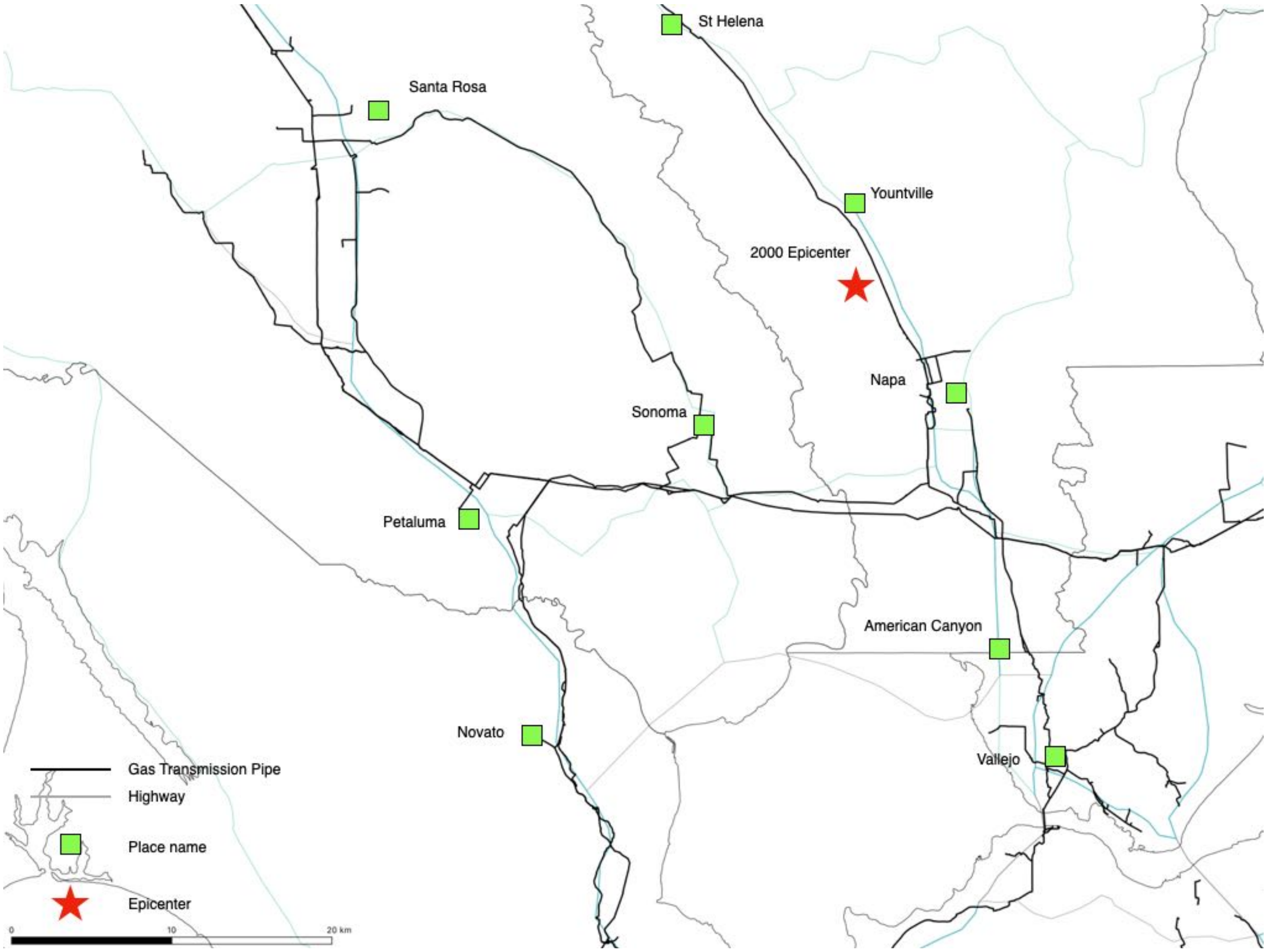


Figure 6.13-1. Yountville Earthquake, M 5.0, 2000

Gas System

There may have been a few leaks in the gas distribution system leaks on or soon after September 3 2000 near Yountville as well as northwest portion of Napa, but the repair record for this earthquake is incomplete. For example, there were about 23 potable water pipe repairs in the City of Napa water system, and there was also damage to sewer pipes in the Napa.

6.14 San Simeon M 6.5 2003

The San Simeon M 6.5 earthquake of December 22, 2003 occurred at 11:16 am local time, on a previously unmapped fault (blind thrust), just north of the town of San Simeon, in central California.

Gas System

Figure 6.14-1 shows the gas transmission and distribution system in the area. PG&E owns the Line 306 20-inch transmission pipe (black) to the gas-fired power plant at Morro Bay (green "lightning" symbol). SoCalGas owns most of the gas pipelines (green) in the area. The green lines includes distribution pipes that operate at higher than 60 psi.

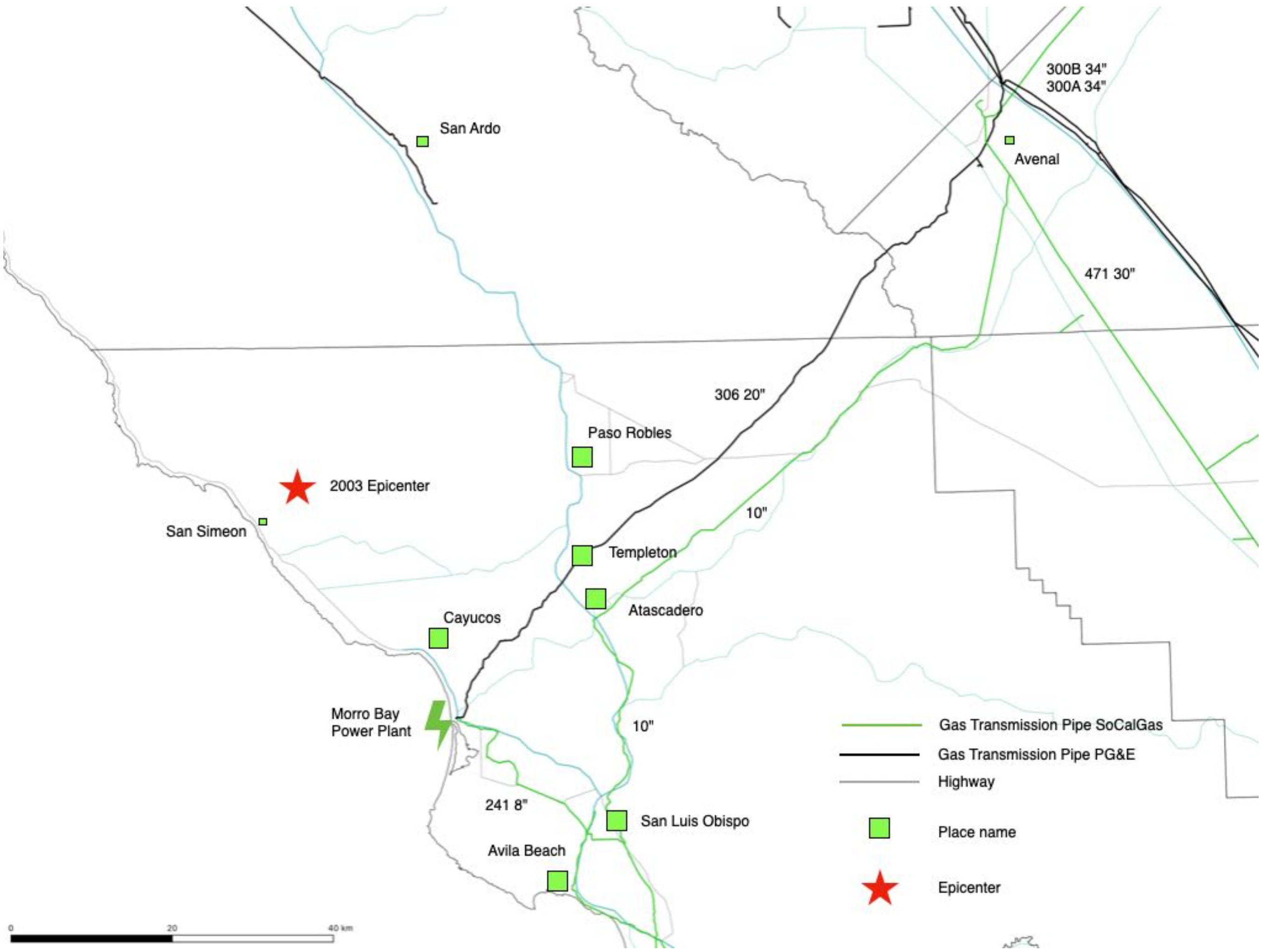


Figure 6.14-1. San Simeon Earthquake, M 6.5, 2003

There were no reported gas leaks in the PG&E gas transmission system in this area after the earthquake.

There was minor damage to SoCalGas. About 500 customers suffered one to two day gas outages, with all reported damage taking place downstream of the customer's meters (so-called "in-house" damage). No SoCalGas transmission pipes were damaged.

The San Ardo oil field experienced light levels of ground shaking in this earthquake. In 2003, the oil field was producing about 12,000 barrels of oil per day. There was no reported damage to any oil or gas drilling production facilities. The field included more than 20 at-grade welded steel tanks with capacity of more than 400,000 gallons; none were reported to have leaked or suffered any damage.

Oil from this field used to be transported to the Estero Marine Terminal located between Cayucos and the Morro Bay power plant (taken out of service 1999) via three pipelines (these pipes are not shown in Figure 6.14-1). The pipeline alignment traversed the areas with the highest levels of shaking (PGA > 0.4g). Prior to the time of the earthquake, all three pipelines had been taken out of service, but were being maintained and pressurized with nitrogen (for corrosion control) at 15 to 20 psi. The pipes were 4-inch, 6-inch and 10/12-inch diameter butt welded steel pipelines, typically buried with two or three feet of cover. Immediately after the earthquake, the alignment was overflown, with no observation of damage or landslide across these pipes. Nitrogen pressure was maintained, suggesting no leaks.

6.15 Alum Rock M 5.6 2007

On October 30, 2007, 8:04 pm local time, a M 5.6 occurred with epicenter on the Calaveras fault. The rupture direction was towards the southeast, extending about 5 km.

Figure 6.15-1 shows the gas system in the vicinity of the earthquake. The red star is the epicenter. The green boxes denote major place names. The black lines are the gas transmission pipes.

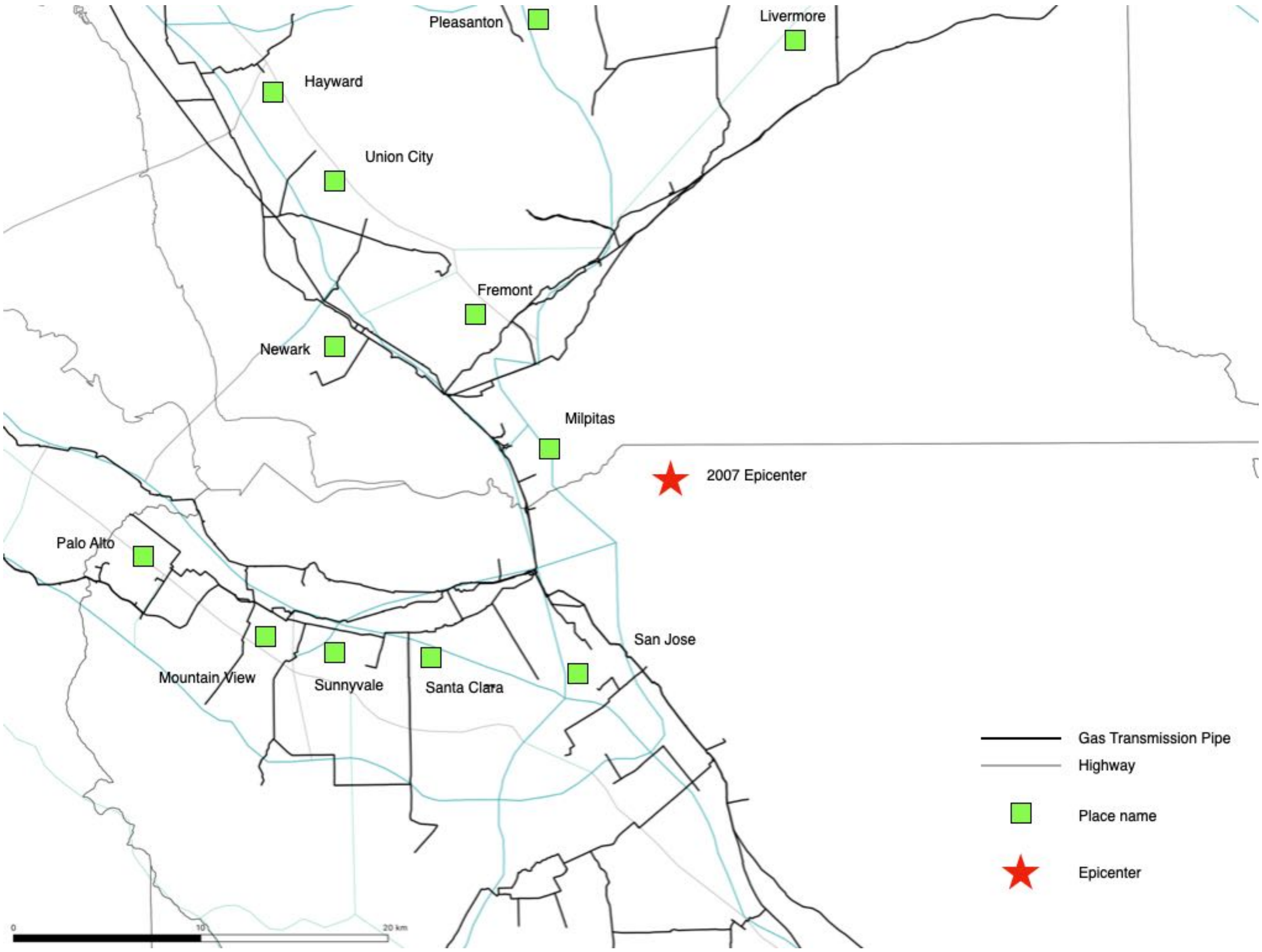


Figure 6.15-1. Alum Rock Earthquake, M 5.6, 2007

Gas System

There was one leak in the gas transmission system on the day following the earthquake. The leak occurred near Mountain View. The level of shaking was low at this location, possibly in the range of PGA = 0.02g to 0.08g.

A review of available information suggests that there were few leaks in the distribution system due to the earthquake. It cannot be distinguished if these leaks were "earthquake related" or "day-to-day corrosion related".

6.16 Eureka M 6.5 2010

On January 9 2010, at 4:27 pm local time, a M 6.5 earthquake occurred under the Pacific Ocean, about 53 km west of Eureka. This was followed by a M 5.9 aftershock on February 4 2010. This was the most significant earthquake near Eureka since the 1992 Cape Mendocino earthquake.

Figure 6.16-1 shows the gas transmission system near Eureka and Fortuna. Black lines represent gas transmission pipes. Green squares represent the larger population areas. The red star is the approximate location of the January 9 2010 epicenter. Grey lines show major highways in the area.

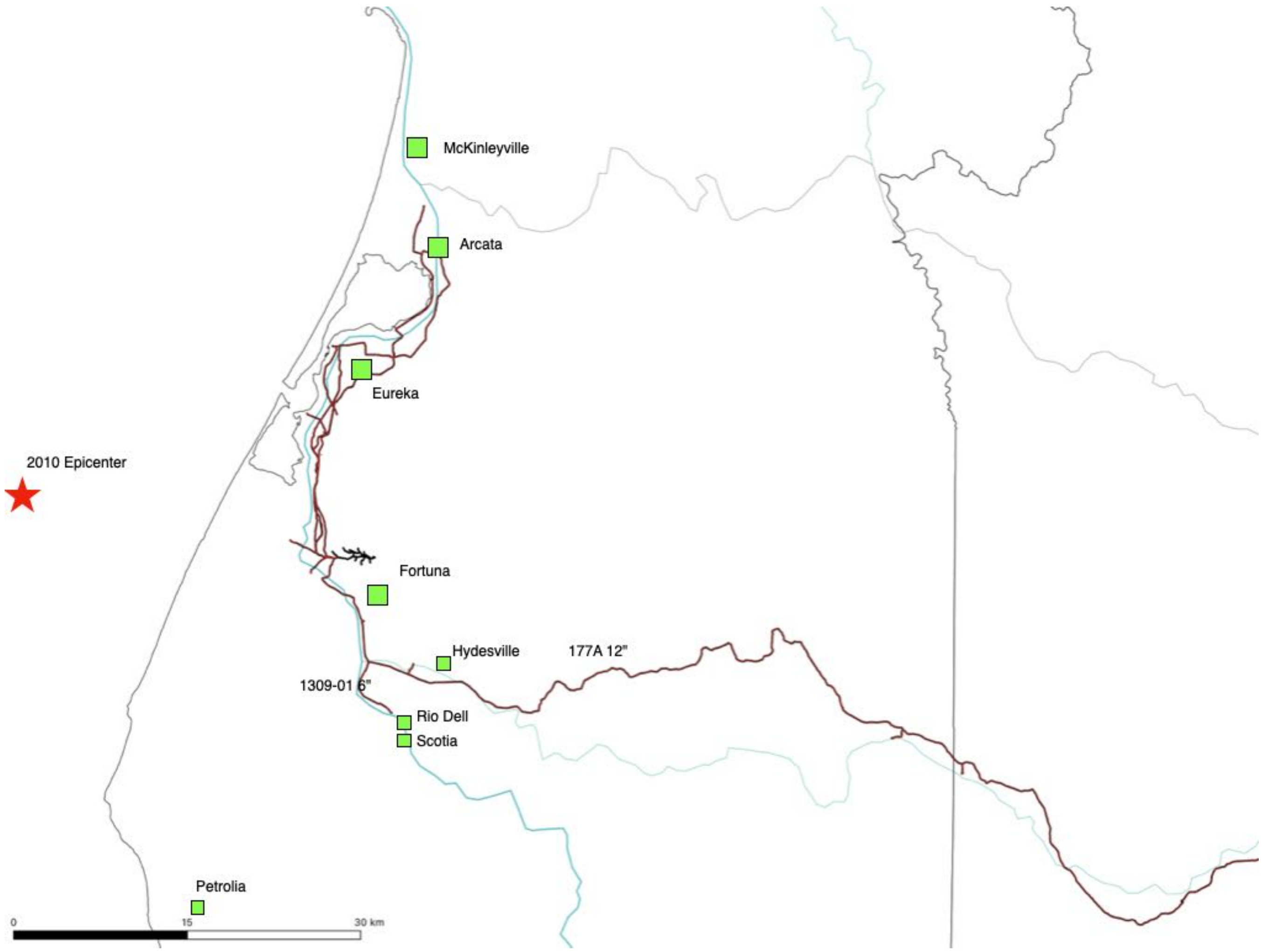


Figure 6.16-1. Gas System near Eureka

Structural damage occurred to a variety of buildings in Eureka.

Gas System

There was one leak reported in the gas transmission system on the day after the earthquake. The leak occurred in Eureka. The level of shaking was moderate at this location, possibly in the range of PGA = 0.20g to 0.30g; the soils in the area are not mapped as being susceptible to liquefaction.

There were about 280 leaks reported in the distribution system near Eureka in the week following the earthquake. Of these, about 60 - 65% were on riser pipes; 20 - 30% on below ground service laterals, and 10 - 15% on distribution mains.

At the time of the earthquake, the distribution system mains were about 60% steel and 40% plastic, while the damage to the distribution mains were 85% steel and 15% plastic.

6.17 Napa M 6.0 2014

On August 23, 2014, a M 6.0 occurred with epicenter on the West Napa fault. The rupture direction was northerly. Surface faulting of 3 to 9 inches was observed along the fault trace. There was liquefaction in some high-water table areas in Napa.

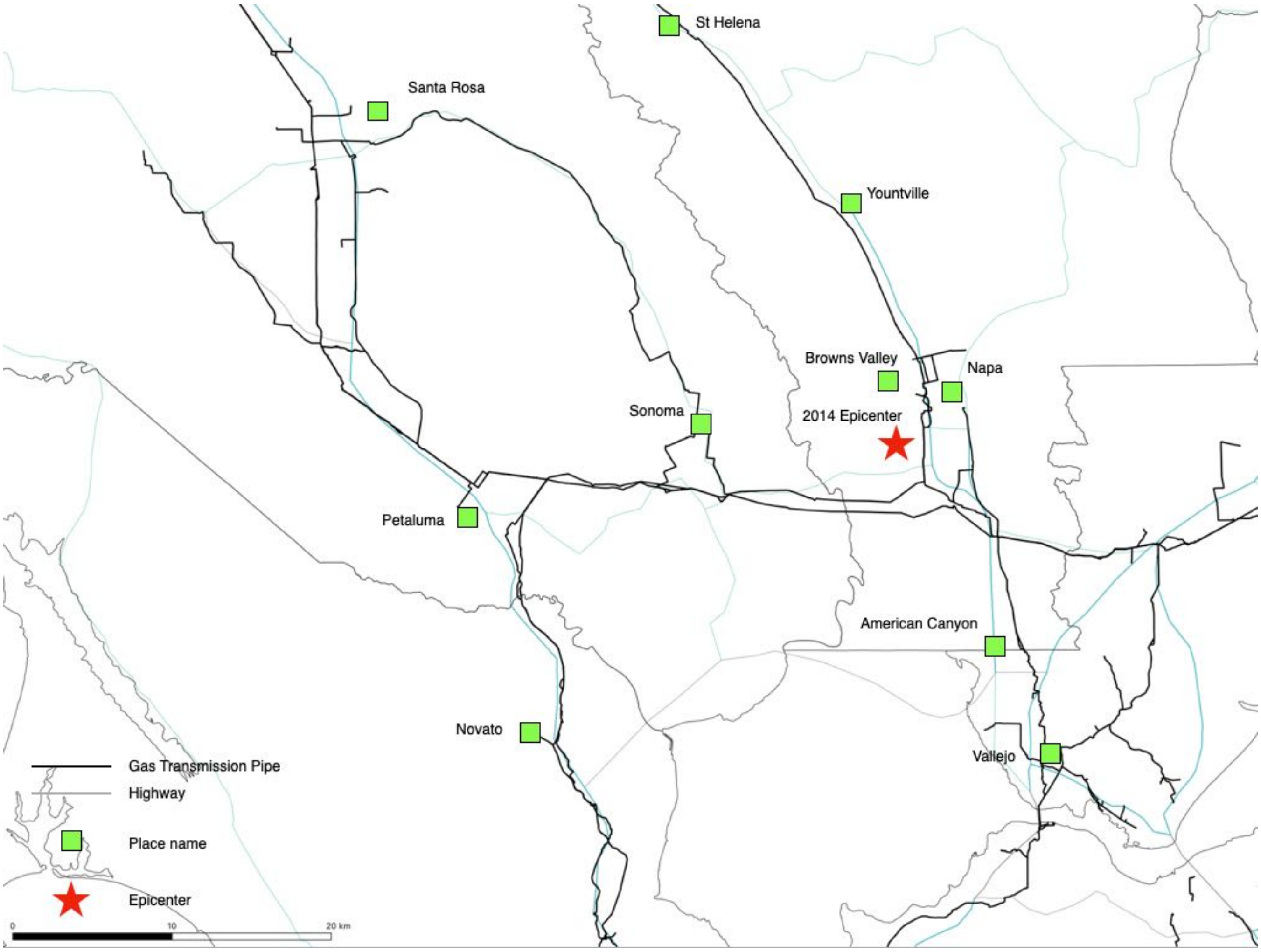


Figure 6.17-1. Gas System near Napa

Gas System

There were no leaks in the gas transmission system shown in Figure 6.17-1.

There were about 390 leaks in the distribution system, including about 180 in Napa, 110 in American Canyon, 90 in Vallejo and fewer than 10 in Sonoma. These leaks were on distribution mains (10 - 15% of total), buried service laterals (20 - 25%), and risers (60 - 70%). All the leaks to distribution mains were on steel pipe; at the time of the earthquake, steel pipe represented about 45% of all distribution pipe; the bulk of the remainder being plastic pipe.

Many of the leaks were in the downtown Napa area, as well as in the Browns Valley area. Some of the leaks in the residential areas west of downtown Napa and east of Browns Valley are attributed to liquefaction, based on reconnaissance in areas with water table at or within a foot of the surface; coupled with various cracks in pavements, coupled with high concentration of damage to cast iron water pipes.

Some of the leaks in the Browns Valley area might be attributed to surface faulting. The amount of surface faulting in the Browns Valley area was commonly between 5 and 9 inches of right lateral offset, including co-seismic and after slip. The level of shaking in the Browns Valley area was PGV ~ 30 to 35 cm/sec. None of the leaks in the Browns Valley area are attributed to liquefaction.

As a precautionary measure, within a few months after the earthquake, PG&E replaced Aldyl-type plastic distribution pipes in the Browns Valley area with new plastic pipes where these pipes might have been stressed by fault offset.

Most of the leaks in the American Canyon area were on service laterals that had a history of leaks prior to the earthquake. PGVs in this area were about 24 cm/sec.

Figure 6.17-2. Napa Earthquake, Pipes at Crossing Zones – South Napa

In Figure 6.17-2, two transmission pipes (Lines 021A and 021B) crossed the West Napa fault that had surface rupture in the 2014 earthquake. In this map, the surface fault trace (red line) was observed to initially (within one day) to have about 2 to 3 inches of right lateral offset, and post-event after slip (within a week) about doubled the amount of offset. Neither of these transmission pipes leaked gas after the earthquake. As a precautionary measure, within a few weeks after the earthquake, PG&E replaced both of these steel transmission pipes with new unstressed steel pipes.

6.18 Ridgecrest M 6.4 and M 7.1 2019

On July 4 2019, a M 6.4 earthquake occurred in the Ridgecrest area at 10:33 am local time. This earthquake resulted in surface faulting along several previously unmapped northeast-to-southwest trending fault traces; surface faulting was primarily left lateral offset.

On July 5 2019, a M 7.1 earthquake occurred in the Ridgecrest area at 8:19 pm local time. This earthquake resulted in surface faulting along previously unmapped northwest-to-southeast trending fault traces; surface faulting was primarily right lateral offset.

This earthquake sequence also produce a large number of aftershocks, including a few in the M 4.9 to 5.7 range. These aftershocks did not produce new surface fault offsets. For the most part, over several days after the initial M 6.4 and M 7.1 events, there did not appear to be any post-event creep / after slip along the surface at places where the initial M 6.4 and M 7.1 shocks produced surface faulting.

Prior to this earthquake sequence, there were many faults mapped in the general area around Ridgecrest. There were dozens of mapped faults, including a few that had historic surface rupture in the early 1980s. Few of these mapped traces generally coincided with the actual locations of surface rupture in either the M 6.4 or M 7.1 events.

Overall, it is now generally recognized that the actual earthquakes occurred on previously unmapped faults. Over the past three decades, this trend has been repeated several times, where actual earthquakes trigger rupture on multiple fault traces (examples: Landers 1992, Hector Mines 1999, Denali 2002, Laguna Salada 2010, Napa 2014, Ridgecrest 2019) rather than on a single mapped fault trace. This implies that the location of surface fault offset cannot be definitively defined only upon the historical-earthquake or paleo-earthquake record. This implies that for design of buried pipes for fault offset, a prudent strategy might be to install pipe that is capable of sustaining PGDs due to fault offset and/or liquefaction and/or landslide at any location mapped as having potential infirm ground conditions, with more special design details (such as specialized backfills, extra heavy walls, pipe-soil controlled friction; pipe-fault alignment angles, pipe appurtenances) included where the hazard is highest and well defined.

The M 6.4 event caused limited non-structural damage to PG&E's gas system customer service center in Ridgecrest. The M 7.1 event resulted in additional non-structural damage (fallen ceiling tiles). This damage was repaired by July 6.

Gas System – Transmission Pipes

The following highlights the response to PG&E's gas transmission pipes in the area.

Figure 6.18-1 shows a map with PG&E's gas transmission pipes in the vicinity of the Ridgecrest earthquakes. In Figure 6.18-1, the surface faulting of interest for the July 4 M 6.4 event is highlighted as a blue line, striking NE to SW; and the surface faulting for the July 5 M 7.1 event is highlighted as a red line, striking NW to SE. Other mapped faults in the area are highlighted as thin red or orange (Holocene active) or green (last 130,000 years) or blue (last 1,600,000 years) lines. Gas transmission pipes are shows as heavy black lines (Lines 300A, 300B, both 34-inch), or thin black lines (10-inch, 6-inch).

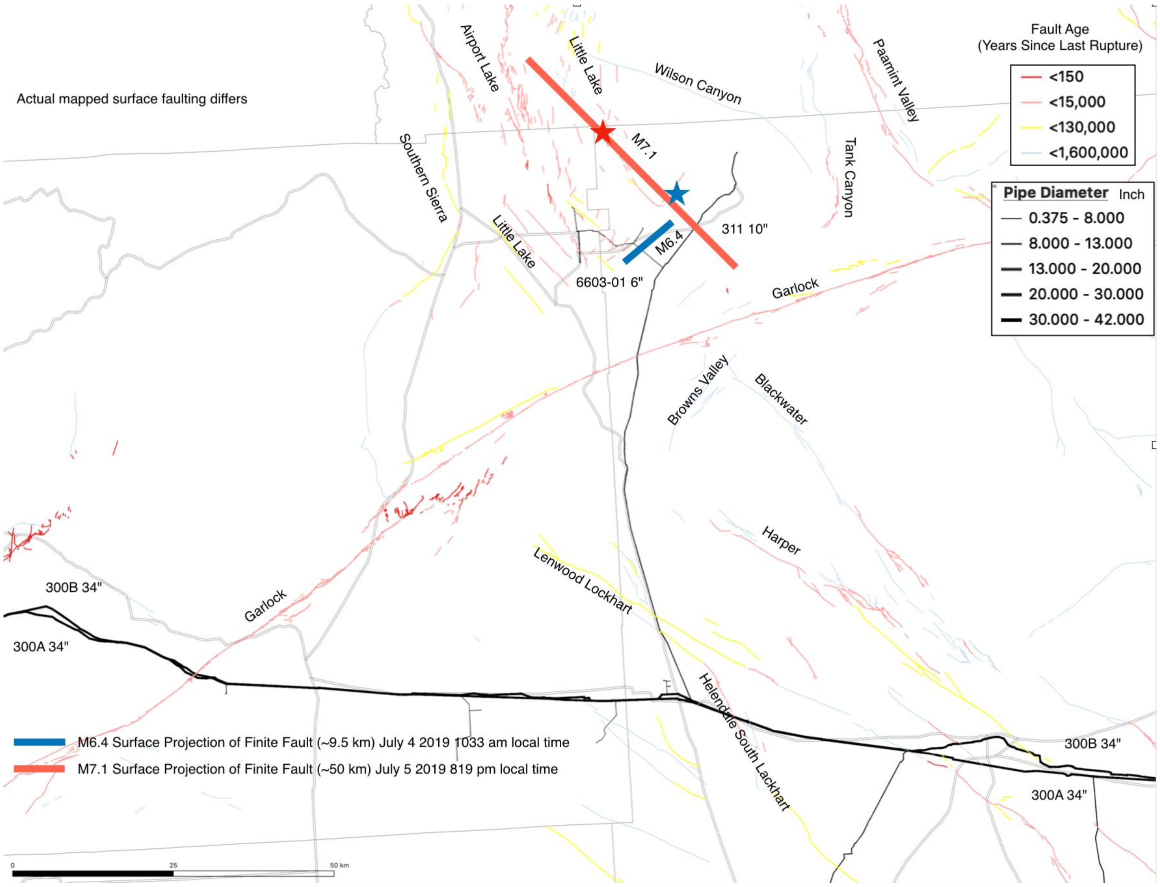


Figure 6.18-1. Ridgecrest Earthquakes – Gas Transmission Pipes

Gas leak surveys were performed along gas transmission pipelines. Pressure and leak testing confirmed that the M 6.4 rupture did not result in a leak along the 6-inch gas transmission pipeline at the surface faulting location. Pressure and leak testing after the M 7.1 event confirmed there was still no leaks at the 6-inch pipe crossing of the M 6.4 fault, and similarly no leaks of the 10-inch pipe at the M 7.1 fault offset location.

Both lines 311 (10-inch) and 372 (6-inch) crossed traces of the events with surface faulting. The style of surface offset at each of the two locations was:

- July 4 M 6.4 event. Left lateral offset at line 372. The pipe crossed the fault at nearly right angles, and the offset produced primarily high bending in the pipe. The width of the fault offset zone can be described as "wide".

- July 5 M 7.1 event. Right lateral offset at line 311. The width of the fault offset zone can be described as "narrow".

A distribution main under Argus Avenue (just southwest of Trona) was observed to traverse an area that had ground cracking due to liquefaction. This distribution main was excavated and observed to be in good condition.

Figures 6.18-2 and 6.18-3 show aerial photos of the two fault crossing locations. The Searles 12-inch water pipe broke at the fault crossing in Figure 6.18-2 in the M 7.1 event.

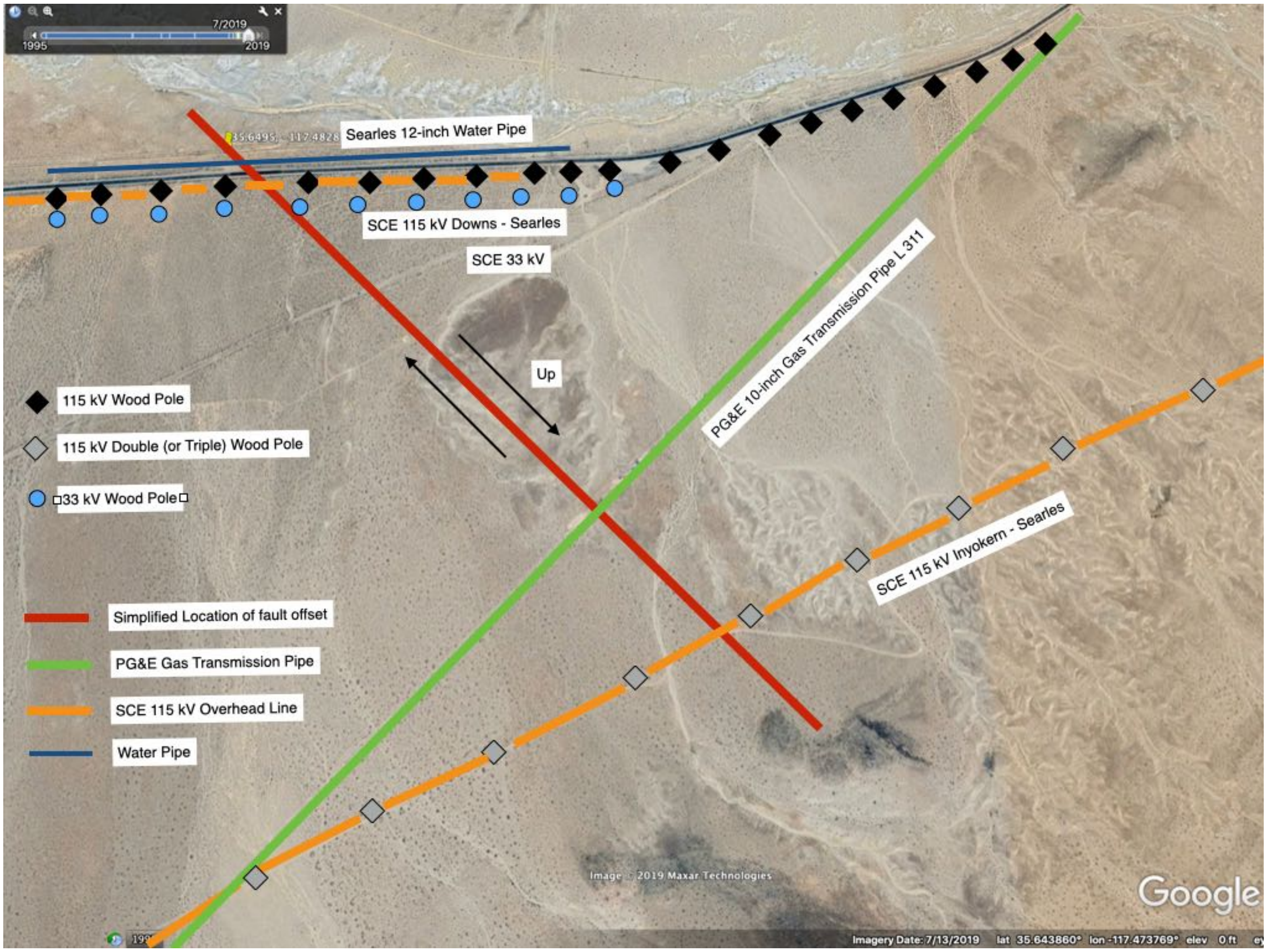


Figure 6.18-2. M 7.1 Offset Location Showing Line 311 and Nearby Lifelines

Figure 6.18-3. M 6.4 Offset Location Showing Line 372

Within a week after the earthquakes, PG&E crews dug trenches along the two transmission pipes at the crossing zones, with the intention to observe the condition of the pipes, as well as to replace the stressed pipes with new unstressed pipes. Figure 6.18-4 shows Line 311. Figure 6.18-5 shows Line 372. At the stage of excavation shown in these figures, the pipes are still mostly buried. Lines 311 (10.75" OD) and 372 (6.625" OD) were both replaced where each crossed the faults.

Figure 6.18-4. Line 311 after Trench and Pipe were Partially Exposed (Courtesy PG&E)

Figure 6.18-5. Line 372 after Trench and Pipe were Partially Exposed (Courtesy PG&E)

The level of Shaking in Ridgecrest and Trona areas due to the M 7.1 event were about horizontal PGA = 0.25g to 0.40g and horizontal PGV = 30 to 85 cm/sec, see Figures 6.18-6 and 6.18-7. The motions in these maps were developed using average of five 2013-vintage GMPE models (Abrahamson et al 2013, Boore et al 2013, Campbell et all 2013, Chiou et al 2013 and Idriss 2013). At locations where Vs30 < 450 m/sec, the Idriss GMPE is excluded. The gas transmission lines are colored coded by diameter. The red line in Figure 6.18-4 corresponds to the approximate location of observed surface rupture in the M 7.1 event. The motions in Figures 6.18-6 and 6.18-7 are medians actual motions at any specific location can vary at least ±50% from the medians at the 16th to 84th percentile not to exceed levels.

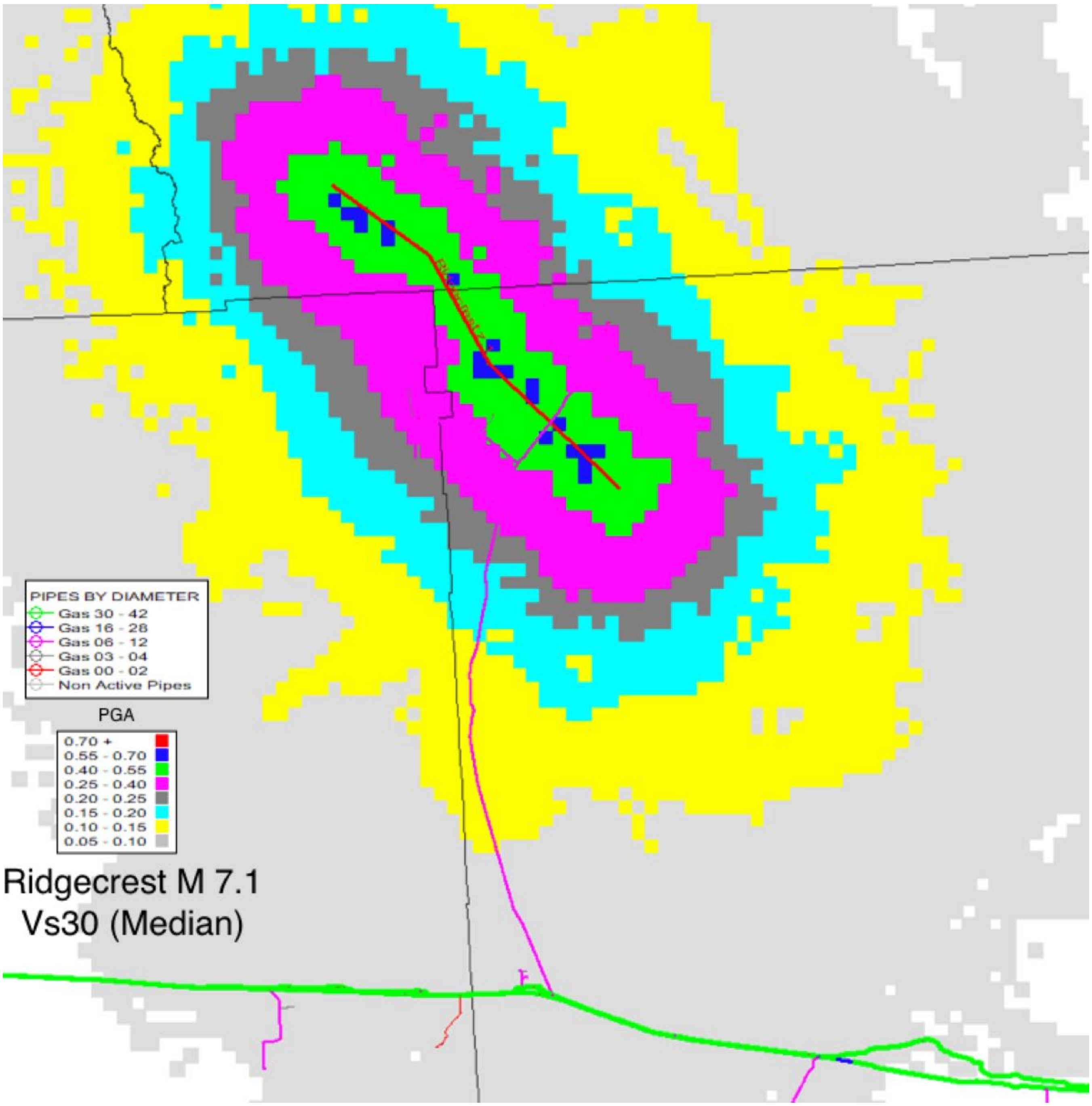


Figure 6.18-6. Ground Motions, PGA, M 7.1 Event

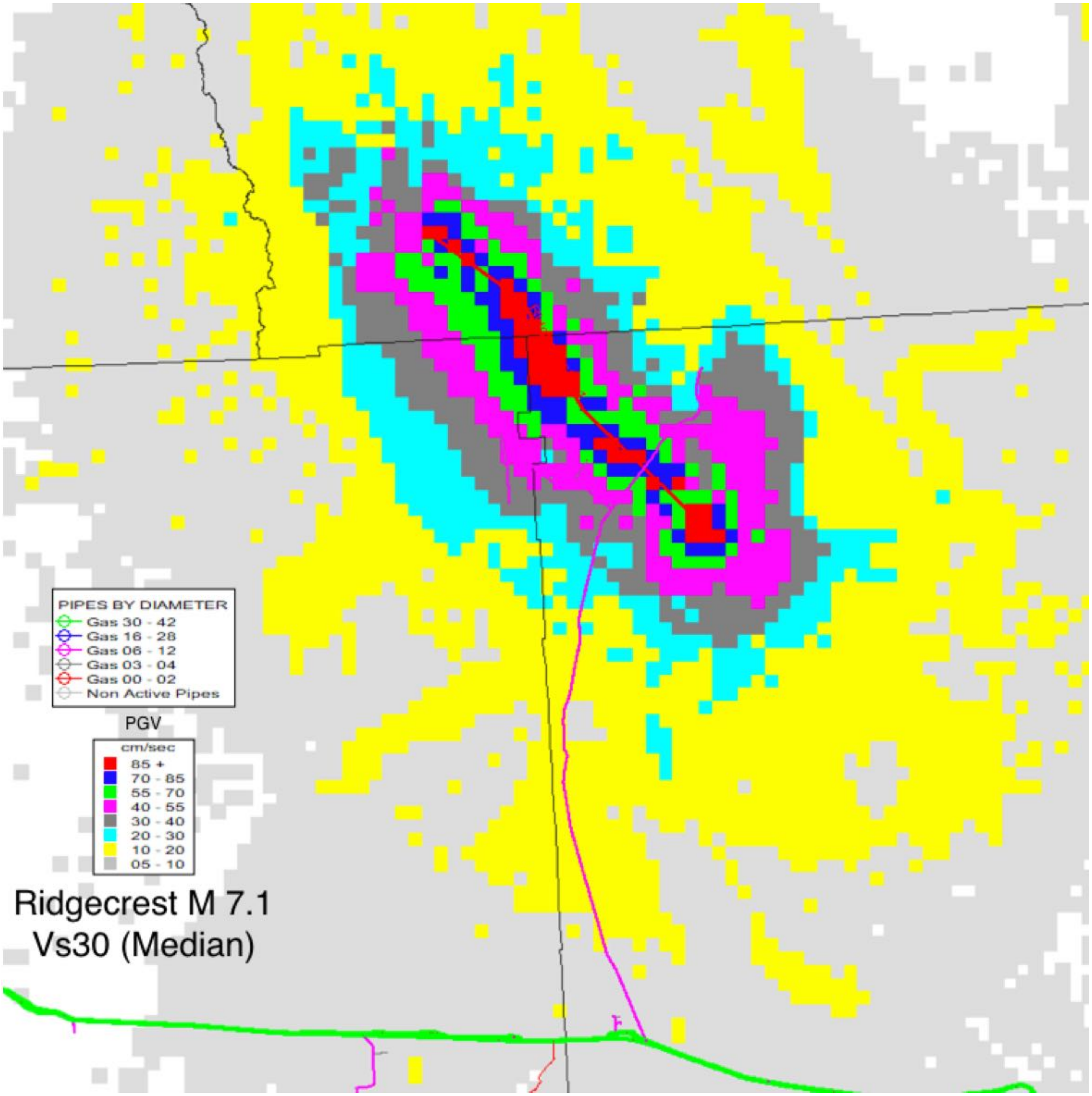


Figure 6.18-7. Ground Motions, PGV, M 7.1 Event

Based on discussions with local personnel, and observations of more than a dozen PG&E service crews doing work in the days following the earthquake sequence, there were about 360 leaks reported in the distribution and service lateral gas system. Of these, about 5% to 10% were to distribution mains, 50% to 60% were to risers, and 35% to 45% were to buried service laterals. At the time of the earthquake, the estimated percentage of distribution pipe materials was about 65% plastic and 35% steel. A preliminary estimate indicated that about half the distribution main repairs were to plastic and half to steel pipe.

One expects that plastic gas pipe should have a very small rate of leakage under ground shaking only (as was observed in the Napa 2014 earthquake). One expects that small diameter steel pipe, especially if located in "hot" (aggressive corrosion) soils, such as the case in Napa, would have a moderate to high leak rate.

There was liquefaction in the Argus area. Figure 6.18-8 shows an aerial view, looking easterly, of the PG&E gas regulator station at the north terminus of Line 372. The yellow dashed line is an approximate location of the western extent of ground cracking at this location. The sense of movement is indicated by the yellow colored arrows, towards the Searles lakebed. Observations of excavations in this area suggest that the top layer of soil is granular, underlain by hard clay, underlain by rock. The thickness of the top layer would be thicker towards the Searles lake bed, thinning out or disappearing entirely toward the mountainous terrain to the immediate west of Argus, Trona and Pioneer Point. Where the water table was high, liquefaction occurred in the top soil layer. Many ground cracks were observed along Trona Road through the communities of Argus and Trona, but none was observed in Pioneer Point.

Figure 6.18-8. Trona Gas Regulator Station

6.19 Fort Tejon Earthquake M 7.9 1857

The Fort Tejon M 7.9 earthquake of 1857 left a rupture scar 350 km (possibly as much as 400 km) in length along the San Andreas fault, see Figure 6.19-1. The epicenter is estimated to have been located about 72 km northeast of San Luis Obispo, with the rupture directed to the southeast. Maximum surface offset recorded was about 9 meters, averaging about 4.5 meters of right lateral offset.

