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CASE NO. 07-829-GA-AIR; 07-830-GA-ALT; 07-831-GA-AAM; 08-169-GA-ALT; 06-1453-GA-UNC

EXHIBITS OF TRANSCRIPT ELECTRONICALLY FILED FOR HEARING HELD ON WEDNESDAY, AUGUST 6, 2008 BEFORE A.E. C. PIRIK AND S. FARKAS.

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Distribution Service, Approval of an Alternative Rate Plan for its Gas Distribution Service, Approval to Change Accounting Methods, Approval of Tariffs to Recover Certain Costs Associated with a Pipeline Infrastructure Replacement Program Through an Automatic Adjustment Clause, and for Certain Accounting Treatment, and Approval of Tariffs to Recover Certain Costs Associated with Automated Meter Reading Deployment Through an Automatic Adjustment Clause, and for Certain Accounting Treatment.	:	Case Nos. 07-829-GA-AIR 07-830-GA-ALT 07-831-GA-AAM 08-169-GA-ALT 06-1453-GA-UNC

- - -

VOLUME II - PROCEEDINGS

before Ms. Christine M.T. Pirik and Mr. Scott Farkas, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 8:30 a.m. on Wednesday, August 6, 2008.

EXHIBITS ONLY

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EXHIBIT

DEO Ex. 11

BUILDING A WORLD OF DIFFERENCE®

DOMINION EAST OHIO

Comparative Analysis of the Bare Steel Piping of Dominion East Ohio

June 18, 2008

Confidential Attorney Client Work Product Prepared in Anticipation of Litigation

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APPENDICES

EXECUTIVE SUMMARY

At the request of Dominion East Ohio ("Dominion" or the "Company"), Black & Veatch Corporation ("Black & Veatch") has performed a comparative analysis of Dominion's bare steel distribution and transmission piping data. This analysis was based on information reported annually by natural gas distribution and transmission operators to the U.S. Department of Transportation, Office of Pipeline Safety ("DOT") for the years 2002 through 2006 and data provided by Dominion.

The purpose of this analysis was to provide Dominion with: 1) a better understanding of how it compares to national and regional companies on benchmarks related to aging pipeline infrastructure on natural gas distribution and transmission systems; and 2) an independent opinion on the need for Dominion to accelerate its replacement program for its: bare steel and cast & wrought iron mains, bare steel services, and bare steel transmission piping.

The analysis of the 2006 DOT distribution data reveals that Dominion has the largest inventory of bare steel mains (3,862 miles) remaining in service of all of the nation's gas distribution operating companies reporting to the DOT (1,481 companies), and in 2006 it reported the highest number of corrosion leaks on mains (3,391 leaks) for all companies reporting. During the last two years Dominion had taken extra efforts to significantly reduce the number of its year-end backlog of leaks waiting to be repaired. The impact of this effort may have had the effect of increasing the number of corrosion leaks reported in 2006 and 2007. This is because as a larger amount of backlog leaks were repaired they were then classified according to initial cause, including corrosion. A trend line analysis of the 2002-2005 period estimates a 2006 level of corrosion leaks on mains to be 2,855, which would have ranked second highest in the nation.

While Dominion has a high number of corrosion leaks compared to other distribution companies, on the measure of corrosion leaks per mile of non-cathodically protected bare and coated steel main experienced during 2006, Dominion had a lower value at 0.56 compared to the average value of 1.29 for regional companies and 0.96 for national companies (not including Dominion) that have more than 50 miles of bare steel main in their distribution systems. The data also shows that Dominion's corrosion leaks and corrosion leak rates on mains have increased steadily since 2003.

Dominion's 2007 data also shows that 80% (3,582) of its total leaks on mains (4,490) were caused by corrosion.

Dominion reports that it has 222 miles of bare steel mains that were installed approximately 100 years ago (1900-1910) and another 927 miles of bare steel mains that were installed from 1910 to 1939. Half of Dominion's bare steel and cast or wrought iron mains (2,044) were installed before 1950. Experience and data have taught the natural gas industry that these aging mains will need to be either retired, or replaced with plastic or cathodically protected steel mains. In our opinion it is not a matter of "if", but rather "when" these mains will need to be replaced, in order to reduce the risks and costs associated with leaking gas mains, as well as to deliver on Dominion's overarching commitment to safety.

In 2006 Dominion replaced 34 miles of its bare steel mains at a rate of approximately 0.9% per year as compared to the national average replacement rate of 3.7% per year. At the 2006 Dominion replacement rate, it would take the Company 114 years to eliminate its aging bare steel mains compared to 26 years for the nation as a whole (not including Dominion). Dominion's proposed term for its accelerated replacement program (25 years) is in line with the national average. As the

company with the largest amount of bare steel in the nation and a history of a high number of corrosion leaks on mains, Black and Veatch believes that such action by Dominion is prudent and reasonable.

The focus on the number of corrosion leaks is critical because science and industry studies demonstrate that "when a section of pipeline system starts to develop leaks, experience has shown that further leaks will develop at a continuously increasing rate."[1] Furthermore, it is Black & Veatch's experience that corrosion leaks on underground non-cathodically protected (unprotected) bare and coated steel pipe can be expected to increase exponentially over time until the pipes are either cathodically protected, retired, or replaced.

In the case of Dominion, the data also shows that even with this high number of corrosion leaks per year, the Company maintained a rate of corrosion leaks on mains per mile of bare and non-protected coated steel main that was lower than the average rate of regional companies. However, as the bare steel pipe inventory continues to age, at the current rate of main replacement, we believe Dominion's number of corrosion leaks will increase.

For example, if the corrosion leak rate for Dominion was to rise to the level of the average leak rate for regional companies in 2006 that would mean that Dominion's annual corrosion leaks would increase from 3,391 to between 5,716 and 7,855 corrosion leaks (a 69% to 132% increase) depending on the calculation method. In either case, a 69% increase in leaks alone could create additional safety risks, as well as create a serious leak management challenge for the Company. It is our opinion that the focus of Dominion's efforts must be towards accelerating the identification and replacement of its aging higher risk mains before the leak rate becomes excessive and it finds itself in a crisis mode of replacement. Without instituting such an accelerated replacement effort, it is our opinion that Dominion will face the risks associated with an ever increasing number of corrosion leaks.

Dominion has 112 miles of cast and wrought iron mains in its distribution system. Cast iron mains, while less prone to corrosion leakage, are also poor performers due to their joining methods. Cast iron sections of pipe are typically joined together with calked lead and jute bell and spigot joints, which leak increasingly over time. In addition, because of its brittle failure mode, leaks in cast iron pipe due to cracks or breaks, can be sudden and serious. This is especially true with small diameter piping. Seventy seven percent of Dominion's cast and wrought iron main inventory is less than or equal to 4 inches in diameter. Such small diameter mains experience higher stresses when placed under bending moments due to soil loadings and such higher stresses pose an increased risk of cracking.

Dominion also has 35 miles of bare steel transmission piping remaining in its system. This is likely the oldest pipe in Dominion's transmission system and older transmission pipes generally pose the highest risk. Unless Dominion's bare steel transmission pipe can be assessed with in-line intelligent inspection (ILI) devices (smart pigs), or similar technologies to identify and target the most severely affected areas, we believe implementing pipe replacement programs for the remaining bare steel transmission inventory best reduces this risk.

[1] Peabody's "Control of Pipeline Corrosion," second edition 2001. Chapter 15, Page 290.

We support Dominion's PIR program efforts to prioritize its higher risk mains for replacement first, and accelerate the replacement of these aging mains before the leak rates increase. Without such an accelerated replacement effort, it is our opinion, supported by corrosion science and data, that Dominion will face the risks associated with an increasing number of corrosion leaks.

We believe it is in the best interest of Dominion's customers that Dominion implement its PIR program, rather than expose customers to the ever-increasing risk and expense of emergency repairs to leaks on such mains, and then replacing them in response to a harder to manage leak rate.

In addition to the customer safety and system reliability benefits mentioned throughout this report, a well planned accelerated main replacement program would have qualitative benefits for the public such as fewer unplanned disruptions to traffic on roads for emergency gas leak repairs, and improved coordination with local town and village governments. Although these quality of life benefits are dwarfed by the safety and reliability benefits, it is Black & Veatch's opinion that utility system operators must prudently manage their systems in a manner that protects the customer, assures the integrity of the gas system, and does not adversely inconvenience the customers' quality of life.

We believe that with Dominion experiencing as many corrosion leaks as it has, and a recent bare steel mains replacement rate of between 114 and 155 years (2006 and 2007 respectively), its proposed Pipeline Infrastructure Replacement (PIR) program is an example of what is needed to continue to be a responsible system operator. We believe that Dominion should implement a systematic accelerated replacement of its aging higher risk mains and services.

Black & Veatch recommends that the Public Utility Commission of Ohio ("PUCO") approve the implementation of Dominion's proposed accelerated mains replacement program.

PURPOSE OF THE REPORT

Dominion East Ohio, Inc. ("Dominion" or the "Company") has requested approval from the PUCO for "tariffs to recover, through an automatic adjustment mechanism, costs associated with a 25 year Pipeline Infrastructure Replacement ("PIR") program". This program is an accelerated mains replacement program targeting its bare steel, cast iron and wrought iron distribution mains and services, as well as its bare steel transmission piping.

Dominion has requested approval of this program because, while it has been replacing and maintaining its aging mains, it has determined that a higher level of effort and investment will be required by the Company to ensure that its leak experience remains manageable and that acceptable levels of safety and reliability are maintained.

Dominion has requested Black & Veatch provide: 1) a better understanding as to how Dominion compares to national and regional companies on benchmarks related to aging pipeline infrastructure of natural gas distribution and transmission systems and 2) an independent opinion as to the need for a Dominion accelerated replacement program for its: bare steel and cast & wrought iron mains, bare steel services, and bare steel transmission piping.

THE DATA UTILIZED

This section identifies the data utilized in the analyses and discusses specific characteristics of the data that are relevant to the analysis. In performing the analyses, Black & Veatch utilized data from the U.S. Department of Transportation Office of Pipeline Safety ("DOT") web site, data provided by Dominion, as well as Black & Veatch's calculations using this data.

Department of Transportation Data

Gas distribution and transmission pipeline operators are required by the DOT to annually submit certain main, service and leak data utilizing, as appropriate, either DOT form PHMSA[2] F7100.1-1 or PHMSA F7100.2-1. This data is available to the public through the DOT web site. (http://ops.dot.gov).

The DOT data, as of April 2008 included the elements listed below for the years 2002 to 2006. DOT 2007 data was not yet available through the DOT, therefore Dominion provided Black & Veatch its 2007 DOT data. In addition, Dominion has provided updated data for 2002 to 2006.

- Miles of bare steel, cast iron and other categories of main and service materials in the system at the end of each year;
- Number of corrosion leaks eliminated or repaired for mains and services;
- Number of total leaks eliminated or repaired for mains and services for various leak causes; and
- Number of leaks remaining in backlog at year-end.

Corrosion Leaks

While DOT data provides the total number of corrosion leaks for mains, DOT does not provide a breakdown of the number of corrosion leaks by type of main material. Due to this DOT data limitation, for the purposes of this review, we assumed that the reported corrosion leaks on distribution mains predominately occurred on either non-cathodically protected bare steel or non-cathodically protected coated steel mains. For transmission piping, since all of Dominion's bare steel is reported as cathodically protected, we compared it to other companies that also reported their bare steel as cathodically protected.

Based on our experience we believe that this assumption is reasonable since, while it is recognized that corrosion leaks can occur on cathodically protected coated steel mains, most corrosion leaks occur on unprotected bare and coated steel pipe. Our opinion is supported by information provided by Dominion, based on its 2007 Cleveland-Western Shop Bare Steel Replacement Pilot, which identified that 91% of its corrosion leaks on mains occurred on bare steel low pressure pipe. More specifically, operating experience leads one to conclude that:

- Mains that are cathodically protected, while they occasionally develop corrosion leaks, are generally protected from corrosion leaks;
- Cast iron main leaks are typically not caused by corrosion (graphitization) and are generally caused by leaking joints or main breaks; and
- Plastic mains do not corrode.

Black & Veatch Calculations

Utilizing DOT data, Black & Veatch prepared several comparisons and developed certain metrics to assist in comparing Dominion to other companies. They included comparisons related to:

- Annual change in bare steel mains inventory.

[2] Pipeline and Hazardous Materials Safety Administration

- Annual change in corrosion leaks eliminated or repaired
- Annual number of corrosion leaks eliminated or repaired per mile of bare and unprotected coated steel main.
- Leak causes
- Types of material
- Annual number of corrosion leaks per 1,000 bare steel and unprotected coated steel services
- Year-end backlog of leaks pending repair

If the DOT data was missing a data point for a particular company, in a given year, Black & Veatch substituted for the missing data point the average data of the prior and subsequent year.

Observations Regarding the Data:

- The DOT 2006 database contained data for 1,481 distribution and 1,433 transmission companies.
- Most of the companies that filed with the DOT do not have bare steel mains or have a very small amount of bare steel mains compared to Dominion.
- DOT database sorting criterion for distribution data – Black & Veatch utilized a sorting criterion intended to limit the focus to companies with a significant amount of bare steel, yet still incorporate a reasonable sample of companies. The sorting criterion chosen was all companies with a minimum of 50 miles of non-cathodically protected bare steel in 2006. Additional data which reinforced the reasonableness of this sorting criterion included:
  - Nationwide, 83 companies, including Dominion, meet the 50 miles of bare steel sorting criterion. They are listed in Appendix A of this report. Generally, these are also investor owned companies that are larger in size than the average company reporting, as measured by the number of gas services (68 have more that 50,000 services), and are subject to state regulatory oversight similar to Dominion.
  - The 83 nationwide companies meeting the sorting criterion represent 97% of the non-cathodically protected bare steel in the DOT 2006 database (51,283 miles out of 53,100 miles).
- DOT database sorting criterion for transmission data – Black & Veatch utilized a sorting criterion intended to limit the focus to companies with a significant amount of bare steel, yet still incorporate a reasonable sample of companies. The sorting criterion chosen was all companies with a minimum of 10 miles of bare steel in 2006. Additional data which reinforced the reasonableness of this sorting criterion included:
  - Nationwide, 80 companies, including Dominion, meet the 10 miles of bare steel sorting criterion and represent 98% of the bare steel in the DOT 2006 database (9,592 miles out of 9,758 miles). They are listed in Appendix B of this report. However, out of the 80 companies, 48 reported having only cathodically protected bare steel (5,843 miles or 61% of the nation's total bare steel). These companies reported no non-cathodically protected pipe. This is similar to Dominion's inventory mix.
- Regional distribution analysis – In addition to the national sorting criterion of 50 miles, Black & Veatch determined that Dominion data might also be reasonably compared to companies in close regional proximity to Dominion. Companies in Ohio and the states bordering Ohio were thought by Black & Veatch and Dominion to possibly experience more similar environmental characteristics (such as weather, soil and age of pipe material) than companies in other areas of the United States.

- The regional states selected include: Indiana, Kentucky, Michigan, Ohio, Pennsylvania and West Virginia.
- There are 30 companies, including Dominion, that meet the sorting criterion and are located in the six regional states. They are listed in Appendix C.
- The 30 regional companies meeting the sorting criteria represent 44% of the bare steel in the DOT 2006 database.

- Regional transmission analysis – In addition to the national sorting criterion of 10 miles, Black & Veatch determined that Dominion data might also be reasonably compared to companies in close regional proximity to Dominion. Companies in Ohio and the states bordering Ohio were thought by Black & Veatch and Dominion to possibly experience more similar environmental characteristics (such as weather, soil and age of pipe material) than companies in other areas of the United States.
  - The regional states selected include: Indiana, Kentucky, Michigan, Ohio, Pennsylvania and West Virginia.
  - There are 21 companies, including Dominion, that meet the sorting criterion and are located in the six regional states. They are listed in Appendix D.
  - The 21 regional companies meeting the sorting criteria represent 24% of the bare steel in the DOT 2006 database. Out of the 21 companies, 9 reported having only cathodically protected bare steel piping (428 miles). These companies reported no non-cathodically protected pipe. This is similar to Dominion's inventory mix.

FINDINGS AND OPINIONS

1. Miles of bare steel distribution main comparison – 2006

For the year-ending 2006, Dominion reported having 3,862 miles of non-cathodically protected bare steel mains in its system.

What is significant about the amount of bare steel in Dominion's distribution system is that it has the greatest amount of non-cathodically protected bare steel reported compared to all other distribution operators reporting to the DOT. Figure 1 illustrates Dominion's miles of bare steel compared to national and regional companies.

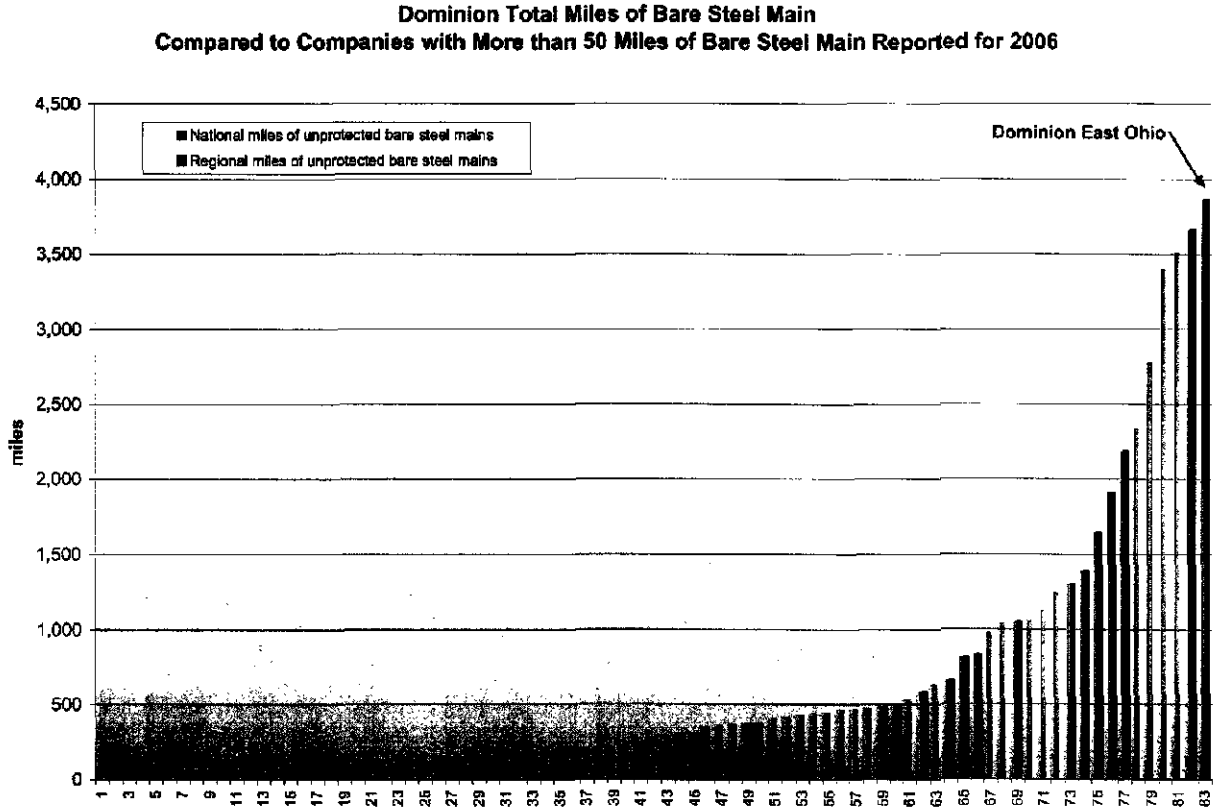


Figure 1

2. Dominion's miles of distribution main by year installed

For the year-ending 2007 Dominion reports that it had 3,837 miles of non-cathodically protected bare steel and 70 miles of cathodically protected bare steel for a total of 3,907 miles of bare steel. Bare steel accounts for 20% of Dominion's total inventory of distribution mains.

The number of years that these mains have been buried in the ground is a major contributing factor to an ever increasing amount of corrosion leaks over time. Figure 2 illustrates the miles of bare steel mains installed by year in Dominion's system.

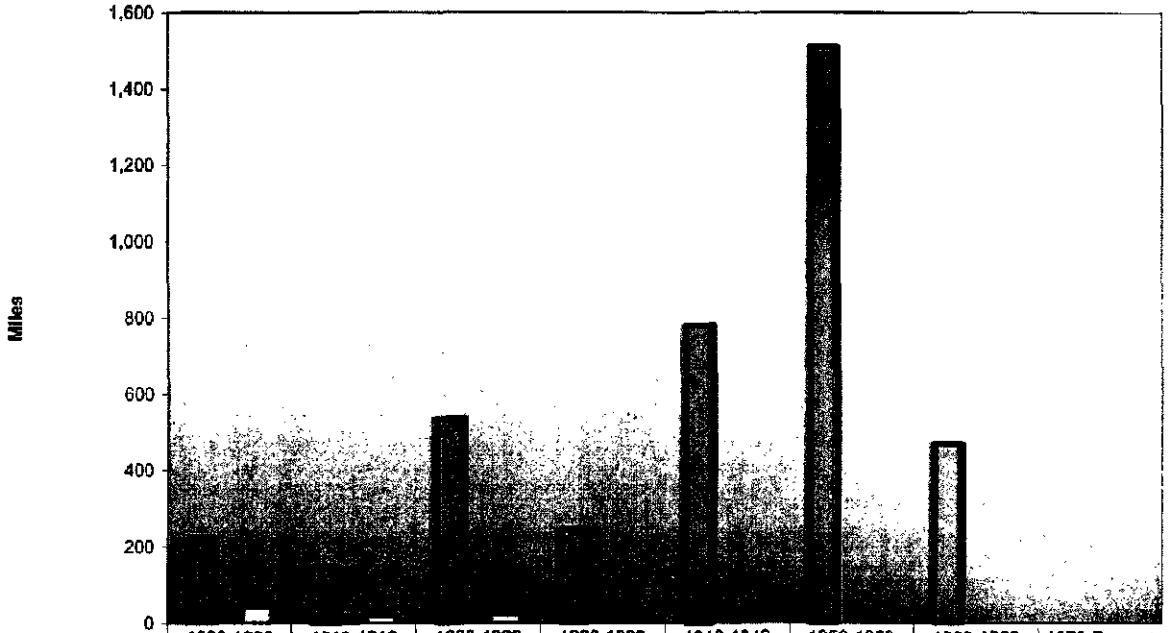
From this chart one can see that 222 miles of Dominion's bare steel main was installed approximately 100 years ago (1900-1909); 148 miles were installed between 1920-1929; 535 miles were installed between 1930-1939); 780 miles were installed between 1940-1949; and 1,978 miles have been installed since 1950. From this data the weighted average amount of time Dominion's bare steel mains have been in the ground is 63 years.

Dominion's practice of installing these main materials during the decades illustrated on the chart is consistent with the pipeline technology at the time.

As explained in further detail later in this report, experience and data have taught the natural gas industry that these mains will need to be either retired or replaced with plastic or cathodically protected steel mains. In our opinion it is not a matter of "if", but rather "when" these mains will need to be replaced, in order to reduce the risks and costs associated with leaking gas mains, as well as to deliver on Dominion's overarching commitment to safety.

Black & Veatch observes that replacing such a large amount of bare steel, in a pragmatic and efficient manner, will require a considerable amount of planning, effort, and expense on the part of Dominion's management. The historic sequence of main installations was to install cast iron, wrought iron and bare steel pipe in the early years and then in later years to install coated steel and plastic pipe. Therefore, it is reasonable to infer that most of the bare steel main in service today was installed prior to 1959.

Dominion Miles of Bare Steel, Cast and Wrought Iron by Decade Installed



	1900-1909	1910-1919	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-Present
Bare Steel	222	148	535	244	780	1509	469	0
Cast Iron	1	24	7	2	0	0	0	0
Wrought Iron	40	15	19	3	0	1	0	0

Figure 2

3. Dominion's distribution main leaks by cause

During 2007 Dominion reported experiencing a total of 4,490 leaks that were eliminated or repaired on mains. Leaks due to corrosion on mains accounted for 3,582 or 80% of the Company's total number of leaks on mains (Figure 3). In 2006 this value was 78% and ranks Dominion in the top 16% of companies reporting more than 50 miles of bare steel in their system in 2006 (Figure 4).

Focusing on gas leaks is important because of the risk they may present to the public and company employees. For example, the proximity of homes or population centers to higher risk pipe (for example, bare steel and cast iron) coupled with the susceptibility of the pipe to leaks or catastrophic failure (breaks) is a safety risk associated with the pipe remaining in service.

Simply waiting and reacting to a failure by making repairs results in higher risks to the public. Operators with large amounts of aging pipe that begins to fail exposes the public to risk as pipe cannot be replaced overnight. This results in costly patrols and leak survey monitoring programs and repair crews responding to emergencies and at times under severe weather conditions.

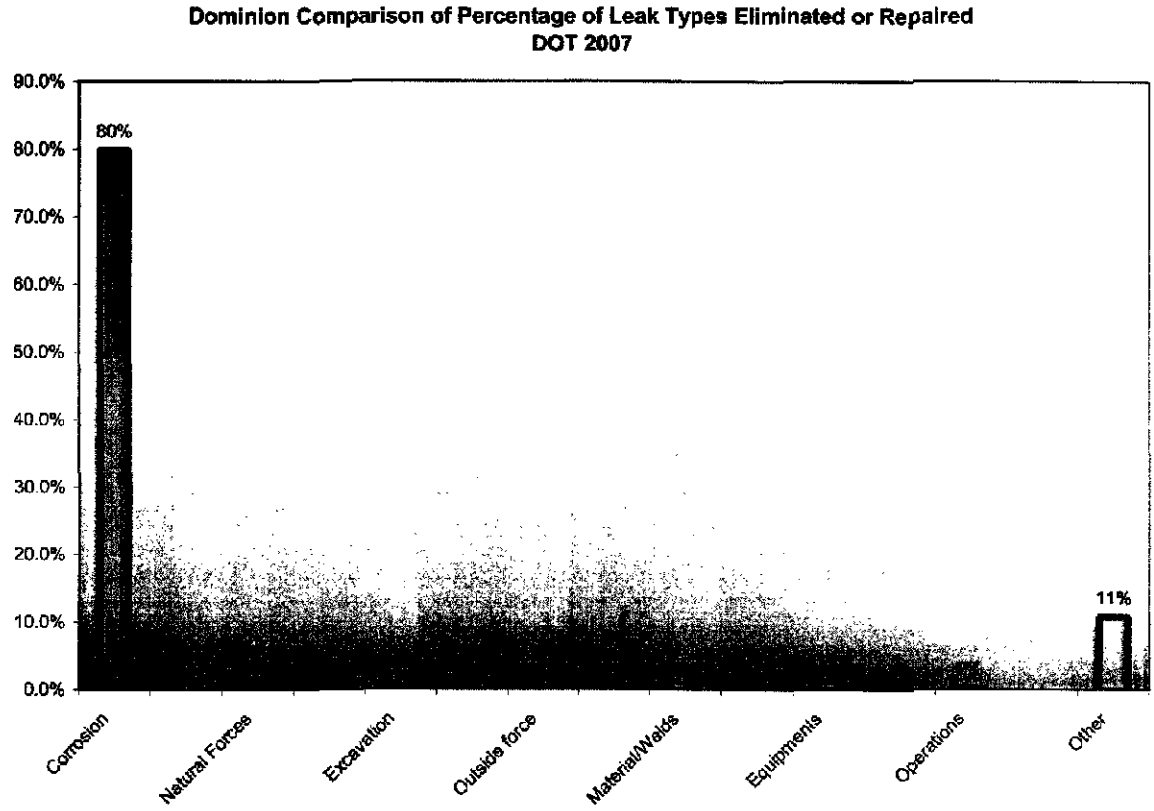


Figure 3

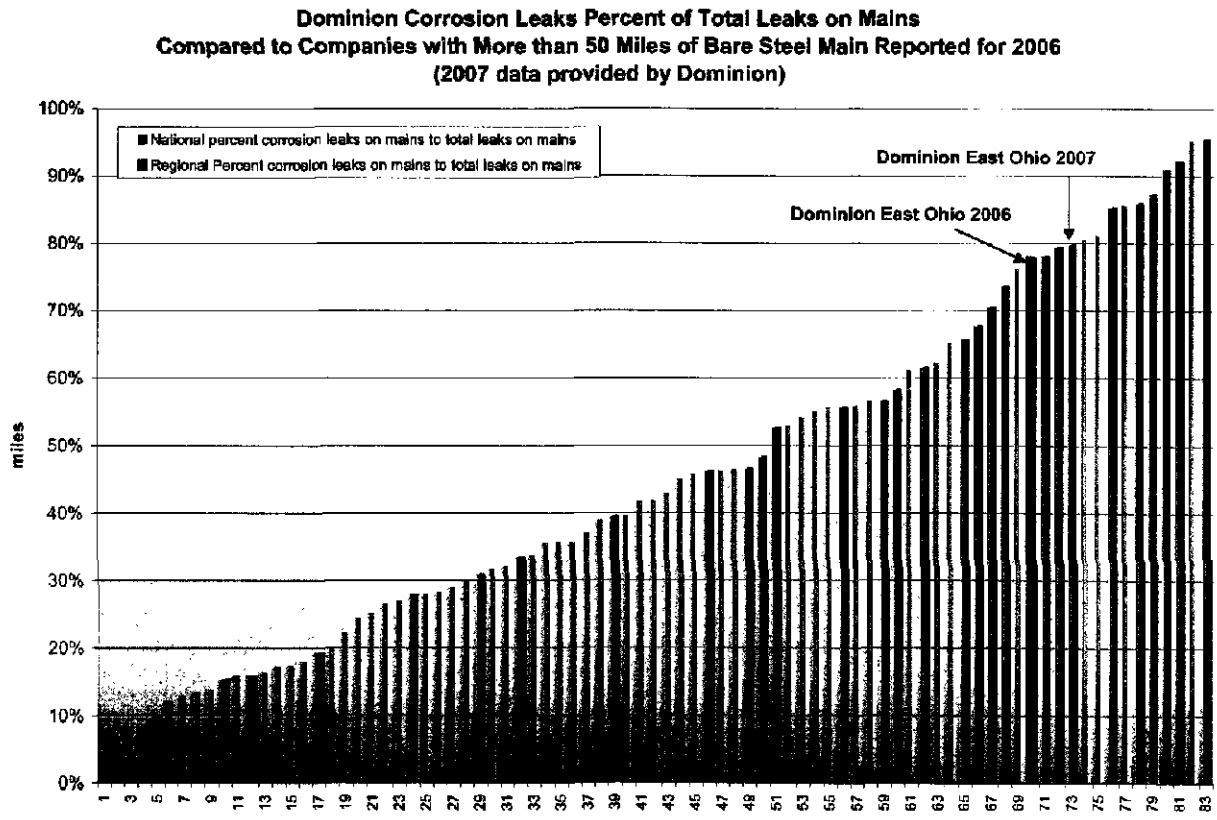

Dominion Corrosion Leaks Percent of Total Leaks on Mains
Compared to Companies with More than 50 Miles of Bare Steel Main Reported for 2006
(2007 data provided by Dominion)
National percent corrosion leaks on mains to total leaks on mains
Regional Percent corrosion leaks on mains to total leaks on mains
Dominion East Ohio 2007
Dominion East Ohio 2006
miles
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%

Figure 4

4. Total corrosion leaks on distribution mains comparison - 2006

Dominion's reported number of corrosion leaks on mains in 2006 ranks as the highest among the 83 companies in the DOT database with more than 50 miles of bare steel in their systems. This is illustrated in Figure 5. Dominion reported eliminating or repairing 3,391 corrosion leaks on mains in 2006 and 3,582 in 2007. Figure 4 also illustrates Dominion's level of corrosion leaks in 2005.

