STATISTICAL MODELING OF CORROSION FAILURES IN NATURAL GAS TRANSMISSION PIPELINES

A Thesis

by

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ABSTRACT

Natural gas pipelines are a critical component of the U.S. energy infrastructure. The safety of these pipelines plays a key role for the gas industry. Therefore, the understanding of failure characteristics and their consequences are very important for designing future operations, operating expenditure, and maintenance decisions.

The oil and gas industry spends billions of dollars annually for the corrosion-related cost of the transmission pipelines, the costs which increases due to aging and deterioration processes in pipeline networks. Therefore, pipeline operators need to rethink their corrosion prevention strategies. These results of corrosion failures are forcing the companies to develop accurate maintenance models based on failure frequency. Statistical methods for modeling pipeline failures and proper maintenance decisions play a key role in future safety of lines, to reduce the rate of occurrence of failures, and the cost-effective operation of pipelines.

This thesis is focused on two challenges. The first challenge is to estimate the failure rate of natural gas transmission pipeline networks from the previous incidents' data in the United States. A specific objective of this part is to determine the characterization of the failure modes of the transmission pipelines, and to develop the statistical models based on the reliability of a repairable system. The second challenge is to develop the optimal preventive replacement actions by using well-developed optimization models. The objective of the second part is to choose appropriate maintenance policies based on the statistical models and to find the optimal maintenance policies.

In this thesis, two of the most commonly applied stochastic models, which are the homogeneous Poisson process and the power law process, are used for the estimation of the failure rate. The point and interval estimators of the failure intensity function are provided and the accuracy of the stochastic models is tested for each determined failure mode. Finally, appropriate maintenance models will be presented for planning preventive maintenance and replacement activities for a repairable and maintainable system. It is assumed that pipeline systems could be restored to operation requirements by some minimal repair process instead of replacement after each failure.

DEDICATION

This thesis is dedicated to my parents who supported me throughout my studies. I am also grateful to my God for giving me the opportunity to complete this task successfully.

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1. INTRODUCTION

Modern economies need energy to produce goods and services. Support transportation and provide heating and other life to communities. Pipelines are key to an effective transportation and distribution of liquid and gas products.

Pipelines represent a dominant means of transporting gas from their upstream location to the downstream. While the oil and gas industry uses other transportation methods such as oil-gas tankers and tank trucks/railroad tank cars, pipelines are the preferred choice. There are two main reasons why pipelines are an important transportation method for oil and gas products. First, pipelines are capable of transporting large amounts of gas and liquid over long distances (Thompson, 2004). For example, replacing a modest-sized oil pipeline, which can transport 150,000 barrels per day, with tanker trucks would require 750 trucks, and with railroad cars would require 225 cars loads per day (AOPL, 2014). Second, the pipelines' design enables them to carry oil and gas products quickly, safely, and cost-efficiently to end-use markets when compared to other forms of transportation (Mohitpour et al., 2010; U.S. Energy Information Administration, 2013; Mohitpour et al., 2007).

Pipeline systems can be divided into three major categories: oil pipelines, natural gas pipelines, and others (water, chemical, etc.). The purpose of oil and gas pipelines is similar. However, the operation processes and the equipment are different (Mohitpour et al., 2010). Gas transmission pipelines use compressors to provide high-pressure for long-distance transport and are connected to distribution systems that deliver the gas via low-pressure and small-diameter pipes that go through the “city gate” valving and the metering station. On the other hand, oil and petroleum product pipelines use pumps to push oil to tankage or storage facilities (Mohitpour et al., 2010).

Complex engineering and economical analysis are required for pipeline system designs. While designing the facility, pipeline engineers must consider all environmental effects, characteristics of oil and gas, volume of fluid, the length of a pipeline, and others variables. After complex studies are completed, engineers design the system by speculating the material type, diameter, wall thickness, route, power requirements, prevention methods, maintenance schedule, etc. (Mohitpour et al., 2007).

Although pipeline systems are the most economical, the most efficient, and the safest way of transportation, there have been an increasing number of incidents in the pipeline industry. The failures of the pipeline system can lead to events such as: injuries, fatalities, environmental issues, product loss, and property damages (Thompson, 2004). As a result of the increasing trends, the reliability of pipelines is a major concern of the operators. Therefore, pipeline operators are interested in understanding the failure characteristics of an individual pipeline asset and all the variables affecting the pipeline’s performance (Baker Jr., 2008; Thompson, 2004).

A systematic approach for pipeline safety is required to reduce the number of incidents. Each company is required to provide a systematic approach to reduce the number of failures, improve system reliability, increase the system’s safety, and reduce maintenance costs. The best way to reach this target is the adoption of an incident-free operation policy (American Society of Mechanical Engineers (ASME), 2010).

Effective maintenance strategies are the most important part of the systematic approach to pipeline safety. These strategies are extremely important to avoid failures during operation. A number of policies have been established to improve system reliability and to prevent the occurrence of system failure, and to reduce maintenance costs (Wang and Pham, 2006). The first step is to determine system reliability (Wang and Pham, 2006). Failure modes can be determined using statistical prediction models. These prediction models help the operators to minimize or eliminate any risks. The second step is to establish the optimal maintenance strategies. The purpose of the optimization problem is to minimize the overall costs of system operation and to maximize the overall reliability of the system by maintenance. Appropriate maintenance strategies can improve the system's reliability.

However, estimating system reliability and establishing optimal maintenance frequency is a difficult task. The failure rate, which is used to express reliability of a system, is affected by many factors such as the environmental conditions (soil type, onshore, offshore, etc.), internal variables (the amount of the liquid water, chemical components of natural gas, etc.), structural characteristics (the material, diameter, wall thickness, etc.), and maintenance variables (protection methods, frequency, etc.). These include a set of variables affecting a pipeline performance is a very difficult task because of the very complicated nature of it. Similarly, finding optimal preventive maintenance policies in multi-component systems requires complex studies.

This section introduces the overall motivation for the study. In addition, this section presents the goals and objectives, summarizes the contributions, and outlines the organization of the thesis.

1.1 Background and Motivation

Pipeline systems are the most popular method for transporting natural gas. Pipelines distribute almost 70 percent of oil and gas products worldwide (Mohitpour et al., 2010). Also, pipeline networks are growing every year due to new pipelines' construction in new areas.

Pipelines require the highest level of reliability due to safety concerns. In fact, pipeline systems are becoming more complex and being located excessively near high-density populated areas ("high-consequence areas" (HCAs)). Any release of hydro-carbon in HCAs could have adverse consequences and great environmental impacts. Therefore, safety is the highest priority for governments and the operators (Hernandez-Rodriguez et al., 2007).

Due to economic and public safety concerns, pipeline systems are operated continually as possible as without an incident. Effective maintenance strategies require reaching this objective. The first fundamental step of effective maintenance actions is to determine system reliability. Reliability of the pipeline systems can be formulated by mathematical models. Mathematical models allow for prediction of future failure behaviors and estimate the probability of pipeline failures (Blischke and Murthy, 2000).

The key to application of reliability to pipeline networks is acquisition, analysis, and interpretation of data. Therefore, effective and efficient collection of data and description and analysis of data plays an important role in application of reliability (Blischke and Murthy, 2000). There are several types of data gathering techniques that can be used in reliability analyst. There are two main approaches: experimental data and failure data. Experimental data gains data from samples from well-defined populations. Although experimental data provides a good indication of the actual condition of the pipeline, it is commonly considered too costly. For pipeline networks, it requires taking out a pipe sample for the entire network. On the other hand, in most cases, failure data can be used in reliability analysis. Failure data has many advantages. First, failure data would go a long way in helping the operators not just to predict the pattern of these untoward incidents but also to provide them with a comprehensive understanding of what has gone wrong in the pipeline systems. Second, gathering failure data is easier than experimental data. For example, the historical failure data sources for the United States, Canada, and Europe are open access (OA) (Andersen and Misund, 1983; Papadakis, 1999; Blischke and Murthy, 2000).

The U.S. Department of Transportation-Pipeline & Hazardous Materials Safety Administration (PHMSA) maintains a database on pipeline incidents. PHMSA has been collecting these data from American pipeline operators since 1986. The PHMSA's database provides invaluable information such as pipeline and operator information, failure causes, consequences of these incidents, cathodic protection conditions, coating conditions, property damage, year of installation information, and etc. However, a number of items are missing. For example, it is very difficult to find information on operators and pipeline systems such as the environmental conditions, total section length of pipelines, design considerations, maintenance frequency, inspection techniques, soil conditions, etc.

The key challenge for the operators is to develop reliable models to estimate the number of future failures. The results of reliability models help the operators achieve this goal. First, the operators can minimize the operational risks such as injury, fatality, economical, and etc. Second, the operators can mitigate and control most pipeline failures. Third, they can produce safer operations. Finally, they can decide on effective maintenance procedures and timing. For example, if maintenance is scheduled too early, the failure of the system cannot be detected and repaired. If maintenance is scheduled too late, the pipeline systems pass to an acceptable safety level to the public and environment, so the failure will likely occur (Hong, 1997).

However, developing task prediction models to estimate failure rate for the pipelines system is a difficult. Pipelines do not have constant failure rate along its entire length because the material, surrounding environmental, and its operational conditions are not uniform for the whole pipeline (Røstum, 2000). Moreover, the pipeline systems consist of many subcomponents such as valves, metering stations, and compressors. Wang and Pham (2006) imply that the failures of different subcomponents in multicomponent system may not be independent failure dependency. Therefore, it is very difficult to model all factors that affect pipeline's performance. To address this problem pipeline systems can be defined as a group of pipelines (network level), which are modeled by the same point stochastic process (Ascher and Feingold, 1984; Caleyo et al., 2008).

It is important to note that the pipeline system can be considered as a system that is repaired upon failure by emergency repair. Hence, it exists as “bad-as-old” type of behavior following application of maintenance actions (Stillman, 2003). The arrival of the system failures over time can be treated as a stochastic point process. Therefore, reliability of the systems could be expressed as a failure rate for repairable systems (Mohitpour et al., 2010). There are two common reliability approaches to model repairable systems: the homogeneous Poisson process (HPP) and the nonhomogeneous Poisson process (NHPP). The NHPP is a popular method to model the failure process of repairable systems such as natural gas transmission pipelines (Krivtsov, 2007).

The next step of pipeline safety is the development of the optimal maintenance models. Based on failure characteristics, the optimal preventive maintenance models can be established. In the past several decades, a number of different preventive maintenance optimization models have been proposed (Wang, 2002). As with the development of reliability model, the development of the optimal preventive maintenance models is difficult. The success of the models depends on the prediction of future pipeline failures, the reliability criteria, the cost of improvements, and maintenance degrees of the system (Thompson, 2004).

1.2 Research Goal and Objectives

The main motivation for this work comes from developing a better understanding of the complexity of characterizing failure behavior and finding optimal preventive maintenance decision in natural gas pipeline networks.

This thesis focuses on significant failures on the natural gas transmission pipelines that lead to adverse consequences. This thesis has two main goals. The first goal is to develop a reliability model for pipeline integrity and safety. The second goal is to choose optimal maintenance policies based on reliability models.

The objectives of this thesis are described as follow:

1. Characterize the failure modes of natural gas transmission pipeline systems in the United States. The characterizing process covers time-dependent failure modes which causes more significant consequences;
2. Develop the statistical models to estimate the failure rate of a natural gas pipeline network by the analysis of observed failure data, which come from the American natural gas pipeline operators. The statistical models need to consider the effect of preventive maintenance and rehabilitation actions;
3. Determine optimal maintenance policy in a realistic way for pipeline system. Moreover, the aim of this thesis to present mathematical models for scheduling preventive maintenance and replacement activities.

1.3 Research Contributions

The main contribution of this thesis is to develop mathematical models to estimate failure rate of the pipeline network and to develop a model to find optimal preventive maintenance and replacement decisions to literature. Based on the complete literature review, only handful of schedule addressed this problem.

Other specific contributions of this thesis to the gas pipeline industry are in following areas:

1. Understanding of the time-dependent failure characteristics of natural gas transmission pipeline systems;
2. Development of a reliability model to predict failure rate;
3. Development of some optimal preventive maintenance and replacement models that can help minimize the overall costs of system operation and maximize the overall reliability. Moreover, the developed models help companies make more accurate maintenance decisions and eliminate and eliminate or reduce future operating expenditure (OPEX).

1.4 Thesis Outline

This thesis is organized in seven sections. Motivations, research goals and objectives, research contributions, and the thesis outline are introduced in this section. The relevant background literature for natural gas pipeline systems, causes of failures, statistical models used for modeling failures on natural gas transmission pipeline networks, preventive maintenance methods, modeling of rehabilitation and replacement decision, and optimization models for maintenance are reviewed and presented in Section 2. Section 3 presents the applied methodology used in reliability and optimal maintenance models. Moreover, this section introduces selection of accurate statistical models, statistical representation of the pipeline systems, and data selection and assumptions. The incident data sources and data prediction or preparations from several pipeline networks in the U.S are described in Section 4. In Section 5, the formulation and the solution approach of the relevant statistical models are presented. In the same section, a number of expected failures model are estimated. The developed statistical models and the models' result are then applied to maintenance optimization and the equipment replacement decisions in Section 6. In the final Section summarizes the key findings and conclusions, and presents recommendations for future research work.

2. LITERATURE REVIEW

This section presents reviews of the existing literature in four major areas within the scope of this thesis: pipeline systems function, failure modes in gas transmission pipelines, modeling pipeline failures, and preventive maintenance and replacements methods. The first subsection presents general information related to pipeline systems. More specifically, the function of natural gas transmission pipeline in the Unites States discusses. The second subsection describes causes and consequences of pipeline failures. In the third subsection, the existing reliability analysis' models are reviewed for estimating pipeline failures. In the fourth subsection, the existing maintenance and replacement models are discussed. In the final subsection, the previous studies that focused on effects of rehabilitation and replacement decisions are reviewed.

2.1 Natural Gas Pipeline Systems

According to a recent estimation from the Energy Information Administration (EIA), global energy demand will increase more than 85 percent from 2010 to 2040. Strong economic growth and expanding world population create this demand. Although renewable energy sources and nuclear power are the world's fastest-growing energy sources, fossil fuels remain and provide almost 80 percent of the world energy supply through 2040 (Stambouli and Traversa, 2002; U.S. Energy Information Administration Office of Energy Analysis, 2013).

Natural gas is the fastest-growing fossil fuel. According to the EIA data (2013), the gas consumption has steadily increases by 1.7 percent per year. If are looks at the reasons for this, natural gas has a clean consumption characteristics. In other words, it is more environmentally friendly compared to other fossil fuels (Obanijesu, 2009). Further, natural gas plays a highly important role as a power generation fuel and is present abundance in the U.S. (Obanijesu and Sonibare, 2005; U.S. Energy Information Administration Office of Energy Analysis, 2013).

The pipeline systems are the best way to transport natural gas to the customers. There are many reasons why pipelines are a popular means of transportation. First, distribution of natural gas with pipelines are a safe and an economically efficient transportation method of carrying gas over long distances as compared to oil and gas tankers, trucks/railroad tank cars, and other transportation methods (Papadakis, 1999; Sun et al., 2000). Mohitpour et al. (2010) noted that the pipeline safety was statistically proved this. In 1998, the total number of fatalities due to pipeline incidents in the U.S. was twenty-seven ppm, which is much lower than the other transportation methods. According to the EIA (2013), "two-thirds of the lower 48 States in the U.S. are almost totally dependent upon the interstate pipeline system for their supplies of natural gas" (Mohitpour et al., 2010; U.S. Energy Information Administration, 2013; Andersen and Misund, 1983).

The key components of the gas pipeline systems include production wells, gathering lines (pipes), separation facilities or processing plants, transmission pipes, valves, metering stations, aboveground or underground storage facilities, compressor stations, metering stations, city gate at distribution center, distribution pipes, regulator station, etc. Figure 2.1 illustrates the major components of this system: a natural gas production (gathering), transmission, storage, and distribution system (Thompson, 2004; Mohitpour et al., 2010).

The pipeline operation processes include the following steps. First, pumping of gas from the wells to gathering lines. Gathering lines then deliver the natural gas to processing facilities to remove undesirable chemical components. After the natural gas is separated, clean gas is pumped into the transmission lines via compression stations. At the end of the transmission lines, the city gates connect to distribution pipelines. The purpose of the city gate is to measure gas via metering stations and to deliver low-pressure gas to the customers using small-diameter pipes (Mohitpour et al., 2010).

Transmission pipelines form the key component of overall pipeline system because transmission pipelines are the main connection between gathering lines and distribution lines (Papadakis, 1999). Although, more than 1,000 companies lead an operation in the transmission lines in the U.S., only, sixty major natural gas pipeline operators are responsible for 80 percent of all natural gas transmission networks in the U.S. (PHMSA, 2013c; PHMSA, 2013d; Hereth et al., 2000).

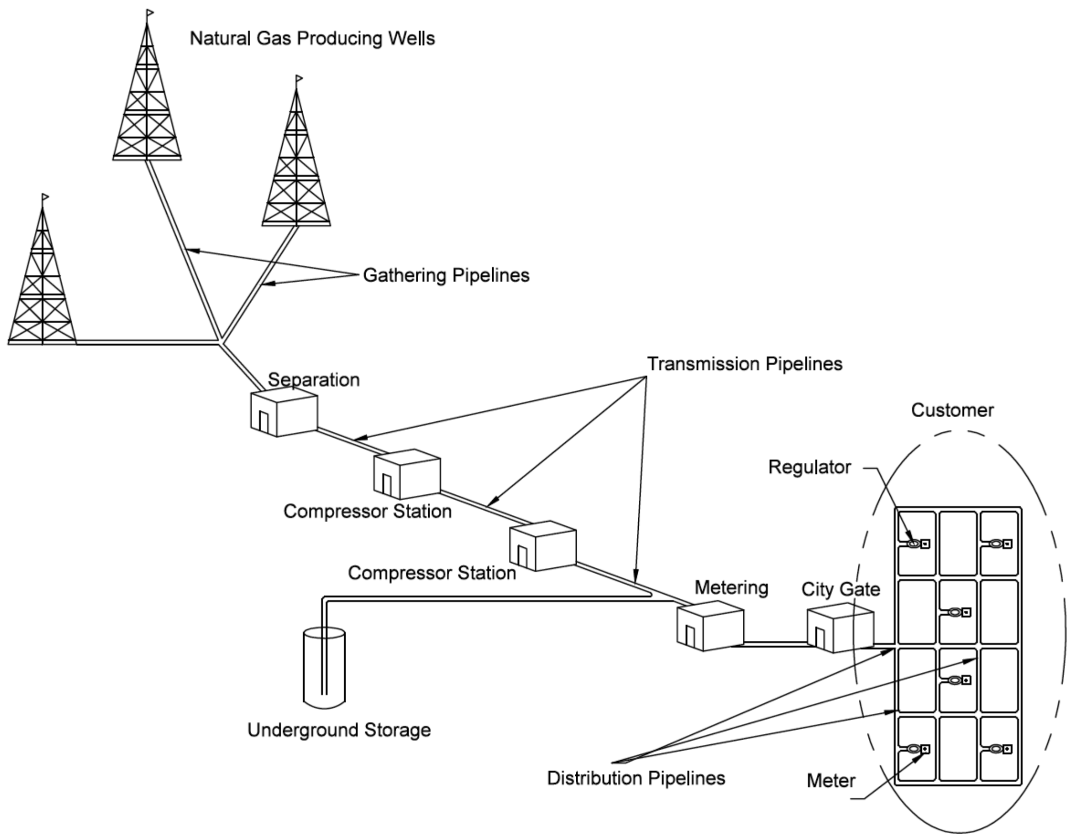


Figure 2.1 Components of a Natural Gas Pipeline System

The transmission pipelines are normally high-pressure, large-diameter, and buried underground or underwater because transmission pipelines are passing across states and counties (Papadakis, 1999). For this reason, pipes should be durable. Therefore, the majority of materials of the natural gas transmission pipelines are made of carbon steel (93 percent), other materials (6 percent), and plastic and concrete (1 percent). Figure 2.2 shows a distribution of natural gas transmission pipelines materials in PHMSA dataset. Ranges of these diameters are from 2 to 48 inches.

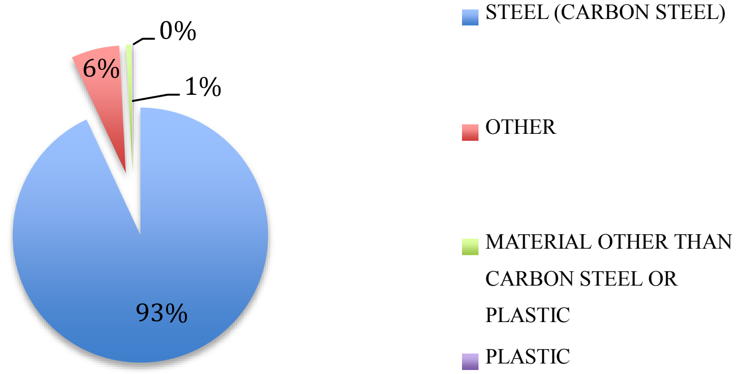


Figure 2.2 Distribution of Materials of Pipeline for Natural Gas Transmission Pipelines from 1986-2012 Source: DOT/PHMSA Pipeline Incidents Data

Although pipelines are the safest and the most economical way of the carrying natural gas, any release on pipelines can have an adverse effect on employees, customers, the public, or the environment (American Society of Mechanical Engineers (ASME), 2010). More specifically, the consequences of pipeline failures depend on where the hydro-carbon release occurs. Pipeline safety regulations use a specific description to identify areas where a release could have serious negative consequences. The name of this concept is "High Consequence Areas" (HCAs). Majority of pipelines are located in "high-consequence areas" (HCAs). Thompson (2004) emphasized that 60 percent of the pipelines are in HCAs. For transmission pipelines, it is almost 261,000 miles of natural gas pipelines in NCAs (PHMSA, 2013a; PHMSA, 2013b).

Pipeline incidents can lead to many important consequences other than costs. Injuries and fatalities are the two obvious ones (Simonoff et al., 2010). According to

DOT/PHMSA Pipeline Incidents Data, a total of 75 fatalities, 334 injuries, and $1,977,571,106 of property damage has occurred due to failure of natural gas transmission pipelines from 1986 to 2012 (PHMSA, 2013d). An illustrating example of this occurred on August 24, 1996. A butane pipeline exploded near by Lively, Texas. Two persons lost their lives as a result of a failure. After the incident, engineers concluded that the cause of failure was external corrosion due to inadequate cathodic protection (Riemer and Orazem, 2000).

Due to an increasing number of incidents and their consequences, reliability of the pipeline system is becoming crucial for the operators and public in general. Public safety concerns have been a driving force for new regulations for managing pipeline operations (Thompson, 2004). First, pipeline operators require following the Code of Federal Regulations (CFR) title 49, Part 192 and 195. 49 CFR Part 192 is titled "Transportation of Natural and other Gas by Pipeline – Minimum Federal Safety Standards" which was established in August of 1970. This regulation prescribes minimum safety requirements for the pipeline industry. More specifically, this regulation specifies a minimum design requirement, material and qualification, internal and external protection requirements, etc. (Parker, 2004).

The last significant effort in improvement public safety was taken on December 17, 2002. President George W. Bush and the 107th Congress passed the "Pipeline Safety Improvement Act of 2002" into law. Under this legislation, the U.S. Department of Transportation (DOT) issued regulations prescribing the standards guidance for implementation of new transmission integrity management programs. Also, the law sets a minimum requirement for integrity management programs for gas transmission pipelines located in “High Consequence Areas” (HCAs) (Baker Jr., 2009).

Following the 2002 legislation, a number of codes, regulations, and standards are established to develop more systematic approach to public, pipeline, and environmental safety. The purpose of these codes and standards are to provide a systematic, comprehensive, and integrated approach to managing the safety and integrity of pipeline systems (Papadakis, 1999). There are two main guidelines that are used by the gas industry: American Society of Mechanical Engineers (ASME) B31.8-2010 “Gas Transmission and Distribution Piping Systems” and ASME B31.8S-2010 “Managing System Integrity of Gas Pipelines” provided by ASME. The ASME B31.8-2010 defines requirements for the safe design and construction of pressure piping. The purpose of the ASME B31.8S-2010 is to provide the operator general information to develop and implement an effective integrity management program.

The general pipeline industry’s goal is to provide a reliable and safe delivery of gas to the end users without an adverse effect on the environment and the public in general. This is a fundamental objective for all gas operators. To reach this aim, the gas operators have to apply the integrity process by reliability and safety engineers. In other words, pipeline operators have adopted an incident-free operation policy. Details of the pipeline integrity management system are defined in the ASME B31.8S-2010 (American Society of Mechanical Engineers (ASME), 2010).

According to the ASME B31.8S-2010, the integrity management of the pipeline systems involves several steps. The first step is to understand failure mechanisms and their consequences. The second step is to develop reliable physical models that describe failure mechanisms using experimental data or the number of previous failures. The third step is to analyze the models with collected data from the perspective of risk and integrity. The fourth step is to find a solution to mitigate or prevent failures by inspection, maintenance, and replacement actions including preparing a plan for future operations. The following subsection summarizes the previous studies in failure characteristics of natural gas pipelines.

2.2 Causes of Pipeline Failures

The first fundamental step in managing the integrity of a natural gas pipeline systems is to understand failure modes of pipeline incidents. Enumerating all pipeline failures modes is beyond the scope of this thesis. However, this thesis provides a general information and explanation about pipeline failure causes.

According to the ASME B31.8S-2010, the natural gas pipeline failure mechanisms are classified under 22 root causes by the Pipeline Research Committee International (PRCI) (7 American Society of Mechanical Engineers (ASME) 2010). A list of possible threats that cause pipeline failures is given in Table 2.1. These 22 threats have been grouped into 9 categories of related failure types based on their nature and growth characteristics. Engineers shall correctly address threats at Table 2.1 for risk assessment, integrity management, and mitigation activities. Each threat shall be considered individually because each threat has its own mitigation strategies (American Society of Mechanical Engineers (ASME), 2010).

The threats to pipeline integrity are classified in three main categories: time-dependent, stable, and time-independent. The time-dependent threats involve corrosion failures. The stable category covers equipment; welding-fabrication related, as well as manufacturing-related defects. The last category includes third party or mechanical damage, incorrect operational procedure, outside force, and weather-related and outside force failure. According to the statistics from PHMSA, the most common known cause of incidents is due to damage by the outside force (26 percent), corrosion (24 percent), material failure or construction defect (20 percent), natural force (6 percent), miscellaneous (4 percent), other or unknown causes (11 percent), and the rest of the causes (16 percent). Figure 2.3 illustrates a summary of the distributions of significant failures by causes (American Society of Mechanical Engineers (ASME), 2010; Papadakis, 1999).

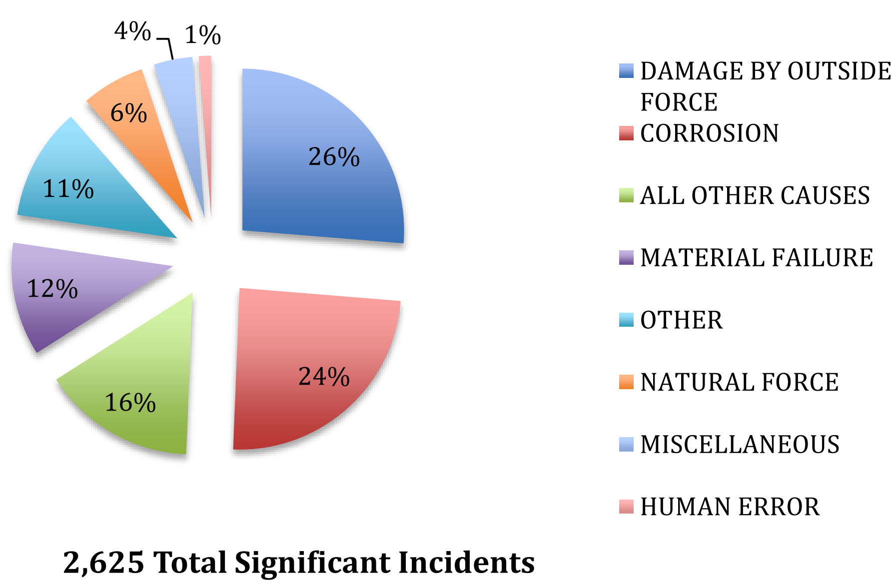


Figure 2.3 Causes of Significant Pipeline Incidents in Natural Gas Transmission Pipelines from 1986-2012 Source: DOT/PHMSA Pipeline Incidents Data

Table 2.1 Whole Threats to Pipeline Integrity Source: ASME B31.8S-2010

Time-related Defect Types	Failure Types Based on Their Nature and Growth Characteristics	Root Causes
Time-Dependent	External corrosion	
	Internal corrosion	
	Stress corrosion cracking	
Stable	Manufacturing-related defects	Defective pipe seam
		Defective pipe
	Welding/fabrication related	Defective pipe girth weld (circumferential)
		Defective fabrication weld
		Wrinkle bend or buckle
		Stripped threads/broken pipe/coupling failure
	Equipment	Gasket O-ring failure
		Control/relief equipment malfunction
		Seal/pump packing failure
		Miscellaneous
Time-Independent	Third party/mechanical damage	Damage inflicted by first, second, or third parties
		Previously damaged pipe
		Vandalism
	Incorrect operational procedure	
	Weather-related and outside force	Cold weather
		Lightning
		Heavy rains or floods
		Earth movement

Failure mechanisms can occurs at different stages of pipeline life cycle. The rate of occurrence of failures (ROCOF) is often described as a “bathtub curve” (Muhlbauer, 2004). The bathtub curve shown in Figure 2.4 is a theoretical curve that represents the failure behavior of a system for repairable systems (Ascher and Feingold, 1984). Facility life cycle is divided into three main phases. First phase of the graph is called “burn-in-phase". This phase represents early lives of the system, failures occur at a relatively high rate, since the stable defect type causes failures (Muhlbauer, 2004). From Table 2.1, manufacturing-related defects, welding/fabrication related, and equipment failure types are observed in the burn-in-phase. These failures may be eliminated when operators start operating the pipe. The second phase is called "constant failure phase". This period represents random failures such as third party damage, weather-related and outside force, and incorrect operational problems. Failure rate is fairly constant on the phase. The last zone is "wear-out phase". The components of pipeline complete their useful service life in this zone, so failure frequency starts to increase due to time-dependent (corrosion and fatigue) failure (Røstum, 2000; Muhlbauer, 2004; Nachlas, 2005).