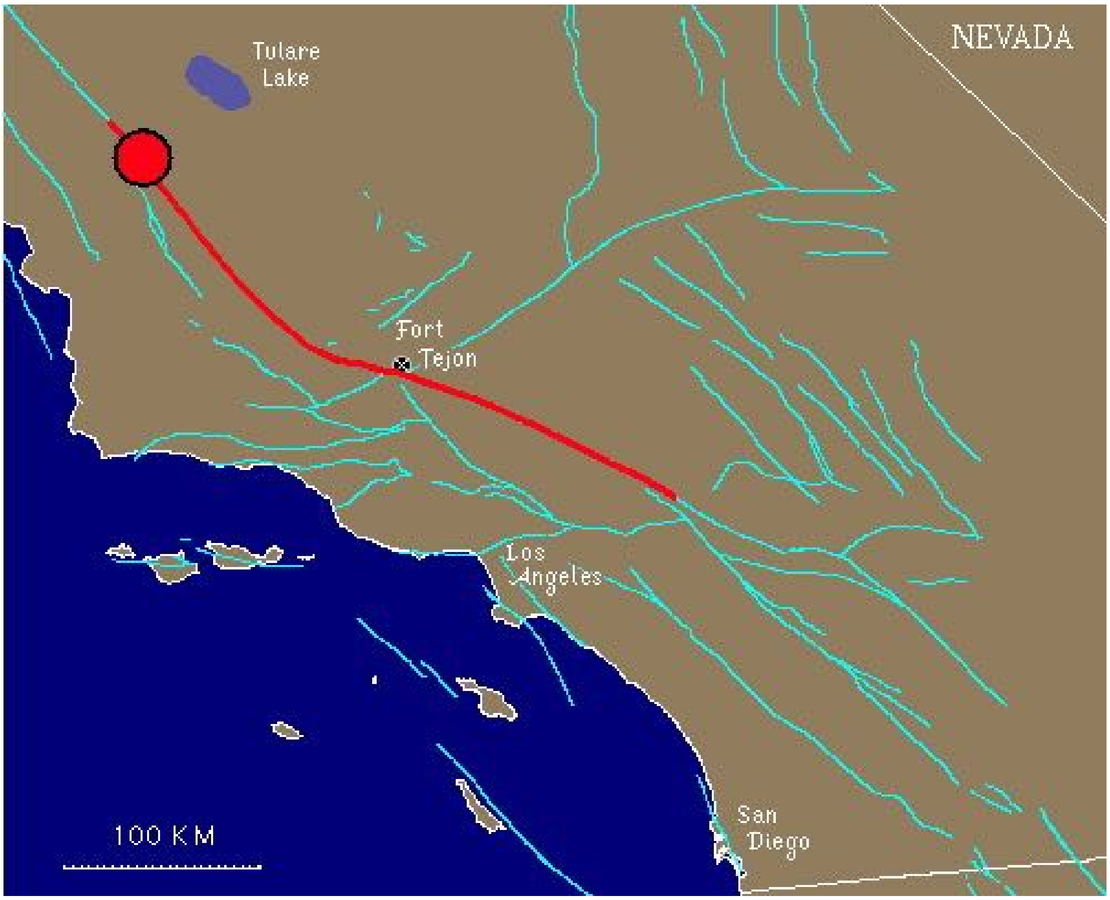


Figure 6.19-1. 1857 Fort Tejon Earthquake. Rupture in Red, Epicenter (?) as Large Dot

This 1857 earthquake is important, even though there was no development of the present-day PG&E, SoCalGas or SDG&E gas systems at that time. This earthquake raises awareness of the potential for large magnitude earthquakes on the southern San Andreas fault.

6.20 Long Beach Earthquake M 6.4 1933

The 5:57 pm March 10, 1933 Long Beach M 6.4 earthquake caused widespread damage to infrastructure in the Long Beach area.

Liquefaction

In the Long Beach area, along the Los Angeles River, as well as in Orange County in Seal Beach area, as well as eastern portions of Dominguez / Compton, there were numerous effects attributed to liquefaction following the 1933 Long Beach earthquake. Liquefaction triggered numerous leaks in gas lines, broken water mains, cracked roads, and displaced pavement (Barrows, 1974).

Figure 6.20-1 shows a drainage map of the Newport Beach to Long Beach area, dated 1888. This map highlights the three main rivers that drain to the Pacific Ocean, as well as the original shorelines and coastal lagoon areas of that time. The grids drawn reflect the surveyed land plats of the era; the main urbanized communities of the time were San Pedro (north of the Long Beach original harbor area), and Anaheim; much of the remaining area was farmland.

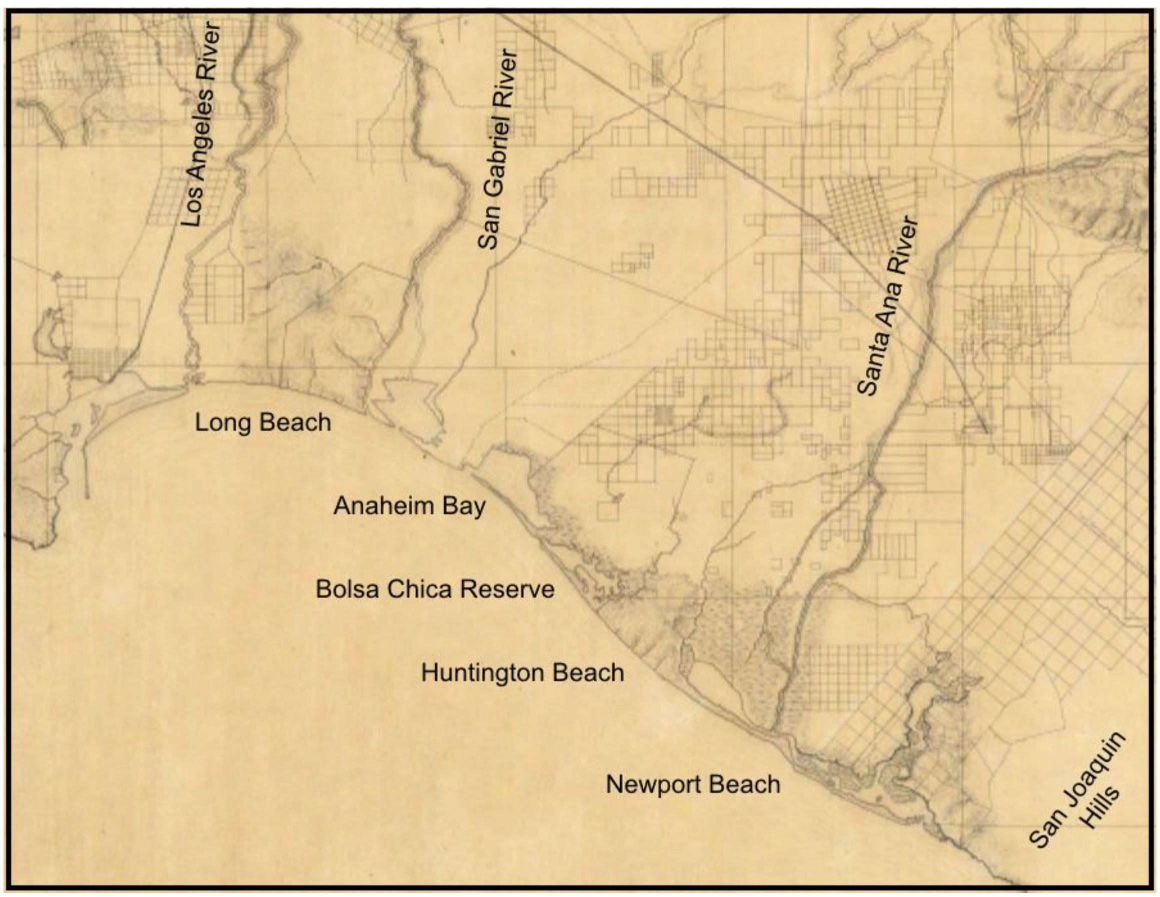


Figure 6.20-1. Drainage Map of the Newport Beach to Long Beach Area, 1888.

Figure 6.20-2 show a map of the Newport Beach to Long Beach area. The map reflects the modern (post 2000) shoreline, including the major development of the ports of Long Beach and Los Angeles. The location of the pipe breaks ("breaks" using the terminology of 1934; today, many of these might have been "leaks", and collectively, all of them would have been "repairs") from the 1933 earthquake are based on Hoff (1934). The liquefaction map is based on regional-scale liquefaction susceptibility mapping by Bedrossian (2011, Los Angeles County) and unpublished work for Orange County. SoCalGas transmission Line 765 is shown schematically as a dashed line, following the west bank of the Los Angeles River to Long Beach. The differentiation between very high, high and moderate liquefaction susceptibility reflects modern (post 2000) interpretation of the underlying ground water depth (0 to 10 feet, 10 to 30 feet, over 30 feet, respectively), as well as the surficial geologic units. The areas mapped in white are mesas or hilly terrain, both of which are generally considered non-liquefiable except locally along minor drainages or zones with perched water.

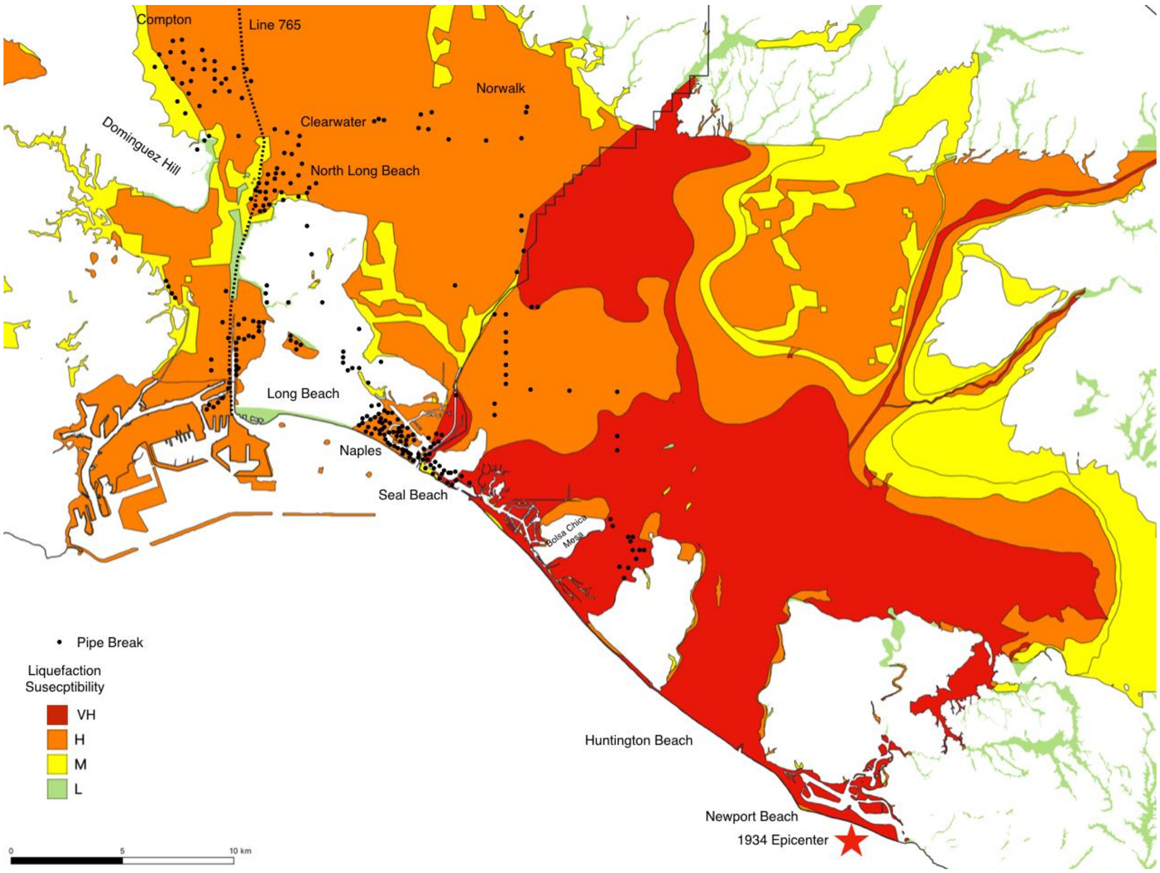


Figure 6.20-2. 1933 Long Beach Earthquake (Pipe Breaks After Hoff 1934)

The urbanized areas in 1933 include where the broken pipelines are mapped, as well as the zone mapped in white as "Long Beach". The majority of the pipeline damage occurred along the floodplain of the Los Angeles River from Compton, North Long Beach and San Pedro; as well as in the mouth of the original San Gabriel River near Seal Beach and Naples. The lack of pipe damage along the Santa Ana River reflects the lack of urbanized development in that area at that time; and / or lack of historic documentation. At the time of the earthquake, the most common types of materials used for buried pipe were cast iron (prevalent for water systems, also used in gas distribution systems), or threaded steel pipe (sometimes used in water systems, prevalent in gas distribution systems), or welded steel pipe (used for high pressure (≥ 150 psi) gas transmission systems).

The epicenter location of the 1933 earthquake was offshore of Newport Beach, indicated by the star in Figure 6.20-2. The rupture proceeded to the northwest towards Long Beach. This earthquake did not produce surface ground rupture.

This was the first seriously damaging earthquake in Southern California. Many unreinforced masonry structures collapsed, and liquefaction contributed to damage.

This event triggered the first large scale efforts for seismic design provisions in California, with new "engineered" installations (post-1933) often designed for V = 0.10W (in comparison, modern design for low rise regular buildings in high seismic zones uses V = 0.18W).

Bryant (1934) and Hoff (1934) both report more than 500 main line breaks of water, gas and oil lines in the epicentral area.

Gas System

Two gas system operators were affected by the 1933 Long Beach earthquake. SoCalGas operated gas transmission line 765. The City of Long Beach operated the LDC serving Long Beach.

Line 765, shown in Figure 6.20-2 as a heavy dashed line, was built in 1931. It was 26-inch diameter, t = 0.25 inch, using Grade A and B steel, with MAOP of 150 psi. This pipe was built using electric arc welds, with girth joints formed by having both ends of the spool piece belled, which were positioned using an underlying steel ring. In this fashion, there is eccentricity at each belled joint. Although this pipe traversed liquefiable zones, there are no records of damage or repair to this line from the 1933 earthquake, even though there were a variety of repairs needed for nearby water pipes made from cast iron.

In the Long Beach Municipal LDC gas system, there were a total of 119 gas main breaks, 91 of which were in the "high" pressure feeder mains (Bryant 1934), particularly in areas that were exposed to liquefaction. Every failure discovered in the high pressure distribution system occurred at a welded joint, and more than 50 of the 91 breaks were in artificially-filled areas. 46 breaks were discovered in the large diameter mains (18 to 20 inch) that supplied the Harbor District of Long Beach, which was an area where artificial fills were predominant. Repair crews reported that the original welds lacked proper penetration and proper bond with the pipe body.

Other damage to the gas system included more than 1,650 service risers broken off below ground at the elbow, and about 1,000 services sheared off at their connections to the mains. Over 90% of the main connection failures were located in the loose, artificially-filled ground in the Naples area (Bryant 1934); the majority of the services in this area had screw-type fittings and were laid in shallow trenches.

6.21 San Fernando Earthquake M 6.7 1971

The February 9 1971 M 6.7 San Fernando earthquake caused widespread damage to gas systems and other infrastructure in the San Fernando Valley. This earthquake occurred on the portion of the Sierra Madre fault system, causing surface fault rupture directly through the City of San Fernando.

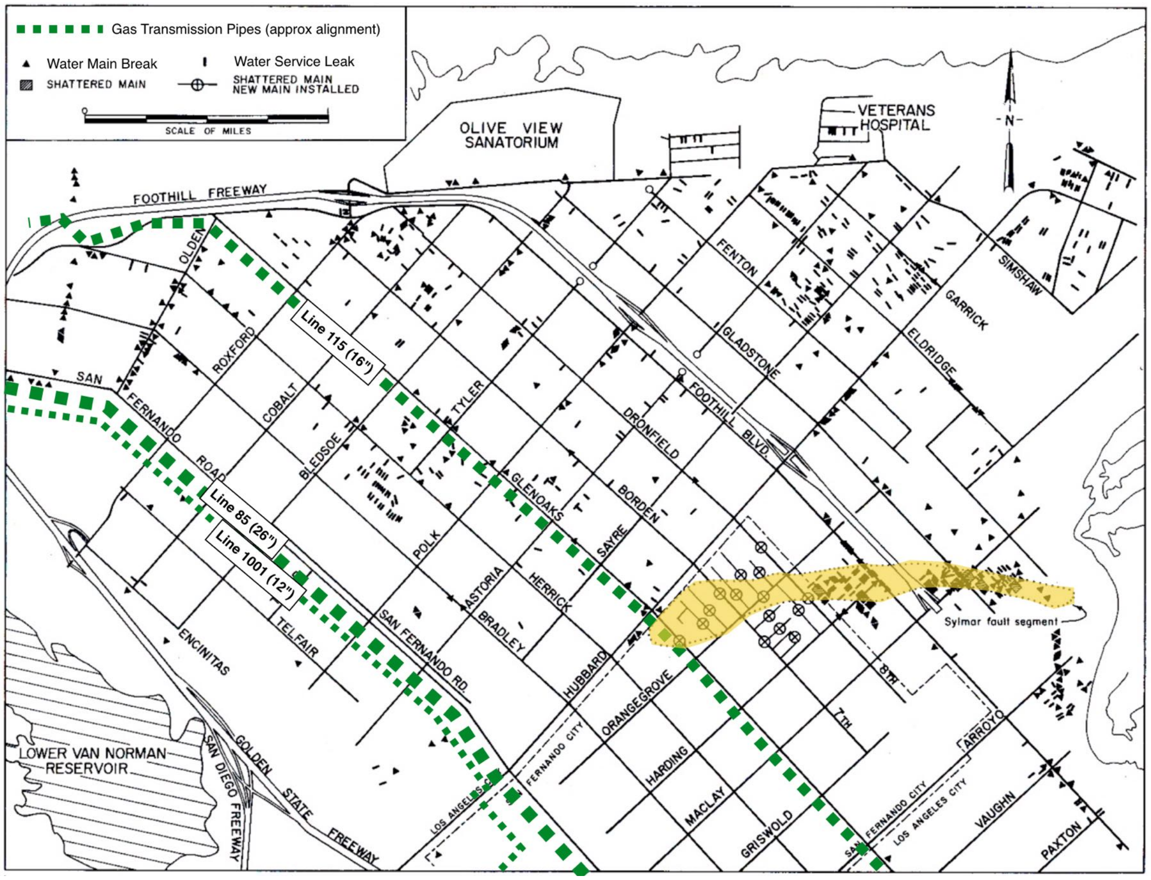


Figure 6.21-1. Map of 1971 San Fernando Earthquake. Damage to water pipes of the LADWP and City of San Fernando water systems indicated. Location of Gas Transmission Pipes indicated.

Maximum ground accelerations in the 1971 earthquake were compiled by Cloud and Hudson (1975). Maximum recorded horizontal PGA values in the valley (excluding Pacoima Dam) were:

- 0.15 – 0.26g. Vicinity of intersection of Sepulveda and Ventura Blvd
- 0.18g. North Hollywood – Griffith Park
- 0.19g. Glendale
- 0.28g. Glendale
- 0.11g – 0.22g. Hollywood

This moderate-sized earthquake occurred in the northeast part of the San Fernando Valley, near the town of San Fernando. Extensive post-earthquake investigations by many researchers discovered that lifelines (including gas, water and power systems) were heavily damaged. In the community, this was the first "lifelines" earthquake. One researcher, Prof. C. Martin Duke of UCLA, led many investigation efforts. Prof. Duke observed that utilities were then "working on their own" in the mitigation of seismic risks, and relied (at that time) primarily on the UBC and the State of California General Orders.

Gas System

McDonough (1995) describes the SoCalGas system at the time of the earthquake as follows:

- There were about 690 miles of transmission and distribution gas pipelines in the earthquake damage area. There were about 456 reported failures to this piping. All but two of these failures were at locations of vertical or lateral ground PGDs.

- There were 380 distribution system leaks, of which 181 were on mains, 137 were on service laterals and the remainder at the connection between the main and lateral.

- The distribution system was damaged over a 12 square mile area. Due to damage to high pressure transmission pipes, pressure was lost to eight distribution regulating stations, which supplied about 16,300 customers. An additional 9,500 customers lost gas supply due to loosened dirt, rust and mill scale within the piping system which clogged filters and pressure regulators.

SoCalGas (1973) described the damage to the gas transmission system in this earthquake as follows:

- There was substantial damage to Lines 1001 and 115 that (then) traversed through the City of San Fernando. These pipes are shown in Figure 6.21-1 as dashed green lines, along with the location and style of damage to nearby water pipes.

- Line 115 was a 16-inch diameter steel pipeline of unknown grade, constructed in 1926 using oxy-acetylene welds. In the ~6 mile reach of the pipe between Clampett Junction and San Fernando, there were 52 breaks. Shell buckling of the pipeline occurred where the pipe crossed the Sylmar segment of the rupture zone (13 damage points in the colored zone in Figure 6.21-1 / hatched zone in Figure 6.21-2).

- Line 1001 was a 12-inch diameter steel pipe, constructed in 1925 with oxy-acetylene welds and operated at MAOP of 345 psi. Because of numerous breaks, predominantly at the welds, about 5.8 miles of the line was abandoned.

- Line 85 was a 26-inch diameter pipe, with Grade A steel and t = 0.25-inch, operated at MAOP 250 psi. In Figure 6.21-2, a mark shows where the welding style switched between oxy-acetylene (northern part) and electric arc (southern part). In 1932, about 30% of the oxy-acetylene welds in the northern section were reconditioned with electric arc welded reinforcements. South of the point, the line was constructed with unshielded electric arc welded belled pipe in a manner similar to that of Line 765 which was affected in the 1933 Long Beach earthquake. The electric arc welded portion of Line 85 was damaged at 7 locations within the zone of lateral spread along the east side of Upper Van Norman Reservoir.

- The utility corridor on the west side of Upper Van Norman Reservoir was subjected to as much as 9 feet of lateral deformation caused by liquefaction, soil movements were distributed primarily across a 1,300 to 1,640 foot long length of the corridor. Gas pipelines at this location included Line 120 (22-inch); Line 3000 (30-inch) and Line 3003 (30-inch), all built using X52 steel in 1966; these three lines were not damaged.

Figure 6.21-3 highlights the gas transmission system damage in the City of San Fernando. The damage locations are based on repair records prepared by SoCalGas personnel. The common damage was rupture of leakage at oxy-acetylene welds. Also shown in the map are the mapped locations of ground failures and surface cracks in the area.

- Line 115. About 3 compression and 10 tensile failures near the Sylmar Segment of ground rupture.

- Line 1001. 1 break where it crossed the Mission Wells Segment of ground rupture, and 3 breaks in the vicinity of the Juvenile Hall lateral spread on San Fernando Road.

- Line 85. 7 breaks in the vicinity of the Juvenile Hall lateral spread on San Fernando Road.

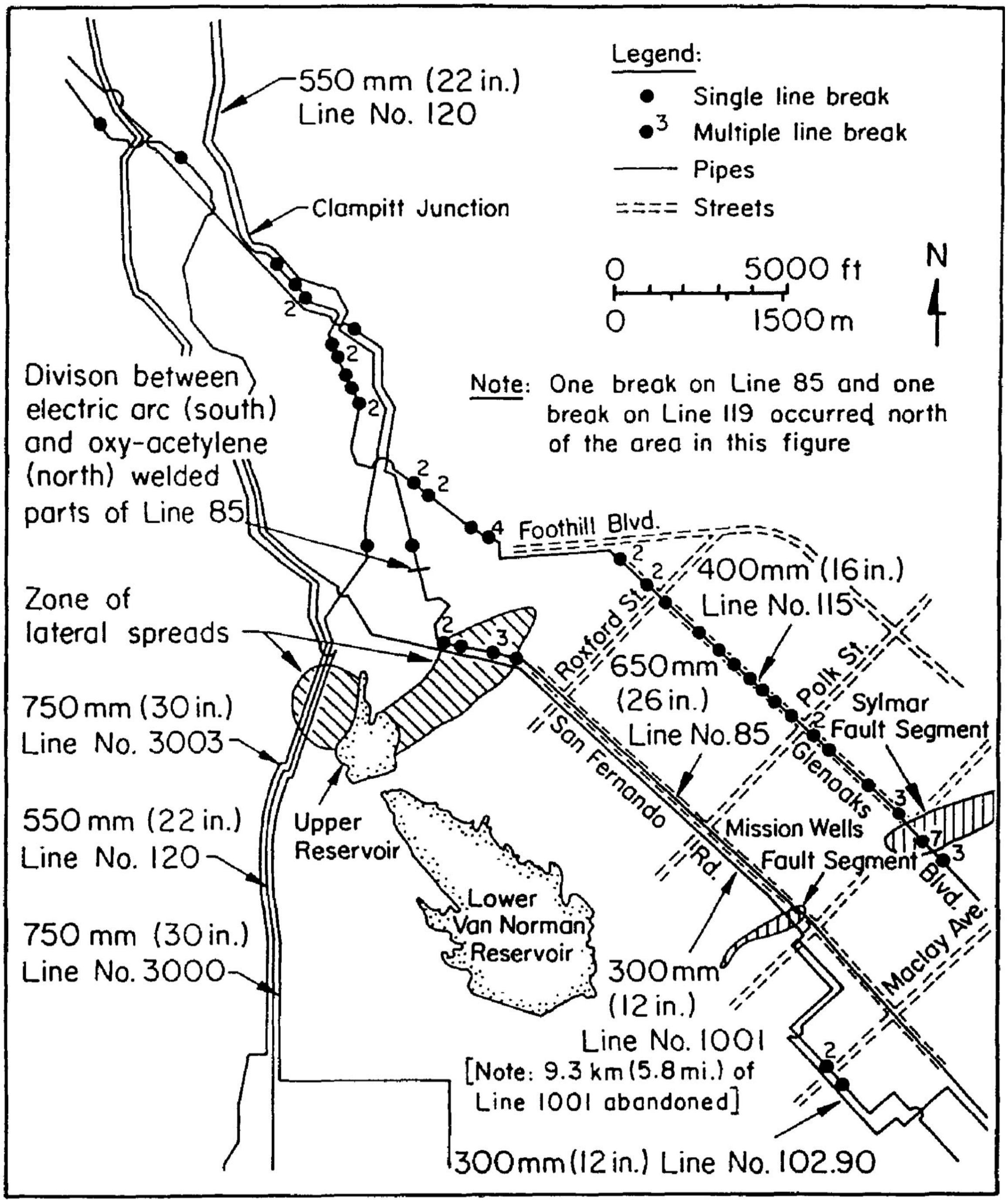


Figure 6.21-2. Location of Gas Pipeline Damage, Lateral Spreads and Fault Segments (after SoCalGas 1973, and O'Rourke 1974)

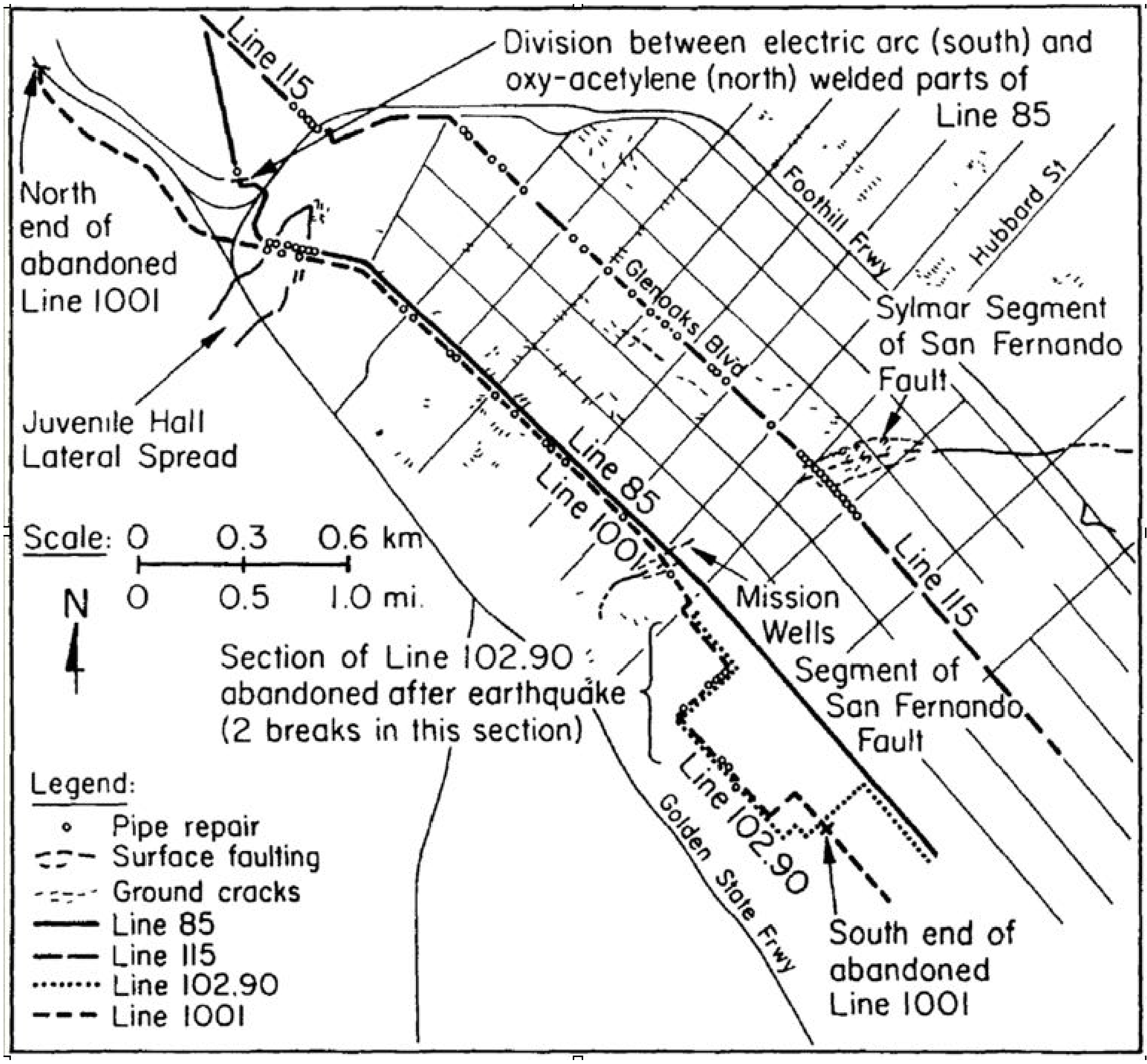


Figure 6.21-3. San Fernando, Location of Gas Pipeline Damage, Lateral Spreads and Fault Segments (after SoCalGas, 1973, O'Rourke 1974)

Figure 6.21-4 shows a map of the modern (circa 2012) SoCalGas transmission system in the vicinity of the 1971 San Fernando and 1994 Northridge earthquakes. The Sylmar fault segment shown in Figure 6.21-4 is the same as highlighted in Figures 6.21-2 and 6.21-3. The gas transmission line numbers have changed over the decades. Figure 6.21-4 highlights the locations where the Santa Susana fault ruptured in 1971 (red lines), bisecting 22-inch Line 537 (22-inch Line 120, Figure 6.21-2) and 30-inch 5117 (30-inch Line 3000, Figure 6.21-2).

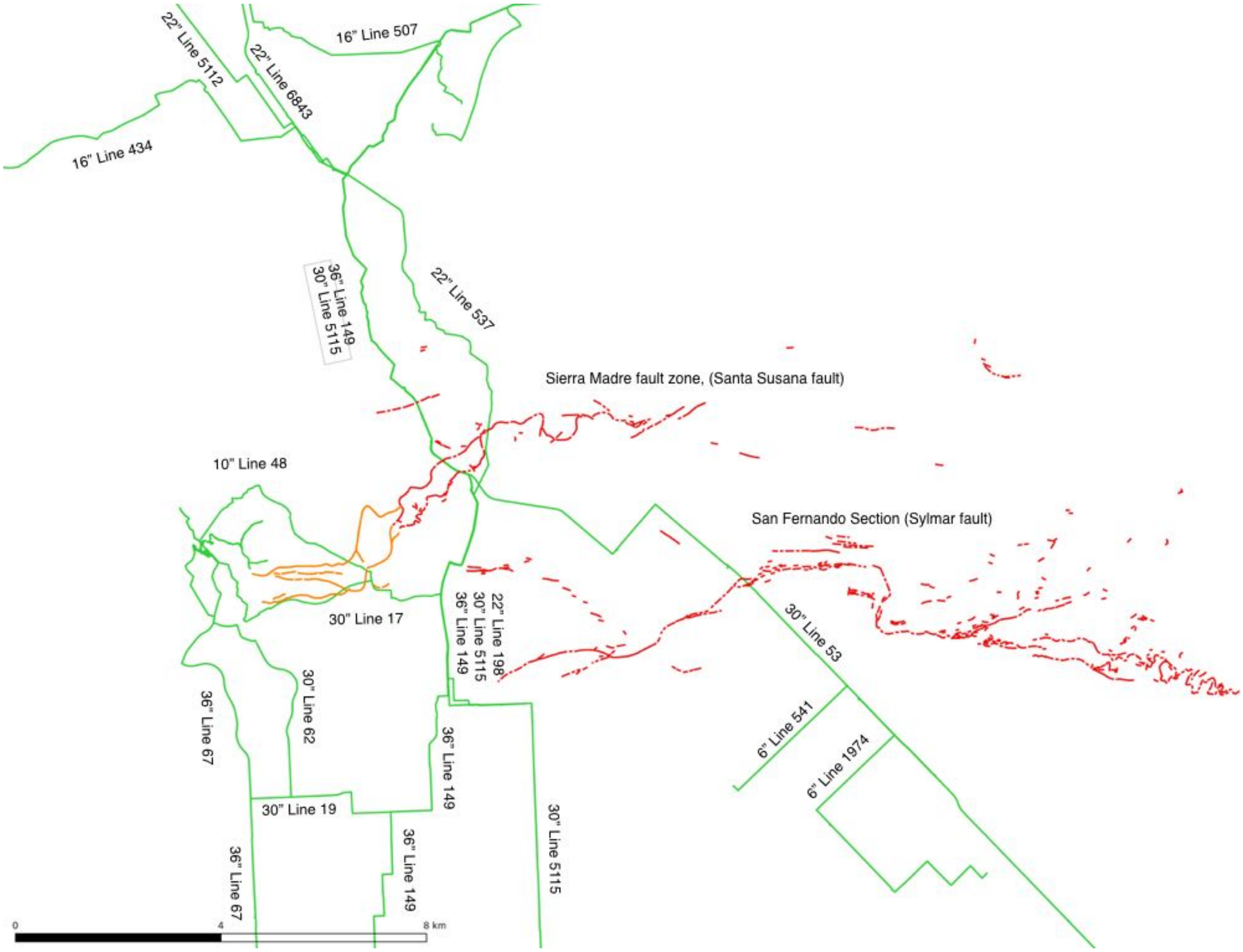


Figure 6.21-4. SoCalGas Transmission Pipes and 1971 Fault Ruptures

6.22 Santa Barbara Earthquake M 5.3 1978

The Santa Barbara M 5.3 earthquake of August 13, 1978, 3:55 pm local time, had its epicenter on a fault located offshore and south of Santa Barbara. The rupture direction was northwestwards towards Goleta. A strong motion instrument at UC Santa Barbara, near Goleta, recorded PGA = 0.45g. The rupture appears to have been on a north dipping thrust fault.

A few fires broke out. 324 mobile homes were damaged. Significant structural damage occurred at 10 University of California Santa Barbara buildings. About 400,000 books at the library were thrown to the floor. A railroad track became kinked, and a train moving at 50 mph derailed.

There is no current available record of damage to gas pipes in this earthquake.

6.23 Imperial Valley Earthquake M 6.6 1979

The Imperial Valley M 6.6 earthquake of October 15, 1979, 4:16 pm local time, shaking the urban area of El Centro, California. The causative fault was the Imperial fault. The sense of slip was right lateral.

The maximum right lateral displacement on the Imperial fault was about 22-24 inches, measured the first day after the earthquake and near the international border; measurements taken 5 months after the earthquake near the southeast end of the rupture showed there was an additional 11 inches of post seismic slip, for a total of 31 inches at that location.

The 1979 fault rupture followed the same trace that ruptured in the 1940 El Centro earthquake, with maximum offset near the international border. There is some evidence that the Brawley fault, to the north underwent sympathetic offset in both the 1940 and 1979 events.

There were a modest number of structural collapses in the town of El Centro (population then about 30,000 people).

Gas System

Ground rupture crossed three of SoCalGas's steel pipelines. This included two supply lines running north-to-south along Dogwood Road and a 4-inch distribution line running east just north of Highway 80, towards Holtville. This earthquake did not damage (resulting in leak) any of these three gas pipelines.

Figure 6-23-1 shows the region, highlighting (in heavy black boxes) the two parallel steel high pressure gas pipelines along Dogwood Road that deliver gas from the north to the community of El Centro in the south and the 4-inch pipe delivering gas to the community of Holtville to the east. Light blue lines indicate major roads in the area. Dark red lines shows historic fault ruptures in the area along the Imperial Valley and San Jacinto faults; orange lines show mapped active faults in the area; the Brawley fault zone is shown schematically; gas transmission lines are shown in green; urbanized areas shown as shaded blue boxes.

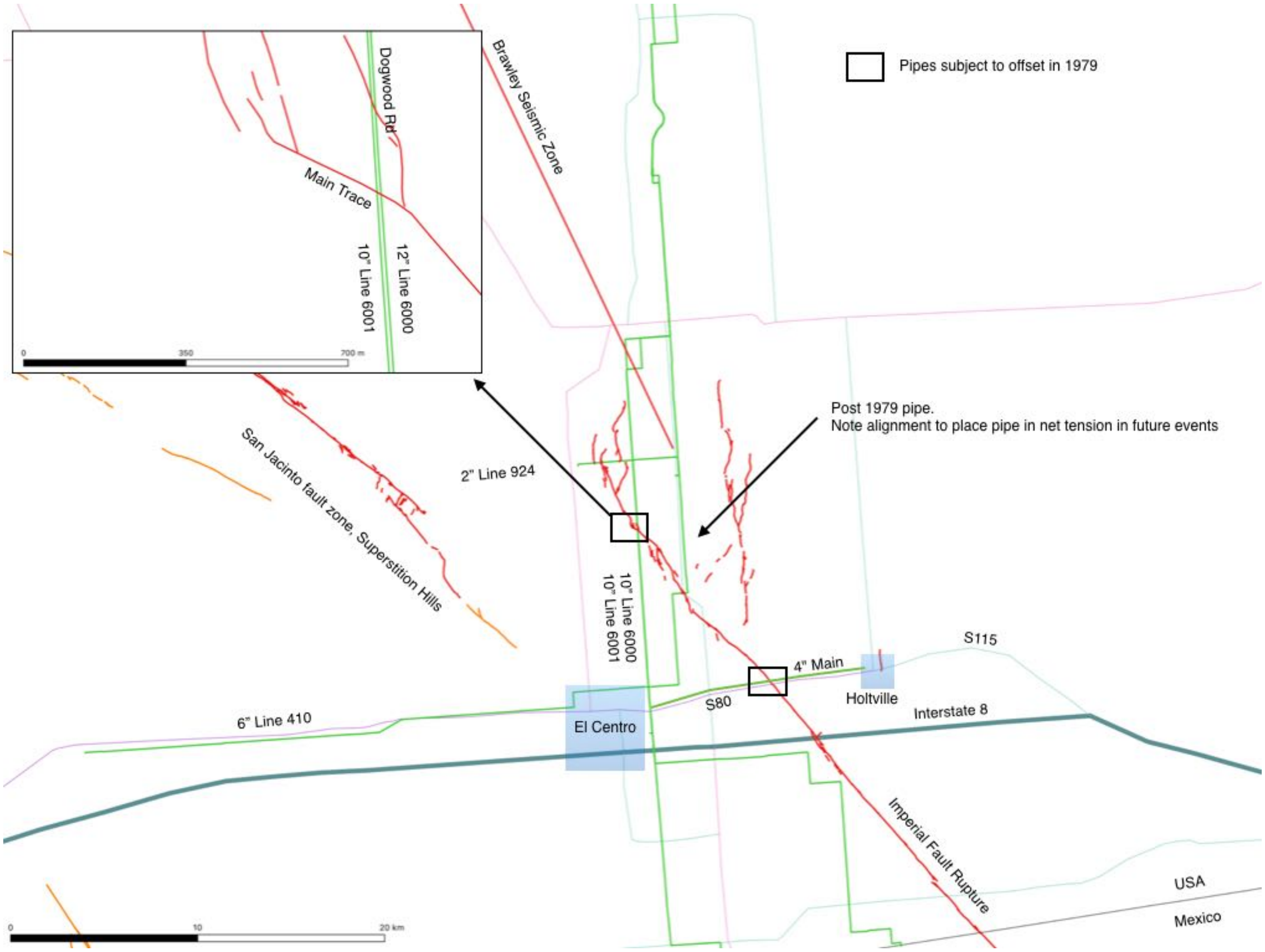


Figure 6.23-1. SoCalGas Transmission Pipes and 1979 Imperial Valley Fault Rupture

Details of the pipes at the offset zones of 1979 (black boxes) are as follows (adapted from McNorgan 1989, Dobry et al 1992).

- Line 6001. 10-inch diameter transmission pipe, OD = 10.75 inches, t = 3/16 inch, API Grade B, SMYS = 35 ksi, Fu = 60 ksi, MAOP 1,000 psi, 3 feet of cover, built 1966, electric arc welds. Crossed fault along Dogwood Rd. About 6 inches of right lateral offset with a 4-inch vertical offset (up on the south) along the main trace. The pipe was excavated after the earthquake, and as more and more of the pipe was excavated, the pipe deflected more and more. The pipe was inspected; the pipe was observed to be intact with no evidence of local wrinkling. Based on the sense of offset and the observations, the pipe was under a high state of net compression, owing to the shortening action induced by the fault offset. In 1981, the pipe was shut down; a trench 200 feet long was excavated; a section of pipe at the fault offset zone was cut out; the remaining adjacent pipe lengthened 4.75 inches; a new 10-foot segment was welded in place and the pipe restored to service. Including accumulated slip due to creep from 1966 through 1979, the co-seismic slip, and after slip, total offset applied to the pipe at this location has been estimated at about 9± inches.

- Line 6000. 12-inch diameter transmission pipe, OD = 12.75 inches, t = 0.28 inches, X-42, SMYS = 42 ksi, MAOP 1,000 psi, 3 feet of cover, built 1948, electric arc welds. Note: the diameter of this pipe is reported at 10-inch or 12-inch from two data sources. Crossed fault along Dogwood Rd. About 6 inches of right lateral offset with a 4-inch vertical offset (up on the south) along the main trace. The pipe was excavated after the earthquake, and as more and more of the pipe was excavated, the pipe deflected more and more. The pipe was inspected; the pipe was observed to be intact with no evidence of local wrinkling. Based on the sense of offset and the observations, the pipe was under a high state of net compression, owing to the shortening action induced by the fault offset. Including accumulated slip due to creep from 1966 through 1979, the co-seismic slip, and after slip, total offset applied to the pipe at this location has been estimated at about 12± inches.

- 4-inch diameter distribution pipe, OD = 4.5 inches t = 3/16 inch, Fy = 25 ksi, Fu = 48 ksi, built 1948, 3 feet of cover, acetylene welds. Subjected to about 12 inches of right lateral offset a measured by ground cracks near the pipe. The pipe was excavated after the earthquake for a length of about 72 feet; as the trench was lengthened from 36 feet to 72 feet, it was observed that the deflected shape of the pipe changed, with less and less curvature as the trench was lengthened. The pipe was inspected; the pipe was observed to be intact with no evidence of local wrinkling; and it was noted that there was soil between the exterior tape wrap and the pipe. The tape wrap was removed, the pipe cleaned, and the pipe re-wrapped and then backfilled. Based on the observations during excavation, it is apparent that the pipe sustained yielding. Including accumulated slip due to creep from 1948 through 1979, the co-seismic slip, and after slip, total offset applied to the pipe at this location has been estimated at about 24± inches.

Also shown in Figure 6.23-1 is another gas transmission line to the east of Lines 6000 / 6001. This line crosses the Imperial fault in an orientation to allow net tension due to ongoing fault creep and future co-seismic fault offset. This pipe did not exist at the time of the 1979 earthquake.

6.24 Devers (North Palm Springs) Earthquake M 5.9 1986

The North Palm Springs M 5.9 (variously reported as 5.7 to 6.0) earthquake of 2:21 am, July 8, 1986. The earthquake occurred in a complex setting along the San Andreas fault zone at San Gorgonio Pass. The epicenter was located between two segments of the Banning Fault and the Mission Creek strand.

About 2 to 3.4 inches of strike slip offset was observed at the surface of the Banning fault.

The earthquake shook Palm Springs, the nearest community, where the damage included some mobile homes knocked off their foundations, and some shattered windows. One of the two barrels of the Colorado River Aqueduct was damaged (reported variously as "damaged at several locations"), leaking about 3.3 million gallons per day; the break was near I-10, not far from the known Banning fault rupture zone. There were two fire ignitions in the San Jacinto mountains (unknown cause), and 1 at a glass company in Cathedral City, possibly caused by a quake-related short circuit.

Gas System

The epicenter was located in a rural area. There was no gas system damage reported. The epicenter was 8 km from two 30-inch and one 36-inch SoCalGas gas transmission pipes.

Electric System

The most significant lifeline-related damage occurred at SCE's Devers substation, where there was widespread damage to the 500 kV yard, and some damage in the 220 and 115 kV yards. Power was interrupted to 80,000 SCE customers until 7:30 am. The prime cause of the power outages was the damage at the Devers substation.

The recorded ground motions at the Devers substation yard were PGA = 0.95g, 0.60g (initial data processing, H1, H2 orthogonal horizontal directions, respectively) (later reported as 0.97g NS, 0.72g EW and 0.48g vertical). Strong shaking (PGA > 0.1g) lasted about 5 seconds.

6.25 Whittier Narrows Earthquake M 6.1 1987

The Whittier Narrows earthquake occurred on October 1 1987, at 7:42 am. The magnitude has been variously reported as 5.9 to 6.1. The epicenter was in Montebello. This earthquake occurred on a portion of the Elysian Park fault.

Three people died during this earthquake, with about 1,000 people treated at local hospitals for various injuries. About 10,000 commercial and residential buildings were damaged, including 123 single family houses completely destroyed and 513 with major damage.

Gas System

McDonough (1995) reported the following:

- There was no damage to SoCalGas high pressure gas pipeline system in this earthquake.

- There were 22 leaks discovered in the gas distribution system. One of these, a break in a 4-inch cast iron pipe was directly related to the earthquake; the remainder were corrosion-related leaks which may or may not have been initiated by ground shaking. There were no damage reported for polyethylene gas pipes.

- Thousands of leaks or other damage were found on customer's property. This includes damage to about 3,000 service lines, running from the streets to the buildings. Many of these showed evidence of corrosion. About 75% of the leaks discovered on customer's property were related to connections to inadequately anchored appliances, primarily water heaters. There were five minor appliance fires caused by leaking gas.

- About 27,000 customer calls were received. 21,000 of these were by customers who turned off their gas needlessly. This was in part due to media announcements, immediately after the earthquake, urging people to do this as a safety precaution[1].

[1] A similar trend was observed in the Anchorage 2018 M 7.0 earthquake: customers of Enstar (natural gas supplier for Anchorage) were turning off the gas to their (and neighbor's) houses. Enstar made public announcements immediately after the earthquake to tell customers to not turn off the gas unless they smelled gas. It is commonly accepted by members of the gas system engineering community in California (but not by gas valve suppliers and some politicians) that automatic shut off valves (shaking initiated) is not a cost effective practice, causing possibly needless and expensive post-earthquake gas re-light efforts, while eliminating few fire ignitions. In Japan, automated gas shut-off valves are used within gas transmission pipelines serving large neighborhoods. In the Kobe Japan 1995 M 7 earthquake, automatic shut off valves operated in gas transmission lines as well as at meters serving individual houses; the operation of these valves did not prevent all fires within houses, in particular those houses that collapsed and broke the gas riser / service lateral pipes leading to the meter. The topic of automatic gas shut off valves is complex, and there is not yet industry-wide consensus as to what a practical and cost effective approach might entail.

6.26 Landers Earthquake M 7.3 1992

The Landers M 7.3 (variously reported between 7.3 and 7.6) earthquake occurred at 4:58 am (local time) on June 28, 1992. The earthquake occurred along a series of north to north-west-trending faults located in the western portion of the Mojave Desert. Primary ground rupture initiated along the Johnson Valley fault and propagated to the north along the Homestead Valley, Emerson and Camp Rock faults. These faults are located east of the San Andreas fault and between the east-west-trending Garlock fault to the north and the Pinto Mountain fault to the south.

A strong motion instrument at SCE's Coolwater substation recorded PGA = 0.43g, 0.28g (two horizontal directions), and 0.16g (vertical). Minor damage occurred at the Coolwater 220 kV switchyard. The adjacent SCE-owned power plant had been de-energized and depressurized since 1989, and was reported to also have had some damage.

Another ground motion instrument was located at the proposed site of a combined cycle natural gas power plant, located about 1 mile from the fault. That instrument recorded PGA = 0.88g, 0.68g (two horizontal directions) and 0.63g (vertical).

Gas System

Figure 6.26-1 shows the gas transmission system pipelines in the vicinity of the 1992 Landers earthquake (red lines "Landers 1992"). While there were many PG&E sand SoCalGas transmission pipes near the fault rupture, none of the pipes actually crossed locations where the gault did rupture.

Also shown in Figure 6.26-1 is the location of the 1999 Hector Mines earthquake (red lines) as well as several other active faults (orange lines) in the upper Mojave Desert (from west to east, Helendale, Lenwood, Johnson Valley, Calico, Pisgah) and the Pinto Mountain fault towards the south edge of this map. Future large magnitude earthquakes could challenge the gas transmission system. For example, the Calico fault (capable of ~M 7) crosses four transmission lines (PG&E - 2, SoCalGas - 2).