The increase in corrosion leaks from 2005 to 2007 is further discussed in the next section.

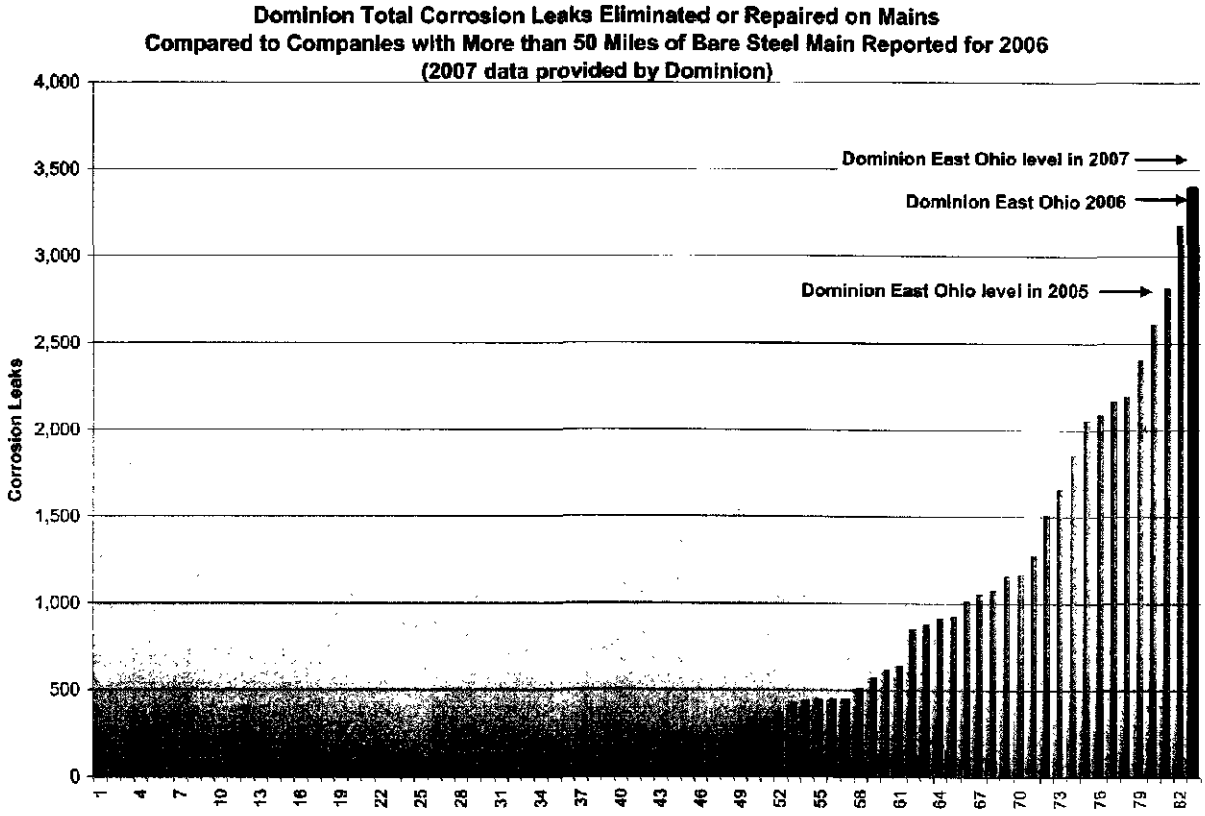


Figure 5

5. Dominion's distribution year-end backlog of leaks pending repair – 2002 - 2007

Each distribution operator is also required by the DOT to also report the number of leaks awaiting repairs at the end of each year (commonly known as leak backlog). Leaks remaining in backlog are not classified by cause until they are repaired or eliminated. Leaks in backlog typically include leaks on both mains and services, due to corrosion, natural forces, joints leaks, material or weld failure, outside forces, and other. Typically they do not include leaks due to third party excavations damage since those leaks are usually repaired the same day.

The number of leaks pending repair at the end of a year is a direct function of the amount of unprotected bare and coated steel pipe and cast iron inventory, its associated level of corrosion and joint leaks, and the Company resources available to repair or replace the offending sections of main. In addition to individual leaks being worked by the company until they are repaired, as sections of main are replaced, it will reduce the production of new leaks, and also eliminate the existing leak backlog associated with those main segments.

The significant increase in Dominion's reported number of corrosion between leaks from 2005 to 2007 may be due to the additional efforts that Dominion has put towards reducing its year-end backlog of leaks waiting to be repaired. Dominion's efforts to reduce its level of year-end leak backlogs are commendable.

Dominion may not have ranked as the company with the highest reported corrosion leaks on mains in 2006 if it had not significantly reduced its level of leaks awaiting repair at year end (backlog) by 3,038 leaks. We have been advised by Dominion that during the last two years it had taken extra efforts to significantly reduce the year-end backlog of leaks waiting to be repaired. The impact of this effort may have had the effect of increasing the number of corrosion leaks reported in 2006 and 2007. This is because as leaks in backlog were repaired, they were then classified according to initial cause, including corrosion.

A trend line analysis of the 2002-2005 period estimates a 2006 level to be 2,855.

In 2006, a corrosion leak level of 2,855 corrosion leaks on mains leaks would have ranked second highest in the nation. This is further discussed in the next section.

While the extra effort of reducing Dominion's backlog of leaks may have resulted in additional corrosion leaks being identified, compared to if the level of backlog leaks had remained the same year to year. The fact remains that Dominion's number of leaks due to corrosion is high and will go higher as the corrosion process continues on these aging pipes. Dominion's corrosion leak rate is currently the highest in the nation. It may remain in that position until it retires or replaces a significant amount of its bare steel.

Figure 6 illustrates Dominion's change in year-end backlog of leaks and the number of corrosion leaks on mains reported for the period 2002 – 2007.

The average number of corrosion leaks for 2002-2005 was 2,639 per year and a linear trend analysis (shown on Figure 5) for this period results in a 2006 value of 2,855 leaks and a 2007 value of 2,942 leaks. It is reasonable to assume that based on the age of Dominion's bare steel system and the increase in corrosion leaks observed between 2002 and 2005, that if Dominion's annual level year-end leak backlog in 2006 and 2007 had remained at the same level as prior years, the number of

corrosion leaks would likely have increased, but not to the 2007 reported level of 3,500 corrosion leaks per year.

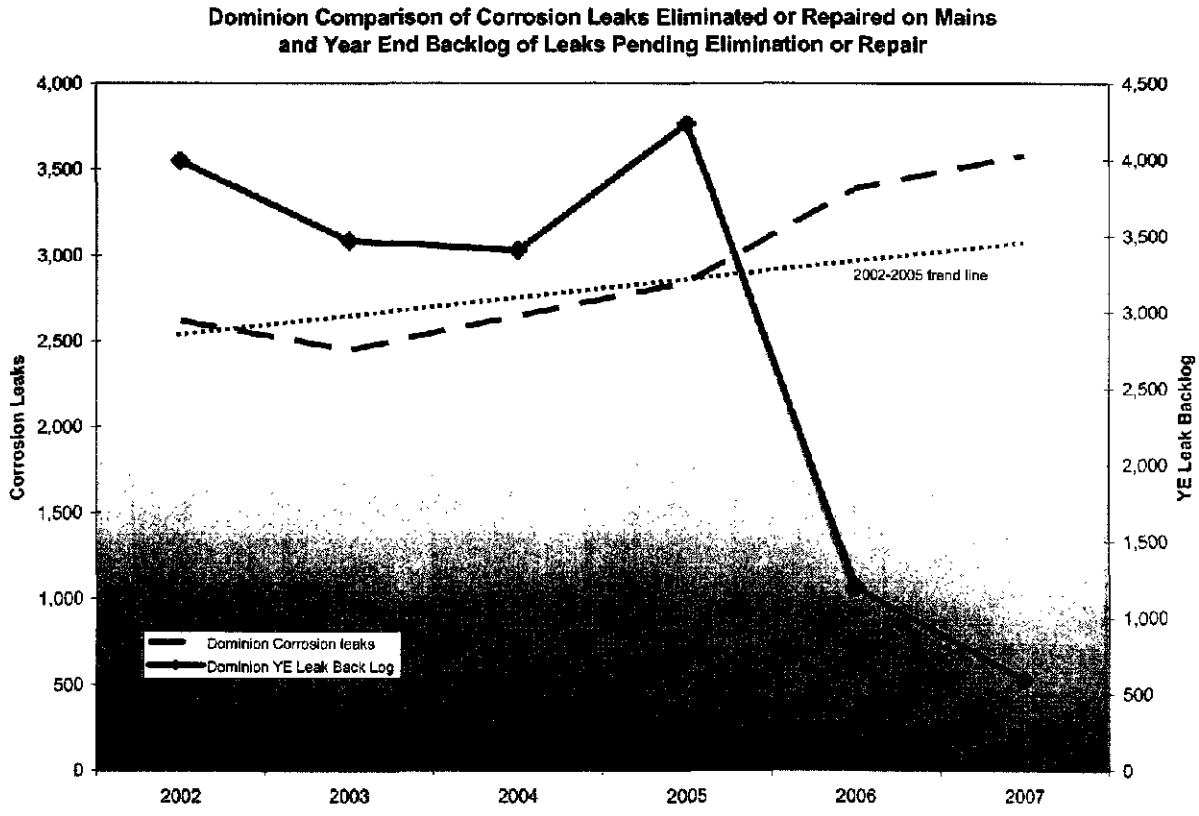


Figure 6

Whether the annual number of corrosion leaks is 2,600 or 3,500, Dominion's large number of corrosion leaks, resulting from a very large inventory of aging bare steel mains, creates additional safety, reliability and maintenance risks that it must diligently manage.

Dominion's PIR program should reduce substantially the number of corrosion leaks, as more and more bare steel mains are either retired or replaced.

6. Total corrosion leaks on distribution mains compared to bare steel main inventory

In 2006 Dominion's rate of replacement of non-cathodically protected bare steel was 34 miles approximately 0.9% of its inventory (3,862 miles) and the nation's was 3.7%. In 2007 it was 25 miles (0.6%). Figure 7 illustrates the reduction in Dominion's bare steel inventory and the change in corrosion leaks on mains for the period 2002 – 2007.

Extrapolating Dominion's 2006 rate of bare steel replacement (34 miles per year) into the future would result in the replacement of its bare steel main inventory (not including cast) in approximately 114 years, compared to approximately 26 years for the nation as a whole (not including Dominion). Dominion's 2007 replacement rate would result in the replacement of its bare steel main inventory in approximately 155 years.

Dominion's bare steel, and cast & wrought iron mains are its oldest pipelines. The Company reports that 1,149 miles of bare steel main are in the pre-1940 category. Dominion's bare steel mains have been in the ground an average of 63 years. We understand that the newest vintage of the Company's risk mains are those installed in the 1960's. While the Company will replace mains based on their risk priority, if it was to replace the oldest mains first, it would result in the last main being replaced when it is 153 years old.

Black & Veatch believes that these mains will continue to corrode at an increasing rate for reasons discussed in this report, and that Dominion's present rate of main replacement increases the risk to its customers.

Figure 7 also illustrates that while the Company has been retiring or replacing its bare steel inventory, it has reported an increase in the number of corrosion leaks on mains that have been either eliminated or repaired each year. The significance of this data was discussed in the prior section.

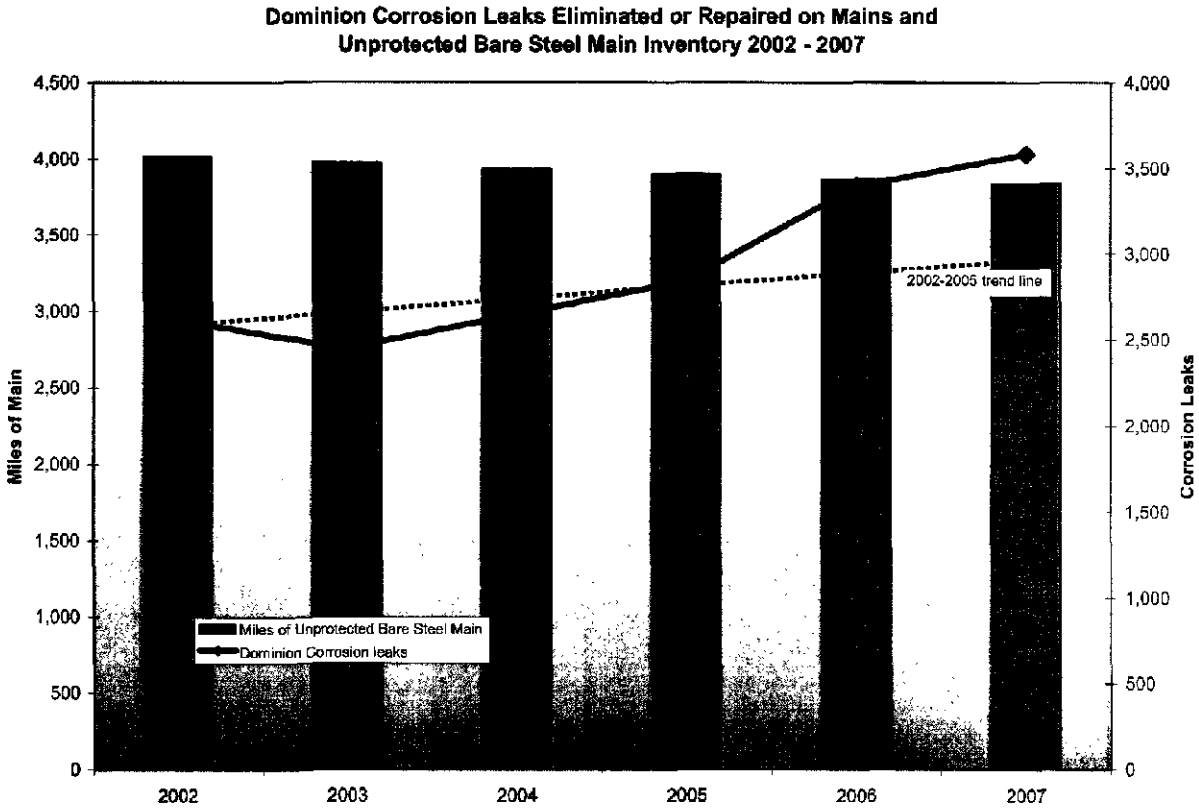

Dominion Corrosion Leaks Eliminated or Repaired on Mains and
Unprotected Bare Steel Main Inventory 2002 - 2007
Miles of Main
Corrosion Leaks
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2002-2005 trend line
Miles of Unprotected Bare Steel Main
Dominion Corrosion leaks
2002
2003
2004
2005
2006
2007

Figure 7

7. Dominion's change in corrosion leaks on distribution mains – 2002 - 2007

For the period 2002 – 2007, the Company had reported a high level of corrosion leaks eliminated or repaired on mains compared to the average of regional companies. This is illustrated in Figure 8 where it is compared to the average number of corrosion leaks for regional companies with more than 50 miles of bare steel main in their systems. In 2006 Dominion reported 3,391 corrosion leaks eliminated or repaired on mains and in 2007 it reported 3,582. We have included in the graphic the 2002-2005 annual corrosion leak trend line as discussed previously.

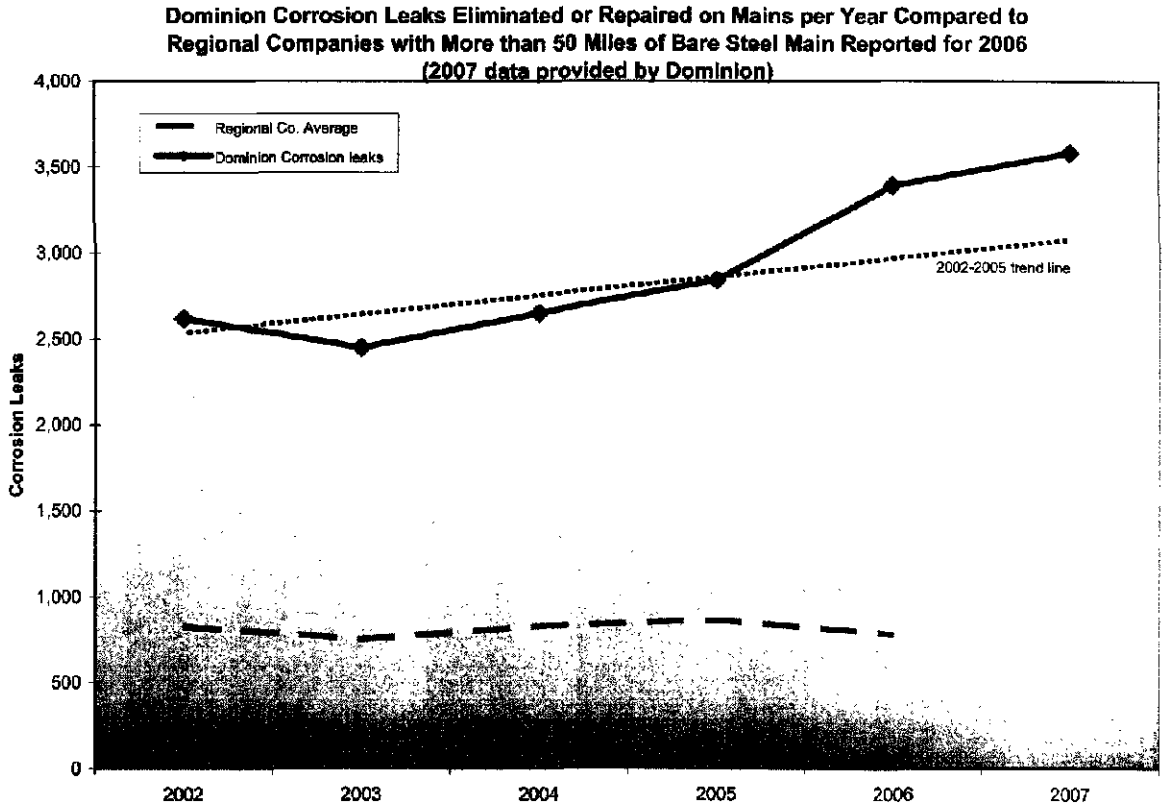


Figure 8

8. Corrosion leaks per mile of non-protected bare steel and coated steel distribution mains – 2006

The measure of corrosion leaks per mile of unprotected bare steel and coated steel main is a frequently used metric to illustrate the condition of these mains in a distribution system. Figure 9 compares for 2006, this measure for all companies having mo re than 50 miles of bare steel main in their system. It can be seen that Dominion's 2006 rate of 0.56 is better than the region and national averages. The average rate of the regional companies is 1.29 and average rate of the national companies is 0.96 (not including Dominion). In 2007 Dominion's rate rose to 0.59[3].

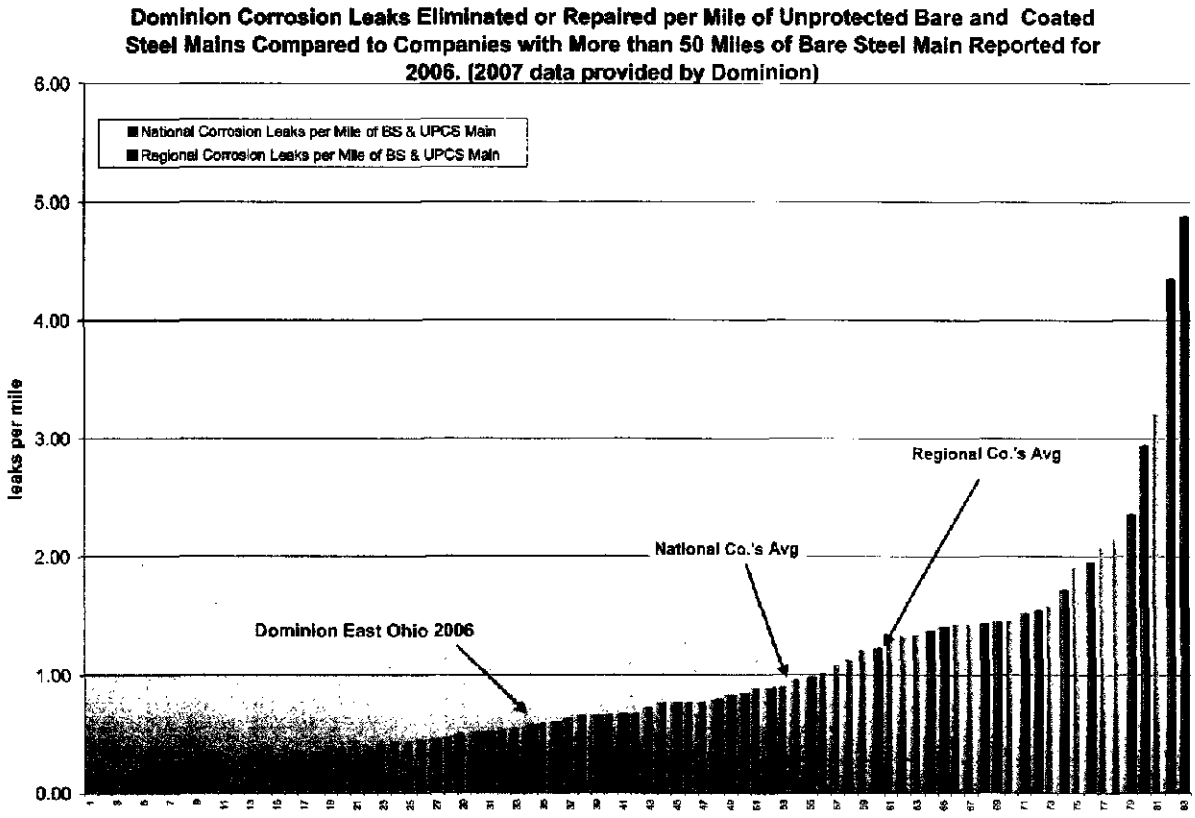


Figure 9

[3] Dominion believes that their miles of unprotected coated steel mains may be overstated. If this was true, this would result in a lower corrosion leak rate per mile than would otherwise be calculated if the miles of unprotected coated steel mains were lower. To illustrate this, if Dominion had no unprotected coated steel mains its corrosion leak rate for 2006 would be 0.88 compared to the average of regional companies of 1.48 (using the same calculation).

9. Change in Dominion's corrosion leaks per mile of non-protected bare steel and coated steel distribution mains – 2002 - 2007

The plot of Dominion's corrosion leaks per mile of unprotected bare and coated steel main and the regional companies for the period 2002 - 2007 is presented in Figure 10.

Dominion's corrosion leak rate per mile in 2006 was 0.56 corrosion leaks per mile of unprotected bare and coated steel main and in 2007 it was 0.59. In addition, because of the impact that the reduction in leak backlog likely had on Dominion's corrosion leak rate, we have also estimated, based on the 2002-2005 corrosion leak rate trend line analysis, the 2006 and 2007 corrosion leak rate to be 0.47 and 0.49 respectively.

If Dominion's corrosion leak rate was to rise to the level of the average corrosion leak rate for regional companies in 2006, we believe that Dominion would experience an increase in leaks of such levels that would create additional risks and likely severely challenge the Company's ability to keep up with its leak management duties. We have estimated Dominion's theoretical number of leaks (assuming Dominion's leak rate was to rise to the level of regional companies) based on assuming the reported Dominion inventory of unprotected bare and coated steel main. If Dominion's corrosion leak rate of 0.56 was to rise to the level of the average leak rate for regional companies in 2006 (1.29), that would mean that its annual corrosion leaks would increase from 3,391 (in 2006) to 7,855 leaks. This would be a 132% increase in the number of leaks[4]. We believe that the risk associated with such an increase in number of leaks must be avoided.

Black & Veatch believes that such a higher level of leaks would add incremental risks to the public and Dominion. We support the Company's decision to begin an accelerated replacement program of its aging mains to drive down the 2007 corrosion leak rate of over 3,500 leaks per year and to improve the safety and reliability of their system. Without an accelerated mains replacement program, we believe that the Dominion's rate of corrosion leaks will continue to increase.

[4] As noted, Dominion believes that its number of miles of unprotected coated steel may be overstated. If we assume that Dominion has no unprotected coated steel main and if Dominion's corrosion leak rate of 0.88 was to rise to the level of the average leak rate for regional companies in 2006 (1.48), that would mean that its annual corrosion leaks would increase from 3,391 (in 2006) to 5,716 leaks. This would be a 69% increase in the number of leaks.

Dominion Corrosion Leaks Eliminated or Repaired per Mile of Unprotected Bare and Coated Steel Main Compared to Regional Companies with More than 50 Miles of Bare Steel Main Reported for 2006. (2007 data provided by Dominion)

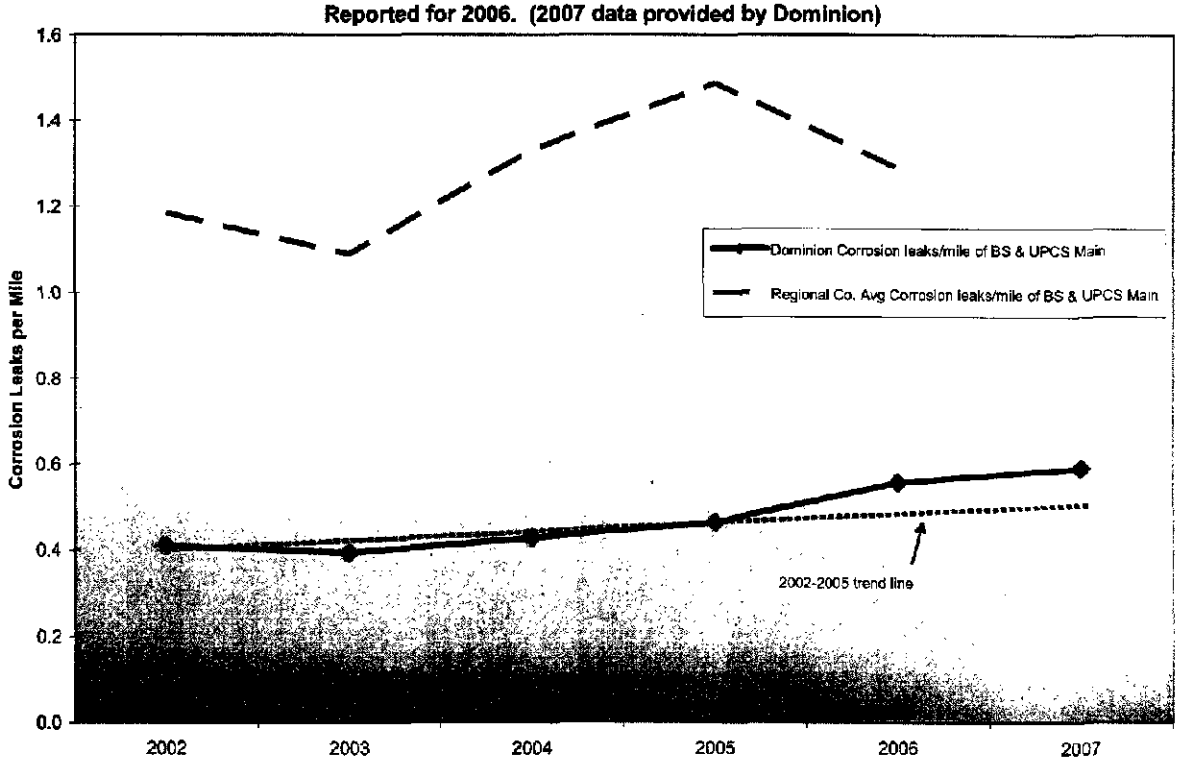


Figure 10

10. Pipeline corrosion science - industry data

Black & Veatch's opinion is supported by our gas distribution industry experience, data and science. For example, the modes of failure and the mechanisms associated with bare steel corrosion are well understood by corrosion experts and documented in a number of texts on the topic. It is a known fact that bare steel pipe, buried in the earth where there is moisture in the soil and without cathodic protection, will corrode over time. This corrosion may occur over the entire surface of the pipe and it may take many years before the first single corrosion leak occurs. However, once the first leak on a pipeline segment occurs, there are other points on the pipe where it is loosing metal and where pits are becoming deeper and deeper due to corrosion. As the corrosion pitting continues and the pipes continue to loose metal, these pipes will experience additional leaks in a shorter and shorter timeframe as the corrosion pits completely breach the wall of the pipe. Eventually many additional points of corrosion may result in an unmanageable leak rate as the pipe becomes fragile and sometimes unrepairable.

This deterioration mentioned above is a function of time in the ground, moisture levels, and soil type, etc. This fact is evidenced by the fact that the DOT has not allowed the installation of bare steel for gas service since 1971. Furthermore, an early scientific reference regarding the failure rate of buried steel pipe was given in the book "Soil Corrosion and Pipe Line Protection" by Scott Ewing Ph.D. published in 1938. In the text the performance of the service pipes in the Philadelphia Gas Works System was plotted and showed that corrosion leak occurrences over time on bare steel pipe increased at an exponential rate. This graph is shown below in Figure 11. When this text was written the natural gas industry was still in its infancy and the high performance materials such as plastic and well coated and cathodically protected steel were not available or well understood.