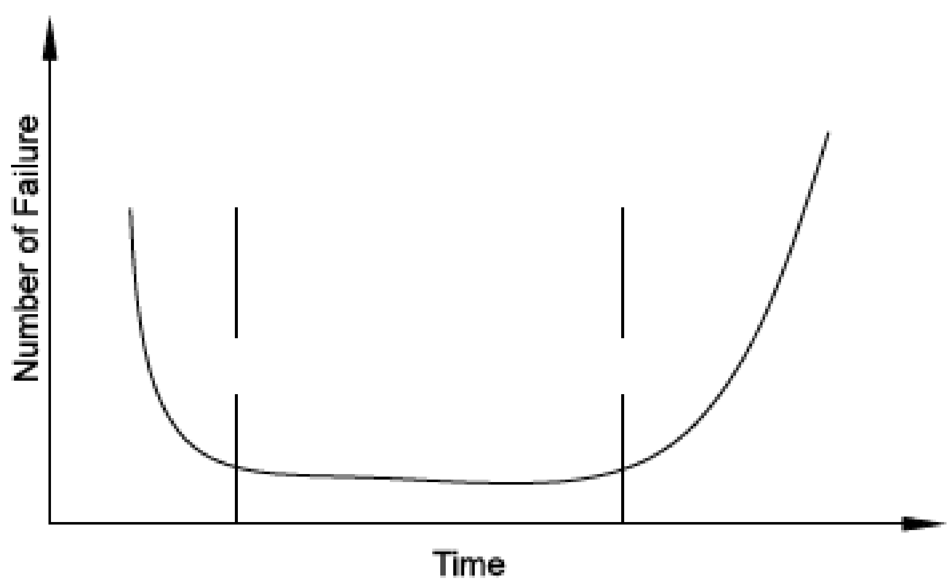


Figure 2.4 Repairable System Bathtub Curve

Companies and researchers have extensively studied the causes of pipeline failures (Thompson, 2004; Baker Jr., 2008; Baker Jr., 2009). The main sources of data are the annual incident reports that are produced by governments, non-profit organizations, researchers, and institutions (Andersen and Misund, 1983; European Gas Pipeline Incident Data Group (EGIG), December 2011). The purpose of these studies is to provide basic information about pipeline failures, frequency, and to spread awareness on pipeline safety. For example, essential information of incidents such as frequency, nature of incidents, and causes of failures are available for the United States, Canada, and Europe, from PHMSA, the Canadian National Energy Board (NEB), and the European Gas pipeline Incident data Group (EGIG), respectively (Baker Jr., 2009). An illustrating example of these reports is reported incidents that have been collected by the fifteen major gas transmission system operators in Europe since 1970, were analyzed by the European Gas pipeline Incident data Group (EGIG, 2008) (Baker Jr., 2009). It is important to note that those analyses are very useful for researchers. However, each pipeline system has its own designed, so databases should not be compared with each other easily.

Previous studies show that wear-out phase is the most important phase for maintenance and renewal strategies (Røstum, 2000; Papadakis, 1999). Pipeline failures frequency starts to increase on wear-out phase due to time. Moreover, pipeline operators seek for options to extend the life of the pipeline system with accurate maintenance decisions. As, most of the studies focus on the failures happening in the wear-out phase (Kermani and Harrop, 2008; Song, 2011; Gomes et al., 2013).

In the gas industry, the corrosion is the most common threat to pipeline integrity in wear-out phase (Thompson, 2004; Ahmad et al., 2011). Corrosion leads to leaks and ruptures (Baker Jr., 2008). Stated in other words, corrosion represents a process that increases probability of failures over time (Gomes et al., 2013). Baker Jr. (2009) implied that corrosion has been responsible for almost 23 percent of significant failures. Moreover, 40 to 65 significant corrosion incidents per year were observed onshore and offshore gas transmission pipelines from 1988 to 2008 in the U.S. The EGIG report (2008) showed that corrosion was the second most important failure cause after external interference failures.

From the operation point of view, the failures due to corrosion represent the biggest problem for pipeline operators. Corrosion costs approximately \$5.4 to \$8.6 billion annually to the transmission pipeline operators (Thompson, 2004). Annual operation and maintenance cost associated with corrosion is 15 percent of total operation and maintenance cost. According to Baker's report (2008), corrosion leads to \$7 billion of total cost to the oil and gas industry annually.

Corrosion is a process of destruction or deterioration of a material because of the reaction with its environment (Patel, 1969; Baker Jr., 2008). In other words, corrosion is chemical or electrochemical oxidation of metals in reaction with an oxidant. Corrosion on the wall of the steel pipeline may occur anytime internally or externally (Thompson, 2004).

Well-developed reliability models depend on failure characteristics; therefore cause of corrosion should be understood well. Corrosion depends on several factors. For example, internal corrosion occurs when corrosive liquids are carried through the pipelines (Thompson, 2004). In detail, internal corrosion depends on the amount of the liquid water in the natural gas and chemical components of gas such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), oxygen (O_2), flow velocity, density, temperature, surface condition of the steel, and presence of bacteria in the natural gas. Those factors cause different internal corrosion types like uniform corrosion, pitting or crevice corrosion, erosion-corrosion, and microbiologically influenced corrosion (MIC) (Thompson, 2004; Song, 2011; Ahmad et al., 2011). Conversely, external corrosion mainly occurs due to soil environment (types, moisture, level of salts, or bacteria), coating degradation (disbandment) or local damage of the external coatings (holiday), inadequate cathodic protection (CP), and alternating current or direct current interferences (Rajani and Kleiner, 2001).

The main problem is the corrosion cannot be controlled fully, as pipelines interact with its environment that naturally triggers corrosion process. However, the corrosion process can be mitigated with proper corrosion prevention strategies (Alfon et al., 2012). These strategies relate to the models that formulate the expected number of failures in future. Therefore, the estimation of number of failures plays a fundamental role for future operation. The expected number of failures can be predicted with statistical models. The following subsection summarizes the previous research in statistical modeling.

2.3 Statistical Models to Predict Pipeline Failures

Modeling of the pipeline systems' failures is the second step in reliability analysis of pipeline networks (Røstum, 2000). Reliability analysis is commonly used for describing the failure behavior of a system. Therefore, reliability plays a key role to improve system performance. A good prediction of the expected number of failures can be used in an economic analysis of repair versus replacement option. Statistical models can help companies develop more accurate maintenance decisions and eliminate or reduce future operating expenditure (OPEX). Therefore, pipeline operators can avoid unnecessary operation such as early repair or removal of a pipeline coating (Røstum, 2000).

The system reliability depends on system characteristics that in case of pipelines can be defined as non-repairable and repairable. A repairable system was defined as: " a system which, after failure to perform at least one of its required functions, can be restored to performing all of its required functions by any methods, other than replacement of the entire system" by Ascher and Feingold (1984).

Majority pipeline system repairs typically involve a replacement of only a very small component or part of a system rather than replacing the entire system because repairing the pipes is the most practical and economical rehabilitation approach. The natural gas transmission pipeline networks therefore are considered to be repairable systems (Rigdon and Basu, 2000; Røstum, 2000; Caleyo et al., 2008). For example, Røstum (2000) evaluated statistical methods for modeling pipe failures for individual pipe in a water distribution network. The water pipeline networks are considered to be repairable systems (Røstum, 2000).

The measures of system reliability involve the specification of probability distributions (Nachlas, 2005). There are some of the commonly used probability distributions for repairable systems such as the exponential, Weibull, and gamma. The selection of proper distribution is important for good prediction the probability of failure in a certain interval. The Weibull distribution is a good choice for repairable systems. First, it is probably the most widely used distribution for the life lengths of very many devices (Nachlas, 2005). Second, the Weibull distribution is related to the power law process, which is a commonly used model for repairable systems (Rigdon and Basu, 2000). Another advantage of the Weibull distribution is that it provides a graphical plot that illustrates cumulative probability of failure against the age to failure (Mohitpour et al., 2007). The cumulative failure rate plot's slope is beta that is defined as shape parameter. Beta >1 indicates increase in wear-out failures, beta = 1 shows constant failure rate, and beta<1 denotes a decreasing failure rate on the "bathtub curve" (Mohitpour et al., 2007).

The pattern of failures, which denotes the times between successive failures of a single repairable system, is very important for reliability analysis (Ascher and Feingold, 1984). There are two mathematical models for defining the pattern: stochastic point processes and differential equations. Ascher and Feingold (1984) defined the stochastic point process as: "a mathematical model for a physical phenomenon characterized by failures events distributed randomly in time". The most popular stochastic point processes, which can be applied to repairable systems, are the homogeneous Poisson process (NPP), the nonhomogeneous Poisson process (NHPP), the renewal process, and superimposed renewal process (SRP) (Ascher and Feingold, 1984). Also, Caleyo et al. (2008) emphasized that the pipeline systems refer to a group of natural gas pipelines, which are modeled by the same point stochastic process. In contrast, differential equations are quite different than the point process approaches. These equations are very useful for reflecting known underlying mechanisms, which contribute to reliability growth (Ascher and Feingold, 1984).

The ROCOF plays an important role in selecting a model for a repairable system. The ROCOF of the pipeline systems contains the information about the likelihood of a failure at any time t and how the system ages over time. In other words, the ROCOF measures reliability of a repairable system (Rigdon and Basu, 2000).

The selection of appropriate repairable system models depends on how the system is affected by failures and repairs (Rigdon and Basu, 2000). In general there are five repair (maintenance) actions: minimal, renewal (or prefect), imperfect, worse, and the worst repair (Wang and Pham, 2006). Rigdon and Basu (2000) defined the minimal repair as "the repair done on a system leaves the system in exactly the same condition as it was just before the failure". In the same book, they defined renewal (or perfect) repair as; "the system is brought to a like new state after the repair". In other words, it refers to the "good-as-new". It is assumed that imperfect repair restores the system operation condition somewhere between "as good as new" and "as bad as old". The rest of repair actions lead to the system fail or breakdown (Wang and Pham, 2006). Rigdon and Basu

(2000) state that the minimal repair model leads to the NHPP and the renewal repair model leads to the renewal process.

Although, the renewal assumption represents many maintenance situations such as single cell components, a large proportion of the practical maintenance situations are not well represented in the renewal assumption. As Coetzee (1997) emphasized minimal repair represents the majority of the maintenance situations.

Louit et al. (2009) imply that for complex systems such as distribution networks each component has different failure modes. Repair actions are generally specific for each failed part. Each failure affects only one small section of the entire system; therefore, repair action does not have a significant effect on the complete system's probability of failure. Due to fact that, repair actions leave the rest of the system's failure rate unchanged. In this kind of situation, the failure pattern of the system can be commonly represented by NHPP. NHPP assumes that maintenance (repair) actions return the system to its previous state. This is referred to as minimal repair (Louit et al., 2009). Røstum (2000) explained this situation for water pipes networks; pipeline systems could be restored to operation requirements by some minimal repair process other than replacement of the entire system. Therefore, pipeline system's reliability, after repair process, is defined as "bad-as-old". The risk of the entire pipeline system would only be modified after a significant maintenance operation, such as recoating of the entire system. Due to the behavior of the pipeline system, repairable system assumption is reasonable with minimal repairs only. This assumption causes that system reliability is modeled as a non-homogeneous Poisson process (NHPP) (Ascher and Feingold, 1984; Pievatolo and Ruggeri, 2004).

Many studies have been conducted to develop statistical reliability models using historical failure data. Majority of studies in pipeline reliability relate to water supply network failures due to data availability (Røstum, 2000; Kleiner et al., 2001; Rajani and Kleiner, 2001). Hence, it is difficult to find in the published literature reliability analyses for natural gas pipeline systems.

Although there is limited study for natural gas pipelines, majority of other studies are related to repairable systems such as power distribution systems or water distribution systems (Stillman, 2003; Rajani and Kleiner, 2001). One example was found for natural gas pipeline system. Caleyo et al. (2008) conducted a study to estimate the failure rate of a pipeline population from the historical failure data, which are pooled from multiple pipeline system in Southern Mexico. In the study, Caleyo et al. (2008) emphasized that the study was conducted on the basis of the statistical methods for reliability of repairable systems (Caleyo et al., 2008).

Due to the limited sources for natural gas pipeline system reliability study, repairable system reliability process and analysis are used for natural gas transmission pipeline systems. The basic process of modeling corrosion failure rate for pipeline systems is discussed in details in the next subsection.

2.3.1 Failure Function

The actual failure characteristics of systems are generally based on the analysis of observed failure data. When data is obtained from the system, the parameters of life distribution or reliability of the system can be determined. The estimations of the parameters of the life distribution are called parametric statistical methods (Nachlas, 2005).

The analysis of previous failure data is mentioned in many articles. Røstum (2000) emphasized that the most important factor to predict future failures in water supply network is previous failures. Further, the age is an important element to estimate the first failure on water supply network. Similarly, Kleiner and Rajani (2001) stated that the previous historical failures could be used to identify pipe breakage patterns. They assume that historical failure pattern will continue into the future. Therefore, probability of breakage can be estimated with statistical methods. Previous authors used statistical methods to predict failure rate of water main breaks by way of the past failures.

Parametric statistical methods for analyzing reliability data require an assumption of the form of the life distribution. The choice of a distribution model depends on experience about similarity of the systems. With the estimation of the parameters, reasonable representation of the failure probabilities can be obtained (Nachlas, 2005).

First, the basic parameters of parametric statistical estimation of failure rate are discussed. Failure rate can express reliability for repairable system (Mohitpour et al., 2010). Also, Caleyo et al. (2008) use this fact in their study and they emphasize that the term of "failure rate" is used in the ROCOF. Hence, the reliability of pipeline network is represented by failure rate. N(t) denotes the number of failures in the intervals (0,t] in a pipeline system. The rate of occurrence of failure (ROCOF, $\mu(t)$) and the failure intensity (rate) function ($\lambda(t)$) of a point process are given in Equation 2.1 and Equation 2.2, respectively (Rigdon and Basu, 2000; Caleyo et al., 2008).

$$\mu(t) = \frac{d}{dt}(E(N(t))) \tag{2.1}$$

$$\lambda(t) = \lim_{\Delta(t)\to 0} \frac{P[N(t,t+\Delta(t)\geq 1]}{\Delta(t)} \tag{2.2}$$

where E($N(t)$) denotes the expected number of failures in the interval (0,t] in a pipeline system.

Rigdon and Basu (2000) noted that the intensity function and the ROCOF are measures of the reliability of a repairable system. They proved that these two functions are equal, provided that simultaneous failures cannot occur. Caleyo et al. (2008) stated that this assumption is reasonable for pipeline systems, in which simultaneous failures occur with a probability very close to zero.

If failure mechanisms do not depend on time, failure rate shows a constant failure rate. Therefore, failure mechanisms, which have a constant failure rate, can be modeled using a homogenous Poisson process (HPP) with constant failure rate (λ) (Caleyo et al., 2008). On the other hand, if the systems deteriorate or improve their reliability with time, the failure rate of the system can be modeled using the nonhomogeneous Poisson process (NHPP) (Caleyo et al., 2008). The following subsection summarizes the previous research for the estimations of parameters of life distribution and parametric statistical methods for the failure rate.

2.3.2 Parametric Estimation of the Failure Rate

As mention previously, pipeline systems are defined as repairable system, which can be modeled with a stochastic process. Poisson distribution is one of the important processes used in the modeling of repairable systems (Rigdon and Basu, 2000). Two types of stochastic point process are commonly used in modeling pipeline failures: the homogeneous Poisson process (HPP) and the nonhomogeneous Poisson process (NHPP).

2.3.2.1 The Homogeneous Poisson Process

The homogeneous Poisson process (HPP) is a Poisson process with an intensity function that is constant (Rigdon and Basu, 2000). The HPP is one of the simplest possible models for repairable system. However, it should be applied with caution because the HPP model cannot be used to model a system that deteriorate or improve over time. Therefore, only table and time-independent failures from Table 2.1 can model by a homogeneous Poisson process (HPP) with constant failure rate (λ) (Rigdon and Basu, 2000). The HPP is characterized by exponentially distributed times between failures.

The pipeline system failures are assumed to be time truncated. Rigdon and Basu (2000) defined the terminology as when a system could be observed until a predetermined time t, the number of failures N(t) is a random variable. The predetermined time, t, is T_{obs} for the pipeline systems in this thesis. The meaning of T_{obs} is observation time of the pipeline system. Therefore, the total number of failure in the observation time is $N(T_{obs})$ (Bain and Engelhardt, 1980; Rigdon and Basu, 2000; Caleyo et al., 2008).

Basically, the failure rate of the pipeline system can be predicted with Equation 2.3 (Caleyo et al., 2008).

$$\hat{\lambda} = \frac{N_{(T_{obs})}}{L_{exposure}T_{obs}} \quad (2.3)$$

where $N(T_{obs})$ is the total number of failures in the observation time in observing pipeline system, T_{obs} is the observation time (year), and $L_{exposure}$ is total length of the pipeline system (mile) that is observed. Pipeline conditions are assumed uniform throughout the line in the studied section. The failure rate of a pipeline has the unit of number of failures per year and per unit of length of the pipeline, 1/(mile-year) or "per mile year" (Caleyo et al., 2008).

The statistical uncertainty of failure rate can be determined with a significance level α. The quantity $2\lambda T_{obs}$ has a chi-square distribution (χ^2) with $2N(T_{obs})$ degrees of freedom for the HPP truncated at time T_{obs}. The Equation 2.4 shows the 100(1-α)% confidence interval for λ (Caleyo et al., 2008; Rigdon and Basu, 2000).

$$\frac{\chi^2_{1-\alpha/2}(2N(T_{obs}))}{2L_{exposure}T_{obs}} < \lambda < \frac{\chi^2_{\alpha/2}(2N(T_{obs}))}{2L_{exposure}T_{obs}} \quad (2.4)$$

2.3.2.2 The Non-Homogeneous Poisson Process (NHPP)

As mentioned in the beginning of this subsection the minimal repair assumption leaded to the nonhomogeneous Poisson process (NHPP). The NHPP plays an important role for improvement of failure analysis techniques for repairable systems (Coetzee, 1997; Krivtsov, 2007).

Continuous growth models, especially power law model, are suitable for the pipeline systems. As mentioned previously, point process models are divided into NHPP reliability growth models and alternative reliability growth models (Ascher and

Feingold, 1984). Power law model is defined under NHPP reliability growth models (Ascher and Feingold, 1984; Pievatolo and Ruggeri, 2004).

The nonhomogeneous Poisson process (NHPP) is a Poisson process with an intensity function that is non-constant (Rigdon and Basu, 2000). The NHPP is similar to the HPP with the exception that the expected number of failures is the function of time (Moghaddam and Usher, 2011). The NHPP can be used to model the systems that deteriorate or improve over time. Hence, the NHPP can be used to model the failure process of repairable systems (Rigdon and Basu, 2000; Krivtsov, 2007).

Coetzee (1997) discussed the selection criteria for implementation of the NHPP model. First, the NHPP is a suitable model whether there is a trend in the times between failures. Second, if the system can be defined as the "bad-as-old ", the NHPP can be selected for modeling data. Third, if the systems are defined as repairable systems, again the NHPP is a good choice for modeling data. Characteristic of the pipeline failures match up with these selection criteria.

As discussed at the beginning of third subsection, the cumulative number of failures is indication used in the reliability analysis (Nachlas, 2005). In addition, the NHPP is characterized by the cumulative intensity function, $\Lambda(t)$, which represents the expected cumulative number of failures as a function of operation time (Krivtsov, 2007). Krivtsov (2007) defined the cumulative intensity function as: $\Lambda(t) = \int_0^t \lambda(t)dt,$ where $\lambda(t)$ is known as ROCOF.

The intensity of the NHPP can be determined with a number of different parametric models such as power law model, the linear model, and the log-linear model.

The power law model is most commonly used technique in the literature. In the next subsection, the power law model is discussed.

2.3.2.2.1 Power Law Process

Power law model is considered to represent the NHPP. In fact, the NHPP is commonly referred as the power law process. Rigdon and Basu (2000) explain this situation as special case of the NHPP, where ROCOF is proportional to the global time t raised to a power. Also, the power law model is sometimes referred as a Weibull process, since the intensity function has the same functional form as the hazard function of the Weibull distribution (Røstum, 2000).

The power law process is a model when the intensity function has the form $\lambda(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1}$, where $\beta > 0$ and $\theta > 0$ (Rigdon and Basu, 2000; Caleyo et al., 2008).

The functional form of the expected number of failures for the pipeline system and the intensity function of pipeline failures through time t are shown in Equations 2.5 and 2.6 (Rigdon and Basu, 2000):

$$E[N(t)] = \Lambda(t) = (t/\theta)^{\beta} \tag{2.5}$$

$$\lambda(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} \tag{2.6}$$

where $\theta>0$ and $\beta>0$ are the scale (the characteristic life) and shape parameters of the failure intensity function, respectively.

The estimator β affects how system deteriorates or improves over time and θ is a scaling follow (Stillman, 2003; Rigdon and Basu, 2000). If:

- $\beta > 1$, $\lambda(t)$ is increasing, the failures tend to occur more frequently; if

• $\beta < 1$, $\lambda(t)$ is decreasing, and the failures are less frequent; and if

• $\beta = 1$, the power law process reduces to a HPP, with intensity = $1/\theta$.

As noted before, the time truncated case can be used for the pipeline failure data at T_{obs}. Let $T_1<T_2<\ldots<T_N<T_{obs}$ denote the observed failure times before time T_{obs}. If the failure data is assumed that at least one failure occurs before time T_{obs}, the maximum likelihood estimators exist and are equal to (Rigdon and Basu, 2000):

$$\hat{\theta} = \frac{T_{obs}}{N_{(T_{obs})}{}^{1/\beta}} \qquad (2.7)$$

$$\hat{\beta} = \frac{N_{(T_{obs})}}{\sum_{i=1}^{N_{(T_{obs})}} \log(T_{obs}/t_i)} \qquad (2.8)$$

where t_i is the time of the *ith* failure and $N(T_{obs})$ is the total number of failures in the observation time in observing pipeline system.

Based on the maximum likelihood estimations, the intensity function of the failure process can be estimated with Equation 2.9.

$$\hat{\lambda}(t) = \frac{\hat{\beta}}{L_{exposure}\hat{\theta}^{\hat{\beta}}} t^{\hat{\beta}-1} \qquad (2.9)$$

The statistical uncertainty of β can be determined with a significance level α. The quantity $2N_{(T_{obs})}\,\beta/\hat{\beta}$ has a chi-square distribution (χ^2) with $2N(T_{obs})$ degrees of freedom for a power law process truncated at time T_{obs}. The Equation 2.10 shows the $100(1-\alpha)\%$ confidence interval for β (Caleyo et al., 2008; Rigdon and Basu, 2000).

$$\frac{\chi^2_{1-\alpha/2}(2N(T_{obs}))\hat{\beta}}{2N(T_{obs})} < \beta < \frac{\chi^2_{\alpha/2}(2N(T_{obs}))\hat{\beta}}{2N(T_{obs})} \qquad (2.10)$$

Caleyo et al. (2008) state that there is not any method to determine the exact confidence intervals for θ when the data are time truncated. Rigdon and Basu (2000) emphasized that confidence intervals for θ are usually not computed when the data are time truncated.

It is important to note that, it is often to test H_0: β=1 versus H_1: β≠1 as the power law process reduces to the homogeneous Poisson process when β=1 (Rigdon and Basu, 2000). In other words, the null hypothesis is: the best model is a HPP, while the alternative is: the power law process is the best. The rule is to reject H_0 if (Rigdon and Basu, 2000; Caleyo et al., 2008).

$$\chi^2_{\alpha/2}\left(2N_{(T_{obs})}\right) < \frac{2N(T_{obs})}{\hat{\beta}} \text{ or } \frac{2N(T_{obs})}{\hat{\beta}} > \chi^2_{1-\alpha/2}\left(2N_{(T_{obs})}\right) \tag{2.11}$$

2.4 Preventive Maintenance Methods

As mentioned in the first subsection, pipeline operators try to avoid pipeline failures because it may lead to significant injuries and fatalities, environmental issues, product loss, and property damages. Not only the nature of the failure events but also the frequency of failures are very important for the safety. These results force the companies to avoid pipeline failures and to use their available funds more effectively for preventive maintenance actions. At that point, developing an optimum corrosion prevention strategy plays a key role to extend the useful life, to improve the system reliability, and to reduce the rate of occurrence of failures of transmission pipelines (Nachlas, 2005).

Maintenance helps the operators to use the resources more efficiently. Although the pipelines are designed, conducted, and operated correctly, deterioration occurs on the line internally or externally, directly or indirectly (Mohitpour et al., 2010). Therefore, routine maintenance activities are crucial to keep the pipeline operation safe (Mohitpour et al., 2010). Maintenance policies help decrease the unexpected failures and reduce

OPEX. For example, Baker Jr. (2008) emphasized that, although the failure pattern was consistent over time, the pattern was not affected by the aging of the infrastructure (Baker Jr., 2008). Due to the this reason, Baker Jr. (2008) did not observe any significant increase for pipeline failure from 1988 to 2008, due to the effectiveness of the industry efforts to control corrosion (Baker Jr., 2008). Moreover, the pipeline system reliability can be maximized and failure costs can be minimized with proper maintenance decisions (Wang, 2002).

Maintenance can be defined as actions to: 1) control the system's deterioration process which leads to failure and 2) restore the system to its operational state, through corrective actions after a failure (Blischke and Murthy, 2000). Under the same scope of maintenance, Mohitpour et al. (2010) define the pipeline system maintenance objectives is as "The primary purpose of any pipeline maintenance program is to maximize throughput and prolong the life of a pipeline system while ensuring public safety and respecting the environment" (Røstum, 2000; Thompson, 2004; Mohitpour et al., 2010).

Reliability and maintenance are closely related to each other. Nachlas (2005) defined reliability as: "Reliability is the probability that a device properly performs its intended function over time when operated within the environment for which it is designed." It follows from here that the equipment or the device can be operated correctly within design limits by maintenance (Mohitpour et al., 2010). Due to above definition, the first step of the optimal maintenance policy is to determine system reliability (Wang and Pham, 2006).

Maintenance actions can be divided into two major classes: preventive maintenance and corrective maintenance (Wang, 2002). Preventive maintenance (PM) is a broad term that involves a set of activities to improve the overall system reliability. These activities are planned activities such as monitoring, cleaning, CP, testing, patrolling, training, repair, and replacement (Nachlas, 2005). For all types of systems, the manufacturer or operators prescribe maintenance schedules to reduce the risk of system failure (Moghaddam and Usher, 2011). Mohitpour et al. (2010) summarize required performance and time by code requirement for routine maintenance activities in Table 2.2 for corrosion type failures. For example, cathodically protected pipeline systems must be controlled annually, and the interval between two-inspections cannot exceed 15 months (Baker Jr., 2008). Corrective maintenance (CM) or emergency repair (ER), on the other hand, implies emergency response (unscheduled) that is performed as a result of the failure like a rupture or a leak (Wang, 2002). Corrective maintenance involves often replacement or repair to a section of a pipeline to restore the system from a failed state to a specified condition (Mohitpour et al., 2010).

Previous studies shows that a significant number of maintenance actions are performed as corrective maintenance in pipeline systems (Røstum, 2000; Thompson, 2004; Baker Jr., 2008). The meaning of the CM is that failures occur before measures are taken.

Table 2.2 Routine Maintenance Schedules of Major Pipeline Elements (Mohitpour et al., 2010)

Maintenance Activity	Maintenance Schedule or Frequency	Requirement or Remarks
CP monitoring	Annual, not to exceed 15 months	ASME B31.1 (1999)
Internal Corrosion Monitoring	<6 months	ASME 31.4 (1998): if line internally coated, pigged, dehydrated/corrosion inhibition, corrosion coupon used
Exposed pipe: External monitoring	<3 years	ASME B31.4 (1998)

On the other hand, preventive maintenance determines the maintenance requirements by providing systematic inspection, detection and prevention of incipient failures (Wang, 2002). Preventive maintenance requires a good knowledge of the pipeline characteristics, including whole variables that affect pipeline performance (Mohitpour et al., 2010; Røstum, 2000).