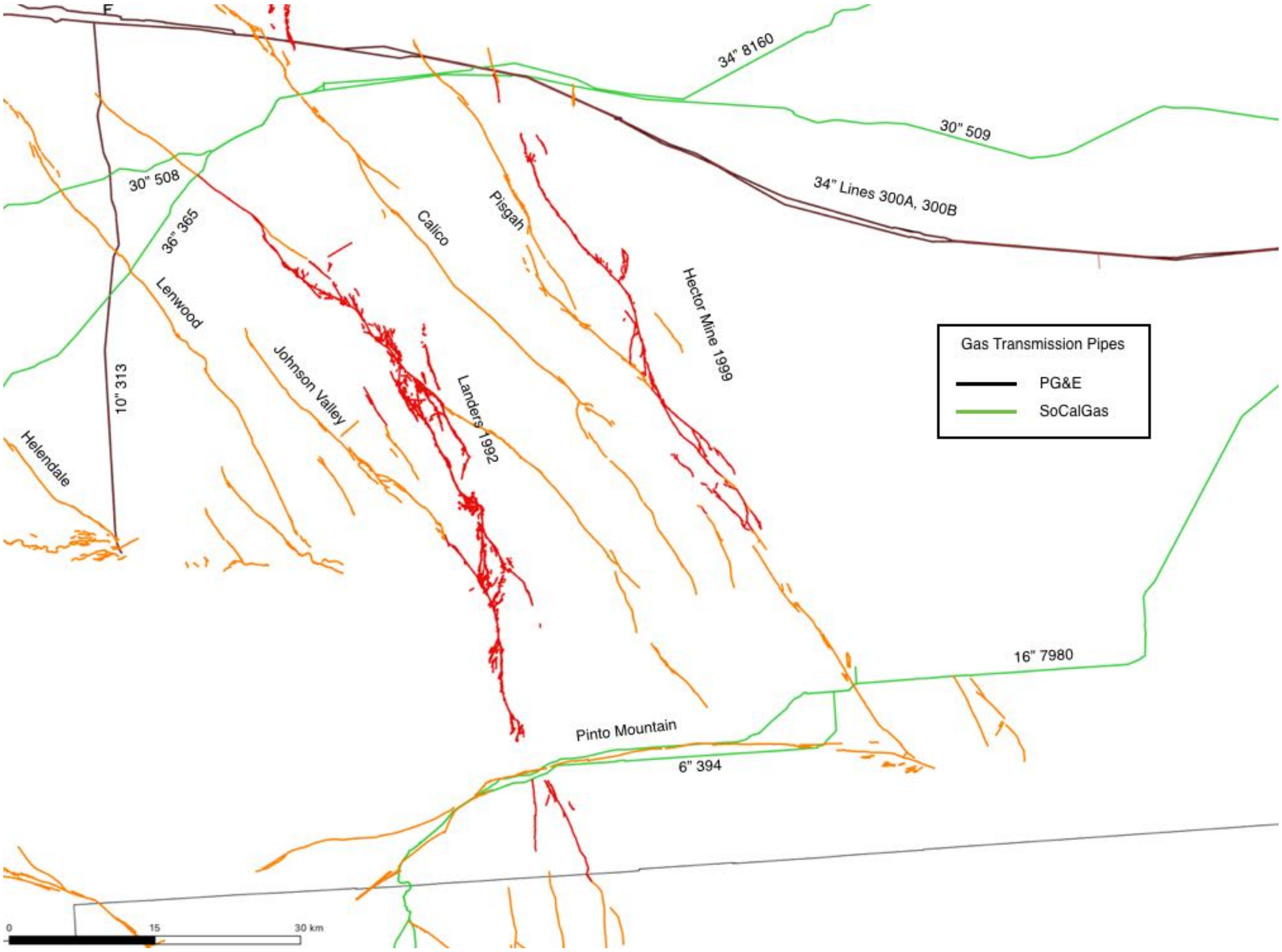


Figure 6.26-1. Transmission Pipes near the 1992 Landers Earthquake

6.27 Big Bear Earthquake M 6.4 1992

At 8:04 am, June 28, 1992 an independent (triggered?) M 6.4 earthquake occurred on a blind thrust fault under Big Bear, California, about 22 miles to the southwest of the Landers earthquake. It is postulated that the stress induced onto this fault was increased by the nearby Landers earthquake that occurred just 3 hours earlier.

One instrument in Big Bear recorded the motion, with PGA = 0.55g, with about 10 seconds of strong motion (PGA > 0.1g). In the town of Big Bear, 2,600 chimneys were damaged, 20 residences fell off their foundations, and 40% of all structures had some type of damage. Typical ground motions were PGA = 0.2g to 0.3g throughout the urbanized area. A few URMs had partial collapses.

Gas System

Southwest Gas operates the gas distribution distribution system serving the Big Bear Valley area. Southwest Gas purchases natural gas from PG&E's transmission system. Gas is received in Big Bear area via two pipes originating in Victorville.

Some commercial buildings and older residential buildings rely on propane, but about 99% of customers rely on piped natural gas.

A survey after the 1992 earthquake showed that only one service line leak could be attributed to the earthquake.

6.28 Northridge Earthquake M 6.7 1994

The earthquake occurred on Monday, January 17, 1994, at 4:31 A.M., Pacific Standard Time (PST), the epicenter was located 20 miles (32 kilometers) from the center of Los Angeles, in the Northridge community (San Fernando Valley) of Los Angeles, California. The magnitude was M 6.7. The impact of the earthquake was wide spread in western Los Angeles and eastern Ventura Counties. The earthquake had an impact on natural gas pipelines, large diameter water conveyance facilities as well as other lifeline utilities, in addition to damage to residential and commercial buildings, and freeways. The estimated damage was approximately $20 billion and there were approximately 58 fatalities.

Gas System

Figure 6.28-1 shows the gas transmission pipes in the area of strong shaking. Figure 6.28-2 shows the area in the north part of San Fernando Valley where ground failures occurred along Line 120.

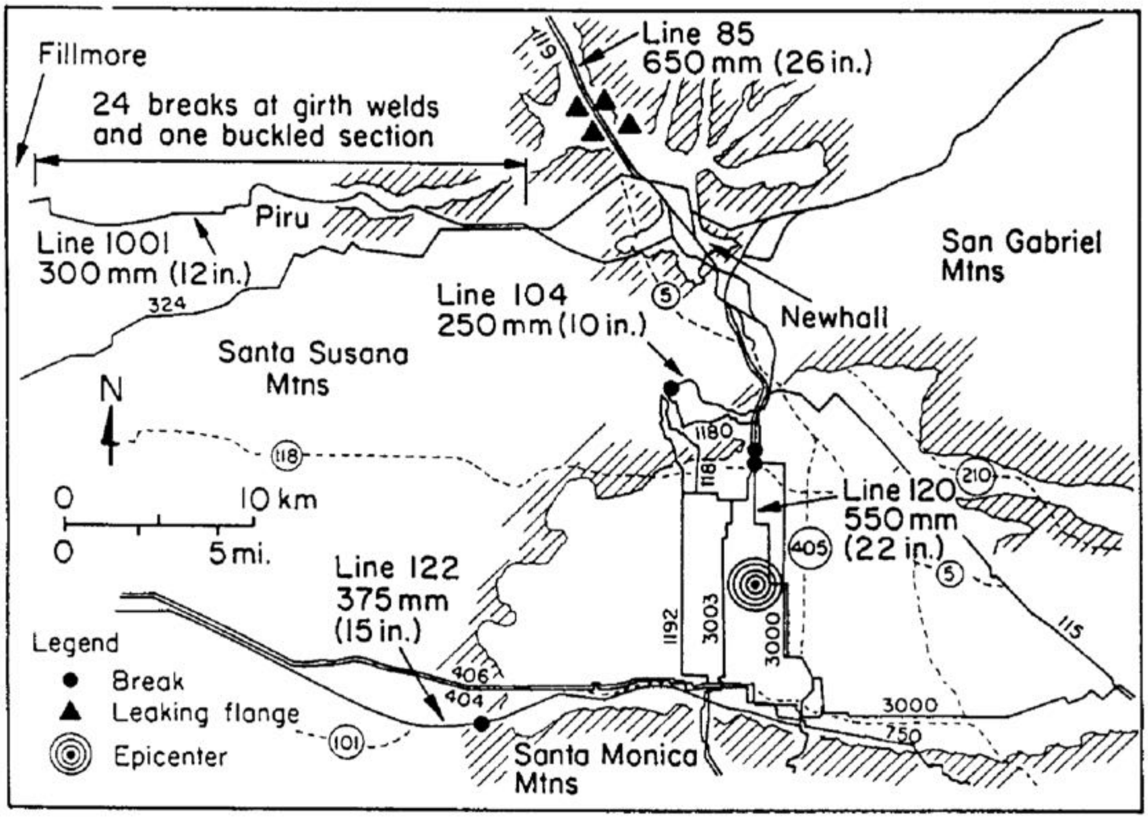


Figure 6.28-1. Gas Transmission Pipelines and Area of Strong Ground Shaking, 1994 Northridge (after O'Rourke 1996)

There were 35 non-corrosion related repairs in the gas transmission system, of which 27 were at cracked or ruptured oxy-acetylene girth welds in pre-1932 pipelines. The failure of the Line 120 on Balboa Blvd resulted in a large fire, is possibly the most "famous" of these pipe failures, and aspects of that fire are described in "Fire Following Earthquake" (Scawthorn, Eidinger, Schiff, 2004).

- Line 1001. 24 breaks at oxy-acetylene welds and one buckled pipe location, 18 of which were in Potrero Canyon. This pipe runs along an east-west valley of the Santa Clarita River, from

Newhall to Piru and Fillmore. Ground shaking along this alignment was generally moderate to strong, PGA commonly 0.25g to 0.50g. There were collapsed URM buildings in Fillmore. Line 1001 was constructed in 1925, and was operating at 245 psi internal pressure. It is a 12-inch steel pipe, unknown grade, t = 0.22 inches. 6 of the broken welds were located in areas adjacent to the Santa Clarita River east of Piru and west of Potrero Canyon. 1 weld failed at the eastern city limit of Fillmore, leaving a crater 9 feet deep and 15 x 20 feet in plan. Gas escaping at the location of this break under Highway 126 was ignited by a downed power line. There were considerable PGDs in Potrero Canyon due to liquefaction. About ½ to 2/3 of the pipe failures of Line 1001 coincided at or near the PGD zones in Potrero Canyon; with the others in areas apparently exposed only to strong shaking.

- Line 85 is a 26-inch pipe with t = 0.25 inch, Grade A steel, operated at 317 psi. There were gas leaks noted at above ground flanges at sections of above ground pipe, at the locations shown in Figure 6.28-1. This area was exposed to very strong shaking (PGA > 0.5g). Damage was mainly in the form of flange separation and leaking gaskets; one of the flanges was fractured. A oxy-acetylene weld failed about 24 miles northwest of Newhall (off map). There was another weld failure near Taft, about 75 miles north of the epicenter; this portion was built in 1931 with electric arc welds, pressure 360 psi.

- Line 119. There was a leaking flange. This pipe is 22 inch diameter, built 1931, t = 0.312 inch, welded (unknown style of construction), pressure = 360 psi, Fy = 30 ksi.

- Line 122 (Figure 6.28-1). There was a failed oxy-acetylene weld. Pressure 150 psi. Pipe built 1927, t = 0.25 inch, unknown grade of steel.

- Line 104. Break at the Aliso Canyon gas storage field. This pipe is 10-inch diameter, MAOP 228 psi, constructed 1941 with electric arc welds, t = 0.203 inches, unknown grade.

- Line 120. Two breaks on Balboa Boulevard. 22-inch diameter steel pipe built 1930 (variously reported as 1941) with unshielded electric arc girth welds. Pressure 175 psi, t = 0.281 inches, Grade B steel. The pipeline failed in tension at a lateral spread crack about 900 feet north of another location where the pipe failed in compression wrinkling. A parallel 24-inch pipe, X-60, t = 0.25 inch had already been constructed parallel to the older Line 120, along McLennan Ave. It had not yet been put in service at the time of the earthquake. This parallel pipe was exposed to similar PGDs both in tension and compression, but did not fail. There were also two 1956-vintage 30-inch gas pipes that were not damaged, as well as a 16-inch oil pipeline that was not damaged (built 1961, X-52). Two parallel water pipelines (49-inch and 68-inch) failed in both tension and compression, immediately parallel to the failed Line 120 gas pipe. Gas released by Line 120 was ignited by a stalled pickup truck, leading to an explosion and fire, burning down 5 adjacent single family residences. A parallel 6-inch gas distribution pipeline on the eastern side of Balboa Blvd was also ruptured in tension and compression (45 psi); escaping gas caught fire.

Aliso Canyon is a gas storage field, covering 3,600 acres and including 35 miles of access roads. Gas is injected into the field during times of low gas demand (summer months) and extracted in times of heavy gas demand (winter months). Earthquake effects at Aliso Canyon included deformed above ground pipe supports, displaced above ground injection and withdraw pipes, and structural damage to a fan unit used to cool compressed gas before injection in storage wells. The supply of gas from Aliso was disrupted for 5 days. Two decades later, a well failed resulting in uncontrolled release of stored gas.

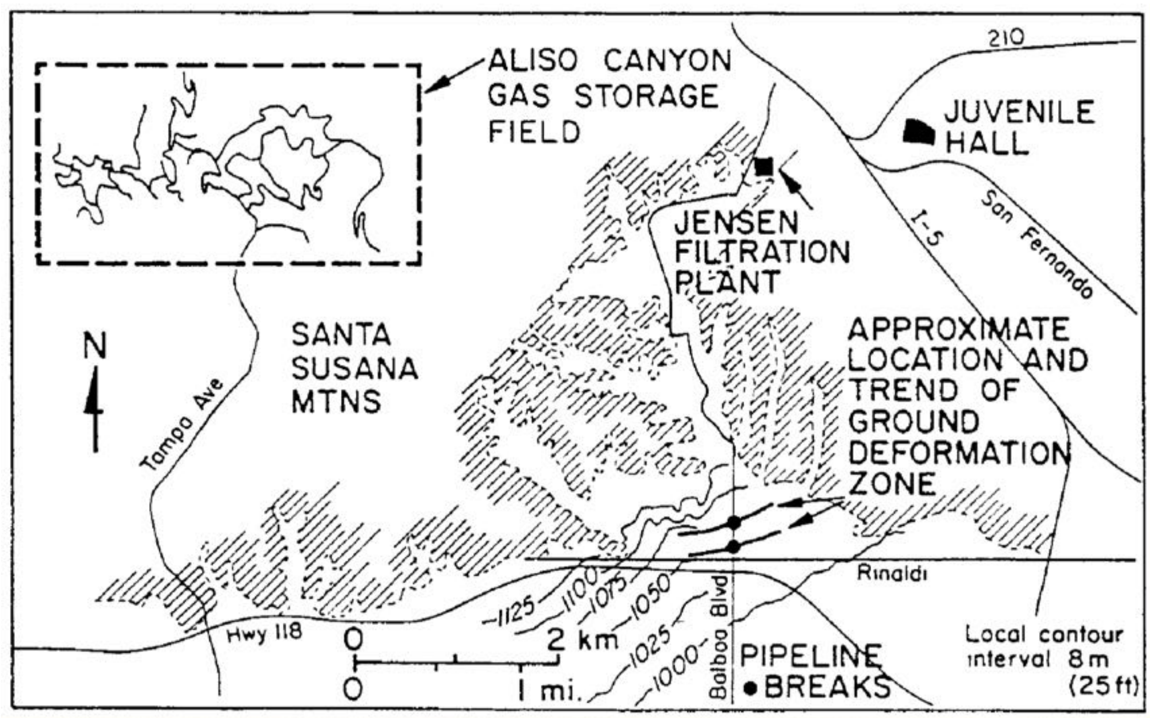


Figure 6.28-2. Gas System in Northern San Fernando Valley, Balboa Boulevard (after O'Rourke)

By applying a length to each pipeline, O'Rourke derived a "repair rate per km) trend for SoCalGas Transmission pipes in the 1952 Taft, 1971 San Fernando and 1994 Northridge earthquakes. He found the following trends:

- RR ~ 1 to 1.6 / km for pre-1929 pipes, exposed to strong shaking and no readily apparent concurrent PGDs.
- RR ~ 0.1 to 0.2 / km for post-1930 pipes, exposed to strong shaking and no readily apparent concurrent PGDs.
- RR ~ 0 for pipes with modern electric arc welds, exposed to PGDs on the order of a few inches to ~1 to 2 feet.

In Section 7 of this report, this information is updated to correlate the damage rates with PGVs.

McDonough (1995) provides the following additional information:

- At the time of the earthquake, there were no cast iron gas pipes in the SoCalGas system.

- In addition to the above-described damage to transmission gas pipes, there were 123 steel distribution main failures, 84 service line failures and 33 polyethylene breaks (primarily on transition fittings and punch tees). An additional 394 corrosion-related leaks were identified.

- About 150,800 customers were without gas service, primarily due to the customers shutting off their own gas service valves. 15,021 of these actually had leakage or damage. About 122,000 of these customers had service restored within 12 days; as with other earthquakes, the gas re-light effort was the most time consuming activity. The remaining number were not immediately restored due to building structural damage or the customers having temporarily relocated and unavailable to coordinate the re-light effort.

- About 841 automatic shut-off valves were identified as having closed. There was gas leakage at 162 (19.3%) of these locations.

- About 2,526 unstrapped water heaters were damaged while 211 strapped water heaters sustained damage or were leaking.

- About 184 mobile homes were destroyed by fire. Some of these fell off their foundations (typically steel tripods), sometimes causing leaks at the gas service riser, interior gas line or water heater. The close spacing between some of these mobile homes and the loss of water pressure, contributed to the spread of the initial fires to adjacent buildings, even though there was nearly no wind at the time of the earthquake.

- SoCalGas responded to the earthquake. About 400,000 telephone calls were received and processed within the first two weeks of the earthquake. SoCalGas received mutual aid from 4 neighboring gas utilities. About 2,840 miles of pipe were leak surveyed to identify leak locations.

6.29 Hector Mine M 7.1 1999

The M 7.1 Hector Mine earthquake occurred on October 16, 1999 at 2:47 pm local time (variously reported as M 7.0). This was a strike-slip earthquake in a remote part of the Mojave Desert, 47 miles east-southeast of Barstow.

The epicenter was at 34.59°N 116.27°W. Surface rupture extended for 48 km, along the Lavic fault in the northwest and the Bullion fault in the southeast. A maximum of about 5 meters of right lateral offset was recorded near the center of the rupture length. Prior to this earthquake, the Lavic fault had been mapped, but had shown no evidence of being Holocene active.

Almost no damage was reported in the immediate area of the earthquake due to its remote location in the Mojave Desert.

Figure 6.26-1 shows the mapped surface rupture traces of associated with the 1999 Hector Mine earthquake (red lines in the northeast), as well as the mapped traces for five other faults in the Mojave desert with possible maximum earthquakes (Pisgah 7.0, Calico 7.0, Landers 7.4, Lenwood 7.2, Helendale 7.2). The faults in red have had historic ruptures (Hector Mine 1999, Landers 1992); the faults in orange are Holocene active.

6.30 Niigata M 7.5 1964

The M 7.6 Niigata earthquake occurred on June 16 1964 at 1:01 pm local time. Niigata is a large city on the west coast of Japan. The epicenter was about 50 km offshore, north of Niigata. There were over 3,400 houses destroyed and a further 11,000 damaged. Much of Niigata was built atop the delta of the Shinano and Agano rivers, and liquefaction was widespread. Collapse of large apartment buildings and the collapse of multiple spans of the Showa bridge across the Shinano River, both due to liquefaction, are among the more notable failures in this earthquake. Failures of a liquid fuel pipe led to large releases of gasoline that later caught fire, spreading to nearby fuel tanks; the fire continued for 12 days.

There was about 64 km of welded steel gas transmission pipes exposed to strong shaking / liquefaction effects in this earthquake. These pipes included both older-style gas-welds and newer-style arc-welds for the girth joints. Narita (1976) observed that the gas-welded joints tended to have extremely poor root penetration; and these types of pipes had about a 5-fold higher break rate (4.4 per km) than those with arc-welded girth joints (0.9 per km). These repair rates (0.9 to 4.4 per km) are high, and possibly reflected lower quality welded pipe.

There was also about 162 km of arc-welded steel 6-inch to 10-inch diameter gas distribution and transmission pipes. These pipes were reported to have higher quality welding and inspection (including spot radiography). These had about 0.01 to 0.02 failures per km, or about 70 times lower than for other arc-welded pipes that had not been installed with higher quality welding and inspection.

6.31 Kobe M 6.9 1995

The M 6.9 Kobe earthquake (in Japan, this earthquake is more commonly called the Great Hanshin earthquake) occurred on January 17, 1995. The earthquake caused over 5,500 deaths and nearly 200,000 houses collapsed or damaged.

The earthquake resulted in strongest shaking in the city of Kobe (population 1.2 million), with modest levels of shaking in Osaka (population 19 million), and strong shaking in several smaller communities. The Osaka Gas company provides natural gas for this entire area.

Oka (1996) reported the following. Osaka Gas suspended gas supply to about 0.86 million = of a total of 5.7 million customers. The suspensions were triggered by sensors on transmission pipe that were set to automatically isolate (close the valve) the pipe in the event that PGA thresholds were exceeded. Restoration efforts were especially difficult due to large amounts of water and sand inside the damaged gas pipes. Restoration of the gas system to most customers was completed 85 days after the earthquake.

Damage to the natural gas system was widespread. There were no failures to transmission pipes (~490 km, all steel, 1 MPa to 4 MPa. 150 - 400 psi), about 106 failures in the medium pressure pipes (90% steel) (~0.1 MPa to 1 MPa, 15 psi to 150 psi) and over 26,000 failures in the low pressure distribution pipes (~ < 2.5 kPa, < 0.4 psi).

At the time of the earthquake, medium pressure pipes were either steel or cast iron; low pressure distribution pipes were steel (welded or mechanically of screwed jointed), cast iron, PE.

Of the failures to steel medium pressure pipes, 96 were to steel pipe (14 failures at welded joints, 22 at flanged joints, 60 at dresser couplings). There were also 10 failures for cast iron pipe. All of the failures were attributed to joints; none to the main body of the pipe. All 14 welded girth joint failures were attributed to butt welds described as "low quality". About half the damage was located in areas with nearby observed effects of liquefaction; many of the remainder in areas that were subjected to moderate to very strong levels of shaking (PGA generally > 0.3g); and about 10% located in areas subjected to moderate levels of shaking (PGA ~0.1 to 0.2g).

The failures in the low pressure distribution system included the following. ~2.3% on distribution mains; ~18.2% on branch pipes; 24.5% on service pipes (in the street); 14.7% on service pipes (on customer's property); 40.2% on pipes within the customer's house. The damage to service laterals / meter sets included many cases where the house collapsed. At the time of the earthquake, the low pressure distribution pipes were almost entirely screwed steel, with still a small percentage of cast iron. More than 99% of all the damage to low pressure distribution pipes were attributed to joint failures; less than 1% to failure of the main body of the pipe.

In the years after the earthquake, many gas companies in Japan adopted the strategy to use real-time ground motion instrumental data to isolate blocks of the gas systems. By the time of the 2016 Kyushu earthquake, this was set at an equivalent PGV of 60 cm/sec. The basis of PGV = 60 cm/sec was in part derived from the observations in the 1995 Kobe earthquake that the majority of damage to the gas system was at locations where PGV exceeded 60 cm; and nearly no damage at locations with PGV < 60 cm/sec.

6.32 Christchurch, New Zealand M 6.0 - 7.1 2010-2011

A sequence of strong earthquakes affected the City of Christchurch New Zealand and nearby urban centers. There were three major earthquakes in the sequence: M 7.1 (September 4 2010); M 6.3 (February 22 2011); M 6.0 (June 13 2011). There were many aftershocks after each of these events.

The September 4, 2010 Darfield, New Zealand earthquake occurred at 4:30 a.m. local time had a moment magnitude (M) of 7.1. The epicenter of this earthquake was located west of Rolleston at 43.53°S, 172.12°E with a depth of 10 km; about 30 km southwest of the central business district of Christchurch. There was about 22 km of surface rupture, with up to 4 meters (average along the entire fault rupture zone of about 2 meters) right lateral offset; there was some surface uplift at various places along the fault. Heavy localized damage occurred to water and wastewater pipelines caused by liquefaction-induced lateral spreads and settlements in Christchurch and nearby Kaiapoi; liquefaction damaged the Port of Lyttleton; surface faulting and liquefaction damaged railroad tracks; moderate levels of ground shaking in Christchurch (commonly around PGA = 0.2g) caused some damage to electric power substations. Liquefaction also damaged roads, bridges, buried telecommunication cables, and levees. Moderate levels of ground motion damaged some unreinforced masonry buildings, but there were no fatalities. This earthquake caused a few fire ignitions.

The February 22, 2011 magnitude 6.3 Christchurch Earthquake occurred at 12:51 p.m. local time. The epicenter of this earthquake located about 10 km southeast of Christchurch (43.58° S, 172.70° E) with a depth of 5 km, in the hills close to Lyttleton Port. The epicenter's close proximity to Christchurch central business district as compared to the September 4 2010 event led to much higher ground shaking (commonly in the range of PGA = 0.5g) and far more damage in this M 6.3 event than in the prior M 7.1 event. This event triggered widespread liquefaction, with severe damage to buried utilities in central and eastern Christchurch (water pipes, wastewater pipes, power cables, several water wells, the wastewater treatment plant); and more damage to the port, roads, bridges. Very high levels of shaking in the Port Hills led to substantial rock falls and some landslides. The largest City potable water reservoir was destroyed. This event resulted in significant damage to buildings in the central business district and 181 fatalities. Due to (perhaps) concern for more damage due to potential aftershocks, much of the central business district was "closed" to the public for many months, creating a "ghost town" with accumulating economic impacts to the community.

The June 13, 2011 magnitude 6.0 Christchurch Earthquake occurred at 2:21 p.m. local time. The epicenter of this earthquake located about 10 km southeast of Christchurch (43.58° S, 172.74° E) with a depth of 9 km in the hills close to suburban community of Sumner. Its close proximity to the Christchurch central business district led to very high levels of ground shaking for the eastern side of Christchurch, further damaging previously-weakened unreinforced buildings. Liquefaction again damaged some buried water and wastewater pipes.

There is a liquid petroleum gas (LPG) reticulated (piped) distribution system that serves the Central Business District and other parts of Christchurch, owned by Contact Energy operating under the Rockgas brand. This is the only gas pipeline supply network in Christchurch. At the time of the earthquake sequence, it was about 10 to 15 years old (portion within the Central Business District ~15 years old; the outer portions were ~10 years old).

In Figure 6.32-1 the heavy bold lines show streets with gas pipelines, while the remaining streets shown in light color do not have piped gas service. A small amount of the LPG is supplied by rail and truck. The distribution system includes about 170 km of pipelines, ranging in nominal diameter from 63 mm to 315 mm; all are medium density polyethylene (MDPE) with electrofusion welds. The common pipe wall thicknesses are about 9 mm (90 mm pipe) to 14 mm (160 mm pipe).

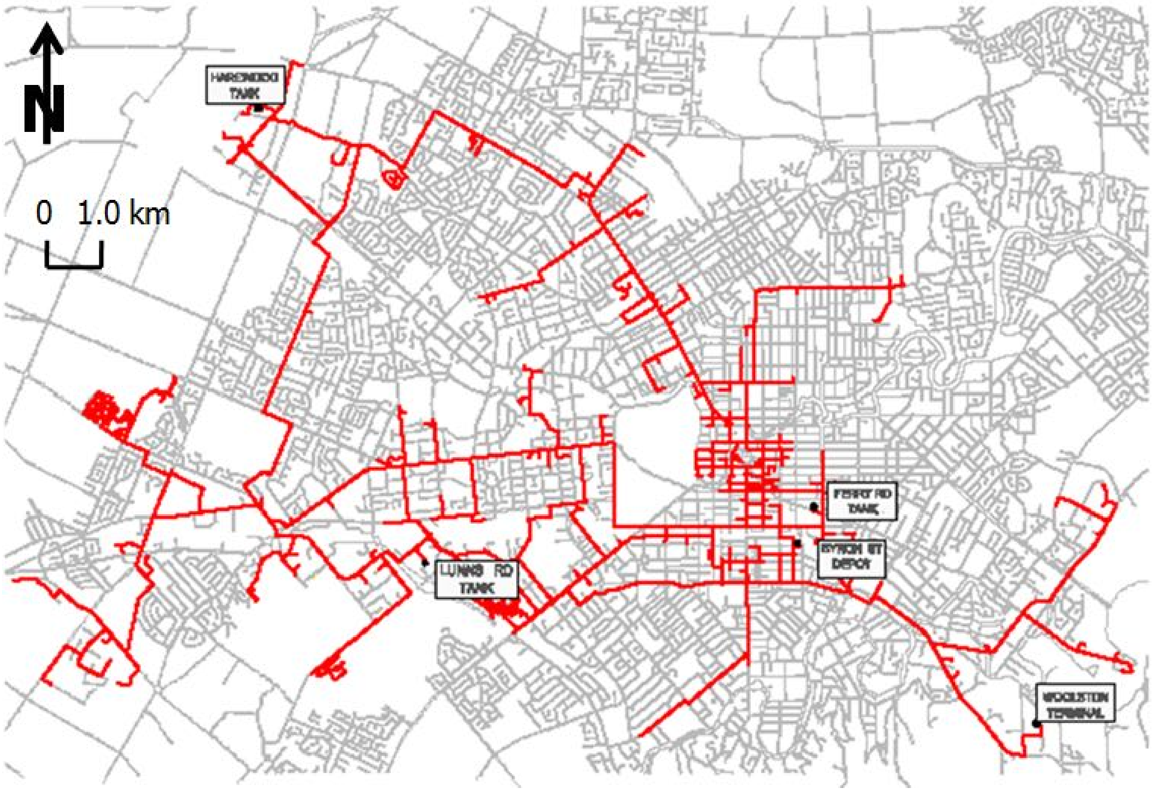


Figure 6.32-1. Gas Pipeline Network in Christchurch

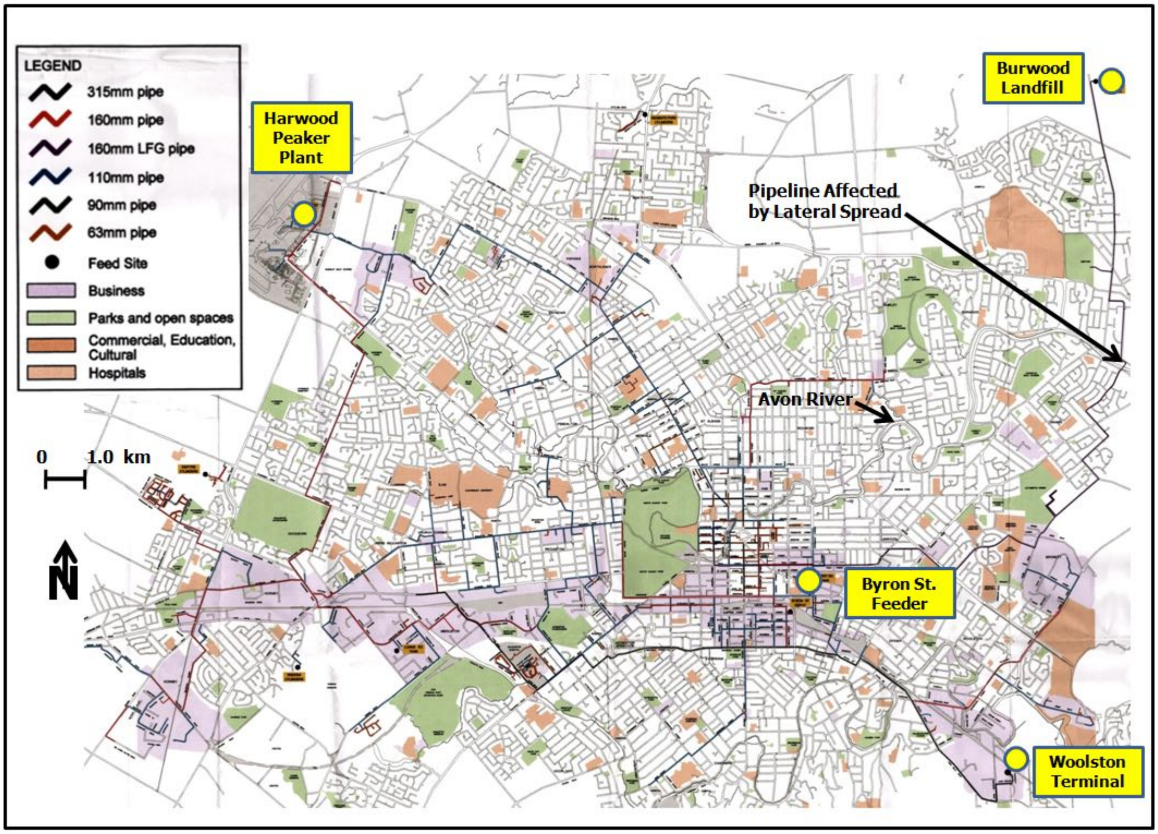


Figure 6.32-2. Gas Pipeline Network in Christchurch, Selected Features

Most of the gas for the distribution system is supplied from Woolston Terminal (Figures 6.32-1 and 6.32-2), which receives LPG through a pipeline from the neighboring wholesaler, Liquigas. Liquigas has 2000 tons storage, supplied by a pipeline across the Port Hills from Lyttleton Port. There is 500 tons of tank storage at the Woolston Terminal and a vaporization plant to convert LPG to gas phase. There is the Harewood peaker plant at Christchurch Airport and three back-up feeder plants, all of which receive LPG by truck.

The Woolston Terminal requires water for hot water heating to vaporize the LPG as well as electric power for controls to manage the heating of the water. Water is also used for the fire sprinkler system. Diesel engines and electric generators were available for backup power.

The petroleum gas consists of a mixture of propane and butane. At the feeder plants the LPG is vaporized. The vaporization process predominantly uses hot water to heat the gas and transform it from a liquid. As a backup, gas can be supplied for a limited time from residual pressure in the tanks.

The distribution network is subdivided into about 189 separately valved zones. To close off a zone, service people must be dispatched to manually shut off a valve. Outside the main distribution network, several standalone networks are fed from gas cylinders or tanks.

September 4 2010 Earthquake. At the time of the September 4, 2010 earthquake, the gas mixture was 60% propane and 40% butane, at an average network pressure of about 90 kPa (13 psi).

Overall, the system performed very well in this earthquake. There was no disruption to gas service. The only loss to the system was failure of a backup generator at the peaker plant at Harewood. Power was restored to this site late Saturday September 4, 2010. There was no observed damage to the distribution pipelines. Most of the gas pipelines were outside zones of liquefaction-induced ground deformation, although some were located close to a zone of liquefaction adjacent to Hagley Park. One 160 mm MDPE pipeline from the Burwood Landfill (Figure 6.32-2) was located in areas of liquefaction along Bower Avenue, Palmers Road and Carisbrooke Street, but did not sustain damage.

Contact Energy performed a gas leakage survey after the earthquake. It was found that there were a number of valve pits where the surface of the road sustained permanent ground deformation relative to the buried valves. Although some restoration around the valve pits was warranted, there was no damage to the underlying pipelines.

February 22 2011 Earthquake. After the February 22, 2011 earthquake, gas flow into the Christchurch Central Business District was shut off, starting about 3:00 pm at the request of Civil Defense. All feeders were shut off in stages. Selected valves were closed to ease the re-pressurization process. The Harewood peaker was the last to be turned off around 6:00 pm. The lines were shut down from about 70 - 90 kPa (10 - 13 psi) and equalized at approximately 20 kPa (3 psi), which was the shut-in pressure during restoration of the system.

All shutdowns were manual. Because traffic was a hindrance, bicycles were used in many instances to negotiate traffic and gain access to various valve locations.

Difficulties were experienced with hand held radios. There was topographical interference with some radio transmissions. Most cell phone service was restored by February 23 2011, and cell phone communication was used extensively among the crews during restoration of service.

Crews from Wellington and Queenstown came to assist, arriving on February 23 2011. Twenty-two gas company staff and contractors, with help from 8 additional personnel from the parent company worked on restarting the system. A hazard risk analysis was performed on February 23 2011 and determined it was acceptable to start re-pressurizing the main lines, initiated the night of February 23, starting with the Harewood peaker. Both water and electricity were available in the western parts of the city when this process was started.

Once a section of main was re-pressurized, a 1-hour test was run to ensure the pressure could be held. The pressurization process was as follows: (1) isolate pipeline sections, (2) shut all customer services, (3) put a gage on one service, and (4) ensure system is holding pressure before accepting. This process was repeated until the entire system was livened.

Although electric power had been lost at the Woolston terminal during the first day after the earthquake, backup diesel-powered generators were available. Loss of water interrupted operation of the hot water vaporizers, but residual pressure was available in the storage tanks for gas flow. Refueling storage tanks was suspended until water was restored to operate the sprinkler system for fire suppression.

It took about 12 days to re-pressurize the entire system, excluding the central business district. Approximately 1,400 services were shut down. No services were energized until the customers were contacted. All services except those in the central business district were restored within 2 weeks, proceeding slowly with about 15% of customers restored at 8 days and 60% at 14 days. Basically, within two weeks gas was restored to customers who could receive it.

To protect against gas leakage, all Rockgas pipelines supplying damaged portions of the central business district were cut and capped. These pipelines represent approximately 15% of the pipelines within the system. The Byron St. feeder plant was not placed back in operation until water service was restored to it.

There was no damage to any of the MDPE mains in the system that was restored to operation. Significant parts of the system in eastern Christchurch were located in areas with liquefaction-induced ground deformation.

Figure 6.32-2 highlights the 160-mm pipeline conveying gas from the Burwood Landfill. A portion of this pipeline parallel to the Avon River moved in an area where there was displacement and contact by a nearby water well head. The deformed portion of the pipeline was circumvented by replacing approximately 100 meters of pipe between two elbows that had not moved.

Gas service was not restored to many customers due to lost buildings and businesses. In April, 2011 Rockgas had lost about 40% of its customer services, and was providing about 1/3 of the gas supply prior to the February 22, 2011 earthquake. Approximately 25% of the gas supply customers had been businesses, such as hotels and restaurants, which were located in the central business district.

Damage in the gas distribution network was minimal. There was documented damage in only one service, which was tied into a concrete block that reportedly was subjected to ground deformation. There were two minor flange leaks on steel pipework at the Woolston Terminal. There were no known gas related fires.

June 11 2011 Earthquake. There was no damage in the gas distribution system as a result of the June 11 2011 event.

6.33 Tohoku M 9.0 2011

The Great Tohoku M 9.0 earthquake occurred on March 11 2011. By far the largest losses to life and property were due to tsunami inundation.

The following description of natural gas pipelines includes information provided by Prof. Maruyama, Prof. Nojima and the Japan Gas Association, and observations by the author. Except where noted, all these effects were due to ground shaking, liquefaction, or landslide, and exclude damage from the tsunami.

There were 16 separate moderate to large natural gas companies involved with the earthquake. This reflects the very large area affected by the earthquake, coupled with the fact that there were many small coastal communities. The largest communities in the zones with high shaking are the cities of Sendai (population ~1.1 million) and Ishinomaki (population ~200,000). There are dozens of small coastal communities with populations up to about 20,000 people. The major population center of Tokyo was located south of the area with strong shaking, and much of Tokyo was exposed to PGA < 0.05g.

Natural gas service to customers was disrupted in many areas along the Pacific Ocean coastline between Tokyo in the south and Hachinohe in the north. A total of about 456,000 customers immediately lost gas supply, including the effects of tsunami. Restoration times varied in this large geographic area, lasting until about April 15 2011 (35 days post-earthquake) to restore gas supply to customers otherwise unaffected by the tsunami and able to receive gas supply.

A high pressure steel gas transmission pipe was constructed in 1996 to bring natural gas from a LNG terminal in Niigata (west coast of Japan) to two natural gas power plants (900 MW and 450 MW) on the east coast near Sendai. This pipe is 251 km long, constructed of API 5L X60 steel pipe, diameter 508 mm (20 inches) with wall t=11.91 mm (0.47 inches), operating pressure 6.86 MPa (1,000 psi), design Factor of Safety on hoop pressure = 2.5. The gas power plants were both inundated by the tsunami; the 900 MW plant was subsequently demolished; the 450 MW plant was repaired and restored to service in 2012. The eastern half of the gas transmission pipe was exposed to moderate to very strong shaking (PGA ~ 0.5g along the east coast). The pipe traversed some zones with landslide-caused and liquefaction-caused permanent ground deformations. The pipe suffered no leaks. The regulating stations at both power plants were inundated by the tsunami; no leaks were observed; although the transmission pipe had external coating damage. Six valve stations along the pipeline alignment south of the power plants were inundated by the tsunami; there was damage to electrical equipment and adjacent buildings; but no leaks to the pipe itself. In the mountainous terrain, there were landslides / road embankment failures along three stretches of the pipe; at one locations, maximum PGDs along the pipe were about 80 cm (31 inches) over a length of about 53 meters (173 feet), and post-earthquake analysis suggested the steel pipe sustained strains as high as 0.26% (just modestly over yield strain). Because this transmission pipe had no leaks, gas was able to be quickly restored to the City of Sendai's residential and commercial customers.

In the Sendai area, natural gas is provided to customers by the Sendai Gas Bureau. In Sendai, ground shaking was high enough to initially shut off the transmission pipes serving the city. Ground motions were high enough (PGV > 60 cm/sec) that 3 of the 11 blocks of the Sendai gas distribution system were manually isolated. Once the tsunami inundation began at shore line areas (about 45 minutes after the earthquake), it was decided to shut off the entire system as a precaution; which led to shut-off of gas to all 360,000 customers. The level of shaking in much of Sendai was modest, commonly with PGA < 0.2g. The areas affected by the tsunami have relatively low population, with about 3,560 customers in the inundation zones. There were no failures to any medium pressure pipes (45 psi - 150 psi), and there were 190 pipe repairs made to low pressure gas distribution pipes (170 repairs for steel pipes, 20 repairs for ductile iron pipes). The relatively low number of repairs in the Sendai gas system was attributed to the widespread use of seismic resistant pipe. Some of the 190 pipe repairs were at locations where there were local landslides / slope failures in the hilly portions of Sendai, well inland from the ocean.

In the Ishinomaki area, (north of Sendai) gas supply began to be restored about a month after the earthquake; the delay was due to the extensive tsunami inundation impacts in Ishinomaki. There was water inundation at some gas terminal facilities, and cross bracing of gas holders showed evidence of yielding due to inertial shaking.

In the Tokyo area, gas supply was recovered to most areas within a few days. There was extensive liquefaction in Urayasu (a port area immediately northeast of downtown Tokyo), where 8,631 customers lost gas supply for up to 3 weeks.

There was also extensive damage to above ground pipe and other facilities at a nearby LNG terminal along the Pacific coast, due to tsunamic inundation.

6.34 Kumamoto, Kyushu M 7.0 2016

Two strong earthquakes affected the City of Kumamoto, Japan and the nearby urban centers. The two earthquakes are characterized as the fore shock (April 14 2016) and the main shock (April 16 2016). The moment magnitudes of the fore shock was M 6 and the main shock was M 7. The fore shock of M 6 occurred at 9:26 PM (local time). The main shock of M 7 occurred about 28 hours later at 1:25 AM (local time). The main shock produced several recorded motions with PGA (Peak Ground Acceleration) around 0.5g to 1.0g, and PGV (Peak Ground Velocity) around 75 cm/sec. The main shock triggered many landslides, as well as permanent ground deformations (PGDs) due to fault offset (common) and liquefaction (less common). Lifelines were heavily damaged both due to high inertial shaking as well as due to PGDs.

Total fatality after the main shock was 69 dead with 1 missing, in addition to 364 seriously injured and 1,456 with minor injury, as of June 30 2016.

In the area affected by strong ground shaking, about half the area is supplied with natural gas by a piped system. In areas where ground shaking was recorded by instruments to have ground velocities greater than 60 cm/sec (see Section 6.35 for further details), automatic valves cut off the gas supply via the transmission pipe network. The selection of 60 cm/sec was based on Japanese observations that older non-seismic-installed gas pipes (such as galvanized steel pipe with screwed joints) tend to get damaged at or above this level. Most structures had gas meters with earthquake sensors, and these meters automatically turned off due once they sensed high levels of shaking. There was some damage to older non-seismic-designed gas mains, but more than 85% of the gas mains were constructed with seismic-resistant pipes and these had little or no damage. Most of the gas system repair effort occurred to service laterals and meters, as well as work within customer's houses. Restoration of the gas system took some time. The shut-off of the gas transmission pipes and the local shutoff at customer meters may have helped avoid gas-fed fires; there were no fire conflagrations in this earthquake sequence.

The pipe inventory in the area was about 1,647 km of transmission mains and 12,689 km of distribution mains. At the time of the earthquake, about 86% of this inventory was constructed using seismic resistant pipes, including both welded steel transmission or polyethylene (PE) distribution pipes. There was no damage to any PE pipes in the system.

The following damage to gas mains occurred:

- 0 repairs to medium pressure (~45 to 150 psi) transmission pipes
- 9 repairs for medium pressure pipe mains (~15 to 45 psi). Damage was at mechanical joints. In each case, the damage can be characterized as a loosening of the joint that resulted in a detectable leak. The typical repair was to excavate the pipe, and tighten the joint, see Figure 6.34-1.
- 79 repairs to low pressure pipe mains (79 / 12,689 km = 0.0062 repairs per km). This includes damage to mechanical joints at 23 places (needing tightening of the joint, see Figure 6.34-2), and damage at 46 low pressure galvanized steel pipes that were connected with screwed connections

(damage included cracks, breakage of the joint, with repair needed pipe replacement, see Figure 6.34-3).

- There was no damage to PE (polyethylene) pipe used for either medium pressure or low pressure distribution pipe.

There was substantial damage to service laterals, as follows:

- Supply pipe. 41 locations, including mechanical joints (14 locations) and screwed joints on galvanized steel pipe (27 locations).

- 416 locations, buried, see Figure 6.34-4, including mechanical joints (87 locations), screwed joints in galvanized steel pipe (185 locations), and meter gas stoppers (144 locations) etc.

- 375 locations, above ground, with damage being on the downstream side of the microcomputer gas meter with earthquake isolation function.

- There was no damage to PE pipe.

The trends were as follows:

- In areas where fewer than 80% of all pipes were MDPE (considered to be earthquake resistant), the pipe repair rate for mains was 0.10 repairs per km, correlated to a typical ground motion PGV of about 80 cm/sec.

- In areas where between 80% to 90% of all pipes were MDPE (considered to be earthquake resistant), the pipe repair rate for mains was 0.05 repairs per km, correlated to a typical ground motion PGV of about 85 cm/sec.

- In areas where over 90% of all pipes were MDPE (considered to be earthquake resistant), the pipe repair rate for mains was 0.03 repairs per km, correlated to a typical ground motion PGV of about 80 cm/sec.

Figure 6.34-1. Repair to medium pressure steel pipe; repair was to tighten the mechanical joint (typical of 9 locations)

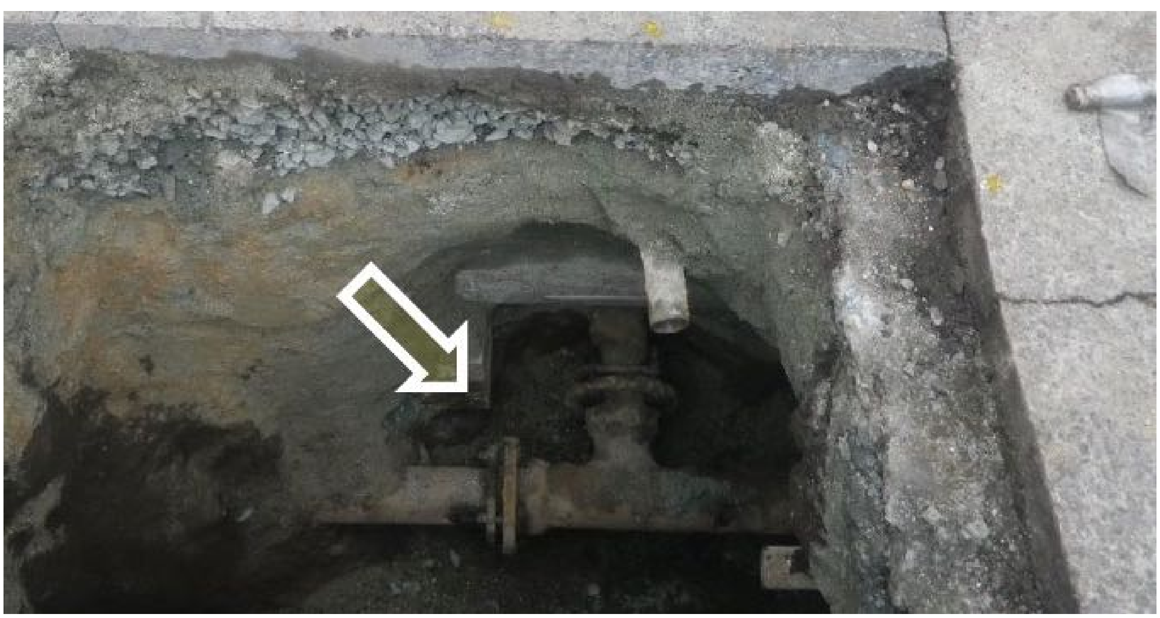


Figure 6.34-2. Repair to low pressure distribution steel pipe; repair was to tighten the mechanical joint (typical of 23 locations)

Figure 6.34-3. Repair to low pressure distribution steel screwed joint pipe; repair was to tighten the mechanical joint

Figure 6.34-4. Repair to low pressure service lateral

The repair of all the gas pipes, including re-lights, etc., took a substantial effort. Figure 6.34-5 shows the number of workers involved with the restoration of the gas system, which peaked at 4,641 workers. Saibu Gas provided 1,965 workers. The Japan Gas Association provided an additional 2,676 workers, with these people coming from 22 other gas companies in Japan.

As part of the emergency response effort, 127 mobile gas generating facilities were used, and 15,022 cassette stoves (portable gas stoves) and more than 60,000 cassette gas cylinders were distributed to houses, municipalities, etc.

It was felt that the interruption of supply and automatic gas shut off valves at houses reduced (eliminated) secondary impacts, namely gas-fueled fires.

It was felt that since about 85% of all pipe had already been replaced with "seismic resistant pipe", that the overall impacts were greatly reduced. It was felt that a continuing effort to replace vulnerable distribution pipe with seismic resistant pipe is a good practice.