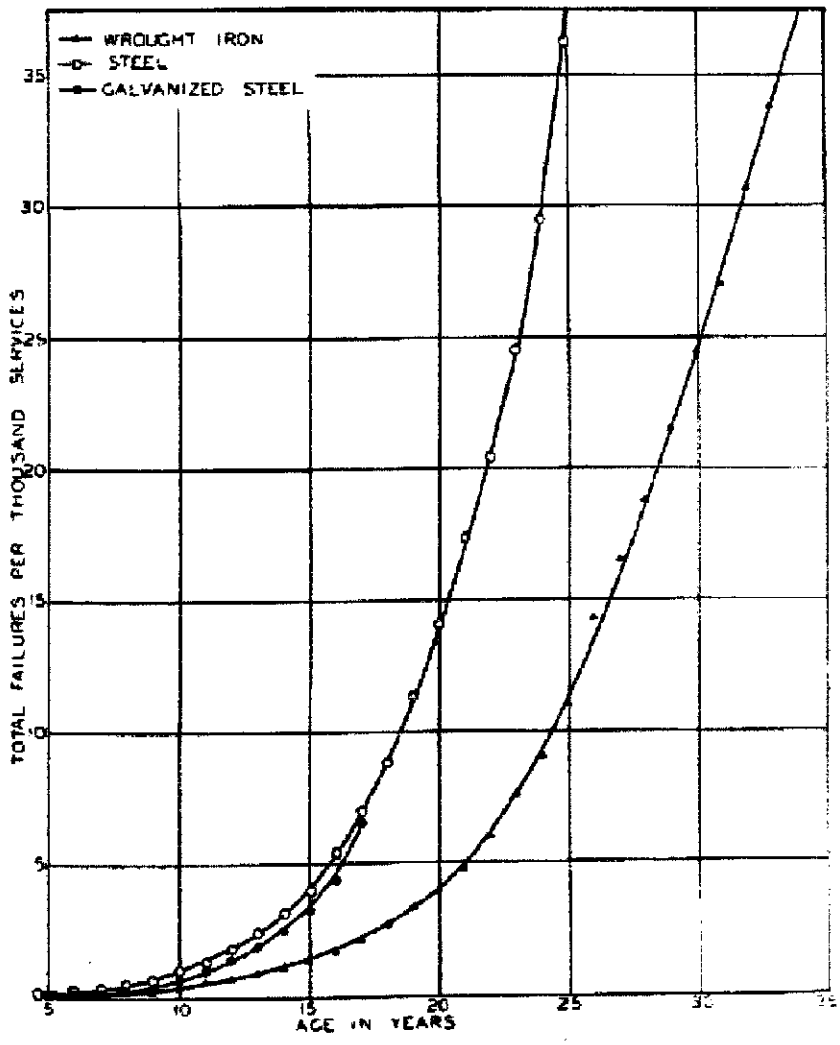


Fig. 7. Failure curves of house services in the Philadelphia Gas Works System.

Figure 11 - Chart from 1938 text showing exponential leak rates for bare steel pipe in gas service

This very same finding is corroborated today in more modern corrosion science texts. One such text which is considered by many to be a foundational book for the study of corrosion is "Peabody's Control of Pipeline Corrosion" by A.W. Peabody, published by the National Association of Corrosion Engineers International, the Corrosion Society (Second Edition 2001). This text published more than 60 years after the Ewing text reaffirms the fact that leak incidents on bare pipe will occur at an exponentially increasing rate. In the Peabody text this is shown as an example plotted on semi log paper. A copy of the graph used to describe this in the Peabody text (Figure 15.1 in Peabody) is shown in Figure 12 below.

As can be seen on this graph, no leakage occurs during the initial life of the pipe (first leak occurred 4 years after placing the piping in service). Then, in the next 4 years, 1.5 new leaks occurred. Then,

in the next 4 years, 4.5 new leaks occurred. Then, in the next 4 years, 11 new leaks occurred. This accelerating occurrence of leaks continues at a rate that places the cumulative leak count off the scale, past the 23rd year, with more than 100 cumulative leaks occurring. What is important to note is not that the leaks are occurring, but that they are occurring at an ever increasing frequency as a function of time.

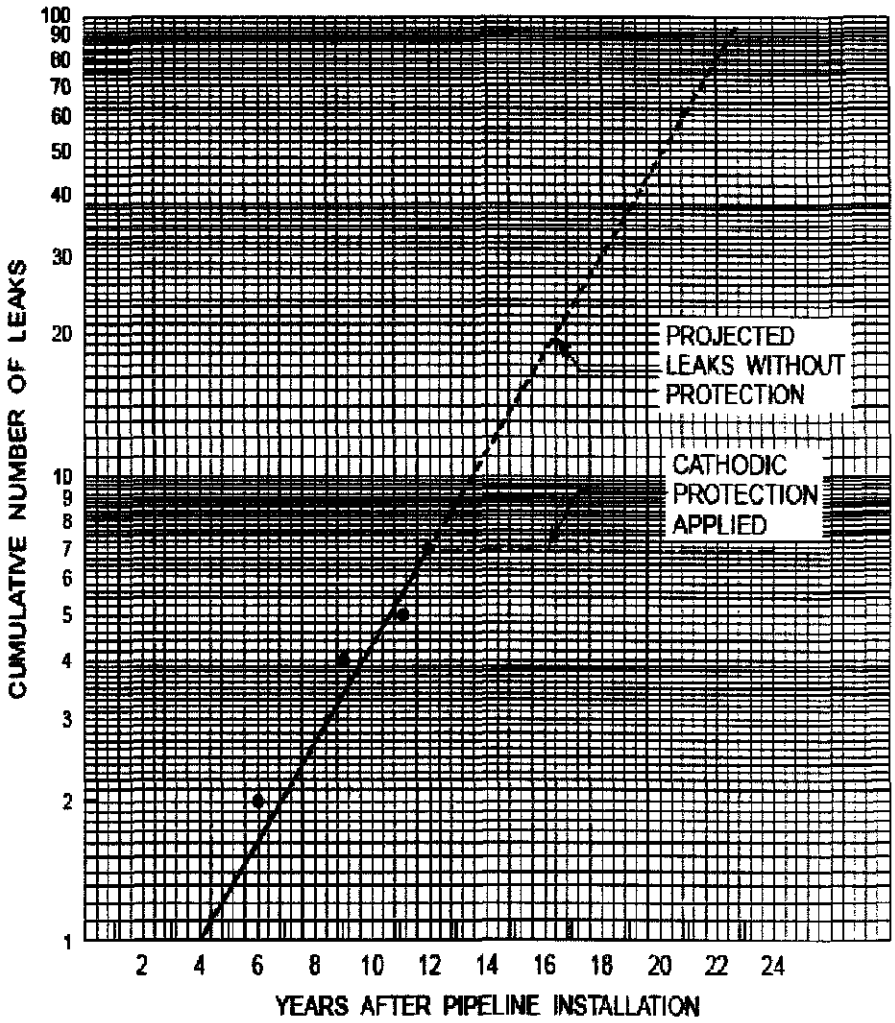


Figure 15.1 Cumulative number of leaks without CP.

Figure 12 - Chart from 2001 text showing exponential leak rates for bare steel pipe in gas service.

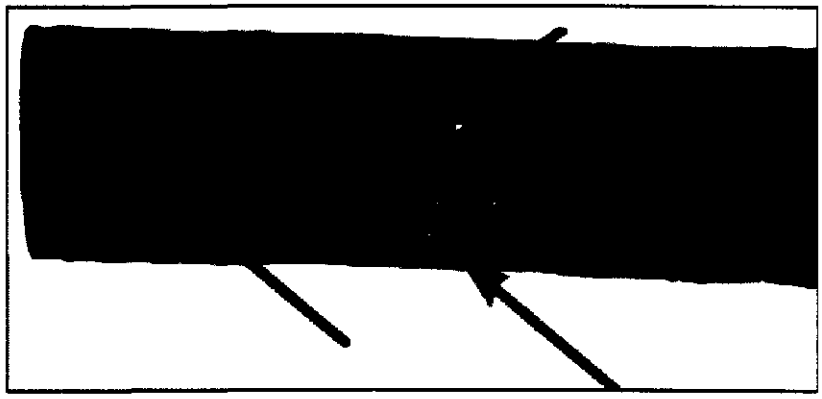
This exponential growth of leak occurrences on bare steel pipe is scientifically documented as indicated in the text above. This exponential growth of leak occurrences on bare steel pipe is also well known by experienced gas system operators who perform bare steel repairs and find themselves installing leak repair sleeve after sleeve on sections of corroding pipe.

This increasing frequency of leak incidents is also intuitively evident based on the corrosion mechanisms. Intuitively speaking, the wall thickness of a pipe is undergoing continuous deterioration by corrosion. In some locations the deterioration is more aggressive than in other

locations. Typically the wall thickness is many times thicker than needed to resist the hoop stresses caused by the pipeline pressure. When the first few corrosion leaks occur in a pipe segment, it is intuitive that many more future leaks are nearing their emergence as the corrosion pits become deeper and approach the point where they have fully breached the wall of the pipe and allow the gas to escape. In many cases although the wall thickness is penetrated at only a single point it can be seen that the entire pipe may have been degraded to the point where future leaks will occur at an ever increasing rate. This is visually obvious by viewing the piece of corroded pipe shown from the DOT OPS website in Figure 13. In this excerpt and picture, there may be only a few points of actual leakage, but as can be seen the pipe shows signs of distress along the entire wall thickness.

Corrosion is the deterioration of metal pipe. Corrosion is caused by a reaction between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Although corrosion cannot be eliminated, it can be substantially reduced with cathodic protection (see FIGURE III-1).

FIGURE III-1 BARE PIPE -NOT UNDER CATHODIC PROTECTION



An example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground. Operators should use either polyethylene pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Figure 13 - Excerpt from DOT OPS website
http://ops.dot.gov/regs/small_ng/Chapter3.htm

The following photograph was provided by Dominion as an additional illustration of the degree to which corrosion can destroy the integrity of bare steel pipelines. In the photo, when a section of bare steel main was cleaned of dirt and scale, it revealed a corrosion hole in the pipe (Figure 14).

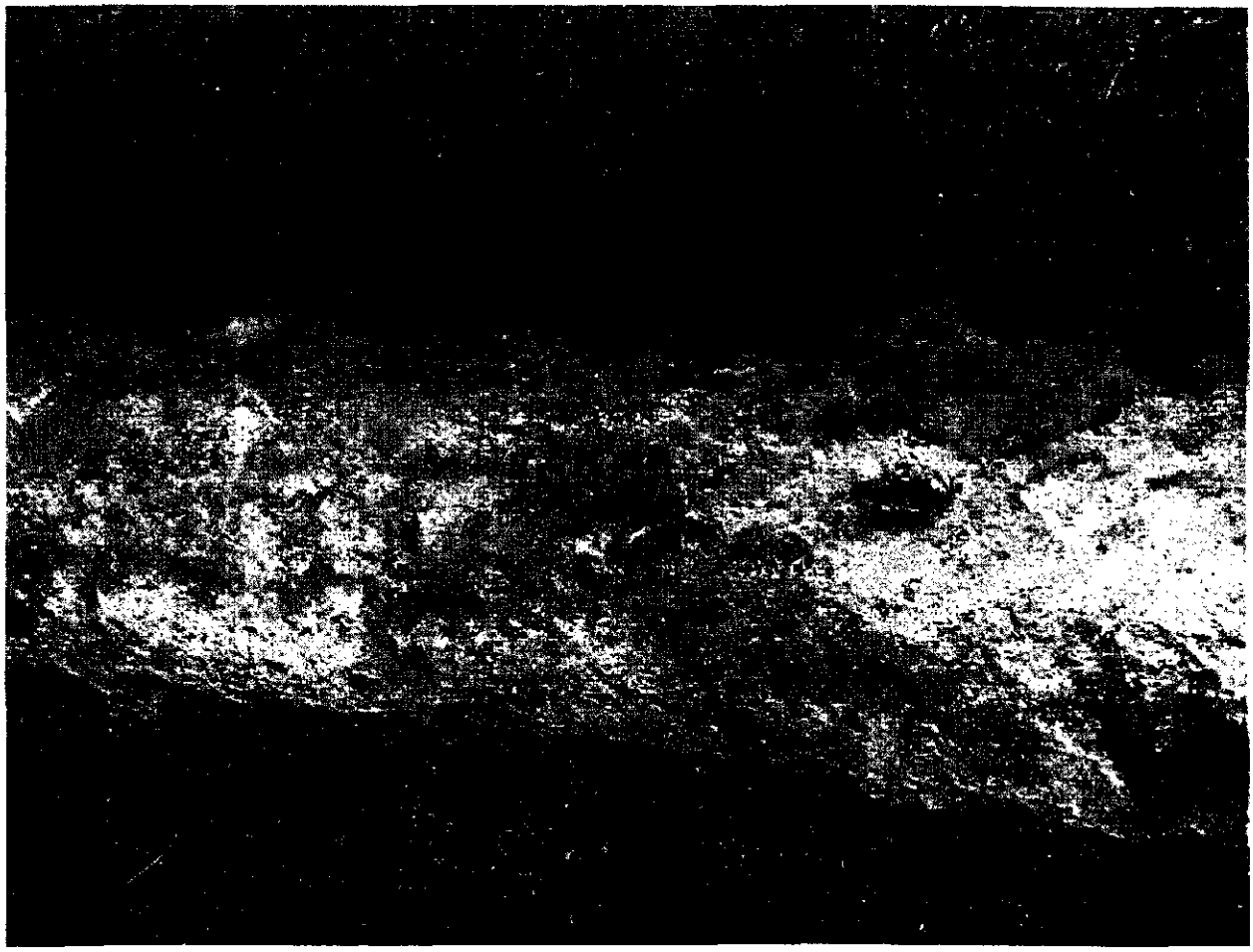


Figure 14

The issue that Dominion faces is not "if" it will need to replace its bare steel mains, but over what time frame it will need to replace mains to best serve the needs of its customers. With the clear understanding that Dominion's system is aging (with new corrosion pits approaching the point of leakage), and with the knowledge that the leak occurrence rates are a function of the number of years a main segment is exposed to a corrosive environment (the age of the mains), there are a number of scenarios that could be considered. For example:

Scenario 1 - Status Quo

In this scenario, Dominion may continue at its present rate of pipeline replacement. As discussed previously, at the Company's 2006 bare steel replacement rate, it would take another 114 years to replace these mains. While the Company will replace mains based on their risk priority, if it was to replace the oldest mains first, it would result in the Dominion's late vintage of main installed in the 1960s being replaced when it is 153 years old.

When these main segments age to the point that they begin to experience a continuing increase in the number of corrosion leaks and a corresponding increase in the leaks per mile, this situation will challenge Dominion's ability to manage risk and to keep up with the necessary level of leak repairs. This problem is not unique to Dominion – other companies that have a very large inventory of bare steel pipe are faced with the same challenge. When greater amounts of pipe begin to experience a

continuing increase in the number of corrosion leaks, the additional leaks increase the risks, as well as increase the costs to remedy the problem. For these reasons, Black and Veatch does not recommend this approach.

Scenario 2 – Proactive

In this scenario, Dominion would replace its bare steel mains at a rate significantly greater than today, while remaining manageable beginning with the mains that are in the worst condition, as identified by Dominion management, using all of its decision making support tools.

Dominion's management has stated that it has determined the shortest manageable time frame to complete the necessary main replacements is 25 years. Under this scenario Dominion would strive to replace or retire five and a half times the amount it replaced in 2007[5] or approximately 162 miles per year[6]. Black & Veatch believes that this rate of replacement is a reasonable expectation and would bring Dominion in line with the current nationwide average rate of replacement.

This proactive approach would provide a planned mechanism to replace or retire Dominion's entire aging higher risk pipe with mostly plastic, and in some instances, with cathodically protected coated steel pipe. In Black and Veatch's opinion, this is the most prudent scenario because it helps protect the safety of the Company's customers while avoiding numerous repairs of the piping before its eventual replacement.

However, if during the planned 25 year replacement program Dominion observes that the rate of corrosion leaks per mile is increasing and becomes unmanageable, it may need to increase the rate of replacement of its aging higher risk mains.

It should be noted that other companies in the same region as Dominion have also realized the need to replace their bare steel, cast and wrought iron mains. Duke Energy Ohio had presented its case for the replacement of its bare steel to the PUCO and requested rate relief and the authorization to institute an Accelerated Mains Replacement Program ("AMRP") tracker. The PUCO approved the program and the tracker. The request by Duke Energy was for the replacement of all the bare steel and cast iron main over a 10 year period. According to Gary Hebbeler's recent testimony on behalf of Duke Energy, in Case No. 07-589-GA-AIR, it had replaced 559 miles of cast iron and bare steel during the period 2001-2006. This equates to 93 miles per year compared to Dominion's plan to replace approximately 162 miles per year for the next 25 years. While Duke Energy's 10-year replacement program may appear to be more aggressive than Dominion's 25 year plan, one must recognize that for the Company to replace its bare steel mains in 10 years, it would need to replace about 400 miles per year. This is over four times the amount of miles that Duke Energy replaced each year. In our opinion it is not reasonable to plan for a replacement program of a higher magnitude than Dominion is instituting as long as its corrosion leak levels remain under control. As it is, the Company is planning to replace approximately 162 miles per year which will be a resource challenge. Duke Energy's replacement program, as testified by Mr. Hebbeler, has resulted in a significant reduction of leaks from 6,223 leaks in 2002 to 4,196 leaks in 2006 when the replacement program was only 48% complete. Black and Veatch would expect similar results for Dominion as its program is implemented.

[5] 2007 replacements equaled 29 miles based on 25 miles of bare steel distribution main, 3 miles of cast iron and 1 mile of transmission bare steel

[6] Assumes 4,055 miles to be retired or replaced: (3,907 miles of bare steel, 112 miles cast and wrought iron and 1 mile of copper mains and 35 miles of bare steel transmission piping).

11. Miles of bare steel transmission comparison – 2006

In 2006, Dominion reported having 62 miles of cathodically protected bare steel pipe. These values are compared to national and regional companies in Figure 15.

Dominion's high-pressure transmission system in 2007 consisted of 35 miles of cathodically protected bare steel pipe. This is 2.8% of its total transmission system mileage. The 27-mile reduction in cathodically protected bare steel pipe mileage from 2006 to 2007 is due to the Company replacing 1 mile of pipe and reclassifying 26 miles of transmission pipe to distribution main.

While other transmission companies continue to maintain non-cathodically protected bare steel transmission piping, Dominion has no transmission mains that are not cathodically protected.

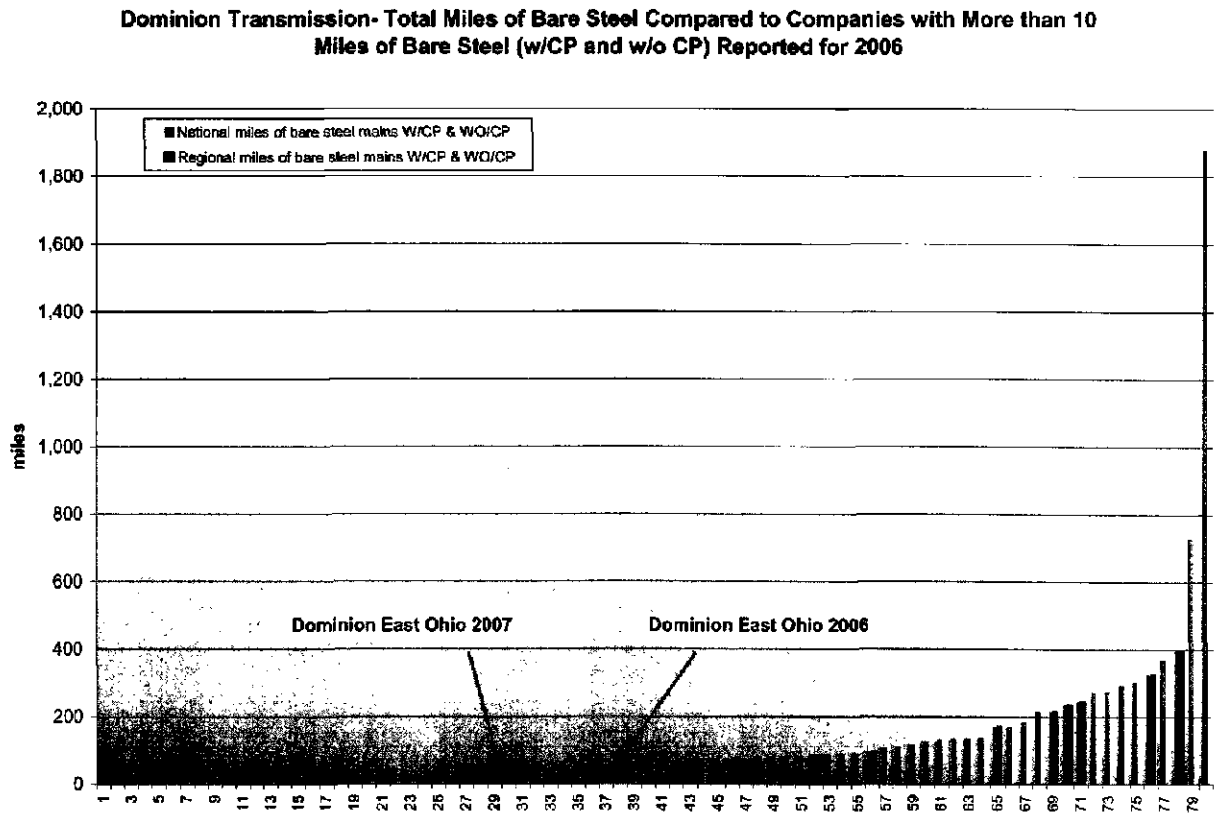


Figure 15

12. Total corrosion leaks on transmission piping compared to bare steel main inventory

Figure 16 illustrates the reduction in Dominion's bare steel transmission piping for the period 2002 – 2007. In addition it also illustrates the reduction in corrosion leaks reported each year. One may note that the number of transmission leaks due to corrosion is relatively small compared to distribution system corrosion leaks, however, due to the operating pressures of transmission pipelines, each and every transmission gas leak is a very serious matter and every effort is typically taken to minimize such leaks.

We believe that it is reasonable to assume that the significant reduction in corrosion leaks was directly related to the reduction in the Company's transmission inventory of bare steel.

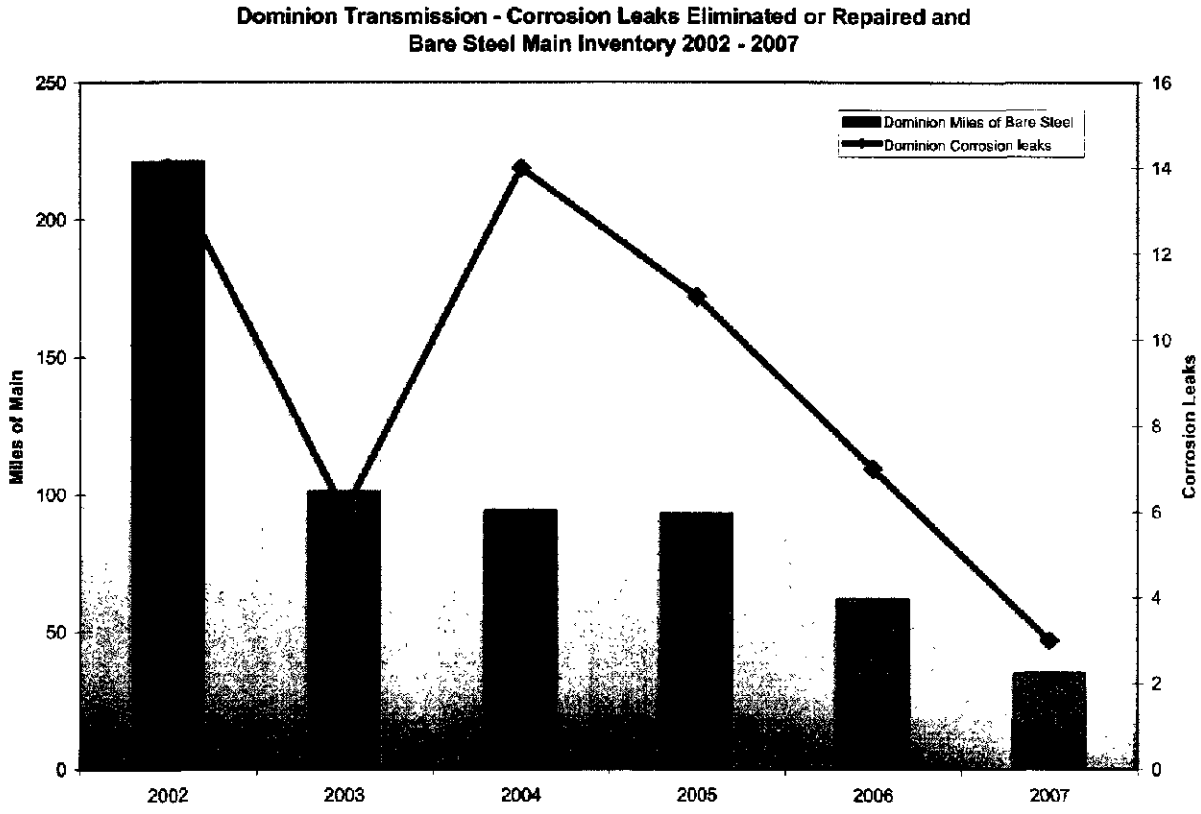


Figure 16

13. Corrosion leaks per mile of protected bare steel transmission – 2006

The measure of corrosion leaks per mile of unprotected bare steel and coated steel main is a frequently used metric to illustrate the condition of these pipes. However, Dominion has a small amount of cathodically protected bare steel and no non-cathodically protected bare steel transmission piping while some other companies have both. Using the above measure is difficult because Dominion has no non-cathodically protected bare steel. We have determined that in 2006 there were 48 national and 9 regional companies that also have cathodically protected bare steel and no non-cathodically protected bare steel transmission piping. Therefore, for this measure we are only using miles of cathodically protected bare steel in the denominator of the corrosion leaks per mile equation.

Figure 17 compares for 2006, this measure for all transmission companies having more than 10 miles of bare steel main in their system. Dominion's 2006 rate was 0.11, which is higher than the regional average. In 2006 the average rate of the regional companies was 0.09 and average rate of the national companies was 0.06 (not including Dominion). In 2007 Dominion's rate dropped to 0.086.

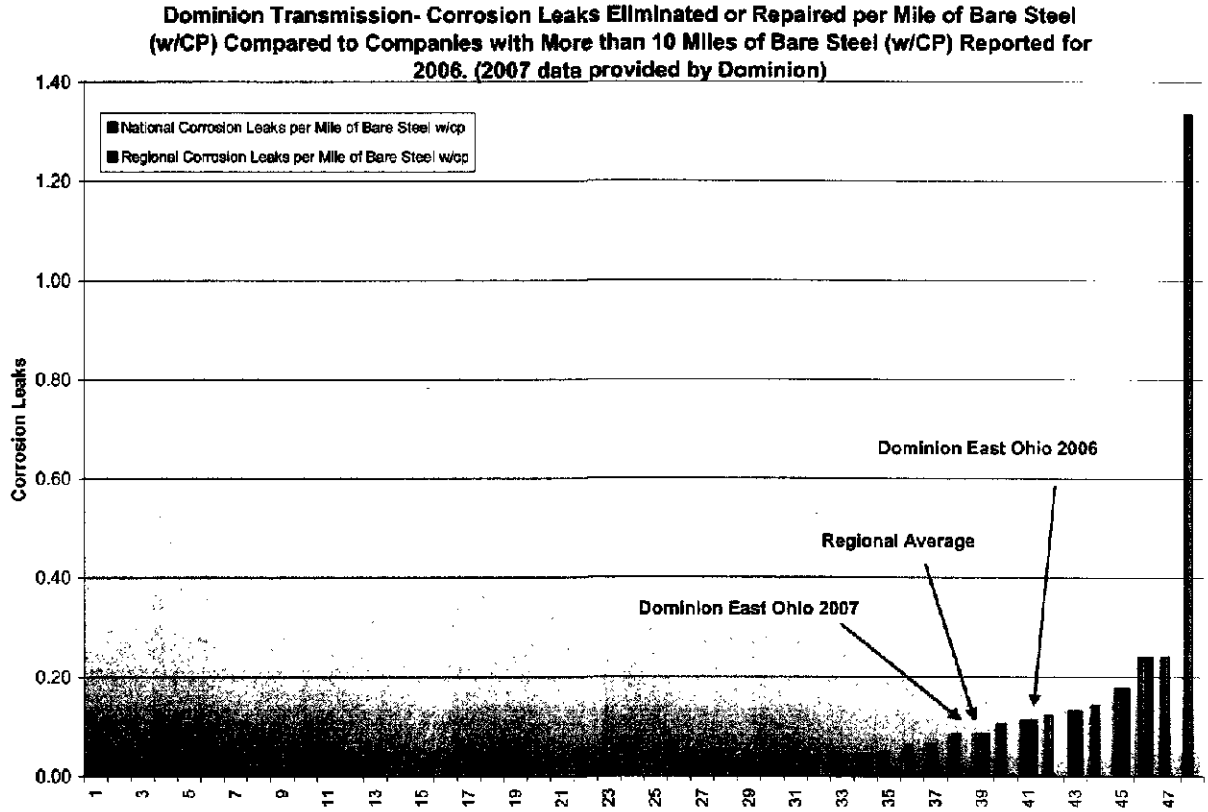


Figure 17

14. Dominion's change in transmission corrosion leak rates – 2002 - 2007

Figure 18 illustrates for the period 2002 – 2007, the Company's transmission corrosion leaks eliminated or repaired per mile of cathodically protected bare steel compared to the average corrosion leak rate of regional companies with more than 10 miles of bare steel main in their systems. In 2006 Dominion's rate was slightly higher than the regional average.