As previously discussed, the main purpose of maintenance actions is to improve the system reliability and to prevent the probability of system failure (Wang and Pham, 2006). However, there are varieties of possible applications of PM policies (Nachlas, 2005). Therefore, in the last several decades, a number of different preventive maintenance optimization models have been proposed to establish the optimal maintenance policies. Barlow and Hunter (1960), Nakagawa (1981), Nakagawa (1986), Valdez-Flores and Feldman (1989), Wang (2002), and Wang and Pham (2006) survey and summarize the research and practice in reliability, maintenance, replacement, and inspection in different ways. It is important to note that, discussing all maintenance models are beyond the scope of this thesis. However, general information and a few models are discussed in this thesis.

As discussed in the third subsection, the system operating condition can be classified according to how the system is affected by maintenance, and then five repair (maintenance) actions are discussed. For instance, in some cases, maintenance involves the replacement of a component of the system before to failure. In contrast, maintenance actions sometimes consist of simple inspection and testing (Nachlas, 2005). Due to these reasons, each of the maintenance policies depends on maintenance costs and/or different maintenance restoration degrees (minimal, imperfect, perfect) (Wang, 2002).

In the literature, there are two main replacement-types of preventive maintenance policies: age replacement and block replacement policies (Nachlas, 2005).

Age replacement policy means that the system is replaced when the system achieves an age equal to the policy age. The earliest age replacement policy considers that the system is replaced by a new one after each preventive maintenance or ER. The policy considers renewal theory-based models for system performance. Therefore, systems are repaired to the “good-as-new” condition at each repair action due to renewal model assumptions. However, maintenance practice showed that a system or equipment continues to deteriorate even when the system or equipment was renewed. Although PM reduces failure probability, it does not restore the system operation condition to a “good as new” state. Therefore, renewal models are not suitable for many real systems (Coetzee, 1997; Gertsbakh, 2000; Nachlas, 2005).

As an alternative to renewal process, minimal repair models are proposed. The earliest minimal repair models were suggested by Barlow and Hunter (1960) (Nachlas, 2005). This model assumes that the system failure rate is not disturbed by any minimal repair of failures and the system is replaced at predetermined times (Nguyen and Murthy, 1981). In other words, the minimal repair eliminates the failure but leaves the failure rate unchanged (Gertsbakh, 2000; Nachlas, 2005). For pipeline systems, the failure rate increases with age; therefore, operation of the system would become increasingly expensive to maintain by minimal repairs. Thus, the main problem of the minimal repair models is when replacement actions are optimal instead of performing minimal repair (Valdez- Flores and Feldman, 1989).

Minimal repair models generally assume that 1) the failure rate function of the system increase, 2) minimal repairs do not affect the system's failure rate, 3) the cost of a minimal repair is less than the cost of replacing, and 4) system failures are detected immediately (Valdez- Flores and Feldman, 1989).

With the concepts of minimal repair and imperfect maintenance, these models were improved. These new established models are referred to as the age-dependent PM policy. This policy assumes that a system is preventively maintained at some predetermined age, or repaired at failure until a perfect maintenance is received (Wang, 2002). Wang (2002) noted that PM at the predetermined age and CM at each failure might be minimal, imperfect, or perfect. Therefore, many maintenance models are developed based on different types of PM (minimal, imperfect, perfect), CM (minimal, imperfect, perfect), cost structures, etc. (Wang, 2002). On the contrary, if a system is repaired with only minimal repair at failure, the age replacement policy reduces to “the periodic replacement with minimal repair at failure” policy (Wang, 2002).

Periodic (block) replacement policy is based on scheduled actions rather than on the system age. As is the case with age replacement policy, the earliest studies consider that the system is replaced by a new one after each preventive maintenance or ER. However, with the concepts of minimal repair and imperfect maintenance, another PM periodic policy is established. This model is called “periodic replacement with minimal repair at failure” policy in which a system is replaced at predetermined times and failures are removed by minimal repair (Wang, 2002). Also, this policy was introduced firstly by Barlow and Hunter (1960) as policy II.

Many extensions and variations are proposed for periodic replacement with minimal repair at failure policy. Nakagawa (1981) studies four models of modified periodic replacement with minimal repair at failures. The first three models study a failure that occurs just before the replacement time is specified. The last model considers failure, which occurs well before replacement time. The last model suggests that the system is replaced at failure or at time, whichever occurs first. All models obtain the optimum T_0^*,T^* to minimize the cost rates, when T is the replacement time which minimizes the expected cost rate for the basic replacement model. If $0<T_0^*<T$ and $T^*>T$, exists, then the models have a lower cost rate (Nakagawa, 1981; Wang, 2002).

Costs of PM can be optimized based on an optimal maintenance cost models. The cost models for these PM policies can be formulated without considering the maintenance time. Basically, the preventive maintenance costs can be divided into three:

failure costs, maintenance costs, and replacement costs. The final cost of the preventive maintenance is a function of the all the actions taken in the life cycle of the system (Moghaddam and Usher, 2011). Therefore, the total cost per unit time is an informative measure of system performance (Nachlas, 2005).

The preventive maintenance costs can be divided into three: failure costs, maintenance costs, and replacement costs. The final cost of the preventive maintenance is a function of the all the actions taken in the life cycle of the system (Moghaddam and Usher, 2011).

There are many approaches to determining the optimal maintenance policy. Under the scope of this thesis, selected approach for cost model considers the maintenance interval, which minimizes the total expected cost per unit time for the system. The cost per unit has to take into account both costs associated with failures, and costs of the PM (replacement). The optimization problem can be pictured as shown in Figure 2.5. It can be observed on Figure 2.5 that with low level of PM action, the PM cost is low but the expected CM costs are high. With increasing PM action, the CM cost decreases and the PM cost increases as shown in Figure 2.5. Moreover, the total cost that includes PM and CM decreases initially and then increases with increasing PM action. Therefore, there is an optimum level of PM effort that can minimize the total costs of maintenance (Damnjanovic, 2006; Louit et al., 2009; Blischke and Murthy, 2000).

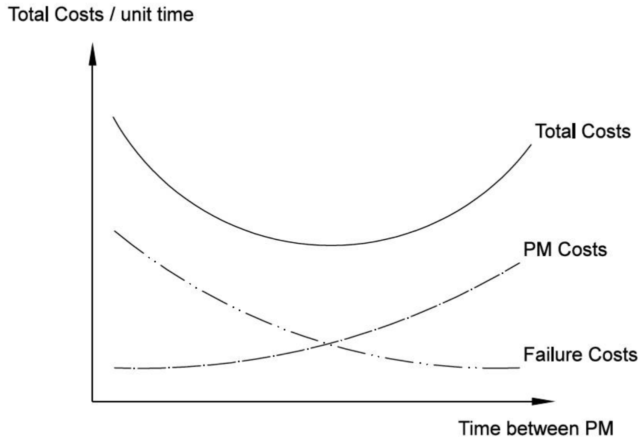


Figure 2.5 Optimal PM Intervals for Costs Minimization

The optimal maintenance interval can be solved with a fixed interval. Therefore, the fixed interval problem will be solved with the block replacement policy. The advantage of the fixed interval policy is easy practical implementation (Louit et al., 2009).

The cost models for the block replacement policy are formulated without considering the durations of the maintenance exercises. As mentioned previously, the costs represent the implications of failure and of planned replacement. Hence, the total cost per unit time is an informative measure of system performance (Nachlas, 2005). In the view of such information, a model for the total cost per unit time for a block replacement PM strategy is described in Equation 2.12 (Louit et al., 2009; Nachlas, 2005).

$$C(T) = \frac{C_{repair}E\big(N(T)\big)+C_{replacement}}{T} \tag{2.12}$$

where, C(T) is the expected cost per unit time given a PM interval equal to T, E(N(T)) is the expected number of failures in [0,T], $C_{replacement}$ is the average cost of system replacement, and C_{repair} is the average cost of repair of a failure through minimal repair.

Louit et al. (2009) suggested that E(N(T)) should be estimated for different failure modes separately such as internal corrosion and external corrosion. Therefore, Equation 2.12 is modified for incorporating multiple failure modes that is given in Equation 2.13 (Louit et al., 2009).

$$C(T) = \frac{C_{repair} \sum_{i=1}^{m} E\big(N_i(T)\big) + C_{replacement}}{T} \tag{2.13}$$

where, $E(N_i(T))$ is the expected number of failures for failure mode i, i=1,2,…,m.

The intensity of failures per unit time can be estimated with Equation 2.6 for particular types of corrosion failures. From the intensity function $\lambda_i(t)$, the expected number of failures $E(N_i(T))$ can be estimated for each failure mode. This calculation is given in Equation 2.14 (Coetzee, 1997; Gertsbakh, 2000; Louit et al., 2009):

$$E\big(N_i(T)\big) = \int_0^T \lambda_i(T)\, dt \tag{2.14}$$

This equation will give the cumulative number of failures in [0,T] for each type of corrosion failures.

2.5 Pipeline Protection and Corrosion Control Methods

Operators are rethinking and developing new maintenance strategies that may improve business outcomes (Mohitpour et al., 2010). Estimation of future pipeline failure rate is critical for developing the budgets for rehabilitation and replacement needs (Røstum, 2000). Therefore, the operators would like to apply the best maintenance strategy, which will give the most effective results (Mohitpour et al., 2010).

As discussed in the fourth subsection, the purpose of the maintenance is to minimize the overall costs of the system operation and to maximize the system reliability (Moghaddam and Usher, 2011). The overall costs include the failure costs (production cost), maintenance costs, and replacement costs. Another part of the maintenance is to make proper decision for replacement for the end of the life cycle of equipment and facilities.

Full replacement is not a cost-effective choice for pipeline operators after each occurrence of failure. As mentioned previously, pipeline systems are linear structures, and each failure affects only one small section of the entire system. Thus, the most appropriate approach is to repair the pipes until the failure costs clearly outweigh the replacement cost, or until new pipeline projects make replacement economically attractive (Røstum, 2000).

Thompson (2004) and Mohitpour et al. (2010) suggested replacement criteria, if the following conditions occur:

- Severe corrosion damage of a pipeline is not properly cathodically protected;
- Stress corrosion cracking is through a large area of pipeline;
- Performance is inadequate for current requirements;
- Reliability reduces below acceptable levels;
- Maintenance and technical support is no longer available;
- The increasing cost of operation and maintenance justifies replacement by similar or more suitable equipment.

Rehabilitation or replacement decisions should be properly timed. According to the case studies of replacement/rehabilitation policies by Thompson (2004), the average rehabilitation cost of the existing line is estimated to be approximately 60 percent of the replacement cost in 1996. Also, in the same study, rehabilitation cost to be estimated 40 percent to 80 percent of the new pipeline construction cost (Thompson, 2004). This study shows that early replacement decision can lead to large financial losses.

Moreover, to make a proper maintenance decision, the variables that affect the maintenance decisions must be analyzed well. The costs of maintenance are one of the crucial variables. The corrosion costs can be divided into two parts: direct and indirect. Direct cost includes annual test point cathodic protection surveys, maintenance coating operations, training, pipe inspection at excavations point, rectifier readings (monthly), casing and insulator inspection, CP maintenance and upgrades (including materials), record-keeping, and close interval survey (Kermani and Harrop, 2008; Thompson, 2004). The indirect cost, on the other hand, is related to third party activities. The indirect cost has a more complex structure because it is related to several factors like damages to the environment, disruption to the public, injury or fatality (judicial process), permits, property damages, and lost revenue because of pipelines being out of service due to ruptures (Thompson, 2004; Kermani and Harrop, 2008).

The pipelines must operate in design and operation requirements until the final decision of replacement time. Therefore, routine maintenance activities are crucial to keep the pipeline in operation requirements. Several pipeline protection and control methods have been established. It is important to note that each mitigation strategies depend on the individually threats which are given at Table 2.1.

As discussed in the second subsection, corrosion failures are considered in the scope of this study. Mitigating strategies are different for each type of corrosion mode. For instance, external corrosion preventing strategies are not a feasible option for internal corrosion. More specifically, internal corrosion treatment requires cutting out and replacing the sections of the pipeline that is affected. In contrast, cathodic protection and re-coating may protect the pipe from external corrosion factors (Thompson, 2004).

In the next subsection, corrosion preventing and mitigation maintenance methods are discussed for corrosion failure modes.

2.5.1 Pipeline Protection and Corrosion Control Methods for External Corrosion

External corrosion is a chemical or electrochemical phenomenon that occurs due to a reaction between the pipeline surface and the pipeline environment. Therefore, external corrosion can be controlled by altering the electrochemical condition field around the pipeline or disconnecting interface of pipeline from its environment. There are two main mitigation strategies for external corrosion: coating and cathodic protection (CP) (Thompson, 2004; Baker Jr., 2008; Mora- Mendoza et al., 2011).

Cathodic Protection (CP) is used for control of the corrosion of a metal surface by making it the cathode of an electrochemical cell (Peabody, 2001). For buried pipelines, if voltage around the pipe can be altered by CP technique, the rate of corrosion can be controlled. CP is needed only on the minute areas of pipes' surface that exposed its environment at local damage of the external coatings (holidays) rather than all pipelines' surface of an uncoated pipe (Mohitpour et al., 2010).

Coating is another technique used to prevent external corrosion. There are different coating techniques such as Fusion Bond Epoxy (FBE), bituminous enamels, asphalt mastic pipe, cold applied tapes, wax coatings, fused tapes, and three-layer polyolefin (Thompson, 2004).

However, pipeline surface cannot be protected fully by coating because it is impossible to produce a perfect line of coating. There are always coating flaws (holidays), there are due to the construction damage, inappropriate application, natural phenomenon, completed life cycle of coating, or soil stresses (Baker Jr., 2008; Thompson, 2004). When the coat has holidays, pipeline systems need more CP (Thompson, 2004). With poor coating, corrosion process can occur on the pipeline surface, even though appropriate CP levels are applied. Moreover, protecting bare pipeline with CP throughout pipes' length is not a cost effective method. Therefore, CP and external coating techniques are used together whenever possible to mitigate external corrosion (Thompson, 2004). The purpose of the coating is to reduce the amount of required protection area of the pipe as much as possible (Ireland and Lopez, 2000; Thompson, 2004; Beavers and Thompson, 2006; Baker Jr., 2008; Mora- Mendoza et al., 2011).

Older pipelines, installed before 1950s, might have many unprotected pipeline segments resulting in corrosion problems. Although major pipeline operators started to coat their line in the 1950s, they did not provide CP until it became a requirement to do so (Baker Jr., 2008). Following 49 CFR Part 192, the oil and gas industry has been familiar with mitigation and corrosion prevention (Thompson, 2004).

One of the important questions for developing external corrosion plan is determining the frequency of pipe coating. Coating deterioration starts when pipeline reaches to the end of the effective life cycle of coating. Because of this reason, CP and external coating techniques are used together whenever possible is. Deterioration of coating affects the success and cost of CP, directly. For this reason, the best way to extend pipeline operation-life is pipeline coating rehabilitation (recoating of the line). According to the Ireland and Lopez (2000), recoating saved 40 percent of cost versus replacement of coating (Thompson, 2004; Baker Jr., 2008; Ireland and Lopez, 2000).

2.5.2 Pipeline Protection and Corrosion Control Methods for Internal Corrosion

Internal corrosion is an electrochemical process. However, mitigating strategies are different than from external corrosion. For example, CP is not a feasible option for mitigating the efforts of internal corrosion. However, there are other mitigating the efforts of internal corrosion strategies such as dehydration, chemical treatment, periodic cleaning, and internal coating.

The most common method of preventing internal corrosion is dehydration (dewatering). Moisture-free gas (dry gas) does not cause corrosion because there is not any corrosive material in the gas (Thompson, 2004). Therefore, the pipeline operators need to control the amount of corrosive fluids such as moisture, oxygen, and CO_2 contents. In the natural gas pipeline, dehydration control is done through separation facilities. The purpose of the separation facilities is to remove the undesirable components from the gas before pumping the gas to the transmission pipelines. However, those components can reenter the pipelines by way of compressor stations, metering stations, valves, control stations and SCADA systems, or storage facilities (Thompson, 2004; Hacioglu, 2012).

The other option for preventing internal corrosion is chemical treatment (inhibitors and biocides). Chemical inhibitors are injected into the gas being transported to reduce the corrosion to an acceptable rate. Also, biocides are used to prevent microbiological activity. The chemical treatments are expensive prevention strategies because chemical treatment requires monitoring of the inhibitor additive and continuous injection of inhibitors or biocides (Thompson, 2004; Hacioglu, 2012).

Periodic cleaning of the line with smart pigs is another mitigating strategy. There are different kinds of pigs that are used for different purposes. During the cleaning operation, the pigs scrape the line and apply cleaning solution such as solvents, biocides, acids, and detergents when it passes through the line. The pigs remove the operation of debris from the line before leaving (Thompson, 2004).

The operators do not prefer internal coating, because the line must be disconnected from the service during the coating process. This result is loss of profit due to shutdown, so they prefer other mitigation and preventing methods for internal corrosion (Thompson, 2004).

As a summary, this section presents the literature review relevant to the overall objectives of the thesis and introduces the necessary background to analyze system reliability and optimal maintenance actions for pipeline systems. In the following section, the methodological framework of this thesis is formulated and discussed.

3. THE OVERALL METHODOLOGY

The next step of this thesis is to develop a mathematical representation of the pipeline system, its failures, and develop a model for determining optimal maintenance action. Figure 3.1 shows a schematic diagram of the research framework used for the reliability modeling and preventive maintenance strategies. The research framework involves six steps. First, the raw incident data is collected from PHMSA data sources. The data is then classified according to pipeline attributes such as diameter, installation year (service age), wall thickness, amount of property damage, cause of incidents, etc. Second, the failure intensity function is formulated based on whether the failure data is fit the homogeneous Poisson process (HPP) or non-homogeneous Poisson process (NHPP) (power law process). Third, the HPP is tested against the power law process for corrosion failure modes. The null hypothesis is H_0: $\beta=1$ versus H_1: $\beta\neq1$. Fourth, based on the null hypothesis results, a proper stochastic model is selected. If the system is suitable for NHPP, the power law parameters and their confidence intervals are estimated. If the HPP is suitable, the generic (constant) failure rate and the confidence intervals are evaluated. Fifth, the expected number of failures and the intensity functions of the failure are estimated for any time point and their confidence intervals are estimated with results of selected statistical models. Finally, the models for determining an optimal preventive maintenance schedule are developed based underlying point process. The following subsections present the details of the methodology framework and assumptions.

3.1 System Characterization

Pipeline systems refer to a group of natural gas pipelines. PHMSA does not provide detailed information about each line's length. PHMSA just provides total miles of pipe for each company by nominal size and decade of installation, so pipelines should be considered as a network instead of single line. Due to the above reason, pipeline systems are modeled as a network by a point stochastic process (Caleyo et al., 2008).

Success of the statistical models depends on the quality of the data. As discussed in Section 2, pipeline failures depend upon various factors such as maintenance types, maintenance time, pressure, diameter, employees' training level, environmental conditions, etc. It is very difficult to include these variables into reliability models. Also, failure data cannot be collected under similar conditions because lines in the same networks have different materials, soil conditions, construction techniques, installation years, and design requirements. Due to this reason, environmental variations and operational variations are assumed as uniform throughout the whole pipeline systems (Røstum, 2000). Moreover, due to the Code of Federal Regulations (49 CFR Parts 191, 195) and the effectiveness of the industry efforts to control corrosion, it is assumed that the pipelines are internally and externally protected by proper methods.

As noted in literature review, there are more than 1,000 natural gas pipeline operators. Working with all the companies' data requires time and more analysis. This study considers only the largest eleven natural gas operators' failure data that were chosen for this thesis. These companies hold almost 33 percent of natural gas pipeline networks in the United States.

The development of reliability models requires previous number of failure recorded. This research uses the historical failure data set include incidents from 2001 to 2011 and is used estimate the expected number of failures for the networks. In the Section 4, more detailed information about the selection criteria of the time interval are provided and discussed.

The expected number of failures of the system includes the unit of the number of failures per year and per unit length of the pipe.

3.2 Modeling Failures

The scope of this thesis is the developed statistical models for reliability of repairable systems. First, failure characteristics of natural gas pipeline system are defined. As noted in the literature review, the natural gas pipeline failure mechanisms have been classified under 22 root causes. Corrosion failures are considered in this study because corrosion failures rate are not a constant rate. In other words, corrosion failures deteriorate or improve over time. Therefore, statistical models require describing failures mode on wear-out phase for corrosion.

Characterization of failure, which depends on probability distribution of the number of failures, is the most important step of good predictions. The first step of characterization is to calculate failure rate for a taken time interval. Basically, failure rate can be figured out with a nonparametric estimate of the failure rate equation. Each statistical data has different distributions, as in the pipelines failures. After figuring out the failure rate, proper distribution fitting methods should be selected to fit probability distribution.

There are several probability distributions for modeling reliability as discussed in Section 2. Selecting the most appropriate methods of fitting of a probability distribution requires having good statistical knowledge. One of the distributions can fit better into probability distribution than others. Selections of the methods depend on the characteristics of the dataset.

The pipeline systems deteriorate or improve the reliability of the system over time. Also, the systems are defined as repairable systems and failure data has trend. Pipeline system, after the repair process, is defined as bad-as-old. This assumption causes reliability of repairable systems to be modeled as a non-homogeneous Poisson process (NHPP), mainly the Power Law process (Ascher and Feingold, 1984; Pievatolo and Ruggeri, 2004).

There is no statistical software available for handling the NHPP. Therefore, MATLAB® was chosen for solving these NHPP' equations and the shape parameters of power law process under the scope of this thesis.

3.3 Optimal Preventive Maintenance Methods

The pipeline operators are seeking not only the expected number of failures, but also an optimal solution to minimize potential failures in the future operation. As noted in the literature review, predictive models can be used to improve maintenance decisions. Therefore, the expected number of failure is a step towards a preventive maintenance. As noted in the literature review, there are number of corrosion mitigation strategies to prevent the lines. Although, these methods are used by majority of pipeline operators, the pipeline systems continue to deteriorate. Therefore, the rehabilitation and renovation plan should be prepared for each line. Optimization preventive maintenance involves these plans for future pipeline operation.

Optimization preventive maintenance refers to combining many situations and systems, then selecting the best solution from all feasible results. The usual selection criteria are based on maintenance cost measures such as expected maintenance cost per unit of time, total discounted costs, gain, etc. (Wang and Pham, 2006). First, proper maintenance policy is chosen for a repairable and maintainable system. There are number of optimal maintenance policies which depend on system characteristic. The pipeline systems consider to be repairable system with minimal repairs only. Therefore, the periodic replacement with minimal repair at failure policy is adopted in this study.

Second, the selected maintenance policy needs cost data that is related to maintenance and replacement cost to find optimal solution. The pipeline systems are complex systems and there is a limited source to find current costs information. Therefore, average costs are taken for related costs information.

As noted in in the literature review, the purpose of the maintenance is to minimize the overall operation costs and to maximize the system reliability. The optimal maintenance decision is an optimum level of PM effort that can minimize the total cost of maintenance. This decision can be developed with proper cost models. Finally, based on optimal maintenance policy, cost models are developed to find optimal maintenance time and minimum maintenance cost.

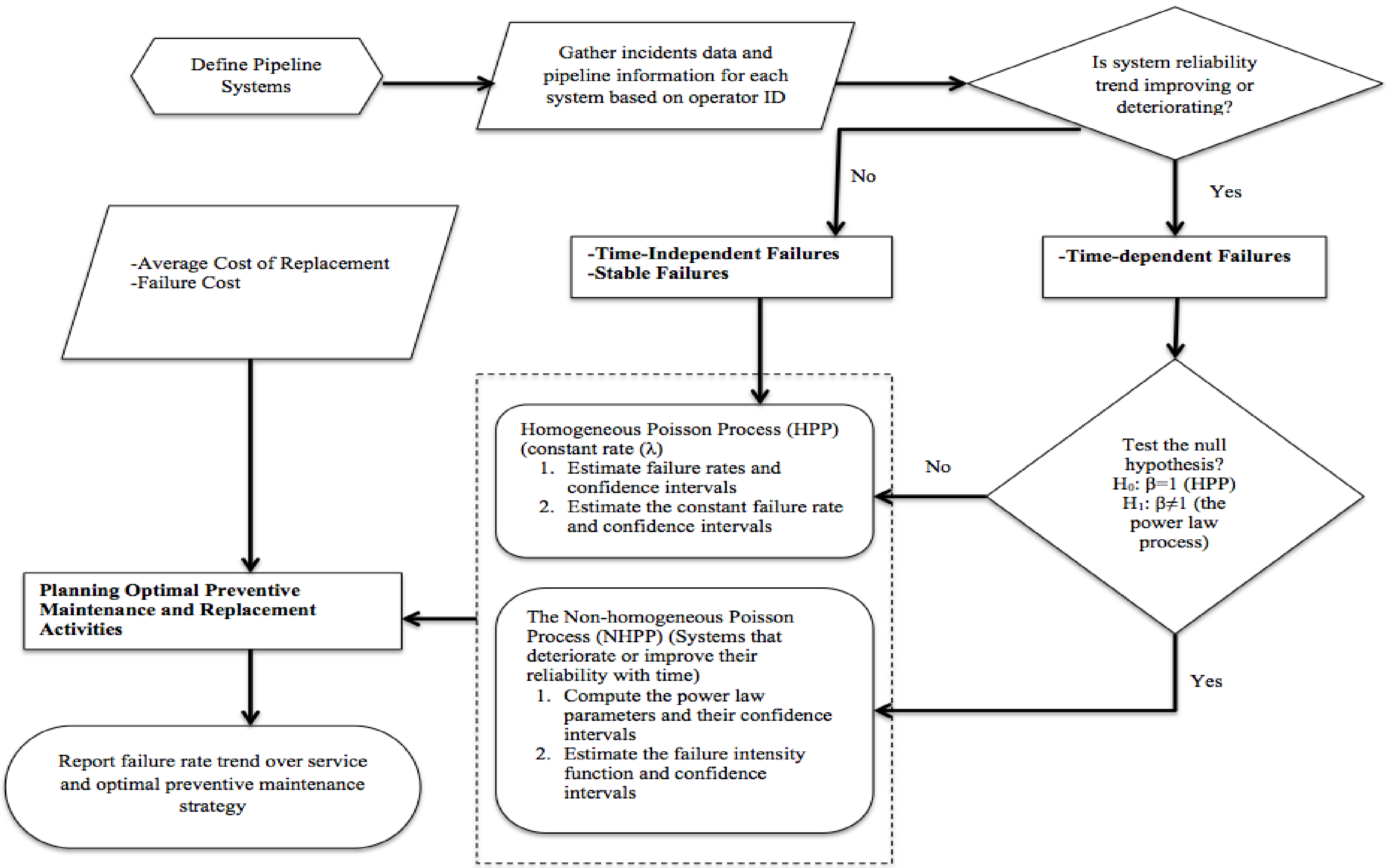


Figure 3.1 Schematic Diagram of Thesis Methodology

4. DATA SETS DEVELOPMENT

The next step of this thesis is to prepare data sets for the reliability modeling. Figure 4.1 shows the data set used in the thesis. Two major data sets are used in this thesis. Data set 1 is required for getting the total miles information for each operator, and data set 2 is required for analyzing incidents data. In the following subsections, details about the two main data sets are provided.

4.1 Data Set 1- Distribution, Transmission, and Liquid Annual Data

Due to the Code of Federal Regulations (49 CFR 191.15), written incidents reports are required for gas transmission and gathering systems by the natural gas operators. These data is collected by PHMSA. Government agencies, the industry professionals, researchers, and PHMSA generally use these annual reports for purpose of safety, inspection planning, and risk assessment. This database is called Distribution, Transmission, and Liquid Annual Data, and can be downloaded from PHMSA website (PHMSA, 2013c). The data that is downloaded on July 31, 2012 is used in this thesis. An example of the data set is shown in Table 4.1. The annual reports contain general information such as pipeline operators' information, total pipeline mileage, miles by material of pipeline, miles by diameter, and decade of installation from 1970 (PHMSA, 2013c).