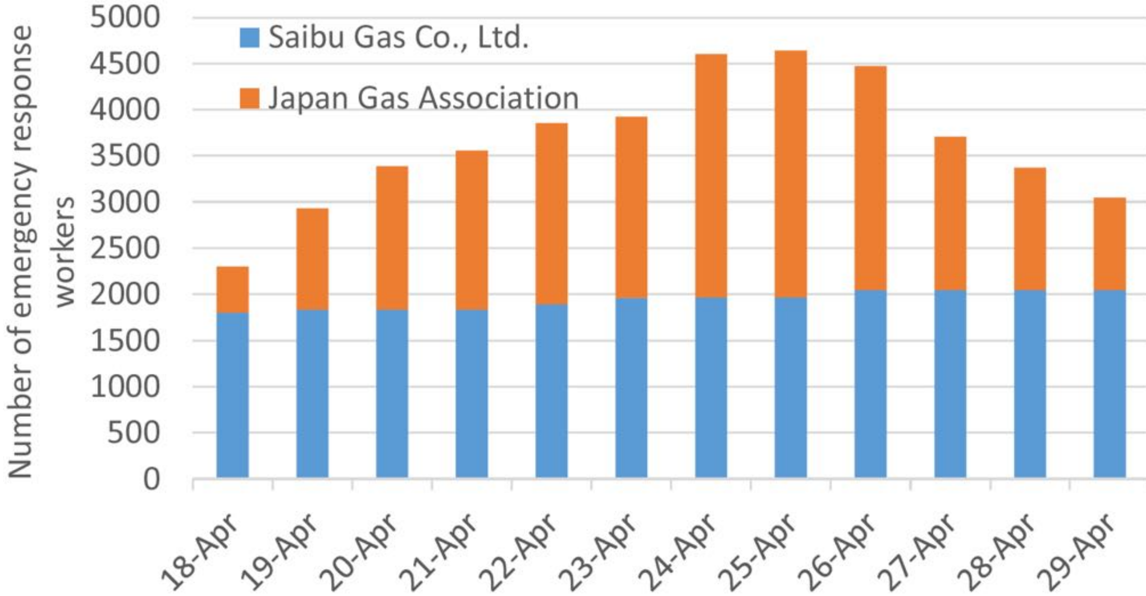


Figure 6.34-5. Gas workers in emergency response

For further information about lifeline performance in this earthquake, see Tang and Eidinger (2017).

6.35 Hokkaido M 6.7 2018

A strong earthquake occurred southeast of Sapporo, Japan at 3:08 am, September 6 2018 local time. The moment magnitude of the main shock was M 6.7. The epicenter was located at 42.671° N, 131.933° E at a depth of 31 km, Figure 6.35-1. In Japan, this earthquake is sometimes referred to as the Hokkaido Ballistic Eastern Earthquake of Heisei 30, or sometimes the Hokkaido Iburi East Earthquake. In this report, it is called the Hokkaido earthquake. See Eidinger and Tang (2018) for a description of lifeline performance in this earthquake.

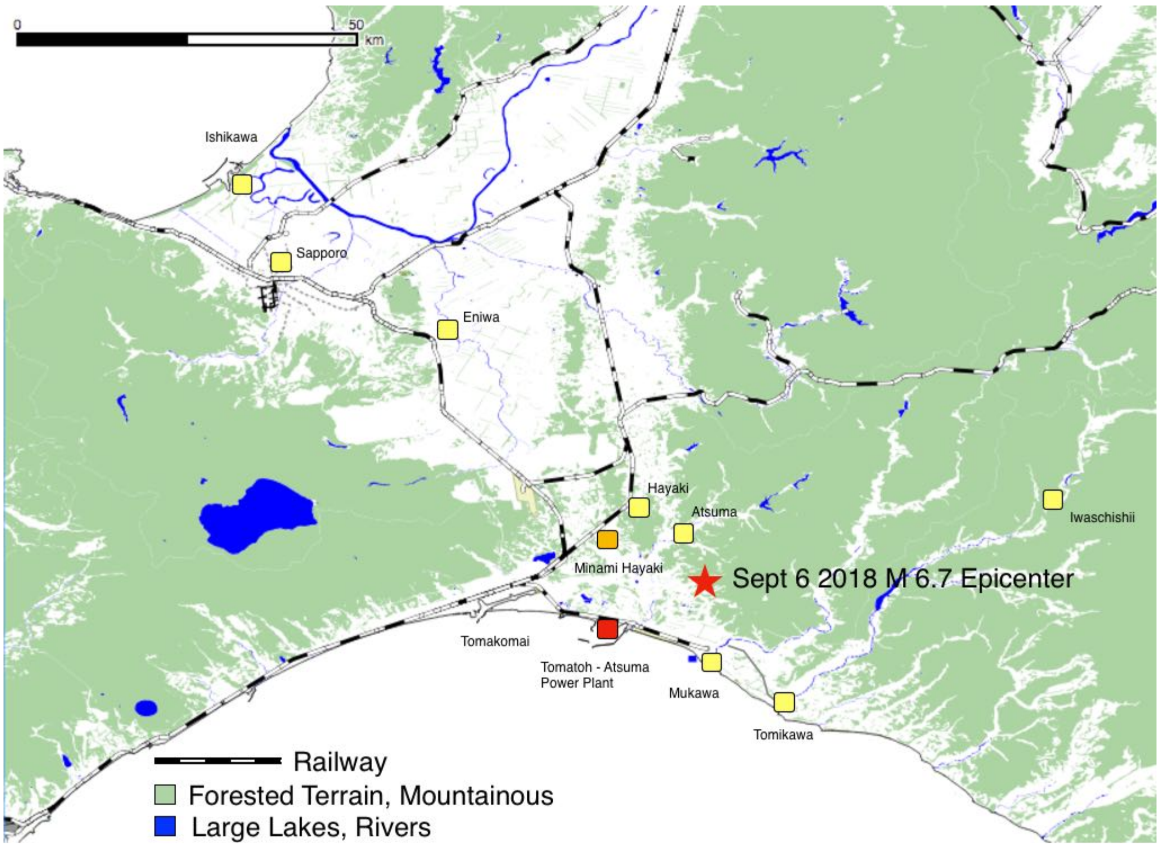


Figure 6.35-1. Location of Epicenter and Selected PlaceNames

The earthquake triggered many landslides (widespread), as well as liquefaction (less common). This earthquake probably produced the greatest number of landslides with significant PGDs in Japan in the past 100 years or more. In the mountainous areas exposed to strong shaking (commonly PGA in the range of 0.4g to 0.6g, located north of the red star epicenter symbol in Figure 6.35-1), there were thousands of landslides, and about 10% to 20% of these slide-susceptible areas had deep-seated slides with PGDs commonly over a meter; in some cases, 10s of meters; and in a few cases, 100s of meters. Figure 6.35-2 shows one hillside area in the epicentral region that sustained many deep landslides, with debris run-outs on the order of 100 meters. Much of the underlying soils in the area were deposited by volcanic ash over the past 40,000 years; this material, when saturated, is especially prone to failure. Most of the fatalities in this earthquake were due to people being killed in their houses when impacted by the slides.

Figure 6.35-2. Landslide zone near the epicenter

The epicentral region was largely rural, with valleys dominated by agriculture; there were no underground natural gas systems in that area. About 60 km to the northwest of the epicenter is the city of Sapporo, with an urban population of about 2 million people. Nearly all the urbanized areas are served by a piped natural gas network. Figure 6.35-3 shows a map of the cities in Hokkaido with natural gas systems supplied by underground pipe to end-user customers. The Kita Gas Company operates the natural gas system for Sapporo.

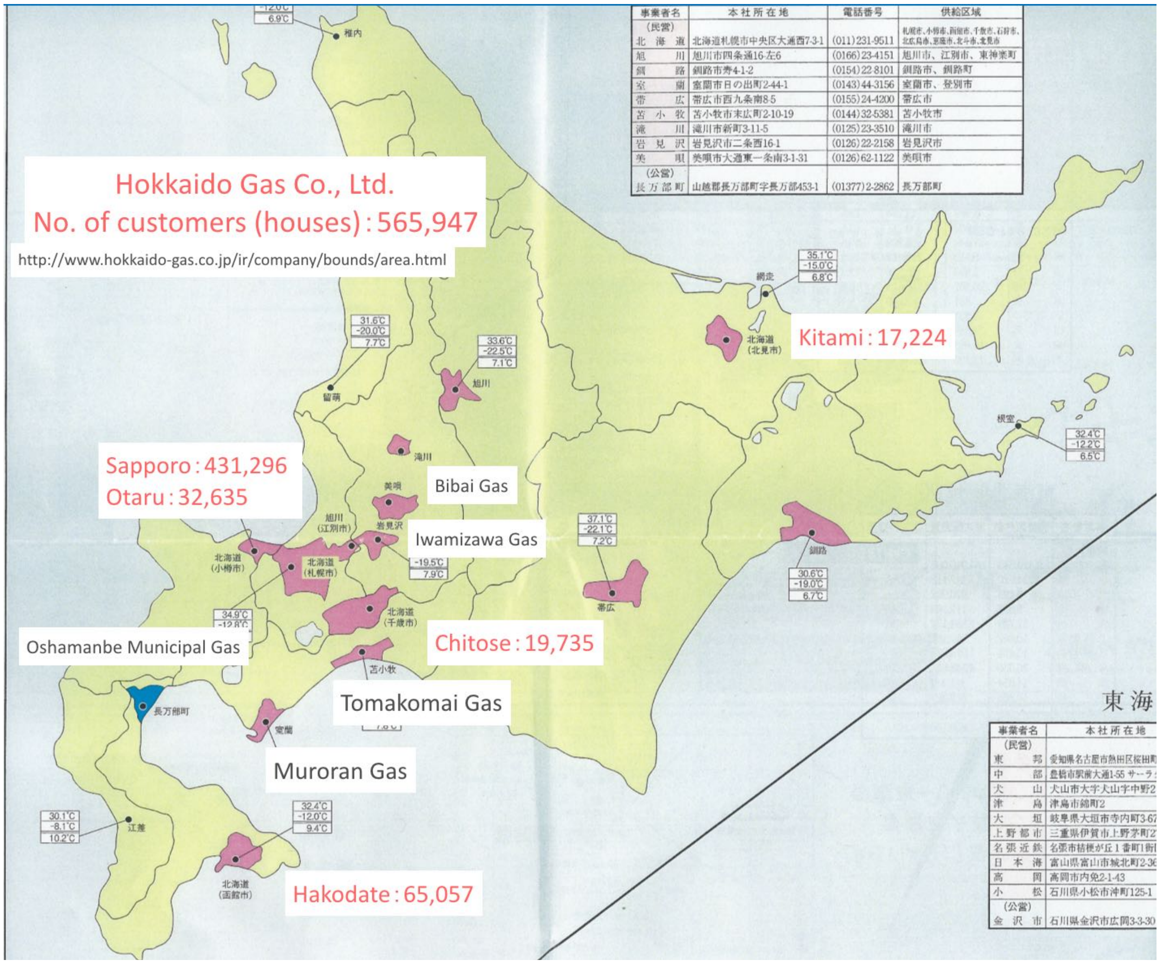


Figure 6.35-3. Natural Gas Systems, Hokkaido Island

By far the largest system serves the City of Sapporo, with about 431,000 customers. Figure 6.35-4 shows a schematic that describes how the gas system operates and the underlying seismic design strategy. LNG gas is delivered to Hokkaido at the LNG terminal where it is offloaded into large circular concrete tanks via "high pressure" pipelines. These tanks and pipes were designed for seismic forces.

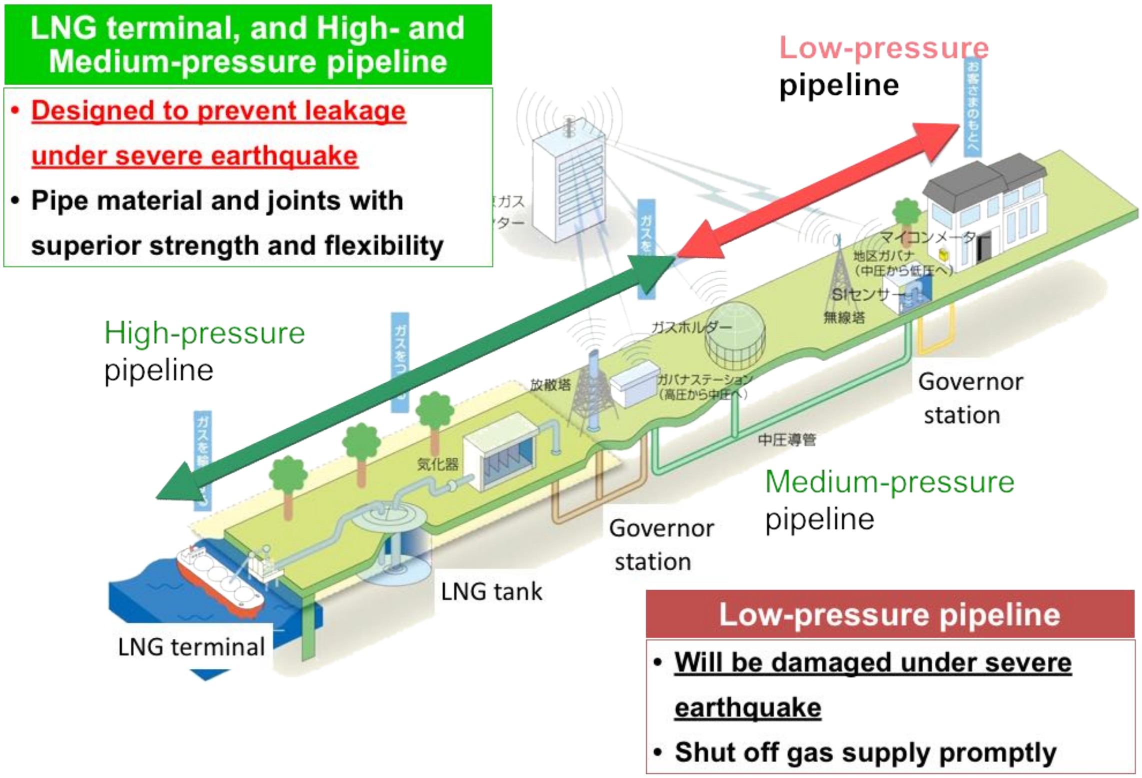


Figure 6.35-4. Schematic Gas System in Sapporo (credit: Prof. Maruyama)

Figure 6.35-5 shows the LNG terminal where natural gas is offloaded from Liquified Natural Gas ships and then stored in four very large tanks at the Ishikari port. Two of these large tanks store gas for the Kita Gas Company; the other two store gas for a nearby gas-fired power plant.

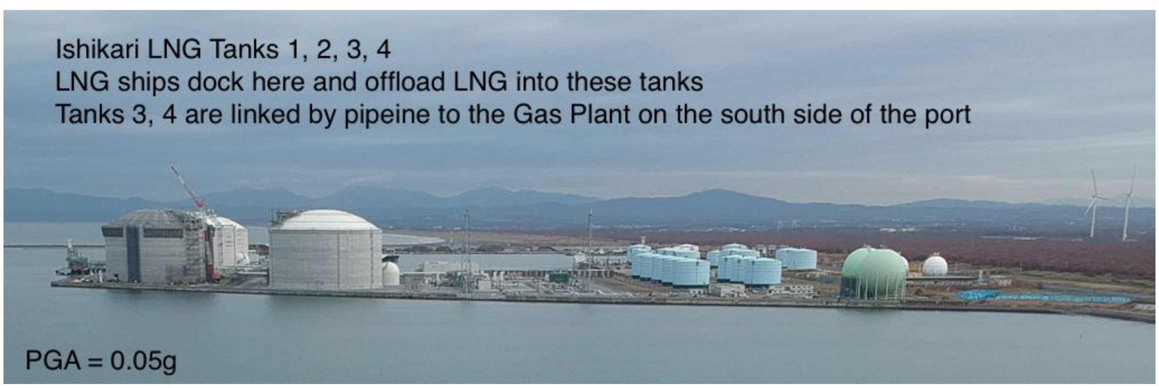


Figure 6.35-5. LNG Tanks at Ishikari LNG Terminal

One of the earthquake strategies used in Japan is to automatically shut off the gas supply transmission system to areas (also called blocks, with about 50,000 houses per block, see Figure 6.35-6) that have experienced ground shaking in excess of a prescribed intensity level, using the following formula. This formula integrates the Spectral Velocity (S_v) response spectrum from an instrument, for 20% damping, for periods T = 0.1 to 2.5 seconds, and if the weighted average is over 60 cm/sec (a moderately high level of ground shaking), the instrument sends a signal to valves in the high pressure gas pipe system to automatically close. The concept here is to avoid new supply of natural gas into an area where ground deformations may have likely resulted in serious levels of underground gas pipe damage. This strategy is relatively easy to implement, needing only a suitable instrument and logic to convert a felt motion into an integrated spectrum, a process that can be done within a few seconds or so of the end of shaking), and then a signal to suitable pipe valves at suitable locations to close. Of course, it would be better if this strategy relied on PGDs (rather than ground velocities), as well as actual gas pipe damage (indicated by sudden loss of pressure), but PGDs are nearly impossible to measure within the first seconds after an earthquake, and knowing the exact pattern of gas pipe damage is similarly difficult to assess in the first seconds after an earthquake. The isolation of the gas supply pipes does little to nothing to resolve the residual amount of gas within all the gas pipes, which can be a substantial source of fuel for feeding any fire ignitions, should fire ignitions occur.

$$SI = \frac{1}{2.4}\int_{0.1}^{2.5} S_v^{\xi=0.20}(T)dt \geq 60\ cm/sec \text{ [Eq 6-1]}$$

In this earthquake, the highest recorded SI was 57.7 cm/sec, for an instrument near the Chitose airport, located about 20 km west of the epicenter. Therefore, none of the shutoff valves were actuated during this earthquake.

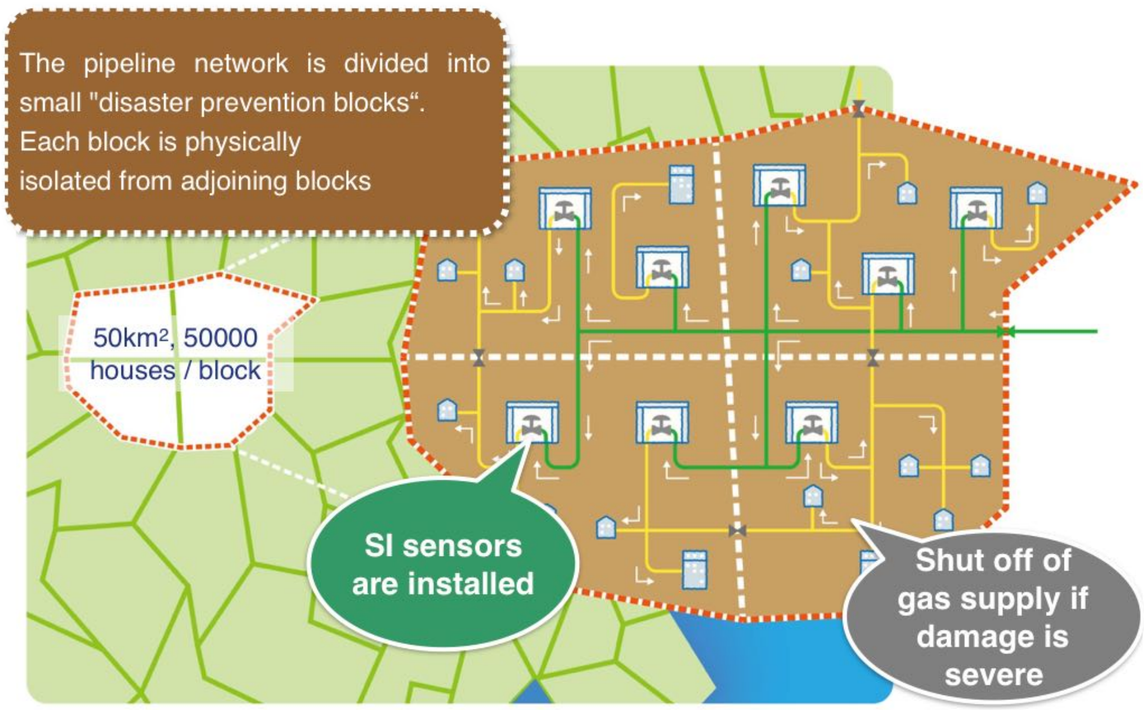


Figure 6.35-6. Gas System Blocks (credit: Prof. Maruyama)

For the City of Sapporo, Figure 6.35-7 shows the locations of the actual blocks (heavy black lines). Recorded SI in Sapporo were: 55 cm/sec (Block B-3, west side of city); 43 cm/sec (Block D-1, north central part of city); 31 cm/sec (Block E-2, east side of city); 26 cm/sec (north of the airport); 35 cm/sec (northeast of the Chitose airport); 57.7 cm/sec (south end of Chitose airport).

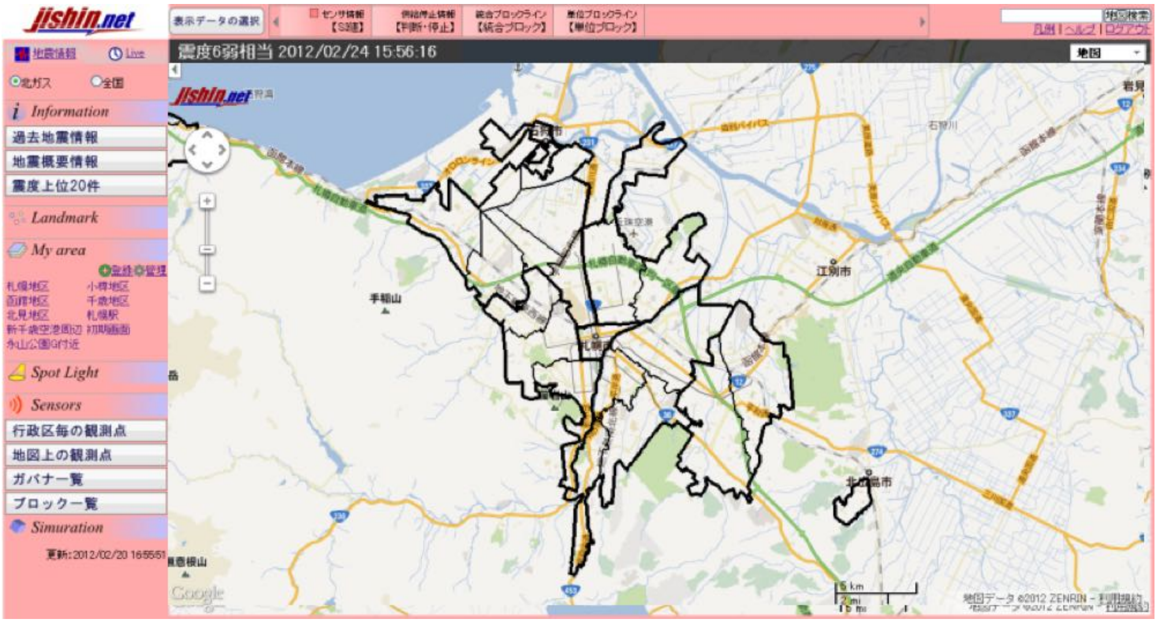


Figure 6.35-7. Gas System Blocks for Sapporo

The concept is that after the earthquake, the strong motion instruments record the motion. Then, software converts the motions into the equivalent SI intensity (cm/sec), using the equation above. This should take place within 5 minutes of the earthquake. For any gas transmission pipe location where SI exceeds 60 cm/sec, shut-off valves are closed. Power to operate the shut-off valves is derived from differential pressure within the pipes; not from offsite power.

In this earthquake, no shut off valves closed because no motions exceeded 57.7 cm/sec. Therefore, gas was constantly supplied to Sapporo and to Chitose. There were no fires reported in either of these areas.

At the LNG terminal, offsite power was immediately lost at 3:07 am. The gas generator plant then stopped due to loss of offsite power. Operations continued using power from emergency generators. Offsite power was restored to the LNG port at 23:35 September 6 2018 (about a 20 hour outage).

By 3:14 am, all the instruments reported in that SI was less than 60 cm/sec. Therefore, operations continued.

By 3:53 am, an emergency response team was formed to respond to any issued that might arise.

For the three days from September 6 to September 9, gas survey teams were dispatched to look for leaks. No leaks were reported. At 16:30 on September 9, the survey teams were dismissed.

There was no damage reported to any of the gas controls in the system.

The status of buried pipes was as follows. The range of motions in Sapporo was commonly PGA = 0.05g (west side) to 0.15g (east side); PGV = 10 cm/sec (west side) to 30 cm/sec (east side). There were a few areas with liquefaction in Sapporo; the areas with the most severe liquefaction had no buried natural gas pipes; those areas did have water pipes that were damaged, see Eidinger and Tang (2018) for details.

- High pressure pipe from the LNG plant to regulating stations (~ 1 MPa, 150 psi). About 40 km of welded steel pipe. No damage.

- Medium pressure pipe (~ 45 psi). 654 km. No damage.

- Low pressure pipe (< 0.5 psi). 4,697 km. 2 leaks. Both pipes were located in soft ground areas. Mostly Medium Density Polyethylene Pipe.

- Service laterals to houses. 11 leaks. These leaks appeared to be due to corrosion. These leaks were found when customers reported a smell from gas, and called in.

There was no reported damage to either the Tomakomai Gas system (common PGA ~0.25g to 0.35g) or the Muroran Gas system (common PGA ~ 0.10g).

The good performance of the gas system is attributed to the following factors:

- There were very few natural gas pipes exposed to PGDs due to liquefaction; none due to surface faulting; none due to landslide.

- The vast majority of the gas system distribution pipes are MDPE and all the gas transmission pipes are welded steel (essentially, all seismically-capable).

- The level of shaking in the gas system areas was just below the threshold of automatic shutoff valve systems. Had the motions been somewhat larger, the shutoffs would have resulted in extra effort as part of re-lights / inspections.

- There were very few fire ignitions (about 2) and no conflagrations in this earthquake sequence.

- There were almost no house structure collapses in the urbanized areas served by natural gas. Unlike the situation in Kobe in 1995, there were no instances where gas service laterals were ruptured due to the collapse of the house.

- Most of the gas system repair effort occurred to service laterals and meters, as well as work within customer's houses.

- In rural areas, many houses use kerosene or propane from onsite storage tanks. Even in areas with very strong shaking (PGA > 0.5g), complete toppling of these tanks was not observed by the authors; but not inspected every building, so this failure mode cannot be ruled out. There were reports of broken lines connected to some of these tanks, and tilting of some tanks was observed in areas subjected to liquefaction PGDs. The typical tank has a shut off valve installed. Some (but not all) tanks were observed to have a pig-tail pipe arrangement to allow for differential movements between the tank and the building.

6.36 Anchorage M 7.1 2018

A strong earthquake occurred at 8:29 am, November 30 2018 local time. The moment magnitude of the main shock was M 7.1. The epicenter was located at 61.346° N, 149.955° W at a depth of 47 km. The epicenter was about 10 km northwest of downtown Anchorage, just on the west side of the Knik Arm to Cook Inlet, see Figure 6.36-1.

Figure 6.36-1. Epicenter of M 7.1 Anchorage Earthquake

The 2018 Anchorage Earthquake was the largest earthquake to impact the Anchorage area since the Great Alaska M 9.2 earthquake in 1964. At the time of the Anchorage Earthquake in late 2018, the population of the greater Anchorage area was about 370,000 people. This includes about 300,000 people in Anchorage (including the adjacent military bases), and about 70,000 people in the Matanuska Valley (Palmer, Wasilla and adjacent communities, to the north of Anchorage). At the time of the Great Alaska earthquake in 1964, the population of the greater Anchorage areas was about 80,000 people, and about 20,000 people in the Matanuska Valley area.

The main shock was recorded by 28 strong ground motion instruments in or very near to the City of Anchorage and 2 strong ground motion instruments in the Matanuska Valley. The average recorded by these 30 instruments (maximum of North-South and East-West components) was PGA = 0.29g and PGV = 31 cm/sec.

The duration of moderate to strong shaking (PGA > 0.05g) was commonly 15 to 20 seconds. Some people reported that they felt the earthquake last for as long as 45 seconds. Some people reported that they felt the earthquake last as short as 10 seconds.

The earthquake triggered some liquefaction and landslides. PGDs in liquefaction zones were commonly settlements on the order of an inch to a few inches. Landslides included rockfalls, snow avalanches and some deep seated slides. Rockfalls did not impact urbanized areas, but it was reported that falling rocks just missed some people.

A few road embankments slumped downwards and sideways, with movements of 10 feet or more. These road embankment failures were amongst the most spectacular soil failures in this earthquake, Figure 6.36-2. A 4-inch diameter steel natural gas pipeline (yellow line shows pre-earthquake location) was embedded in one of these embankments in Wasilla. The pipe underwent lateral displacements up to 16 feet (green line shows post-earthquake location), Figure 6.36-3. The pipe remained in service with no leaks; this reflects the rather gradual curvature of the soil movements over a span of about 350 feet; the high quality of construction of the pipe; and the very soft / weak nature of the soils along this pipe alignment.

Figure 6.36-2. Roadway Deformations (December 1 2018)

Figure 6.36-3. Gas Pipe Location (June 20 2019)

There was no observed surface faulting in the 2018 Anchorage Earthquake.

In the Great Alaska earthquake of 1964, there were severe ground failures at a few locations in Anchorage (permanent ground movements over 10 feet) and a variety of lesser ground failures at several locations in Anchorage. For the most part, the so-called "Bootlegger" formation that failed in Anchorage in the 1964 earthquake did not fail again in the 2018 earthquake. This might reflect the shorter duration of strong shaking in the 2018 earthquake, meaning that the Anchorage area remains vulnerable from future soil failures in future M 8.5 – 9.0± great subduction zone events, which are nearly sure to occur in the next few hundred years.

The natural gas system in and near Anchorage is owned and operated by Enstar. Enstar's service area includes all of Anchorage, Eagle River and the Matanuska Valley. The gas system in Anchorage was developed beginning in 1961.

The gas system includes steel transmission mains (about 440 miles) and HDPE distribution mains (about 3,200 miles).

Over time, Enstar has been replacing copper service laterals, owing to their relatively high vulnerability to corrosion and requirement for ongoing repairs. At the time of the earthquake, there were about 1,000 remaining copper service laterals. Enstar has an ongoing program to replace these copper service laterals, averaging about 100 replacements per year.

The gas system suffered a variety of impacts. Overall, the level of impacts was not serious.

- Surveyors were initially dispatched to look for leaks. Areas perceived to be relatively higher risk (high population density areas) were prioritized.

- It was found that the gas system damage was relatively concentrated in the Eagle River area.

- About 2,000 orders were received to check for gas leaks. Most orders were "called in" by gas customers requesting assistance either for gas leaks (or perceived gas leaks), or requests to reset pilot lights for gas appliances.

- Frost heave is an important issue for normal design of buried infrastructure in Alaska. To accommodate frost heave, there are flexible connections on service lines to customers. These flexible connections may also have helped reduce damage to service connections during this earthquake.

- Some customers were turning off gas valves, including both their own and their neighbors'. The reason(s) for turning of the gas valves apparently had to do with perceived instructions from other municipalities, such as in the Los Angeles area, where this action is often discussed in the media. Shutting off gas valves is not a recommended practice by Enstar, unless there is a gas leak (usually smelled by the odorant, or otherwise observed). Enstar issued public notifications to tell its customers not to turn off their gas valves unless there was a gas leak.

- After assessing all the damage post-earthquake, Enstar reported that there were 3 repairs needed to the gas pipe system due to earthquake damage, and another 12 repairs due to corrosion or other effects. The 3 earthquake-related repairs were all on service lines / taps, and none on the gas mains.

- There were no plans by government authorities to shut off the gas supply while looking for gas leaks.

- There were no requirements to install automatic gas shut off valves in the Enstar service area. After this earthquake, no federal, state or local building official who were contacted thought that future installation of such valves would be needed based upon what happened in this earthquake. No such valves (or very very few) of such valves are known to have been installed for any Anchorage area residential customers. A few automatic shut-off valves were known to be installed (falling ball-type, activated by high inertial shaking) at large commercial / industrial / education customers; those customers usually have on-site maintenance engineers capable to address the shut-off / restart issues related to gas system isolation. No fires are known to have been fed by natural gas at any location. Natural gas is considered essential in the area for providing space heating, and due to the seasonal cold temperatures in the area, shutting off gas supply using automatic gas shut off valves is thought to be a practice that may present more life-safety issues than perceived seismic "benefits".

- Enstar reports that they had on the order of $1 million in damage / repairs / inspection costs due to this earthquake.

6.37 Magna M 5.7 2020

A moderate earthquake occurred at 7:09 am, March 18 2020 local time. The moment magnitude of the main shock was M 5.7. The epicenter was located 4 km north northwest of the community of Magna, Utah, at a depth of 11.9 km, latitude 40.751°, longitude -112.078°. The following is adopted from Eidinger, Maison and McDonough, (2021).The epicenter was about 18 km west of downtown Salt Lake City, see Figure 6.37-1.

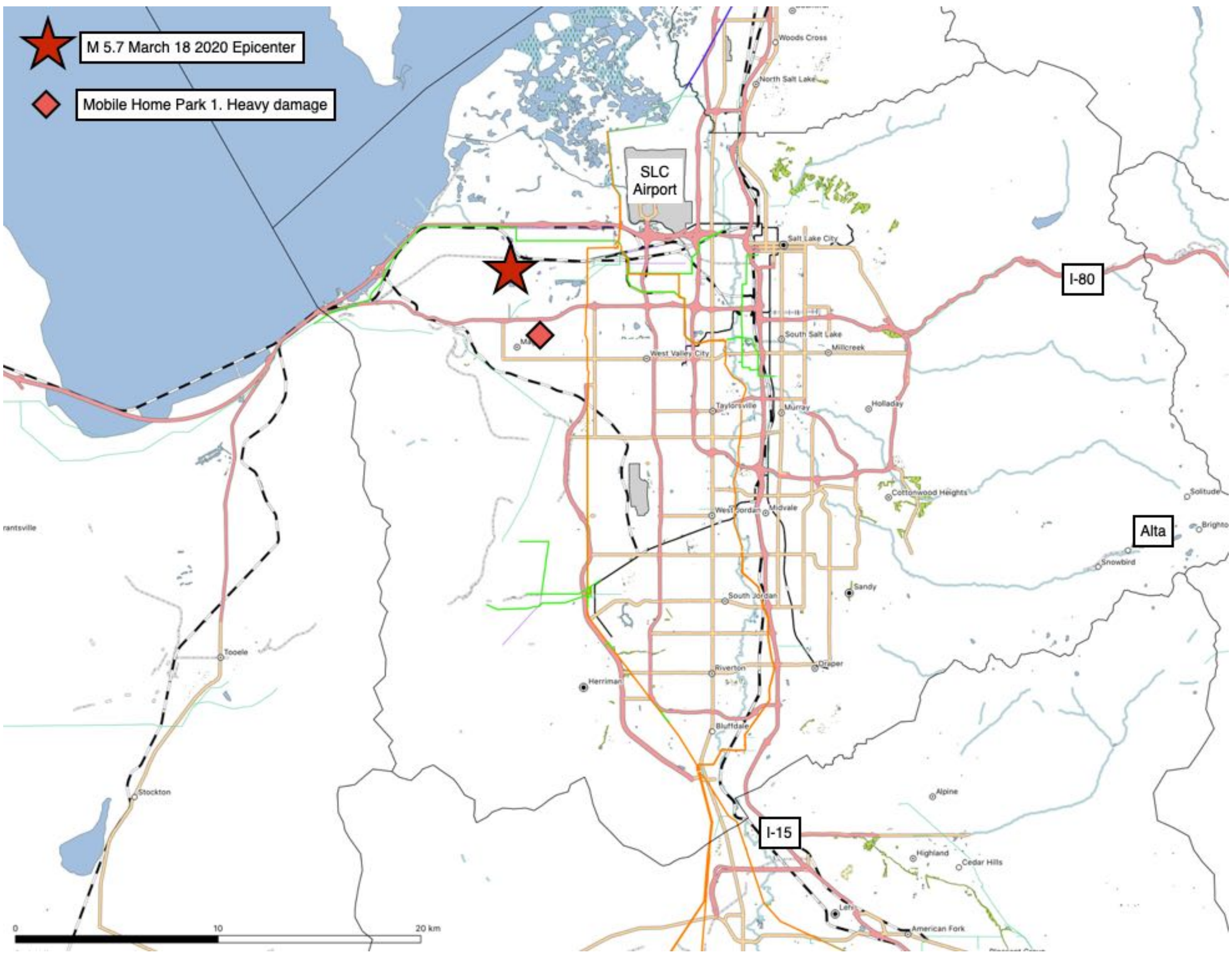


Figure 6.37-1. Magna Earthquake Epicenter

Peak motions were about 20 cm/sec near Magna; many urbanized areas were exposed to PGVs on the order of 10 to 20 cm/sec, Figure 6.37-2. Downtown Salt Lake City, was exposed to about 10 cm/sec. A gas system engineer was shaken out of bed in Layton, about 25 km north of downtown Salt Lake City.

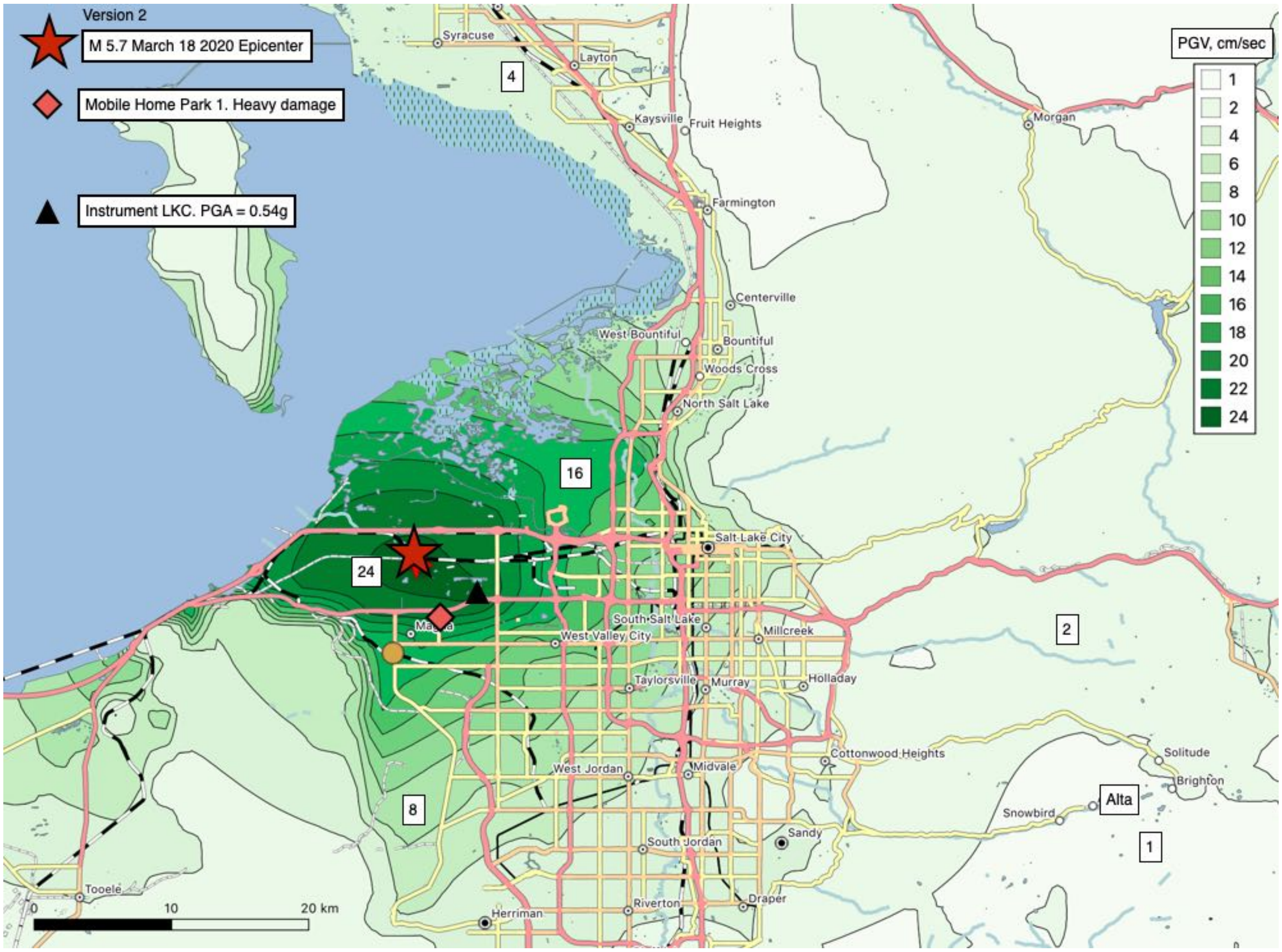


Figure 6.37-2. Magna Ground Motions (PGV)

The natural gas system operator for Salt Lake City was Questar for many year, recently bought by Dominion Energy. The earthquake had the following effects on the natural gas system:

- There were 468 meter leaks (for locations, see Figure 6.37-3). These leaks were located at or near above ground gas meters where leaking gas was reported by customers or found by Dominion service crews. These leaks include gas leaks found in the riser pipe, the meter set and its appurtenances, and generally the pipe (hose) between the meter and the building.
    - Some of the meter leaks were likely leaking before the earthquake. It is common to find leaks after every leak survey, even without earthquakes.
    - The leaks reported after the earthquake include both leaks caused by the earthquake, as well as leaks caused by other factors, such as aging of materials. Practically speaking, all these leaks still need to be addressed post-earthquake.
- There were 11 service line leaks. Service line leaks are leaks found in buried pipe between the distribution main and the riser to the meter.

    - These include 4 leaks at the tap from the service line to the distribution main. Of these, 1 was for a PE service tee; 1 was at a steel cap; 1 was at a corroded steel service.

- There were 0 leaks in the high-pressure transmission system. There was no damage to any gas compressor station (the nearest being in Wyoming, and exposed to very small ground motions).

- There were 0 reported leaks in high-pressure subtransmission pipe. These are commonly 6-inch to 24-inch in diameter welded steel pipe.

- There was 1 reported leak to gas distribution pipe:

    - This leak was on a 2-inch PE distribution pipe. This PE pipe apparently impinged on rock. It is possible this leak pre-dated the earthquake.

- Almost all small diameter distribution pipe (pressures commonly < 60 psi) are PE.

- Almost all service laterals are buried. Service laterals include both PE (generally newer installations) and steel pipe (generally older installations). Most service lines are 1-inch diameter or smaller.

- There were 113 leaks on in-house customer pipes. Of these, 21% were water heated related. Dominion has stressed the need to install seismic-straps for water heater installations.

- About 48% of gas customers who turned off the gas at their meters actually had leaks.

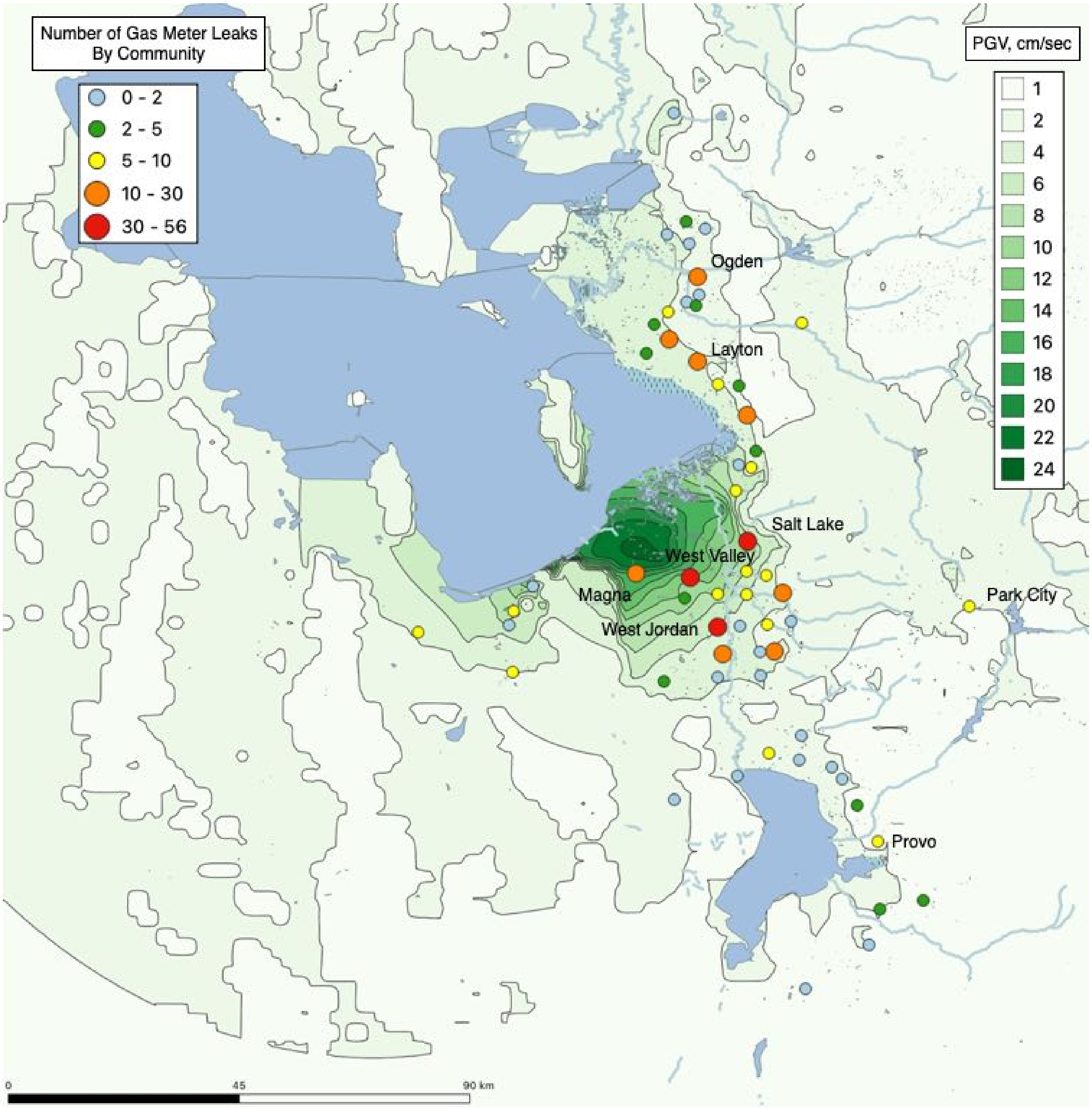


Figure 6.37-3. Number of Gas Leaks at Meters, by Community

The following examines the situation of gas meters at the mobile home park, indicated at MHP-1 in Figure 6.37-1. MHP-1 includes about 206 mobile homes. The vintage of the mobile homes suggests common installations around 1990 or so. It is believed that all the mobile homes were anchored for wind loads. About 23% of all the trailers either collapsed (slid off their foundations) or had extensive damage (slid sideways on their foundations and required re-centering after the earthquake). The estimated motions were about PGA = 0.33g at this site, and for a very short duration earthquake (2.5 seconds of strong shaking), the 23% failure rate is rather high, and undesired performance.

A survey of the gas meters in October 2020 (6 months after the earthquake) showed the following:

- All the surveyed gas meters were attached to the mobile home via a flexible hose.
- 32 gas meter sets were significantly tilted, suggesting impact between the meter set and adjacent mobile home during the earthquake, or inertial overload of the riser pipe / support foundation system of the meter set.
- 8 gas meter sets were entirely replaced, suggesting that the damage was severe enough as to warrant outright replacement.
- The distance "D" between the hard-piped portion of the gas meter set and the skirt of the mobile home was estimated in the survey.
    - Count, D < 0.2 feet. 2
    - Count, ≤ 0.2 D < 0.5 feet = 10
    - Count, ≤ 0.5 D < 1.0 feet = 18

Despite the high rate of damage of the buildings and the gas meters at this mobile home park, there were no fire ignitions. This is attributed, in part, to the use of Excess Flow Valves in each service lateral. These valves are installed at the branch from the distribution pipe to the service lateral, and all are buried. These valves were originally intended to limit (not entirely shut off) the flow of gas to the gas meter should the service lateral be broken (say, due to inadvertent rupture of the service lateral pipe due to digging operation). These valves are much less effective in limiting gas flows due to damage beyond the meter. There were no "automatic seismic shut off valves" at this mobile home park.

Even so, the installation conditions of the gas meters at this mobile home park were not ideal:

- The lateral steel strap-type restraints for mobile homes supported on steel stands were not satisfactory for moderate to strong seismic ground motions.
- The length of flex hose between the gas meter and the mobile home was not always high enough to prevent building - meter impacts.

Addressing the mobile home / gas meter seismic issues requires an understanding of the seismic response of mobile homes, the issues related to gas meter installations for mobile homes, with an appreciation that solutions need cost effective approaches. These issues are examined in some detail in Maison and Eidinger (EERI, 2021) and Eidinger, Maison and McDonough (EERI, 2022 *in press*).

CHAPTER 7: Pipe Stresses, Strains and Fragility

In Chapter 6, the empirical record was presented as repairs made to gas system in prior earthquakes. The empirical record is important for establishing seismic fragility, as it reflects real-world evidence.

In Chapter 7, a different approach is presented to establish the seismic capacity of gas pipelines. This approach is based on the traditional concepts of Strength of Materials and Structural Mechanics. Essentially, it is commonly assumed that if the earthquake-induced plus other operating stresses in a pipe is under the yield stress of the pipe, then the pipe should be highly reliable and not fail in an earthquake. For conditions where the earthquake-induced stresses exceed the yield level of the pipe, then as the post-yield strain increases, there is an ever-increasing chance that there will be a rupture in the pipe's pressure boundary.