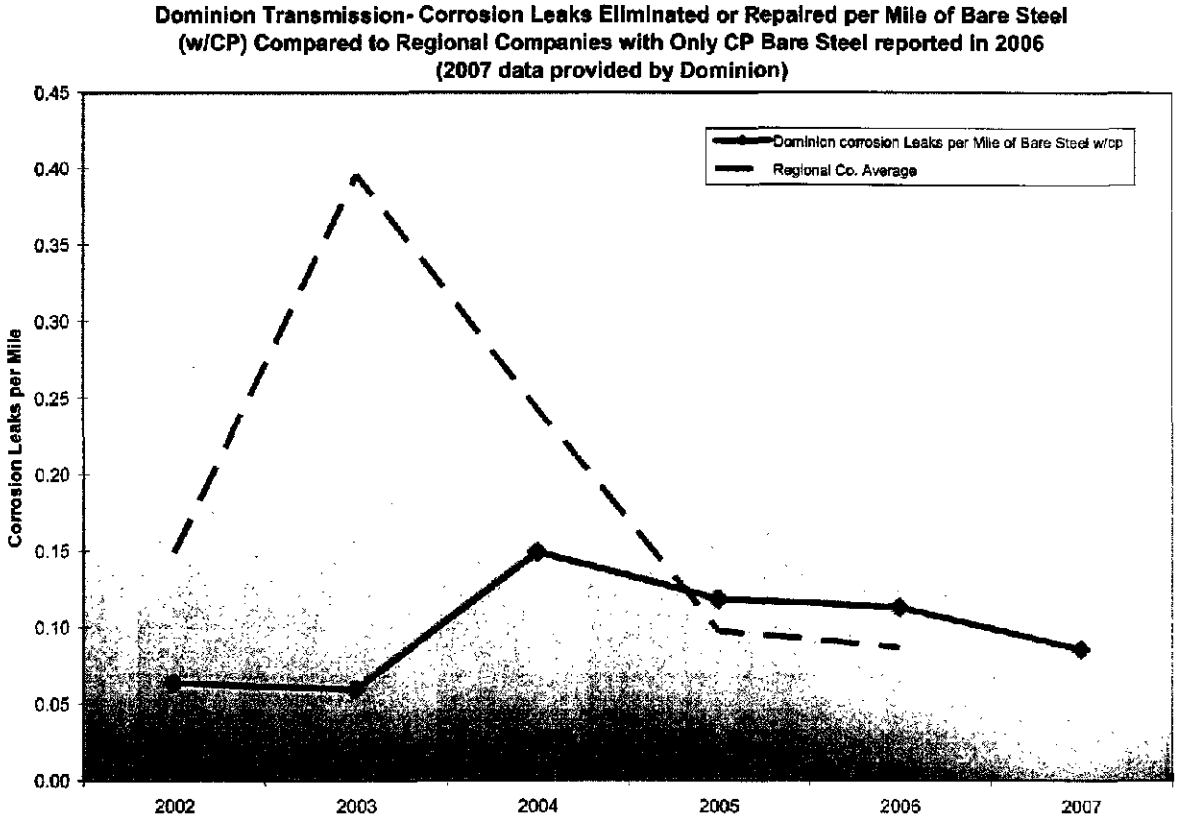


Figure 18

The Federal Government's Integrity Management Programs (IMP) for transmission lines, in practical terms, require operators to gather and analyze pipe on its system to determine those pipe categories and segments most in need of repair, maintenance or replacement. For transmission piping systems, this means identifying categories of pipe more prone to failure. Older pipes generally pose the highest risk. Unless Dominion's bare steel pipe can be assessed with in-line intelligent inspection (ILI) devices (smart pigs), or similar technologies to identify the most severely affected areas, we believe implementing pipe replacement programs for the remaining bare steel inventory best reduces their risk. Dominion's 35 miles of bare steel transmission piping are included in our estimate of approximately 162 miles per year to be replaced under Dominion's 25-year PIR program.

15. Dominion's number of bare steel services comparison - 2006

When comparing the number of bare steel services among the companies reporting having more than 50 miles of bare steel main in 2006, Dominion had the highest number of bare steel services in the nation (approximately 671,500 or 52% of Dominion's services). This is illustrated in Figure 19. This is a significant number of services that will need to be replaced. We were advised by Dominion that the majority of these services are included in its proposed PIR program.

Bare steel gas services have thinner wall thicknesses than bare steel gas mains and if they are not cathodically protected they will likely exhibit a leak due to corrosion faster than mains.

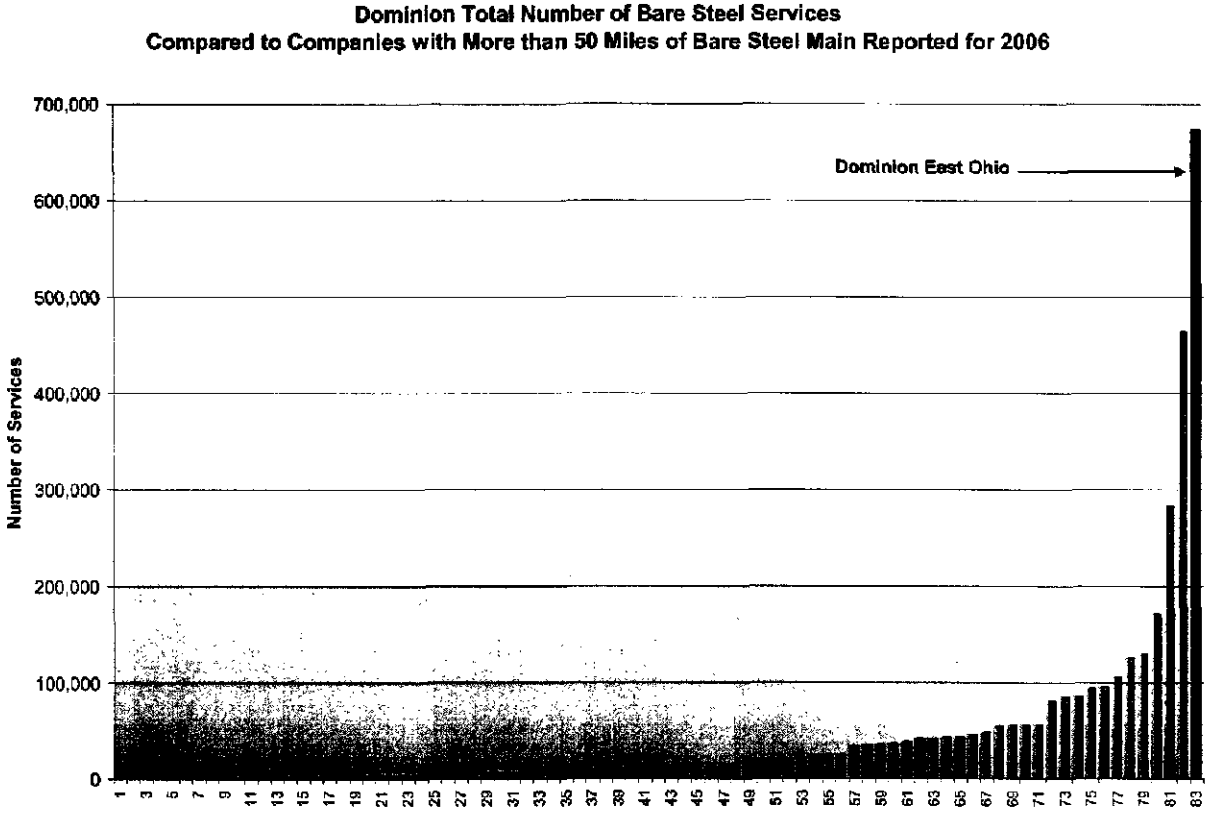


Figure 19

16. Dominion's corrosion leaks per 1,000 unprotected bare and coated steel services comparison - 2006

Figure 20 illustrates a comparison of the measure of corrosion leaks per 1,000 bare and non-protected steel services among companies with more than 50 miles of bare steel mains.

Dominion's ranking in this metric is favorable to the other national and regional companies. However, continued improvement is required to further reduce the annual number of corrosion leaks on services from the 2007 reported level of 4,054.

As part of the Company's efforts to reduce service related leaks, Black and Veatch believes that Dominion should follow the industry's best practices of replacing such services at the time the bare and non-protected coated steel mains are replaced. In addition, it may be necessary to replace existing coated steel services, if field supervision determines this to be prudent due to the condition of the existing coated steel service. There is a significant benefit to the gas customers in the efficiency of gas service leak repair when replacement of bare steel or otherwise deteriorated services occurs at the time of main replacement. In doing this there is an economic advantage, since this work is completed by crews already on site under the same work permit and without the need to perform the very costly leak investigation.

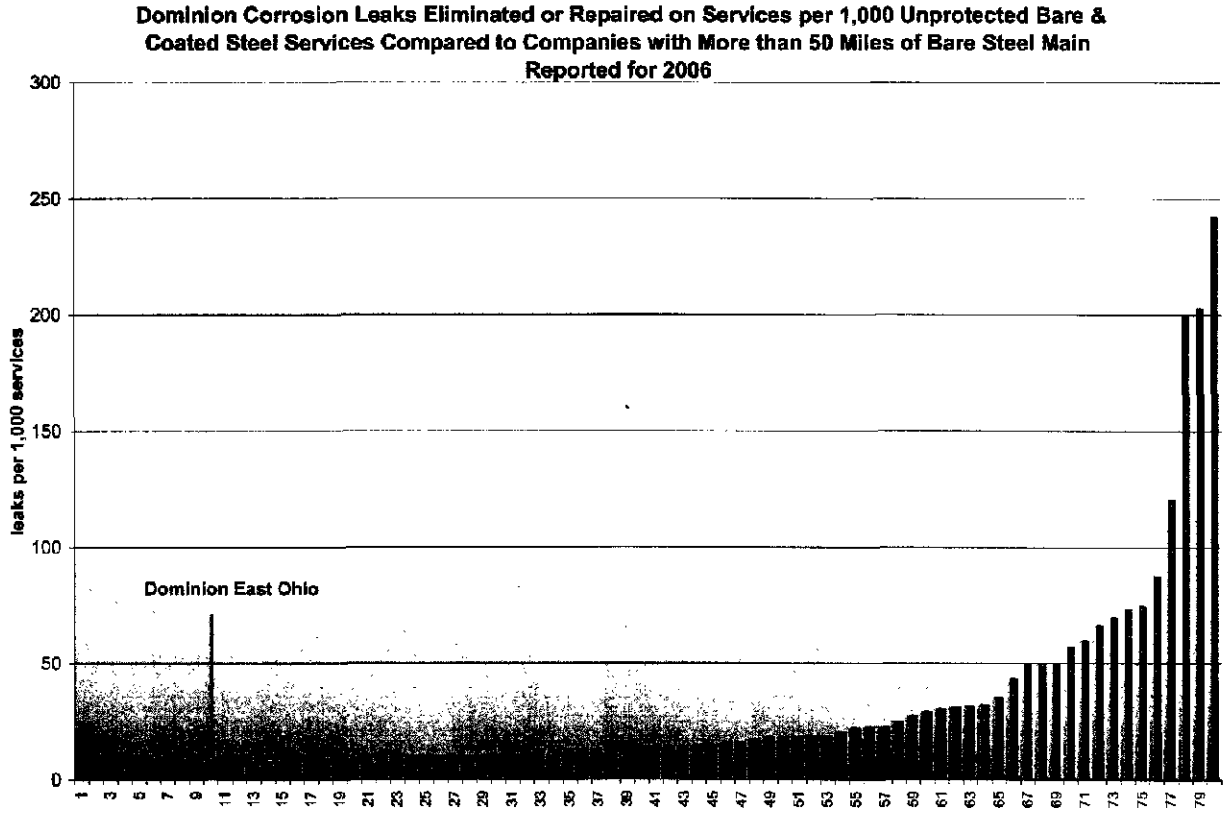


Figure 20

17. Dominion's cast and wrought iron mains

The natural gas industry typically includes cast and wrought iron mains among its list of higher risk main materials, along with bare steel mains. These mains are among the oldest mains remaining in distribution systems dating back to before the 1900's and are a problem for distribution operators because of the way they leak. Just like with bare steel mains, the DOT no longer permits these mains to be installed.

Cast iron main sections are typically joined together by jute and lead caulking at its bell and spigot joints. Over time these joints become dried out and due to the flexing of the pipe that may occur due to traffic vibration, seasonal weather, and construction activities, these joints eventually leak. Of greater concern is the fact that cast iron mains are more susceptible to cracks or main breaks due to earth movement. Such breaks are of a major concern due to the amount of gas that may be released in such circumstances. Unlike a corrosion leak that starts small, often a cracked main may leak at such a high rate that it can quickly saturate the area around the leak with natural gas and it may enter underground passageways to homes or other confined spaces such as underground utility vaults and sewers. Cast iron main breaks are particularly a concern during very cold temperatures when frost may cause additional stresses on these mains and when frost may also make the earth's surface an impermeable surface unable to allow the gas to vent out safely. The inability of the gas to safely escape increases the risk to near-by residents as this gas follows the path of least resistance which all too often is the basement of the house. Cast iron is capable of corroding under the right soil conditions, but is much more likely to leak at joints or crack in a brittle failure mode. Wrought iron, while less brittle than cast iron main, is subject to corrosion. A viewing of the chart provided in Figure 11 shows the corrosion of wrought iron as being similar to bare steel in its exponential leak rate growth. It too is part of the family of poor performers that needs replacement.

Regarding the replacement of cast and wrought iron mains, 86 miles or 77% of Dominion's cast iron and wrought iron mains are smaller than 4 inches in size. Smaller diameter mains experience higher stresses when placed under bending moments due to forces. Such higher stresses pose an increased risk of cracking.

Dominion has 112 miles of cast and wrought iron mains in its distribution system. It is Black & Veatch's opinion that similar to the bare steel mains, these mains should be also targeted for replacement under the Company's proposed 25-year replacement program. Such replacements should be prioritized based on the analysis of data using all of the tools available to Dominion's management. These miles of cast and wrought iron are included in Black & Veatch's estimate of approximately 162 miles per year to be replaced under Dominion's 25-year PIR program.

CONCLUSIONS

Throughout this report, Black & Veatch has compared Dominion's bare steel piping, using various measures, against other national and regional distribution and transmission operating companies that reported to DOT having more than 50 miles of bare steel distribution mains or 10 miles of bare steel transmission piping in their systems in 2006.

Our key findings and opinions are summarized as follows:

1. Of all of the distribution gas operating companies reporting to the DOT in 2006, Dominion has the greatest amount of bare steel mains remaining in its distribution system. At the end of 2006, Dominion reported having 3,862 miles of bare steel in its distribution system. Dominion's inventory of bare steel main is 20% of its total inventory of mains.
2. Dominion's 2007 data also shows that 80% (3,582) of its total leaks on mains (4,490) were caused by corrosion.
3. Dominion reported the highest number of corrosion leaks on mains in the nation in 2006 with 3,391 leaks. Dominion's efforts to reduce the number of leaks in their year-end back log of leaks waiting to be repaired likely resulted in increasing the number of corrosion leaks reported for the year. A trend line analysis of the 2002-2005 period estimates a 2006 level of corrosion leaks on mains to be 2,855. In 2006 a corrosion leak level of 2,855 corrosion leaks on mains would have ranked second highest in the nation.
4. The data also shows that even with this high number of corrosion leaks on mains per year, Dominion has maintained a corrosion leaks per mile of bare and non-protected coated steel mains rate that was lower than the average rate of regional companies. However, if the Dominion's corrosion leak rate was to rise to the level of the average leak rate for regional companies in 2006, that would mean that its annual corrosion leaks would increase from 3,391 to 7,855 leaks (a 132% increase)7. We believe that the risk associated with such an increase in number of leaks must be avoided.
5. We believe that a rise in leak rates that mirrors the average of regional companies would create additional safety risks, as well as create a serious leak management challenge for the Company. It is our opinion that the focus of Dominion's efforts must be towards prioritizing the worst mains for replacement first and accelerating the replacement of these aging mains before the leak rate gets out of hand. Without such an accelerated replacement effort it is our opinion that Dominion will face the risks associated with an increasing number of corrosion leaks.
6. In 2006 Dominion replaced 34 miles its bare steel distribution mains at a rate of approximately 0.9% per year as compared to the national average replacement rate of 3.7% per year. At the present Dominion replacement rate, it would take the Company 114 years to eliminate its aging bare steel mains compared to 26 years for the nation as a whole (not including Dominion). Dominion proposed accelerated replacement program (25 years) is in line with the national average. With Dominion having the largest amount of bare steel and a high number of corrosion leaks on mains, Black and Veatch believes that such action by Dominion is prudent and reasonable.

[7] As noted, Dominion believes that its number of miles of unprotected coated steel may be overstated. If we assume that Dominion has no unprotected coated steel main and if Dominion's corrosion leak rate of 0.88 was to rise to the level of the average leak rate for regional companies in 2006 (1.48), that would mean that its annual corrosion leaks would increase from 3,391 (in 2006) to 5,716 leaks. This would be a 69% increase in the number of leaks.

7. Dominion has 112 miles of cast iron and wrought iron mains. While less prone to corrosion leakage, these mains are also poor performers due to its joining methods. Cast iron sections of pipe are typically joined together with calked lead and jute bell and spigot joints which leak over time. In addition, cast iron can leak because of its brittle failure mode that can result in sudden and serious leakage. Seventy seven percent of Dominion's cast and wrought iron main inventory is less than or equal to 4 inches in diameter. Such small mains experience higher stresses when placed under bending moments due to soil loadings and such higher stresses pose an increased risk of cracking.
8. In 2007 Dominion also has 35 miles of bare steel transmission piping in its system. This is likely the oldest pipe in Dominion's transmission system and generally older pipes pose the highest risk. Unless Dominion's bare steel pipe can be assessed with in-line intelligent inspection (ILI) devices (smart pigs), or similar technologies to identify the most severely affected areas, we believe implementing pipe replacement programs for the remaining bare steel inventory best reduce their risk.
9. Corrosion science experts (e.g., Peabody) have documented the exponential growth of corrosion leaks on bare steel as a function of time. This exponential growth rate begins after the first leak in a main segment occurs. A gas system with bare steel mains may be exposed to an acceleration of leakage incidents as its system ages. If a gas system has a relatively small amount of bare steel, this accelerated leak rate growth can be managed via a short time frame (ten years) mains replacement program. In the case of Dominion, with nearly 4,000 miles of bare steel, cast and wrought iron mains, an increase in its corrosion leak rate could not be efficiently mitigated in a short time frame. Hence, now is the time to begin an accelerated mains replacement program.
10. Dominion has the highest number of bare steel services (671,586 services) among all companies reporting to the DOT with more than 50 miles of bare steel main. In 2006 Dominion had 4,054 corrosion leaks on services ranking it as having the highest number of corrosion leaks on services among all of the companies in the nation reporting to the DOT. As part of the Company's effort to reduce service related leaks, Black and Veatch believes that Dominion should follow the industry's best practices of replacing such services at the time the bare and non-protected coated steel mains are replaced. Furthermore, there is a significant benefit to the gas customers in the efficiency of gas service leak repair when replacement of bare steel or otherwise deteriorated services occurs at the time of main replacement. In doing this there is an economic advantage, since this work is completed by crews already on site under the same work permit and without the need to perform the very costly leak investigation.

In addition to the customer safety and system reliability benefits noted throughout this report, a well-planned accelerated main replacement program would have a host of qualitative benefits for the public such as fewer unplanned disruptions to traffic on roads for emergency gas leak repairs, and improved coordination with local town and village governments. Although these quality of life benefits are dwarfed by the safety and reliability benefits, it is Black & Veatch opinion that utility operators need to prudently manage their systems in a manner that protects the customer, assures the integrity of the gas system and does not adversely inconvenience the customer's quality of life.

Black & Veatch recognizes and commends Dominion's concern for the safety of its customers and employees, its desire to be a responsible steward of the gas system it operates. We affirm its need to implement its PIR program.

Black & Veatch recommends that the PUCO approve the implementation of Dominion's proposed accelerated mains replacement program.

APPENDIX A:
LIST OF 83 DISTRIBUTION COMPANIES MEETING THE SELECTION CRITERIA WITHIN THE NATIONAL SAMPLE

1 Alabama Gas Corporation
2 Aquila Networks (Kansas)
3 Aquila Networks (Nebraska)
4 Arkansas Western Gas Company
5 Atlanta Gas Light
6 Atmos Energy - West Texas Division
7 Atmos Energy Corp., Mid-Tex Division
8 Atmos Energy Corporation, Colorado Kansas Division
9 Atmos Energy Corporation - KY/Mid States Division
10 AtmostEnergy Corporation - KY/Mid States Division
11 Baltimore Gas & Electric Company
12 Bay State Gas Company
13 CenterPoint Energy
14 CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Minnesota Gas
15 Central Florida Gas, (Winter Haven)
16 Central Hudson Gas & Electric Corporation
17 Chartiers Natural Gas Company, Inc.
18 Chesapeake Utilities Corporation Maryland Gas Division (See Part F).
19 Clearwater Gas System
20 Columbia Gas of Kentucky
21 Columbia Gas of Maryland
22 Columbia Gas of Ohio
23 Columbia Gas of Pennsylvania
24 Columbia Gas of Virginia
25 Consolidated Edison Company of New York, Inc.
26 Consumers Energy Company
27 Consumers Gas Utility Company
28 Corning Natural Gas Corporation
29 Delta Natural Gas Company, Inc
30 Dominion East Ohio
31 Duke Energy Ohio, Inc.
32 Energy Services of Pensacola
33 Equitable Gas Company
34 Florida Public Utilities
35 Florida Public Utilities
36 Hope Gas Inc, DBA Dominion Hope
37 Indiana Gas Company, Inc.
38 Kansas Gas Service
39 Kansas Gas Service
40 KeySpan Energy Delivery - Boston Gas
41 KeySpan Energy Delivery - Colonial Cape
42 KeySpan Energy Delivery - Long Island
43 KeySpan Energy Delivery- New York City
44 Lancaster Municipal Gas Dept.
45 Louisville Gas & Electric Company
46 Michigan Consolidated Gas Company
47 Mountaineer Gas Company
48 National Fuel Gas Distribution Corp - NY
49 National Fuel Gas Distribution Corp - PA
50 National Gas & Oil Cooperative
51 National Grid USA
52 National Grid USA (Rhode Island)
53 New England Gas Company - Fall River
54 New Jersey Natural Gas
55 New York State Electric & Gas
56 Nicor Gas
57 Northern Indiana Public Service Company
58 NSTAR Gas Company
59 Oklahoma Natural Gas Company
60 Orange & Rockland Utilities
61 Pacific Gas & Electric Company
62 PECO Energy Company
63 PPL Gas Utilities Corporation
64 Public Service Company Of Colorado
65 Public Service Electric & Gas Company
66 Puget Sound Energy
67 Rochester Gas And Electric Corp.
68 SEMCO ENERGY Gas Company
69 South Jersey Gas Company
70 Southern California Gas Company
71 Southern Connecticut Gas Company
72 Southern Indiana Gas & Electric Company
73 Suburban Natural Gas Company
74 T. W. Phillips Gas And Oil Co.
75 TECO Peoples Gas
76 Texas Gas Service Company
77 The Gas Company, LLC.
78 The Peoples Natural Gas Company DBA Dominion Peoples
79 UGI Penn Natural Gas
80 UGI Utilities, Inc.
81 Vectren Energy Delivery of Ohio
82 Washington Gas Light Company
83 Yankee Gas Services Company

APPENDIX B
LIST OF 30 DISTRIBUTION COMPANIES MEETING THE SELECTION CRITERIA WITHIN THE REGIONAL SAMPLE

1 Atmos Energy Corporation - KY/Mid States Division
2 Chartiers Natural Gas Company, Inc.
3 Columbia Gas of Kentucky
4 Columbia Gas of Ohio
5 Columbia Gas of Pennsylvania
6 Consumers Energy Company
7 Consumers Gas Utility Company
8 Delta Natural Gas Company, Inc
9 Dominion East Ohio
10 Duke Energy Ohio, Inc.
11 Equitable Gas Company
12 Hope Gas Inc, DBA Dominion Hope
13 Indiana Gas Company, Inc.
14 Lancaster Municipal Gas Dept.
15 Louisville Gas & Electric Company
16 Michigan Consolidated Gas Company
17 Mountaineer Gas Company
18 National Fuel Gas Distribution Corp - PA
19 National Gas & Oil Cooperative
20 Northern Indiana Public Service Company
21 PECO Energy Company
22 PPL Gas Utilities Corporation
23 SEMCO ENERGY Gas Company
24 Southern Indiana Gas & Electric Company
25 Suburban Natural Gas Company
26 T. W. Phillips Gas and Oil Co.
27 The Peoples Natural Gas Company DBA Dominion Peoples
28 UGI Penn Natural Gas
29 UGI Utilities, Inc.
30 Vectren Energy Delivery of Ohio

APPENDIX C
LIST OF 80 TRANSMISSION COMPANIES MEETING THE SELECTION CRITERIA WITHIN THE NATIONAL SAMPLE

1 Aquila Networks (Kansas)
2 Arkansas Oklahoma Gas Corp
3 Arkansas Oklahoma Gas Corp
4 Arkansas Western Gas Company
5 Atmos Energy Corporation - KY/Midstates Division
6 Atmos Pipeline - Texas
7 CenterPoint Energy
8 Centerpoint Energy Gas Transmission - TX
9 CenterPoint Energy Gas Transmission - OK
10 CenterPoint Energy Gas Transmission - LA
11 CenterPoint Energy Gas Transmission - AP
12 Chevron Pipe Line Company
13 Columbia Gas Transmission - VA
14 Columbia Gas Transmission - MD
15 Columbia Gas Transmission - KY
16 Columbia Gas Transmission - NY
17 Columbia Gas Transmission - WV
18 Columbia Gas Transmission - Pa
19 Columbia Gas Transmission Corp
20 Consumers Energy Company
21 Cranberry Pipeline Corporation
22 Crosstex Ccng Transmission Ltd
23 Crosstex Lig, LLC
24 Crosstex Processing Services, LLC
25 Dominion East Ohio
26 Dominion Transmission Inc - Pa
27 Dominion Transmission, Inc. - NY
28 Dominion Transmission, Inc. - WV
29 Dow Pipeline Company
30 Enbridge Pipelines (Midla) L.L.C. - MS
31 Enbridge Pipelines (Midla) L.L.C. - LA
32 Enbridge Pipelines (North Texas) L.P.
33 Energy West Wyoming
34 Enogex Inc
35 Equitable Production Company, Llc
36 Equitable Gas Company
37 Equitrans, L.P.
38 Gas Solutions Ii Ltd.
39 Greenlight Gas
40 Gulf South Pipeline Company, LP - MS
41 Gulf South Pipeline Company, LP - LA
42 Jefferson Gas LLC
43 Kansas Gas Service
44 Kentucky West Virginia Gas Company, LLC
45 Kinder Morgan, Inc.
46 Louisville Gas & Electric Company
47 Mississippi River Transmission Corp.
48 National Fuel Gas Distribution Corp
49 National Fuel Gas Supply Corporation - NY
50 National Fuel Gas Supply Corporation - PA
51 NGO Transmission, Inc.
52 Northern Natural Gas Co - MN
53 Northern Natural Gas Co - NE
54 Northern Natural Gas Co - OK
55 Northern Natural Gas Co - TX
56 Northern Natural Gas Co - IA
57 Northern Natural Gas Co - KS
58 Occidental Of Elk Hills, Inc.
59 Oklahoma Natural Gas Co
60 OkTex Pipeline Company - TX
61 OkTex Pipeline Company - OK
62 ONEOK Gas Storage, LP
63 ONEOK Gas Transportation, LLC
64 ONEOK Transmission Company
65 Panhandle Eastern Pipeline Co. - MO
66 Panhandle Eastern Pipeline Co. - KS
67 PPL Gas Utilities Corporation
68 Public Service Company Of New Mexico
69 Southern California Gas Company
70 Southern Natural Gas Company
71 Southern Star Central Gas Pipeline, Inc. - OK
72 Southern Star Central Gas Pipeline, Inc. - KS
73 Targa Intrastate Pipeline, LLC
74 Texas Eastern Transmission, LP
75 The Peoples Natural Gas Company DBA Dominion Peoples
76 West Texas Gas, Inc.
77 Western Gas Interstate Company - TX
78 Western Gas Interstate Company - OK
79 Williston Basin Interstate Pipeline Company - ND
80 Williston Basin Interstate Pipeline Company - MT

APPENDIX D
LIST OF 21 TRANSMISSION COMPANIES MEETING THE SELECTION CRITERIA WITHIN THE REGIONAL SAMPLE

1 Atmos Energy Corporation - KY/Midstates Division
2 Columbia Gas Transmission - KY
3 Columbia Gas Transmission - PA
4 Columbia Gas Transmission - WV
5 Columbia Gas Transmission Corp
6 Consumers Energy Company
7 Cranberry Pipeline Corporation
8 Dominion East Ohio
9 Dominion Transmission Inc - PA
10 Dominion Transmission, Inc. - WV
11 Equitable Gas Company
12 Equitrans, L.P.
13 Jefferson Gas LLC
14 Kentucky West Virginia Gas Company, LLC
15 Louisville Gas & Electric Company
16 National Fuel Gas Distribution Corp
17 National Fuel Gas Supply Corporation
18 NGO Transmission, Inc.
19 PPL Gas Utilities Corporation
20 Texas Eastern Transmission, LP
21 The Peoples Natural Gas Company DBA Dominion Peoples

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BLACK & VEATCH
Building a **world** of difference®.

EXHIBIT

OCC Ex. 6

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 2 08-169-GA-ALT

Question Number: 70

Subpart:

Request Date: 06/17/2008

Due Date: 07/08/2008

Topic:
Distribution Infrastructure

Question:
Referring to the Pipeline Replacement Program testimony of Mr. McNutt All references to testimony in this set of discovery requests are to testimony filed as part of a supplement to the Pipeline Replacement Program application, Case No 08-169-ALT (May 30, 2008)., pp. 9-10, please explain why DEO's current main replacement program to replace its existing bare steel, cast iron, wrought iron, and copper mains cannot be completed until 2097.

Answer:
DEO objects to this request because it improperly seeks a detailed, narrative response. Under the applicable Commission rules and Ohio Civil Rules, "[a]n *interrogatory seeks an admission or it seeks information of major significance* in the trial or in the preparation for trial. It does not contemplate an array of details or outlines of evidence, a function reserved by the rules for deposition." Penn Central Transp. Co. v. Armco Steel Corp., 27 Ohio Misc. 76, 77 (Montgomery Cty. 1971). Subject to and without waiving this objection, DEO responds as follows:
On page 5 of the Application filed in Case No. 08-169-GA-ALT, DEO estimates the net mileage to be replaced in the proposed PIR program is 3,567 miles. Over the past five years, DEO has replaced an average of 40 miles of bare steel, cast iron and wrought iron pipe per year. Applying that historical rate to estimated net mileage to be replaced yields an 89-year period, which would end in 2097.