Table 4.1 Example of Annual Report of Distribution, Transmission, and Liquid Annual Data

Report Year: 2008	**Operator ID**			
	The miles of transmission ONSHORE lines in the system at end of year, by diameter	**The miles of transmission OFFSHORE lines in the system at end of year, by diameter**	**The miles of transmission ONSHORE lines in the system at end of year, by decade of installation**	**The miles of transmission OFFSHORE lines in the system at end of year, by decade of installation**
Unknown	0	0		
4 in or less	104	0		
> 4 in and ≤10 in	519	45		
>10 in and ≤20 in	2255	22		
>20 in and ≤28 in	1634	0		
> 28 in	891	0		
Unknown			0	0
Pre 1940			22	0
1940 - 1949			251	0
1950 - 1959			968	0
1960 - 1969			569	40
1970 - 1979			931	27
1980 - 1989			420	0
1990 - 1999			578	0
2000 – 2009			1664	0

4.2 Data Set 2- Significant Incident Data Reports

U.S. Department of Transportation-Pipeline & Hazardous Materials Safety Administration (PHMSA) provides also historical incident statistics that has been collected from American pipeline operators since 1986. The database involves different type of pipelines information such as gathering, distribution, and transmission pipeline incidents and different category of incidents such as serious and significant. Within the scope of this study, only significant incident data are considered. A significant pipeline incident is identified by PHMSA when any of the following conditions occur (PHMSA, 2013d):

1. Fatality or injury requiring in-patient hospitalization,
2. $50,000 or more in total costs, measured in 1984 dollars,
3. Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more,
4. Liquid releases resulting in an unintentional fire or explosion.

The significant incident data' reports are generated from various data sources maintained for Pipeline Safety Regulation. PHMSA shares the database to the public to raise awareness of pipeline safety. This database involves significant pipeline incidents information for onshore and offshore pipelines such as the pipeline operators information, failure causes, total dollar amount of property damages, installation year of line, maximum pressure and pressure on failure time, depth of cover, local date and time of failure, the pipe diameter, wall thinness of pipe, the pipe materials, coating information, CP information, release type, and fatally or injury information. The raw incident data can be downloaded from PHMSA website (PHMSA, 2013d). The database was divided into three time periods that are 1986-2001, 2002-2009, and 2010-present. 2,625 significant pipeline incidents have been reported in the U.S. since 1986. The costs associated with incidents are also provided in 2012 dollars in the datasets (PHMSA, 2013d).

4.3 Preparation of Final Data Set

The PHMSA databases were collected from a wide range of sources that covered all types of pipelines (e.g. gathering, transmission, and distribution) and all failures causes. Therefore, there are many number of variables that are related to incidents and the pipeline operators in the PHMSA' datasets. However, the study does not need all the information in datasets. Therefore, the datasets were cropped carefully based on operator ID number. Appendix A, Appendix B, and Appendix E illustrate more details of dataset.

As noted in previously, natural gas transmission pipelines incident data were considered. These incident data can be divided into subsections such as, failure characteristics and groups of pipes with the same decade of installation. Røstum (2000) implied that, each installation decade of pipeline has had different construction practices and with technologies that are no longer appropriate. Therefore, pipelines have different failure characteristics depending on installation decade.

Due to above reason, time interval (the decades of installation) is divided into eight groups based on the decade of installation in DOT/PHMSA distribution, transmission, and liquid annual data. Table 4.2 shows decades of installation of the dataset.

Table 4.2 Decade of Installation of Natural Gas Transmission Pipelines in the U.S in DOT/PHMSA Distribution, Transmission, and Liquid Annual Data

Decade of installation of the transmission pipeline networks							
Pre 1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009

Second, DOT/PHMSA distribution, transmission, and liquid annual data set are examined from 2001 to 2011.Before 2001 only a few companies sent their information properly to DOT/PHMSA for the scope of Code of Federal Regulations. Another problem is that, there is not any information about the decade of installation before 2001.

In summary, the data sources were carefully prioritized based on type of failure caused by corrosion. Pipeline reliability models are established for corrosion failure. 98 internal corrosion failures were recorded from 2001 to 2011. In same time interval, 46 external corrosion failures were recorded.

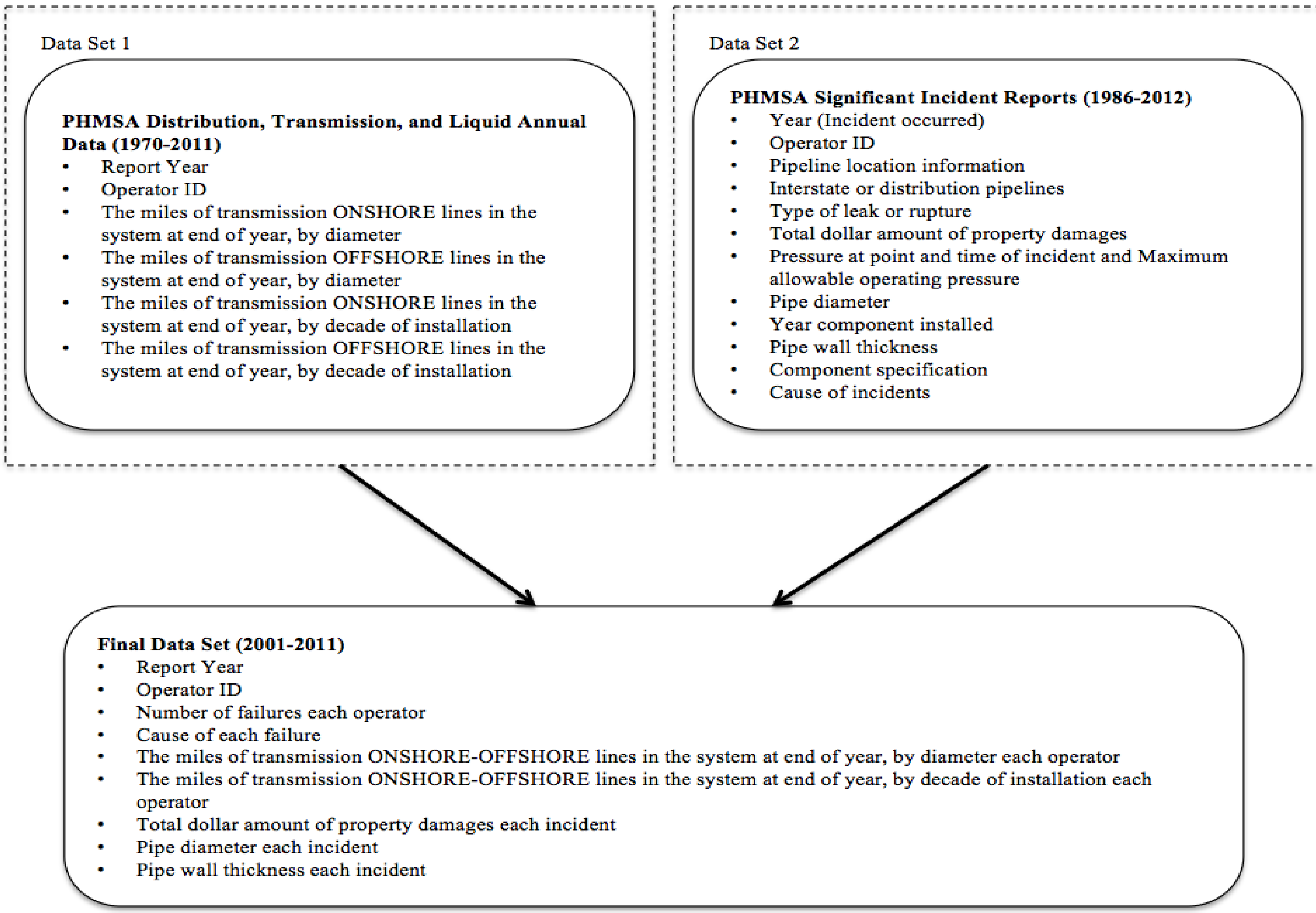


Figure 4.1 Data Processing for Reliability Analysis

5. RELIABILITY MODELS FOR NATURAL GAS TRANSMISSION PIPELINES

This section presents development of reliability models for the estimation of failure rate of pipeline networks. In the first subsection, reliability models are formulated for internal corrosion mode. In the second subsection, reliability models are formulated for external corrosion.

5.1 Reliability Models for Internal Corrosion

Based on the eleven largest natural gas pipeline operators' data from 2001 to 2011, 98 internal corrosion failures were recorded. Table 5.1 shows the total number of failures from 2001 to 2011 for each observation year.

Table 5.1 Number of Incidents Recorded per Year Due to Internal Corrosion

Year incident occurred	**Number of total incidents**
2001	5
2002	7
2003	7
2004	9
2005	5
2006	8
2007	9
2008	7
2009	10
2010	18
2011	13

The cumulative number of failures for internal corrosion is shown in Figure 5.1. The plot represents incidents data from 2001 to 2011 and decades of installation from pre 1940 to 2011. As noted in Section 4, each pipeline has different failure characteristics by installation decade. Due to this reason, these 98 incident data was divided into sub-groups, which are 1950-1959, 1960-1969, 1970-1979, and 1980-1989 based on the decade of installation. Before 1950 and after 1989 failure data are not considered because majority of data is between from 1950 to 1989.

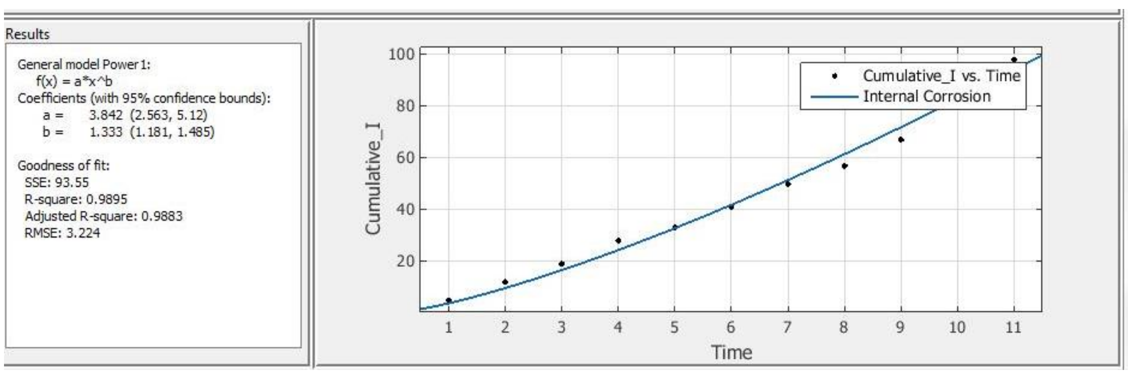


Figure 5.1 Internal Corrosion Cumulative Number of Failure Plot from 2001 to 2011

As mentioned before, there is not any geographical data so there is not any information of individual line’s length. However, PHMSA provides total pipeline miles by the decade of installation for the each company. The total miles and failures were shown in Appendix F.

As noted in Section 2, the power law model is a feasible model for the estimation of expected number of corrosion failures. Although reliability improves with maintenance, corrosion continues to reduce pipeline reliability. Therefore, pipeline reliability links to a growing number of failures with pipeline's service time. To show the relation between reliability and failures, the cumulative number of failures caused by internal corrosion was analyzed in MATLAB for predetermined groups, based on Equation 2.6. Table 5.2 illustrates the results of the analysis. θ and β scale and shape parameters were calculated with Equations 2.7 and 2.8. Equation 2.9 was used to produce the 95 percent confidence intervals for shape parameter β. A complete set of cumulative plots showing the observed number of failures for all predetermined decades of installation is shown in Appendix C.

Table 5.2 Cumulative Number of Failures (N(*t*))' Scale and Shape Parameters and 95 Percent Confidence Intervals of Failures Rate of the Internal Corrosion Incidents

Cause	**Decade of Installation**	**Number of Incident**	$\hat{\beta}$	$\hat{\theta}$	**95% Confidence Intervals for β**	
Internal Corrosion	Overall	98	1.333	0.353	1.082	1.610
	1950-1959	12	0.954	0.812	0.493	1.564
	1960-1969	25	1.633	1.532	1.057	2.333
	1970-1979	32	1.778	1.566	1.216	2.445
	1980-1989	20	0.957	0.480	0.584	1.419

According to the results in Table 5.2, reliability of pipeline systems is deteriorating for internal corrosion failures for overall, 1960-1969, and 1970-1979. For 1950-1959 and 1980-1989 the estimator β is less than 1; therefore, probability of failure will occur less frequent. Based on the result at Table 5.2, the β estimator is not enough to determine if the system deteriorates or improves over time. As discussed in the literature review, the failure trend can be modeled by an NHPP. Therefore, accuracy of the NHPP has to be tested.

Although the non-homogeneous Poisson process (NHPP) is selected to model pipeline systems, adequacy of the NHPP must be tested to verify the model. The null hypothesis is H_0: $\beta=1$ or the HPP model is the best model for internal corrosion failures data with $\alpha=0.05$. The alternative hypothesis is H_1: $\beta\neq1$ or the power law process is the best model for internal corrosion failures data with $\alpha=0.05$. Equation 2.11 was used to test the adequacy of the HPP.

Table 5.3 Test the Null Hypothesis to Verify Model for Internal Corrosion Failures

Cause	**Decade of Installation**	$\frac{2N(T_{obs})}{\hat{\beta}}$	$\chi^2_{1-\alpha/2}\left(2N_{(T_{obs})}\right)$	$\chi^2_{\alpha/2}\left(2N_{(T_{obs})}\right)$	**Reject H_0: HPP with α=0.05**
Internal Corrosion	Overall	147.04	159.122	236.663	Yes
	1950-1959	25.17	12.401	39.364	No
	1960-1969	30.62	32.357	71.420	Yes
	1970-1979	36.00	43.776	88.004	Yes
	1980-1989	41.81	24.433	59.347	No

The results of the analysis are shown in Table 5.3. According to the results, the null hypothesis is rejected for internal corrosion with $\alpha=0.05$ for the decade of installation of all data, 1960-1969, and 1970-1979. Based on the results, the pipeline systems for internal corrosion failures can be modeled by the power law process for all data, 1960-1969, and 1970-1979. Otherwise, the HPP model is the best model for the decade of installation for 1950-1959 and 1980-1989. The average failure rates were calculated for 1950-1959 and 1980-1989. Equation 2.3 and 2.4 were used to analyze failure rates based on the HPP model. Table 5.4 provides the results of the estimations with the significance level at 5 percent for the HPP.

Table 5.4 Estimates and 95 Percent Confidence Intervals for Failure Rate of the Pipeline Systems for Internal Corrosion

Cause	**Decade of Installation**	$\hat{\lambda}(t)$ $(per\ mile\ year)$	**95% Confidence Intervals (per mile year)**	
Internal Corrosion	1950-1959	3.17263E-05	1.63935E-05	5.20365E-05
	1980-1989	0.000232051	0.000141725	0.000344248

Results of table 5.3 and Table 5.4 are summarized in Table 5.5. The final expressions are given for the cumulative number of failures for each predetermined decade of installation for internal corrosion.

Table 5.5 Reliability Trend in the Pipeline Systems for Internal Corrosion

Cause	**Decade of Installation**	**Best Model**	**N (t)**	$\hat{\lambda}(t)$ **per mile year**	**Reliability Trend**
Internal Corrosion	Overall	NHPP	$3.842t^{1.333}$	$5.04x10^{-5}t^{0.333}$	Deterioration
	1950-1959	HPP	$1.022t^{0.9535}$	3.17263E-05	Stationary
	1960-1969	NHPP	$0.4618t^{1.633}$	$2.96x10^{-5}t^{0.633}$	Deterioration
	1970-1979	NHPP	$0.425t^{1.778}$	$9.73x10^{-5}t^{0.778}$	Deterioration
	1980-1989	HPP	$2.293t^{0.9566}$	0.000232051	Stationary

Summary of beta shape parameters and 95 percent confidence internals results are illustrated in Figure 5.2. The expected results were beta parameters increase with increasing network age. In other words, the network's failure intensity increases with increasing pipes' age. The results indicate that with increasing the network age, beta parameters increase, except the beta parameter for the decade of 1950-1959. This result can be explained with the effectiveness of the industry efforts to control corrosion.

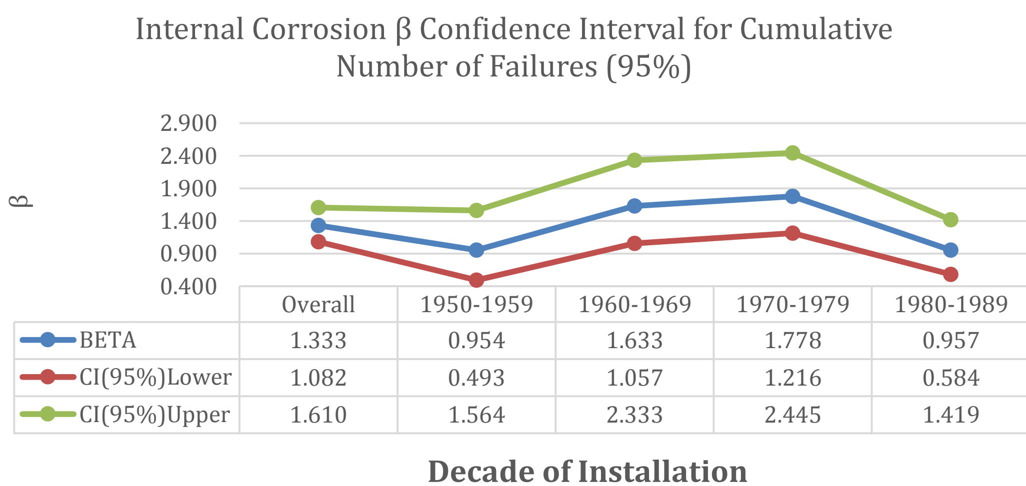


Figure 5.2 Estimates of the β Parameters and 95 Percent of Confidence Intervals of the Failure Rate of the Internal Corrosion

Figure 5.3 illustrates the recorded cumulative failures and the estimated cumulative failures for internal corrosion from 2001 to 2011. These plots might be used to graphically evaluate the power law results with recorded failures. According to the power law model results, 94 failures were evaluated compared to the recorded data that was 98 failures. Beta parameter is more than 1. It means that the system a deteriorating networks when includes all internal corrosion failure data. In other words, the future failures will most properly occur due to internal corrosion for natural gas transmission pipelines.

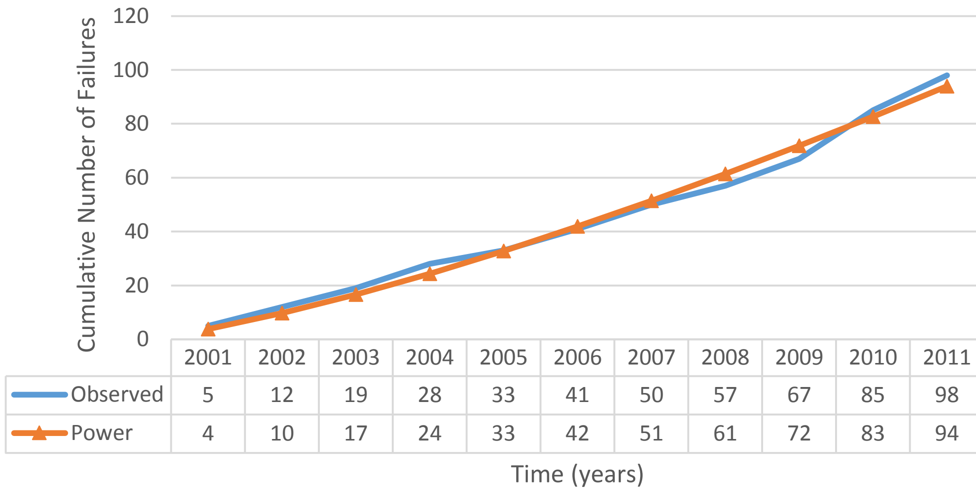


Figure 5.3 Cumulative Failures Plot for Internal Corrosion for the Period 2001-2011

Similar plots are also made for each group for internal corrosion mode. A complete set of cumulative plots for all groups are given in Appendix C.

5.2 Reliability Models for External Corrosion

46 external corrosion failures were recorded based on the eleven largest natural gas transmission pipeline operators' data from 2001 to 2011. Table 5.6 shows the total number of failures from 2001 to 2011 for each observation year.

Table 5.6 Number of Incidents Recorded per Year Due to External Corrosion

Year incident occurred	**Number of total incidents**
2001	0
2002	4
2003	4
2004	5
2005	4
2006	7
2007	7
2008	6
2009	3
2010	5
2011	1

The cumulative number of failures for external corrosion is shown in Figure 5.3. Failure data in the plot represent the whole decades of installation from pre 1940 to 2011. As mentioned earlier, age is an important factor for reliability analysis. Due to this reason, these 46 incident data were divided into sub-groups, which are 1920-1929, 1930-1939, 1940-1949, 1950-1959, and 1960-1969, based on decade of installation. Before 1920 and after 1969 failure data are not considered because majority of data is between from 1920 to 1969.

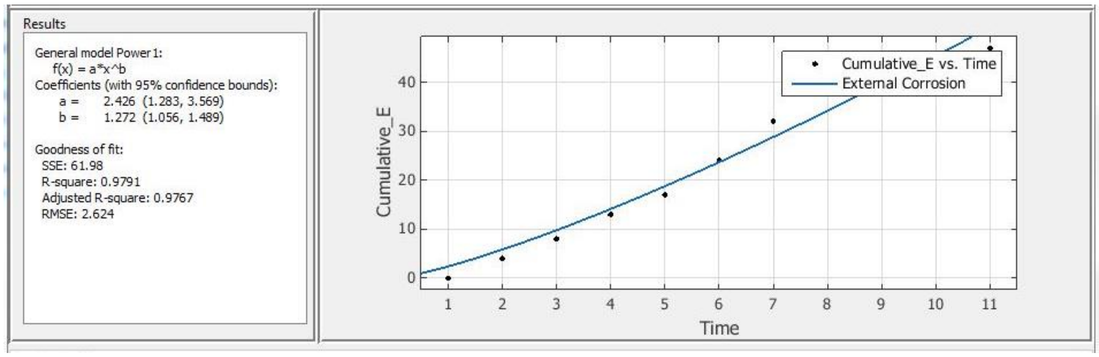


Figure 5.4 External Corrosion Cumulative Number of Failure Plot from 2001 to 2011

As discussed in Section 1, there is not any geographical data so there is not any information of individual line's length. In contrast, PHMSA provides total pipeline miles by the decade of installation for each company. The total miles and failures were shown in Appendix F.

As noted in Section 2, the power law model is a feasible model for corrosion failures. Although reliability improves with maintenance, corrosion continues to reduce pipeline reliability. Therefore, pipeline reliability links to a growing number of failures with pipeline's service time. To show the relation between reliability and failures, the cumulative number of failures caused by external corrosion was analyzed in MATLAB for predetermined time periods based on Equation 2.6. Table 5.7 shows the results of the analysis. θ and β scale and shape parameters were calculated with Equation 2.7 and 2.8. Equation 2.9 was used to produce the 95 percent confidence intervals for shape parameter β. A complete set of cumulative plots showing the observed number of failures for all predetermined decades of installation is shown in Appendix D.

Table 5.7 Cumulative Number of Failures (N(t))' Scale and Shape Parameters and 95 Percent Confidence Intervals of Failures Rate of the External Corrosion Incidents

Cause	Decade of Installation	Number of Incident	$\hat{\beta}$	$\hat{\theta}$	95% Confidence Intervals for β	
External Corrosion	Overall	46	1.272	0.542	0.931	1.665
	1920-1929	3	0.954	3.478	0.197	2.298
	1930-1939	2	2.219	8.049	0.269	6.182
	1940-1949	11	1.118	1.288	0.558	1.869
	1950-1959	9	1.970	3.606	0.901	3.450
	1960-1969	14	0.999	0.783	0.546	1.586

According to the results in Table 5.7, the reliability of pipeline systems is deteriorating for external corrosion failures for overall, 1930-1939,1940-1949, and 1950-1959. For 1920-1929 and 1960-1969 the estimator β is less than 1; therefore, probability of failure will occur less frequently. Although the β estimator is an important variable on how the system deteriorates or improves over time, it is not enough itself.

Although the non-homogeneous Poisson process (NHPP) is selected to model pipeline systems, adequacy of the NHPP must be tested to verify the model. The null hypothesis is H_0:β=1 or the HPP model is the best model for external corrosion failures data with α=0.05. The alternative hypothesis is H_1: β≠1 or the power law process is the best model for external corrosion failures data with α=0.05. Equation 2.11 was used to test the adequacy of the HPP.

Table 5.8 Test the Null Hypothesis to Verify Model for External Corrosion Failures

Cause	Decade of Installation	$\frac{2N(T_{obs})}{\hat{\beta}}$	$\chi^2_{1-\alpha/2}(2N_{(T_{obs})})$	$\chi^2_{\alpha/2}(2N_{(T_{obs})})$	Reject H_0: HPP with α=0.05
External Corrosion	Overall	72.33	67.356	120.427	Yes
	1920-1929	6.29	1.237	14.449	No
	1930-1939	1.80	0.484	11.143	No
	1940-1949	19.68	10.982	36.781	Yes
	1950-1959	9.14	8.231	31.526	Yes
	1960-1969	28.03	15.308	44.461	Yes

The results of the analysis are shown in Table 5.8. According to the results, the null hypothesis is rejected for external corrosion with α=0.05 for the decade of installation all of data, 1940-1949, 1950-1959, and 1960-1969. Based on the results, the pipeline systems for external corrosion failures can be modeled by the power law process for all data, 1940-1949, 1950-1959, and 1960-1969. On the other hand, the HPP model is the best model for the decade of installation for 1920-1929 and 1930-1939. The average failure rates were calculated for 1920-1929 and 1930-1939. Equation 2.3 and 2.4 were used to analyze failure rates on the basis of the HPP model. Table 5.9 shows the results of the estimations with the significance level at 5 percent.

Table 5.9 Estimates and 95 Percent Confidence Intervals for Failure Rate of the Pipeline Systems for External Corrosion

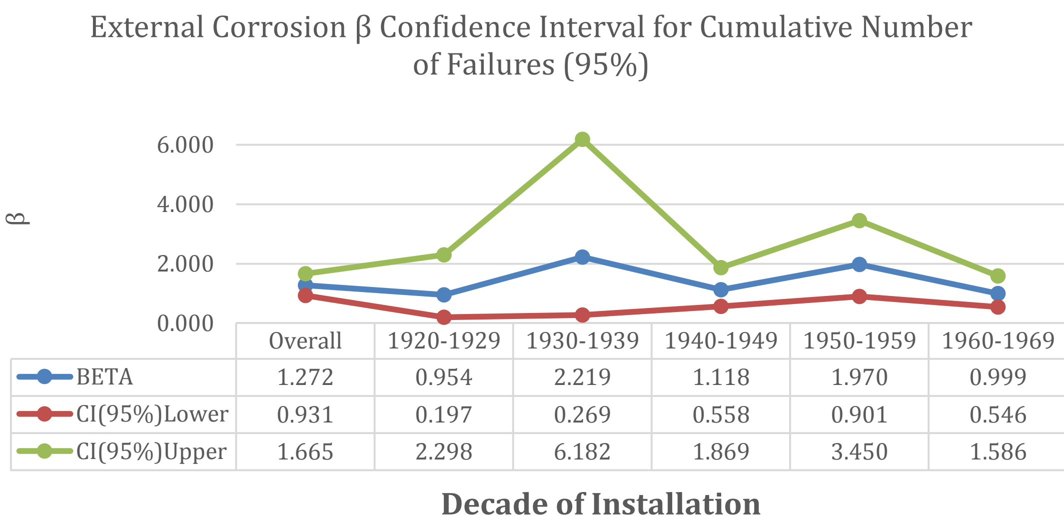
Cause	**Decade of Installation**	$\hat{\lambda}(t)$ $(per\ mile\ year)$	**95% Confidence Intervals (per mile year)**	
External Corrosion	1920-1929	5.40722E-05	1.11506E-05	0.000130218
	1930-1939	3.60481E-05	4.36543E-06	0.000100442

Table 5.10 shows the final expressions for the cumulative number of failures for each predetermined decade of installation for external corrosion.

Table 5.10 Reliability Trend in the Pipeline Systems for External Corrosion

Cause	**Decade of Installation**	**Best Model**	**N(t)**	$\hat{\lambda}(t)$ $(per\ mile\ year)$	**Reliability Trend**
External Corrosion	Overall	NHPP	$2.426t^{1.272}$	$2.62x10^{-5}t^{0.272}$	Deterioration
	1920-1929	HPP	$0.2981t^{0.9542}$	5.40722E-05	Stationary
	1930-1939	HPP	$0.01196t^{2.219}$	3.60481E-05	Stationary
	1940-1949	NHPP	$0.852t^{1.118}$	$7.21x10^{-5}t^{0.118}$	Deterioration
	1950-1959	NHPP	$0.07754t^{1.97}$	$4.58x10^{-6}t^{0.970}$	Deterioration
	1960-1969	NHPP	$1.448t^{0.999}$	$4.65x10^{-5}t^{-0.001}$	Improvement

Summary of beta shape parameters and 95 percent confidence internals results are shown in Figure 5.4. The expected results with increasing the network age, beta parameter increase, such as internal corrosion. However, the results illustrate that there is not real trend for beta parameters with increasing network age. The beta parameters begin to decrease with 1960-1969. This result can be explained with the effectiveness of the industry efforts to control corrosion and 49 CFR Parts 191, 195.



	Overall	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969
BETA	1.272	0.954	2.219	1.118	1.970	0.999
CI(95%)Lower	0.931	0.197	0.269	0.558	0.901	0.546
CI(95%)Upper	1.665	2.298	6.182	1.869	3.450	1.586

Figure 5.5 Estimates of the β Parameters and 95 Percent of Confidence Intervals of the Failure Rate of the External Corrosion

Figure 5.6 illustrates the recorded cumulative failures and the estimated cumulative failures for external corrosion from 2001 to 2011. According to the power law model results, 51failures were evaluated compared to the recorded data that was 46 failures. Beta parameter is more than 1. It means that the system a deteriorating networks when includes all external corrosion failure data. In other words, the future failures will most properly occur due to external corrosion for natural gas transmission pipelines.