7.1 Stress and Strains for Pipes Subjected to PGV, PGD

From a structural mechanics point of view, fragility models should ideally correlate the potential and type of damage against the state of stress and strain in the pipe. Section 7.1 presents an introduction to the computation of stresses and strains in pipes due to earthquakes. Section 7.2 presents further detailed computations.

Within the elastic range, the stress in the pipe can be computed as the strain in the pipe times Young's modulus:

$$\sigma_p = \varepsilon_p E \qquad \text{[Eq 7-1]}$$

For cases where the pipe is not exposed to PGDs, it is commonly assumed that the strain in a buried pipe is the same as the strain in the ground (no slippage between the pipe and ground), for ground strains associated with low to moderately-strong levels of ground shaking. In other words:

$$\varepsilon_p = \varepsilon_g \qquad \text{[Eq 7-2]}$$

Equation 7-2 is reasonable for long continuous pipes without any branch connections, without any slip joints, and not adjacent to any anchorage points (like where a pipe enters a buried concrete vault, etc.). For the bulk of a gas transmission system, these limitations do not apply, so Equation 7-2 is valid. Most pipes in a gas distribution system have numerous branch connections (in urban areas, perhaps a branch connection every 100± feet as laterals to customers, and every 500± feet as branches at street intersections), so without adjustment, Equation 7-2 is not generally not directly applicable to the bulk of gas distribution pipes.

Equation 7-2 also does not apply in the following situation:

- At locations where the ground is subjected to PGDs (liquefaction, landslide, fault offset)

- At locations with extremely high ground motions, for pipes with low-friction coatings, where slippage between the pipe and soil can be expected.

- Where the pipe has discontinuities (including branch connections, slip joints, anchor points).

The ground strain due to shaking, at locations away from discontinuities, can be computed as being proportional to the ground velocity V, and the wave propagation speed c, and a factor κ, as follows (see ALA (2005) or ASCE (1984) for derivation):

$$\varepsilon_g = V/\kappa c \quad \text{[Eq 7-3]}$$

Where κ is a factor that reflects the type and direction of the principal incident damaging seismic waves. The most common condition is that damaging seismic waves are the result of vertically propagating shear waves, in which case κ = 2, and c may be taken (absent site specific evaluations) as 12,000 feet / sec. For some conditions, surface waves may control, in which case κ = 1 and c may be taken as 1,000 feet/sec. The ground strains will vary over time as either "positive" (soil pulling apart) or "negative" (soil pushing together), as the waves travel past a location.

For well-made steel pressure pipe, located in a geographically-large alluvial basin, subjected to vertically-propagating shear waves, if one assumes PGV = V = 40 inches per second (a real strong earthquake motion), then the ground strain is (40 / (2 * 12000 * 12)) = 0.000139, and elastic pipe stress is (±0.000139 * 29,000 ksi) = ±4 ksi. Vertically-propagating shear waves cannot be visually observed, as they create no up-down movement at the ground surface. Clearly, a well-made steel pipe should be able to accommodate a seismic incremental stress of ±4 ksi, and failures should nearly never happen. Using equations 7-2 and 7-3, to get steel stresses high enough to approach yield would require PGVs on the order of 300 inches per second or so; which is entirely unrealistic.

For steel pressure pipe, in alluvial soil locations nearly adjacent to mountains, the incident fast moving shear waves may be refracted at the rock / soil interface, and a portion of the energy will be converted to slow moving surface waves. This has been twice observed to occur in Mexico City (1985 distant earthquake, 2017 local earthquake), and is believed to have occurred in the 1971 San Fernando and 1994 Northridge earthquakes in the northern San Fernando Valley and nearby narrow canyons surrounded by mountainous terrain. Surface waves can be visually observed as "rolling like" up-and-down motions of the ground surface; akin to waves seen in oceans. In these cases, if one assumes PGV = V = 20 inches per second (a real strong earthquake motion), then the ground strain is (20 / (1 * 1000 * 12)) = 0.001667, and pipe stress is (±0.001667 * 29,000 ksi) = ±48 ksi. A well-made steel pipe with ductile girth joints should be able to accommodate a seismic incremental stress of 48 ksi, (with perhaps some modest yielding); but a steel pipe with limited capacity girth welds (with defects, partial penetration welds or otherwise non-ductile) can fail in tension; or if the pipe has a high D/t ratio, the pipe can wrinkle in compression. Some of the observed damage to SoCalGas pre-1930 steel pipe in the 1952 Taft, 1971 San Fernando and 1994 Northridge earthquakes, at locations not exposed to PGDs, coupled with weak / brittle field-made girth joints, may have failed due to this effect.

The problem of travelling waves is further complicated if the pipe has a slip joint (like a Dresser coupling). At the slip joint, the pipe strain must necessarily be zero (or nearly so), as the slip joint is constructed to allow no axial forces across the joint. As the seismic waves traverse the slip joint, there is a discontinuity and $\varepsilon_p \neq \varepsilon_g$. ALA (2005) provides formulae to compute the potential for joint opening at these locations; conceptually, the amount of joint opening is proportional to the integration of the traveling wave displacement motions over a wave length. The worst case arises when there is a single Dresser coupling along a very long (for example, over 1 mile) reach of pipe, in which case the joint opening can be several inches in a large earthquake. Most unrestrained Dresser-type couplings can only take about an inch or so of axial movement before leaking or 2 inches before complete disengagement and rupture. Failures due to joint openings have been common in water pipes in past earthquakes; water pipes have many unrestrained joints. Failures due to joint closings (impacts) have occasionally occurred in concrete water pipes in past earthquakes. For gas pipes without slip joints, joint opening and joint crushing failures are not likely failure modes.

Most modern buried gas transmission pipes in California have no slip joints. Depending on the design philosophy, some California water agencies commonly install slip joints in their steel transmission pipes, especially adjacent to valves; while other water agencies never install slip joints in their steel transmission pipes. In the oldest gas pipes in California (such as pre-1940s), there may be slip joints at selected locations. Therefore, a loss estimation model should assign different fragilities for gas pipes with (rare) or without (common) slip joints.

The use of slip joints or other types of thermal expansion devices might be prevalent for above ground pipes (such as at gas storage fields, regulating stations, etc.). For any loss estimation, it is recommended to verify the actual style of pipeline installation at above ground facilities in order to assign suitable fragility parameters that match the as-installed pipeline configurations.

For seismic loading of buried or above ground pipes, it is the general consensus that for one-time loads (like fault offset, liquefaction, landside), that the pipe material can safely and reliably take some post-yield strain in tension:

- For pipes constructed with ductile (high strain to rupture) and tough (high Charpy v-notch capability) carbon steels commonly used for gas pipelines, the tensile strain at rupture will usually be 20% or higher.

- Steel that is exposed to cold temperatures can become brittle. This situation can be avoided by specifying suitably tough steels with good weldability characteristics for those environments. In coastal California, cold temperatures are not encountered and this issue is usually not critical. Even so, specifying steel with good toughness and weldability characteristics is good practice in all locations in California.

- The weld material used to make field girth welds should be specified to have a strength equal-to or greater than the base steel in the main barrel of the steel pipe. Situations to avoid include using E60 electrodes (Fu = 60 ksi) for X52 pipe (Fy (min) = 52 ksi, Fy(max) = 76.9 ksi). In these cases, the weld can yield and fracture before yielding of the main barrel of the pipe. As a girth weld joint is very short, even if such a weld is ductile, the weld may be unable to deform sufficiently to accommodate the overall deformation of the pipe that is needed to accommodate the PGD. This situation can be further complicated as it is not uncommon for pipe manufacturers to provide substantially overstrength pipe (Fy higher than minimum specified); in non-seismic conditions, having higher Fy is usually a good thing; but in seismic design where controlled yielding is desired, the complete design must assure that the bulk of the yielding occurs in the main barrel of the pipe and not in the welds. During the fabrication and construction phases of a project, the Engineer must verify that the actual yield levels of the actual pipe delivered to the job site are within a range that is consistent with the intent of the design.

- Various "allowable" tensile strain limits for the seismic load cases have been proposed around the world, from as low as 0.3% (Japan) to as high as 5% (ASCE 1984). Modern adaptations in guidelines like ALA (2005) and PRCI (2009) have adopted a tensile allowable of 4%. This 4% level assumes that the main body of the pipe barrel sustains the bulk of the yielding, and that the pipe has well-made girth full penetration butt weld with no backer plates, and the loading is for a one-time load case (like fault offset). For pipes that are needed to accommodate up to multiple nonlinear events over its lifetime, a lower tensile strain limit of 2% has been proposed. Once an actual event occurs that has strained a high pressure gas transmission pipe, it has been common practice in California to cut-out the yielded pipe and replace it with a non-yielded pipe (as happened in 1952 Taft, 1979 Imperial Valley, 1994 Northridge, 2014 Napa, 2019 Ridgecrest earthquakes - see Section 6 for details). Gas transmission pipes that have undergone excessive yielding / repairs have been abandoned entirely, as happened in the 1971 San Fernando earthquake.

- At the current time, there is a lack of test data for various grades of plastic pipe that are used in gas distribution systems. A common "allowable" strain for plastic pipe is not commonly available in the literature. From limited testing of HDPE pipe, coupled with observations of how HDPE and MDPE pipe have performed in prior earthquakes, it is believed that a tensile allowable of 10% might be suitable. (But, see Section 9 for recommendations for further testing). This 10% strain is applicable for MDPE / HDPE pipes with field-made full penetration fusion (or similar) butt weld joints. There is not enough information to presently suggest an allowable tensile strain for plastic pipe that might be embrittled or otherwise subject to sudden crack initiation. Some kinds of plastic may subject to creep-to-failure, where the plastic is able to sustain an initial high strain loading, but over time that local high strain progresses to failure: for example, this can happen on buried HDPE pipe that is installed resting on a hard point such as another nearby buried pipe; for plastic pipe, it is especially important to maintain spatial distance from all nearby pipes or other obstructions / hard points.

- For steel pipes using threaded fittings, the limit before small leak might be about 50% to 75% (or so) of the bending moment needed to reach initial yield (My = S * Fy) of the adjacent unthreaded portion of the pipe. Designing for some post-yield performance of threaded jointed pipes is not a recommended practice. Testing of threaded joints (see Section 9) can provide further insight as to suitable stress / strain capacities for threaded steel joints.

In compression, the failure mechanism is not the rupture of steel due to compressive stress / strain, but rather the tensile strain induced by secondary bending within a local wrinkle. In other words, as a pipe is compressed (either in direct compression across the entire cross section, or local compression due to high bending), thin-walled steel pipe will eventually wrinkle. In this report, a "wrinkle" means the same as a local buckle. For buried pipe, buckling of the entire cross section (like the buckling of a yardstick when placed under compression; sometimes called "beam buckling") is not a concern when the pipe is placed into net tension; but should be checked when the pipe is placed into net compression in above ground installations; or in below ground installations using especially shallow burial where the pipe could buckle upwards.

Code-based approaches (such as ASCE 7, ASCE 41, IBC 2012 etc.) to reduce seismic inertial loads using response modification concepts like Rw, R, m or similar, should not be adopted for gas pipelines.

Once the pipe wall begins to wrinkle, it will have large induced local bending, leading to high local tensile strains. Tests and the empirical evidence shows that the buckle often forms as a "bulge" outwards on pipes with lap-welded girth joints; but can also be net inwards on pipes with butt-welded girth joints. As the bulge increases, the hoop-direction strain can reach the initial rupture strain before the longitudinal-direction strain reaches the rupture strain. The field evidence is that for modestly-wrinkled steel pipes, the steel can rupture as a split along the long axis of the pipe (meaning that the initial rupture strain was in the hoop direction).

Both ALA (2005) and PRCI (2009) provide equations that show the "allowable" compressive strain in a steel pipe. The following summarizes some of the salient points.

The theoretical compressive stress to reach onset of wrinkling for a perfect cylinder (Timoshenko and Gere 1961) is:

$$\sigma_{classical} = \frac{1}{\sqrt{3(1-\mu^2)}} \frac{tE}{R} \qquad \text{[Eq 7-4]}$$

Where μ is Poisson's ratio and E is Young's modulus, t is the pipe wall thickness and R is the radius of the pipeline. For μ = 0.3, the theoretical buckling strain simplifies to:

$$\varepsilon_{theory} = 0.6\frac{t}{R} \qquad \text{[Eq 7-5]}$$

The theoretical buckling limit is for a perfectly circular pipe with no out-of-plane irregularities. Real world pipes may not be so ideal, and some out-of-roundness and some offsets at girth joints cannot be entirely ruled out. Given these issues, ALA (2005) recommends the inset of local buckling of a practical butt welded pipe as:

$$\varepsilon_{onset} = 0.175\frac{t}{R}\ to\ 0.2\frac{t}{R} \qquad \text{[Eq 7-6]}$$

Tests on. 30-inch diameter steel pipe (DelCol 1998) showed that for D/t = 92, Fy = 70 ksi, and internal pressures ranging from 0 to 312 psi, the initial buckle formed at an average compressive strain of about -0.5%, which corresponds to 0.229t/R. This is not too far different than [Eq 7-6], and confirms that the theoretical limit in [Eq 7-5] is too high for real world application.

The strain limit in Eq [7-6] might be suitable for a high pressure gas pipe where wrinkling of the pipe might restrict the passage of pigs; or failure of the pipe might result in a fire or explosion that could seriously impact nearby people, facilities and habitat. For other gas pipes where some limited post-wrinkling bulging behavior is acceptable, a more relaxed compressive limits in [Eq 7-7] are considered suitable for design. By using the criteria in [Eq 7-7], it is implied that post-earthquake inspection and possible repair / replacement may be needed.

The allowable compressive strain is set at:

$$\varepsilon_c = \frac{0.88t}{R} \qquad \text{[Eq 7-7]}$$

For example, for a high pressure gas pipe with R = 12 inches and t = 0.5 inches, $\varepsilon_c = 0.88 * {}^{0.5}/_{12} = -3.67\%$. (Note: it is recommended to use the mean radius of a pipe in this computation, with the mean radius being the inside radius plus t; some use the outside radius, leading to a somewhat lower strain limit).

A high pressure gas steel pipe with D/t = 24/0.5 = 48 is a rather "stout" pipe, and an allowable compressive strain of -3.67% is robust. This compressive strain is limited to -4.0 percent.

For steel pipes used in water systems, the common D/t ratio is 125 to 175, recognizing that the internal water pressures for water systems are commonly 125 to 150 psi.

For example, for a medium pressure water pipe with D = 48 inches and t = 0.3125 inches, $\varepsilon_c = 0.88 * \frac{0.3125}{24} = -1.30\%$.

The empirical evidence shows many instances with wrinkled steel water pipes; and nearly no wrinkled high pressure gas pipes. The compressive allowables in the above two cases follow this trend.

These tensile and compressive limits assume that the pipe has a circular cross section with no significant out-of-roundness. For water pipes in the USA, the common girth joint is a "slip joint", meaning one end of the pipe is belled outwards, and one (or two) fillet welds are used to make the girth joint in the field. This bell arrangement creates significant out-of-roundness, and this induces additional local bending moments in the pipe, as when the pipe wall is compressed, this leads to wrinkling initiation at stresses below nominal yield in compression in the main barrel of the pipe. For common D/t ratios in water pipes with belled connections, wrinkling could even initiate at compressive strains of about -0.001 or so; below the compressive yield level of steel. Wrinkled steel water pipes have occurred just due to ongoing creep deformations of a creeping fault; with the wrinkle being discovered after the wrinkle has progressed to rupture, and water begins to appear at the ground surface.

The above descriptions of compressive strain assumes that the computation of these strains is based on plane-sections-remain-plane assumptions. This assumption is valid up to the point that the wrinkle begins to have very large distortions (for example, see Figure 7-2). This compressive strain can be computed using nonlinear "beam" on "non-linear soil" models, using "beam-type" finite elements such as those found in computer codes such as ANSR, ABAQUS, ADINA, ANSYS, DRAIN, PIPLIN, PWHIP, SAP, etc[2]. Most nonlinear analysis programs have relatively simple constitutive laws for "beam type" elements. Some models (like the full plasticity element in ANSR) use more advanced (using a Von Mises yield criteria that accounts for all three orthogonal states of stress), and some use less advanced (like the independent yield criteria for each orthogonal direction in DRAIN); but in either case, once the yield criteria has been exceeded, the models continue the yielding assuming the original pipe cross sectional shape (plane-sections-remain-plane). Clearly, once the pipe begins to wrinkle, the cross section shape changes substantially, and the computation of strain within the "post-wrinkle" cross section becomes fictitious as the shape continues to distort, as plane sections do not remain plane once the pipe has wrinkled.

Over the past couple of decades, computational speed of computers has vastly increased and the cost of desk top computers has been reduced. As a result, there have been a variety of finite element analyses of buried pipes crossing faults zones, using full 3D finite element models using shell elements. These models can provide more information than a "beam" type model, including ovalization of the cross section as well as tracking tensile strains within the wrinkled joint. In such cases, the compressive strain limit (Eq 7-7) is not directly applicable, and the tensile strains within the wrinkle should be monitored. At present time, the allowable tensile limit within a wrinkle is not addressed directly in either ALA (2005) or PRCI (2009). Specialty steel pipe manufacturers in Japan are presently selling "pre-wrinkled" steel pipe for use in buried water pipe applications at fault / liquefaction / landslide zones; they appear to adopt the philosophy that if the pipe does not rupture, it is acceptable; implying allowable tensile strains of 20% or higher within the wrinkle. For high pressure gas pipes, such a high tensile limit is not recommended, as the consequences of high pressure gas pipe rupture can be much more hazardous to nearby people and buildings (explosion, fire) than the rupture of a water transmission pipe (flooding / inundation), although exceptions can occur.

As mentioned above, these allowable strains presume a well-made full penetration girth joint in the field, and well-made full penetration seam joints (for seamed pipe) made in the factory. In the field, it has been known that some contractors tack-weld on a small "backing plate" at girth joints to allow easy "mating" of two adjacent pieces of pipe. A backing plate with a fillet weld will introduce a stress riser at the joint, and thus the actual stress (strain) computed using beam models will be lower than the true stress. Therefore, when using the allowables described herein, it is presumed that the field girth joints are constructed using a clamping system to mate up the pieces of pipe; that the welds are radiographed; and welds with significant defects are rejected. Further, these allowables require that the welds be full penetration and stronger than the pipe; partial penetration welds might be satisfactory for sustaining internal pressure, but are entirely unsatisfactory for accommodating yielding due to earthquake imposed loads.

7.2 Example Computational Model to forecast Strain

Section 7.2 provides an example of a nonlinear beam on nonlinear soil structural analysis of a steel pipe subject to fault offset.

2 There are many commercially and proprietary nonlinear computational programs available in the industry. The listed programs are some examples. The list is not meant to be exhaustive. This report makes no recommendations about any of these programs.

7.2.1 Summary

In the 1999 Kocaeli earthquake in Turkey, a 2.2-meter (87-inch) diameter buried butt welded steel water transmission pipe was exposed to about 3 meters (10 feet) of right lateral offset. The pipe suffered major wrinkles and leaked water. After the earthquake, the pipe was exposed, backfill soils were classified, post-mortem analyses of the pipe were performed. This work showed that the nonlinear beam-on-nonlinear soil approach (following the provisions of ALA 2005) can accurately predict the pipe strains and pipe performance of the real-world pipe.

The following reviews the performance of this pipeline.

The Thames Water company, along with two Turkish companies, designed, constructed and operated the Izmit Water Supply System. This system went into operation in early 1999, and was soon subjected to a large earthquake on August 17, 1999. The system is composed of a raw water impoundment dam, a 5 km long raw water transmission pipeline, a 480 million liter per day water treatment plant, and 140 km of large diameter treated water transmission pipelines.

The rupture of the North Anatolian fault subjected the water system to strong ground shaking everywhere and surface fault offset to certain pipelines. The level of strong ground shaking was likely about PGA= 0.6g± near the fault, and perhaps on the order of PGA = 0.1g to 0.4g along the transmission pipelines.

Considerable damage occurred to the transmission pipeline where it crossed the North Anatolian fault. The pipe wrinkled severely at two locations, and leaked at about 1% of its flow capacity. The pipe was kept in service (except for a patch on the leak) for 7.5 months after the earthquake, albeit with a flow restriction due to the wrinkles. The damaged pipe was then replaced 7.5 months after the earthquake with two parallel pipelines, in order to restore the hydraulic flow capacity to the original capacity of the system.

A field investigation was performed for the 2.2 meter diameter pipeline where it crossed the fault. Soil samples were taken, and laboratory analyzed to obtain soil properties. A nonlinear pipe-soil "beam type" model of the pipeline was developed for purposes of performing nonlinear stress / strain analyses. The model and results are described in Sections 7.2.2 to 7.2.4. The model was able to reasonably predict the failure mode of the pipeline, namely compressive wrinkling of the pipe. The model demonstrated that the failure mode was governed primarily by high bending moments in the pipeline within a few pipe diameters of the fault offset location; coupled with axial shortening of the pipeline.

7.2.2 Seismic Setting and Pipe Survey

The 3 am (local time) August 17, 1999 Kocaeli earthquake (moment magnitude M_w 7.4) occurred on the North Anatolian fault in northwestern Turkey. The Kocaeli earthquake has also been variously called the Izmit earthquake.

Figure 7-1 shows the locations of fault offset and other hazards for the general area near the 2.2 m diameter pipeline (heavy blue line) that is examined herein.

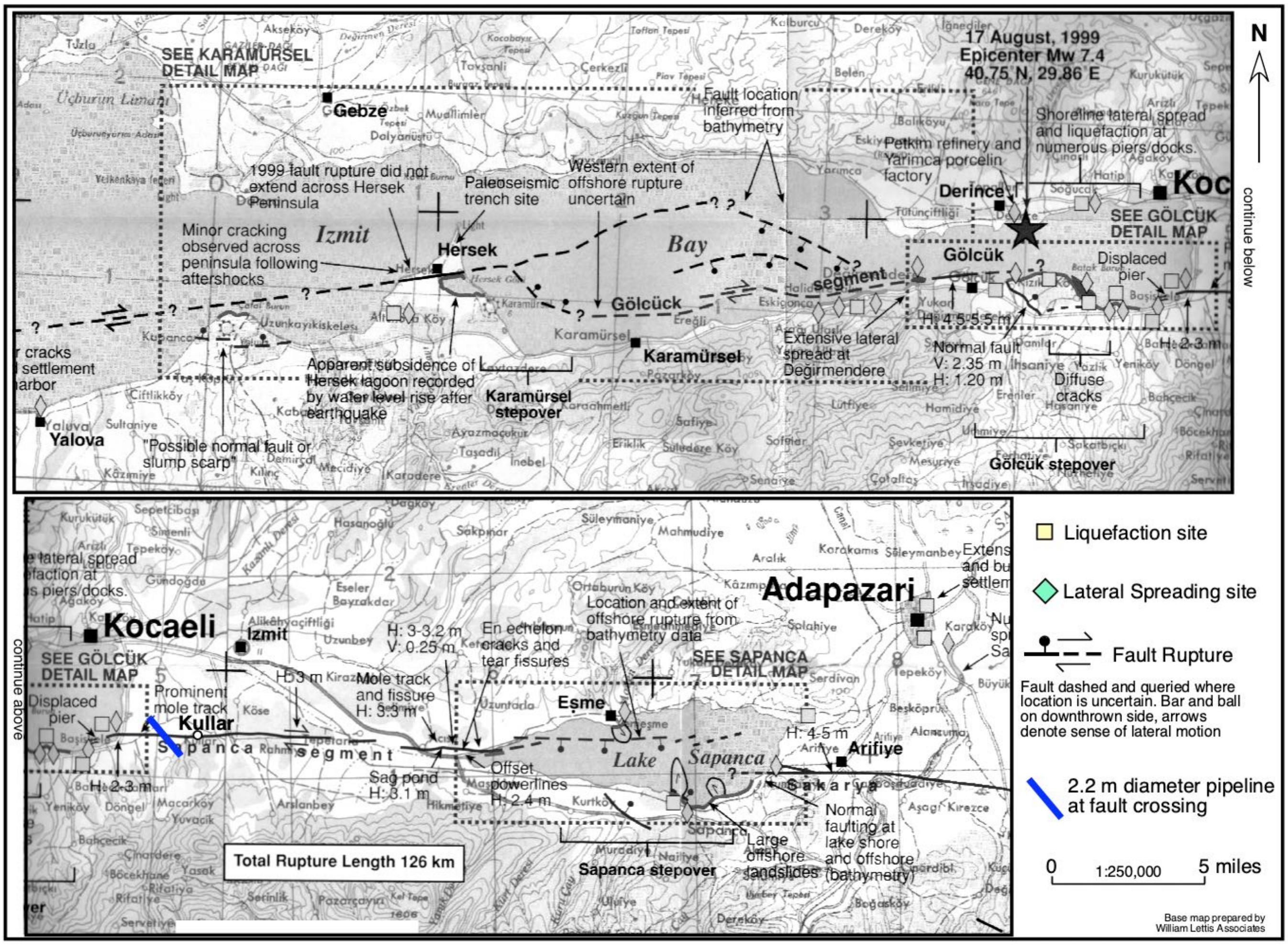


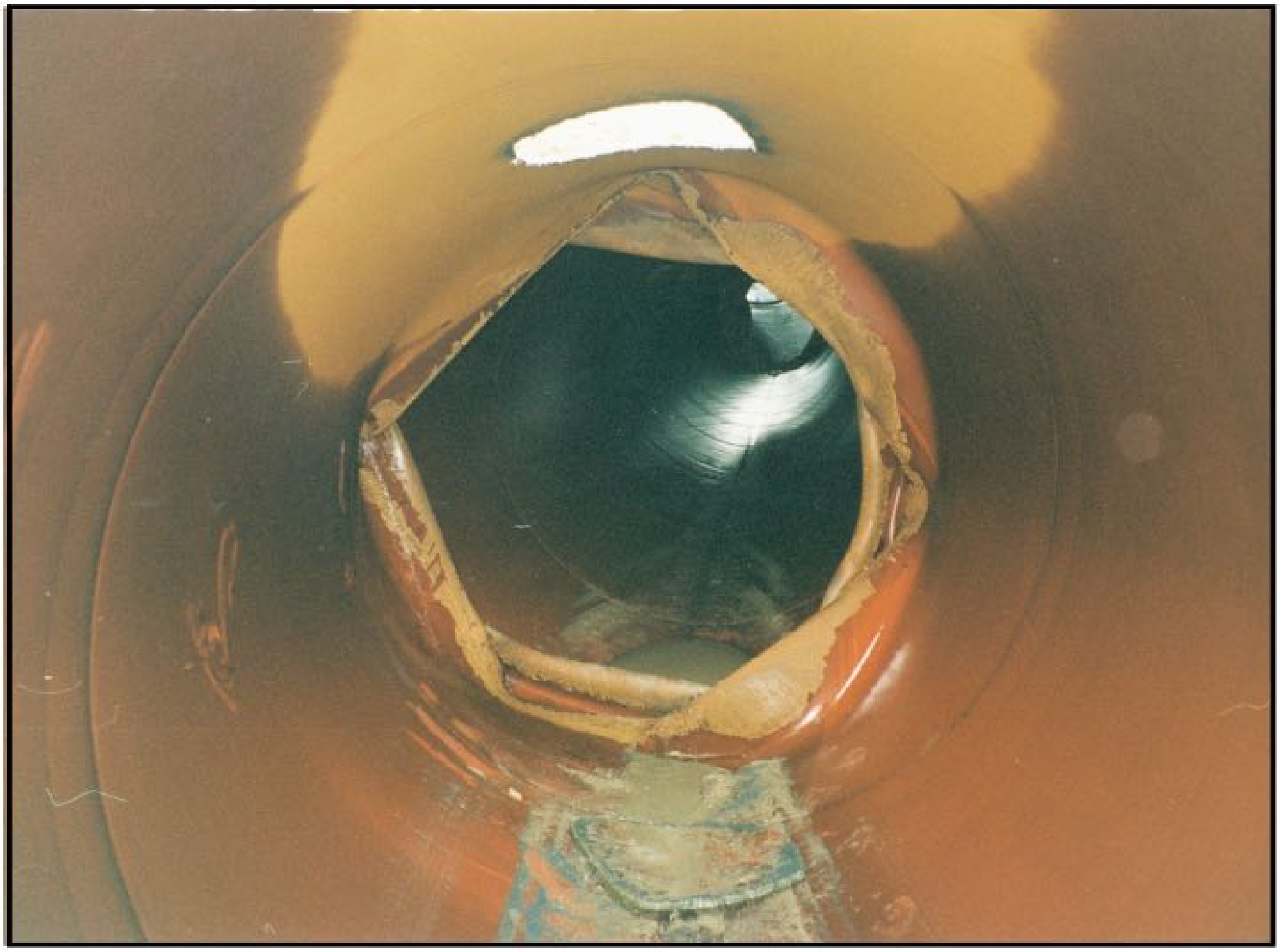
Figure 7-1. Map of Kocaeli Earthquake

Construction of the pipeline began in April 1996. The pipeline takes raw water from a dam (to the south of the fault) to a water treatment plant and then to various treated water customers around Izmit Bay. The main pipeline is 88 km long. This pipeline is butt welded steel pipe, epoxy lined and coated, including cathodic protection using impressed current. Construction was completed in January 1999, about 8 months before the earthquake.

There was damage to the 2200 mm diameter welded steel pipeline where it crossed the North Anatolian fault.

Soon after the earthquake, a small surface leak was initially visible where the pipe crossed the fault. A decision was made not to investigate the damage and undertake repairs in the immediate days after the earthquake; instead, it was decided to keep the pipeline in service in order to continue supplying water to the rest of the system.

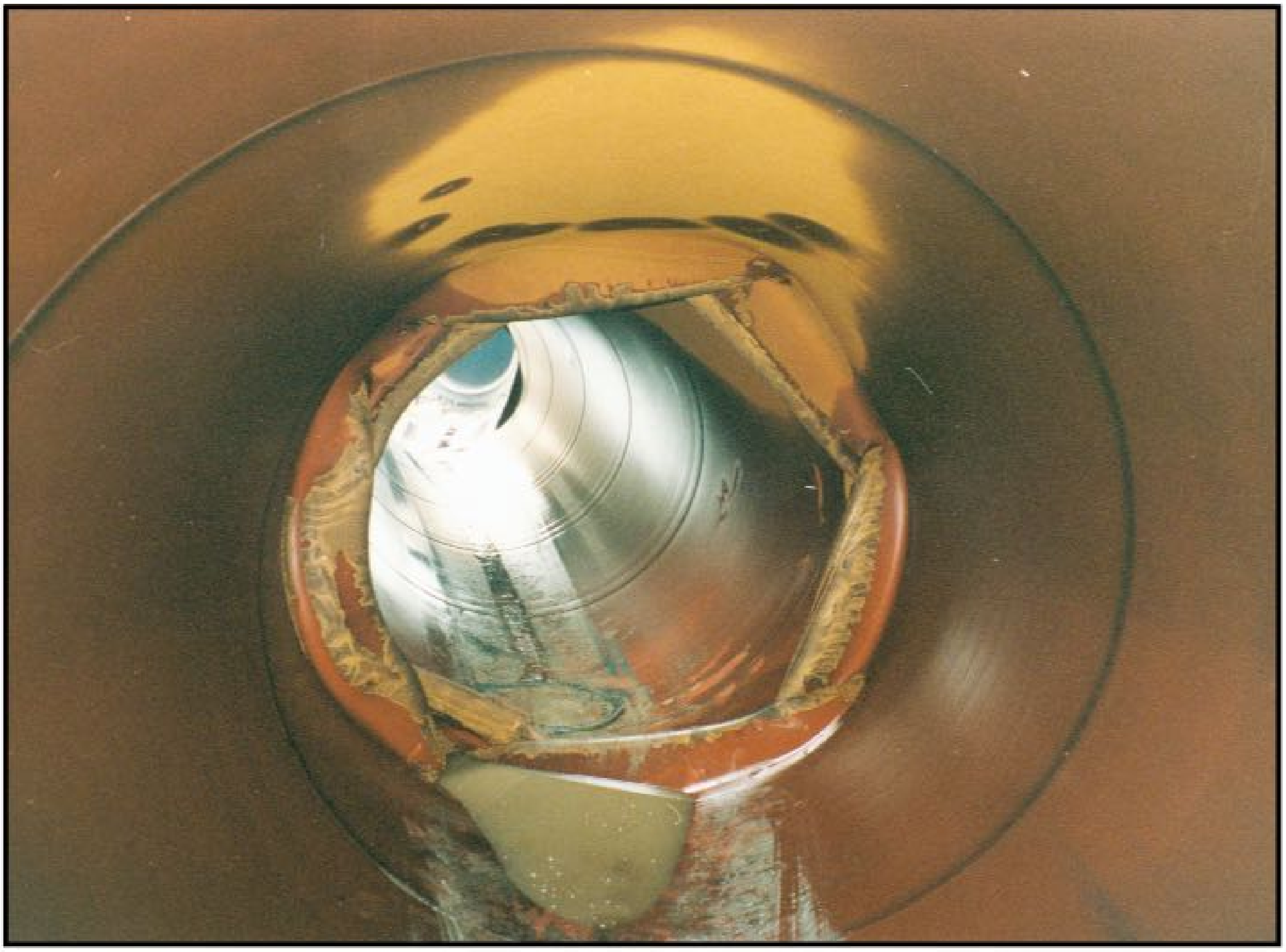
Within a few days after the earthquake, the 2200 mm pipeline was exposed in the area of the fault to allow a better understanding of the nature and extent of damage to the pipe. Soil was excavated from the top of the pipe, to expose about one-quarter of the depth of the pipeline. A manhole was cut into the pipeline at the excavation to allow for access and emptying of the pipeline. Damage was observed at three locations: stations 1+320, 1+337 and 1+349 (see Figure 7-6 for station locations). The primary damage consisted of two very large wrinkles of the pipeline (Figures 7-2 through 7-5). The wrinkles were folded to a depth of typically 200 mm or more; in other words, the steel was folded into the main pipeline. This caused a reduction in net cross sectional area of the pipeline, with a corresponding reduction in flow capacity due to the increased friction losses at higher flow rates. The leakage occurred at a rupture in the steel at one of the two major wrinkles. A small leak was also reported at a smaller third wrinkle. The pipeline was losing less than about 1% of its flow at the larger leaking wrinkle. There was no life safety concern due to this leak.



Notes.

Picture taken at approximately Station 1+400, looking south.
The wrinkle in the foreground is at station 1+337.
The hole at the top of the pipe is a manhole cut into the pipe to allow inspection;
the steel plate at the floor of the pipe is the steel from the hole cut at the top of the pipe.
The wrinkles are as much as 200 mm deep from the original diameter of the pipe.
The internal epoxy lining has been stripped away from the pipe at the wrinkle location.
The wrinkle in the background is at station 1+320.
There is a change in direction of the pipe at both wrinkled locations.
Discoloration shown near the top of the pipe near the manhole is presumed due to the heat caused by torching open the inspection manhole.

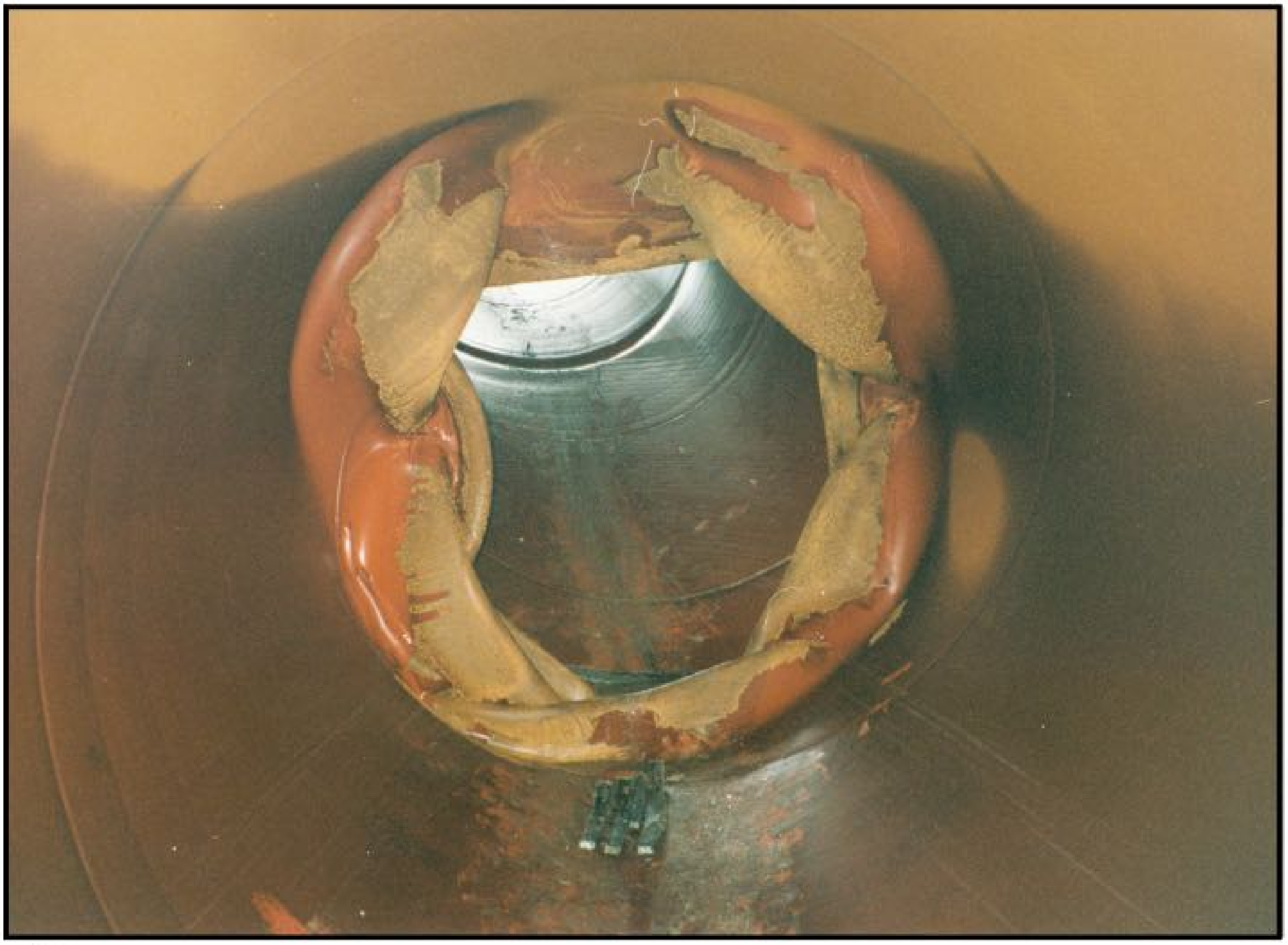
Figure 7-2. Wrinkled Pipe 1+337 Looking South



Notes.

Picture taken at approximately Station 1+340, looking north.
The wrinkle in the foreground is at station 1+337.
The hole at the top of the pipe (not seen) is a manhole cut into the pipe to allow inspection; the steel plate at the floor of the pipe (beyond wrinkle) is the steel from the hole cut at the top of the pipe.
The wrinkle in the foreground is as much as 200 mm deep from the original diameter of the pipe.
The internal epoxy lining has been stripped away from the pipe at the wrinkle location.
The small wrinkle in the background is at station 1+349.
There is a significant change in direction of the pipe at the wrinkled location in the foreground.
Discoloration shown near the top of the pipe near the manhole is presumed due to the heat caused by torching open the inspection manhole.

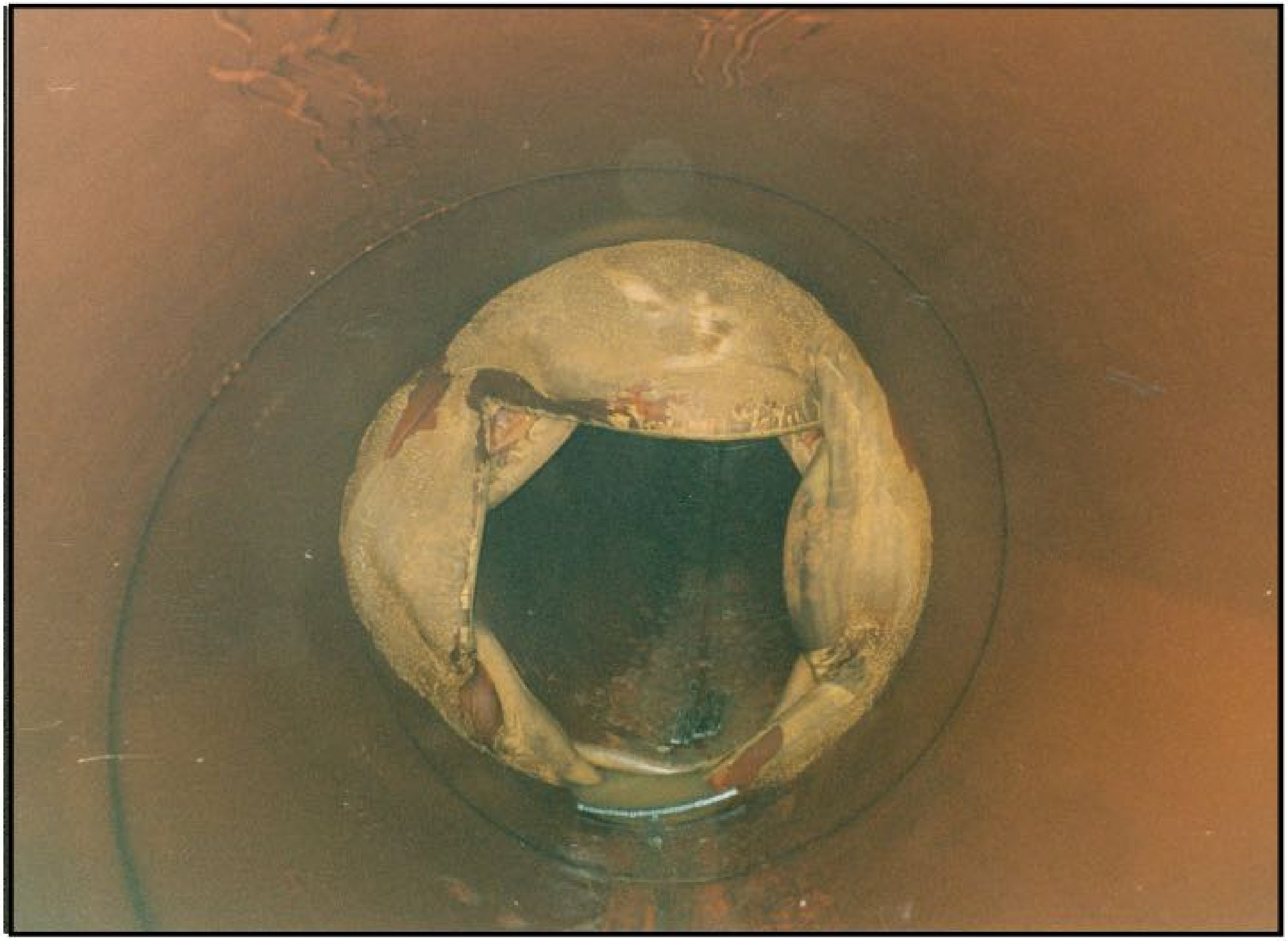
Figure 7-3. Wrinkled Pipe 1+337 Looking North



Notes.

Picture taken at approximately Station 1+317, looking north.
The wrinkle is at station 1+320.
The wrinkle is as much as 200 mm deep from the original diameter of the pipe.
The internal epoxy lining has been stripped away from the pipe at the wrinkle location.
There is a significant change in direction of the pipe at the wrinkled location.
Discoloration shown near the top of the pipe near the manhole is presumed due to the heat caused by torching open the inspection manhole.

Figure 7-4. Wrinkled Pipe 1+320 Looking North



Notes.

Picture taken at approximately Station 1+323, looking south.
The wrinkle is at station 1+320.
The wrinkle is as much as 200 mm deep (or more) from the original diameter of the pipe.
The internal epoxy lining has been stripped away from the pipe at the wrinkle location.
There is a significant change in direction of the pipe at the wrinkled location.

Figure 7-5. Wrinkled Pipe 1+320 Looking South

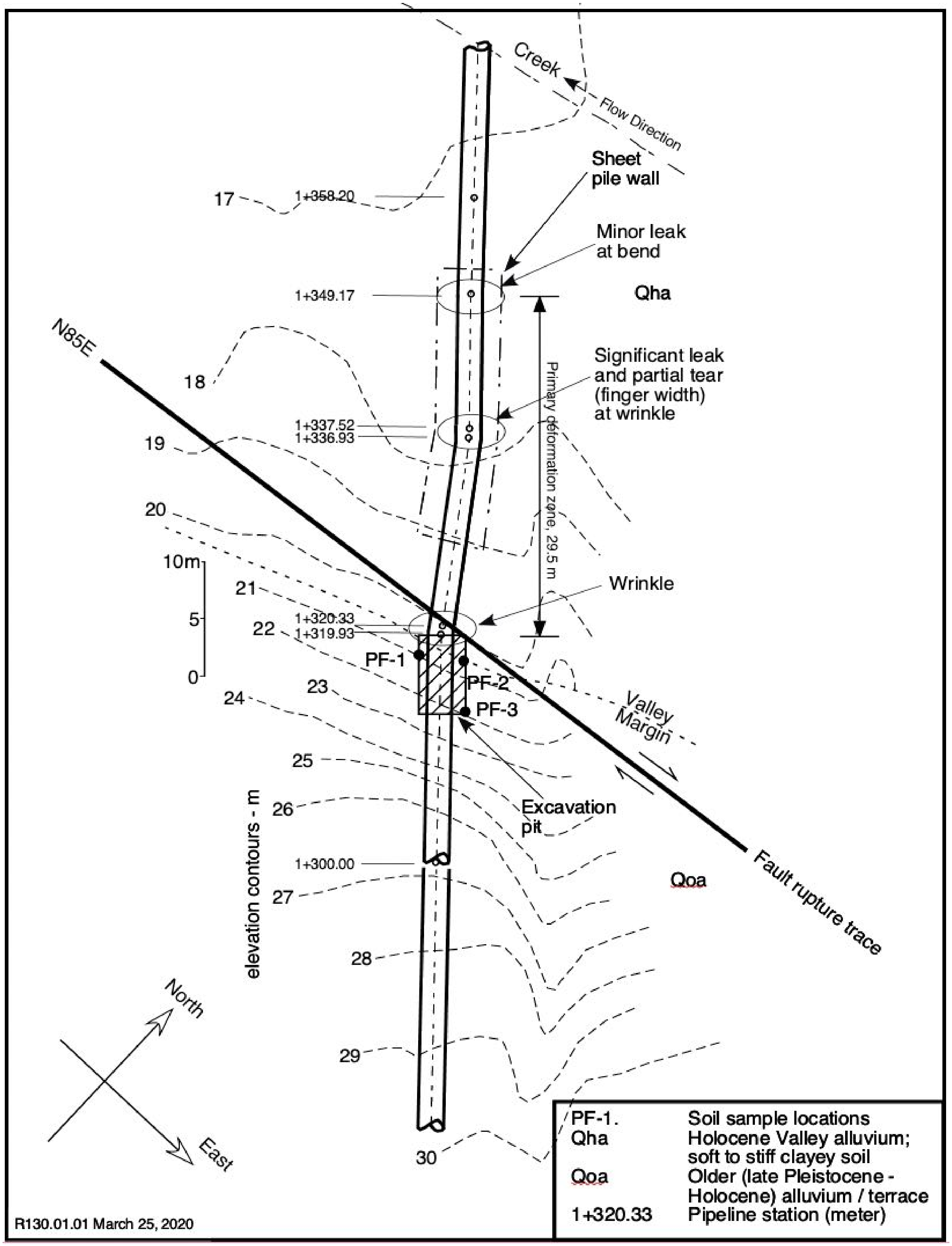


Figure 7-6. Pipe Alignment Through Fault Zone

The operating pressure at the fault crossing location was about 10 bar (150 psi).

The extent of the wrinkles show that the internal diameter had been "necked" down to about 1400 mm diameter at two of the wrinkles. This level of restriction results in about a 1 m loss of hydraulic head under peak flow conditions.

Figure 7-6 shows the plan view of the pipeline at the fault crossing location. Key features include:

- The plan is drawn to scale.
- The outline of the pipeline is based on a post-earthquake survey of the damaged pipe.
- Surface elevation contours are shown using 1 meter contour lines.
- Seven survey points were made at the top of the pipeline (round open dots).
- The excavation pit location is shown.

Assuming a 3 meter right lateral offset, the offset in terms of the pipe alignment was -1.70 meters (shortening) and 2.47 m (right lateral offset). The distance between the two main wrinkles was ~17.6 meters.

The average compression strain including the wrinkles would be about -9.7% (= 1.70 / 17.6). The allowable compressive strain is 0.88 t / R, = 0.88 * 18 mm / 1100 mm = -1.44%. Clearly, with a tendency to shorten of -9.7%, the pipe was bound to wrinkle; and it did. The extreme folding of the wrinkles (Figures 7-2 through 7-5) reflect that once the wrinkle initiated, further shortening of the pipe was accommodated by distortions of the two wrinkles.

For this pipeline, with t = 18 mm and R = 1100 mm, the theoretical strain to reach onset of wrinkling for is = 0.009818 (-0.98%), or an elastic compressive stress of 290 ksi, clearly well beyond yield. To accommodate practical out-of-roundness, ALA (2005) suggests about 0.175 t / R as the strain needed to initial wrinkling, or -0.29%. Given these issues, it is clear that the amount of fault offset imposed on the pipeline was large enough to initiate wrinkling of the pipeline.