Preparer Of Response:
Tim McNutt

Date Prepared:
06/18/2008 01:29:03 PM EDT

Attachments:
No

EXHIBIT

OCC Ex. 7

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 1
08-169-GA-UNC

Question Number: **Subpart:**

Request Date: **Due Date:**
03/18/2008 03/27/2008

Topic:
Distribution Infrastructure

Question:
Referring to page 5, paragraph number 11 of the Application, and the Company's estimate of $1,656,000,000 for pipeline replacement over a 25-year period, of this amount, how has each of the items set forth on pages 3 and 4, paragraph number 8, of the Application been replaced annually since 1993:
a. Distribution Pipeline Replacements;
b. Transmission Pipeline Replacements;
c. Distribution Pipeline Relocations;
d. Transmission Pipeline Relocations;
e. System Improvements;

f. Regulating Stations;

Answer:
The below table contains an estimate of the dollars spent in each category replacing or abandoning bare steel pipe over the period for which information is readily available. Amounts are based on the footage within each category times the respective average cost/foot for each year.

Bare Steel Calculated Costs:
2002
2003
2004
2005
2006
2007
Distribution Pipeline Replacements
$8,578,024
$10,322,057

$11,122,759
$10,782,217
$7,312,515
$7,851,966
Transmission Pipeline Replacements
$1,980,285
$2,935,584
$4,552,739
$3,145,982
$2,059,313
$880,819
Distribution Pipeline Relocations
$1,161,140
$2,782,188
$3,185,332
$8,775,166
$2,579,864
$2,186,145
System Improvements
$38,164
$852
$46,694
$106,126
$48,599
$27,696

Notes:

a. Only data from 2002 – 2007 is readily available.

b. Replacement of field wrapped and ineffectively coated pipe is not included in these numbers.

c. The average cost per foot used to derive total dollars is the actual average in that particular year for each specific category.

d. Transmission Pipeline Relocation totals are included in the Transmission Pipeline Replacement totals above.

e. Replacement of facilities at Regulating Stations is not included in the $1,656,000 estimate.

f. Storage and Gathering replacements are included above in the Transmission category.

g. Wrought iron, copper and cast iron replacements are not included and are not believed to represent a significant portion of the replacements.

Preparer Of Response: [redacted] **Date Prepared:**

P Mark Messersmith [redacted] 03/19/2008 09:39:51 AM EDT

Attachments:

No

EXHIBIT

OCC Ex. 8.

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 1
08-169-GA-UNC

Question Number: **Subpart:**
34

Request Date: **Due Date:**
03/18/2008 03/27/2008

Topic:
Distribution Infrastructure

Question:
What is DEO's current on-going infrastructure investment for each of the following:

a. Distribution Pipeline Replacements;
b. Transmission Pipeline Replacements;
c. Distribution Pipeline Relocations;
d. Transmission Pipeline Relocations;
e. System Improvements;
f. Regulating Stations;
g. Transmission Pipeline Integrity;
h. Distribution Pipeline Integrity; and
i. Environmental Compliance?

Answer:
The below chart shows DEO's current five-year planned expenditures for each of the listed categories absent the expanded replacement program identified in the Application.

2008 to 2012 DEO

Capital Budget Plan
2008
2009

2010
2011
2012
Program

Distribution Pipeline Replacements
$18,500,000
$19,240,000
$20,009,600
$20,809,984
$21,642,383
Transmission Pipeline Replacements
$4,500,000
$4,654,000
$4,840,160
$5,033,766
$5,235,117
Distribution Pipeline Relocations
$9,400,000
$9,776,000
$10,167,040
$10,573,722
$10,996,670
Transmission Pipeline Relocations
N/A
N/A
N/A
N/A
N/A
System Improvements
$2,000,000
$2,100,000
$2,200,000
$2,200,000
$2,300,000
Regulating Stations
$3,988,000
$4,113,400
$4,277,936
$4,449,053
$4,627,016
Transmission Pipeline Integrity
$7,225,000
$9,100,000
$7,800,000
$4,600,000
$3,000,000

Environmental Compliance
$1,000,000
$1,040,000
$1,081,600
$1,124,864
$1,169,859

Notes:
a. Transmission relocations are included with the Transmission Line Replacements.
b. Storage and Gathering replacements are included with the Transmission Line Replacements.
c. The requirements of Distribution Pipeline Integrity have not been finalized and therefore are not included in the above capital budget plan.

Preparer Of Response: [redacted] **Date Prepared:**
P Mark Messersmith 03/19/2008 12:44:28 PM EDT

Attachments:
No

EXHIBIT

OCC Ex. 9

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 1
08-169-GA-UNC

Question Number: **Subpart:**
10

Request Date: **Due Date:**
03/18/2008 03/27/2008

Topic:
Distribution Infrastructure

Question:
Referring to page 3, paragraph number 6 of the Application, what will be the "significant benefits" anticipated by the Company from "reduced incidence of leak repair expenses"?

Answer:
As stated in the Application, DEO anticipates O&M savings comparable to those Duke Energy Ohio reported (See A Report by the Staff of the Public Utilities Commission of Ohio, December 20,2007, Case No. 07-589-GA-AIR, at p. 39) from reduced incidence in leak repair expenses, and like Duke Energy Ohio, DEO will credit savings in avoided operations and maintenance costs to customers. The potential for significant reductions in leak repair expenses on DEO's system is supported by a study of the company's Western operating area in Cleveland which showed that bare steel low-pressure pipe accounted for 25% of the total pipeline in the area and 91% of the total mainline leaks. The reduced incidence of leak repairs will also facilitate the continued safe and reliable delivery of gas service. Finally, leak repairs or emergency replacements are inherently reactionary and create considerable confusion and disruptions for the customer and general public. Planned and scheduled pipeline infrastructure replacement work will result in less customer and traffic disruptions and better coordination with local municipalities and the Ohio Department of Transportation.

Preparer Of Response: **Date Prepared:**
Tim McNutt 03/19/2008 09:47:54 AM EDT

Attachments:
No

EXHIBIT

OCC Ex. 10

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 1
08-169-GA-UNC

Question Number: **Subpart:**
25

Request Date: **Due Date:**
03/18/2008 03/27/2008

Topic:
Distribution Infrastructure

Question:
Referring to page 2, paragraph number 5 of the Application, identify the orginal service life of the pipeline that was installed in each of the following decades:
a. Pre-1909;
b. 1910-1919;
c. 1920-1929;
d. 1930-1939;
e. 1940-1949;
f. 1950-1959; and
g. 1960-1969.

Answer:
DEO does not have records that identify the original service life assumptions for the pipeline installed in the decades referenced above.

Preparer Of Response: **Date Prepared:**
Tim McNutt 03/19/2008 10:44:37 AM EDT

Attachments:
No

EXHIBIT

OCC Ex M

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 1
08-169-GA-UNC

Question Number: **Subpart:**
39

Request Date: **Due Date:**
03/18/2008 03/27/2008

Topic:
Distribution Infrastructure

Question:
Referring to page 7, paragraph 15 of the Application, what are the projected meter reading costs for the Company if the Company moves the residential customers' meters to outside locations?

Answer:
The Company has not performed that calculation and thus cannot respond to the question. It should also be noted that, because meter relocation plans will be discussed with Staff on an annual basis throughout the PIR program, such a calculation cannot be done with the information available at the present time.

Preparer Of Response: **Date Prepared:**
Joe Patten 03/19/2008 12:51:25 PM EDT

Attachments:
No

EXHIBIT

OCC Ex. 12

Good Afternoon Mr. Poulos and Sarah.

I have sent a copy of PIR - OCC Int 1-60 below. I don't know why when the data request is converted to an email pdf it will not display the table.

Sorry for any inconvenience this may have caused. I will resend OCC Int 6-153 also.

Have a good day,
Melanie Moneypenny

Melanie Moneypenny
Regulatory and Pricing Analyst
Dominion East Ohio
(216) 736-5336
Tie Line 8-650-5336
Melanie M Moneypenny/Energy/5/Dom@VANCPOWER
----- Forwarded by Melanie M Moneypenny/Energy/5/Dom on 04/10/2008 12:32 PM -----

Dominion

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR

Response to Data Requests

Requesting Party:
OCC
Data Request Set:
PIR - INT Set 1 08-169-GA-UNC

Question Number:	**Subpart:**
60	

Request Date:	**Due Date:**
03/18/2008	03/27/2008

[redacted]

Topic:

Distribution Infrastructure

Question:

Since the Company's last rate case in 1993 (Case No. 93-2006-GA-AIR), by year how much of the Company's pipeline infrastructure (in miles of pipeline and in dollars) has been repaired or replaced pursuant to the Company's current pipeline replacement plan?

Answer:

Please see the information below for the years for which data is readily available.

2002 to 2007 DEO Capital $ Program	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007
Distribution Pipeline Replacements	12,416,583	14,265,520	15,435,906	14,995,818	11,703,004	14,916,552
Transmission Pipeline Replacements	5,523,623	3,463,909	4,495,607	2,376,034	1,887,860	2,304,490
Distribution Pipeline Relocations	4,599,790	8,778,281	7,997,810	6,676,287	9,513,689	7,935,902
System Improvements	296,304	1,586,634	854,963	928,533	2,150,792	2,365,282
Transmission Pipeline Integrity	0	2,672,979	5,130,093	6,470,918	4,826,817	3,684,984
Miles of Pipe						
Distribution Pipeline Replacements	42	48.5	45.3	36.3	39	47.7
Transmission Pipeline Replacements	7.8	5.0	5.0	2.2	3.1	4.5
Distribution Pipeline Relocations	14.8	21.6	21.8	6.4	34.3	25.7
System Improvements	1.9	10.2	7.7	2.5	10.9	13.1
Transmission Pipeline Integrity	0	3.5	5.7	0.8	1.9	0.8

[redacted]

Preparer of Response: P Mark Messersmith

Date Prepared: 03/28/2008

Attachments:

Attach here-->

EXHIBIT

OCC Ex. 13

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - RFP Set 1
08-169-GA-UNC

Question Number: 11

Subpart:

Request Date: 03/18/2008

Due Date: 03/27/2008

Topic:
Distribution Infrastructure

Question:
Please provide copies of all reports, analyses, studies, communications, workpapers, data, source documents, and/or other information relating to the Company's response to OCC Interrogatory Nos. 8 and 9 regarding the 25 year period for the PIRP.

Answer:
Please see the attached.

Preparer Of Response:
Tim McNutt

Date Prepared:
03/20/2008 08:21:26 AM EDT

Attachments:
Yes

Attachment Names:
11-19-07 PIR Meeting.ppt
01-23-08 PIR Meeting.ppt

EXHIBIT

Dominion

Scope of Dominion East Ohio's Bare Pipe Exposure

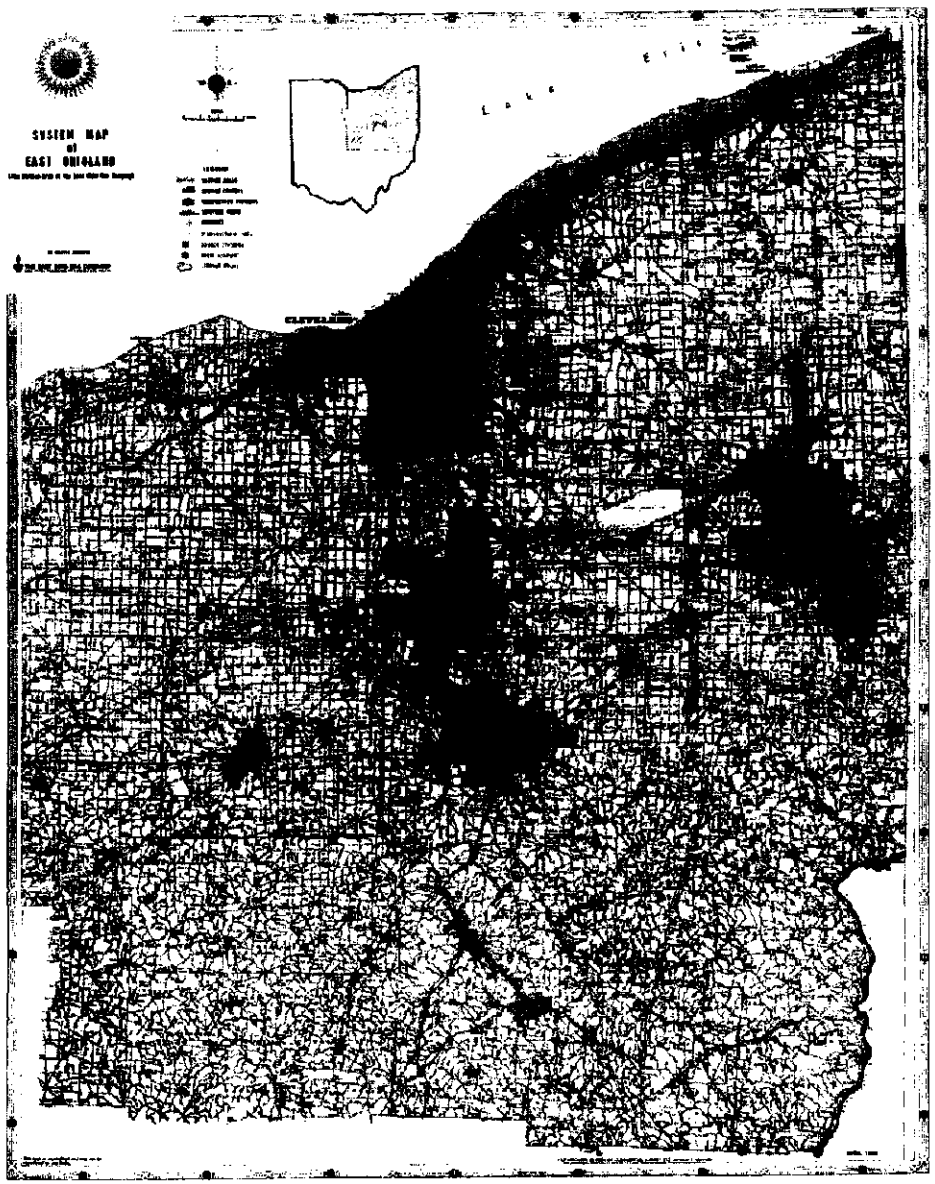
Tim McNutt

November 19, 2007

OCC Ex. 13A

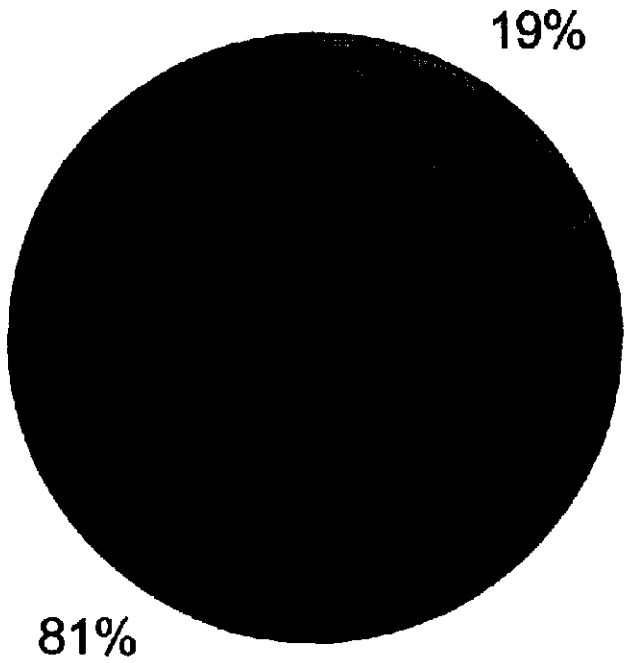
Dominion

Dominion East Ohio Territory



Dominion

Bare Pipe vs Total Pipe

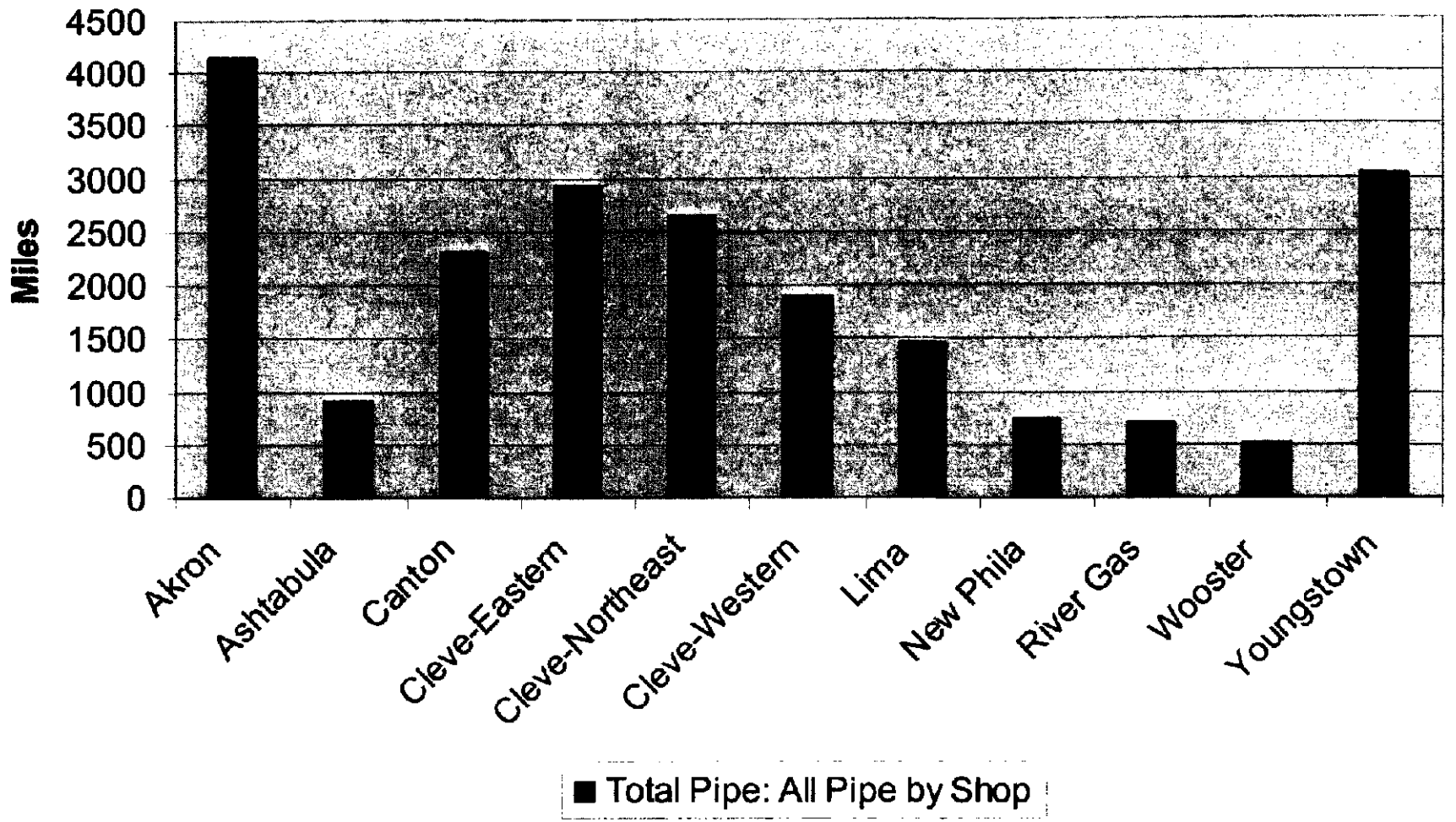


- Target Pipe: Bare Steel, Cast & Wrought Iron
- Total Pipe: All DEO Pipe in System (Plastic, Coated Stl, etc)