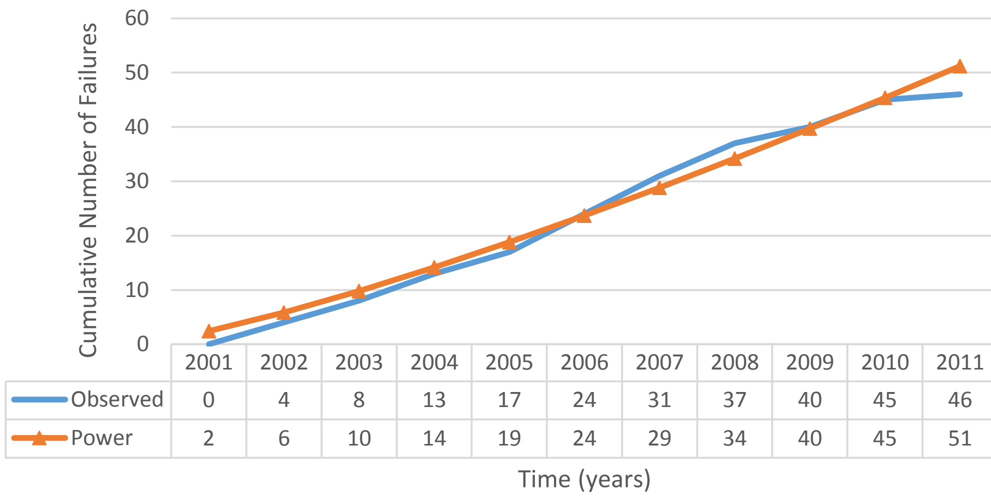


Figure 5.6 Cumulative Failures Plot for External Corrosion for the Period 2001-2011

Similar plots are also made for each group for external corrosion mode. A complete set of cumulative plots for all groups are given in Appendix D.

5.3 Summary

The natural gas transmission pipeline networks are analyzed using with stochastic point processes. The pipeline failure mode is divided into internal and external corrosion. Moreover, internal corrosion failure mode is divided into five groups that represent the decade of pipes' installation year. As different from internal corrosion, external corrosion is divided into six groups that consist of different decade of installation.

Each pipeline network is analyzed separately. Two statistical models, HPP and NHPP are considered for estimation of expected number of failures. These statistical models use the failure data for an eleven-year observation. These two models are tested against each other, and then the best models are selected for each group. Based on the test results, the failure intensity function is calculated for each pipeline groups for network level. The result is given in Table 5.5 and Table 5.10.

6. OPTIMAL MAINTENANCE MODELS FOR NATURAL GAS TRANSMISSION PIPELINES

This section introduces the development of preventive maintenance models. There are two main subsections. In the first subsection, the costs of preventive maintenance that is associated with failure and replacement of natural gas transmission pipelines are discussed. In the second subsection, the formulation of the cost models for finding the optimal preventive maintenance actions is introduced for natural gas transmission pipeline networks.

6.1 Preventive Maintenance Model Specification

In the literature review, an application of preventive maintenance (PM) on the natural gas transmission pipelines is discussed. The purpose of the PM activities is to minimize the overall cost of system operation and to maximize the overall reliability of the system. The main problem of PM is the sequence of PM actions that are maintenance or replacement in the pipeline networks for each time period (Moghaddam and Usher, 2011).

As mentioned in the literature review, reliability and maintenance are closely related to each other and to obtain the optimal maintenance policy requires determining system reliability. The results of the reliability analysis are given in Table 5.5 and Table 5.10.

The second step is to formulate the optimal maintenance actions based on the system reliability and characteristics. Optimization of preventive maintenance refers to combining many situations and systems, then selecting the best solution from all feasible results. Hence, selection of the best solution requires complex engineering and economic analysis. To find the optimization models consist of two main subsections. The first subsection involves finding costs associated with preventive maintenance. The second subsection includes finding optimum costs and time for preventive maintenance actions.

6.2 Costs of Preventive Maintenance and Replacement Actions

The operator would like to estimate their future operating expenditure (OPEX) accurately. The biggest part of OPEX is the costs of unplanned system failures. There is no model that can predict such failures correctly on time. However, if the pipeline systems have a high ROCOF throughout their life, expected failure could most likely happen. Then the operators can estimate their OPEX based on the expected number of failures. In contrast, a low ROCOF may cause a low cost of failure in the same time intervals. Because of the above reason, the expected number of failures should be estimated for accurate estimation of OPEX (Moghaddam and Usher, 2011).

The expected number of failures is estimated with the NHPP. The results of the number of failure functions are shown in Table 5.5 and Table 5.10. If the failure costs are known, future OPEX can be figured out by the results of the number of failures (Moghaddam and Usher, 2011).

The costs of maintenance are associated with corrosion can be determined with engineering analysis. The costs of maintenance are affected either directly or indirectly by maintenance and are divided into two: direct and indirect costs of maintenance. The direct costs involve cost of manpower, material, tools, equipment, and overhead. The indirect costs include material losses, excessive energy consumption, delay in fulfilling orders, legal, etc. (Blischke and Murthy, 2000). Thompson (2000) discusses that indirect costs that are associated with corrosion are more difficult to understand and to assign value. It could be explained by inherent properties of the impact of corrosion. More specifically for pipeline systems, indirect costs involve costs associated with damages to the environments or disruption, public relations costs, legal costs, lost revenue, etc. (Thompson, 2004).

Property damage cost can be used in the study for determining direct maintenance costs. The PHMSA provides detail of total dollar amount of property damages for each pipeline incident in PHMSA's database. Due to the Code of Federal Regulations (49 CFR 191.15), all relevant costs associated with corrosion available at the time of submission must be included on the written incidents reports. The property cost includes all direct costs of the incident such as property damage to the operator's facilities and the property of others, facility repair and replacement, and the environmental cleanup and damage. The average property damages cost, which is $F_{property}$ ($ per failure) for each predetermined the decades of installation is illustrated in Table 6.1. Due to above reason, property cost reflects the actual failure cost. Based on minimal repair assumption, the cost model needs cost of failure. Therefore, property damage cost is used as $C_{failure}$, which denotes cost of failure (Thompson, 2004).

As discussed in the literature review, the most appropriate approach is to repair the pipes until the failure costs clearly outweigh the replacement cost, or until new pipeline projects make replacement economically attractive (Røstum, 2000). Therefore, maintenance is the most effective way to reduce ROCOF of the pipeline systems.

Repair techniques are various from the installation of a reinforcing sleeve to full replacement when failure occur. Corrosion failures can be either leaks or ruptures for both internal and external corrosion. Baker Jr. (2008) emphasized that leaks generally do not cause property damage. Conversely, ruptures are more likely to cause an explosion and fire.

The main external repair techniques are: the cut out and replace, the bypass, grinding, the weld depositions, the metallic sleeves, and the composite sleeve (Batisse and Hertz-Clemens, 2008). Thompson (2004) implied that for localized corrosion flaws, composite sleeves, steel sleeves, or replacement of the pipe segment are the most commonly used techniques for corrosion repair actions. Local flaws repairing process depends on company procedures and criteria. These kinds of problems are generally solved with composite sleeves and steel sleeves process. Conversely, the companies consider replacement or rehabilitation actions when large-scale corrosion or coating deterioration problem occurs.

Table 6.1 Property Damages for Each Predetermined Decade of Installation

Cause	Decade of Installation	Average Property Damage Due to Corrosion (per failure)	
		Average	**Standard Deviation**
Internal Corrosion	Overall	$563,481	$856,348
	1950-1959	$200,172	$229,851
	1960-1969	$715,519	$1,412,253
	1970-1979	$589,603	$537,857
	1980-1989	$690,259	$736,810
External Corrosion	Overall	$2,694,061	$12,914,999
	1920-1929	$185,603	$175,889
	1930-1939	$273,107	$287,543
	1940-1949	$703,621	$1,005,536
	1950-1959	$2,027,638	$3,861,197
	1960-1969	$6,764,024	$23,247,348

As mentioned previously, all relevant costs associated with corrosion available at the time of submission must be included on the written incidents reports. The costs of repair (composite sleeve, steel sleeve, and pipe replacement) are included to the property damage cost. Therefore, it requires no extra effort to find the cost of each repair techniques.

The optimal maintenance models not only the cost of a corrective maintenance action through minimal repair but also need cost of a PM action involving replacing a nonfailed component by a new one (Blischke and Murthy, 2000). ASRC Constructors Inc., Michael Baker Jr. Inc., and Norstar Pipeline Company (2007) conducted a technical report for Alaska spur pipelines for summarizing the detailed construction costs. In the study, direct and indirect construction costs, material (include freight) costs, miscellaneous costs, and project indirect costs are evaluated for different length of the gas transmission pipelines. The detail of the pipeline cost estimation is given in Appendix H. Based on the estimation, the average cost of new construction pipeline for Alaska Spur Gas Pipeline projects is estimated as $2,245,823 per mile. Let $C_{replacement}$ denote the average cost of replacement cost in this thesis. Moreover, it is assumed that all of the replacement is related to corrosion (Thompson, 2004; ASRC Constructors Inc. et al., 2007).

As discussed in Section 2, several considerations require making a final decision on whether a pipeline section should be maintained or replaced. For both rehabilitation and replacement decision is part of preventive maintenance policy. In the literature review detail of preventive maintenance is discussed. Based on this information, optimal values for the policy times could be determined by analyzing appropriate cost models (Nachlas, 2005). The following subsection is formulated the optimal cost model for the natural gas transmission pipeline networks.

6.3 Cost Models (Optimization)

The optimum a system replacement time can be done in order to balance the cost of maintenance against capital expenditure optimally. There are several optimal solutions for this problem that depend on the criteria selected for optimization. In this thesis, the model, which minimizes the total expected cost per unit time for the system is selected. Coetzee (1997) provided a solution to optimize the maintenance strategy for repairable systems by adding relevant cost information (Louit et al., 2009).

In the literature review, two main preventive maintenance policies, which are age policy and block policy, are discussed. After all discussions, it is decided that the periodic replacement with minimal repair at failure policy is feasible option for pipeline systems.

Coetzee (1997) uses the above policy in the cost models. There are two types of cost models, which can be applied with success repairable system cost optimization, are type 2 policies and type 3 (Coetzee, 1997).

6.3.1 Type 2 Policies

Type 2 replacement policies include the planned replacement of a system at a certain age with minimal repairs at breakdown up that age. In other words, preventive maintenance policy is based on the age of the system, and only minimal repair is made for each failure (Wang, 2002). These replacement policies were introduced by Barlow and Hunter (1960). The model assumes: 1) after each failure, only minimal repair is made so that the system's failure rate is not distributed; 2) the system is restored to its original state after preventive maintenance (Barlow and Hunter, 1960). The model optimizes cost per unit time over time. T* denotes the optimal replacement time that minimizes the total maintenance cost. Estimation of T^* is given in Equation 6.1 (Coetzee, 1997).

$$T^* = \left[\frac{C_{replacement}}{\left(\frac{1}{\theta\beta}\right)(\beta-1)C_{Failure}}\right]^{\frac{1}{\beta}} \tag{6.1}$$

where θ>0 and β>0 are the scale (the characteristic life) and shape parameters of the failure intensity function, $C_{Replacement}$ is cost of system replacement, and $C_{Failure}$ is cost of repair of a failure (minimal repair).

6.3.2 Type 3 Policies

Type 3 policy involves a system replacement after an optimum number of failures n^* has been repaired with minimal repair policy. These replacement policies were introduced by Makabe and Morimura (1963). The optimum number of the minimal repairs before the system replacement is given in Equation 6.2 (Coetzee, 1997).

$$n^* = \frac{C_{replacement}}{(\beta-1)C_{Failure}} \tag{6.2}$$

where β>0 is the scale (the characteristic life) of the failure intensity function, $C_{Replacement}$ is the cost of system replacement, and $C_{Failure}$ is the cost of repair of a failure (minimal repair).

If the total number of failure is equal to or greater than a number of minimal repair n^*, the replacement should be done as soon as possible; otherwise, maintenance actions are not required (Wang, 2002).

The pipeline failures data set is analyzed in Section 5, and the best model is decided for each decade on installation for internal and external corrosion. The result in the Table 5.5 and Table 5.10 can be used to illustrate the use of the cost models to optimize the system replacement strategy.

The optimal maintenance cost per unit time is given in Equation 6.3 (Coetzee, 1997).

$$C(T^*) = \frac{C_{repair}\lambda(t) + C_{replacement}}{T^*} \tag{6.3}$$

where, $\lambda(t)$ is the expected number of failures in $[0,T^*]$, $C_{replacement}$ is the average cost of system replacement, and C_{repair} is the average cost of the repair of a failure (minimal repair). Under minimal repair assumption, the expected number of failures can be expressed in the interval (T_1, T_2) is (Coetzee, 1997; Gertsbakh, 2000):

$$\lambda(t) = \int_{T_1}^{T_2} \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} dt = \left(\frac{T_2}{\theta}\right)^{\beta} - \left(\frac{T_1}{\theta}\right)^{\beta}, T_2 \geq T_1 \geq 0 \tag{6.4}$$

In Table 6.1, average property damage cost is given. To find more reliable results, a range cost of property damage is used instead of constant cost. Cost of replacement is given as \$2,245,823 per mile. However, selected 10-mile section will provide more reliable result: therefore, the cost of a corrective maintenance action through minimal repair is multiplied by 10-mile.

Based on type 2 policies and Equation 6.1, the optimal replacement time is determined by maximizing the expected cost effectiveness. Figure 6.1 shows how the scheduled replacement time changes with expected cost of failure for internal corrosion for all internal corrosion failures (98 incidents). An illustrating example for average cost of property damage, when $C_{Replacement}$=\$22,458,230 (10 mile section) and $C_{Failure}$=\$563,481, the optimal replacement time is at T^* = 13 year and the corresponding cost is $C(T^*)$=\$7,034,496 for overall group of internal corrosion.

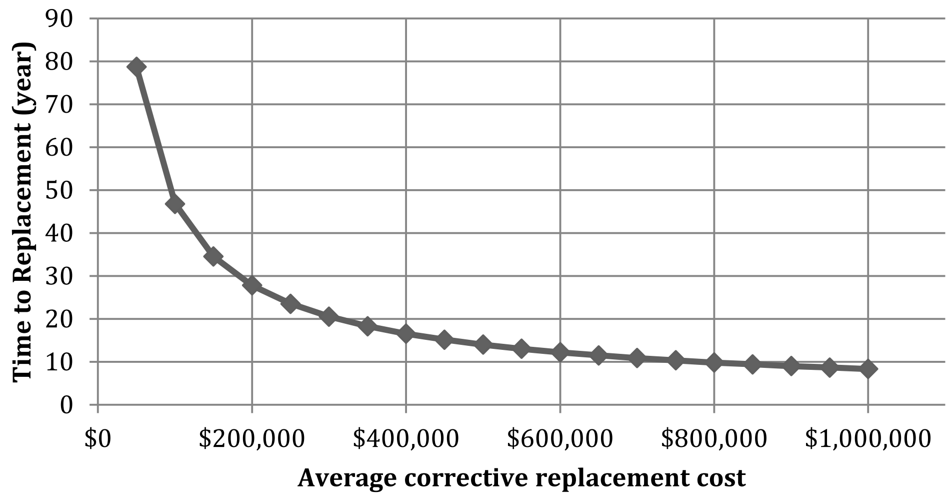


Figure 6.1 Cost Effectiveness as Function of Scheduled Replacement Time for Internal Corrosion Overall Group

Moreover, the optimal replacement time depend upon the ratio of preventive to corrective replacement costs. Therefore, the optimal time can be analyzed by the derivative of Equation 6.3. Figure 6.2 shows how the scheduled replacement time changes with this ration for internal corrosion for all internal corrosion failures.

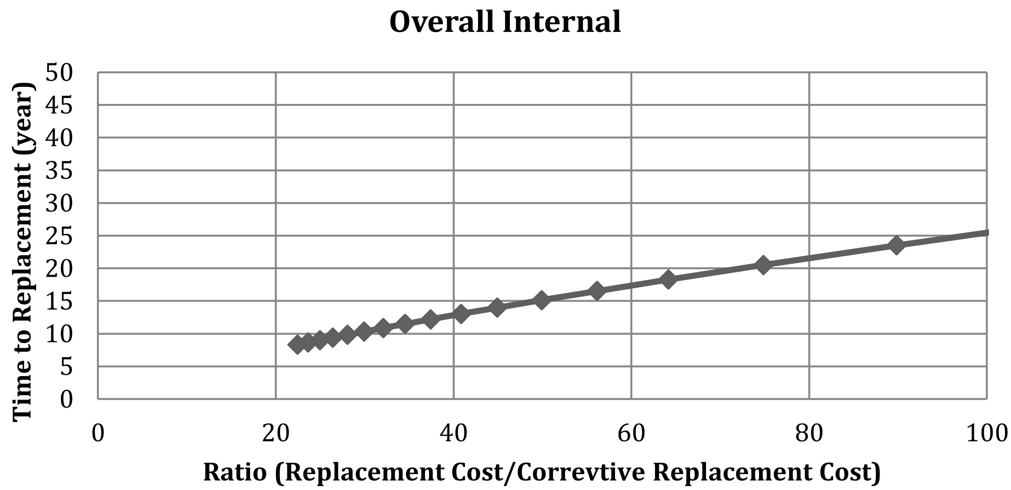


Figure 6.2 Scheduled Replacement Time as Function of Ratio of Preventive to Corrective Replacement Costs for Internal Corrosion Overall Group

Steps of the optimal cost models are repeated for external corrosion. Figure 6.3 shows how the scheduled replacement time changes with expected cost of failure for external corrosion for all external corrosion failures (46 incidents). An illustrating example for average cost of property damage, when $C_{Replacement}$=$22,458,230 (10 mile section) and $C_{Failure}$=$2,694,061, the optimal replacement time is at T^* = 8 year and the corresponding cost is $C(T^*)$=$13,138,560 for overall group of external corrosion.

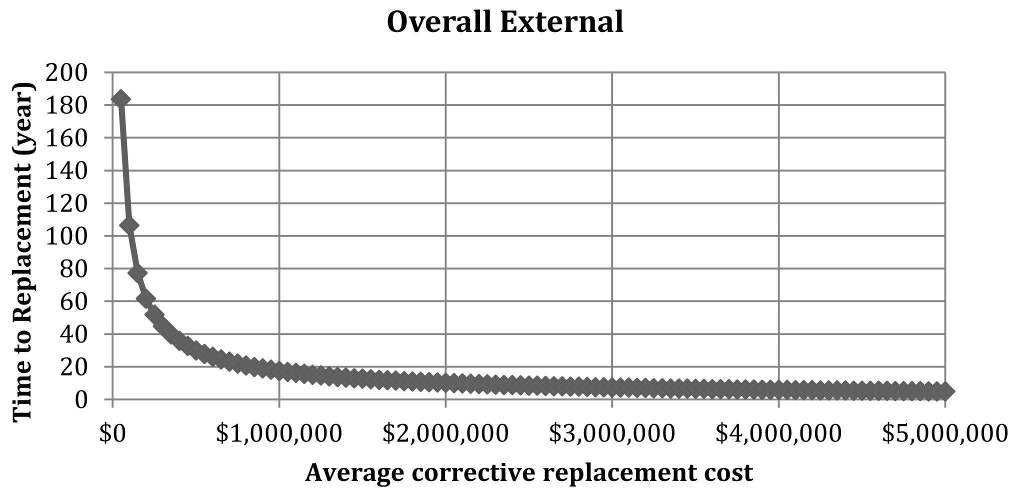


Figure 6.3 Cost Effectiveness as Function of Scheduled Replacement Time for External Corrosion Overall Group

Such in internal corrosion, the optimal replacement time depend upon the ratio of preventive to corrective replacement costs. Therefore, the optimal time can be analyzed by the derivative of Equation 6.3. Figure 6.4 shows how the scheduled replacement time changes with this ration for internal corrosion all external corrosion failures.

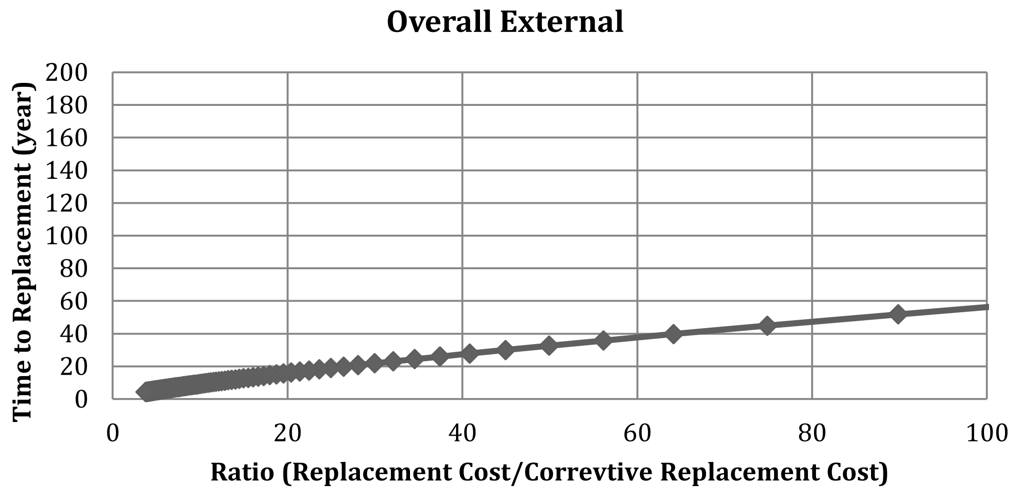


Figure 6.4 Scheduled Replacement Time as Function of Ratio of Preventive to Corrective Replacement Costs for External Corrosion Overall Group

The remaining the decades of installation are illustrated for the optimal maintenance cost models. The results are shown separately in Appendix H.

In summary, the natural gas transmission pipeline system will be replaced after the number of minimal repairs results of analysis. The results show that the length of the replacement interval depends upon a ratio of the replacement costs. Therefore, cost of repair and cost of replacement must be analyzed carefully before evaluating cost models.

7. SUMMARY AND RECOMMENDATIONS FOR FUTURE STUDY

This section summarizes major findings, discusses results, and suggests directions for future study. The section is organized in two subsections. In the first subsection, a summary of the thesis work is presented. In the second subsection, the directions for future work are suggested.

7.1 Summary

The purpose of this study is to formulate statistical models for the estimation of failure rate and to develop the optimal maintenance actions for natural gas transmission pipeline networks. Although much literature exists for repairable systems, there is a limited amount of work for natural gas pipelines. Therefore, this thesis tries to build a small bridge between previous studies, which are conducted for repairable systems or the other type of networks, and natural gas pipeline systems and to develop a method of maintenance optimization models establishment for pipeline systems. It is assumed that the readers of this thesis have some idea about the basic of theory of stochastic processes and reliability for repairable systems.

This thesis work focuses on three major topics. The first topic is characterization of natural gas transmission pipeline system failure modes. The discussion of this topic is discussed in Section 2.

The second topic is the development of reliability models to estimate the expected number of failures. Two reliability models are considered to explain characterization of pipeline failures in the literature review. It is found that the stochastic point processes are the most convenient processes to use a parametric model like the homogeneous Poisson process (NPP) and the nonhomogeneous Poisson process (NHPP) for natural gas transmission pipeline systems.

Application of the statistical models is illustrated in Section 5. The models used for natural gas transmission pipeline incidents data were observed from 2001 to 2011. Under the scope of this thesis, the pipeline networks are divided into two main groups (internal and external corrosion) based on failure characteristics. The following covariates are found to be significant: decades of installation and the number of previous failures.

The point and interval estimators of the failure intensity function (NHPP) are evaluated and the accuracy of the stochastic models is tested for each determined failure mode and decade of installation. The null hypothesis shows that both HPP and NHPP are convenient for estimating the failure rate of transmission pipelines. Therefore, NHPP and HPP are highly recommended for modeling failures' characterization in natural gas transmission pipeline networks for corrosion failure modes.

The thesis illustrated that three out of five pipeline networks are deteriorating due to internal corrosion failures. The other two network groups have stationary behavior. For external corrosion failures, three out of six pipeline networks are deteriorating, two of them have stationary behavior, and one network is improving reliability over time.

Based on the finding in this study, internal corrosion failures more significant than external corrosion. As mentioned in Section 5, there is an increasing trend of beta shape parameters for internal corrosion with over time. On the other hand, it is hard to illustrate a trend of beta shape parameter for external corrosion with over time. The results can be explained that the oil and gas industry has been familiar with corrosion mitigation and prevention strategies due to 49 CFR Part 192. Due to the legislative regulation and industry effort, external corrosion has been kept under control.

The statistical models give the expected number of failures. However, there is no guarantee that these failures will occur. The results of the statistical models can be used in reliability analysis, risk analysis, and optimum maintenance decisions. As mentioned earlier, the second purpose of this study is to optimize maintenance for pipeline networks. Therefore, the results of statistical models underlie the maintenance optimization models.

The third topic is the development of optimal preventive maintenance actions for gas pipelines. Details of the maintenance models are presented in Section 2 and Section 6. Maintenance actions can be divided into two major classes: preventive maintenance and corrective maintenance. Corrective maintenance occurs as a result of failures; therefore, it does not affect the overall system reliability. On the other hand, preventive maintenance changes the system reliability.

The optimal preventive maintenance actions are chosen based on minimal repair process by the non-homogeneous Poisson process assumption. Based on the minimal repair process, the cost model is selected. The cost model takes into consideration optimal preventive maintenance schedule and minimum average total cost per time unit criterion. In other words, the purpose of selected cost model minimizes the total expected cost per unit time for the pipeline networks.

The results of this study are a contribution to decision-makers in the gas industry to predict the expected number of failure in future operation more accurately and to help to decide proper preventive maintenance decisions.

7.2 Directions for Future Research

Even though this thesis work has presented a framework to estimate failure rate and to determine the optimal preventive maintenance decision for the natural gas transmission pipeline networks, it does not mean that it solves all the problems that are associated with reliability and maintenance optimization.

Reliability and maintenance optimization models require further research attention are as follows:

1. The development of reliability models that can predict the probability of failure and the expected number of failures depend upon many performance variables such as pressure of gas, environmental conditions, temperature, diameter, wall thickness, record of previous maintenance history, etc. Due to lack of information, the reliability models developed in this thesis consider the decades of installation of lines, corrosion failure mode, and the number of previous failures. The models can be improved by including other failure modes, multiple performance variables, and exact pipeline length for scope of future research.
2. The pipes in the natural gas transmission networks are only considered in this work. However, pipeline systems consist of pipes and other subcomponents such as compressors, valves, metering stations, etc. For more accurate reliability

analysis for the entire pipeline network, whole subcomponents performance should be considered.

3. The development of preventive maintenance models depends on many variables such as different maintenance restoration degrees. The optimal preventive maintenance models developed in this thesis consider minimal repair restoration degrees. Other maintenance restoration degrees such as imperfect or perfect could be included in the scope of future research.
4. The development of preventive maintenance models considers the periodic replacement with minimal repair at failure policy. On the other hand, some other models consider previous maintenance time and frequency of maintenance until preventive maintenance actions are taken. Therefore, other possible applications of preventive maintenance could be considered for future research.
5. The accuracy of the optimization models generally depends upon two variables: accuracy of failure intensity functions and accuracy of cost. Accuracy of failure intensity functions can be improved with the first comment. However, estimating the costs that are associated with failure, construction conditions, and maintenance actions are not easily obtainable. This problem could be obviated in the future with a closer collaboration with the oil and gas industry, pipeline safety agencies, and researchers.