The specified material for the pipeline was API Grade B steel (or better). Grade B has minimum specified yield stress of Fy = 35,000 psi (241 N/mm^2) and the minimum ultimate strength of Fu = 60,000 psi. It is not uncommon that modern steel with these minimum properties could actually have yield stress up to about 53,000 psi and ultimate stress up to about 78,000 psi. The properties for the steel in the actual pipeline was not tested, so is unknown.

The location of the fault and the two closest observed wrinkles is what would be expected just due to high bending moments in the pipeline. For example, if a continuous welded steel pipeline is at 90 degrees to the fault (right angles to the fault), then large fault offset will produce two zones with high bending moments in the pipeline at a moderate distance away from the fault. The sense of the bending moments would be opposite, as the pipe takes on a "S" type shape across the fault. The high bending moments would impose high compressive strain in the outer fiber of the pipeline, and with enough fault offset, the high strain due to bending would initiate a wrinkle. Even at 90° offset direction, there would be induced net tension in the pipe across the fault, owing to large geometry effects.

Thus, it is reasonable to observe two wrinkles, one on either side of the fault. The two main wrinkles are at stations 1+320 and 1+337, as evidenced by the abrupt change in pipe direction at those points. A third bend (wrinkle) at station 1+349 occurred, due to the attenuated (but still high) bending moments (beam on nonlinear foundation compliance). The analytical model described in Section 7.2.3 further investigate these issues.

The distance between the two main wrinkles was about 17 meters. Given that the pipeline has nominal diameter of 2.2 meters, this puts the spacing between the wrinkles at about 8 pipe diameters. Analytical studies have shown that for a given pipe diameter, the thicker the pipe wall, the wider the location between the two wrinkles, whereas for a higher soil stiffness surrounding the pipeline, the shorter the location between the two wrinkles.

The wrinkled pipelines at stations 1+320 and 1+337 have wrinkles on the order of 10s of centimeters (see Figures 7-2 to 7-5). A finger-width tear and leak occurred at station 1+337. A slight leak was reported to have occurred at station 1+349.

The pipeline crosses the fault at a break-in-slope between an older alluvial terrace or ridge slope to the south, and a small active alluvial valley to the north. The surficial geologic units are denoted Q_{oa} and Q_{ha} in Figure 7-6.

At the fault crossing (i.e., between stations 1+320 and 1+349), the pipe is underlain by Holocene alluvium.

Native soils exposed at the excavation pit consist of medium stiff, dark brown clay and silty clay.

When visited, there was some standing water at the bottom of the excavation pit, which may represent either groundwater, pipe leakage or recent rainfall accumulations. In any case, groundwater is likely to occur at shallow depth in the small alluvial valley at the fault crossing.

Laboratory testing was performed on three hand collected samples from the excavation pit adjacent to the pipeline to document the three main soil conditions near the pipeline (locations PF-1, PF-2, PF-3 in Figure 7-6). The samples included:

- Native clay soil (clay to silty clay with sand and fine gravel)
- Compacted backfill (mixed native clay soil and bedding)
- Granular bedding (well graded gravel with silt and sand)

Results from the lab testing are listed in Table 7-1. Native soils at the fault crossing consisted of medium stiff, fat clay (CH) to silty clay with sand and fine gravel. A three point direct shear test was performed on the native clay soil sample, indicating peak shear strength of about 44 kPa (= 920 psf) at a normal stress of 29 kPa, and effective stress parameters of $\phi' = 30 – 32°$ and $c' = 28$ to 31 kPa (= 585 to 650 psf).

Pocket penetrometer soundings in the trench wall and backfill clay soil indicated unconfined compression strength values of between 38.6 kPa to 76.5 kPa.

Table 7-1. Soil Properties

Sample No.	Material	USCS Description	Field Pocket Penetrometer Test	Sieve Analysis (percent finer)				Attenberg Indices			Natural Moisture Content	Direct Shear Peak Strength / envelope
			(kg/cm^2)	No. 200	No. 40	No. 4	2-inch	LL	PL	PI		
PF-1	Native Alluvial Clay	Brown fat clay (CH) with sand and fine gravel	0.4 to 0.8	75%	87%	95%	100%	73.8%	21.5%	52.3%	37.0%	6.4 psi / ϕ = 30°, c=4.5 psi
PF-2	Trench Backfill, compacted and mixed native soils with some granular bedding	Brown fat clay (CH) with sand and fine gravel	0.4 to 0.8	52%	66%	88%	100%	58.2%	20.2%	37.9%	33.0%	
PF-3	Select granular bedding / shading	Brown well-graded gravel (GW) with silt and sand		7%	18%	51%	100%					

7.2.3 Pipe Stress / Strain Analysis

Nonlinear structural analyses were performed to evaluate the performance of the pipeline at the fault crossing. A finite element model using nonlinear beam elements to represent the pipe and nonlinear spring elements to represent the soil was developed. The ANSR-III computer program was used. Figures 7-7 and 7-8 show the approach to model the pipeline. Major features of the model and pipe are noted below:

- The total length of pipe in the model is 1,400 feet.
- Each segment of the pipeline is modeled using 3-dimensional distributed plasticity 2-node, 12-degree-of-freedom (ANSR type 6) beam elements.
- In the transverse (Z) and axial (X) directions, the soil is modeled using 3-dimensional nonlinear 2-node, 2-degree-of-freedom truss (ANSR type 1) elements. The elements use bilinear load deflection curves.
- In the vertical (Y) direction, the soil is modeled using 3-dimensional nonlinear 2-node, 1-degree-of-freedom (ANSR type 5) elements. Two elements are used to model the upwards and downwards motions, reflecting the differences in soil behavior in those directions. For example, soil spring element 4-1 models the soil in the downwards direction; and soil spring element 5-1 models the soil in the upwards direction.

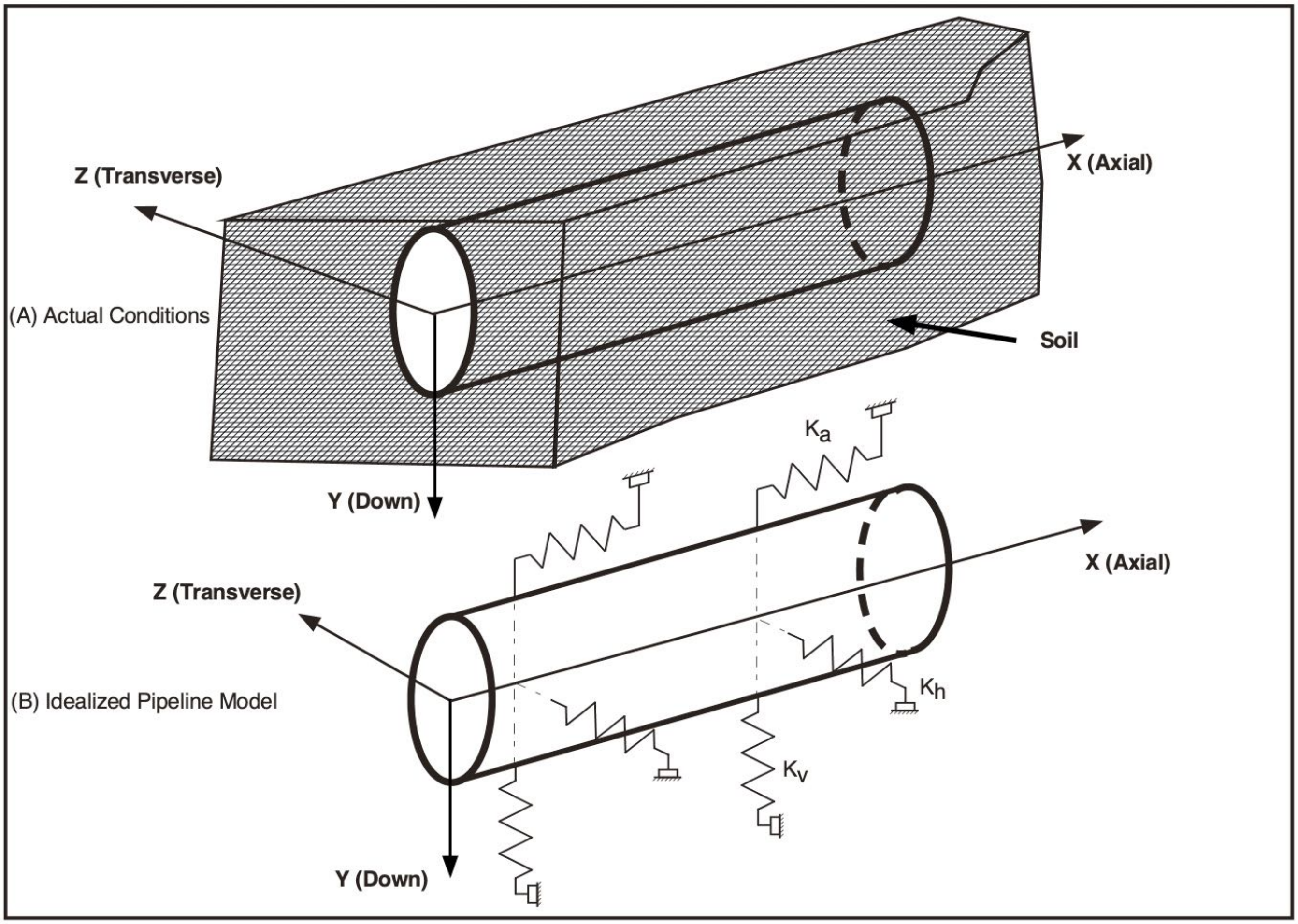


Figure 7-7. Pipe - Soil Spring Idealization

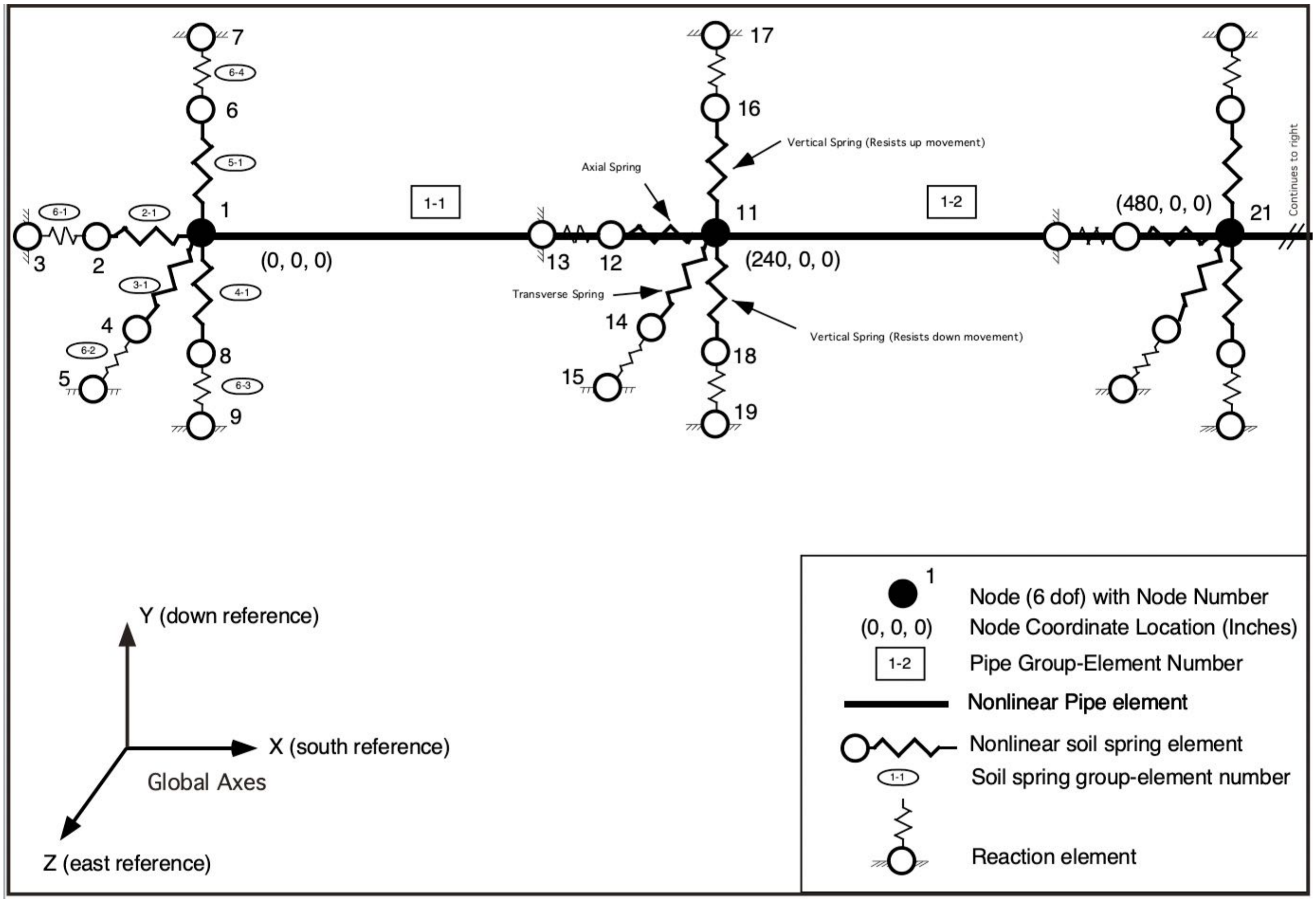


Figure 7-8. Pipe - Soil Model Connectivity (partial model shown)

Model Geometry

Begin at X = 0.0 inches, north side of fault.

The model uses 25 pipe elements, each 20 feet long (500 feet total).

The model then uses 30 pipe elements, each 5 feet long (150 feet total).

The model then uses 50 pipe elements, each 1 feet long (50 feet total).

The fault is assumed to be located at this point.

The model then uses 50 pipe elements, each 1 feet long (50 feet total).

The model then uses 30 pipe elements, each 5 feet long (150 feet total).

The model then uses 25 pipe elements, each 20 feet long (500 feet total).

In total, there are 210 pipe elements, and the total length of the model is 1,400 feet.

Boundary Conditions

At the start of the model, node 1 has all 6 degrees of freedom (d.o.f.) fixed. Node 1 is 700 feet north from the assumed location of the fault-pipe crossing.

Along the pipeline (nodes 11, 21, 31, etc. through 2111), all 6 d.o.f. are free.

For the axial soil springs, nodes 12, 22, etc. in the local X-direction d.o.f. are free.

For the transverse soil springs, nodes 14, 24, etc. in the local Z-direction d.o.f. are free.

For the vertical down (stiffer) soil springs, nodes 18, 28, etc. in the global Y-direction d.o.f. are free.

For the vertical up (weaker) soil springs, nodes 16, 26, etc. in the global Y-direction d.o.f. are free.

Mass

The analysis is based on a pseudo-static imposed displacement of the fault. Inertial effects on the pipeline are negligible and are neglected (all masses are set to zero).

Imposed Deflections

The maximum displacement imposed on the south side of the model is +3 meters (=118.08 inches). The north side moves easterly and southerly relative to the south side.

X (pipe axial direction in pre-earthquake alignment) movement = 118.08 cos 55° = -67.728 inches.

Z (direction transverse to the pipe axial direction) movement = 118.08 sin 55° = -96.676 inches.

Y (global) movement = 0 inches.

These three movements are applied to all nodes north of the fault offset location.

Analysis Parameters

The analysis is run as a static nonlinear analysis. The total ground offset of 118.08 inches is applied in 1000 equal steps, using equilibrium iteration after each step. There are 2,100 equilibrium equations in the model.

Soil Spring Parameters

Figure 7-9 shows the idealized pipe - soil trench arrangement. Soil springs are attached to each pipeline element. Formulations for the soil properties are provided for the three orthogonal directions. These soil properties are incorporated into the model using the bilinear (or trilinear) soil spring models described in ALA (2005).

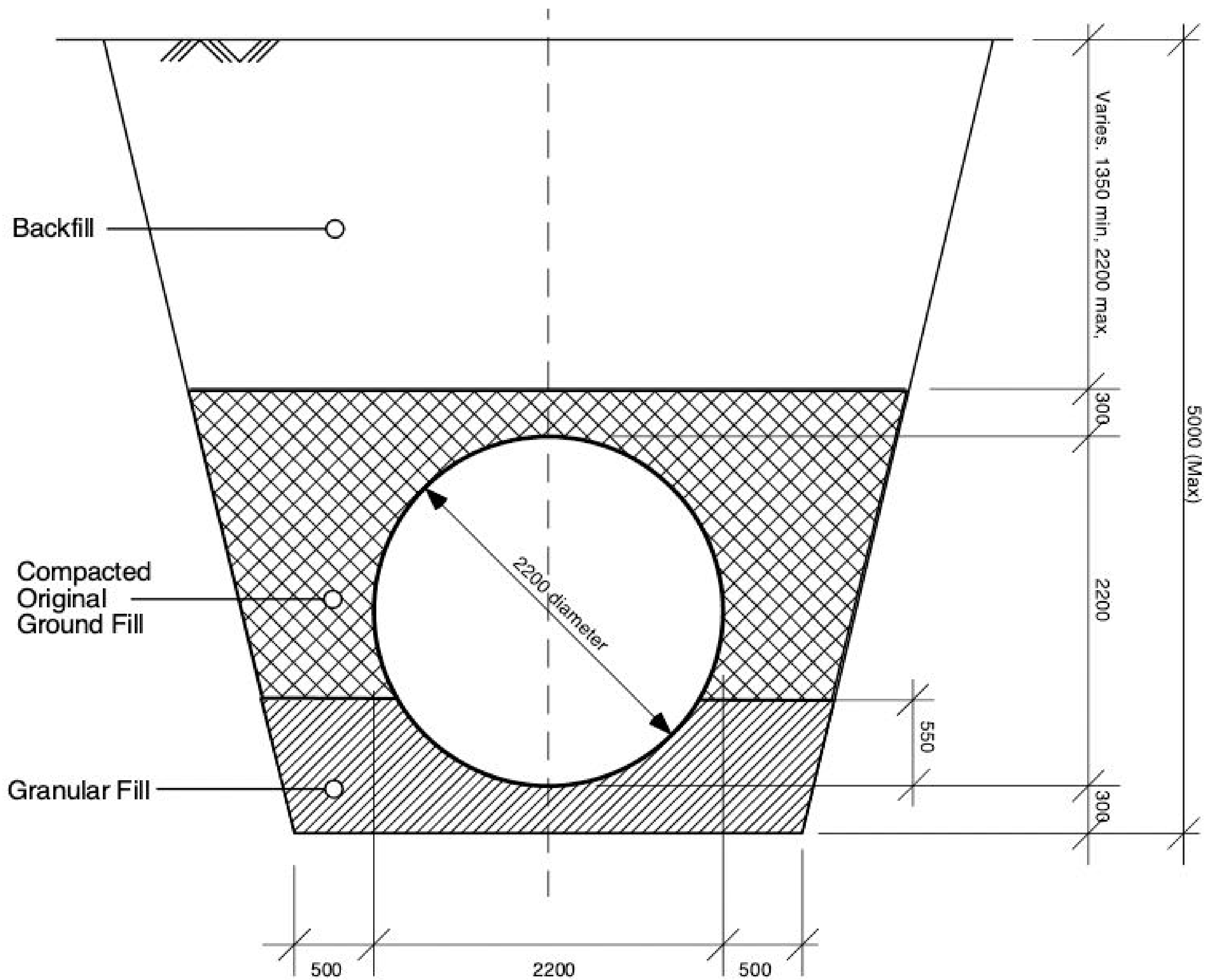


Figure 7-9. Pipe - Trench

The pipe properties are based on a 86.6 inch (2.2 meter) inside diameter pipeline with wall thickness of 0.708 inch (18 mm).

The average depth from the surface of the soil to the top of the pipeline is assumed to be (1.65 m + 2.5 m) / 2 = 2.075 meters.

To establish soil springs for the analytical models, some assumptions are made about the in-situ soils and soil failure planes. For transverse loading of the pipeline it is assumed that the native clay type soils beyond the pipe trench have an average undrained shear strength of clay based on the field data for native alluvial clays (Table 7-1) of $c = 4.6$ psi and $\phi = 30°$. These soil properties were taken from an excavated location where the pipeline begins to slope up rather steeply, and this soil condition might not be applicable to the soils in the flat creek basin. Assuming a soil density of 120 pcf, and 6.33 feet of cover, then the mean undrained shear strength of the clay is estimated as S_u = 10.7 psi = 1,540 psf.

A common approach is to do seismic design reflecting that the actual soil properties might have a range of ±50% from the mean. The lower bound properties will tend to show lower peak strains in the pipe, but longer reaches of pipe with high axial forces; the upper bound properties will tend to show higher peak strains, but shorter reaches of pipe with high axial forces. A complete design should accommodate the full range of soil properties.

Axial Spring (t-x curve)

The pipe is bedded on granular material, with compacted backfill placed above the pipe. Assume that the average soil spring can be estimated using a combination of these two conditions.

The t-x soil spring is a function of: D is the outside diameter of the pipe; γ = saturated density of sand; H is the depth from the soil surface to the spring line of the pipe; K_o, a factor for soil resistance, $\tan\delta$ = the friction between the pipe and surrounding granular backfill; α the adhesion between the pipe and surrounding cohesive materials; and x_u the assumed "yield" displacement of the trench fills. See ALA (2005) for details of each factor.

Transverse (Horizontal) Spring (p-y curve)

For transverse loading, the soil resistance is usually governed by the native soils beyond the trench unless the trench is designed to allow for major movements which could be accomplished using gently-sloped trench filled with pea gravel or similar. For the trench shown in Figure 7-7, the compacted fill trench will transfer lateral load from the pipe to / from the clay-type native soils behind the trench walls. The undrained shear strength of the clay is assumed to be S_u = 1,000 psf (lower bound).

The p-y soil spring is a function of: S_u the undrained shear strength of the clay; N_{ch} a factor from a chart in ALA (2005), and y_u the assumed "yield" displacement of the native soils.

Transverse (Vertical Upwards) Spring (q-z curve)

The q-z soil spring (weak upwards direction) is a function of: S_u the undrained shear strength of the clay; N_{cv} a factor from a chart in ALA (2005), and z_u the assumed "yield" displacement of the native soils.

Transverse (Vertical Downwards) Spring (q-z curve)

The q-z soil spring (strong downwards direction) is a function of: S_u the undrained shear strength of the clay; N_c a factor from a chart in ALA (2005), and z_u the assumed "yield" displacement of the native soils.

Results

Figures 7-10 through 7-13 display selected results assuming lower bound soil properties. The following are the key points made in these figures.

Figure 7-10. The top portion shows the transverse displaced shape of the entire pipeline model. Directions (northwest, southeast, northeast, southwest) are relative to North in Figure 7-6). The bottom portion of Figure 7-10 plots the same pipe displaced shape as the top portion, but at a larger scale for the pipeline near the fault offset, as well as the open boxes which indicate the assumed knife-edge fault offset of –96.7 inches is applied over a 1-foot wide zone. The solid boxes indicate the movement of the pipe. The pipe movement tends to "spread" the knife edge fault offset over some length of pipe, and the pipe deformations beyond the fault offset movement reflect the compatibility of pipe and soil deformations.

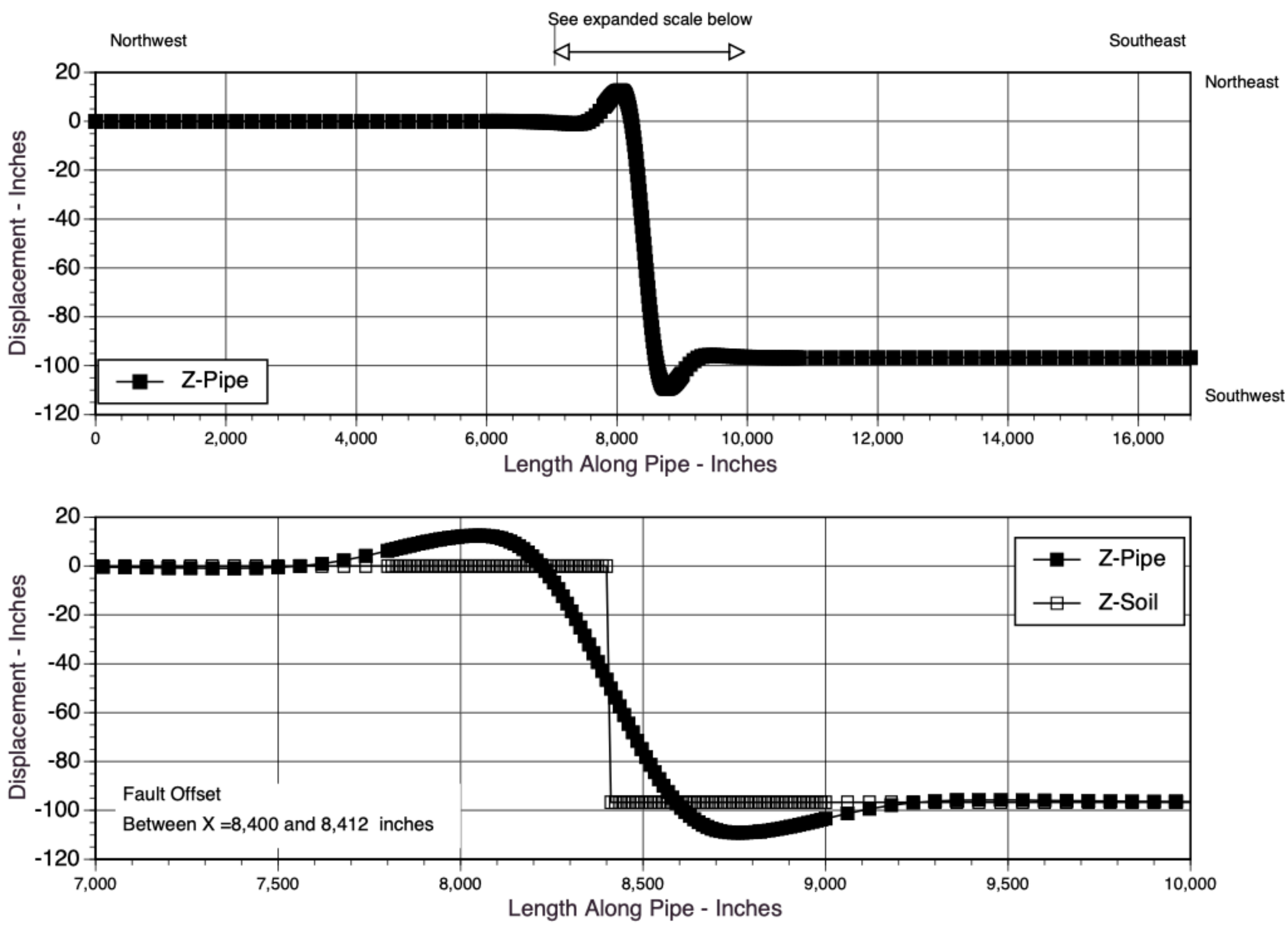


Figure 7-10. Transverse Displacements

Figure 7-11 shows the computed bending moment about the vertical axis within the pipeline. This is the bending moment caused by transverse movement of the soil.

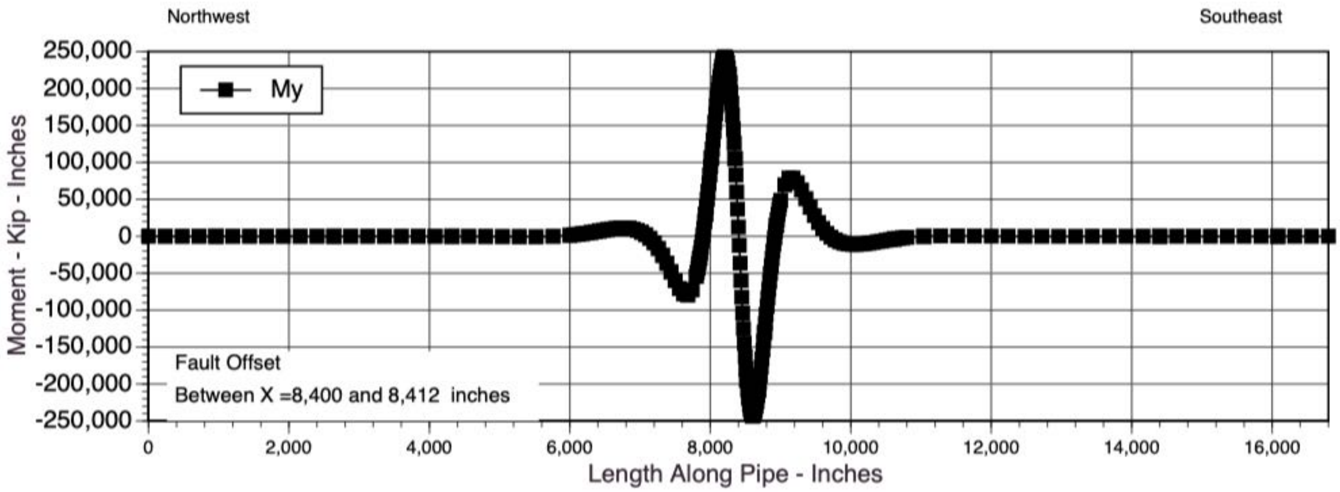


Figure 7-11. Pipe Bending Moments

Figure 7-12. The top portion shows the computed axial force within the pipeline. The bottom portion shows the computed average axial strain within the pipeline. The highest force is 9,671 kips (positive meaning compression). The highest average axial strain is –3.6% (negative meaning compression). As the model does not have post-wrinkling pipe elements, these forces and strains should be interpreted as average values through the entire pipe, excluding the additional local softening caused by the excessive wrinkles. A more detailed analysis with a shell-type model would show a different force and strain pattern. These type of refinements are not necessary, as the computed strains are clearly high enough to initiate wrinkling, as the allowable compressive strain is –1.44%, much lower than the computed compressive strain. The rapid variations in computed peak axial strain nearest the fault reflects the simultaneous application of high bending forces in the pipe, with a von Mises yield surface assumption with strain hardening, coupled with the assumptions of large geometry deflections of the pipeline near the fault. In other words, if the fault offset design displacement called for 3 meters of offset, this design would *fail* the code guidelines; and in practice, it did fail.

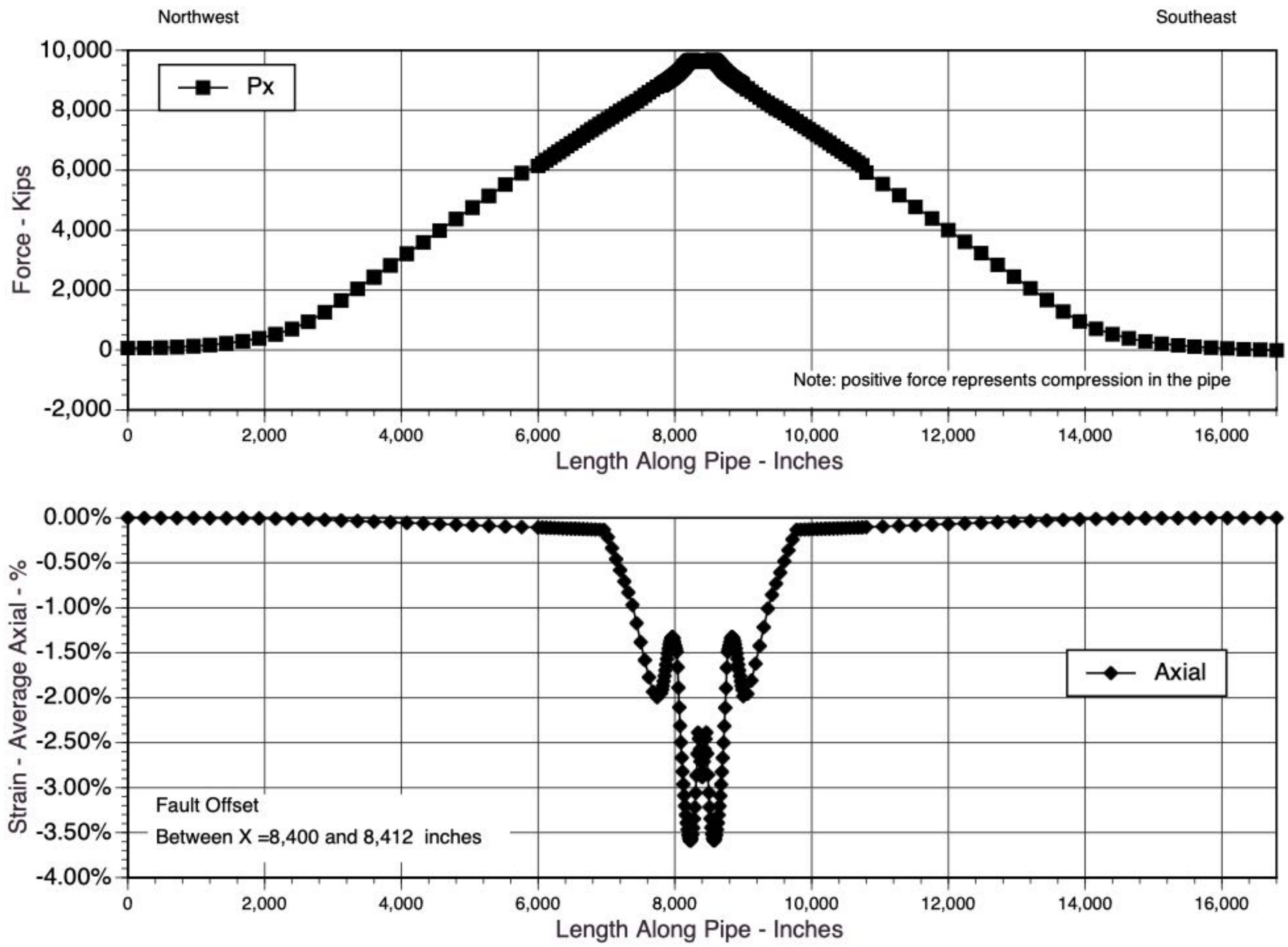


Figure 7-12. Pipe Axial Forces and Strains

While the results from Figure 7-12 already show the pipe should fail, these results do not tell the entire story. The transverse offset of the fault induced high bending moments in the pipe, and it is the combination of both bending (Figure 7-11) and axial (Figure 7-12) that is of interest. Figure 7-13 shows these results.

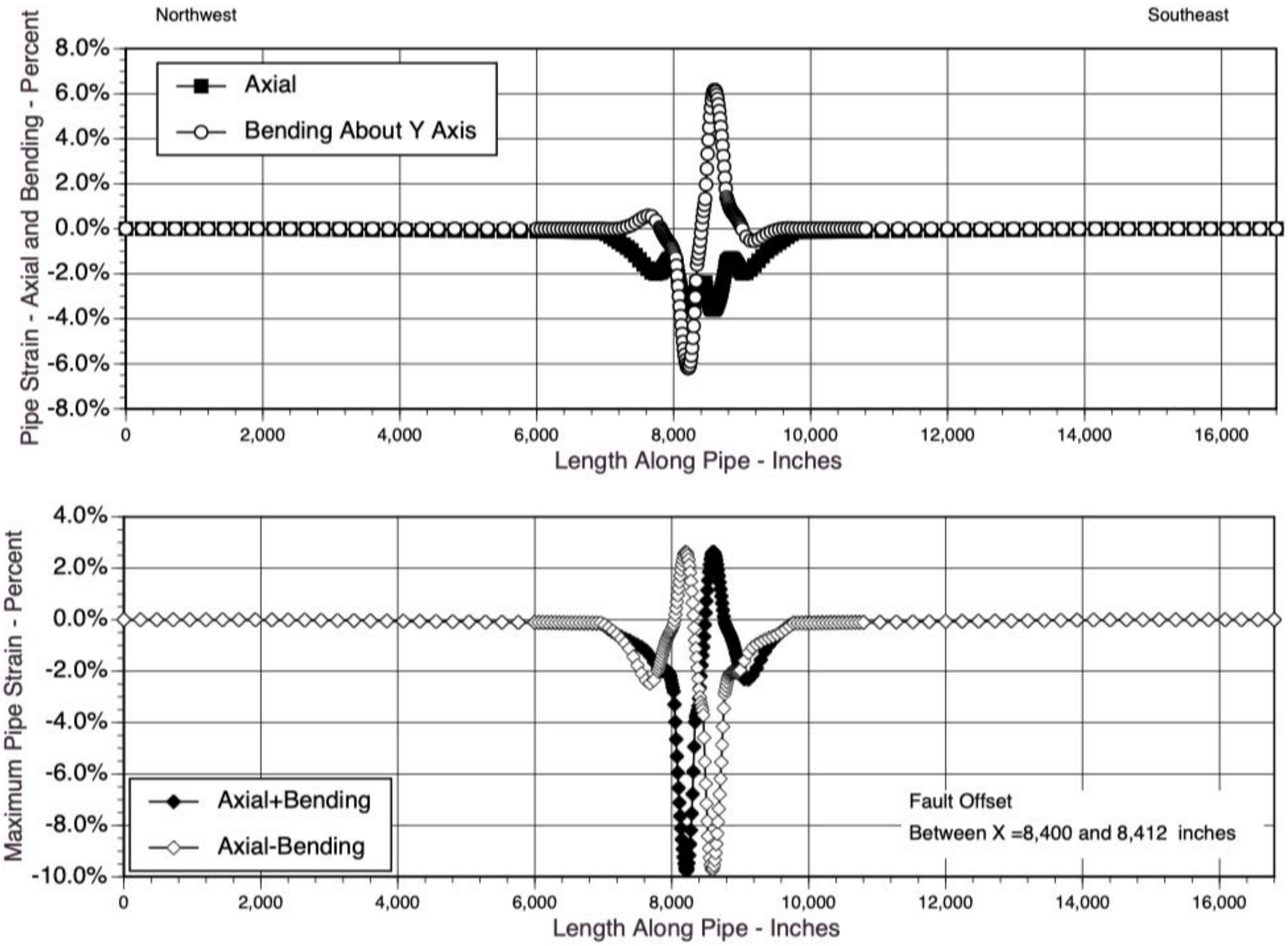


Figure 7-13. Pipe Combined Axial and Bending Strains

The top portion of Figure 7-13 shows the computed strain in the pipe separately for axial forces (same as Figure 7-12) and bending moments. The bending strain shown is based on the assumption of no wrinkling in the pipeline, and plane sections remaining plane, even in the post-yield condition; these assumptions are not valid at locations where the pipe undergoes severe wrinkling; but by that time, the pipe has "failed". The bottom portion of Figure 7-13 combines the average axial and peak bending components of strain, to produce a net maxima / minima strain diagram along the pipeline. If the pipe does not wrinkle, the highest strains in the pipeline would be about +2.6% (tension) and –9.8% (compression). The comparison of the axial and bending strains clearly shows that the bending strain is numerically larger (-6.2% bending vs. –3.6% axial), suggesting that the onset of wrinkling is caused primarily by the high bending moments. This suggests that computational models which ignore the effect of pipe bending near the fault cannot accurately predict the onset of pipe wrinkling. Once wrinkles occur, the imposition of additional fault offset will tend to distort the pipe mostly at the wrinkled locations, due to the "softening" of the pipe at those locations, with little increase in deformations in the pipeline at non-wrinkled locations. As wrinkling proceeds at wrinkled locations, the local bending in the pipe, coupled with hoop stress, will ultimately result in localized pipe strains in excess of the rupture capacity of ductile steel, somewhere in the 20% to 30% (local) range. Figures 7-2 through 7-5 show both sides of the two main wrinkled locations in the pipeline; the distortions in these wrinkles would suggest that localized strains likely exceeded 20% in many locations; it is surprising that only one tear (rupture of the pressure boundary) of the steel actually occurred.

As previously mentioned, the soil properties are uncertain, and design should consider a range of the soil properties. If one assumes stiffer bound properties (Su = 2,000 psf), then the model shows the following:

- Predicted maximum strains in the pipeline are +4.7% (tension) and -14.6% (compression). In comparison to results with lower bound soil properties), the predicted pipe strains are higher when upper bound soil properties are assumed. This trend is as expected for an increase in soil stiffness and strength.

7.2.4 Observations

The analyses in Section 7.2.3 suggest the following:

- For practical design, a range of fault offset patterns should be used. In general, a "knife edge" pattern results in the highest pipe stresses / strains. The design also needs to consider uncertainty as to where this "knife edge" offset occurs.

- For practical design, a range of soil parameters should be considered. A typical range is ±50% from the best estimate soil properties. Changing the soil properties will result in different forecasts of peak pipe strain as well as different patterns of forces within the pipe.

- For right lateral fault offset of 3 meters (118 inches), the maximum computed strains for this pipe were -9.8% (lower bound soil stiffness) or -14.6% (upper bound soil stiffness).

- The nominal allowable compressive strain is -1.44%. At this level of strain, some bulging of the pipe would occur.

- If the acceptance criteria allows the pipe to initiate wrinkle, but not to allow the wrinkle to excessively deform (-1.44%), then this design for this fault offset "fails". Perhaps a better design would have been to use a pipe alignment that would allow net tension across the fault (not net compression), and then select D/t on the order of 50. This would result in much higher capacity against wrinkling. Possibly, the trench backfill could have been engineered with pea gravel or similar granular or soft backfill material, which would reduce the curvature of the pipe, and hence reduce the bending moments. From a cost perspective, having D/t = 50 means having a wall thickness of 44 mm, which is much thicker (and costlier) than is needed to carry the internal pressure. However, examining Figure 7-13, the length of pipe subject to high bending / strains is about 200 feet; so the extra heavy wall pipe need only be specified for that length, and thinner wall pipes can be selected beyond those zones, careful to assure that the thinner wall pipes can still take the high axial anchor forces which extend for a much wide zone (see Figure 7-12 top). Practically speaking, a better designed pipe might have D/t = 50 for 200 feet, D/t = 90 for 800 feet, and D/t = 122 (maximum to accommodate the internal pressure) beyond; if the local site conditions permit, a pea-gravel trench through the primary fault offset zone can be a good design feature. The incremental cost for such a design can be modest in context of the complete pipeline cost, as the length of pipe so requiring the special fault offset features is relatively short.

7.3 Simplified Hand Calculation Models to forecast Pipe Strain

In ASCE (1984), two simplified "hand calculation" methods are described: the so called Newmark and Hall (1975) method and the so called Kennedy (1977) method. Both these approaches make a number of assumptions about how the pipe bends / stretches to conform with the fault offset, and then computes a strain in the pipe.

However, both approaches neglect large geometry issues, and may not entirely capture that there is both local bending as well as a net stretch / compression for all pipes that cross faults (or other PGD zones).

Section 7.2 shows that common finite element "beam-type" models can reasonably capture both the net stretch / compression and local bending cases. Since about 1995, almost all major gas and water pipes that have been designed and constructed in California to cross faults have adopted the finite element "beam type" approach to compute the internal stresses and strains in the pipe.

Effectively, the "Newmark" and "Kennedy" simplified methods should be "retired". Neither of these simplified methods is included as an acceptable approach in ALA (2005).

Takada et al (2001) introduced improved hand-calculation methods for design of buried steel pipes across faults, in order to recognize that high local bending moments often control the peak strains. It might be reasonable to use such an improved hand calculation approach. For important gas transmission pipes, the finite element approach is better than any simplified hand calculation approach, in that the finite element approach can factor in a larger variety of variables that might arise at any given location.

7.4 Strain Based Fragility

In Section 8 of this report, fragility models are described that reflect the empirical record. These models forecast the probability of a damage state as a function of PGV or PGD.

In Section 7 of this report, the evidence of pipe failure has been presented using a strength-of-materials approach, with an example of an actual pipe that sustained damage in a past earthquake. Some in the community have expressed interest in having a fragility model that correlates damage as a function of strain (stress) in the pipe. The benefits of this type of model is that it can be used with general purpose non-linear beam-on-nonlinear soil formulation.

The empirical evidence for buried steel pipes suggests the following:

- Imperial Valley 1979. Three pipes underwent several inches to a foot or so of fault offset. See details in Section 6.23. The pipes did not leak.

- Napa 2014. Two pipes underwent several inches of fault offset. See details in Section 6.17. These pipes might, or might not have yielded; clearly, they were highly stressed and possibly they did yield. The pipes did not leak.

- Ridgecrest 2019. Two pipes underwent fault offset on the order of about a foot. See details in Section 6.18. Clearly, both pipes yielded (see Figures 6.18-4, 6.18-5). The pipes did not leak.

- Kocaeli 1999. Several steel pipes underwent fault offset on the order of several feet. Section 7.2.1 provides details of post-event analyses, showing predicted strains on the order of -9.8% and +2.6%. The pipe sustained severe wrinkles at two locations, one either side of the fault offset; with a tear in the steel (leak) at one wrinkle. The pipe also had a minor leak at one other location.

Given the empirical evidence, and considering strength-of-mechanics issues, one can say the following:

- Post-earthquake, any pipe that is thought to have yielded due to fault offset (or other form of PGD), even if not observed to be leaking gas, should be prioritized for replacement with new unstressed pipe. The time line for replacement has ranged from days (Napa 2014, Ridgecrest 2019) to a to a few years (Imperial Valley 1979, Anchorage 2018) post-earthquake.

- If the predicted strain in the main barrel of the pipe is < 1% (tension) and less than 0.22t/R (1/4 of compressive buckling limit), then a well-built pipe should be highly reliable and not leak gas.

- If the predicted strain in the main barrel of the pipe is < 2% (tension) and less than 0.44t/R (1/2 of compressive buckling limit), then a well-built pipe should be quite reliable and not leak gas.

- If the predicted strain in the main barrel of the pipe is < 4% (tension) and less than 0.88t/R (compressive buckling limit), then a well-built pipe should be reliable and not leak gas.

- If the predicted strain in the pipe is ~ 8% (tension) and two times higher than 0.88t/R (compressive buckling limit), then a well-built pipe might or might not leak gas. This is not a reliable pipe.

- If the predicted strain in the pipe is ~ 16% (tension) and four times higher than 0.88t/R (compressive buckling limit), then a well-built pipe is likely to leak gas. This is not a reliable pipe.

Table 7-2 provides a fragility model for the main barrel of a well-built steel pipe without corrosion or stress/ strain risers. The method to compute stress / strain for use with Table 7-2 are models of the sort described in Figures 7-7 and 7-8. If shell models are used, and these shell models allow for computation of strains within wrinkles, then the Tension limits can be used, and the Compression limits are not applicable.

In Table 7-2, the meaning of "break" is a large gas leak that releases gas in sufficient pressures and quantities as to likely allow ignition / explosion if there is an ignition source; the meaning of "leak" is a small gas leak that releases gas at low pressures and quantities to essentially preclude ignition even if there is an ignition source; the meaning of "no leak, replace" is that if the pipe is exposed and observed to have visible offset, that the pipe will be replaced with a new un-stressed pipe. The distinction of break or leak will depend on the operating pressures, quantity of available gas supply before shutoff, the ultimate size of the tear in the steel, the restraint and attenuation afforded by surrounding soils and other factors. For purposes of loss estimation, for fault offset, it can be assumed that loss of the pressure boundary on the main barrel of the pipe can be considered a "break"; for liquefaction / landslide, it can be assumed that loss of the pressure boundary on the main barrel of the pipe can be either a "leak" or a "break". Ultimate uniform strain is the strain from a uniaxial test corresponding the maximum stress sustain by the test specimen, before necking of the specimen. The values in Table 7-2 presume that the steel does not fail by brittle fracture.

Table 7-2. Stress / Strain Fragility Model

State of Stress / Strain	Tension	Compression	P(DS3 or DS2) Break or Leak	P(DS1) No Leak, Replace
Elastic	< Fy	< -Fy	~0	~0
Minor yielding	< 1 %	< 0.22 t/R	0.01	25%
Some yielding	< 2 %	< 0.44 t/R	0.02	50%
Code level yielding (one time loading)	< 4 %	< 0.88 t/R	0.05	100%
Major yielding	< 10 %	< 1.5 t/R	0.50	100%
Extreme yielding	< 20 %	< 2 t/R	0.95	100%
Ultimate uniform strain	Material-specific, peak of stress/strain curve before necking	> 2 t/R	1.00	100%

Table 7-2 presumes that the weld is stronger than the main barrel of the pipe, and the bulk of the yielding occurs in the main barrel of the pipe away from the weld. For pipes where the girth weld is controlling / limiting element, the chance of failure of the pipe is controlled by the post-yield capability of the weld; yielding of such girth welds will afford little capability of the pipe sustaining major offset; for such pipes, failure may be conservatively assumed if the predicted stress / strain exceeds the pipe's yield level or the weld's strength level, considering defects. For pipes with longitudinal or helical seam welds that are not equal or stronger than the main barrel of the pipe, failure may be conservatively assumed if the elastically predicted stress / strain in these welds exceeds the weld's strength level, considering defects.

Table 7-2 assumes all welds are full penetration butt welds without stress / strain risers. Table 7-2 excludes damage to appurtenances, branch connections, blow offs, regulating stations and other components that are part of the gas system. Features such as backing plates and fillet welds impose stress and strain concentrations. Stress risers can be computed using approaches in the ASME B31.8 code (such as at branch connections, fillet welds, elbows, etc.), if one is using elastic limits. In the post-yield condition, strain risers can be computed using three-dimensional models. It is normally recommended to avoid any irregularities in a steel pipe at locations where it may be exposed to post-yielding performance (such as at a known fault offset location), but this might not be practical for pipes exposed to liquefaction, especially in urban areas where there will be many branch connections; and at blow offs where pipes traverse nearby drainages. At some locations, the pipe might be anchored either side of the fault; appurtenances used for anchorage (pipe restraints, etc.) must be designed to be highly reliable (ideally keeping stresses at or below yield).