Total Pipe in DEO System: 21,263 Miles

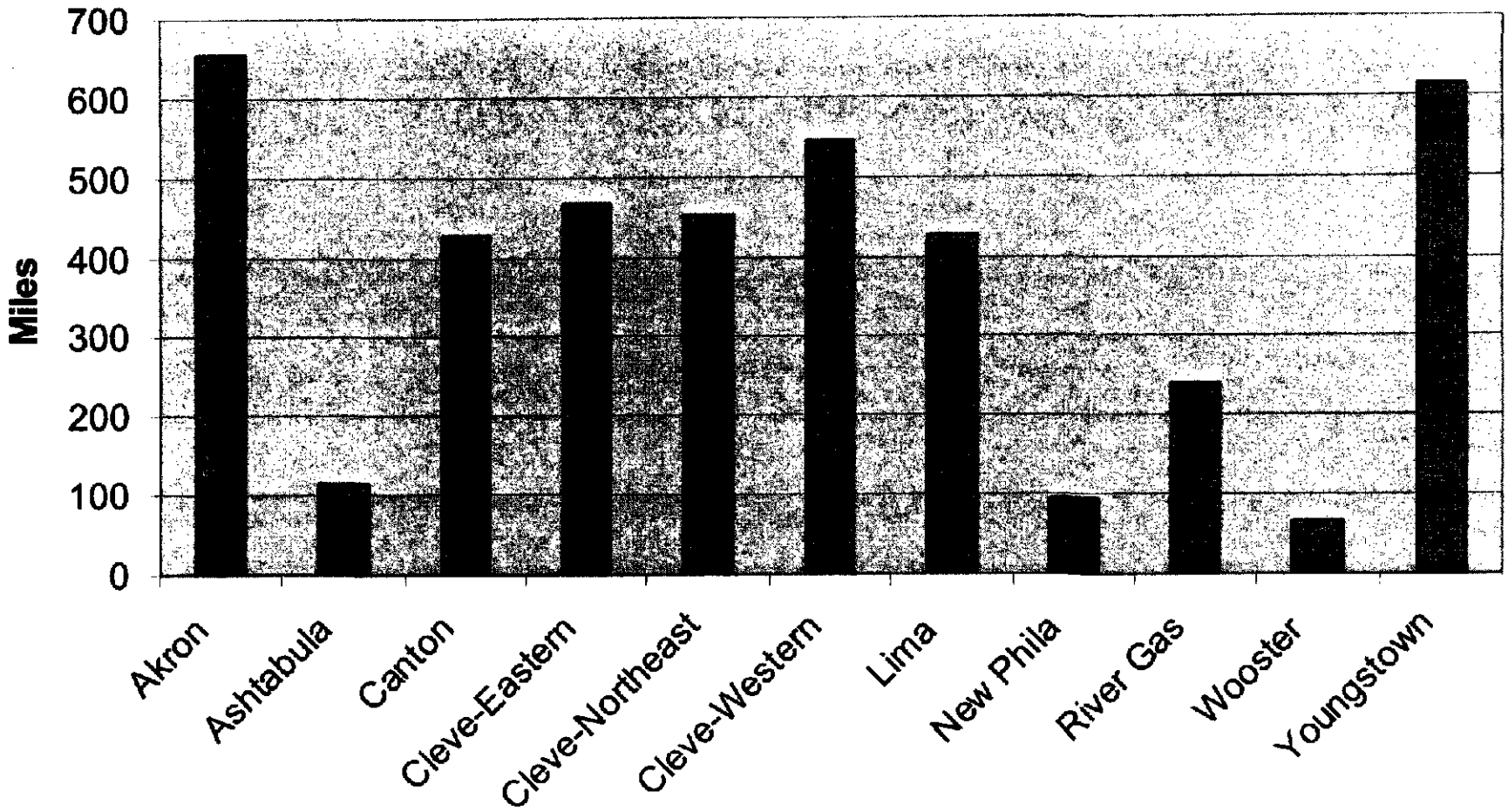
Dominion

Total DEO Pipe by Shop



Dominion

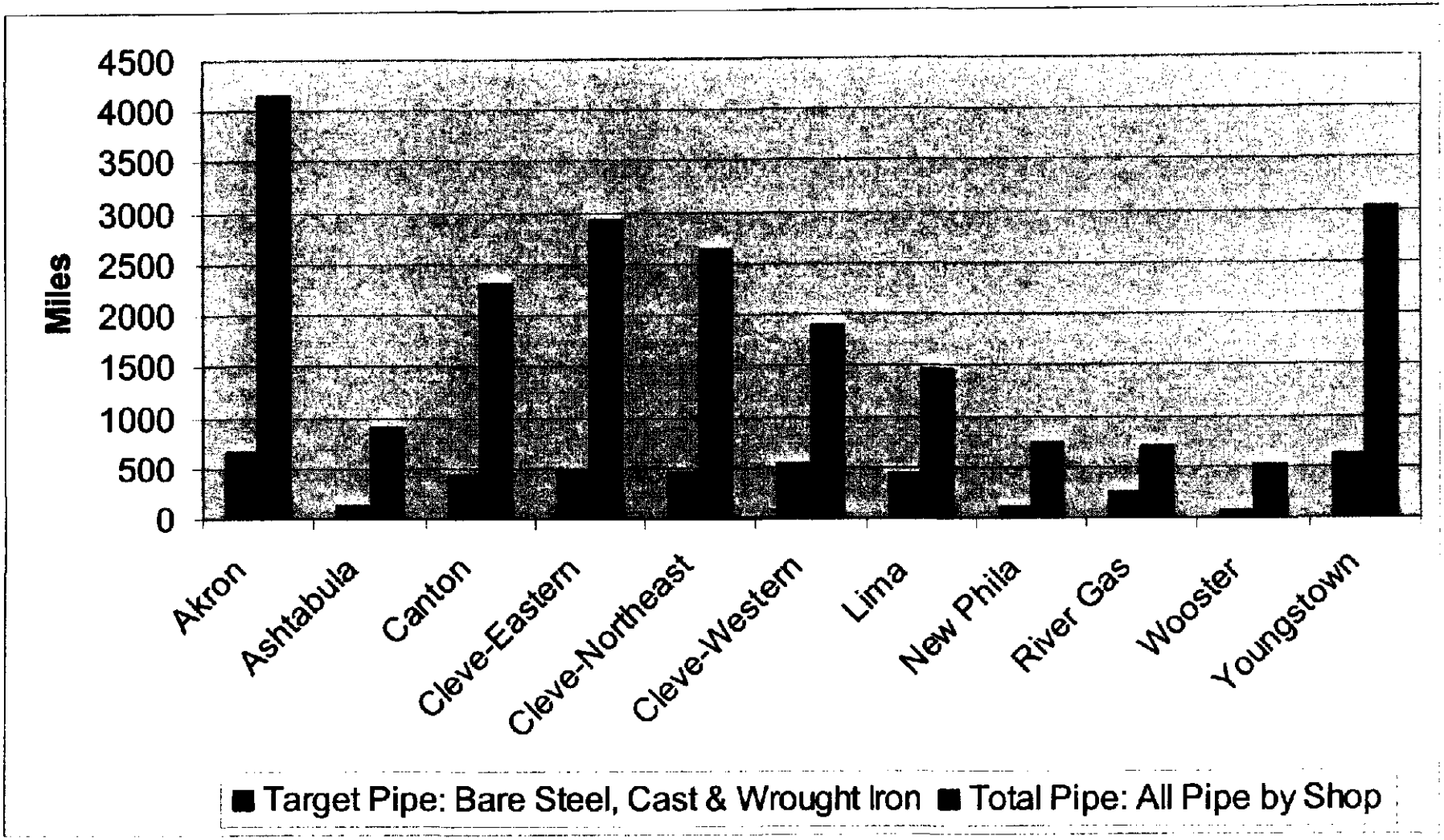
Target Pipe by Shop



Target Pipe: Bare Steel, Cast & Wrought Iron

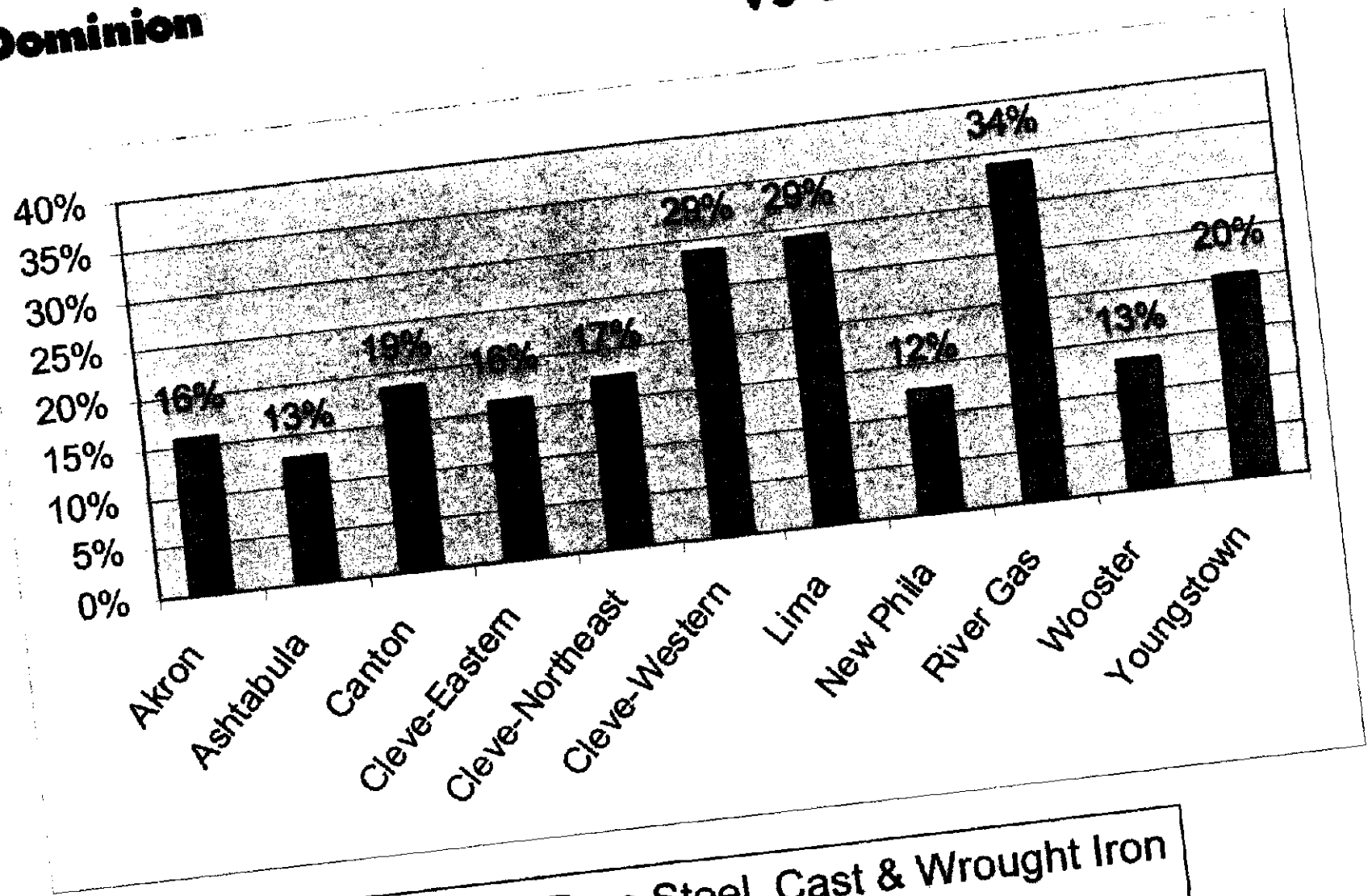
Dominion

Target Pipe vs Total Pipe



Dominion

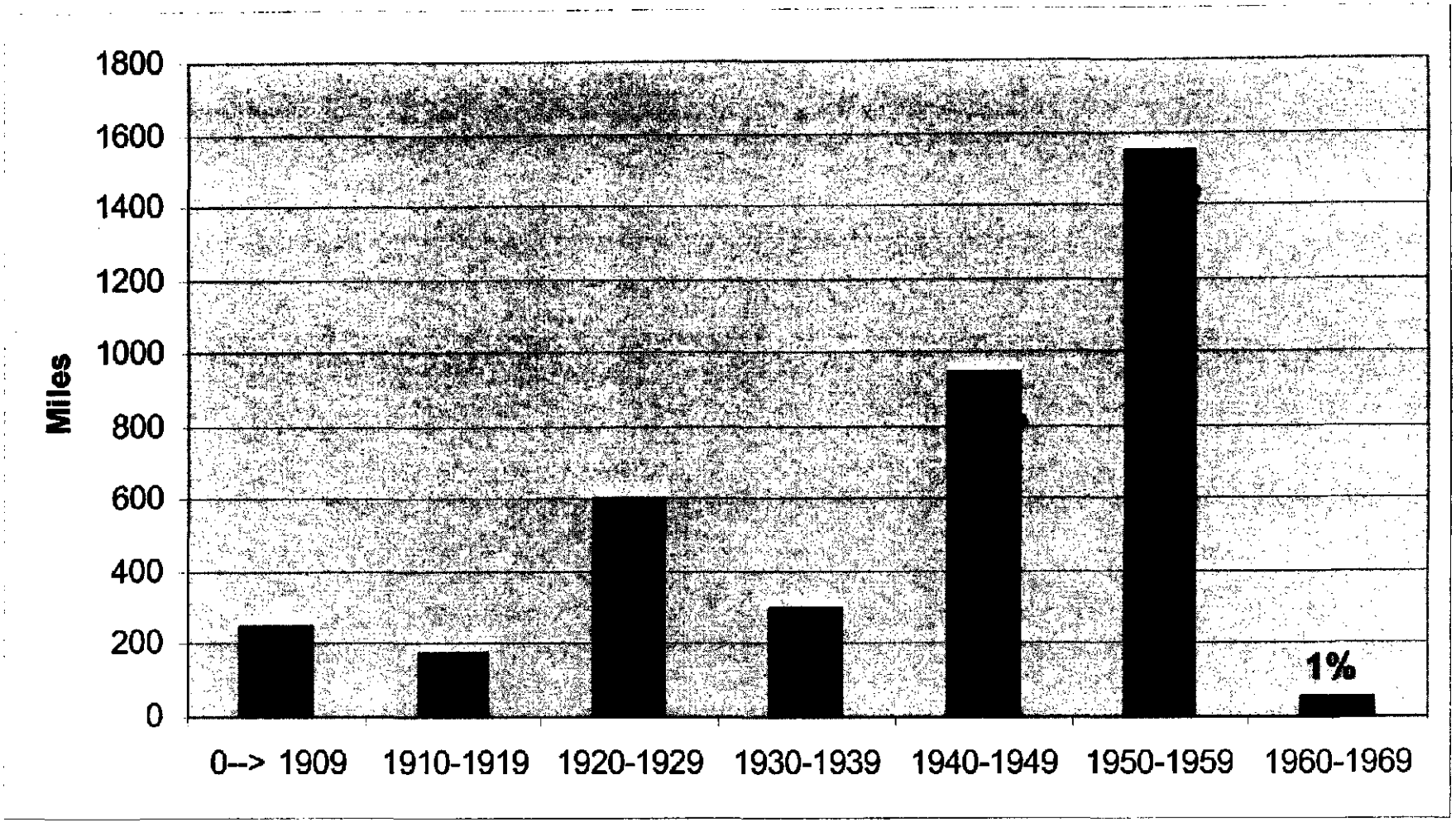
% of Target Pipe vs Total Pipe by Shop



Target Pipe: Bare Steel, Cast & Wrought Iron
Total Pipe: All DEO Pipe in System

Dominion

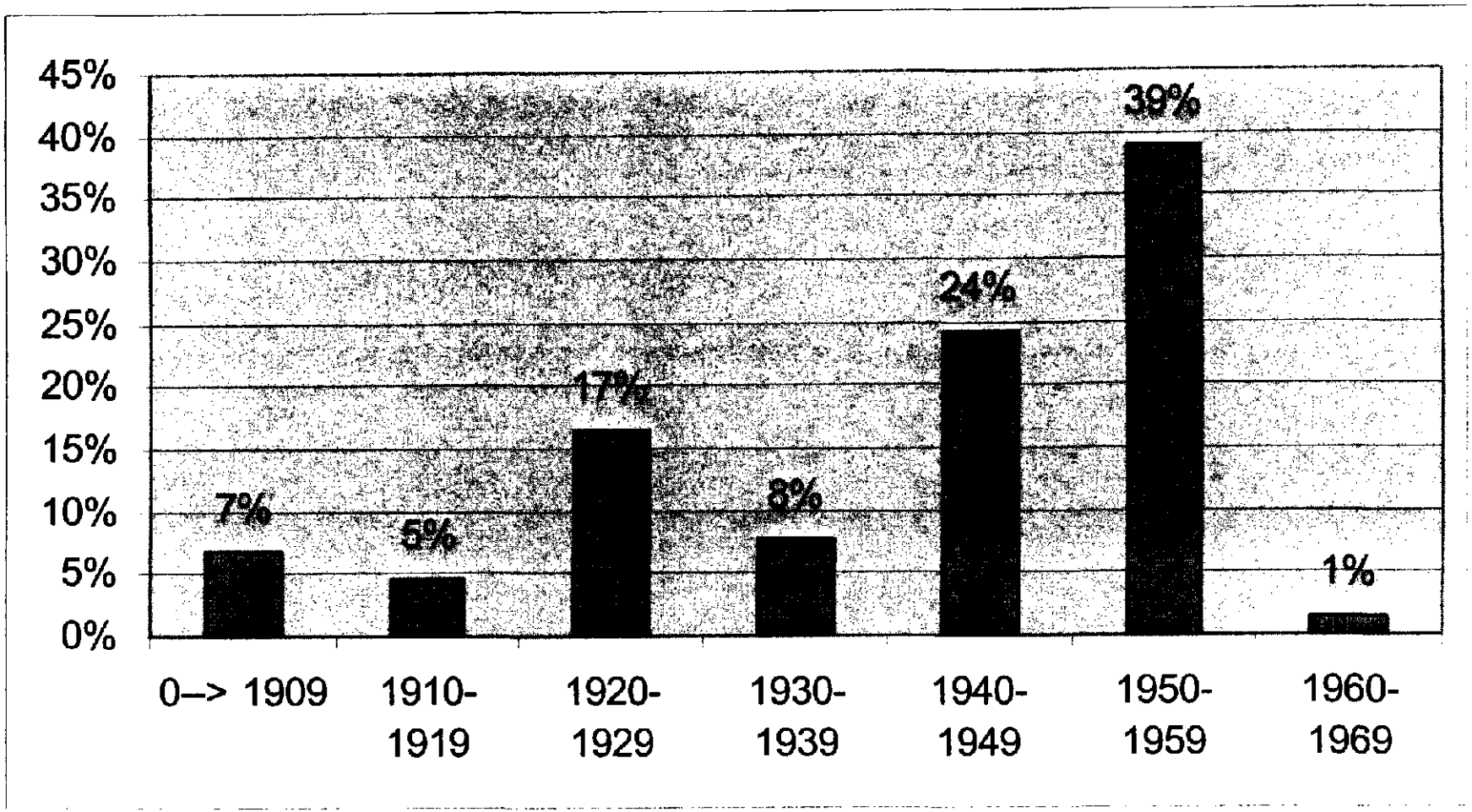
Miles and % of Target Pipe by Decade of Installation



Target Pipe: Bare Steel, Cast & Wrought Iron

Dominion

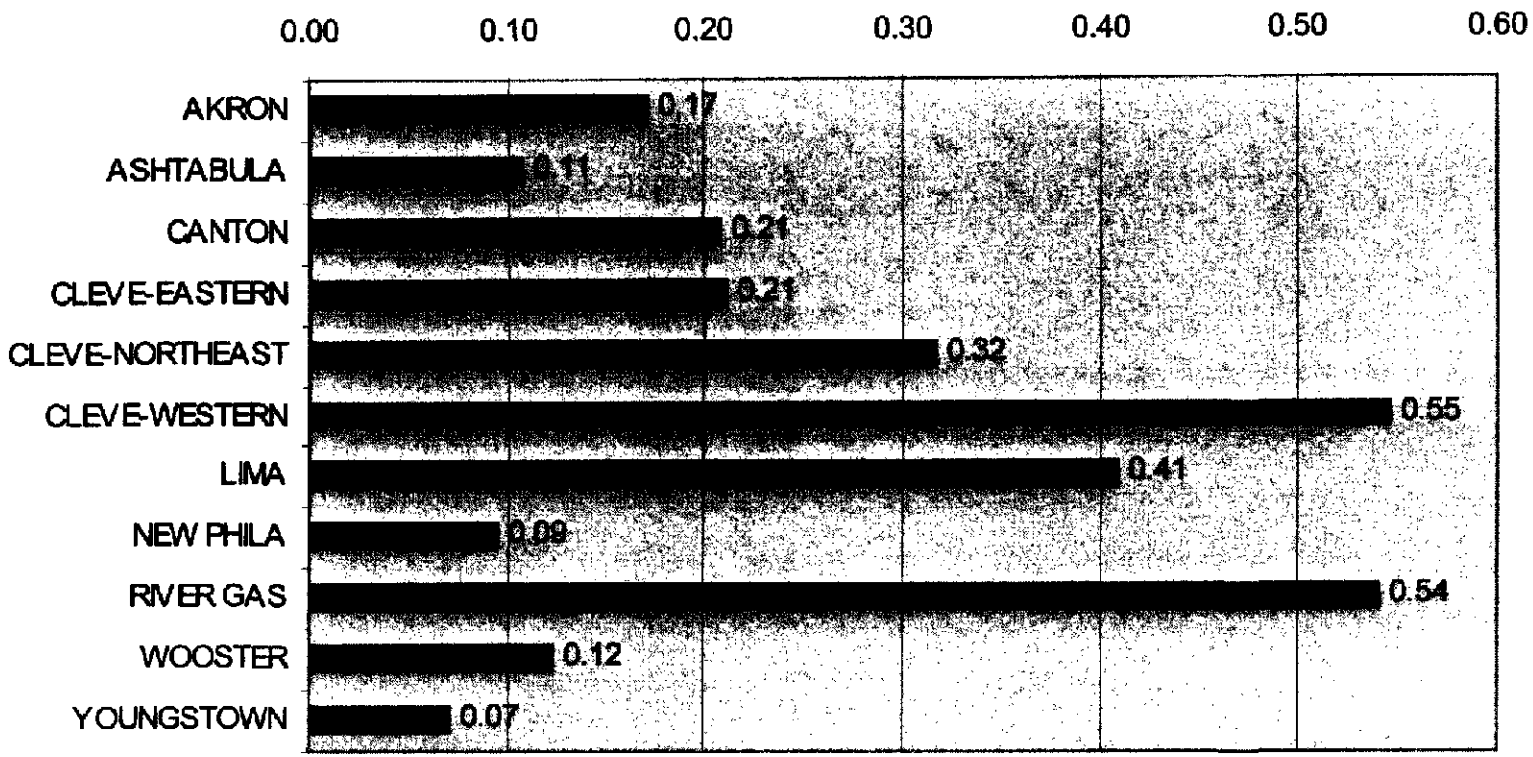
% of Target Pipe by Decade of Installation



Target Pipe: Bare Steel, Cast & Wrought Iron

Dominion

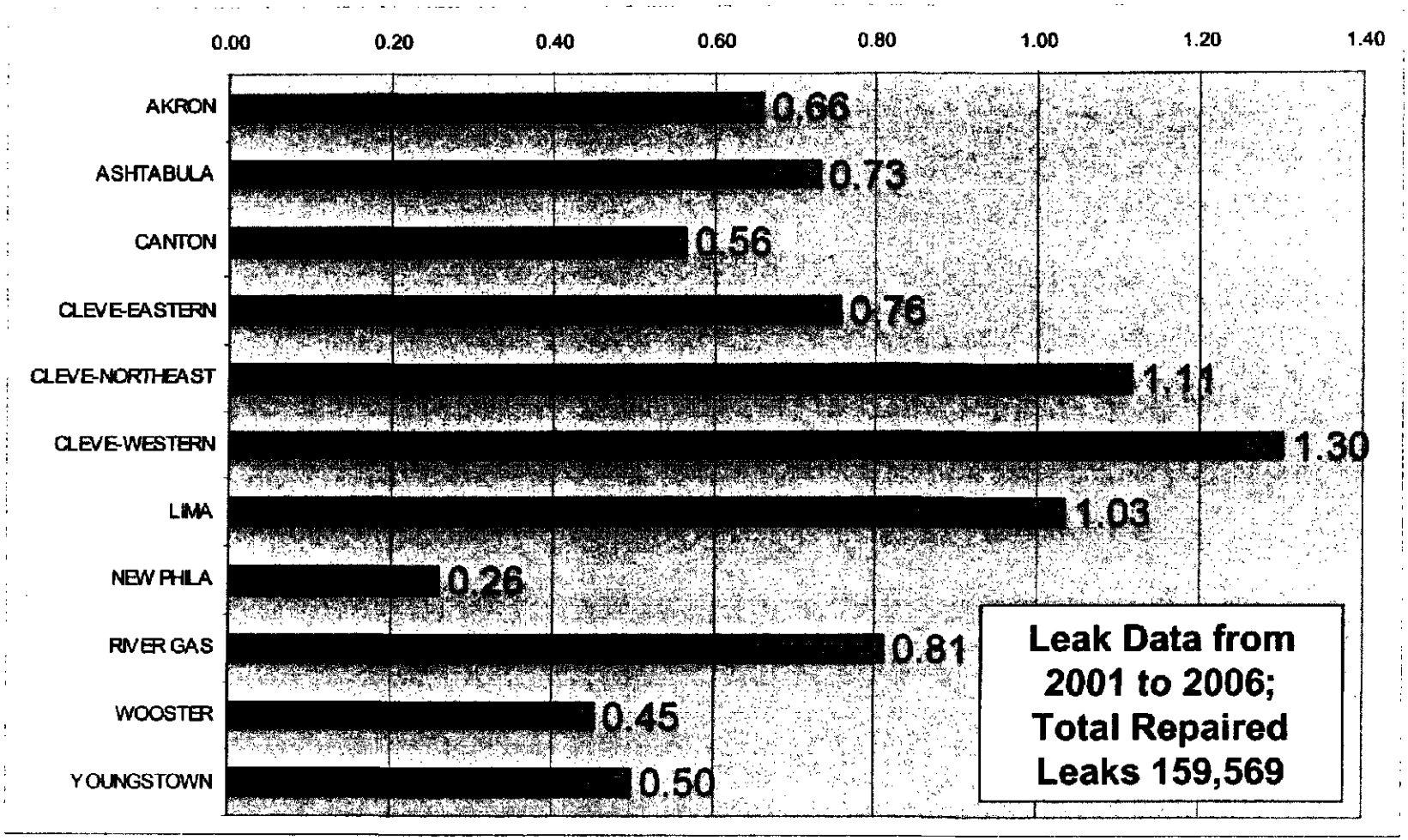
Mainline Leaks Per Mile



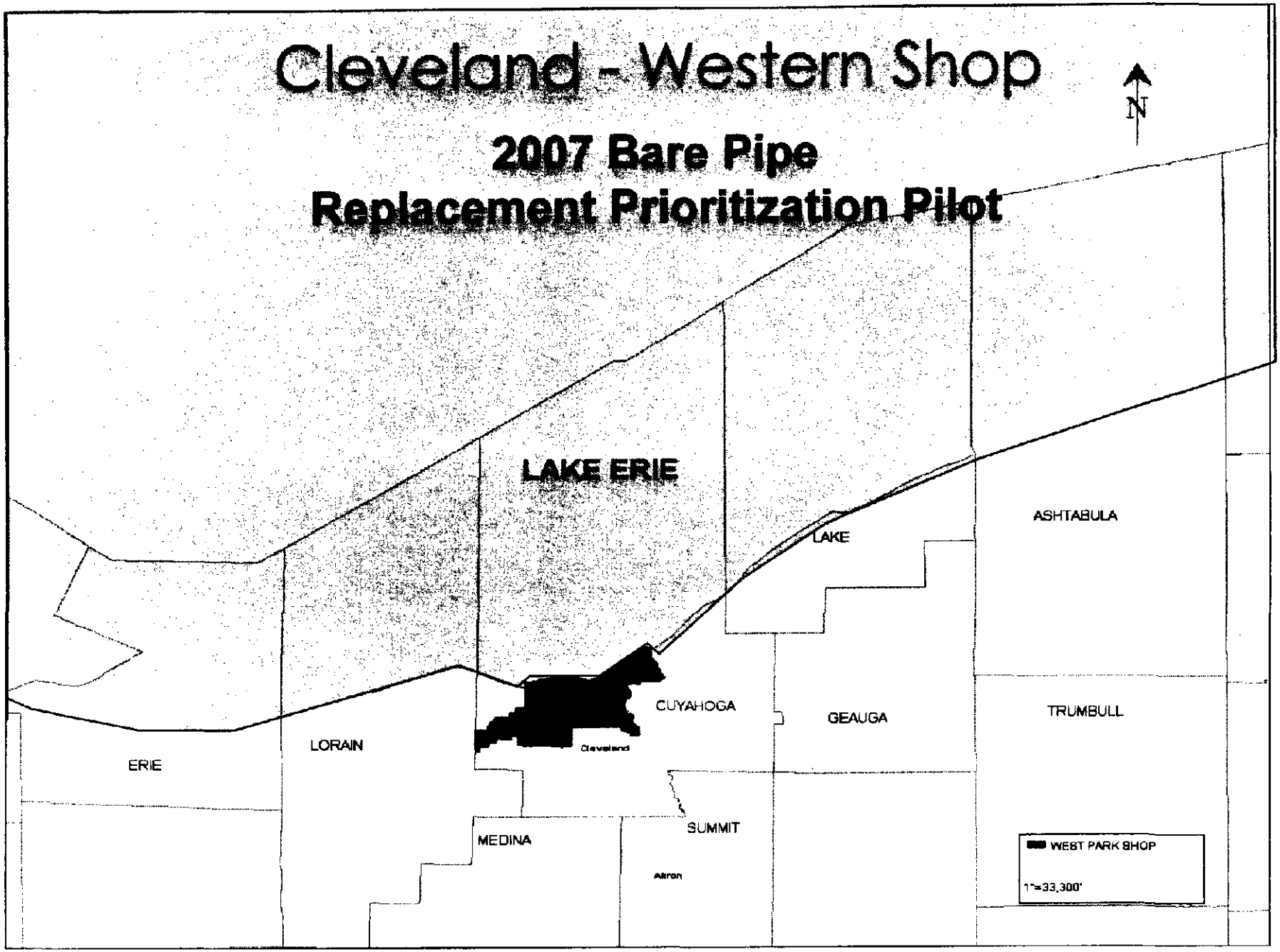
Leak Data from 2001 to 2006
Total Mainline Repaired Leaks 30,726

Dominion

Total Leaks Per Mile

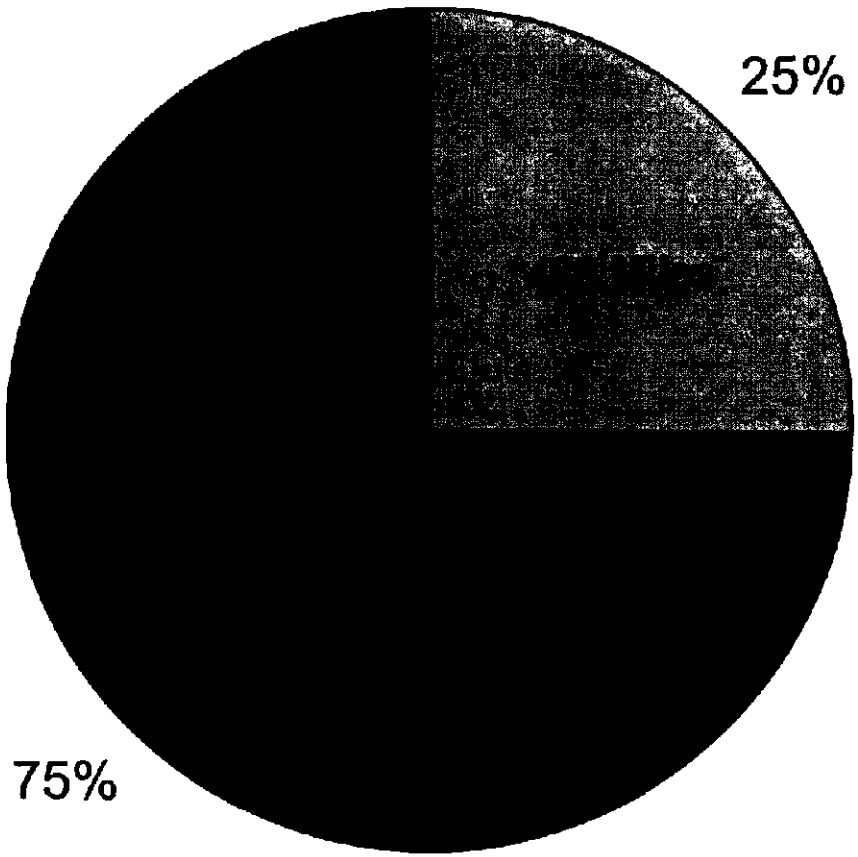


Total Leaks: Mainline, At Meter, Houseline, Curb to Meter, Curb Valve, Gate Box, Valve, Main to Curb and Other


Cleveland - Western Shop
2007 Bare Pipe
Replacement Prioritization Pilot
N
LAKE ERIE
ASHTABULA
LAKE
CUYAHOGA
GEAUGA
TRUMBULL
LORAIN
ERIE
Cleveland
SUMMIT
MEDINA
Akron
WEST PARK SHOP
1"=33,300'

Dominion

Cleveland - Western Shop Analysis: Low Pressure Bare Steel Pipe vs Total Pipe



- LP Bare Stl P/L
- All Other Pipe Types

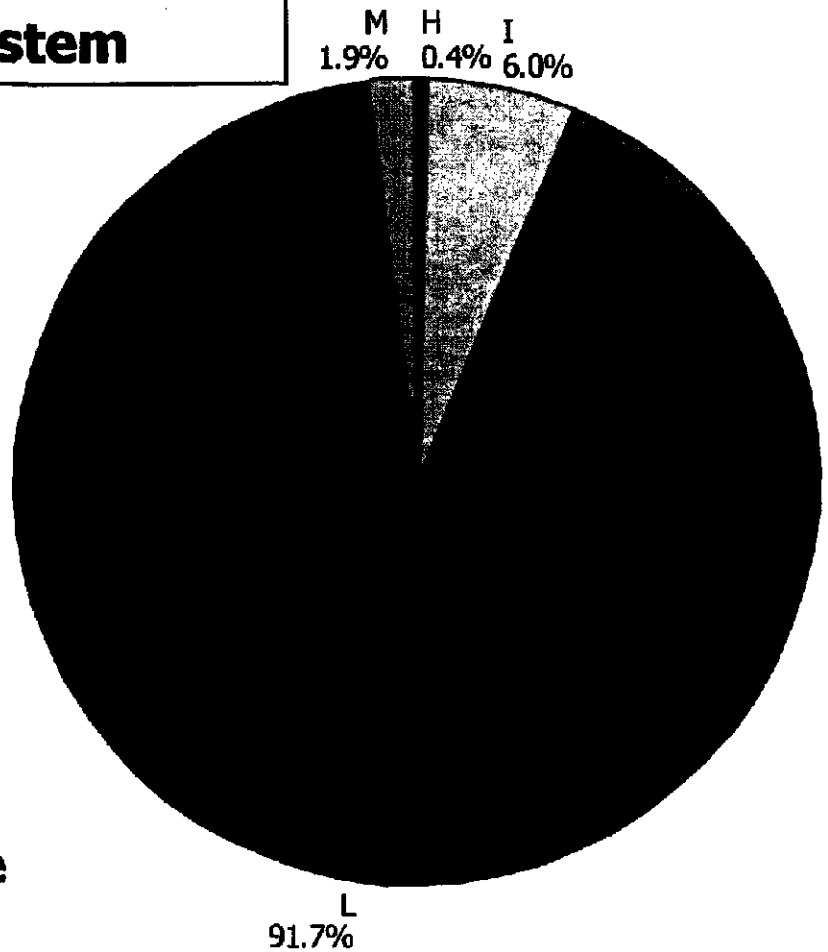
Total Pipe = 1,918 Miles

25% of Our Pipeline is Responsible for 91% of the Mainline Leaks

Dominion

Cleveland - Western Shop Analysis: Pressure & Repaired Leaks

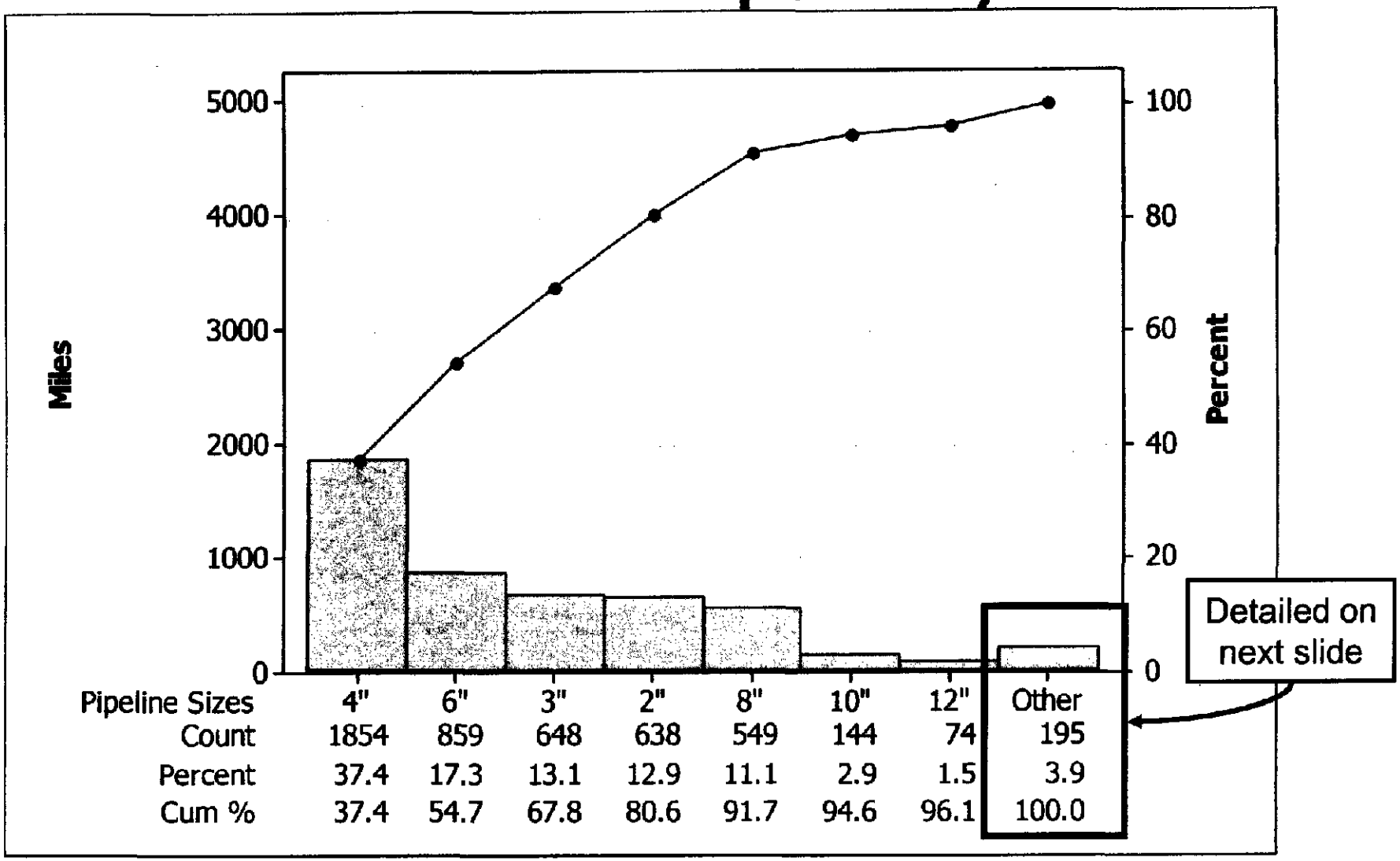
91% of the Mainline Leaks Are on Our Low Pressure System