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APPENDIX A

Table A-1 Summary of internal corrosion failures from 2001 to 2011-A

Year incident occurred	**Number of total incidents**	**Cumulative number of total incidents**	**Total Property Damage (PRPTY) Due to Corrosion (per failure) ($ x thousand)**	**Average of PRPTY Due to Corrosion (per failure) ($ x thousand)**	**Standard Deviation of PRPTY Due to Corrosion (per failure) ($ x thousand)**	**Galvanic Corrosion**	**Microbiological Corrosion**	**Other**
2001	5	5	55,221	563	856	2		3
2002	7	12				3	1	3
2003	7	19				3	2	2
2004	9	28				2	7	
2005	5	33					3	2
2006	8	41				4	4	
2007	9	50				2	6	1
2008	7	57					4	1
2009	10	67				4	4	2
2010	18	85						
2011	13	98						
						Total: 20	**Total: 31**	**Total: 14**

Table A-2 Summary of internal corrosion failures from 2001 to 2011-B

Decade of installation	**Property Damage (PRPTY) Due to Corrosion (per failure) ($ x thousand)**		**Pipe Diameter (in)**		**Pipe Wall Thickness (in)**		**Galvanic Corrosion ($ x thousand)**		**Microbiological Corrosion ($ x thousand)**		**Other ($ x thousand)**	
	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation
Overall	563	856										
1950-1959	200	229	14.17	6.45	0.31	0.07	185	45	251	280	383	500
1960-1969	715	1,412	21.86	9.05	0.41	0.11	136	64	1,155	2,318	241	258
1970-1979	589	537	17.72	6.16	0.44	0.13	353	305	731	548	1,393	1,706
1980-1989	690	736	16.00	7.94	0.37	0.07	1,339	1,151	448	134	468	500

Table A-3 Summary of internal corrosion failures from 2001 to 2011 by the decade of installation between 1950 and 1959

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	**Late Start**	**Without protection**	**Unknown**	**Coated**	**Bare**	**Unknown**
2001	2	2	4	3	0	5	12	0	0
2002	1	3							
2003	1	4							
2004	0	4							
2005	1	5							
2006	0	5							
2007	0	5							
2008	1	6							
2009	1	7							
2010	3	10							
2011	2	12							

Table A-4 Summary of internal corrosion failures from 2001 to 2011 by the decade of installation between 1960 and 1969

<table>
<tr><th rowspan="2">Year incident occurred</th><th rowspan="2">Number of total incidents</th><th rowspan="2">Cumulative number of total incidents</th><th colspan="4">Cathodic protection</th><th colspan="3">Coating condition</th></tr>
<tr><th>Under CP</th><th>Late Start</th><th>Without protection</th><th>Unknown</th><th>Coated</th><th>Bare</th><th>Unknown</th></tr>
<tr><td>2001</td><td>1</td><td>1</td><td rowspan="11">14</td><td rowspan="11">0</td><td rowspan="11">1</td><td rowspan="11">10</td><td rowspan="11">22</td><td rowspan="11">0</td><td rowspan="11">3</td></tr>
<tr><td>2002</td><td>1</td><td>2</td></tr>
<tr><td>2003</td><td>2</td><td>4</td></tr>
<tr><td>2004</td><td>2</td><td>6</td></tr>
<tr><td>2005</td><td>1</td><td>7</td></tr>
<tr><td>2006</td><td>2</td><td>9</td></tr>
<tr><td>2007</td><td>1</td><td>10</td></tr>
<tr><td>2008</td><td>2</td><td>12</td></tr>
<tr><td>2009</td><td>3</td><td>15</td></tr>
<tr><td>2010</td><td>5</td><td>20</td></tr>
<tr><td>2011</td><td>5</td><td>25</td></tr>
</table>

Table A-5 Summary of internal corrosion failures from 2001 to 2011 by the decade of installation between 1970 and 1979

Year incident occurred	**Number of total incidents**	**Cumulative number of total incidents**	**Cathodic protection**				**Coating condition**		
			Under CP	**Late Start**	**Without protection**	**Unknown**	**Coated**	**Bare**	**Unknown**
2001	0	0	18	1	0	13	28	1	3
2002	3	3							
2003	3	6							
2004	2	8							
2005	1	9							
2006	0	9							
2007	3	12							
2008	2	14							
2009	5	19							
2010	8	27							
2011	5	32							

Table A-6 Summary of internal corrosion failures from 2001 to 2011 by the decade of installation between 1980 and 1989

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	Late Start	Without protection	Unknown	Coated	Bare	Unknown
2001	2	2	19	0	0	1	18	1	1
2002	2	4							
2003	1	5							
2004	3	8							
2005	0	8							
2006	6	14							
2007	4	18							
2008	1	19							
2009	1	20							
2010	0	20							
2011	0	20							

Table A-7 Summary of types of PM methods from 2001 to 2011 for internal corrosion

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection			Coating condition	
			Under CP	Late Start	Without protection	Coated	Bare
2001	5	5	3	1	1	5	
2002	7	12	6	1		7	
2003	7	19	7			7	
2004	9	28	9			9	
2005	5	33	5			5	
2006	8	41	8			7	1
2007	9	50	8	1		9	
2008	7	57	7			7	
2009	10	67	9	1		9	1
2010	18	85	17		1	18	
2011	13	98	13			12	1

APPENDIX B

Table B-1 Summary of external corrosion failures from 2001 to 2011-A

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total Property Damage (PRPTY) Due to Corrosion (per failure) ($ x thousand)	Average of PRPTY Due to Corrosion (per failure) ($ x thousand)	Standard Deviation of PRPTY Due to Corrosion (per failure) ($ x thousand)	Galvanic Corrosion	Improper Cathodic Protection	Microbiological Corrosion	Other
2001	0	0	123,926	2,694	12,914				
2002	4	4						1	2
2003	4	8				1			2
2004	5	13				3	1		
2005	4	17				1			2
2006	7	24				3		1	2
2007	7	31				5			2
2008	6	37				2	1	2	
2009	3	40				1			1
2010	5	45				3		1	
2011	1	46							
						Total: 19	**Total: 2**	**Total: 5**	**Total: 11**

Table B-2 Summary of external corrosion failures from 2001 to 2011-B

Decade of installation	**Property Damage (PRPTY) Due to Corrosion (per failure) ($ x thousand)**		**Pipe Diameter (in)**		**Pipe Wall Thickness (in)**	
	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation
Overall	2,694	12,914				
1920-1929	185	175	19.54	10.69	0.26	0.03
1930-1939	273	287	19.00	7.07	0.28	0.04
1940-1949	703	1,005	20.73	5.88	0.32	0.08
1950-1959	2,027	3,861	23.93	4.90	0.30	0.05
1960-1969	6,764	23,247	21.10	11.81	0.30	0.08

Table B-3 Summary of external corrosion failures from 2001 to 2011-C

Decade of installation	**Galvanic Corrosion ($ x thousand)**		**Improper Cathodic Protection**		**Microbiological Corrosion ($ x thousand)**		**Other ($ x thousand)**	
	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation	Average	Standard Deviation
Overall								
1920-1929	220	233						
1930-1939	273	287						
1940-1949	91	28			887		1,015	1,511
1950-1959	3,069	5,449	5,416		57		60	84
1960-1969	408	576			70		172	103

Table B-4 Summary of external corrosion failures from 2001 to 2011 by the decade of installation between 1920 and 1929

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	Late Start	Without protection	Unknown	Coated	Bare	Unknown
2001	0	0	1	0	2	0	2	1	0
2002	1	1							
2003	0	1							
2004	0	1							
2005	0	1							
2006	1	2							
2007	0	2							
2008	0	2							
2009	0	2							
2010	1	3							
2011	0	3							

Table B-5 Summary of external corrosion failures from 2001 to 2011 by the decade of installation between 1930 and 1939

Year incident occurred	**Number of total incidents**	**Cumulative number of total incidents**	**Cathodic protection**				**Coating condition**		
			Under CP	**Late Start**	**Without protection**	**Unknown**	**Coated**	**Bare**	**Unknown**
2001	0	0	0	2	0	0	0	2	0
2002	0	0							
2003	0	0							
2004	0	0							
2005	0	0							
2006	0	0							
2007	1	1							
2008	1	2							
2009	0	2							
2010	0	2							
2011	0	2							

Table B-6 Summary of external corrosion failures from 2001 to 2011 by the decade of installation between 1940 and 1949

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	Late Start	Without protection	Unknown	Coated	Bare	Unknown
2001	0	0	2	9	0	0	9	2	0
2002	0	0							
2003	2	2							
2004	1	3							
2005	3	6							
2006	2	8							
2007	0	8							
2008	2	10							
2009	0	10							
2010	1	11							
2011	0	11							

Table B-7 Summary of external corrosion failures from 2001 to 2011 by the decade of installation between 1950 and 1959

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	Late Start	Without protection	Unknown	Coated	Bare	Unknown
2001	0	0	4	4	1	0	9	0	0
2002	1	1							
2003	1	2							
2004	0	2							
2005	0	2							
2006	1	3							
2007	2	5							
2008	0	5							
2009	1	6							
2010	1	7							
2011	2	9							

Table B-8 Summary of external corrosion failures from 2001 to 2011 by the decade of installation between 1960 and 1969

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection				Coating condition		
			Under CP	**Late Start**	**Without protection**	**Unknown**	**Coated**	**Bare**	**Unknown**
2001	0	0							
2002	2	2							
2003	1	3							
2004	2	5							
2005	1	6							
2006	2	8	9	1	1	3	14	0	0
2007	3	11							
2008	0	11							
2009	1	12							
2010	1	13							
2011	1	14							

Table B-9 Summary of types of PM methods from 2001 to 2011 for external corrosion

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Cathodic protection			Coating condition	
			Under CP	Late Start	Without protection	Coated	Bare
2001	0	0	0			0	
2002	4	4	2		2	4	
2003	4	8	2	2		4	
2004	5	13	4	1		5	
2005	4	17	1	3		3	1
2006	7	24	4	3		7	
2007	7	31	3	3	1	6	1
2008	6	37	3	3		4	2
2009	3	40	3			3	
2010	5	45	2	2	1	4	1
2011	1	46	1			1	

APPENDIX C

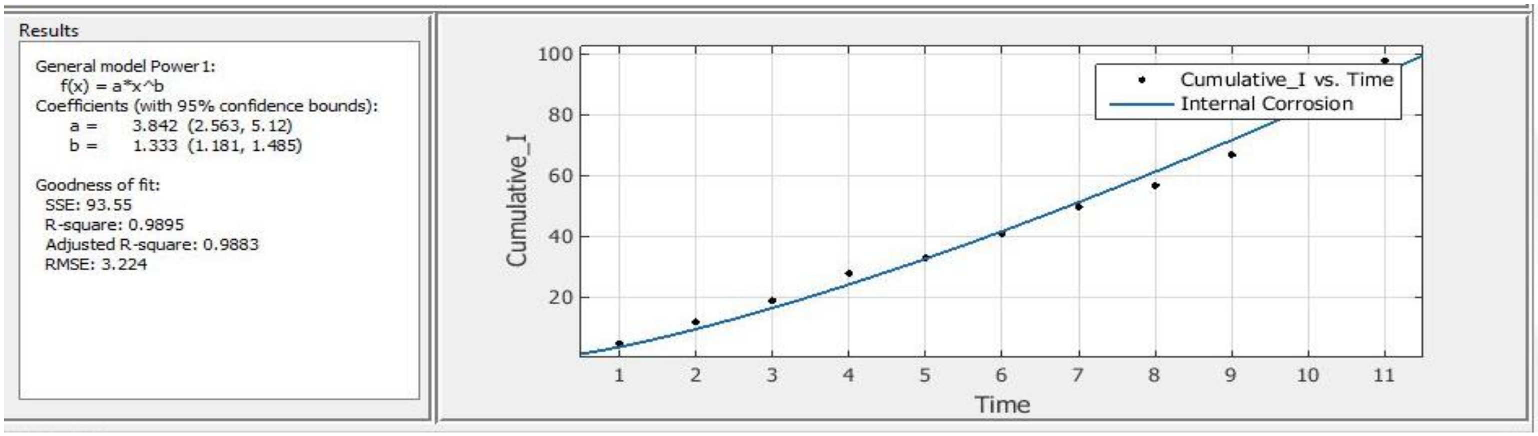


Figure C-1 Overall number of cumulative failures for internal corrosion plot from 2001 to 2011

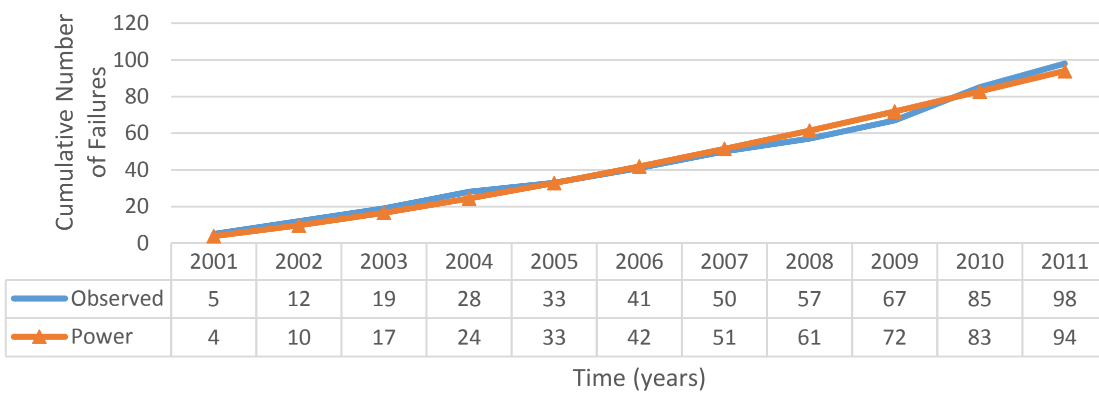


Figure C-2 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011

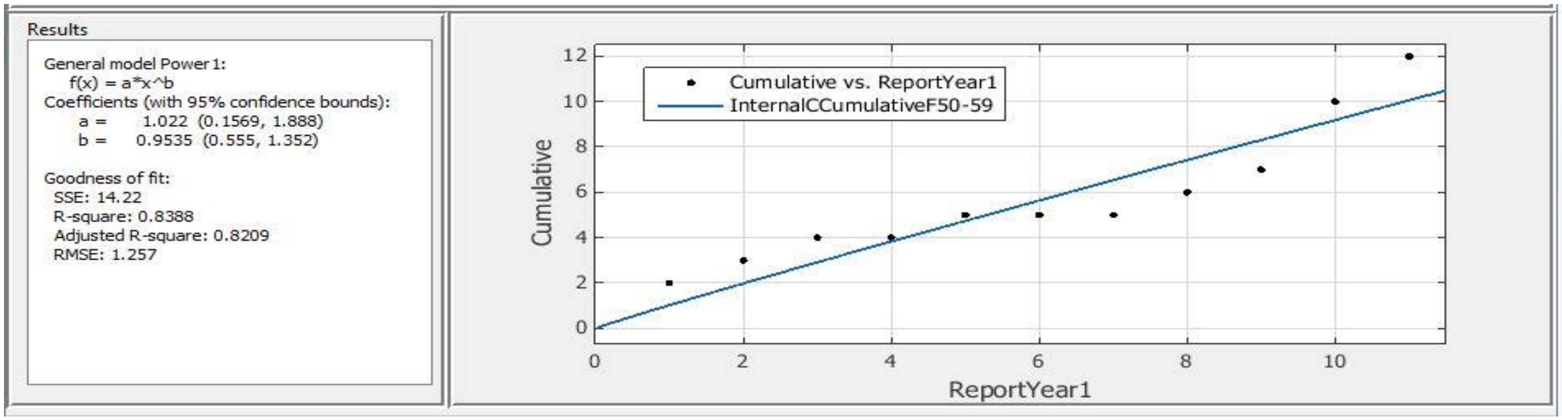
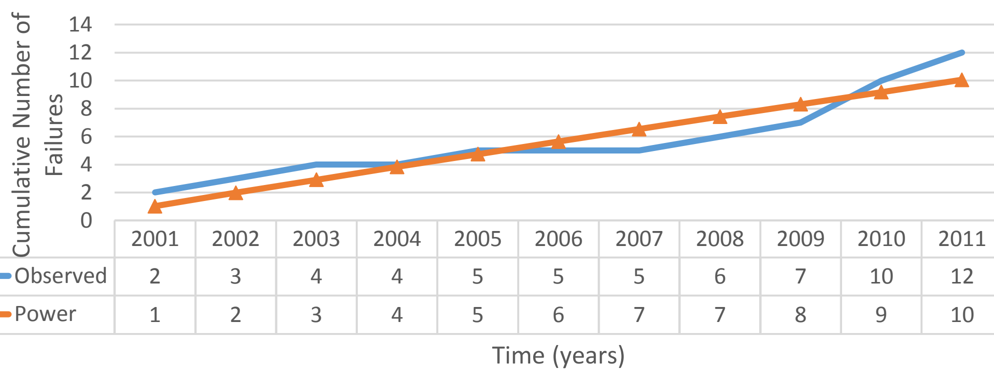


Figure C-3 Number of cumulative failures for internal corrosion plot from 2001 to 2011 by the decade of installation between 1950 and 1959



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Observed	2	3	4	4	5	5	5	6	7	10	12
Power	1	2	3	4	5	6	7	7	8	9	10

Figure C-4 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1950 and 1959

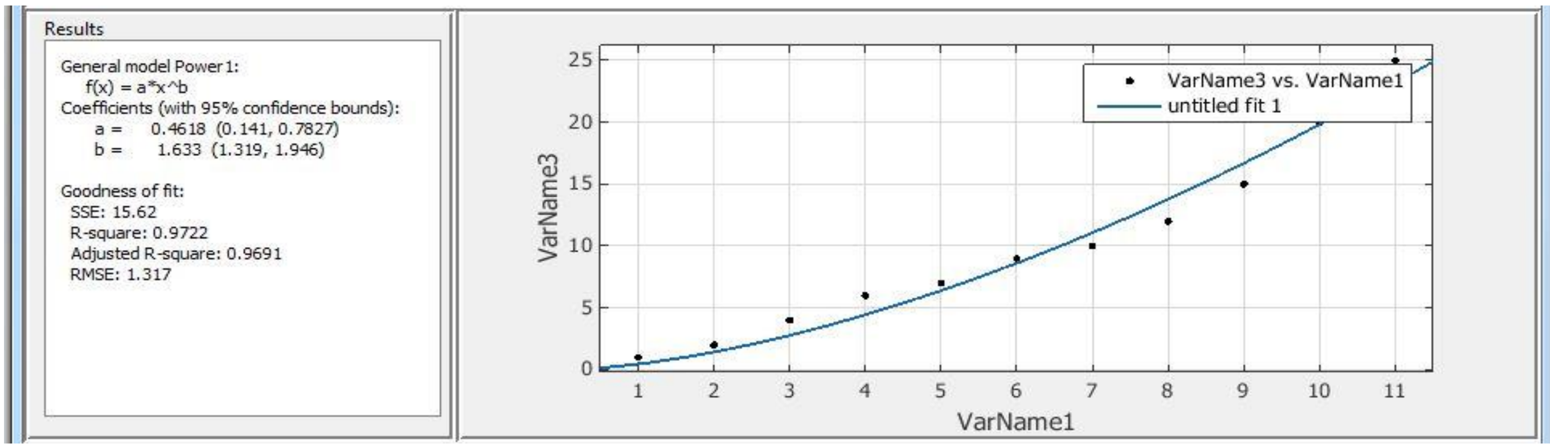


Figure C-5 Number of cumulative failures for internal corrosion plot from 2001 to 2011 by the decade of installation between 1960 and 1969

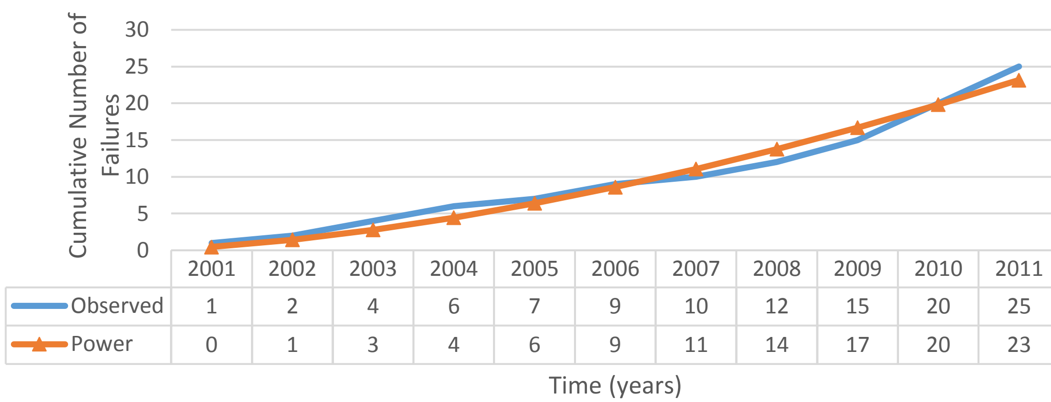


Figure C-6 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1960 and 1969

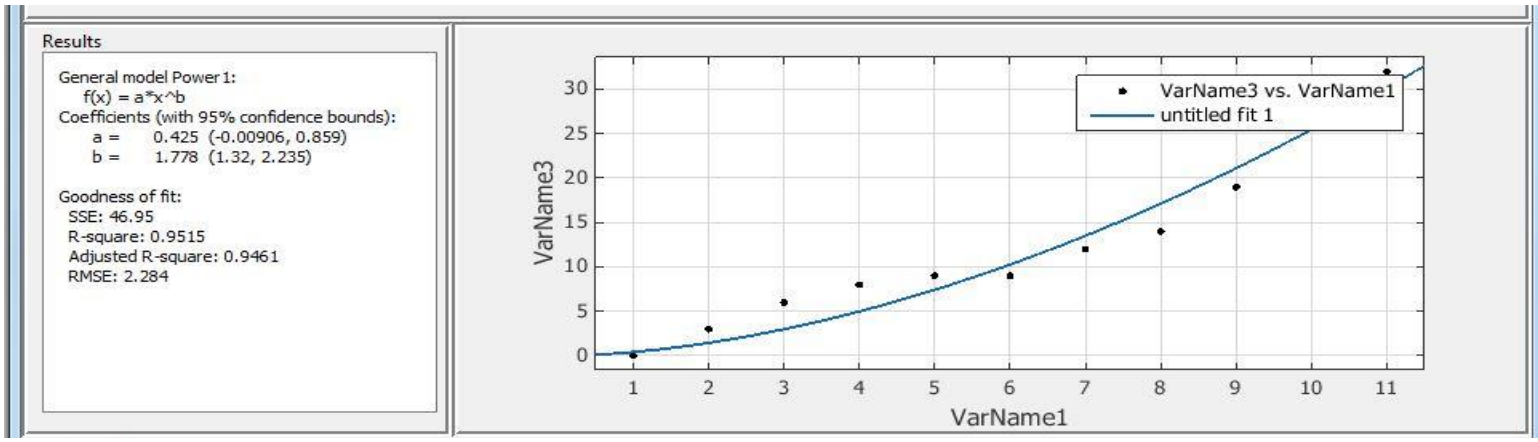


Figure C-7 Number of cumulative failures for internal corrosion plot from 2001 to 2011 by the decade of installation between 1970 and 1979

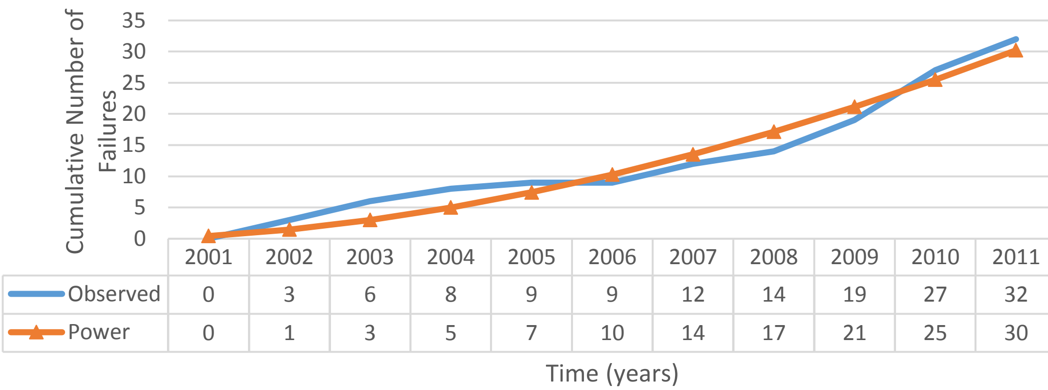


Figure C-8 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1970 and 1979

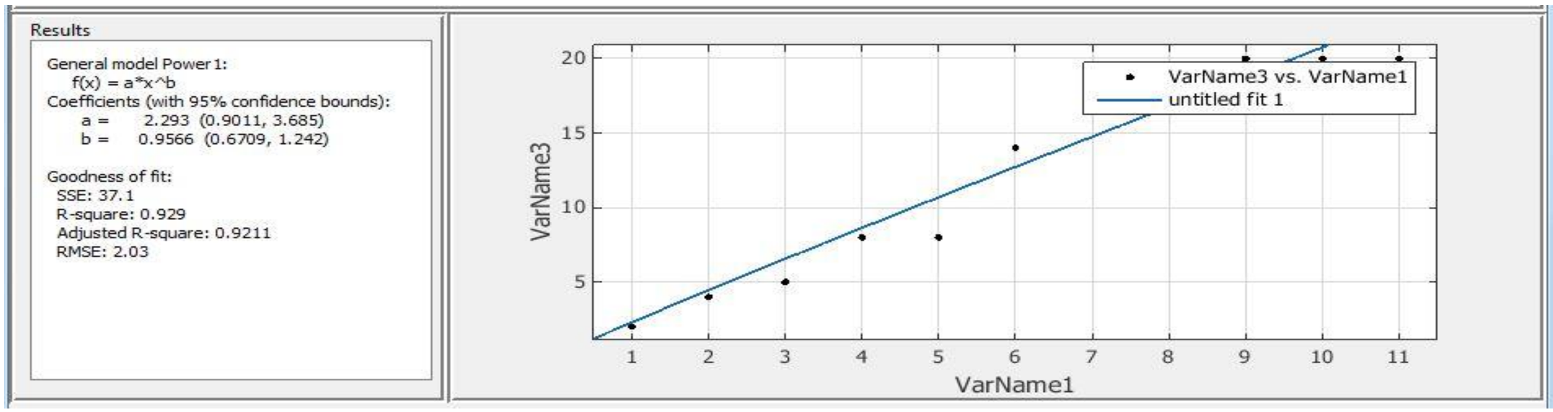


Figure C-9 Number of cumulative failures for internal corrosion plot from 2001 to 2011 by the decade of installation between 1980 and 1989

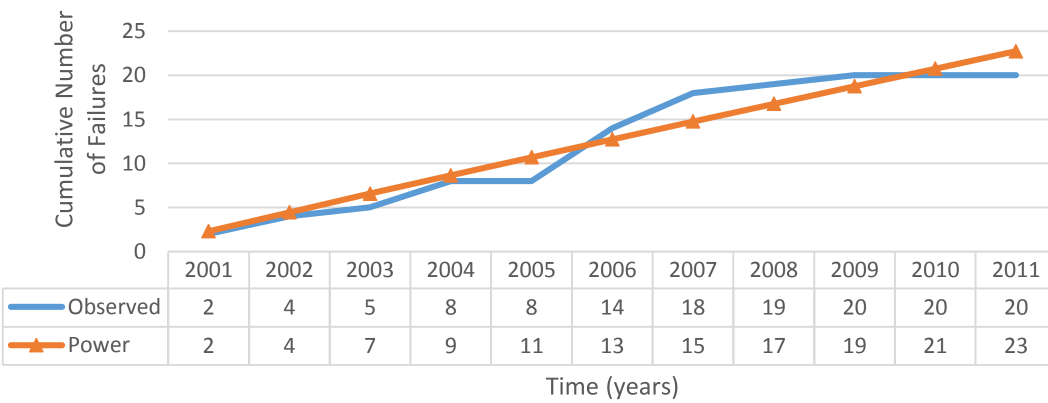
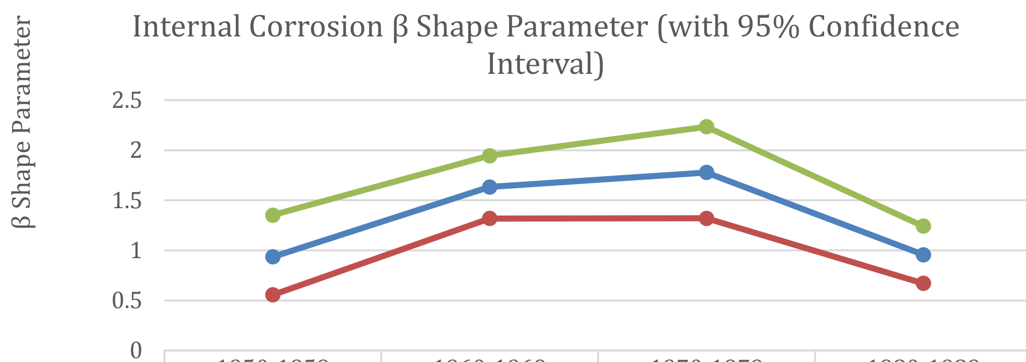


Figure C-10 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1980 and 1989

Table C-1 Summary of internal corrosion failures the maximum likelihood estimators (beta) values

Decade of Installation	**Internal Corrosion Beta Shape Parameter**	**CI (95%)Lower**	**CI (95%)Upper**
1920-1929			
1930-1939			
1940-1949			
1950-1959	0.935	0.555	1.352
1960-1969	1.633	1.319	1.946
1970-1979	1.778	1.32	2.235
1980-1989	0.9566	0.6709	1.242
1990-1999			
2000-2009			



	1950-1959	1960-1969	1970-1979	1980-1989
Beta	0.935	1.633	1.778	0.9566
CI(95%)Lower	0.555	1.319	1.32	0.6709
CI(95%)Upper	1.352	1.946	2.235	1.242

Figure C-11 Summary of internal corrosion failures the maximum likelihood estimators (beta) values as a graphical