The quantified values for P(DS3) in Table 7-2 should be considered to be first-order estimates. If the "Major yielding" level is forecast, the pipe should be considered unreliable and not suitable for design. The "Code level yielding" level is intended for a one-time loading, after which the pipe will be replaced. The "Some yielding" level is intended to be a level where the pipe should be able to sustain about 2 such events over its lifetime before being replaced. A low-cycle fatigue check could be used to consider the cumulative chance of rupture of the steel under multiple loading cycles (for example at a fault offset location: ongoing creep, some small earthquakes, followed by a major earthquake). The "Extreme yielding" limit of 20% reflects that while most quality steels are capable of yielding to 20% before necking / rupture in uniaxial tests, in the field the actual state of stress is three-dimensional, and the pipe must also be able to sustain hoop pressures and various perturbations (out-of-roundness, minor flaws, etc.).

The reader will observe that in Table 7-2, the chance of failure is ~0 if the pipe is computed to remain elastic. The empirical observations are that lots of gas steel pipes have leaked, and likely the state of stress / strain in many of those pipes would have been computed to be under yield. The reason for these differences are many, including the following features: material corrosion, defects, appurtenances, branch connections, stress risers, low toughness, etc. Therefore, Table 7-2 should only be used for idealized segments of steel pipe that can be idealized to have none of these features.

In recent years, some manufacturers have manufactured and tested steel pipe with pre-formed bulges. The intent of these bulges is to control the locations where the pipe will wrinkle in compression. Conceptually, this design is similar to stainless steel bellows, where the deformation needed for fault offset (or thermal expansion, etc.) is accommodated by movements in the bulges / bends; the design varies, though, in that the steel pipe is able to take high internal pressure, whereas most bellows are designed for modest internal pressures. One observed failure mode for stainless steel bellows is fatigue related, with no advance warning of rupture. Conceptually, the "allowables" for a pre-formed bulge steel pipe should include a check on local yielding levels, as well as a low-cycle fatigue check; Table 7-2 is not intended for use with these types of pipes. The reader should be aware that a single loading test on this type of pipe might show its ultimate capacity of that specimen; for design, the fatigue life of the pipe should also be checked for the forecast cumulative load cycle, considering all earthquakes, temperature, internal pressure and soil / vehicle loading conditions.

CHAPTER 8: Fragility Models

Section 8 describes the seismic fragility models for use in seismic evaluations of gas transmission pipelines using "repairs per km" or "repairs per location" approaches.

8.1 Form of Fragility Models

Fragility models are developed to support 3 levels of detail:

- Level 1. Simplest. The least amount of computation of seismic hazards, inventory and fragility analysis.

- Level 2. Additional refinement in the computation of ground motions, inventory and fragility analysis.

- Level 3. More refinement in the computation of ground motions, inventory and fragility analysis.

The two primary seismic hazards that are used as the independent variable in fragility models for Level 1, 2, 3 analyses are:

- PGV (peak horizontal ground velocity)

- PGD (permanent ground deformation)

These fragility models correlate the probability of a damage state as a function of the seismic hazard:

- P(damage state) = function of (PGV) (for shaking). The fragility is described as a Repair Rate per km of pipe.

- P(damage state) = function of (PGD) (for liquefaction, landslide). The fragility is described as a Repair Rate per km of pipe.

- P(damage state) = function of (PGD) (for fault offset). The fragility is described as the chance that a repair is needed for a pipe that traverses through a fault offset crossing zone.

From the discussions in Sections 6 and 7, there are many parameters that could be included in fragility models:

- Pipe Inventory: Pipe material (Fy, Fu, stress-strain curve). Pipe joinery. Pipe outside diameter. D / t ratio. Internal operating pressure. Age (as a proxy for quality / type of construction). Lining and coating systems. Past history of non-earthquake-related leaks / repairs. Depth of cover. Pipe coating - to - trench friction / adhesion capacity. Alignment (straight, bends, branches, etc.).

Nearby special features (bridges, burial under creeks, encasements, slip joints, pile-to-non-pile supported sections, anchor blocks, etc.)

- Soils. Free field soil strength (in particular for most sites in California, the undrained shear strength for clays, Su). Trench design. Soil t-x (axial), p-y (transverse) and q-z (up) and q-z (down) curves. Variation of soil parameters along the length of the pipe.

- Fault offset. The amount of PGD. Accumulated PGDs due to pre-earthquake creep, co-seismic slip, and post-seismic afterslip. Spatial variation of PGD along the length of pipe (knife edge, distributed, etc.). Direction of the PGD relative to the pipe alignment, both 2 dimensional (like for strike slip offset movements) and 3 dimensional (like for reverse thrust offset movements). The general case is three dimensional oblique movements. Note: for pre-seismic and post-seismic slip, the slowly applied PGDs are thought to be consistent with lower soil stiffnesses.

- Liquefaction. Areal extent of liquefaction zone. Peak PGD measured in the zone (amount of PGD may vary with duration). Variation of PGD throughout the zone. PGD at the surface. PGD at the depth of the pipe. Vertical PGDs due to settlements. Lateral PGDs due to lateral spreads, and direction of the lateral spread relative to the pipe. Depth of water table at the time of the earthquake. Note: settlements that occur above the spring line of the buried pipe have little impact on the pipe.

- Landslide (deep seated). Areal extent of landslide zone. Saturation of the soils at the time of the earthquake. Yield level of the slop (Ky) at the time of the earthquake. Peak PGD measured in the zone. Variation of PGD throughout the zone. Direction of PGD relative to the pipe.

- Landslide (debris flow). Debris flows are commonly activated by earthquakes. Most smaller debris flows do not extend deep enough to impact a buried pipe. Very large debris flows can mobilize substantial depths and can impact buried pipes. Generally, debris flows are excluded from the analysis of buried pipe performance, but if a large deep debris flow is forecast, then it can damage a buried pipe.

- Shallow Landslide (surface sloughs). Landslides that only produce surface level soil movements above the pipe will not generally impact the buried pipe; these are often ignored for buried pipe.

- Shaking. PGV for each horizontal direction. Duration of shaking (magnitude M can be used as a proxy). Time history of shaking motions. Wave speeds, c. Ground motions can be computed using three dimensional models, but this is often not practical; so some proxy estimate of the effects at soil boundaries (softer soil-filled valleys near stiff soil / rock mountainous terrain) to consider boundary effects. The imposed strain / stress in a buried pipe is a function of the differential displacement imposed on a non-slipping pipe. Modern GMPE models (such as NGA 08, NGA13, etc.) do not provide estimates of the differential displacements over a length of pipe. Formulae of the type (PGV / c) can be used to suggest a differential displacement over a length of pipe, but the assumptions about wave forms in these formulae are simplified and do not capture the complicated state of transients at boundaries like valley edges, or where there is a transition from stiff to soft soils.

- Estimates of uncertainties and randomness in all of the above.

Conceptually, nearly every repair in a gas pipe is due to some type of overload that results in a breach of the pressure boundary which allows some amount of gas to leak to the atmosphere. Gas system operators will be particularly interested in distinguishing between a variety of types of repairs:

- Major leaks / breaks. A repair is "major" if it has any of the following characteristics: large amounts of gas released; leaks at a gas / air mixture approaching or exceeding 50,000 parts per million and thus can ignite; leaks at locations with nearby houses / population; leaks which result in extended outages to critical customers; leaks which require significant repair efforts. In this report, this is called Damage State 3 (DS3).

- Minor leaks. A leak is "minor" if it is not "major". In this report, this is called Damage State 2 (DS2).

- Other damage. A pipe that has undergone sufficient yielding such that its residual margin to sustain future earthquakes or ongoing operational requirements is degraded. For example, a pipe that has sustained permanent deformation due to ongoing fault offset. A pipe with significant ovalization so as to preclude in-service inspection using a pig is another example. In this report, this is called Damage State 1 (DS1).

8.2 SoCalGas Transmission Pipes

Section 6 of this report present the empirical data as to historical repairs for SoCalGas transmission gas pipes in several past earthquakes. This reflects the data from the 1933 Long Beach, 1952 Taft, 1971 San Fernando and 1994 Northridge earthquakes. Section 8.2 provides statistical analysis of this SoCalGas data.

Figures 8-1, 8-2 and 8-3 shows the SoCalGas gas transmission pipe repair rates due to ground shaking, (excludes pipes exposed to fault offset or liquefaction or landslide). All these pipes were steel. Most repairs were to the main barrel of the pipe (mostly at girth welds, a few cases of pipe wrinkling or leaking flanges). This historical data set does not include damage to appurtenances; this is not to say that this type of damage did not occur.

- Figure 8-1. Includes pipes from 1921 to 1994 vintage. All data are for steel pipe, using both oxy-acetylene welds (generally pre-1928) or arc welded (generally post-1931). Pipe diameter (nominal) 6 to 30 inches.

- Figure 8-2. Includes only arc welded pipes from 1926 to 1994 vintage. All data are for steel pipe. Pipe diameter (nominal) 10 to 30 inches. Total repairs 2.

- Figure 8-3. Includes only oxy-acetylene welded pipes from 1921 to 1927 vintage. All data are for steel pipe. Pipe diameter (nominal) 6 to 26 inches. Total repairs 81.

There is a large scatter in the data. Most of the repairs were at the girth welds; a few were gas leaks at flanges; 1 was for a pipe wrinkle; 1 was due to pit holes; 2 were due to uplift (without leak) of the pipe out of the ground along a slope; all required repair.

There is nearly a 38-fold difference in the capability of steel pipes between Figures 8-2 (generally post 1930) and 8-3 (generally pre-1929). Some researchers initially attributed this to the differences between older-style oxy-acetylene girth welds versus more modern electric-arc welds. But other researchers doubt this to be the case, as well made welds, using either technique, are equally as strong; although the heat affected zone for oxy-acetylene-made welds tends to be larger than for arc-welds, suggesting perhaps lower ductility. However, for ground shaking effects, say at PGV = 20 inch/sec, vertically-propagating shear waves from the earthquake, assuming a propagation speed of 12,000 feet/sec, and no slippage between the pipe and ground, should only result in about 2 ksi tensile or compressive longitudinal stress in the barrel of the pipe. ±2 ksi = 29,000 ksi * [20 inch/sec / (2 * 12,000 feet / sec * 12 inch / feet)]. Even if one adopts 2 times stronger ground velocities (40 inch/sec), and double the ground strains to reflect local topography conditions, one only obtains ±8 ksi longitudinal stress in the main barrel of a straight pipe. So, one would rarely expect yielding of full penetration welds; and yet the empirical evidence shows many failures. Why?

- Explanation A. An explanation is afforded by the observations that many of the older pipes (made using oxy-acetylene welds) had poorly made welds, including lack of root penetration, undercutting and overlapping of the toe, and a lack of good fusion between the pipe and the weld. This is an explanation offered by O'Rourke (1996).

- Explanation B. An explanation is that the ground motions have large variability, and the PGV independent variable in Figures 8-1 to 8-3 are all based on median-PGV values; and the pipe alignment might lead to natural stress risers. The actual PGVs along the pipelines could have been about 65% higher (for 16% of the pipe length) or 65% lower (for 16% of the pipe length) than the median (assumes β = 0.50, the lognormal standard deviation for PGV). At locations where pipes bend up to match the terrain, there is a natural stress riser in the pipe. The wave propagation speed (c = 12,000 feet/sec) assumes common vertically propagating shear waves; but in basins and locations near very stiff slopes and softer deeply filled valleys, the effects of slower moving (lower c) surface waves (Rayleigh waves) may play a larger role in the overall pipe loading. For all these reasons, when the median PGV is forecast to be 20 inch/sec (50 cm/sec), the actual pipe stress consider these effects could rarely exceed tensile yield (more common) or the compressive wrinkling limit (less common for gas pipes with D/t < 100). The empirical dataset observed many more tensile-related failures than compressive wrinkling-type failures for the gas pipes.

- Explanation C. Some of the failed SoCalGas pipes in the 1952, 1954, 1971 and 1994 earthquakes, which have been attributed to strong ground shaking, were in fact also impacted by some type of PGDs. While it has been attempted to omit from Figures 8-1, 8-2 and 8-3 any pipe failures in zones with clear PGDs due to faulting or liquefaction, the currently available evidence that PGDs did not occur may not be complete.

- Explanation D. There were dozens of failures of butt-welded 16-inch to 40-inch diameter steel pipe in the City of Concepcion in the 2010 Maule (Chile) earthquake (Eidinger, 2010). Most of the failures were in zones that underwent liquefaction-related PGDs. These pipes were installed post-1946, so using older oxy-acetylene welding technique would not be a factor. It was apparent when reviewing the joint failures in this earthquake that the welders had not done complete penetration welds; observed failures at girth joints tended to have clean-edges. This would be the expected failure mode if the stress in main barrel of the pipe exceeded about 50% of yield, while the girth weld had only about half the strength of the pipe in the longitudinal direction, owing to a large stress riser at the weld due to the lack of complete penetration. This type of incomplete weld might be satisfactory for many years of normal (non-earthquake) service, when the girth weld only has to take loads due to internal pressure, as these welds are only loaded up to half as much due to pressure as the hoop stress in the main barrel of the pipe. But in the earthquake loading environment, these welds must take the full longitudinal stress in the main barrel of the pipe; if the girth weld is flawed, it will fail prematurely. Similar failures have occurred in post-1950 welded steel pipe in water systems in California, where the root cause was identified as poor-quality welds.

- Considering all the above explanations, one gets a plausible overall rational explanation for the much higher failure rate for SoCalGas's pre-1930 pipe: the welds were poor quality (primary reason), and the ground motions / ground strains were locally much higher than would be predicted using median-based PGV (secondary reason). This implies that any welded steel gas pipe (whether using older oxy-acetylene welds or modern electric arc welds) will fail prematurely in earthquakes if the girth welds are defective (in particular, not full penetration; or with significant internal flaws) in such a manner that the pipe cannot sustain mild yielding in tension under large ground motions, becoming especially important when PGVs are over 50 cm/sec.

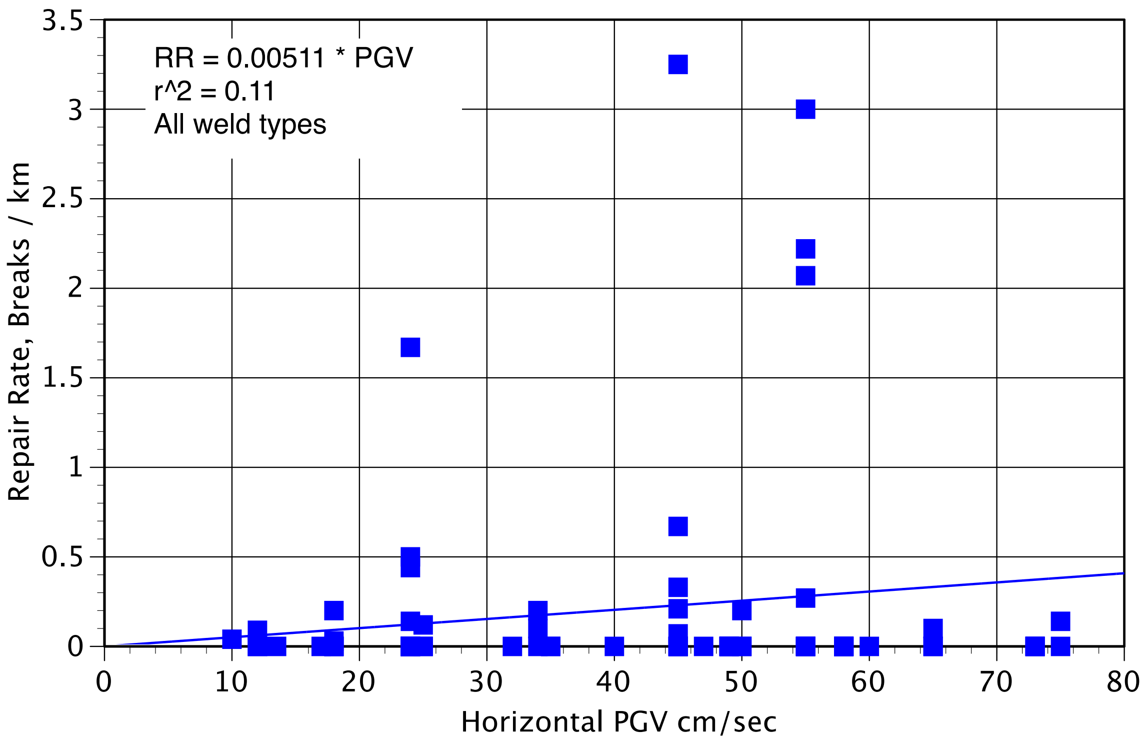


Figure 8-1. Repair Rate, Ground Shaking, Steel All Weld Types, All Ages, SoCalGas

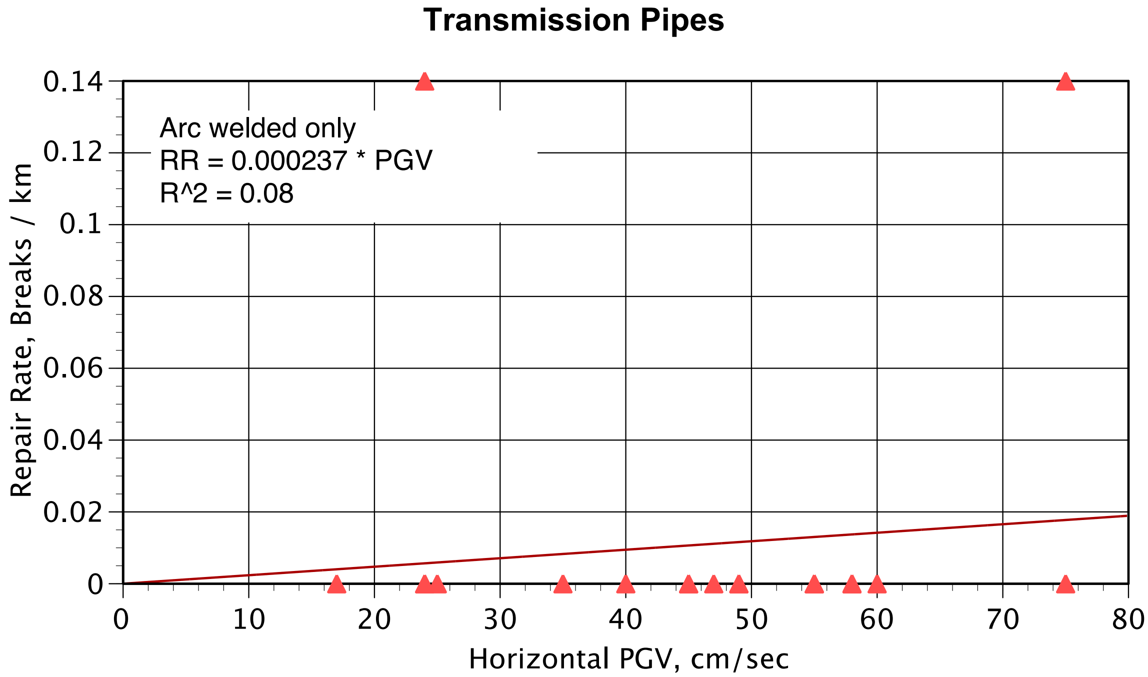


Figure 8-2. Repair Rate, Ground Shaking. Steel Arc Welded Steel Pipes Only – SoCalGas Transmission Pipes

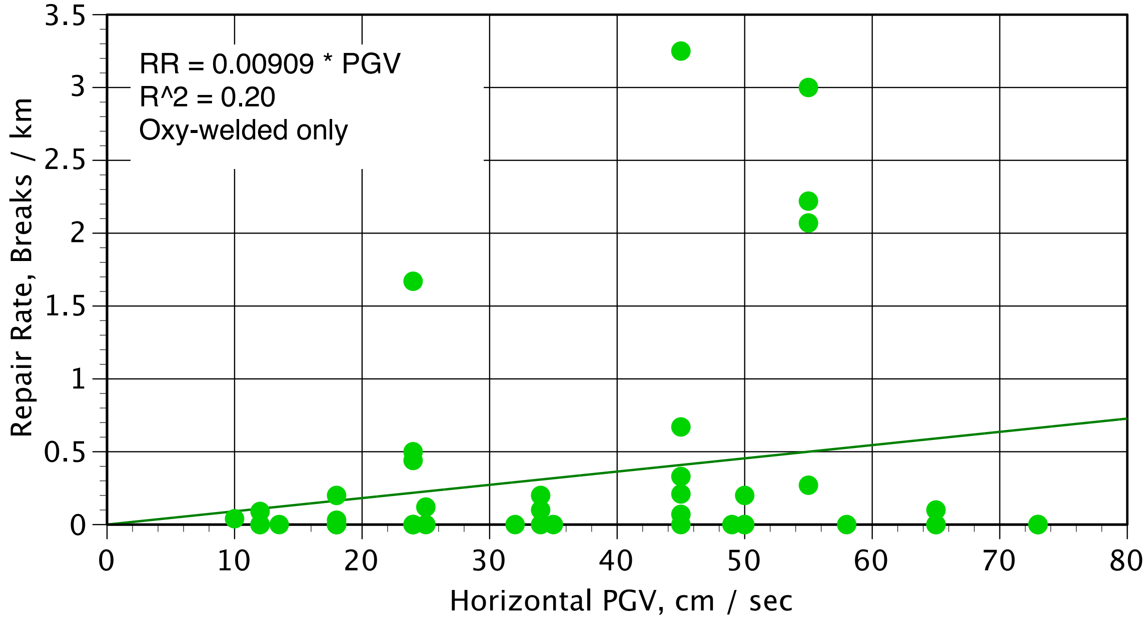


Figure 8-3. Repair Rate, Ground Shaking, Steel Oxy-Acetylene Welded Pipes Only SoCalGas Transmission Pipes

Figure 8-4 shows the repair rates for steel gas transmission pipes, due to differential PGDs. By "differential", it is meant that if the pipe was exposed to a near constant settlement of 2 inches, it would have essentially zero imposed stresses; it is differential PGDs that imposes stress in a pipe.

For PGDs under about 2 to 3 inches, the historical rate of SoCalGas' welded steel pipe failures is essentially nil. Above 3 inches, the historical repair rate becomes significant.

Some of the pipe damage included in Figure 8-4 occurred due to liquefaction effects; primarily in the 1971 San Fernando earthquake, where large lateral spreads transverse to the pipe led to many pipe failures in and adjacent to the PGD zone. In the 1933 Long Beach earthquake, current understanding suggests that Line 765 was exposed to between 1 and 3 inches of settlement PGDs; the available records do not indicate the pipe was exposed to lateral spreads; and the pipe had no repairs. This is interpreted to mean that the settlement PGDs were not especially sharp (not generally knife-edge); and thus might not have loaded the pipe excessively.

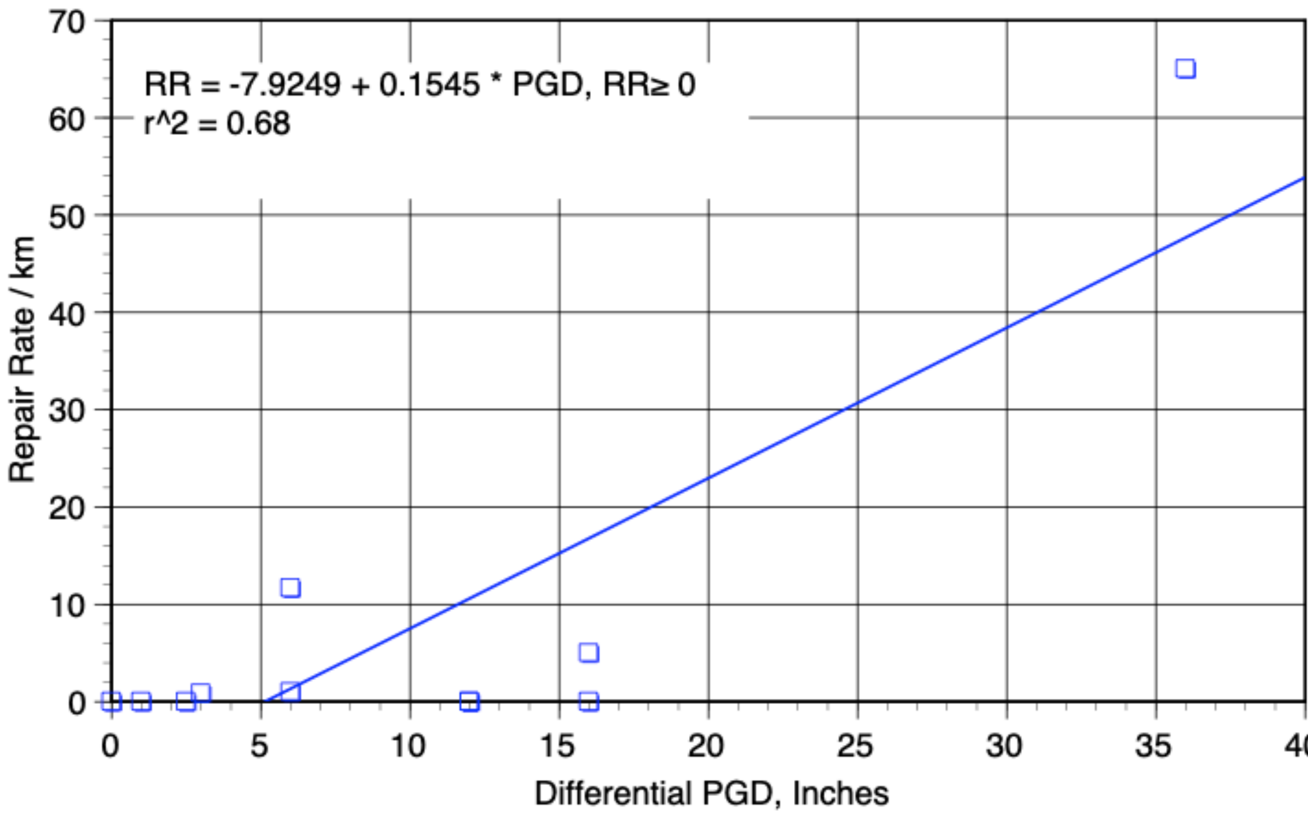


Figure 8-4. Repair Rate, Permanent Ground Deformations, SoCalGas Steel Pipe

8.3 PG&E Transmission Pipes

Table 8-1 summarizes the PG&E transmission pipe repair history for 18 earthquakes. See Section 6 for further details of each of these historic repairs to PG&E's gas transmission pipes.

Table 8-1. Transmission Gas Pipe Repair Data

Earthquake	M	Year	Repair History Quality	No. Transmission Pipe Repairs	No. Transmission Pipe Replacements for Stress Relief
San Francisco	7.9	1906	Marginal	Many	N.A.
Kern County	7.3	1952	Very good	1	2
Daly City	5.7	1957	Marginal	1	? 0
Greenville	5.8	1980	Poor	None ?	0
Coalinga	6.3	1983	Marginal	None	0
Morgan Hill	6.2	1984	Marginal	1 ?	0
Ridgemark	5.4	1986	Marginal	0	0
Calaveras	5.6	1986	Marginal	0	0
Fort Tejon	5.2	1988	Marginal	0	0
Loma Prieta	6.9	1989	Marginal	0	0
Cape Mendocino	7.2	1992	Poor	Some ?	0
Salinas	5.1	1998	Marginal	1 ?	0
Yountville	5.0	2000	Marginal	0	0
San Simeon	6.5	2003	Good	0	0
Alum Rock	5.6	2007	Marginal	1	0
Eureka	6.5	2010	Good	1	0
Napa	6.0	2014	Good	0	2
Ridgecrest	7.1	2019	Very good	0	2
Total				4 + (2 ?)	6

In Table 8-1, the "Repair History Quality" column reflects the confidence that all repairs (or lack of repairs) to the transmission system are described in Section 6 of this report. This is assigned either Poor, Marginal, Good or Very Good:

- Poor. No reports available about the earthquake with respect to the gas system; and/or historical data nearly entirely missing.

- Marginal. Some reports about the gas system available about the earthquake, but missing quantified data; little or no historical data. Possibly that some repairs were not documented. For the 1906 earthquake, the available reports indicate many gas pipe failures; most were cast iron pipes, and all cast iron pipes in the PG&E system have since been replaced.

- Good. Reasonably complete historical data available (including earthquakes in 2003, 2010, 2014). Some historical reports on the earthquake that described the gas transmission system performance. Reasonable confidence that the listed repairs and stress relief actions are comprehensive, but some chance that some actual repairs remain undocumented.

- Very good. Reasonably complete historical digitized data available (2019); or very good historical reports on the earthquake (1952, 2019) that describe the gas transmission system performance. High confidence that the listed repairs and stress relief actions are comprehensive.

The "No. Transmission Pipe Repairs " column lists the number of repairs documented in reports; # = likely earthquake-related, the repair was found within a day or so of the earthquake; ? = possible earthquake related (due to delay in finding the leak until weeks or months after the earthquake). The "No. Transmission Pipe Replacements for Stress Relief" column lists the number of earthquake-stressed transmission pipes that were cut open after the earthquake and replaced with new unstressed pipe; typical replacement lengths varied from a few feet to a few hundred feet, depending on situation (see Section 6 for details). N.A. = not applicable. See Section 6 for further descriptions.

Note: the literature suggests that there were a few (variously reported as 2 or 3) repairs to gas transmission pipes in the 1989 Loma Prieta earthquake. Further review shows that these repairs were to 6-inch to 20-inch diameter steel pipes in the distribution system in Santa Cruz and Oakland. Distribution pipes tend to have many more branch connections than transmission pipes, and are thus more prone to damage.

The empirical evidence between PG&E (Table 8-1) and SoCalGas (Figures 8-1 through 8-4) indicates different historical repair rates. Why?

- Table 5-5 shows that the vast majority of historical repairs has been to appurtenances (~50% to 80% of total), and not to the main barrel of the pipe. In contrast, the available reports for SoCalGas transmission pipes indicate that more than 90% of the historical failures (83 total) were at girth welds in tension; with a handful due to pin holes or buckling / wrinkling.

- The SoCalGas data shows a strong correlation that pipes with oxy-acetylene girth welds (generally pre-1930) are much more fragile than pipes with electric arc welds (generally post-1930). The PG&E historical repair data shows no obvious differentiation in earthquake-related repair rates for pre-1930 or post-1930 pipes.

- Transmission pipes are assigned Class 1, 2, 3, 4. Class 4 pipes are located in dense urban areas / high occupancy areas, and are designed to have a factor of safety of 2.5 (or higher) on hoop stress (SMYS / hoop stress at MAOP). Class 3, 2 and 1 pipes have F.S. = 2.0, 1.666, 1.389, respectively (in other words, hoop stress at MAOP / SMYS = 0.40, 0.50, 0.60, 0.72, for Class 4, 3, 2, 1 respectively). The underlying concept is that there should be a larger factor of safety against hoop-stress-related failures for high pressure gas transmission pipes that are located near densely populated areas. Based on available data for MAOP, SMYS, OD and t, the length of PG&E transmission pipe in each class is as follows:

    - Class 1. 2,516 km. Remote from population.

    - Class 2. 969 km

- Class 3. 1,449 km
- Class 4. 5,724 km. Highest nearby occupancy.

- The PG&E empirical dataset (Table 8-1) shows 0 major breaks, 4 repairs (reported generally within 1 day of the earthquake and 6 post-event stress relief replacements, in 18 earthquakes:
  - The 6 "stress relief" post-event repairs (DS1) were all related to post-1950 welded steel pipes where they crossed faults (2 across the White Wolf fault in 1952; 2 across the Napa fault in 2014; 2 across the Ridgecrest faults in 2019). In each of these earthquakes, post-event leak tests showed that these pipes were not leaking gas. For the 2019 Ridgecrest earthquakes, the data shows that the pipes were clearly yielding due to right- or left-lateral fault offset on the order of 12 to 20 inches. For the 2014 Napa earthquake, the data clearly show that the pipes sustained a few inches of right lateral offset, but after digging up the pipes, no clearly obvious yielding was observed in the steel pipes. For the 1952 Kern County earthquake, exposing two sections of pipe showed them to be under high stress, but the available data is inconclusive if this stress was due to fault offset (on the order of 1 foot), thermal or other effects.
  - In Table 8-1, the repairs are further described as follows:
    - 1952 Kern County. 1 small diameter pressure control line damaged and repaired. Assigned as DS2 (minor leak).
    - 1957. Daly City. A cracked weld on a 1932-vintage 26-inch line on Alemany Boulevard. The exact location of the cracked weld is not presently available. The pipe alignment crosses traces of the San Andreas fault, but the location of the repair is not presently known accurately. The hazard that led to the cracked weld might have been due to strong ground shaking, fault offset or liquefaction.
    - 1984 Morgan Hill. 12.75-inch OD pipe installed 1930. Cause: manufacturing. Reported May 15, 21 days after the earthquake. PGA ~0.13g. Given the 15-day delay in identifying this leak, this repair is denoted with "?" as being earthquake-related.
    - 1998 Salinas. 8.625-inch OD pipe installed 1952. Cause: Third Party Damage. Reported September 5, 24 days after the earthquake. PGA ~0.05g to 0.08g. Given the 15-day delay in identifying this leak, this repair is denoted with "?" as being earthquake-related.
    - 2007 Alum Rock. 24-inch pipe immediately at a branch location to another transmission pipe. The repair was on a original pipe that was originally installed in 1944. Listed cause: external corrosion. Reported November 1, 1 day after the earthquake. PGV ~2 cm/sec. Assigned as DS2 (minor leak).

- 2010 Eureka. 6.625-inch OD pipe installed 1957. Cause: Equipment. Reported January 10, 1 day after the earthquake. PGA ~0.25g. Assigned as DS2 (minor leak).

8.3.1 Shaking Analysis – Ridgecrest 2019

Table 8-2 lists the transmission pipe and repair data along with ShakeMap PGV motions for the 2019 M 7.1 earthquake.

Table 8-2. Transmission Pipe Exposed to PGV, Ridgecrest M 7.1, 2019

PGV (cm/sec)	Length (m)	Repairs (excludes replacement for stress relief)
2	367,321	0
4	675,484	0
6	232,771	0
8	107,272	0
10	88,615	0
12	20,781	0
14	8,242	0
16	12,407	0
18	2,087	0
20	8,379	0
22	10,802	0
24	4,562	0
26	2,455	0
28	2,332	0
30	1,996	0
32	6,699	0
34	6,428	0
36	2,896	0
38	3,470	0
40	7,238	0
42	3,020	0
44	1,566	0
46	1,154	0
48	3,155	0
50	1,052	0
Total	1,582,184	0

The transmission system repair rate (DS2, DS3), for all PGV levels, was observed to be zero for the Ridgecrest 2019 earthquakes.

8.3.2 Shaking Analysis – Napa 2014

Table 8-3 lists the transmission pipe and repair data along with ShakeMap PGV motions for the 2014 Napa earthquake. The column "Length" reflects all transmission pipe. The column "Length (Installed ≤1930)" shows the length of pipe that were installed between 1920 and 1930.

Table 8-3. Transmission Pipe Exposed to PGV, Napa M 6.0, 2014

PGV (cm/sec)	Length (m)	Length (m) (Install 1920 to 1930)	Repairs (excludes replacement for stress relief)
1	1,717,364	48,495	0
2	3,501,648	28,830	0
4	895,170	16,116	0
6	208,612	1,869	0
8	118,924	7,030	0
10	33,438	482	0
12	26,612	682	0
14	15,689	3,250	0
16	17,450	2,808	0
18	15,374	5,303	0
20	4,250	447	0
22	6,867	1,120	0
24	7,193	2,115	0
26	10,550	1,228	0
28	7,769	0	0
30	23,388	5	0
32	21,637	808	0
34	8,331	99	0
36	12,102	455	0
38	10,725	746	0
40	3,310	301	0
42	935	0	0
44	825	0	0
Total	6,668,165	132,328	0

The transmission system repair rate (DS2, DS3), for all PGV levels, is observed to be zero for the Napa 2014 earthquake.

8.3.3 Shaking Analysis – Eureka 2010

Table 8-4 lists the transmission pipe and repair data along with ShakeMap PGV motions for the 2010 Eureka earthquake. The column "Length" reflects all transmission pipe. The column "Length (Installed ≤1930)" shows the length of pipe that were installed in 1930 or earlier.

Table 8-4. Transmission Pipe Exposed to PGV, Eureka M 6.5, 2010

PGV (cm/sec)	Length (m)	Length (m) (Install ≤1930)	Repairs
2	800,542	1,227	0
4	249,102	0	0
6	24,413	0	0
8	9,463	0	0
10	4,986	0	0
12	8,424	0	0
14	2,216	0	0
16	2,454	0	0
18	3,052	0	0
20	3,673	0	0
22	31,514	0	0
24	30,865	0	0
26	25,973	0	0
28	28,183	0	1
30	9,483	0	0
Total	1,294,343	1,227	1

8.3.4 Shaking Analysis – Alum Rock 2007

Table 8-5 lists the transmission pipe and repair data along with ShakeMap PGV motions for the 2007 Alum Rock earthquake. The column "Length" reflects all transmission pipe. The column "Length (Installed ≤1930)" shows the length of pipe that were installed in 1930 or earlier.

Table 8-5. Transmission Pipe Exposed to PGV, Alum Rock M 5.5, 2007

PGV (cm/sec)	Length (m)	Length (m) (Install ≤ 1930)	Repairs
1	2,409,154	56,271	0
2	1,197,942	20,794	1
4	210,833	56	0
6	60,925	0	0
8	32,938	1	0
10	11,433	0	0
12	7,723	0	0
Total	3,930,948	77,091	1

8.3.5 Shaking Analysis – Other Earthquakes

Several prior earthquakes (including 1989 Loma Prieta, 2003 San Simeon) show no repairs due to shaking for the transmission pipe system. The 1952 Kern earthquake caused one repair at PGV = 75 cm/sec, and no repairs for pipes exposed to PGCVs from 18 to 65 cm/sec.

8.3.6 Empirical Repair Rate – PG&E Transmission Pipes - Shaking

Figure 8-5 shows the empirical dataset with repair rates for PG&E's gas transmission pipes due to ground shaking (2019 Ridgecrest, 2014 Napa, 2010 Eureka, 2007 Alum Rock, 1952 Kern County). The horizontal axis PGV represents the highest horizontal PGV of two orthogonal directions. The black line shows the least square regression through the dataset. The repair rate for PG&E transmission pipes is 0.000347 * PGV, including both modern (vast majority) and older (≤1930, minority) gas pipes. The corresponding historical repair rate for arc-welded SoCalGas pipes is 0.000237 * PGV (Figure 8-2).

Unlike the SoCalGas pipes, the empirical data for PG&E's pipes shows no obvious tendency for higher repair rates for pre-1930 pipes.

All of the repairs in Figure 8-5 were to appurtenances, corrosion or to equipment; none were described as girth weld tension failures or pipe wrinkling. All these repairs are assigned DS2.

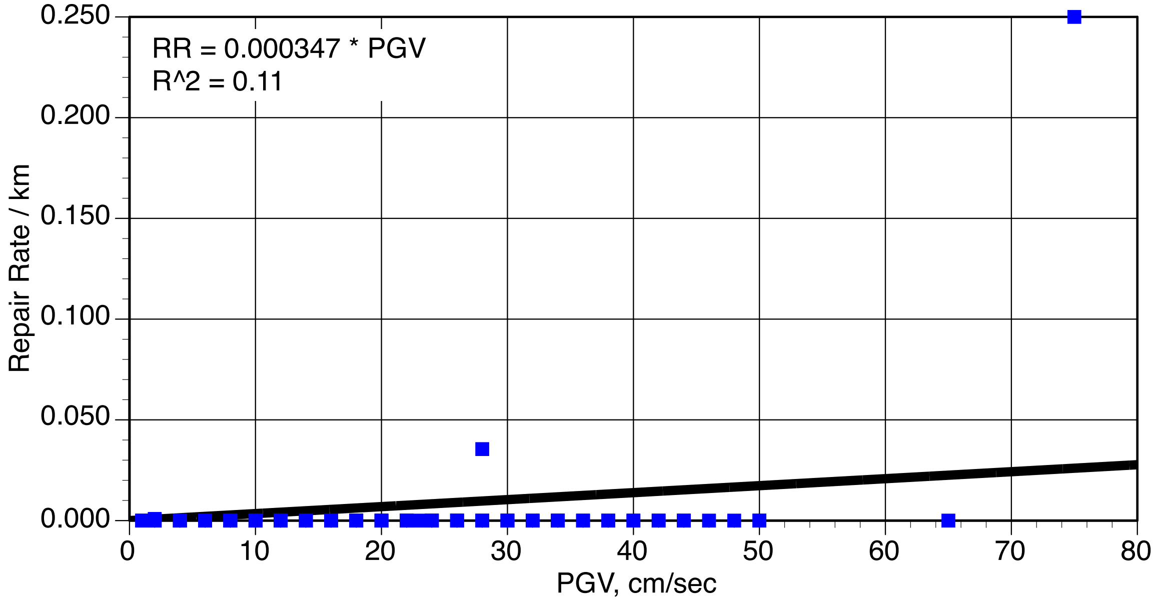


Figure 8-5. Repair Rate, Ground Shaking, PG&E Steel Transmission Pipes

All of the empirical repairs to PG&E's steel transmission pipes have been to appurtenances or due to corrosion. The historical dataset (Table 5-5) shows that 50% to 80% of all historical repairs to appurtenances and valves. If one adopts the fragility model from Figure 8-5, one might assume that all repairs are to appurtenances (relatively minor leaks) (DS2). But, the data in Figure 8-5 excludes the cracked weld in the 1957 Daly City earthquake; the extent of the gas leak in that event is unknown, and whether that leak was due to shaking or PGDs is uncertain. With reasonably confidence, one might conclude that the bulk of leaks to PG&E's transmission pipes have been "minor" and none (to date) have been "major".

There is no historical evidence of repairs for plastic (generally with MAOP ≤ 60 psi) or wrought iron pipes in the PG&E transmission system. Both of these pipe types of very small inventory.

8.4 Pipe Replacement due to Fault Offset

Some transmission pipes have been exposed to fault offset in past earthquakes and subsequently repaired, even though they did not leak gas. These include:

- 1952 Taft (see Section 6.2 for details). On July 21, 1952, a M 7.3 earthquake occurred on the White Wolf fault (variously reported as M 7.3 to M 7.7). The original steel Transmission Line 300 was exposed to about 5 to 18 inches of fault offset. The pipe did not leak gas. After the parallel Line 300 was constructed, the original Line 300 was repaired at two locations where PG&E believed the pipe was exposed to offset; the original Line 300 buried pipe was isolated and de-pressurized; uncovered; cut open to relieve built up stresses; repaired (with inserted new steel pipe); and put back in service on July 4 1953.

- 1979 Imperial Valley (see Section 6.23 for details). Steel transmission lines 6000 (10-inch) and 6001 (12-inch) were exposed to about 9 inches of fault offset and a 4-inch distribution pipe was exposed to about 12 inches of offset. None of the pipes leaked gas. Both transmission pipes were cut open to relieve stress and new steel pipe was inserted.

- 2014 Napa (see Section 6.17 for details). Steel transmission lines 021A and 021B were exposed to about 2 to 3 inches of offset on the day of the earthquake, and post-event slip extended the offsets to about double these amounts. Neither pipe leaked gas. Both pipes were replaced with new unstressed pipes within few weeks of the earthquake. In addition, there were several plastic distribution pipes exposed to about 5 to 9 inches of fault offset in the Browns Valley area; these distribution pipes were suspected as being type "AA" pipes (Aldyl, potentially brittle); as a precautionary measure, PG&E replaced AA-type pipes in the Browns Valley area within a few months of the earthquake.

- 2019 Ridgecrest (see Section 6.18 for details). Steel Transmission Lines 311 (10-inch diameter) and 372 (6-inch diameter) were exposed to fault offset. Line 372 was exposed to about 20 inches of left lateral PGD in the M 6.4 event. Line 311 was exposed to about 10 inches of right lateral offset in the M 7.1 event. Neither pipe leaked gas. Both transmission pipes were cut open to relieve stress and new steel pipe was inserted.

Gas utility practice in California has been to identify pipes that have been exposed, and then replaced the potentially highly stressed (but not-leaking) pipes soon after the earthquake. PG&E has adopted this practice in the 1952 Taft earthquake, the 2014 Napa earthquake and the 2019 Ridgecrest earthquakes. SoCalGas did this after the 1979 Imperial Valley earthquake. In this report, this is identified as Damage State 1.

For example, assume that in a future M 6.5 earthquake on the West Napa fault, Line 021A might be exposed to fault offset. If one assumes a fragility model with median PGD to leak gas as 3 feet with beta = 0.5, and truncates the fragility model to have p(fail | ≤ 12 inches) = 0.0, then the computed chance of immediate gas leak due to offset is: pFail = (0.000, 0.044, 0.374, 0989) if the PGD offset is (11.3, 21.6, 32.7, 71.5) inches. In other words, Line 021A at this location is not expected to fail (pFail = 0.000) if offset is 11.3 inches (reasonable; it did not fail in 2014 when PGD was about 5± inches).

8.5 Ground Shaking Fragility Model

Table 8-6 provides "backbone" pipe vulnerability functions (sometimes called damage algorithms, fragility curves) for PGV and PGD mechanisms from ALA (2001). These functions can be used when there is no knowledge of the pipe materials, joinery, diameter, corrosion status, etc. of the pipe inventory; and when refinements like travelling waves, etc. are excluded. In Table 8-6, RR = Repair Rate per 1,000 feet of pipe; PGV is Peak Ground Velocity in inches/second.

Table 8-6. Buried Pipe Backbone Vulnerability Functions

Pipe Category	Vulnerability Function	Basis
Ground Shaking Transmission	RR = 0.00187 * PGV	ALA (2001)

Section 8.5.1 describes the adjustments made to these functions to reflect gas transmission pipes in California.

8.5.1 Wave Propagation Adjustments for Corrosion, Diameter, Material, Duration

The following factors should be used to estimate the number of repairs to gas pipelines in their current condition, due to ground shaking.

The pipeline-specific form of the fragility model due to PGV (horizontal peak ground velocity at a site, inclusive of local soil amplification effects):

$$RR = k_1 k_2 k_3 k_4 (0.00187)\ PGV \qquad \text{[Eq 8-1]}$$

where

$PGV\ in\ inches/second$

$RR\ in\ repairs\ per\ 1{,}000\ feet\ of\ pipe$

For a pipe subjected to both PGV and PGD hazards, the RR for each hazard is computed separately, and then the larger rate is adopted. Following the equations in Section 7 of this report, the RR can be converted to the idealized pipe barrel stresses for continuous pipes, and the "k" factors can be interpreted as the chance of repair to the pipe given the computed pipe barrel stress; with suitable factors to account for traveling waves, topography and change of stiffness between pipe segments, the RR can be adjusted to reflect similar results as per structural analysis models.

Corrosion Effect (k_1)

Soil resistivity has a role in attacking the pipe from the exterior. Some types of pipe are relatively immune from exterior corrosion, such as plastic pipe. Other types of pipe are sensitive, to varying degrees, to exterior corrosion.

A common approach to quantifying the potential for exterior corrosion is based on the soil resistivity of the soil surrounding the buried pipe. Soil resistivity is measured in terms of Rho, in ohm-cm, for the soil layer at the same depth of the pipe.

The k_1 factor is used to vary the seismic capability of pipes, as follows.

- Rho ≤ 750 ohm-cm. Very corrosive soils. Pipes are weakened by corrosion. Earthquake transient ground motions will result in increased stress in the barrel of the pipe. This can result in pin hole leaks in corrosion-weakened steel pipes.

- Rho > 750 ohm-cm, ≤ 1,500 ohm-cm. Somewhat corrosive soils.

- Rho > 1,500 ohm-cm. Pipes with conventional corrosion protection rarely show sufficient weaknesses as to cause an increase in seismic-related failures.

Steel transmission pipes with cathodic protection (diameter 6 inches and larger). If soil resistivity is unknown, $k_1 = 1.0$. If Rho ≤ 750, $k_1 = 1.0$. If Rho > 750, $k_1 = 0.8$.

Steel transmission pipes without cathodic protection (diameter 4 inches and smaller).

- Very corrosive soils. If Year of installation < 1940, $k_1 = 3.0$ (bare) 2.0 (coated). If Year > 1980. $k_1 = 1.0$. If Year between 1940 to 1980, k_1 is linearly interpolated.

- Somewhat corrosive soils. If Year < 1940, $k_1 = 2.0$ (bare) 1.5 (coated). If Year > 1980. $k_1 = 1.0$. If Year between 1940 to 1980, k_1 is linearly interpolated.

- Less corrosive soils. $k_1 = 1.0$ for all years.

Note: most steel gas pipe in California uses some form of corrosion protection. Table 3-5 shows that there are several categories of corrosion protection: with or without cathodic protection (impressed current); and with / without exterior coating. Pipes without impressed current may still be adequately protected if they were installed with exterior coating systems and sacrificial anodes. The empirical evidence shows that exterior corrosion still represent a significant portion of all pipe gas leaks (Tables 5-1, 5-2, 5-3, 5-5, 5-6).

Diameter Effect (k_2)

Steel transmission pipes.

- All diameters. $k_2 = 1.0$ (no effect by diameter).

Discussion: many prior studies for water pipes (ALA 2001) have shown a distinct variation of damage rates for pipe as a function of the pipe's diameter, especially for diameters 1 to 4 inches. Most gas transmission pipes are 6 inches to 42 inch diameter. The underlying reason for a higher failure rate on very small diameter pipe is due to a combination of corrosion, quality of construction, many branch connections for small diameter pipe, and thinness of the wall. For steel gas transmission pipes of 6-inches and larger, these effects are not dominant, except corrosion that is accounted for using factor k_1.

Pipe Material (k_3)

Steel transmission pipes. (High Quality Welds)

- $k_3 = 0.12$

Steel transmission pipes. (Pre-1930 or any pipe with low quality welds)

- $k_3 = 4.5$

The bulk of California's steel transmission pipes are presumed to have high quality welds.