Total Mainline Leaks 2002 thru 2006 = 5229 Leaks

Dominion

Miles of Target Pipeline by Diameter

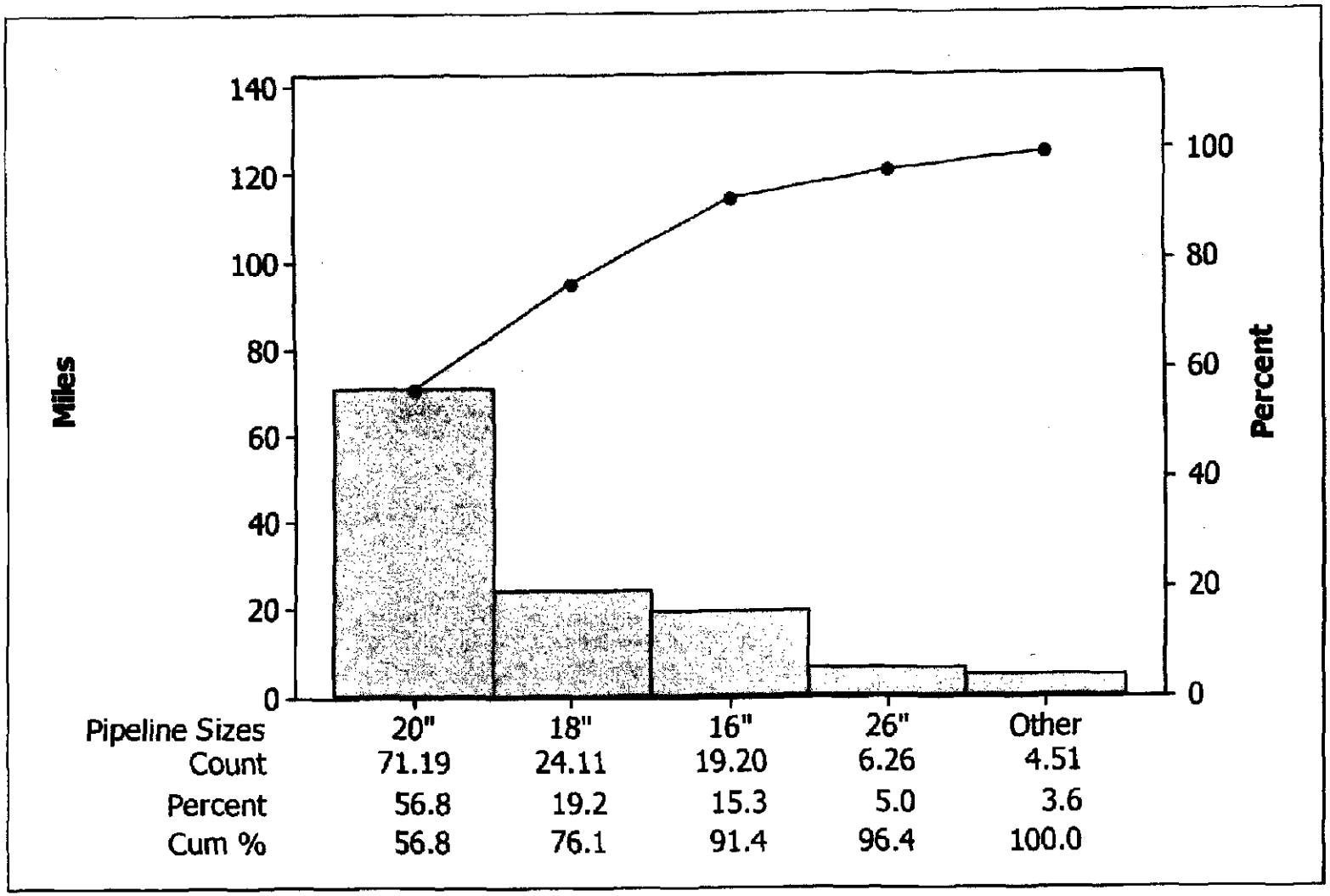


Pipeline Sizes	4"	6"	3"	2"	8"	10"	12"	Other
Count	1854	859	648	638	549	144	74	195
Percent	37.4	17.3	13.1	12.9	11.1	2.9	1.5	3.9
Cum %	37.4	54.7	67.8	80.6	91.7	94.6	96.1	100.0

Target Pipe: Bare Steel, Cast & Wrought Iron

Dominion

Miles of Target Pipe Greater Than 12" Diameter

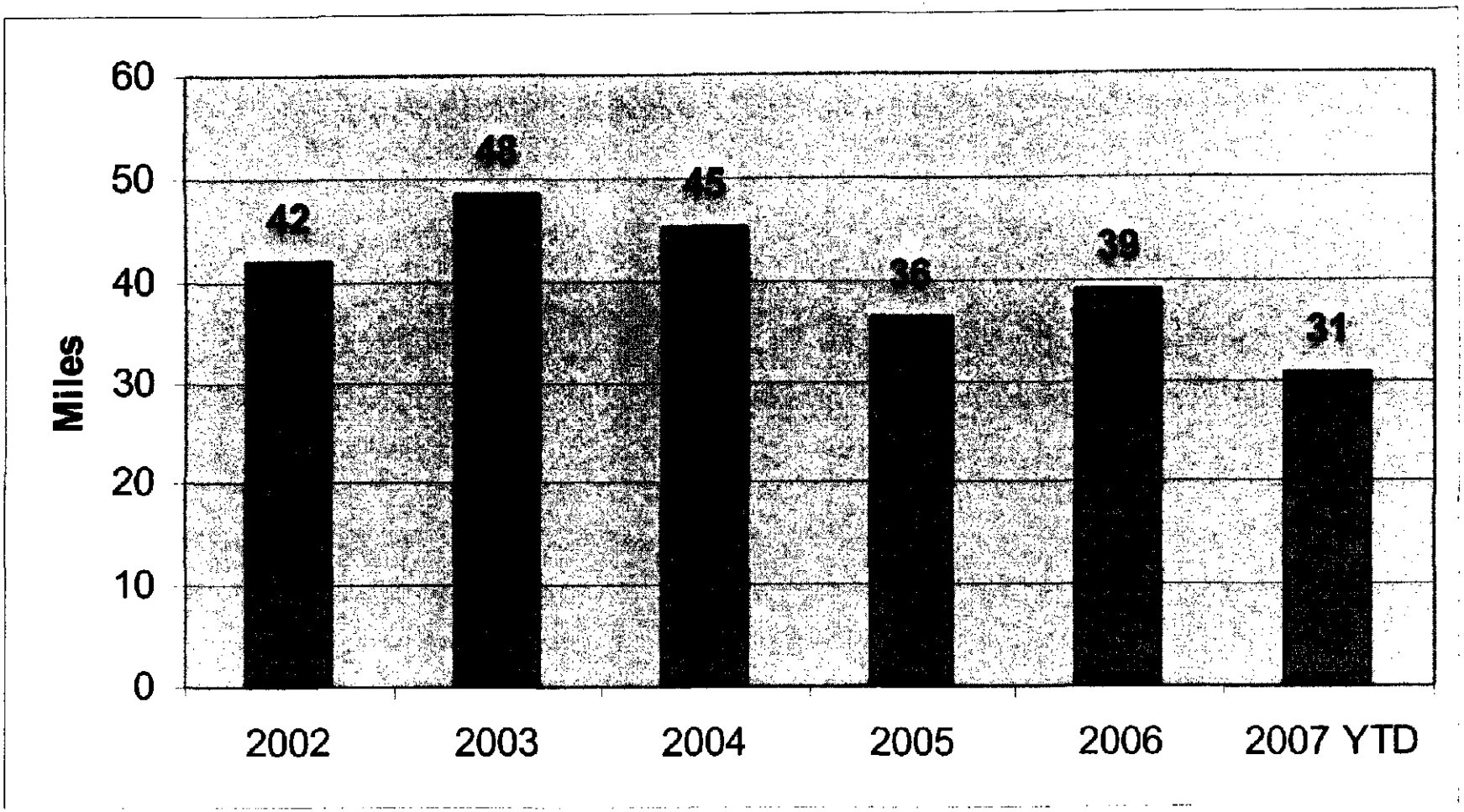


Pipeline Sizes	20"	18"	16"	26"	Other
Count	71.19	24.11	19.20	6.26	4.51
Percent	56.8	19.2	15.3	5.0	3.6
Cum %	56.8	76.1	91.4	96.4	100.0

Target Pipe: Bare Steel, Cast & Wrought Iron

Dominion

Total Distribution Mainline Replacement History



Dominion

Estimated Project Scope

	Estimated Bare Steel Mileage:	4,008	Miles
	Cast Iron Target:	35	Miles
	Wrought Iron Target:	78	Miles
	Copper Target:	1	Miles
	Total Replacement Miles	4,122	Miles
555	Deduction for Double Mains	(555)	Miles
	Target Replacement Program	3,567	Miles
	Number of Main to Curbs	514,527	

Revision 11/15/2007

Dominion

Bare Pipe Replacement Estimate

Size & Pressure Range	Miles Replaced	Replacement Material	Cost / Foot	Cost/Mile	Estimated Replacement Cost
Less than or equal to 6", less than 100 # MAOP	2616	Plastic	$75	$396,000	$1,035,815,616
Less than or equal to 6", greater than or equal to 100 # MAOP	149	Steel	$75	$396,000	$58,944,521
Over 6", less than 100 # MAOP	562	Plastic	$125	$660,000	$371,166,840
Over 6", greater than = 100 # MAOP	240	Steel	$150	$792,000	$189,790,128
Note: All figures are 2007 dollars	**3567**				**$1,655,717,105**
Revision Date: 11/15/07					

Dominion

Main to Curb Replacement Estimate

Size & Pressure Range	Miles	Cost per Main to Curb	# Main to Curbs	Main to Curb Estimate
Less than or equal to 6", less than 100 # MAOP	2616	$950	435,273	$413,509,490
Less than or equal to 6", greater than or equal to 100 # MAOP	149	$1,560	786	$1,226,046
Over 6", less than 100 # MAOP	562	$950	77,203	$73,342,568
Over 6", greater than = 100 # MAOP	240	$1,560	1,265	$1,973,817
Note: All figures are 2007 dollars Revision Date: 11/15/07	**3567**		**514,527**	**$490,051,920**

Dominion

Service Line Replacement Estimate

Size & Pressure Range	Miles	# Main to Curbs	Average Service Line Cost	Service Line Estimate
Less than or equal to 6", less than 100 # MAOP	2616	435,273	$1,000	$435,273,147
Less than or equal to 6", greater than or equal to 100 # MAOP	149	786	$1,500	$1,178,890
Over 6", less than 100 # MAOP	562	77,203	$1,000	$77,202,703
Over 6", greater than = 100 # MAOP	240	1,265	$1,500	$1,897,901
Note: All figures are 2007 dollars Revision Date: 11/15/07	**3567**	**514,527**		**$515,552,641**

Dominion

Summary of Replacement Costs

Size & Pressure Range	Miles	Pipe Replacement Estimate	Main to Curb Estimate	Service Line Estimate	Summary of Cost
Less than or equal to 6", less than 100 # MAOP	2616	$1,035,815,616	$413,509,490	$435,273,147	$1,884,598,252
Less than or equal to 6", greater than or equal to 100 # MAOP	149	$58,944,521	$1,226,046	$1,178,890	$61,349,457
Over 6", less than 100 # MAOP	562	$371,166,840	$73,342,568	$77,202,703	$521,712,110
Over 6", greater than = 100 # MAOP	240	$189,790,128	$1,973,817	$1,897,901	$193,661,847
Note: All figures are 2007 dollars Revision Date: 11/15/07	3567	$1,655,717,105	$490,051,920	$515,552,641	$2,661,321,667

Dominion

Replacement Timeline

Timeline Scenario #1: Entire Program (Pipe, M to Cs, Services) - 100%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	36	24	18	14	12	10
Cost Per Year*	$74,613,706	$111,920,559	$149,227,412	$186,534,265	$223,841,118	$261,147,971

Timeline Scenario # 2: Pipeline and Main to Curbs - 100%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	36	24	18	14	12	10
Cost Per Year*	$60,159,499	$90,239,249	$120,318,999	$150,398,749	$180,478,498	$210,558,248

* Note: All figures are 2007 dollars

Dominion

Replacement Timeline

Timeline Scenario #3: Entire Program (Pipe, M to Cs, Services) - 75%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	27	18	13	11	9	8
Cost Per Year*	$74,613,706	$111,920,559	$149,227,412	$186,534,265	$223,841,118	$261,147,971

Timeline Scenario #4: Pipeline and Main to Curbs - 75%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	27	18	13	11	9	8
Cost Per Year*	$60,159,499	$90,239,249	$120,318,999	$150,398,749	$180,478,498	$210,558,248

* Note: All figures are 2007 dollars

Dominion

Replacement Timeline

Timeline Scenario # 5: Entire Program (Pipe, M to Cs, Services) - 50%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	18	12	9	7	6	5
Cost Per Year*	$74,613,706	$111,920,559	$149,227,412	$186,534,265	$223,841,118	$261,147,971

Timeline Scenario #6: Pipeline and Main to Curbs - 50%						
Miles Per Year	100	150	200	250	300	350
Years to complete Program	18	12	9	7	6	5
Cost Per Year*	$60,159,499	$90,239,249	$120,318,999	$150,398,749	$180,478,498	$210,558,248

* Note: All figures are 2007 dollars

Dominion

Comparison to Other Pipeline Replacement Programs

Company	Cost of Program	Cost / Mile	Total Replacement Miles	Timeline	Number of Customers	Miles of Transmission & Distribution
Duke Energy Ohio & Kentucky (Cinergy)	620 M	442.5 K / Mi	1400	14 1/2	500 K	7228
Columbia Gas of Pa	1.2 Billion	500 K / Mi	2400	20	410 K	7328
Dominion (M/L only)	1.7 Billion	464.2 K /Mi	3567	TBD	1.3 M	21263
Dominion (Total Project: M/L, S/L, M to C)	2.7 Billion	746 K /Mi	3567	TBD	1.3 M	21263

Customer Considerations & Operational Issues

Customer Considerations

- Overall Traffic Pattern Disruptions
- Communication with Affected Customers
- Noise
- Parking Restrictions
- Inconvenience
- Temporary Loss of Gas Service
- Restoration
- Treatment of Inside Customer Meters

DEO Operational Issues

- Time to Ramp-up Replacement Program
- Work Force Levels
- Contractor Availability
- Material Availability

EXHIBIT

Dominion Infrastructure Replacement Team Report Out for PUCO

January 23, 2008

Dominion

OCC Ex. 1315

Scope

- Develop 2008 work plan for initial replacement projects
- Identify 2009 scope and preliminary schedule
- Establish approach to developing post-2009 plans
- Initially focused on steel replacements (TPL's, OOS, HP)
- Focused on creating schedule, project list and initial resource requirements

Dominion

Assumptions

- No changes to basic design/construction process
- No new IT tools in 2008
- Same size, ditch, location for 2008 projects
- Focus on high pressure steel pipe in DEO r/w's (no services)
- Assume service line strategy is in place for 2009 projects
- Resources are 100% incremental
- OPSB permits not required

Dominion

Assumptions Cont.

- **Design and construction contractors are available (concern about welder availability)**
- **Bare pipe work will not affect contractors doing routine work (welder exception)**
- **High degree of oversight and involvement from PUCO and public**
- **Initially use existing design resources to begin preparing packets and later utilize external design resources in 2008**
- **The Infrastructure replacement team recommends 4-step model**
    - Pre-design
    - Design
    - Construction
    - Close-out

Dominion

Findings

- 2008 projects are behind other company's work (Duke, Columbia, Equitable)
- OPSB permit not required for replacements
- Rolling schedule for 2008 and 2009 work is necessary
- Steel pipe is available (May at earliest)
- Lessons learned from Duke – separate work into waves, spread across communities
- No excess capacity in existing DEO departments
- DEO will incur incremental O&M expense and impact should be considered

Dominion

Recommendations

•Create two separate new initiatives

- Implementation Team-Short term issues:
  - Accelerated strategy
  - Welder strategy
  - Contract with design consultant
  - Address core work issues: coordination, impact analysis
  - Refine project list into modules, waves
  - Continue to refine 2009 projects, resources, etc.
  - Communication
  - Engage partners (Dominion Service Company)

- Long Term Strategy Team
  - New IT tools (Risk tool, service line records, WMIS enhancements)
  - Establish prioritization scheme
  - Establish centralized planning
  - Process optimization
  - Labor strategy
  - Performance metrics
  - Records

Dominion

Recommendations Cont.

- **Implementation Leadership Team**
  - Initiative Lead
  - Design Lead
  - Construction Lead
  - Logistics Lead
  - Services Lead
  - Planning lead
- **Long Term Strategy Team**
  - IT/Technology
  - Process optimization, labor strategy
  - Planning
  - Performance metrics, auditing, budget management

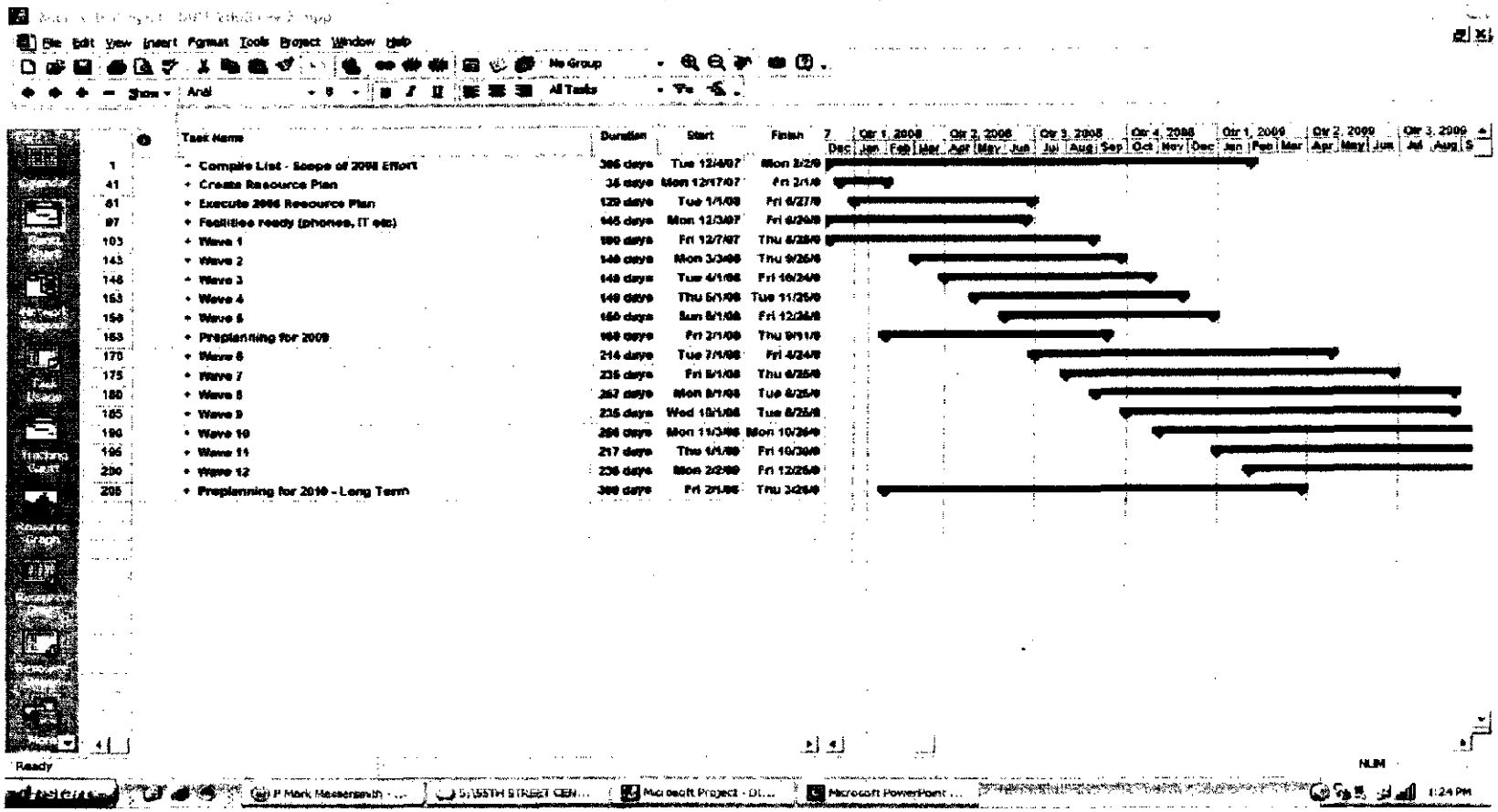
Dominion

Recommendations Cont.

- Separate work from existing work resource and departments initially
- Incorporate Six Sigma Black Belts in initiatives
- Centralized Planning to support this effort
- Align goals and educate Partners (internal and external) regarding Infrastructure Replacement
- Merge 2008 and 2009 work together in a rolling schedule
- Effective communication within DEO and with PUCO, local communities and other external stakeholders is crucial

Dominion

Schedule



*See Handout

Dominion

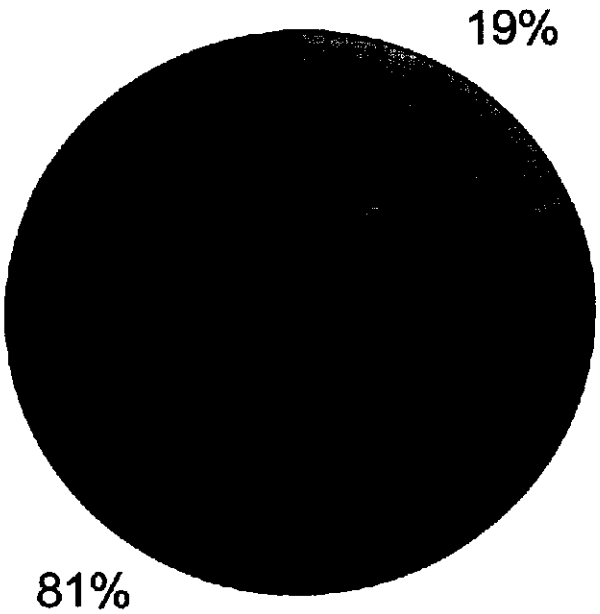
Initial Resource Requirements for '08

- **DEO Staffing: 70**
  - Design 13
  - Supervision/Mgmt 22
  - Planning 6
  - Support 19
  - Construction Support 10
- **Contractors: 33**
  - Excludes construction contractors

*See Handout

Dominion

Bare Pipe vs. Total Pipe

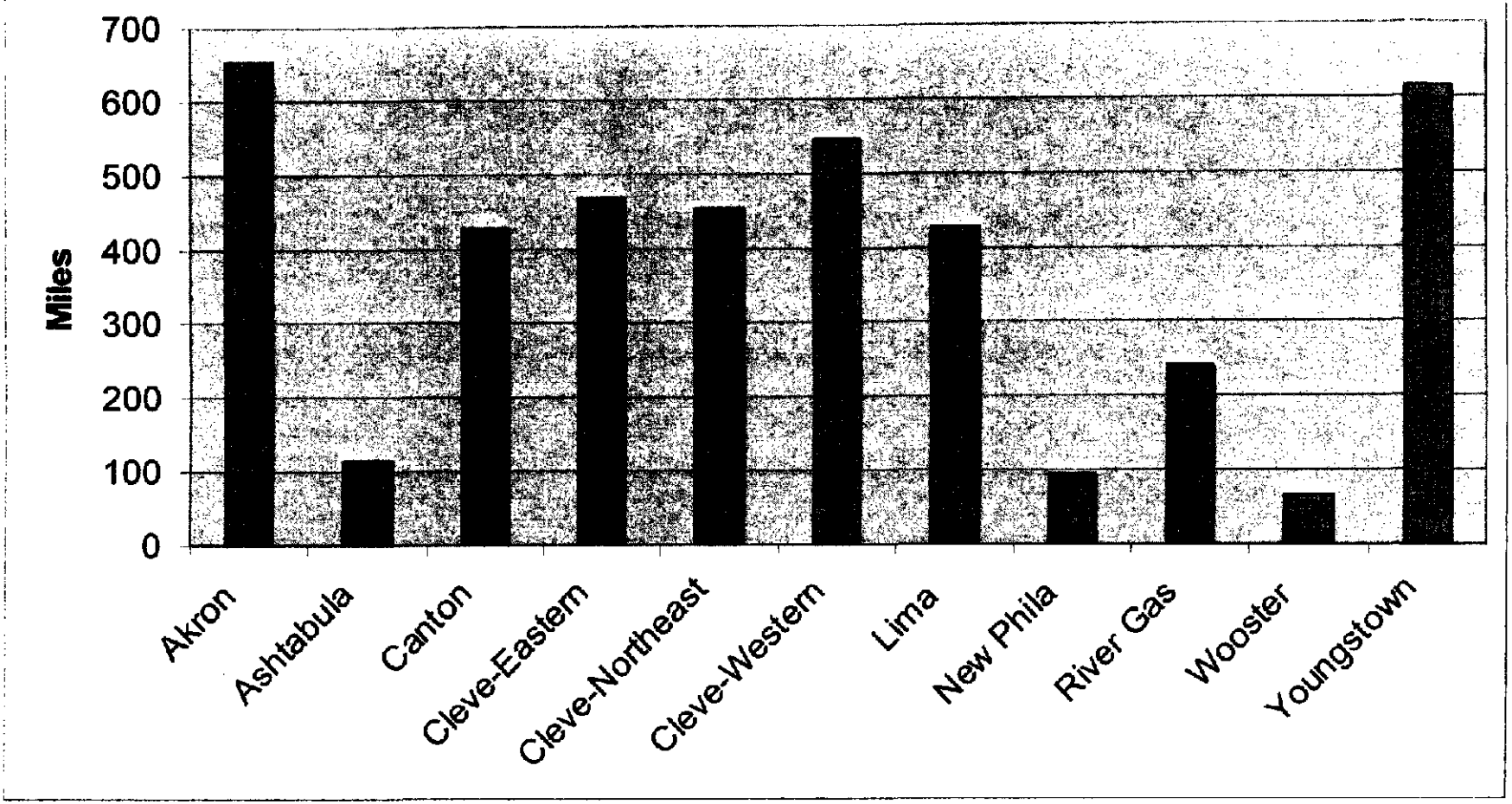


- Target Pipe: Bare Steel, Cast & Wrought Iron
- Total Pipe: All DEO Pipe in System (Plastic, Coated Stl, etc)

Total Pipe in DEO System: 21,263 Miles

Dominion

Target Pipe by Shop



Target Pipe: Bare Steel, Cast & Wrought Iron

Dominion

2008-2009 Projects

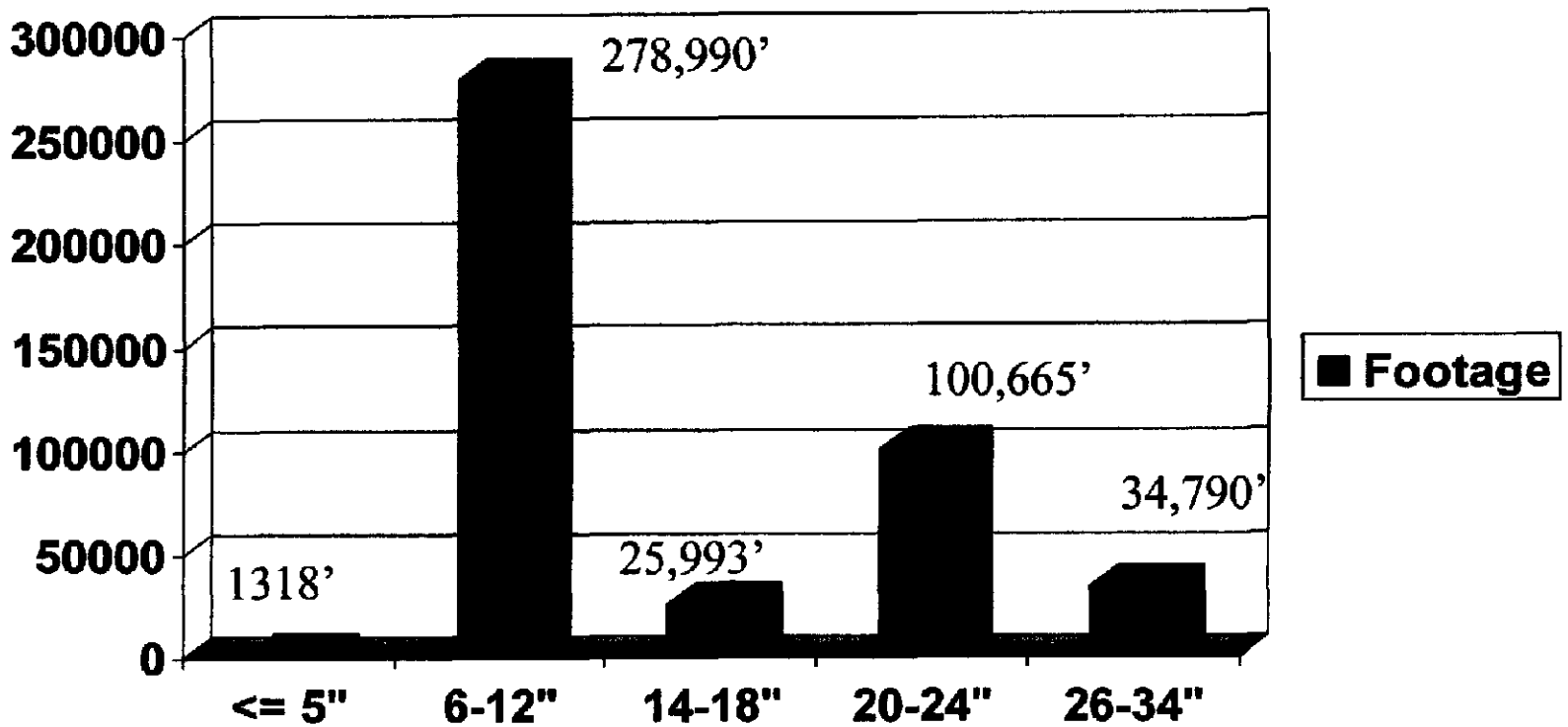
- **84 miles identified**
  - **32 Transmission**
  - **52 OOS**