APPENDIX D

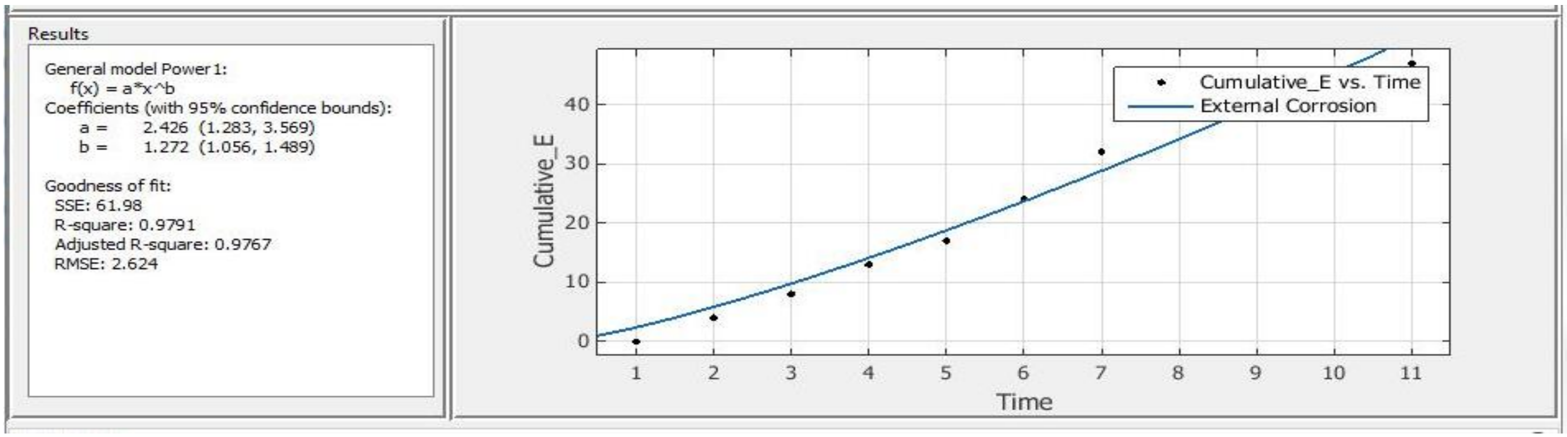
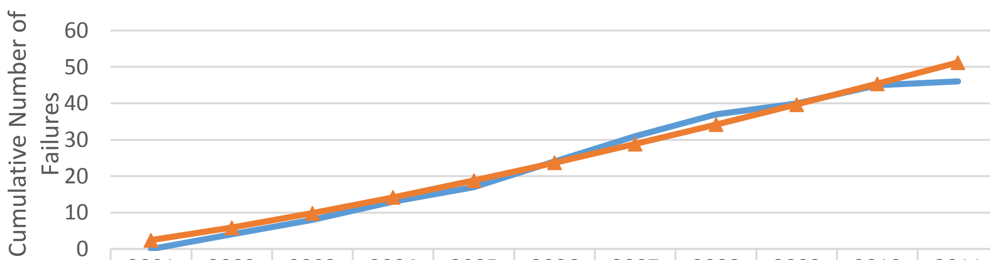


Figure D-1 Overall number of cumulative failures for external corrosion plot from 2001 to 2011



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Observed	0	4	8	13	17	24	31	37	40	45	46
Power	2	6	10	14	19	24	29	34	40	45	51

Time (years)

Figure D-2 Observed cumulative failures and estimated cumulative failures plots for external corrosion from 2001 to 2011

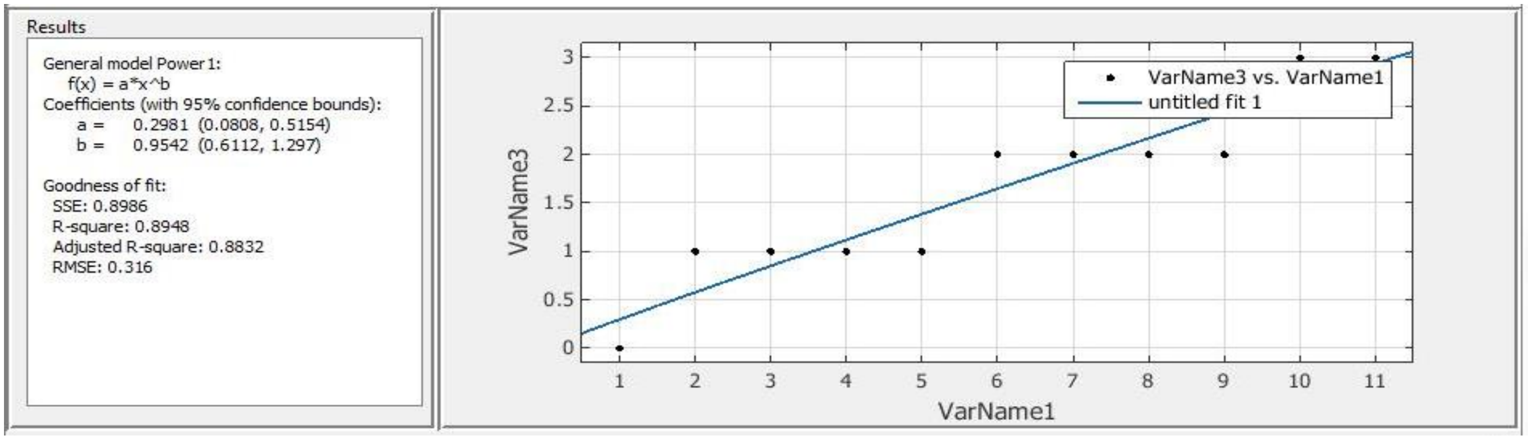
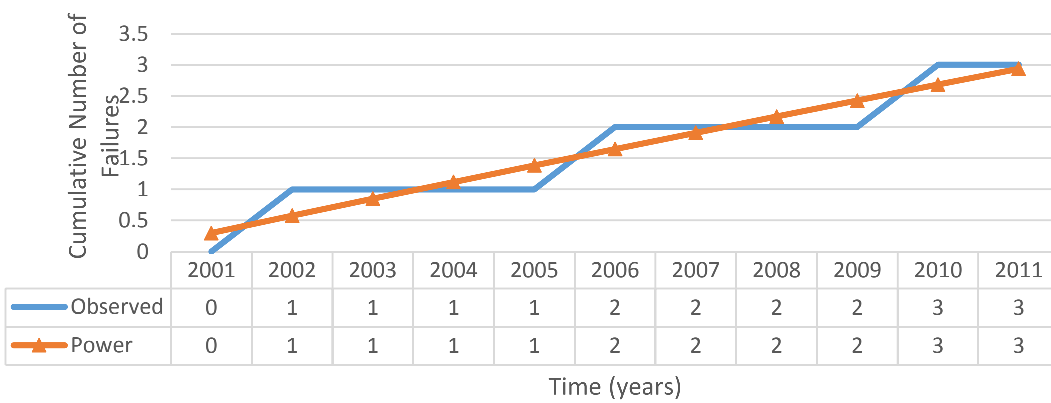


Figure D-3 Number of cumulative failures for external corrosion plot from 2001 to 2011 by the decade of installation between 1920 and 1929



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Observed	0	1	1	1	1	2	2	2	2	3	3
Power	0	1	1	1	1	2	2	2	2	3	3

Figure D-4 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1920 and 1929

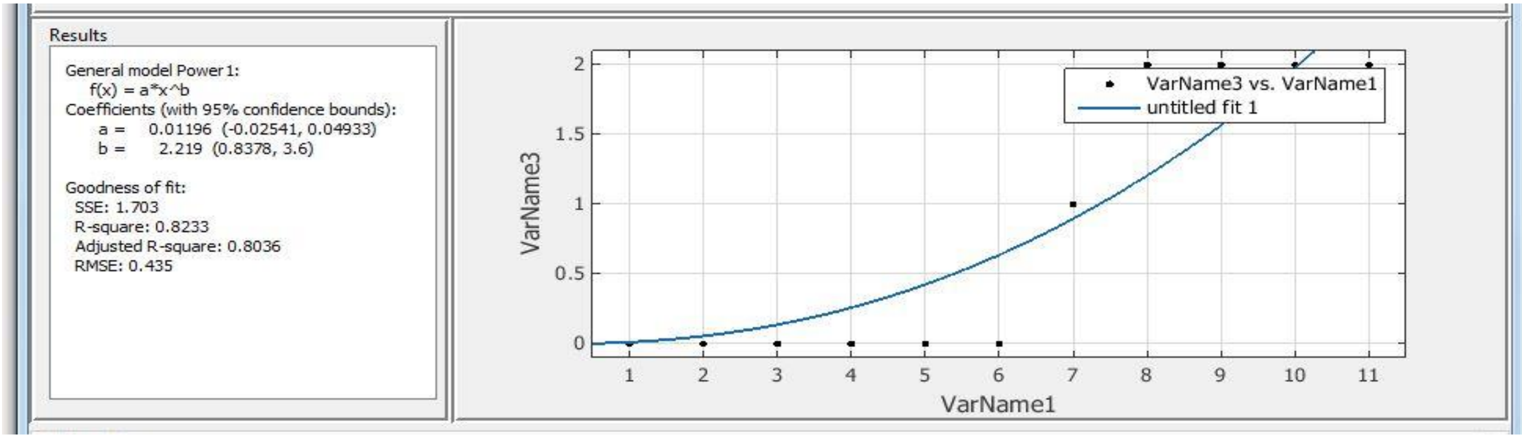


Figure D-5 Number of cumulative failures for external corrosion plot from 2001 to 2011 by the decade of installation between 1930 and 1939

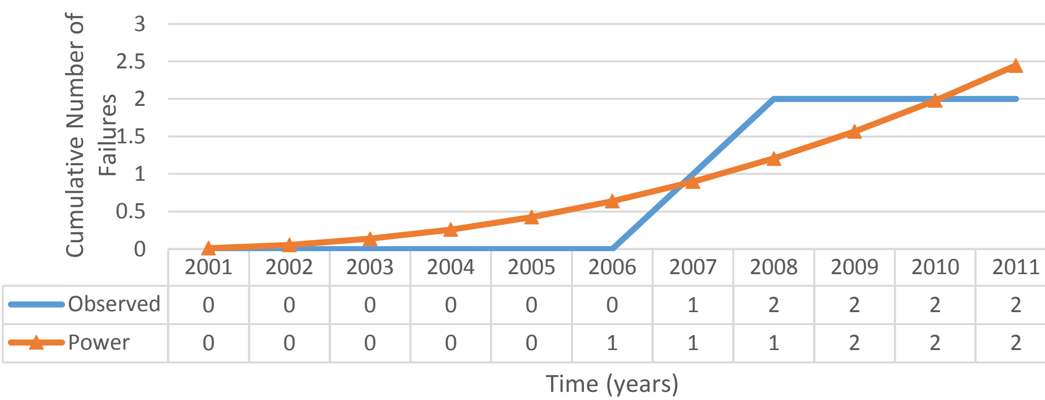


Figure D-6 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1930 and 1939

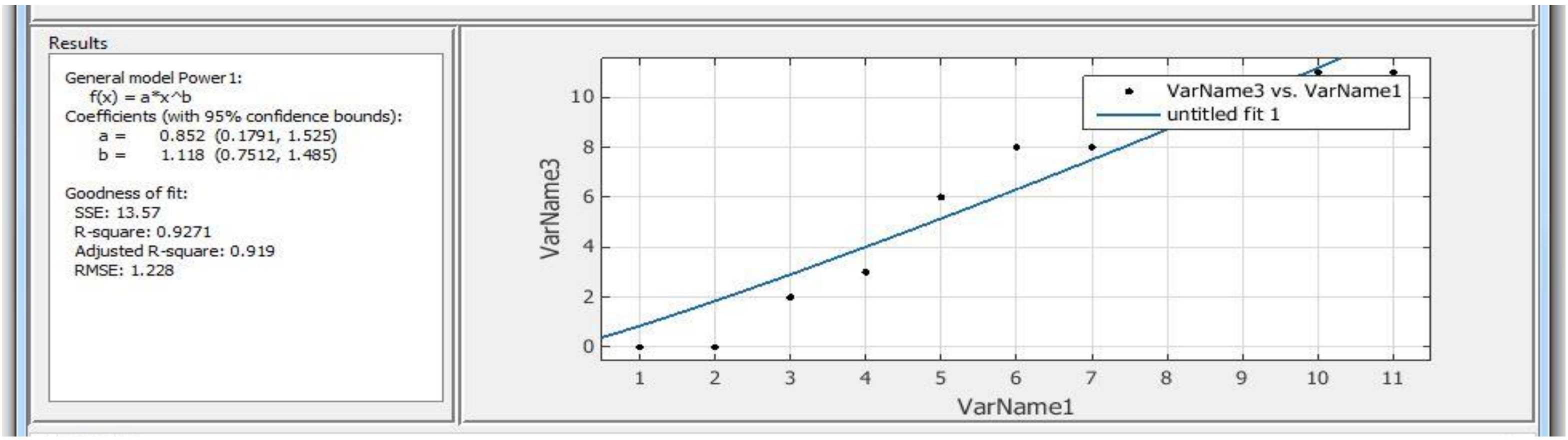
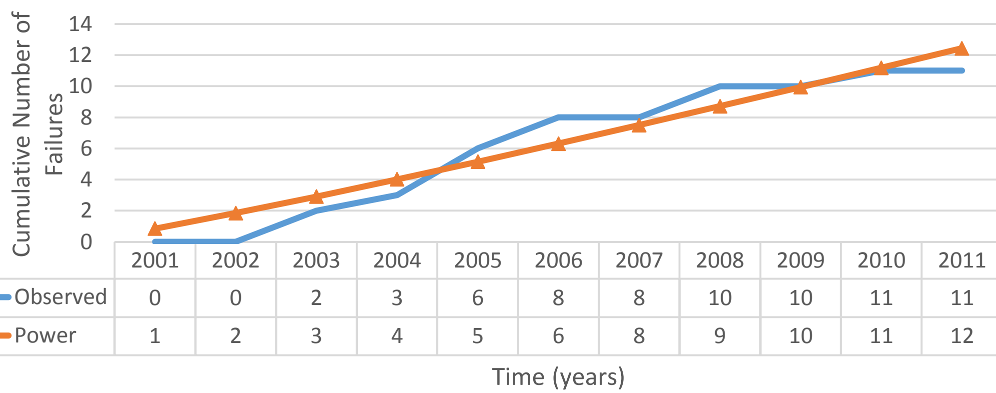


Figure D-7 Number of cumulative failures for external corrosion plot from 2001 to 2011 by the decade of installation between 1940 and 1949



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Observed	0	0	2	3	6	8	8	10	10	11	11
Power	1	2	3	4	5	6	8	9	10	11	12

Figure D-8 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1940 and 1949

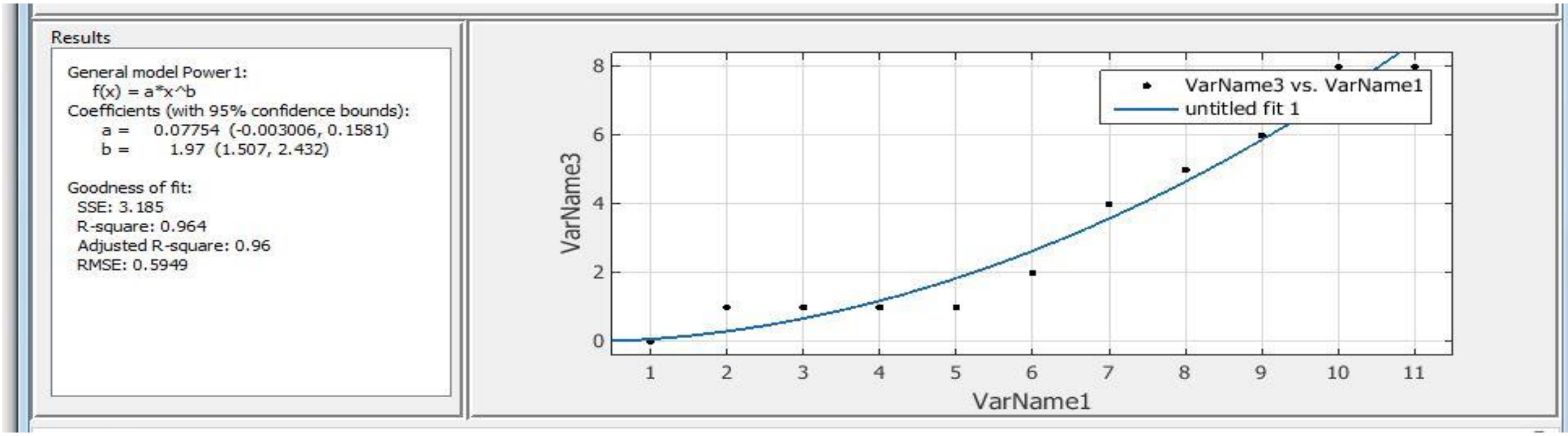


Figure D-9 Number of cumulative failures for external corrosion plot from 2001 to 2011 by the decade of installation between 1950 and 1959

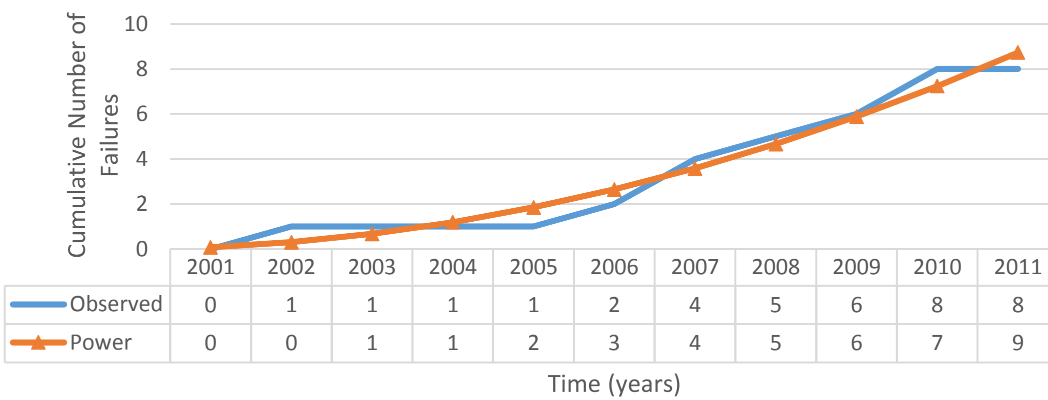


Figure D-10 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1950 and 1959

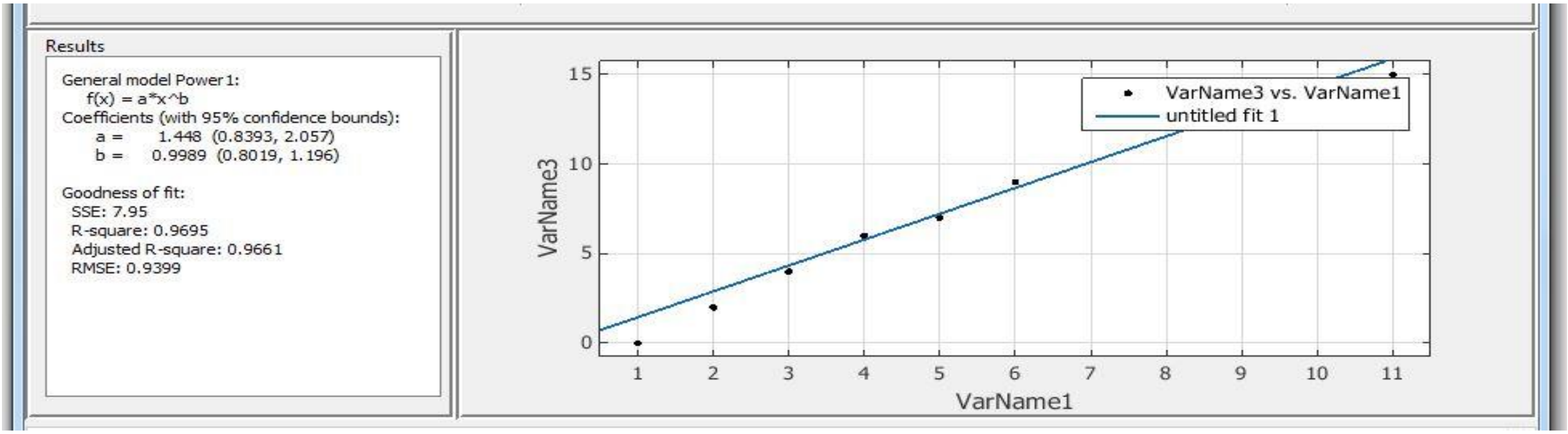
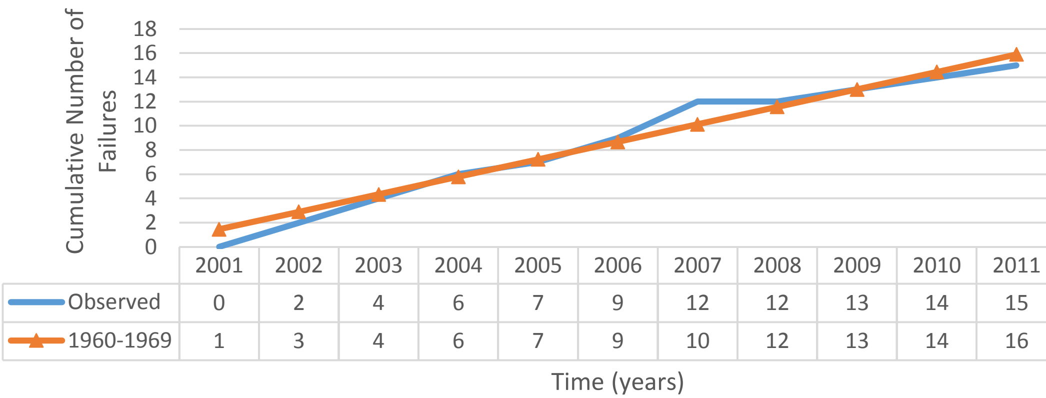


Figure D-11 Number of cumulative failures for external corrosion plot from 2001 to 2011 by the decade of installation between 1960 and 1969

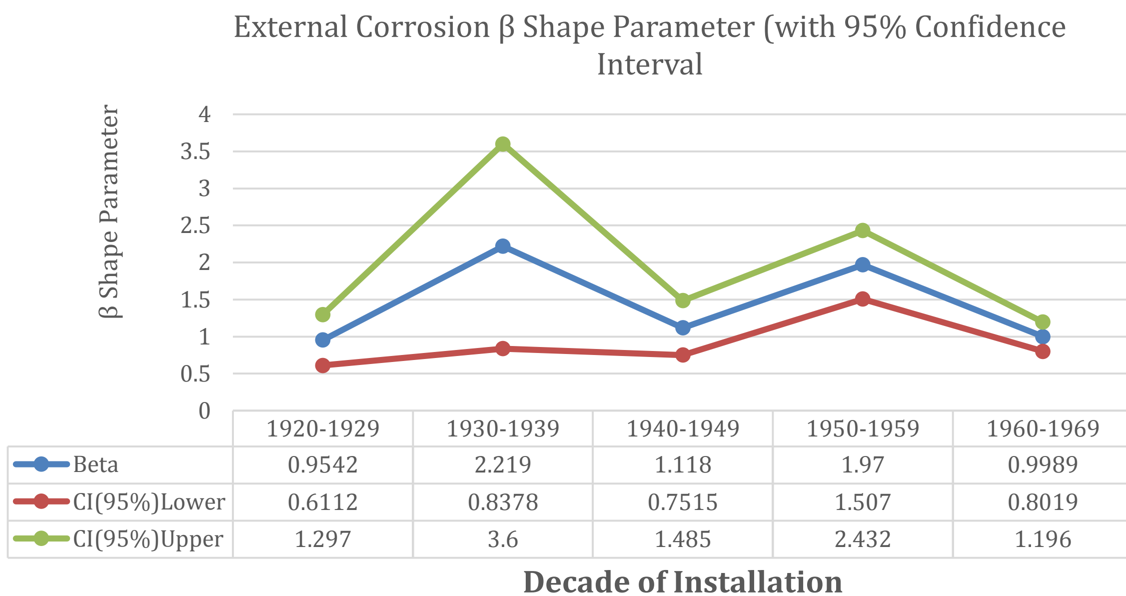


	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Observed	0	2	4	6	7	9	12	12	13	14	15
1960-1969	1	3	4	6	7	9	10	12	13	14	16

Figure D-12 Observed cumulative failures and estimated cumulative failures plots for internal corrosion from 2001 to 2011 by the decade of installation between 1960 and 1969

Table D-1 Summary of external corrosion failures the maximum likelihood estimators (beta) values

Decade of Installation	**External Corrosion Beta Shape Parameter**	**CI (95%)Lower**	**CI (95%)Upper**
1920-1929	0.9542	0.6112	1.297
1930-1939	2.219	0.8378	3.6
1940-1949	1.118	0.7515	1.485
1950-1959	1.97	1.507	2.432
1960-1969	0.9989	0.8019	1.196
1970-1979			
1980-1989			
1990-1999			
2000-2009			



	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969
Beta	0.9542	2.219	1.118	1.97	0.9989
CI(95%)Lower	0.6112	0.8378	0.7515	1.507	0.8019
CI(95%)Upper	1.297	3.6	1.485	2.432	1.196

Figure D-13 Summary of external corrosion failures the maximum likelihood estimators (beta) values as a graphical

APPENDIX E

Table E-1 Summary of the internal corrosion of cathodic protection status for the selected number of failures

Cathodic Protection Status	Percentage (%)
Cathodically Protected	94
Cathodic Protection Started after pipe installation (Late Start)	4
Cathodically Unprotected	2

Table E-2 Summary of the internal corrosion of coating status for the selected number of failures

Coating Status	Percentage (%)
Coated	97
Bare	3

Table E-3 Summary of the cause of corrosion related failures for internal corrosion

Type of Corrosion that Causes Failures	Percentage (%)
Galvanic	31
Stray Current	0
Improper Cathodic Protection	0
Microbiological	48
Stress Corrosion Cracking	0
Other	21

Table E-4 Summary of the external corrosion of the cathodic protection status for the selected number of failures

Cathodic Protection Status	**Percentage (%)**
Cathodically Protected	54
Cathodic Protection Started after pipe installation (Late Start)	37
Cathodically Unprotected	9

Table E-5 Summary of the external corrosion of the coating status for selected of number of failures

Coating Status	**Percentage (%)**
Coated	89
Bare	11

Table E-6 Summary of the cause of the corrosion related failures for external corrosion

Type of Corrosion that Causes Failures	**Percentage (%)**
Galvanic	42
Stray Current	0
Improper Cathodic Protection	5
Microbiological	11
Stress Corrosion Cracking	18
Other	24

APPENDIX F

Table F-1 Analysis of internal corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	5	5	92,441	0.054088554	0.054088554
2002	7	12	107,626	0.065040046	0.1191286
2003	7	19	107,195	0.065301553	0.184430153
2004	9	28	111,487	0.080726901	0.265157054
2005	5	33	107,377	0.046564907	0.311721961
2006	8	41	106,984	0.074777537	0.386499498
2007	9	50	106,328	0.084643744	0.471143242
2008	7	57	106,801	0.065542457	0.536685699
2009	10	67	106,870	0.093571629	0.630257328
2010	18	85	106,118	0.169622496	0.799879824
2011	13	98	105,419	0.123317429	0.923197252
Average			105,877	0.083927023	0.42565356
Standard Deviation				0.035228801	0.278268681

Table F-2 Analysis of internal corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1950 and 1959

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	2	2	31,323	0.063850844	0.063850844
2002	1	3	34,725	0.028797544	0.092648388
2003	1	4	35,048	0.028532149	0.121180537
2004	0	4	36,622	0	0.121180537
2005	1	5	35,267	0.028355462	0.149535999
2006	0	5	34,396	0	0.149535999
2007	0	5	34,410	0	0.149535999
2008	1	6	34,297	0.029156659	0.178692657
2009	1	7	34,260	0.029188266	0.207880923
2010	3	10	34,009	0.08821072	0.296091643
2011	2	12	33,878	0.059035782	0.355127425
Average			34,385	0.032284311	0.171387359
Standard Deviation				0.028333232	0.086564739

Table F-3 Analysis of internal corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1960 and 1969

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	1	1	23,545	0.042471862	0.042471862
2002	1	2	27,695	0.03610747	0.078579333
2003	2	4	26,761	0.074735455	0.153314788
2004	2	6	28,523	0.07011791	0.223432698
2005	1	7	28,017	0.035692459	0.259125156
2006	2	9	28,070	0.07125144	0.330376597
2007	1	10	27,970	0.035752809	0.366129406
2008	2	12	27,915	0.071647054	0.43777646
2009	3	15	27,871	0.107638247	0.545414707
2010	5	20	27,618	0.1810396	0.726454306
2011	5	25	27,578	0.181303241	0.907757547
Average			27,415	0.082523413	0.370075715
Standard Deviation				0.053565608	0.269466162

Table F-4 Analysis of internal corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1970 and 1979