Special cases. Steel transmission mains with slip joints may be exposed to gas leaks / failures due to ground shaking, if there is one slip joint placed along a long (> 2 km) reach of straight pipe. ALA (2005) provides methods to compute the joint opening of such slip joints. Most non-seismically-designed slip joints have capacities on the order of 1 to 2 inches before they fail. Should the inventory indicate that the pipe has slip joints, that inventory should be evaluated for joint opening potential per ALA (2005), and the potential for repairs should be cumulative to that computed using the fragility model [Eq 8-1].

The pipe material factor considers the combined PG&E and SoCalGas steel transmission pipe empirical evidence. The large variation between pipes with high quality / low quality welds reflects the empirical evidence from the 1952 Taft, 1971 San Fernando, 1994 Northridge events; and is consistent with observations in the 1964 Niigata (Japan) earthquake.

These factors are not applicable to steel gas distribution pipes.

Duration Effect (k_4)

The repair rates are largely based on empirical evidence. Most damaging earthquakes have had duration of strong shaking about 15 to 20 seconds. The longer the period of strong shaking, the more cycles of load are applied to the pipe system, and the greater the chance of pipe damage. The following adjustments are made:

- $M \leq 6.0$. $k_4 = 0.5$.
- $M = 7.0$. $k_4 = 1.0$
- $M = 8.0$. $k_4 = 1.5$

- M = 9.0. k_4 = 2.0 (great subduction earthquakes)
- Intermediate M. k_4 is computed based on linear interpolation.

Damage State

The number of repairs predicted using the above fragility model [Eq 8-1] is the total. The following breakdown is used to subdivided the repairs by severity:

- DS3 = 0% - 10%. (Major Break)
- DS2 = 90% - 100%. (Minor Leak)
- DS1 = 0% (No Leak, replace after the earthquake with unstressed pipe)

The category DS3 is the most severe. For well-built steel transmission pipes, without notable weaknesses (non-seismically-designed slip joints), the most likely leaks will be to appurtenances (minor releases at leaking fittings), pin-holes (minor releases), or similar. The range 0% - 10% reflects that for most earthquakes, no major breaks are likely to well-built steel transmission mains (0%), and the range up to (about) 10% is provided to reflect that the empirical observations are incomplete and new trends might be observed in future earthquakes.

8.6 Liquefaction and Landslide Fragility Model

Table 8-7 provides "backbone" pipe vulnerability functions (damage algorithms, fragility curves) for PGD mechanisms from ALA (2001). These functions can be used when there is no knowledge of the pipe materials, joinery, diameter, corrosion status, pipe orientation relative to the PGD direction, etc. of the pipe inventory; and when refinements like travelling waves, etc. are excluded. In Table 8-7, RR = Repair Rate per 1,000 feet of pipe; PGD is permanent ground deformation in inches.

Table 8-7. Buried Pipe Backbone Vulnerability Functions

Hazard	Vulnerability Function
Permanent Ground Deformation due to liquefaction or landslide	RR=1.06 * PGD$^{0.319}$

Section 8.6.1 describe the adjustments made to these functions to reflect gas system transmission pipes.

8.6.1 Permanent Ground Deformation Adjustments for Corrosion, Diameter, Material, Wall t, Orientation for Landslide and Liquefaction

It has been commonly observed in past earthquakes that the bulk of major damage to buried pipelines has been caused by permanent ground deformations (PGD), and not ground shaking (PGV). Therefore, the fragility models used for gas pipelines for PGD effects are very important to the overall estimation of system-wide response.

The pipeline-specific form of the fragility model due to PGD:

$$RR = k_5 k_6 k_7 k_8 (1.06)\ PGD^{0.319} \qquad \text{[Eq 8-2]}$$

where

$PGD\ in\ inches\ as\ measured\ at\ the\ springline\ of\ the\ pipe$

$RR\ in\ repairs\ per\ 1{,}000\ feet\ of\ pipe$

For a pipe subjected to both PGV and PGD hazards, the RR for each hazard is computed separately, and then the larger rate is adopted. The "cause" of failure can be assumed to be the hazard which produces the highest chance of failure.

The PGD should be the PGD as measured at the springline of the pipe (the springline is the elevation of the widest part of the pipe). Most gas pipes are buried with 3 or more feet of cover. Therefore, PGD may be zero if the pipe is buried below the level of small raveling-type landslides, where the depth for sliding material does not extend down far enough to impact the pipe. Empirical evidence of PGDs and many geotechnical models that compute PGD are geared towards the PGD at observed at the surface. For pipes buried in an engineered fill (that does not liquefy), the PGD at the depth of the pipe and the PGD at the surface may be essentially the same. For pipes that traverse deep-seated landslide zones, where the depth of the landslide extends below the springline of the pipe, and the PGD computation based on a Newmark "sliding block" analogy, the PGD so computed can be used in this model.

For pipes that go under creeks, the PGDs of most concern are those at the embankments. If the pipe is buried deep enough under the embankment, there may be no PGDs on the transmission pipe; but there may be PGDs on blowoff pipes that are used to drain the pipe (such as done during hydrotesting) into the creek. The empirical evidence shows that blowoff pipes are damaged in earthquakes even when the adjacent main pipe is not.

Many creeks are described as having "very high" or "high" liquefaction susceptibility in many maps. Rarely do these maps reflect the actual soil conditions at any specific creek crossing, such as by boring or CPT. Instead, many of these maps assign liquefaction susceptibility based on surface geologic units; most creeks are relatively "young" and are assigned as commonly having Holocene materials. For example, when analyzing a 5,000 foot-long pipe that traverses a 100-foot wide creek (or other liquefaction / landslide zone), the following guidance is suggested:

- For Level 3 analyses, digitize the pipe to reflect the geologic mapping. In other words, if a pipe is drawn as being 5,000 feet long and crosses a creek that is 100 feet wide, subdivide the pipe into three sub-segments, one either side of the creek (liquefaction / landslide zone), and analyze the three subsegments. For Level 1 and Level 2 analyses, this extra step of refined inventory digitization may not be needed, as long as the user is interested only in a system-wide forecast of pipe damage, and is not especially interested as to identifying the specific locations of the damage.

- For Level 3 (recommended) and Level 4 (required) analyses, do a field investigation and drawing review to determine the details of how the pipe is constructed through the creek zone, and also to assess the pattern of likely PGDs.

- Pipes that were installed by direct burial underneath the active creek channel may be encased in concrete; over time, scour may expose the concrete encasement, thereby subjecting the pipe to forces due to the flow of water, etc. Many GIS-based maps showing pipes are not drawn with enough detail to identify these details. For this level of detail, a Level 4 analysis is required.

- If possible, determine if the pipe has a blow off into the creek. If a blowoff exists, create a pipe segment for the analysis so that the damage can be tracked by type of pipe. If damage occurs to the blowoff, the fragility model (RR / length) is insufficiently detailed to determine if the damage occurs between the main and the isolation valve (serious break, DS3) or beyond the isolation valve (leak DS2). For this level of detail, a Level 4 analysis is required.

- Gas pipes may cross creeks either as self-supporting (narrow creek) or supported by bridges. The fragility models herein are geared towards buried pipe. Gas pipes have been damaged in past earthquakes at the transition point between the buried pipe and the pipe that is supported by the bridge; this damage is usually caused by relative movement of the pile-support bridge deck and the ground-supported pipe; the relative movements are due to a combination of shaking and PGD effects on the bridge structure as well as the buried pipe. Many GIS-based maps showing gas pipes are not drawn with enough detail to identify the pipe-supported-by-bridge crossings. Level 4 analyses are recommended for these conditions.

This model is geared to predicting the repairs needed to the main barrel of the pipe immediately post-earthquake, so as to return the pipe to regular service. The repairs could be spot welding pin-hole type failures on steel pipes; adding external clamps; re-laying the pipe; replacement if the pipe barrel has wrinkled (steel pipes) or split (plastic pipes); re-welding the joints or adding butt straps if welded joints have cracked (steel pipes); or replacing the pipe if damage is excessive.

In the above model, the width, w, of the PGD zone is not considered. In one extreme, if the width w is less than a few feet or so, the pipe will often be able to sustain the imposed PGDs and the soil might just "flow by" the pipe. In another extreme, if w is very large (say 1000s of feet), then the pipe might simply float within the PGD zone, largely unstressed. In reality, it is differential PGD that imposes high axial and bending moments into buried pipe. Some researchers (M. O'Rourke and Liu 2012) have presented simple closed-form expressions that correlate pipe strain with PGD and w, assuming that the PGD zone can be modeled as a perfect sine wave; these models lend insight, but the reality is that PGD zones are unlikely to actually occur as perfect sine waves. If the user is interested in the state of strain in the pipe, then Level 4 analyses are recommended.

It has not been observed that welded steel pipes have burst radially (due to excessive internal pressure) in earthquakes, so this failure mode for gas pipes can almost be ruled out.

Corrosion Effect (k_5)

The k_5 factor is used to vary the seismic capability of pipes, as follows.

Steel transmission pipes (diameter 6 inches and larger). If soil resistivity is unknown, $k_5 = 1.0$. If Rho ≤ 750, $k_5 = 1.0$. If Rho > 750, $k_5 = 0.8$. This implies that steel pipes are cathodically protected.

Steel transmission pipes (diameter 4 inches and smaller) without cathodic protection.

- If soil resistivity is unknown, $k_5 = 1.0$.
- If Rho ≤ 750, $k_5 = 1.5$ (bare) 1.25 (coated).
- If Rho $> 750 \leq 1500$, $k_5 = 1.2$ (bare) 1.1 (coated).
- If Rho > 1500, $k_5 = 1.0$.

Most steel pipes are cathodically protected. For bare steel pipes, there is a 50% "penalty" if the pipes are located in highly corrosive soils, or a 20% penalty of the pipes are located in corrosive soils; or half as much if the pipes have coating but without sacrificial anodes / impressed current. The "penalty" for corrosion is less so for liquefaction / landslide zones as compared to shaking as the observed damage in PGD zones is thought largely to be due to high strains rather than to corrosion.

Diameter Effect (k_6)

Steel transmission pipes. $k_6 = 1.0$ for Diameter < 12 inches; = 0.8 for Diameter ≥ 12 inches.

The reduction in fragility due to diameter reflects mostly that larger diameter pipe have fewer appurtenances (branch connections) per unit length than medium diameter pipes.

Pipe Material Type (k_7).

Steel transmission pipes with high quality butt welds. $k_7 = 0.03$. This presumes that most gas transmission pipe has $D/t < 60$ (a common steel transmission pipe might have D = 12.75 inches and t = 0.25 inches, or $D/t = 51$).

For Level 3 analysis, k_7 varies from 0.15 ($D/t > 125$) to 0.08 ($D/t = 100$), to 0.03 ($D/t < 60$).

The D/t factor is important is setting the allowable compressive strain in a weld-built steel pipe. The smaller the D/t ratio, the higher the allowable compressive strain. For most pipes traversing through a liquefaction or landslide zone, bending will be the primary mode of failure. Compressive strains increase as bending increases. k_7 is set to 0.15 for $D/t > 125$, which is relevant for thinner-wall water pipes that commonly operate at lower pressures than gas pipes.

Steel transmission pipes (Pre-1930 or any pipe with low quality welds). $k_7 = 1.125$. This value is derived from the ~40-fold increase in steel pipe damage in the empirical record for pipes with potentially low utility / non-ductile welds. This large increase in pipe vulnerability is largely based on damage presumed to have been primarily due to ground shaking; but possibly the empirical record also includes failures due to PGDs. The D/t ratio consideration in omitted here, as the failure mode is presumed to be in the weld.

Direction Effect (k_8)

Pipes that are oriented parallel to the PGD direction will have much higher failure rate than pipes oriented perpendicular to the PGD direction. This reflects that PGDs that are parallel to the pipe will result in nearly direct compression and wrinkling of steel pipes; where as PGDs that are perpendicular (like settlements) will cause bending in the pipe, and relatively smaller moments and actions on the joints.

For Level 1 or Level 2 analyses, $k_8 = 1.0$ (ignores direction effects)

For Level 3 analyses.

- For pipes with unknown angle relative to the PGD direction. $k_8 = 1.0$.

- For pipes that are oriented nearly parallel to the PGD direction. $k_8 = 3.0$.

- For pipes that are oriented nearly perpendicular to the PGD direction. $k_8 = 0.33$. This applies to all pipes that traverse liquefaction PGD zones that are subject only to settlement (no lateral spread).

For Level 2 analyses, it is assumed that the relative direction of the PGD and pipeline is not computed, so $k_8 = 1.0$. Empirical evidence and nonlinear analytical modeling suggests that PGDs parallel to a pipe result in ~ 10 times higher pipe barrel strains than PGDs that are perpendicular to the pipe (the k_8 factor varies from 3 to 0.33, a ratio of 9).

For repairs due to liquefaction or landslide PGDs, assume half are DS3 and half are DS2.

The fragility models for landslide and liquefaction can be further refined to account for a host of other issues, including:

- Branch connections.

- Pipes in direct burial attached to underground vaults on piles.

- The width and depth of the liquefaction zone. The above model assumes that the pipe is within a engineered fill that lies atop a zone that undergoes liquefaction / landslide PGDs. In this case, there will often be a sharp transition of ground movement at distinct locations along the pipe, where the permanently-offset soil that encases the pipe (and rises atop the moving soil) transitions to soil that did not sustain permanent movement. It is at this transition that the pipe is exposed to highest bending (and hence highest potential for wrinkling).

- This model should not be used for special cases such as submarine pipes resting atop the sea floor, possibly overlain by years of sediment. In these cases, Level 4 analyses are recommended.

8.7 Fault Offset Fragility Model

The fragility models used for evaluations of gas pipes due to fault offset are listed in Table 8-8 (for DS3) and Table 8-9 (for DS1). DS3 is for predicting damage substantial enough that would result in immediate gas release and require rapid shutdown of the pipeline. DS1 is for predicting permanent strains within the pipe that are high enough to show permanent offset, but low enough to wrinkle or tear the pipe (no gas leak).

These models do not include damage to appurtenances that might be in or near the fault zone.

Table 8-8. Fault Offset Fragility Models (DS3)

Type of Pipe	System	Median (Inches)	Beta	Cutoff (Inches)
Steel	Transmission	36	0.3	6
Other	Transmission	12	0.3	3

Table 8-9. Fault Offset Fragility Models (DS1)

Type of Pipe	System	Median (Inches)	Beta	Cutoff (Inches)
Steel	Transmission	9	0.3	2
Other	Transmission	3	0.3	1

The "Other" category is meant to cover uncommon pipe inventory with brittle features (for example, steel pipe with poor quality welds). Pipes such as cast iron, copper, wrought iron or other types not listed above could be initially evaluated using the Other category but it is recommended to examine each type of material to assess its capability. Note: if a steel pipe with poor quality welds is strained sufficiently that the load in the welds exceeds the weld capacity, the pipe may fail just at the point that the weld is overloaded; possible at much lower displacements than those listed in Table 8-8; any such gas pipe is not considered reliable for seismic offset.

The term "Median" refers to the PGD level at which there is a 50% chance that the pipe reaches the damage state.

The term "Beta" refers to a lognormal distribution, and represents dispersion for pipe performance given the various pipe installation characteristics (quality of welds, local soil conditions, etc.).

The term "Cutoff" refers to the PGD level below which the model assumes no chance of reaching the damage state.

The values for the median, beta and cutoff in the above tables are selected to approximate the empirical evidence of welded steel gas pipes that have been subjected to fault offset in prior earthquakes, and to provide realistic first-order estimates of the potential for pipe damage. If the chance of damage using Tables 8-8 and 8-9 of a pipe is significant, then for more detail, including the state of stress and strain in the pipe as a function of offset, the analytical approach and fragility models described in Section 7 are recommended.

Unlike the fragility models for ground shaking, liquefaction and landslide, the fault offset model is applied by pipe segment, rather than by pipe unit length. The "segment" is intended to be the reach of pipe that traverse the fault zone, and might be from about one hundred feet to about one thousand feet long (42-inch pipe), depending on pipe diameter, soil conditions and the characterization of the fault zone.

The two models (DS3 and DS1) should be applied in series: first, check to see if DS3 occurs; second, if DS3 does not occur, check to see if DS1 occurs.

The models in Tables 8-8 and 8-9 can be used in Level 2 analyses. The applied PGDs in Level 2 analyses are assumed to be 85% of the average co-seismic displacement across the fault, and that the PGD is applied in "knife edge" fashion over a 1-foot wide zone, and that the pipe was not ever designed for fault offset; the native soils around the pipe are clay-like with an undrained shear strength of between 2,000 and 3,000 psf. The applied PGDs can be from strike slip, reverse or normal faulting; with the most common situation in Northern California being strike slip (such as 2014 Napa, 2019 Ridgecrest); and an occasional situation being reverse thrust (such as 1971 San Fernando).

Under idealized conditions, the damage pattern will be two major wrinkled / broken zones, one zone either side of the fault, nearly equidistant from the knife-edge offset; if the PGD offset is high enough, two additional damaged sections can occur; with the pattern following the trend in bending moment variation with distance along the pipe.

The fragility models in Tables 8-8 and 8-9 do not consider a variety of attributes that would materially change a pipe's ability to withstand fault offset. All of these limitations can be addressed using Level 4 analyses, such as the type described in Section 7 of this report. The main limitations are as follows:

- Branches, bends, appurtenances, encasements. All these features may exist at or near a specific fault crossing zone. Generally, any of these attributes will reduce a pipe's ability to sustain fault offset without damage. For example, a pipe might be able to sustain 3+ feet of offset before reaching a strain limit of 4%, if straight and without appurtenances. The same pipe might only be able to sustain ~1 foot of offset depending on the type and location of these features in or near the fault offset zone.

- Sustained creep. Some faults creep, while others do not. A pipe must be able to sustain both prior creep plus the co-seismic slip plus any slip that might occur in the days (or until such time that emergency response work is completed) after the main shock. Depending on the soils surrounding the pipe, creep offsets might not result in as much strain in a pipe as a sudden co-seismic slip, as certain soils will slowly remold to accommodate some of the imposed pressures induced by the pipe due to slowly applied ongoing slip.

- Pipe orientation versus fault offset direction. Pipes that are oriented parallel to the PGD direction will have a higher failure rate than pipes oriented perpendicular to the PGD direction. This reflects that PGDs that are parallel to the pipe will result in nearly direct tension and also compression / wrinkling of steel pipes; whereas PGDs that are perpendicular (like settlements) will cause bending in the pipe, and relatively smaller moments and forces on the pipe. For Level 1 and 2 analyses, (k_9 = 1.0) for fault offset. Empirical evidence and nonlinear analytical modeling suggests that PGDs parallel to a pipe will have a much higher chance failure than when PGDs are perpendicular to the pipe. For level 3 analysis, apply the following:

- For strike slip offset, angle = 90° for perpendicular condition, 1° if the offset produces nearly pure tension in the pipe, and 179° if the offset produces nearly pure compression in the pipe.
- The median offsets are increased ($k_9 > 1$) or reduced ($k_9 < 1$) as follows:
- 45° to 75°. k_9 = 1.3. In this orientation, the compressive strains due bending moment are reduced due to net tension in the pipe. This assumes that anchor forces outside the fault zone are not controlling.
- 30°. k_9 = 1.4. In this orientation, the pipe has some bending, and the capacity of the pipe is controlled mostly by the tensile strain capacity. This assumes that anchor forces outside the fault zone are not controlling.
- 1%. k_9 = 1.5. In this orientation, the pipe has little bending, and the capacity of the pipe is controlled nearly entirely by the tensile strain capacity. This assumes that anchor forces outside the fault zone are not controlling. Given uncertainties in where the PGDs may actually occur, this may not be a suitable pipe orientation for design.
- 75° to 105°. k_9 = 1.0. In this orientation, the compressive strains due to bending moment will likely control the pipe capacity.
- 105° to 135°. k_9 = 0.8. In this orientation, the compressive strains due to bending moment coupled with some net compression of the entire pipe will likely control the pipe capacity.
- 150°. k_9 = 0.7. In this orientation, the compressive strains due to bending moment coupled with increased compression of the entire pipe will likely control the pipe capacity.
- 179°. k_9 = 0.5. In this orientation, the compressive strains due to compression of the entire pipe will likely control the pipe capacity. This is not a recommended pipe orientation for design.
- For normal faults, apply $k_9 > 1$ as for strike slip for angles that produce increasing net tension.
- For reverse faults, apply $k_9 < 1$ as for strike slip for angles that produce increasing net compression.

  - For example. For angle = 60°, strike slip offset, the median PGD to reach DS3 is 3 * k_9 = 3 * 1.3 = 3.9 feet. This implies a gas pipe with well-made butt welded girth joints and with no special seismic design.

  - For example. For angle = 120°, strike slip offset, the median PGD to reach DS3 is 3 * 0.8 = 2.4 feet. This implies a gas pipe with well-made butt welded girth joints and with no special seismic design.

  - Note: a well-designed, well-constructed and well-maintained buried welded steel pipe subject to strike slip offset at 60° angle can be shown to accommodate about 5 to 6 feet of offset and maintain strains within allowables. In contrast, the fragility model suggests 50% chance of failure at 3.9 feet of offset. The fragility model (Tables 8-8 and 8-9) should be interpreted to be biased towards some over-prediction of damage for well-built, well-constructed and well-maintained pipes.

- Trench design and native soils. Buried gas pipes are in trenches with backfill. The properties of the native soils, the backfill, the pipe-skin friction, the depth of burial, all are factors in determining the strain imposed in the buried pipe due to fault offset. For buried pipes in a trench surrounded by extremely stiff soil (say Su = 10,000 psf or higher, very stiff soil or rock-like materials), the pipe's ability to bend is constrained, resulting in higher curvature in the pipe and higher strain in the pipe. For buried pipes in a trench surrounded by extremely soft soil (say Su = 500 psf or lower, like Bay-mud materials), the pipe's ability to bend is relaxed, resulting in lower curvature in the pipe and lower strain in the pipe.

- Weld Quality. If the welds in a steel pipe are of poor quality, the chance of failure is much higher than would be established at the tensile (+4%) or compressive strain limit of [Eq 7-7]. It has been observed that poorly made welds that led to premature steel pipe failures in the field for cases with poorly-made shop-made longitudinal seam welds; poorly-made shop-made helical seam welds; poorly-made field made girth welds. This report discusses the issue of "pre-1930" oxy-acetylene and "newer" electric-arc welds. Some have addressed the potential for poorly-made welds by setting tensile strain limits to 2% (pre-1930 welds); but this is not a recommended approach herein; if a weld is poorly made, the tensile strain limit might be as low as yield, or for especially weak welds, the pipe may fail at barrel tensile stresses at 60% to 90% (or even lower) of yield. In these cases, the true weld quality (flaws, lack of root penetration, etc.) is not known without careful inspection, so the true capacity of the weld to sustain yielding is unknown. For example: a large diameter 36-inch steel water pipe failed across the creeping Hayward fault, where the shop made welds (1960s vintage) were sometimes just one-quarter of complete penetration. For example, a large diameter 60-inch steel water pipe failed due to ground shaking in the Loma Prieta earthquake at PGA ~ 0.05g, where the shop made welds (1950s) were just one-quarter (or even less) of complete penetration. The methods of fabrication and construction, including specifications for welds, should have especially high quality control for pipes that are intended for use through fault (landslide, liquefaction) zones. Initial hydro-pressure-testing of pipe as the sole means of acceptance testing may find weak longitudinal seam welds, but will not necessarily discover girth-welds that are non-ductile or not strong enough to allow significant yielding in the main barrel of the pipe due to earthquake loading.

- Ovalization. Pipes with high D/t ratios that are buried in trenches that are surrounded by stiff soils will ovalize as PGDs are imposed transverse to the pipe. Ovalization will induced high bending across the pipe wall thickness. This bending will result in high strains that can delaminate / damage interior or exterior coating systems. Ovalization will reduce net cross sectional area of the pipe to flow gas. For steel pipes with D/t on the order of 50, ovalization will not usually pose a serious problem for fault offsets of a few feet. Computation of the state of stress within a pipe due to ovalization can be done using a nonlinear soil-pipe analysis using pipe shell-type elements (most "stick" type pipe elements cannot capture this phenomena). The higher the D/t ratio, the stiffer the soils, the more ovalization will occur. Imposed strains in the hoop direction due to moderate amounts of ovalization are likely to be under 2%, which might be high enough to damage lining / coating systems, but not high enough to rupture the steel pressure boundary.

Various refinements in these fragility models can be made:

- Steel pipes D/t. The potential for pipe failure due to wrinkling is strongly correlated to pipe D/t ratio. High pressure gas transmission pipes commonly have D/t on the order of 45 to 75; depending on the MAOP and type of steel used. Steel transmission pipes that are designed and operated at much lower pressures (say 100 psi or lower, possible in systems where gas is obtained from LNG sources), so D/t ratios can be higher, meaning lower strains needed to buckle the pipe.

- Steel pipe age / corrosion. Many pipes in GIS maps have been assigned a year of installation attribute, and thus age can be used to adjust the fragility models. As steel pipes get older, there is increasing potential for corrosion damage, in particular if the pipe is located in "hot" soils and if the pipe has inadequate corrosion protection measures (impressed current, sacrificial anodes, coating systems, etc.). Corrosion will result in thinner wall t, leading to reduced capacity to sustain internal pressure and imposed PGDs. Most steel transmission pipes have good corrosion protection, so the age effects might be limited except for thinner wall small diameter distribution pipe in especially corrosive soils.

- Trench design. The backfills in the trench, the native soils, the depth of cover, and the pipe-to-soil adhesion, all have a bearing on the induced pipe strains. These can be modeled in Level 4 analyses.

- Given all these factors, the fragility models in Table 8-8 should be interpreted as being first-order accurate. Possibly, a larger Beta could be used to reflect all these sources of uncertainty, some of which could be reduced if more parameters are included in the analyses.

- Given all these issues, including the randomness in the imposed PGDs and uncertainty in pipe performance, the models in Table 8-8 (pipe capacity), the overall loss estimation is believed to be reasonable, targeted to be "about" median-centered, and biased towards over-prediction of pipe failure for well-designed / constructed / maintained pipes. In other words, these models can provide reasonable estimates of the number of pipes leaking gas, over a large pipe inventory. The user should never use individual pipe results from Level 1, 2 or 3 analyses as being precise on an individual pipe basis. The individual pipe results, when coupled with all the other assumptions, can be used as a first order ranking as to which pipes are exposed to fault offset PGDs and a first order estimate of the chance of pipe failure (gas leak).

The above vulnerability models should ideally only be used for vulnerability analyses of a large inventory of pipelines that cross faults. Any seismic analysis for a single pipe where the results are meant to be specific to that pipe, should always be based on Level 4 techniques.

8.8 Variability in Results

Section 8 provides damage algorithms for gas pipes due to shaking, liquefaction and landslide using a damage "measurement" of Repair Rate per 1000 Feet or per km. This is a measure of an overall or global description of pipe damage. Variability in pipe performance can also be incorporated considering randomness (aleatory) and uncertainty (epistemic). Randomness can be thought of as to whether a particular geologic hazard will occur. Uncertainty can be thought as to whether a particular pipe will fail, given that the hazard occurs. The academic community enjoys using the Greek terms aleatory and epistemic to express that some things appear to be truly random, and some things can have reduced randomness if more study is done to quantify the parameters. The engineering community enjoys using common-meaning words to describe things that engineers can address with further refinement (uncertainty) and things that are beyond the engineer's capability to refine (randomness). Whichever treatment is adopted, the user should appreciate that the world is not truly either "aleatory" or "epistemic", and models such as lognormal standard deviations are used because they are convenient mathematically, and not because they are absolutely correct models of the real world.

Some loss estimation models incorporate two parameters to address these issues: β_r (for randomness) and β_u (for uncertainty), where β is the lognormal standard deviation. The β_r terms are incorporated in ground motion GMPEs and β_u terms are included in fragility models for components such as buildings, equipment at substations, etc. The β_r term can be further subdivided to reflect intra-event and inter-event uncertainties.

Randomness in the ground motion can be accounted by calculating the damage to the entire buried pipe system for the median ground motion hazards, and then recognizing that the response of any individual pipe may be different due to random differences in the local ground motions. When evaluating a large population of pipe (say over 1,000 miles of pipe over a wide geographic area), randomness in ground motions at one point (higher than predicted) should generally be counterbalanced by randomness in ground motion at another location (lower than predicted), and the effects tend to cancel out.

The empirical data presented in this report (Figures 8-2, 8-3, 8-4, 8-5) show a lot of scatter. While the empirical evidence is strong that the rate of pipe damage increases with increasing hazard, and the underlying structural mechanics shows that pipes should fail with increasing strain / stress, there remains the key point that the "goodness of fit" is not terribly high, that many pipes leak every year under "day-to-day" conditions and without earthquakes. The user should be aware that the fragility models herein are geared to providing the gas system operator with a reasonable forecast as to the amount of system-wide damage that can be expected in earthquakes; this amount includes damage that was earthquake-caused, as well as damage that was discovered post-earthquake, but might have been existing pre-earthquake.

On a system-wide basis, the forecast in amount of damage should be considered "best estimate", with the following suggested uncertainty bounds:

- > 1,000 miles of pipe. -35% (16th percentile) to +60% (84th percentile).
- 100 - 999 miles of pipe. -45% (16th percentile) to +75% (84th percentile).
- 10 - 99 miles of pipe. -70% (16th percentile) to +200% (84th percentile).
- < 10 miles or a single pipe. Do not use Level 1 or Level 2 analyses. Use Level 3 analysis for a preliminary estimate and use Level 4 analysis for any design or important decision making purposes.
- Individual pipe spool pieces. In no case should the fragility models described in this report for Level 1, 2 or 3 ever be used to forecast the chance that an individual pipe spool piece (like a 40-foot to 80-foot long pipe segment that is fabricated at the pipe factory) will fail in an earthquake. Level 1, 2 and 3 models are *only* suitable for emergency response evaluations of a large system. If the user is interested in short segment-by-segment (such as fabrication pieces) analysis, the user must use Level 4 analysis, including site-specific investigations.
- The Level 1, 2 and 3 analyses in this report are meant to be conducted using median-based hazard estimates. The empirical evidence in this report is presented in terms of median-based hazard estimates, and already factors in that locally, the ground motions were actually higher or lower than the median. While the user could compute the hazard, say at the 99th percentile not-to-exceed level, there is low confidence in the computed risk when using that hazard level when adopting the Level 1, 2 and 3 fragility models presented in this report. If a user is interested in assessing the risk of a short segment of pipe at a specific hazard location (say a specific gas pipe that is several hundred feet long, crossing a specific fault, liquefaction or landslide zone), and if the user wishes to assign extreme motions for design (say PGV ~ 200 cm/sec), then a Level 4 analysis approach is recommended.
- If the user estimates the hazard level at a 84th percentile not-to-exceed level, and uses the median-based fragility models, nominally the result is that the chance of pipe damage is in the range of 84th percentile for that segment. If this approach is adopted, ideally the hazard model should factors in spatial correlations, and possibly use Monte Carlo techniques, so that in a specific scenario event, the 84th percentile of system-wide (over a large geographic area) damage can be estimated (as well as median, etc.). The user is cautioned that the 84th percentile of system-wide damage (over a large geographic area) is never the sum of the individual pipe segment 84th percentile chance of damage.

The above ranges are based on the earthquake occurring in summer time (ground not saturated) conditions. The number of pipes damaged due to landslide can vary by a factor of 5 to 10 or more, as compared to summer time (ground not saturated) conditions.

Many liquefaction susceptibility maps are based on an assumed depth of ground water being at the historic highest levels:

- In many areas in California, the ground water table has been significantly drawn down, and this assumption would generally result in an overestimation of liquefaction (as for example, along the foothills of the San Gabriel Mountains).

- Reliance on the lack of observed liquefaction in historical earthquakes (like 1989 Loma Prieta) might yield false results, as some ground water agencies have since changed from ground water supply to surface water supply, and this has led to an increase in the ground water table (as, for example, in parts of Santa Clara County near San Jose).

Some liquefaction hazard maps assign "very high" or "high" susceptibility to manmade fill areas, as for example, along the shorelines of the San Francisco Bay. However, much of these areas may be underlain by clay-type conditions, which are not strictly "liquefiable", although with high enough strains, can still mobilize and produce PGDs. Careful review of how the filled zones were built is recommended, as there can be great variance in PGDs in similarly-ranked areas in a single earthquake. For example, most USGS-based liquefaction maps show the Oakland Airport and Bay Farm Island as equally susceptible to liquefaction; in the 1989 Loma Prieta earthquake, the Oakland airport had many areas that sustained PGDs; but Bay Farm Island had none; yet both areas were exposed to similar levels of shaking.

8.9 Fragility Models for Wells

The seismic vulnerabilities of gas wells include:

- Variation of gas pressures in the gas-bearing strata caused by the earthquake.
- Potential for sanding at the gas bearing strata caused by the earthquake.
- Damage to the casing pipe due to potential fault offset at depth. This vulnerability is not addressed in this report.
- Damage to the casing pipe due to corrosion.
- Damage to the casing pipe at depths from grade to about 40 feet beneath grade, owing to local PGDs due to settlement or lateral spread.
- Damage to the pipes and appurtenances attached to the well head that deliver gas from the well (extraction well) or gas into the well (injection well).
- Damage to tubing and devices used to measure flows, pressures, gas quality or other attributes.
- Damage to power supplies (battery chargers, batteries, generators, etc.) used to energize various devices.
- Power outages due to disturbances in the electric grid.

There is insufficient empirical data to establish fragility models based only on empirical experience. This reflects that the bulk of the wells exposed to past earthquakes that have been damaged are not owned by any of the IOU gas utilities; and the details of construction are generally not known for the gas wells that have had damage in past earthquakes in California. With these limitations in mind, the following damage states are likely to be the most important:

Inertial Shaking (leading to interruption of gas supply from the well).

- PGA ≤ 0.1g. Wells rarely sand up. Gas pressures unlikely to vary more than a few percent.
- 0.1g < PGA ≤ 0.3g. Wells sometimes sand up. Gas pressures sometimes to vary ~25% percent from normal, and likely to return to near normal within 2 weeks of the earthquake.
- 0.3g < PGA ≤ 0.5g. Wells occasionally sand up. Gas pressures likely to vary ~50% percent from normal, and likely to return to near normal within 2 weeks of the earthquake.
- 0.5g < PGA. Wells occasionally sand up. Gas pressures likely to vary ~50% percent from normal, and likely to return to near normal within 2 weeks of the earthquake. ~1% chance of

complete loss of gas supply from the well due to excessive sanding that clogs the casing; this could be temporary (lasting a few days) or a new well may be required.

Inertial Shaking (casing damage).

- PGA ≤ 0.1g. Well casings do not fail due to corrosion.

- 0.1g < PGA ≤ 0.3g. Well made and recently inspected well casings that show no material corrosion do not fail due to corrosion. Wells with corrosion (or have not been inspected for > 10 years) have a ~1% chance of collapse at some level over the height of the casing.

- 0.3g < PGA ≤ 0.5g. Well made and recently inspected well casings that show no material corrosion do not fail due to corrosion. Wells with corrosion (or have not been inspected for > 10 years) have a ~2% chance of collapse at some level over the height of the casing.

- 0.5g < PGA. Well made and recently inspected well casings that show no material corrosion do not fail due to corrosion. Wells with corrosion (or have not been inspected for > 10 years) have a ~3% chance of collapse at some level over the height of the casing.

Inertial Shaking (Above ground components). It is not recommended to use fragility models to assess above ground piping and related components at gas well fields. The recommended approach is as follows: a cognizant seismic engineer should inspect each and every well to identify the above ground style of construction at the well head and for all pipes and related equipment attached to the well. In parallel, a cognizant engineer and/or geologist should describe the soil layering in the top 40± feet and develop suitable PGD profiles to reflect settlement and/or lateral spreads. The as-installed configuration should be assessed by the engineer for potential damage due to SAMs (either inertial caused or PGD caused) for the well head and all above ground piping. The engineer should then develop suitable mitigation options for any well /piping arrangement that appears to be vulnerable for the design-level earthquake. It is not recommended to use above-ground pipe fragility models (such as 0.1 leaks per 1,000 feet of pipe) for above ground pipe inventory at any gas well field in California; such models without detailed knowledge of actual in-situ installations may not produce satisfactory results.

Inertial shaking (power). It is beyond the scope of this report to develop fragility models for regional power outages or due to damage to on-site backup power equipment (diesel, propane or battery systems). If the user wishes to have a first order estimate that there might be a regional power outage at a specific site, it may be reasonable to assume that at PGA = 0.3g, there is a 50% chance of at least a temporary (lasting 5 minutes or longer) power outage.

Liquefaction (casing damage). The most likely serious damage to a well may occur if the site is prone to liquefaction. Liquefaction can manifest itself as settlements or lateral spreads. Two forms of damage are of concern:

- Settlement of surrounding soils. This can be computed in terms of surface level PGDs. As the soil settles, it will impose a down drag force on the well casing. If the down drag force is high enough, it can buckle the casing (rare) or more commonly, induce a high level of stress / strain in above ground attached pipes. The above ground attached pipes will settle, but the attachment at the well head will not settle (much), and this leads to a high state of stress / strain in the attached pipe due to the seismic anchor motion (SAM). For wells without specific seismic design to accommodate these SAMs, the median PGD to reach leak is 4 inches, with β_u = 0.8; but these values can vary tremendously depending on actual installation configuration, so a Level 4 analysis is always preferred. For wells with specific seismic design to accommodate these SAMs, this failure mode is essentially precluded, as the designer will have mitigated the issue with suitable style of construction. If the well is important, a Level 4 analysis is always preferred.

- Lateral spread of surrounding soils. This can be computed in terms of surface level PGDs. The median PGD to reach leak is 12 inches, with β_u = 0.8; but these values can vary tremendously depending on actual installation configuration, so a Level 4 analysis is always preferred. As the soil moves sideways, it will impose a lateral forces on the well casing. If the PGD is distributed relatively uniformly over the height of the casing, the deformed casing may remain in or near the elastic range; in such a case, the operator may shut down the well after the earthquake, excavate the top ten (or tens) of feet of the casing, and the casing can restore itself to its original vertical alignment. In this case, the repair effort is relatively limited. If the casing has yielded, the casing may still be leak tight, but may be replaced post-earthquake. It is possible that if the casing pipe near the well head area has yielded, that the operator may abandon the well and drill a new well.

- As with gas pipelines, the level of strain imposed into the well casing due to either settlement or lateral spread, will depend upon both the magnitude of the PGD as well as the rate of change of PGD over the height of the well. In turn, this can be reliably computed only if one has the soil profile / ground water table conditions at each specific well.

The above fragility curves are suitable for wells designed and constructed without any seismic design provisions. These fragilities should only be applied for loss estimation purposes over a significant inventory of wells (at least 10). Risk forecasts for individual wells should be based on Level 4 approaches.

CHAPTER 9:
Areas for Additional Research

There are a number of areas where the understanding of gas pipeline fragility can be extended, including test. The following sections outline some of these areas for service laterals, distribution mains and above ground components. As the vast majority of gas leaks have occurred in distribution systems and service laterals, it is felt that research in those areas would be especially valuable in identifying approaches that can improve performance in future earthquakes.

9.1 Gas Service Laterals

This report has shown that the much of damage in past earthquakes has been to gas service lines. This has been the case in the 1989 Loma Prieta, 2010 Eureka, 2014 Napa and 2019 Ridgecrest earthquakes, where 70% to 90% of all gas leaks were reported on service laterals. Similar trends have been seen in the 1933 Long Beach, 1987 Whittier, 1995 Kobe, 2011 Tohoku, 2016 Kumamoto, 2018 Anchorage earthquakes.

On the order of half of the gas leaks on service laterals have been along the vertical riser pipe to the gas meter assembly. It would appear that the relatively large mass of the meter device, coupled with the small diameter pipe, and use of threaded fittings, all combine to allow small gas leaks to occur. The usual rate of gas leak is very small, and a common repair has been to add a "pipe dope" compounds to the threaded connections, so that gas does not leak through the threads.

Modern gas transmission pipeline design more-or-less precludes the use of threaded connections. But, threaded connections were common for steel distribution pipes installed pre-1930 or so. Threaded pipe has widespread use in service laterals, especially along the riser pipes.

As a general rule, threaded connections are commonly leak-tight during original installation, as verified by a leak test done at the time of original installation. But, over time, through a combination of mechanical forces (imposed seismic anchor motions due to ongoing differential movements, seismic inertial loading, other vibratory loading) as well as age effects (corrosion, embrittlement of dope compounds, etc.), the threaded connections can become loose enough as to allow gas to leak through the threads.

Historically, it has been commonly assumed that a threaded connection in a steel pipe will remain leak-tight if the imposed bending moment on the connection is less than about 50% of the moment needed to allow the adjacent non-threaded pipe to reach initial yield. The empirical evidence is nearly devoid of examples where a threaded connection for a small bore threaded steel pipe actually fails (breaks open) due to seismic inertial loading.

The literature is essentially silent on the seismic design of gas service laterals. Additional research is warranted along the following lines:

- Prepare an inventory of common service lateral installations used by PG&E, SoCalGas and SDG&E. This should cover examples from pre-1930 installations (using screwed steel pipe, thought to be the amongst the most vulnerable); welded steel pipe; a range of plastic pipe; copper pipe (most copper pipe laterals have been replaced, so this is a lower priority).

- Prepare an inventory of common risers / meter sets / installations. This would include a range of support configuration (wholly supported on the riser pipe, some support by pipes going into the customer's structure), some support using wood or concrete stacked support under the meter, etc. Consider "hard pipes" connections from the meter into the customer's structure (most common), as well as "flex hose" configurations (such as used for connection to manufactured housing, etc.)

- Perform finite element analyses of the lateral (from the distribution main connection to the meter set) to obtain baseline state of stress in the pipes. These finite element analyses should follow the procedures in ALA (2005) or PRCI (2009) to factor in soil restraint; the pipes can be modeled as "beam-type elements", along with suitable modeling for joints. A portion of the distribution main should be included, to allow examination of the state of stress at the main / lateral connection.

- While full scale shake table tests of an entire service line assembly would be ideal, the size of such a test (likely over 40 feet in horizontal direction), and the need to confine the pipes to represent soil constraint, might make such tests prohibitively expensive.

- Select a suite of configurations suitable for component testing. These components should include: a range of main - lateral connections; a range of common pipes (and their joinery) used in service lines; a range of riser / meter / structure support configurations.

- For each component, perform a suite of load tests to obtain state of stress versus imposed load. Test until failure (minor leak; complete break). Compare these test results to those from finite element analysis. Consider a range of installations, including quality of connections. Where feasible, keep the pipes pressurized (between 2 to 60 psi) with water or other liquid / gas that is easy to detect for any leakage; using natural gas might be problematic, owing to its planned leak under high load, greenhouse gas release, and potential for ignition, so water might be the best choice.

- Identify the range of "weak links" in the service lines / connections.

- Document all findings in reports. Provide recommendations for suitable seismically-robust service line installation details, by type of location:

    - Very stiff / rock like conditions (relative uncommon)

    - Stiff soil conditions not exposed to PGDs (common)

    - Soft soil conditions (common)

  - Soil conditions prone to minor PGDs over a 50-year service life (liquefaction or landslide / soil creep, up to 6 inches over 50 years)

  - Conditions prone to major PGDs over a 50-year service life (major lateral spreads or landslide or fault offset movements of 1 foot or more).

- Perform a benefit cost analysis to demonstrate the efficacy of replacement of service lines with new "seismically designed" service lines.

- Estimated level of effort: $50,000± for data collection, initial analyses, test set up specifications; $50,000± for testing of components; $50,000± for post-test analyses, development of recommendations; $25,000± for reports and meetings. Total: $175,000 to $250,000.

- Recommended support by the IOUs: PG&E, SoCalGas and SDG&E each to provide sketches of 3 to 5 common service line installations, representing their oldest (and thought to be particularly prone to annual repair) and their newest "standard" installation and their common 20 to 40 year old installations. The IOUs should provide service lateral pipes and related equipment for purposes of component testing. Ideally, the older installation hardware should come from recently-replaced service lines; the newer installation hardware should come from components currently included in inventory for new installations.

9.2 Gas Distribution Mains

This report has shown that a portion of damage in past earthquakes has been to gas distribution mains. This has been the case in the 1989 Loma Prieta, 2010 Eureka, 2014 Napa and 2019 Ridgecrest earthquakes, where 10% to 20% of all gas leaks were reported on distribution mains. The empirical evidence suggests that steel mains (especially older mains with threaded fittings) have the most damage, while newer MDPE / HDPE mains might have the least damage.

The literature is essentially silent on the seismic design of gas distribution pipes. Additional research is warranted along the following lines:

- Prepare an inventory of common gas distribution pipes (2-inch diameter being most common) used by PG&E, SoCalGas and SDG&E. This should cover examples from pre-1930 installations (using screwed steel pipe, through to be the amongst the most vulnerable); welded steel pipe; a range of plastic PE pipe. Ideally, obtain PE pipe covering different resins, such as Aldyl A (thought to be potentially brittle) as well as PE pipe now used for new installations.

- Perform finite element analyses for: a distribution pipe without appurtenances; a distribution pipe with multiple service line connections or other discontinuities; a distribution pipe with discontinuities (attachment at regulating stations, etc.)

- Select a suite of configurations suitable for component testing. These components should include: a range of common pipes (and their joinery) used in distribution pipes lines.

- For each component, perform a suite of load tests to obtain state of stress versus imposed load. Test until failure (minor leak / complete break). Compare these test results to those from finite element analysis. Consider a range of installations, including quality of connections. Where feasible, keep the pipes pressurized (between 2 to 60 psi) with water or other liquid / gas that is easy to detect for any leakage; using natural gas might be problematic, owing to its planned leak under high load, greenhouse gas release, and potential for ignition, so water might be the best choice.

- Identify the range of "weak links" in the pipes (at field made girth joints; connections to laterals; etc.) Quantify allowable tensile and compressive stresses / strains for one-time major earthquake load conditions, (or multiple smaller earthquakes / ongoing creep, etc.) factoring in total life cycle loading.

- Document all findings in reports. Provide recommendations as to what might be suitable seismically-robust distribution pipe details, by type of location:

    - Very stiff / rock like conditions (relative uncommon)

    - Stiff soil conditions not exposed to PGDs (common)

    - Soft soil conditions (common)

    - Soil conditions prone to minor PGDs over a 50-year service life (liquefaction or landslide / soil creep, up to 6 inches over 50 years)

    - Conditions prone to major PGDs over a 50-year service life (major lateral spreads or landslide or fault offset movements of 1 foot or more).

- Perform a benefit cost analysis to demonstrate the efficacy of replacement of distribution pipes with new "seismically designed" distribution pipes.

- Estimated level of effort: $25,000± for data collection, initial analyses, test set up specifications; $25,000± for testing of components; $25,000± for post-test analyses, development of recommendations; $10,000± for reports and meetings. Total: $85,000 to $125,000.

- Recommended support by the IOUs: PG&E, SoCalGas and SDG&E each to provide sketches of 3 to 5 common distribution pipe installations, representing their oldest (and thought to be particularly prone to annual repair) and their newest "standard" installation and their common 20 to 40 year old installations. The IOUs should provide distribution pipes and related equipment for purposes of component testing. Ideally, the older installation hardware should come from recently-replaced distribution pipes; the newer installation hardware should come from components currently included in inventory for new installations.

9.3 Above Ground Components

Gas systems include a number of above ground components. These include:

- Pipes and related equipment at well heads / natural gas storage facilities
- Pipes and related equipment at regulating stations
- Pipes and related equipment at compressor stations
- Pipes and related equipment at customer meters
- Pipes and related appliances within residential and commercial structures
- Pipes and related equipment at odorizers and gas quality processing facilities

The empirical evidence shows that the earthquake-related damage at these facilities has included:

- Leaks at threaded connections for above ground piping due to inertial forces
- Damage to valves (inoperable / stuck / fails to operate) due to imposed PGDs that yield the valve
- Many kinds of leaks and sometimes a break to small bore pipes within customer's houses; possibly due to seismic anchor motions induced by rolling / falling appliances
- While not addressed in this report, there are many other kinds of damage at these facilities, ranging from damage to the building structures (not addressed in this report); toppling of motor control centers due to weak / missing anchorage (not addressed in this report); communication outages due to loss of power or other type of damage (not addressed in this report).

Without doing an inspection to identify the inventory of components at these facilities, it is speculative to establish an optimal testing program that could be used to help define the fragility of selected components. This said, from experience, the following tests could shed light on some of the more common components for which there is generally a paucity of available published test data:

- Threaded connections for above ground pipes. Pipes with threaded connections have been used for both buried and above ground installations. Mostly, these will be 2-inch and smaller diameter steel pipes (small bore pipes). Do testing to develop a relationship between the applied bending moment (M) on the connection and the potential for that connection to leak gas at 10 parts per billion, 100 parts per million, 50,000 parts per million rates. Address how long term corrosion (including salty fog environments), ultra violet light exposure, or vibration or aging issues (on pipe dope) might affect the leak tightness of the connections.
- Some installations may include Dresser (or similar) couplings adjacent to valves. These can be installed for 6-inch to 24-inch (or larger) steel pipes. Do testing to develop a relationship between the applied axial (P), bending moment (M) and shear (V) forces on the Dresser coupling

to establish the potential for that coupling to leak gas at 10 parts per billion, 100 parts per million, 50,000 parts per million rates. Track the applied P, V M and thermal / seismic movements to quantify the pull out / rotation resistance of the coupling unit, as well as at what levels of pull out / rotation do various leak rates occur.

CHAPTER 10: References

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