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	7,341	0	0
2002	3	3	7,834	0.382944764	0.382944764
2003	3	6	8,751	0.342816867	0.72576163
2004	2	8	9,351	0.213880228	0.939641858
2005	1	9	8,540	0.117094538	1.056736396
2006	0	9	8,293	0	1.056736396
2007	3	12	8,150	0.368077385	1.424813781
2008	2	14	8,064	0.248004033	1.672817813
2009	5	19	8,065	0.619952271	2.292770084
2010	8	27	8,115	0.985877429	3.278647513
2011	5	32	7,976	0.626899191	3.905546705
Average			8,226	0.3550497	1.521492449
Standard Deviation				0.297194797	1.200557706

Table F-5 Analysis of internal corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1980 and 1989

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	2	2	7,442	0.268744961	0.268744961
2002	2	4	7,918	0.252578064	0.521323025
2003	1	5	7,795	0.128281703	0.649604728
2004	3	8	8,175	0.366957036	1.016561764
2005	0	8	8,237	0	1.016561764
2006	6	14	7,829	0.766370243	1.782932007
2007	4	18	7,683	0.520638772	2.303570778
2008	1	19	7,862	0.127193305	2.430764084
2009	1	20	7,900	0.126582823	2.557346907
2010	0	20	7,756	0	2.557346907
2011	0	20	7,590	0	2.557346907
Average			7,835	0.232486082	1.605645803
Standard Deviation				0.241490177	0.921285467

Table F-6 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	92,441	0	0
2002	4	4	107,626	0.037165741	0.037165741
2003	4	8	107,195	0.037315173	0.074480914
2004	5	13	111,487	0.044848278	0.119329192
2005	4	17	107,377	0.037251925	0.156581118
2006	7	24	106,984	0.065430345	0.222011462
2007	7	31	106,328	0.065834023	0.287845485
2008	6	37	106,801	0.056179249	0.344024735
2009	3	40	106,870	0.028071489	0.372096223
2010	5	45	106,118	0.04711736	0.419213583
2011	1	46	105,419	0.009485956	0.428699539
Average			105,877	0.038972685	0.223767999
Standard Deviation				0.020819727	0.156002744

Table F-7 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1920 and 1929

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	4,544	0	0
2002	1	1	5,594	0.178752895	0.178752895
2003	0	1	5,521	0	0.178752895
2004	0	1	5,651	0	0.178752895
2005	0	1	5,281	0	0.178752895
2006	1	2	5,127	0.195058619	0.373811514
2007	0	2	5,085	0	0.373811514
2008	0	2	4,581	0	0.373811514
2009	0	2	4,559	0	0.373811514
2010	1	3	5,041	0.198383531	0.572195045
2011	0	3	4,497	0	0.572195045
Average			5,044	0.052017731	0.304967975
Standard Deviation				0.08921446	0.178467027

Table F-8 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1930 and 1939

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	4,544	0	0
2002	0	0	5,594	0	0
2003	0	0	5,521	0	0
2004	0	0	5,651	0	0
2005	0	0	5,281	0	0
2006	0	0	5,127	0	0
2007	1	1	5,085	0.196656834	0.196656834
2008	1	2	4,581	0.218307722	0.414964556
2009	0	2	4,559	0	0.414964556
2010	0	2	5,041	0	0.414964556
2011	0	2	4,497	0	0.414964556
Average			5,044	0.037724051	0.168774096
Standard Deviation				0.084070225	0.203500514

Table F-9 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1940 and 1949

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	10,776	0	0
2002	0	0	11,883	0	0
2003	2	2	12,935	0.15461925	0.15461925
2004	1	3	11,989	0.083411935	0.238031185
2005	3	6	11,838	0.253411125	0.49144231
2006	2	8	11,782	0.16975234	0.66119465
2007	0	8	11,823	0	0.66119465
2008	2	10	11,527	0.173509009	0.834703659
2009	0	10	11,450	0	0.834703659
2010	1	11	11,351	0.088101139	0.922804798
2011	0	11	11,241	0	0.922804798
Average			11,690	0.083891345	0.520136269
Standard Deviation				0.091842022	0.362915541

Table F-10 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1950 and 1959

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	31,323	0	0
2002	1	1	34,725	0.028797544	0.028797544
2003	1	2	35,048	0.028532149	0.057329692
2004	0	2	36,622	0	0.057329692
2005	0	2	35,267	0	0.057329692
2006	1	3	34,396	0.029073497	0.086403189
2007	2	5	34,410	0.058123433	0.144526622
2008	1	6	34,297	0.029156659	0.173683281
2009	1	7	34,260	0.029188266	0.202871547
2010	2	9	34,009	0.058807146	0.261678693
2011	0	9	33,878	0	0.261678693
Average			34,385	0.023788972	0.12105715
Standard Deviation				0.021914065	0.09279757

Table F-11 Analysis of external corrosion failure rate and cumulative failure rate per 1,000 miles from 2001 to 2011 by the decade of installation between 1960 and 1969

Year incident occurred	Number of total incidents	Cumulative number of total incidents	Total mileage at the end of year (mile)	Failure rate (failure/1,000 mile)	Cumulative failure rate (failure/1,000 mile)
2001	0	0	23,545	0	0
2002	2	2	27,695	0.072214941	0.072214941
2003	1	3	26,761	0.037367728	0.109582668
2004	2	5	28,523	0.07011791	0.179700578
2005	1	6	28,017	0.035692459	0.215393037
2006	2	8	28,070	0.07125144	0.286644477
2007	3	11	27,970	0.107258428	0.393902905
2008	0	11	27,915	0	0.393902905
2009	1	12	27,871	0.035879416	0.429782321
2010	1	13	27,618	0.03620792	0.465990241
2011	1	14	27,578	0.036260648	0.502250889
Average			27,415	0.045659172	0.277214996
Standard Deviation				0.03219282	0.172389059

APPENDIX G

Table G-1 Estimation of new natural gas pipeline construction costs (ASRC Constructors Inc. et al., 2007)

	Construction Costs (cost /ft.)	Markup (cost /ft.)	Material Costs (cost /ft.)	Miscellaneous Costs (cost /ft.)	Project Indirect Costs (cost /ft.)	Total Project Costs (cost /ft.)
Project 1	$150.72	$30.14	$144.10	$30.35	$66.85	$422.16
Project 2	$150.09	$30.02	$143.64	$45.68	$66.85	$436.28
Project 3	$181.03	$36.21	$148.35	$53.48	$66.85	$485.92
Project 4	$143.77	$28.75	$131.49	$51.24	$67.11	$422.36
Project 5	$166.90	$33.38	$131.79	$80.04	$67.11	$479.22
Project 6	$150.46	$30.09	$143.30	$44.95	$66.85	$435.65
Average	**$157.16**	**$31.43**	**$140.45**	**$50.96**	**$66.94**	**$446.93**

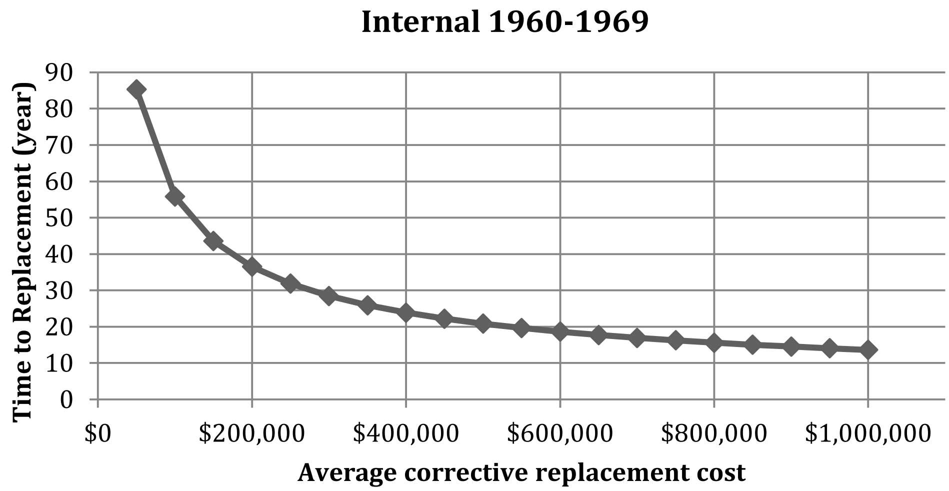


Figure G-1 Cost effectiveness as function of scheduled replacement time for internal corrosion from 2001 to 2011 by the decade of installation between 1960 and 1969

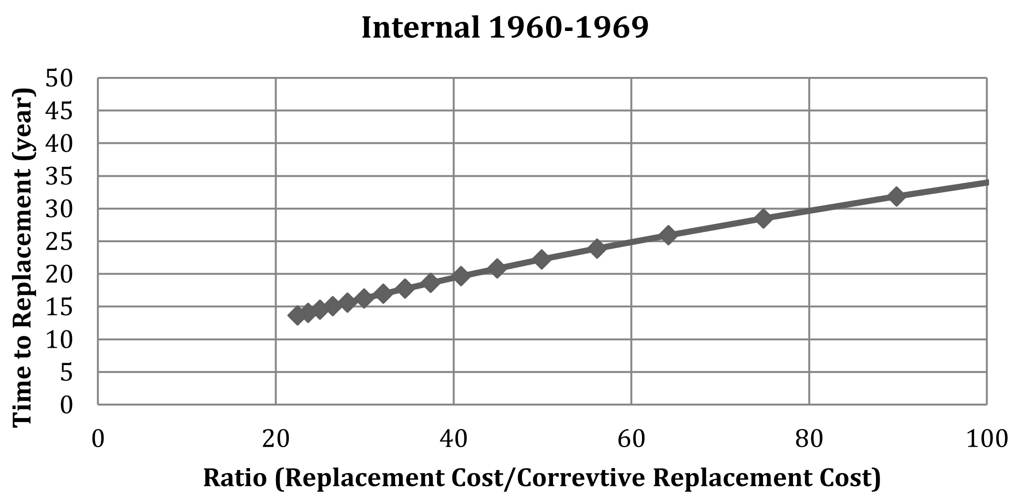


Figure G-2 Scheduled replacement time as function of ratio of preventive to corrective replacement costs for internal corrosion from 2001 to 2011 by the decade of installation between 1960 and 1969

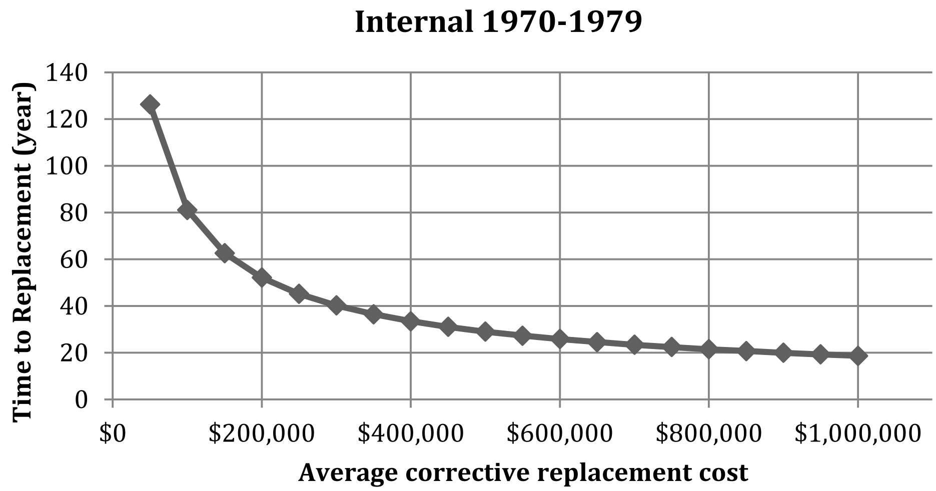


Figure G-4 Cost effectiveness as function of scheduled replacement time for internal corrosion from 2001 to 2011 by the decade of installation between 1970 and 1979

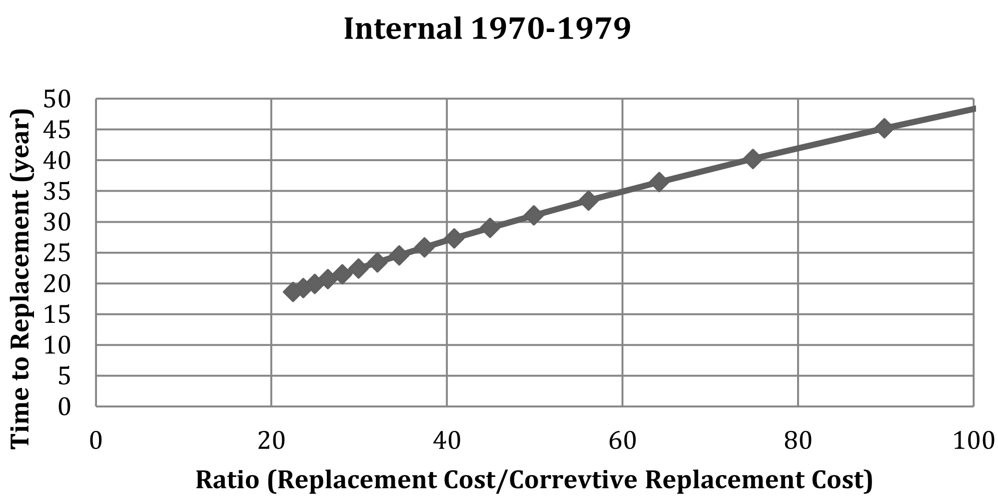


Figure G-4 Scheduled replacement time as function of ratio of preventive to corrective replacement costs for internal corrosion from 2001 to 2011 by the decade of installation between 1970 and 1979

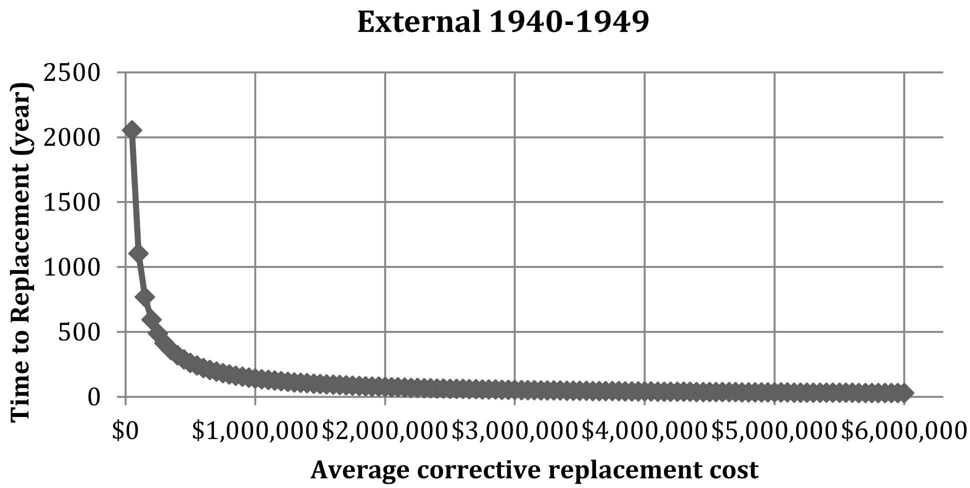


Figure G-5 Cost effectiveness as function of scheduled replacement time for external corrosion from 2001 to 2011 by the decade of installation between 1940 and 1949

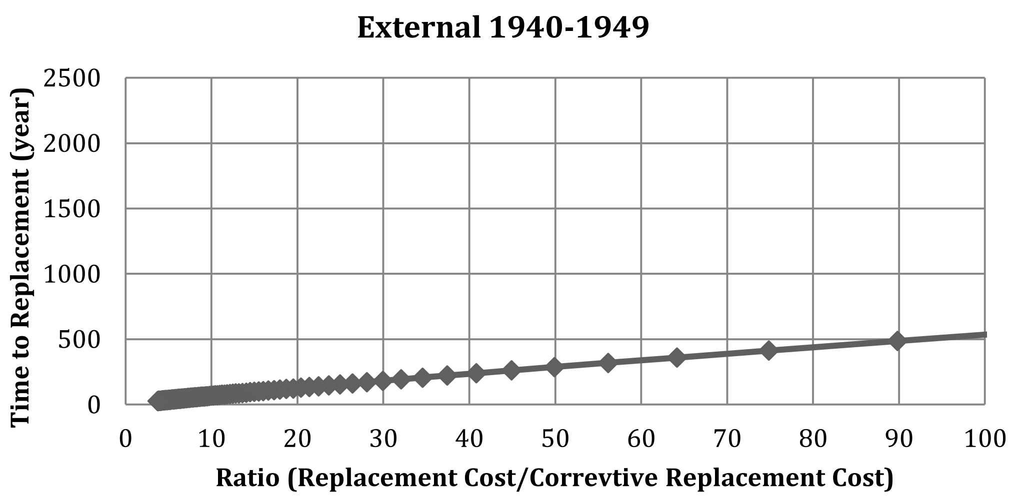


Figure G-6 Scheduled replacement time as function of ratio of preventive to corrective replacement costs for external corrosion from 2001 to 2011 by the decade of installation between 1940 and 1949

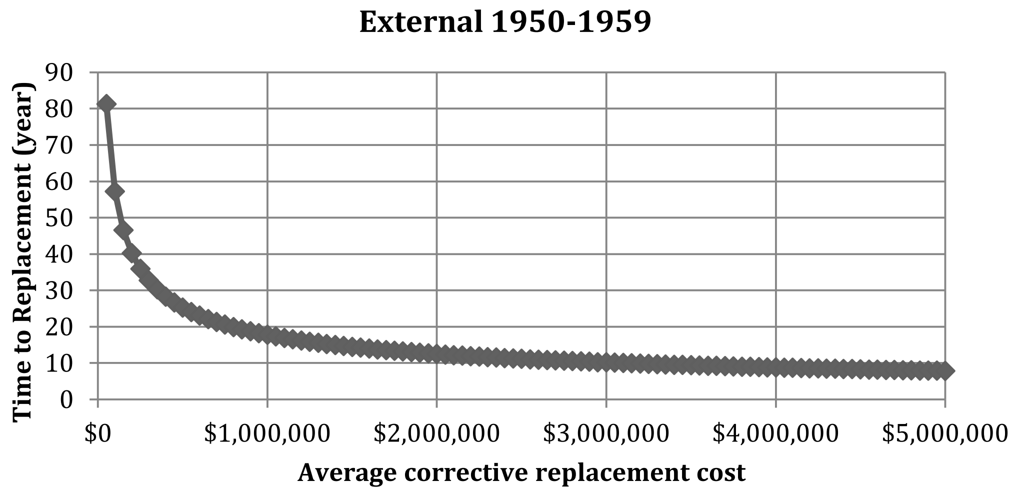


Figure G-7 Cost effectiveness as function of scheduled replacement time for external corrosion from 2001 to 2011 by the decade of installation between 1950 and 1959

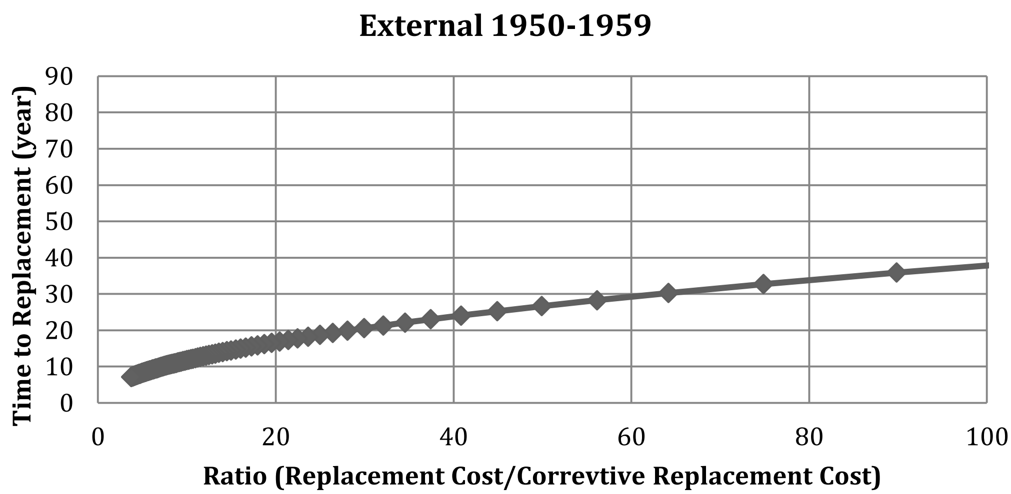


Figure G-8 Scheduled replacement time as function of ratio of preventive to corrective replacement costs for external corrosion from 2001 to 2011 by the decade of installation between 1950 and 1959

UNIT	COST SUMMARY CONSTRUCTION COSTS DESCRIPTION	Revision #3: 8/22/2006	($m) Total Cost	($) Cost/ft.
1	Direct Contractor Construction Costs		$ 117,902	$ 114.75
2	Indirect Contractor Construction Costs		$ 36,960	$ 35.97
	Sub-total Contractor Construction Costs		**$ 154,862**	$ 150.72
3	Contractor Markup (20% overhead and profit)			
	Sub-total Contractor Markup		**$ 30,972**	$ 30.14
	Total Contractor Costs		**$ 185,834**	$ 180.86
	MATERIAL COSTS			
1	Material (includes freight)			
	Total Material Costs		**$ 148,064**	$ 144.10
	MISCELLANEOUS COSTS			
1	Cathodic system protection (allowance, $18,000 per mile)	$ 18,000	$ 3,503	$ 3.41
2	SCADA and Communications (allowance, $3.00 per foot)	$ 3.00	$ 3,082	$ 3.00
3	Camp Rental, mobilzation, setup, & demobilize (subcontract, LS)	LS	$ 12,000	$ 11.68
4	Move camp (subcontract LS)	LS	$ 2,500	$ 2.43
5	Unload, haul and stockpile pipe & materials, based on pipe weight per cwt @4.30	$ 4.30	$ 4,603	$ 4.48
6	Air freight supplies, etc @ $25.00 per cwt	29,400	$ 735	$ 0.72
7	Open pits, mine and process materials, cubic yards at $12.50 per cubic yard	350,000	$ 4,375	$ 4.26
8	Contractor maintenance and warehouse facilities 300 days @ $1300 per day	$ 1,300	$ 390	$ 0.38
	Total Miscellaneous Costs		**$ 31,188**	$ 30.35
	PROJECT INDIRECT COSTS	**Cost per ft.**		
	Detailed Engineering	$ 19.28	$ 19,810	$ 19.28
1	Surveying	$ 3.00	$ 3,082	$ 3.00
2	Permitting	$ 3.74	$ 3,843	$ 3.74
3	Quality Control	$ 11.61	$ 11,929	$ 11.61
4	Project Management, etc.	$ 25.48	$ 26,180	$ 25.48
5	Puchasing and expediting	$ 3.74	$ 3,843	$ 3.74
6	**Total Project Indirect Costs**		**$ 68,688**	$ 66.85
	SUB-TOTAL, TOTAL PIPELINE COSTS		**$ 433,774**	$ 422.17
	OWNERSHIP COSTS			
	Project management		$ -	$ -
1	**Cost of Money**		$ -	$ -
2	**Total Ownership Costs**		$ -	$ -
	CONTINGENCY ALLOWANCE			
	Contingency			
1	**Total Contingency cost**			$ -
	TOTAL SUMMER CONSTRUCTION PIPELINE COSTS		**$ 433,774**	$ 422.17
	COST PER DIA.- INCH MILE $		**$ 111,453**	

Figure G-1 Pipeline cost estimates for Alaska spur gas pipeline study-project 1 (ASRC Constructors Inc. et al., 2007)

UNIT	DESCRIPTION		Total Cost ($m)	Cost/ft. ($)
	COST SUMMARY	Revised #2: 8/22/2006		
	CONSTRUCTION COSTS			
1	Direct Contractor Construction Costs		$ 49,457	$ 101.81
2	Indirect Contractor Construction Costs		$ 23,449	$ 48.27
	Sub-total Contractor Construction Costs		**$ 72,906**	$ 150.09
3	Contractor Markup (20% overhead and profit)			
	Sub-total Contractor Markup		**$ 14,581**	$ 30.02
	Total Contractor Costs		**$ 87,487**	$ 180.10
	MATERIAL COSTS			
1	Material (includes freight)			
	Total Material Costs		**$ 69,773**	$ 143.64
	MISCELLANEOUS COSTS			
1	Cathodic system protection (allowance, $18,000 per mile)	$ 18,000	$ 1,656	$ 3.41
2	SCADA and Communications (allowance, $3.00 per foot)	$ 3.00	$ 1,457	$ 3.00
3	Camp Rental, mobilzation, setup, & demobilize (subcontract, LS)	LS	$ 12,000	$ 24.70
4	Move camp (subcontract LS)	LS	$ -	$ -
5	Unload, haul and stockpile pipe & materials, based on pipe weight per cwt @4.30	$ 4.30	$ 2,162	$ 4.45
6	Air freight supplies, etc @ $25.00 per cwt	11,600	$ 290	$ 0.60
7	Open pits, mine and process materials, cubic yards at $12.50 per cubic yard	350,000	$ 4,375	$ 9.01
8	Contractor mainenance and warehouse facilities 190 days @ $3100 per day	1,300	$ 247	$ 0.51
	Total Miscellaneous Costs		**$ 22,188**	$ 45.68
	PROJECT INDIRECT COSTS	**Cost per ft.**		
1	Detailed Engineering	$ 19.28	$ 9,365	$ 19.28
2	Surveying	$ 3.00	$ 1,457	$ 3.00
3	Permitting	$ 3.74	$ 1,817	$ 3.74
4	Quality Control	$ 11.61	$ 5,640	$ 11.61
5	Project Management, etc.	$ 25.48	$ 12,377	$ 25.48
6	Puchasing and expediting	$ 3.74	$ 1,817	$ 3.74
	Total Project Indirect Costs		**$ 32,473**	$ 66.85
	SUB-TOTAL, TOTAL PIPELINE COSTS		**$ 211,921**	$ 436.27
	OWNERSHIP COSTS			
1	**Project management**		$ -	$ -
2	**Cost of Money**		$ -	$ -
	Total Ownership Costs		**$ -**	$ -
	CONTINGENCY ALLOWANCE			
1	Contingency			
	Total Contingency cost			$ -
	TOTAL SUMMER CONSTRUCTION PIPELINE COSTS		**$ 211,921**	$ 436.27
	COST PER DIA.- INCH MILE $		**$ 115,174**	

Figure G-2 Pipeline cost estimates for Alaska spur gas pipeline study-project 2 (ASRC Constructors Inc. et al., 2007)

COST SUMMARY		Revision #2: 8/22/2006		
	CONSTRUCTION COSTS		($m)	($)
UNIT	DESCRIPTION		Total Cost	Cost/ft.
1	Direct Contractor Construction Costs		$ 48,949	$ 123.44
2	Indirect Contractor Construction Costs		$ 22,834	$ 57.58
	Sub-total Contractor Construction Costs		$ 71,783	$ 181.03
3	Contractor Markup (20% overhead and profit)			
	Sub-total Contractor Markup		$ 14,357	$ 36.21
	Total Contractor Costs		$ 86,140	$ 217.23
	MATERIAL COSTS			
1	Material (includes freight)			
	Total Material Costs		$ 58,826	$ 148.35
	MISCELLANEOUS COSTS			
1	Cathodic system protection (allowance, $18,000 per mile)	$ 18,000	$ 1,352	$ 3.41
2	SCADA and Communications (allowance, $3.00 per foot)	$ 3.00	$ 1,190	$ 3.00
3	Camp Rental, mobilzation, setup, & demobilize (subcontract, LS)	LS	$ 12,000	$ 30.26
4	Move camp (subcontract LS)	LS	$ -	$ -
5	Unload, haul and stockpile pipe & materials, based on pipe weight per cwt @4.30	$ 4.30	$ 1,823	$ 4.60
6	Air freight supplies, etc @ $25.00 per cwt	11,400	$ 285	$ 0.72
7	Open pits, mine and process materials, cubic yards at $12.50 per cubic yard	350,000	$ 4,375	$ 11.03
8	Contractor maintenance and warehouse facilities @ 140 days @ $3100 per dayh	1,300	$ 182	$ 0.46
			$ -	$ -
			$ -	$ -
			$ -	$ -
			$ -	$ -
	Total Miscellaneous Costs		$ 21,207	$ 53.48
	PROJECT INDIRECT COSTS	Cost per ft.		
1	Detailed Engineering	$ 19.28	$ 7,645	$ 19.28
2	Surveying	$ 3.00	$ 1,190	$ 3.00
3	Permitting	$ 3.74	$ 1,483	$ 3.74
4	Quality Control	$ 11.61	$ 4,604	$ 11.61
5	Project Management, etc.	$ 25.48	$ 10,104	$ 25.48
6	Puchasing and expediting	$ 3.74	$ 1,483	$ 3.74
	Total Project Indirect Costs		$ 26,508	$ 66.85
	SUB-TOTAL, TOTAL PIPELINE COSTS		$ 192,680	$ 485.92
	OWNERSHIP COSTS			
1	**Project management**		$ -	$ -
2	**Cost of Money**		$ -	$ -
	Total Ownership Costs		$ -	$ -
	CONTINGENCY ALLOWANCE			
1	Contingency			
	Total Contingency cost			$ -
	TOTAL SUMMER CONSTRUCTION PIPELINE COSTS		$ 192,680	$ 485.92

Figure G-3 Pipeline cost estimates for Alaska spur gas pipeline study-project 3 (ASRC Constructors Inc. et al., 2007)