***See Handout**

Dominion

Pipe Size Breakdown

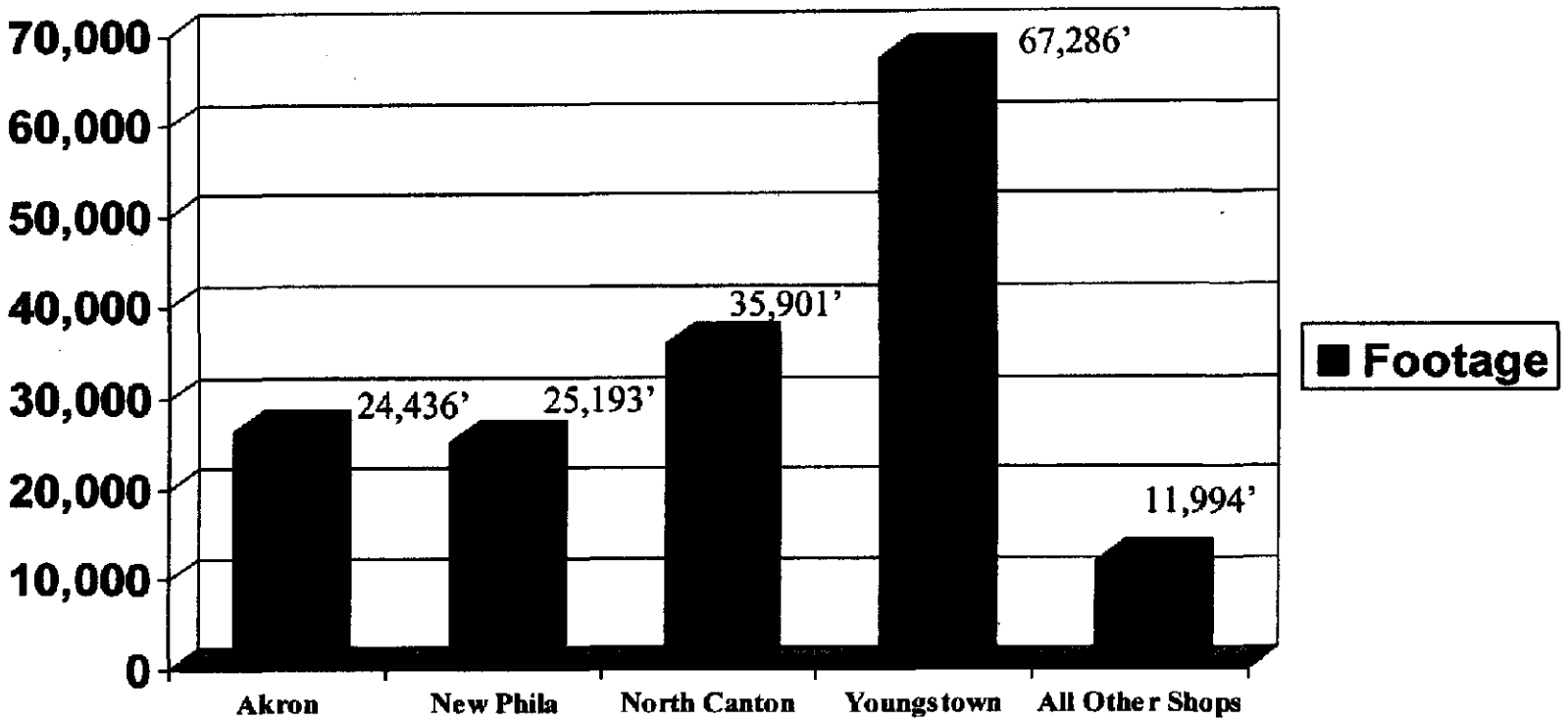
Transmission/ OOS (84 miles)



Dominion

Pipe Footage by Shop

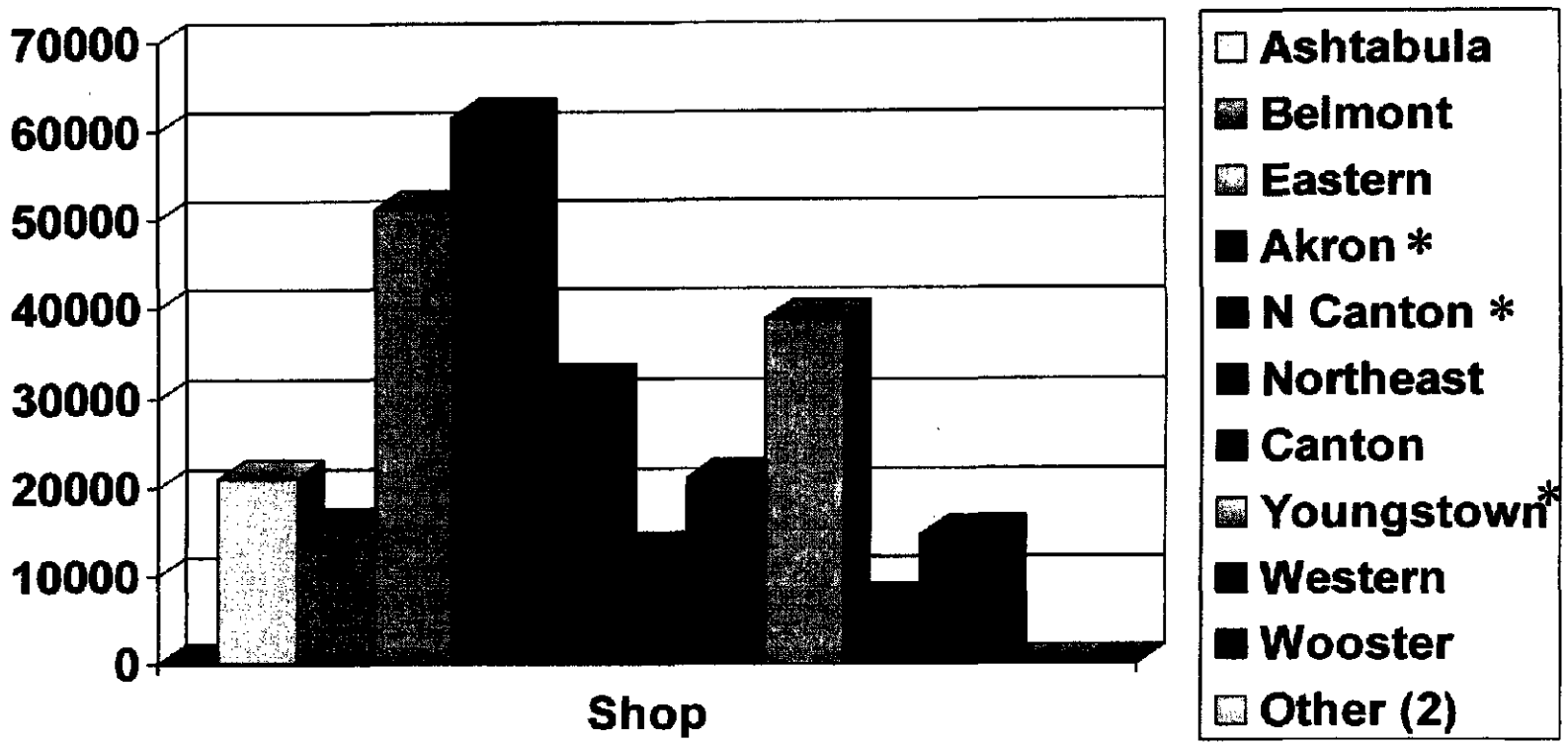
Transmission only (32 miles)



Dominion

Pipe Footage by Shop

OOS only (52 miles)



* Areas of high Transmission Work also

Dominion

Risks

- Tight schedule
- Material, welder and contractor availability
- Performance of design contractors
- Resources in place per the plan
- Competition from other gas utilities for resources and materials
- Prompt decision making

Dominion

Summary

- Created a plan to begin replacements in 2008 and continue in 2009
- Focused on steel replacements (TPL's, OOS, HP) initially with plan to gradually move into plastic work
- Focused on creating schedule, project list and initial resource requirements
- Assumed no changes to basic design/construction process (supplement current resources with staffing additions and contractors)
- Included creation of Implementation and Strategy Teams
- Assumed an early program start in order to complete significant 2008 work

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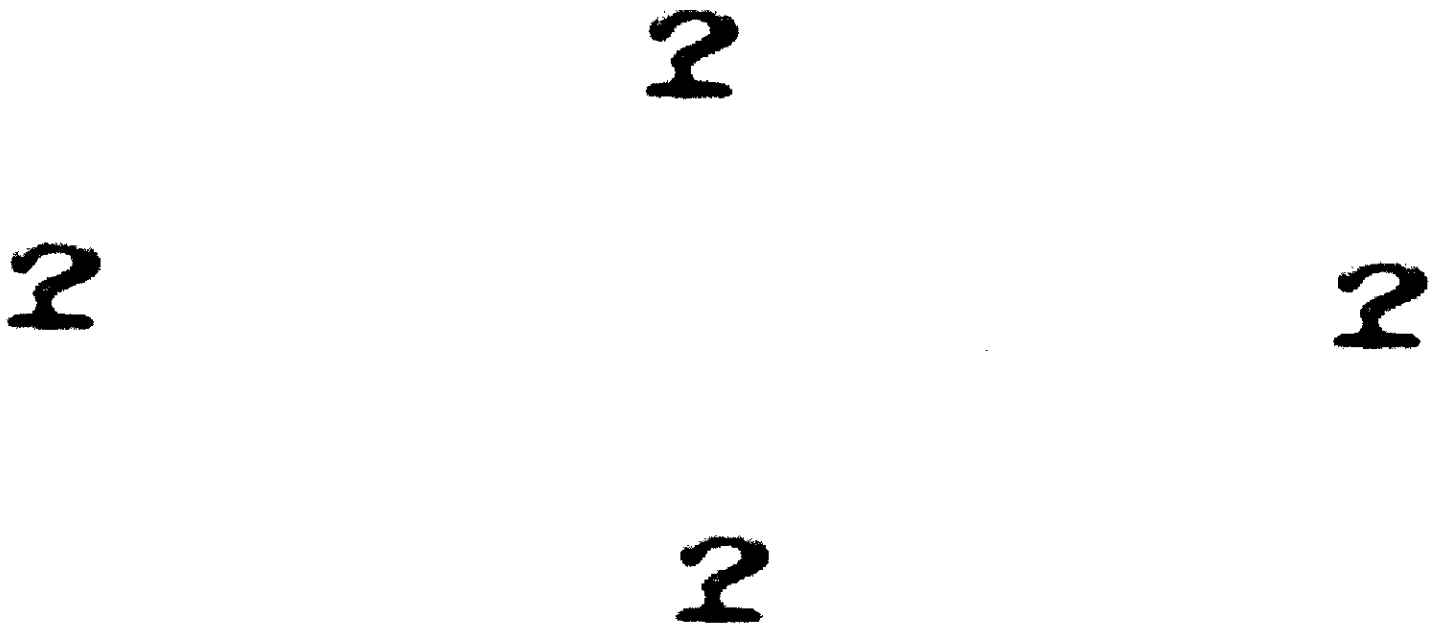
Questions



Dominion

EXHIBIT

OCC Ex. 14

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - RFP Set 2 08-169-GA-ALT

Question Number: 41
Subpart:

Request Date: 06/17/2008
Due Date: 07/08/2008

Topic:
Distribution Infrastructure

Question:
Referring to OCC Interrogatory No. 70 and the Pipeline Replacement Program testimony of Mr. McNutt, pgs. 9-10. Please provide any documentation to support the testimony of Mr. McNutt where he concludes that DEO's current main replacement program to replace its existing bare steel, cast iron, wrought iron, and copper mains cannot be completed until 2097.

Answer:
Please see the attached.

Preparer Of Response:
Tim McNutt

Date Prepared:
06/19/2008 09:10:48 AM EDT

Attachments:
Yes
Attachment Names:
RFP #41.pdf

DEO SUMMARY OF PIPE REPLACED WITH PLASTIC OR COATED STEEL PIPELINE.

Miles replaced	2002	2003	2004	2005	2006	2007	Grand Total
Distribution:	33.0	41.9	41.7	35.0	33.9	31.6	217.2
Transmission	7.1	0.9	1.6	0.3	0.7	0.7	11.2
Storage	0.0	0.0	0.1	0.1	0.1	0.1	0.4
Transmission Integrity	0.0	3.4	5.1	0.7	1.1	0.3	10.5
TOTAL	40.1	46.2	50.7	37.3	35.8	32.6	242.7

Source: Distribution data, WMIS.

Transmission, Storage and Gathering- WMIS, SAP.

EXHIBIT

OCC Ex. 15

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
Interrogatories - 4th Set

Question Number: 185

Subpart:

Request Date: 01/18/2008

Due Date: 01/24/2008

Topic:
Section C - Operating Income

Question:
Referring to the Annual Incentive Plan that was provided in the supplemental information to the Application, volume 3, page MPPO 000000048 that "earnings funding requirements will be adjusted after any E&P sale." According to the Company's response to OCC Interrogatory No. 68(d), the last E&P sale was closed in August 2007.

a. Has the earnings funding requirements been adjusted for the test year;

b. If the response to OCC Interrogatory No. 185(a) is affirmative, what are the funding requirements for both salaried and for hourly personnel for the test year; and

c. If the response to OCC Interrogatory No. 185(a) is affirmative, have the funding requirements been announced to employees?

Answer:
a. Yes. A decision was made that Dominion senior executive leadership and the Board of Directors would determine Dominion's 2007 financial performance and the associated funding level after the year was completed.

b. Please see the discussion of the 2007 AIP funding on pages 17-18 of Dominion's 2008 proxy statement, which is available at the following link: http://www.dom.com/investors/pdf/proxy2008.pdf

c. Yes.

Preparer Of Response: Vicki Friscic

Date Prepared: 01/18/2008 01:34:46 PM EST

Attachments:
No

Dominion®

2008 PROXY STATEMENT

our financial performance against our peer companies as part of our annual compensation setting process, as described above under *Our Process* and below under *The Peer Group and Peer Group Comparisons.*

The Peer Group and Peer Group Comparisons

Dominion uses peer company data to: (i) compare Dominion's stock and financial performance against its peers using a number of different metrics and time periods; (ii) analyze compensation practices within our industry; (iii) benchmark base pay, annual incentive pay, long-term pay and total direct compensation; and (iv) benchmark other benefits such as our Employment Continuity Agreements and the use of long-term equity incentives.

Dominion's peer group is generally consistent from year to year, with merger and acquisition activity being the primary reason for any changes. The 2007 peer group consisted of a diversified group of 13 energy companies and is the same peer group used for compensation setting purposes in 2006 with the addition of Constellation Energy Group, Inc. and Public Service Enterprise Group:

American Electric Power Company, Inc.	Nisource, Inc.
Constellation Energy Group, Inc.	PPL Corporation
Duke Energy Corporation	Progress Energy, Inc.
Entergy Corporation	Public Service Enterprise Group
Exelon Corporation	Southern Company
FirstEnergy Corporation	TXU Corp.
FPL Group, Inc.	

For Mr. Radtke, former CEO of our Exploration & Production (E&P) business unit, we used a separate group of peer companies for 2007:

Anadarko Petroleum Corporation	EOG Resources Inc.
Apache Corporation	Pioneer Natural Resources Company
Chesapeake Energy Corporation	XTO Energy Inc.
Devon Energy Corporation	

Because of unusually high compensation practices, the E&P peer group company XTO Energy, Inc. was not used for compensation setting purposes. Due to the divestiture of a substantial portion of our E&P assets in 2007, Dominion will no longer reference a separate E&P peer group.

Elements of Dominion's Compensation Program

Our executive compensation program consists of three basic components:

- Base Salary
- Annual Incentives
- Long-Term Incentives

Base salary compensates our officers, along with the rest of our workforce, for committing significant time to working on Dominion's behalf. Annual salary increase reviews achieve two primary purposes: (i) an annual adjustment to keep salaries in line and competitive with the market and to reflect changes in responsibility, including promotions; and (ii) a motivational tool to acknowledge and reward excellent individual performance, special skills, experience and other relevant considerations.

While the base salary component of our program generally is targeted at or slightly above market median, our primary goal is to compensate our executives at a level that best achieves our compensation philosophy, whether or not this results in actual pay for some positions that may be higher or lower than our stated target. We find that proxy and survey results for particular positions can vary greatly from year to year, so we consider market trends for certain positions over a period of years rather than a one-year period in setting compensation for such positions.

Our incentive programs are designed to compensate our officers for the achievement of pre-set performance criteria and align their interests with those of our shareholders through equity grants. The incentive-based components of our executive compensation program include an annual incentive program and a long-term incentive program made up of performance-based cash or stock grants tied to the achievement of specific performance criteria. For our CEO, just over 50% of his 2007 targeted compensation (annual and long-term) is at risk and is dependent on the achievement of performance goals. For the other named executive officers, 2007 targeted compensation at risk ranges from 48% to 54%, and for a typical vice president, the percentage of targeted compensation at risk for 2007 is approximately 37%. This compares to an average of approximately 13% of total pay at risk for non-officer employees. This structure ensures that officers will have compensation that could be significantly lower than market median if performance goals are not achieved, depending on the extent that goals are missed. If performance goals are exceeded, officers will receive compensation that is closer to or even exceeding the market 75th percentile, depending on the extent that goals are exceeded and each particular officer's compensation position relative to the market.

Additionally, a substantial portion of each officer's total direct compensation is tied to the performance of Dominion's stock through long-term restricted stock grants, ranging from 17% of targeted total compensation for a typical vice president up to 36% for Mr. Farrell. For Mr. Farrell, this means that almost 90% of his total direct compensation is stock-based or has a performance component.

Generally, the 2007 annual incentive program and long-term performance-based awards were designed to allow the CGN Committee to use negative discretion for senior executive officers for certain goals, as identified in each program's description. The Committee does not expect to provide for such negative discretion for the 2008 programs, as all participants will have the same goals. While our programs are not otherwise designed to provide for the use of discretion with respect to payouts to senior executive officers, the CGN Committee always has the ultimate authority to apply discretion for any of the company's performance grants if it deems the use of such discretion appropriate under the

circumstances of such program, and taking into account any tax or accounting implications of the application of such discretion. Unanticipated events such as significant regulatory changes, acts of nature, mergers, acquisitions or divestitures and other significant, unanticipated events are typically the type of circumstances that may warrant such discretion. Also, business unit goals may be adjusted to reflect intra-company adjustments that do not ultimately have an impact on company earnings or performance overall.

The Board may seek to recover performance-based compensation paid to officers who are found to be personally responsible for fraud, negligence or intentional misconduct that causes a restatement of financial results filed with the SEC.

Base Salary

For 2007 base compensation, all officers received a base salary adjustment of at least 4%. Certain officers received salary adjustments in excess of 4% for one of the following reasons: (i) increase or other change in job responsibility; (ii) market-based reasons; or (iii) based on one or more of the factors in setting compensation described above in *Factors in Setting Compensation*.

CEO Base Salary. Mr. Farrell received a 10% increase in base salary in 2007. This increase moved his base salary closer to the median for his peers. When Mr. Farrell was promoted to the position of President and Chief Executive Officer in January 2006, the CGN Committee determined it would raise his base salary to market median over the course of a few years, based on his achievements and performance in office. The CGN Committee also considered Mr. Farrell's performance and the complexity of his job in approving his 2007 increase.

Base Salaries for Other Named Executive Officers. The other named executives' salaries increased in 2007 by the following amounts: Mr. Chewning – 7.0%; Mr. Radtke – 7.0%; Mr. McGettrick – 8.0%; and Mr. Johnson – 7.0%. For these officers, in addition to the market benchmarks for compensation for their positions, individual performance and scope and complexity of their positions relative to other positions at the company were considerations in setting 2007 compensation, including salaries. For Mr. McGettrick, we considered the increasing size, complexity and competitiveness of the business unit for which he is responsible.

The Annual Incentive Program

Overview

Our annual incentive program continues to play a critical role in our compensation practices and our philosophy of aligning the interests of our officers with those of Dominion's shareholders while rewarding performance. Our annual incentive program is a cash-based program focused on short-term goal accomplishments. All non-union employees scheduled to work 1,000 hours or more in a calendar year and union employees covered under collective bargaining agreements that provide for participation in the company's incentive plan are eligible for annual incentive bonus payments.

The annual incentive program is designed to:

- Tie interests of shareholders and employees closely together;
- Focus our workforce on company, operating group, team and/or individual goals that ultimately influence financial results;
- Reward corporate and operating group earnings performance;
- Reward operational, stewardship, and Six Sigma cost savings success;
- Emphasize teamwork by focusing on common goals; and
- Provide a competitive total compensation opportunity.

Target Awards

Target bonus awards are determined as a percentage of an executive's annualized base salary as of December 31 for the plan year (for example, 45% of base salary). The target award is the amount of cash that will be paid if an executive achieves a score of 100% for the goals established at the beginning of the year, and the plan is funded at the threshold funding target set for the year. The target bonus awards under the Annual Incentive Plan established each year are generally designed so that the executive's total cash compensation for the year will be at or slightly above market median if the plan goals are achieved or exceeded. If the goals are not achieved, the executive's total cash compensation may be significantly lower than market median, depending on the extent to which goals are not achieved.

For our 2007 Annual Incentive Plan (the 2007 AIP), Mr. Farrell's annual incentive target was 120% of his base salary, consistent with our intent to have a significant portion of his compensation at risk. His annual incentive plan target was increased from 110% to 120% of his base salary for 2007 in an effort to move his targeted total cash compensation closer to market median. The 2007 AIP targets for the other named executive officers as a percentage of base salary were: Mr. Chewning – 95%; Mr. Radtke – 95%; Mr. McGettrick – 95%; Mr. Johnson – 85%.

Funding of the 2007 AIP

Funding of the 2007 AIP was based solely on consolidated operating earnings for officers. Consolidated operating earnings are our reported earnings determined in accordance with generally accepted accounting principles (GAAP), adjusted for certain items. For non-officers, 25% funding was guaranteed, with 75% of the funding based on consolidated operating earnings. This created the potential for incentive payouts for non-officers even if the company did not reach its consolidated operating earnings threshold so as to reward employees for operational excellence during the year.

The consolidated operating earnings goal is designed to drive employee behavior and performance to achieve management's consolidated operating earnings goals for the company for that fiscal year. The goal is designed to ensure that shareholders are receiving an appropriate return on their investment in Dominion.

At the beginning of 2007, due to the uncertainty of 2007 earnings as a result of the pending E&P divestitures, we set different funding goals for officers potentially subject to the deduction limits imposed by Internal Revenue Code Section 162(m) than the goals set for other officers and employees. For the named executive officers, 2007 consolidated operating earnings of $1,198 million would achieve full funding of the 2007 AIP, with funding increased by three percent for every $4.4 million in consolidated operating earnings achieved above the full funding target, up to a maximum funding level of 200%.

For other officers and employees, the 2007 AIP had a full funding target of $1,626 million in consolidated operating earnings, with a maximum of 200% funding based on a formula that provides equal sharing of consolidated operating earnings between plan participants and shareholders up to the maximum plan funding. Full funding means that the plan is 100% funded, and participants can receive their full targeted AIP payout if they achieve 100% score for their particular goal package, as described below under *How We Determine AIP Payout Scores*. At the maximum plan funding level of 200%, participants can earn up to two times their targeted AIP payout.

Dominion reported consolidated operating earnings of $1,678 million for 2007 as compared to reported earnings in accordance with GAAP of $2,539 million. This level of earnings resulted in each of the named executive officers earning 200% funding and other officers and employees earning 182% funding. However, the CGN Committee exercised negative discretion and approved 182% funding for the named executive officers, consistent with the funding level approved for all other plan participants.

How We Determine AIP Payout Scores

Each officer other than the named executive officers must meet certain payout goals, including a consolidated operating earnings goal that is the same as the AIP funding goal described above, business unit financial goals, operating and stewardship goals, and Six Sigma goals, in order to earn all or a portion of their funded AIP payout. The percentage achievement of the payout goals determines how much of an officer's funded payout will be earned, up to 100%.

Business unit financial goals are set based on the levels necessary to achieve the consolidated earnings goal for Dominion. Breaking the consolidated goal into smaller goals for each business unit provides line-of-sight goals for officers and employees, and facilitates financial and business planning.

The business unit operating and stewardship goals are designed to provide line-of-sight goals that may not be financial and that can be customized for the business unit or individual. Goals such as safety, outage targets for power plants, and capital spending goals are some examples. The accomplishment of these goals often supports the business unit financial goals or focuses on other key areas such as safety and customer service. The most common operating and stewardship goals have objectives in the following areas: safety; reliability; expenditures and production; forced outages; and service level requirements.

Six Sigma goals support the company's mission to continue to use a Six Sigma business process improvement program. Our Six Sigma program uses data and statistical analysis to measure and improve company operational performance, practices and systems. Six Sigma projects are designed to increase productivity, reduce costs and enhance customer service. Six Sigma targets are based on the positive financial impact of projects utilizing these Six Sigma goals and methodology.

Each executive's goals are weighted according to his or her responsibilities. The overall goal score cannot exceed 100%. The goal weightings for bonuses under the 2007 AIP are as follows:

	Consolidated Financial Goal	Business Unit Financial Goals	Operating/ Stewardship	Six Sigma
CEO/CFO	90%	—	—	10%
Other Officers	25%	50%	15%	10%

For the named executive officers, bonuses were based solely on the consolidated earnings goal, with the CGN Committee having discretion to reduce final payouts to the extent appropriate based on any goal accomplishment that was less than 100% for the corporate-wide Six Sigma goal and for Messrs. Johnson, McGettrick and Radtke, any goal accomplishment that was less than 100% for their business unit financials goals or their own personal operating and stewardship goals. Therefore, at 182% funding, each named executive officer is entitled to an AIP payout of 182% of his or her target award. For the named executive officers, the goal percentages set forth above serve only as guidelines for the CGN Committee to consider in exercising negative discretion to lower the AIP payout for these officers if deemed appropriate. Negative discretion can be exercised based on several factors. To promote consistency among the named executive officers and other officers, the CGN Committee in 2007 specifically considered, for the CEO and CFO, the level of achievement of the corporate Six Sigma goal, and for the other named executive officers, the achievement of the business unit financial, operating and stewardship, and Six Sigma goals, up to the percentages indicated for each goal. The Committee exercised negative discretion for Mr. McGettrick based on these goals, as described in *2007 AIP Payouts* below.

2007 AIP Payouts

The formula for calculating an award is:

Base Salary x Target Award Percentage x Funding Percentage x Total Payout Score Percentage (with CGN Committee negative discretion adjustment if any) = Actual Award

As an example, the payout for an officer with a base salary of $200,000, an annual incentive target of 45% and a 2007 total payout score of 95% due to an operating and stewardship

goal shortfall would be determined as follows, based on the approved 182% level of funding:

$200,000 (salary) x 45% (target award) x 182% (level of funding) x 95% (total payout score) = $155,610 payout.

The consolidated operating earnings goals and goal achievement are described above in *Funding of the 2007 AIP*. The business unit financial goals and performance of such goals were as follows:

Company	Threshold (Net Income)	100% Payout (Net Income)	2007 (Net Income)	2007% Accomplishment
(million/$)				
Dominion Delivery	$383	$395	$415	100%
Dominion Energy*	286	354	387	100%
Dominion E&P	636	N/A	N/A	100%
Dominion Generation	678	703	756	100%

* None of the named executive officers had this goal.

The company's service organization, Dominion Resources Services, Inc. has a financial goal based on its level of expenses. In 2007, the CGN Committee exercised discretion and scored officers and employees in Dominion Resources Services, Inc. as having achieved 100% of their expense goal because items causing added expense were accounted for elsewhere in corporate results. None of the named executive officers was affected by such discretion.

The Six Sigma goal for 2007 had a 10% weighting made up of two parts, with 5% tied to financial and improvement targets established for each business unit and 5% tied to a Dominion-wide savings goal of at least $85 million. Achievement of the business unit goals contributed to the overall $85 million financial target. If the positive financial impact was $120 million or more, a 4% credit was granted that could be applied to offset any shortfall in operating and stewardship goals other than goals based on safety and regulatory compliance. Each business unit other than E&P achieved its individual goals. The Six Sigma positive financial impact exceeded $120 million, resulting in all employees earning the 4% extra credit, which was applied to offset any operating and stewardship goal shortfalls other than goals based on safety and regulatory compliance.

All E&P employees, including Mr. Radtke, who remained employed in 2007 following the divestiture of a substantial portion of the company's E&P assets received 100% goal achievement credit for goals impacted negatively by the divestiture. Therefore, the CGN Committee did not exercise negative discretion to lower Mr. Radtke's payout score even though the Dominion E&P goals were not met.

Each business unit scores its own operating and stewardship goals and Mr. Farrell reviews the scores for each officer. The general categories of operating and stewardship goals in 2007 for the named executive officers other than Mr. Farrell and Mr. Chewning were as follows: safety, emergency response, response to power outages, environmental, legal and regulatory compliance, system reliability, costs and expenditures, supplier diversity, and risk management.

Based on a missed safety goal in the Generation business unit, the CGN Committee exercised negative discretion and lowered Mr. McGettrick's payout score to 96.3%. The other named executive officers were paid out based on a 100% payout score.

Amounts earned under the 2007 AIP by named executive officers are set forth below and are also reflected in the Summary Compensation Table under the Non-Equity Incentive Plan Compensation column.

Name	Base Salary		Target Award %		Funding %		Total Payout Score %		2007 AIP Payout
Thomas F. Farrell, II	$1,100,000	x	120%	x	182%	x	100%	=	$2,402,400
Thomas N. Chewning	$ 642,000	x	95%	x	182%	x	100%	=	$1,110,018
Duane C. Radtke	$ 615,300	x	95%	x	182%	x	100%	=	$1,063,854
Mark F. McGettrick	$ 567,000	x	95%	x	182%	x	96.3%	=	$ 944,070
Jay L. Johnson	$ 467,100	x	85%	x	182%	x	100%	=	$ 722,604

The Long-Term Incentive Program

Our long-term incentive program focuses on longer-term goals and retention, with annual grants typically made at the beginning of the second quarter of the year. We do not time the grant dates based on any release of material information or expectations of stock price changes. Newly-promoted officers receive pro-rated grants for the current year's program.

Fifty percent of our long-term program is in the form of restricted stock grants. The other 50% of the program is in the form of either cash-based performance grants or, for officers who have not achieved at least 50% of their stock ownership requirements, goal-based stock. Dominion has not issued any stock options to employees since 2002.

Although the CGN Committee reviews prior grants to the CEO before approving new long-term grants, the determination of the appropriate grant for the CEO in any given year is based on the results of the process we described above for our executive compensation program. The fact that an executive received long-term incentive awards over the course of his or her career is not a significant factor in determining the executive's entitlement to appropriate long-term incentive awards in the current year, although the CGN Committee does consider prior awards. Similarly, if a newer executive does not have prior grants outstanding due to his or her short tenure, we do not increase the compensation paid to such executive due to a lack of outstanding grants from prior years.

2007 Restricted Stock Grants

Restricted stock grants serve as a retention tool and align the interests of officers with the interests of our shareholders. All officers received a restricted stock grant on April 3, 2007 based on a stated dollar value. The number of shares awarded was determined by dividing the stated dollar value by the closing price of Dominion's common stock on April 2, 2007. For officers other than E&P officers (including Mr. Radtke), the grants have a three-year vesting term, with cliff vesting at the end of the restricted period on April 3, 2010. Because of the proposed divestiture of E&P assets, E&P officers, including

Mr. Radtke, received a restricted stock grant that was one-third the size that such officers would normally receive and the grants had a one-year vesting term. Upon vesting, all officers are expected to hold any vested shares, net of shares used to cover taxes.

The fair value of each named executive officer's 2007 restricted stock grant is disclosed in the Grants of Plan-Based Awards table.

2007 Performance Grants

All officers received performance grants on April 3, 2007. For officers who had achieved at least 50% of their targeted share ownership, the performance grants were for a stated target dollar amount. The CGN Committee believes cash-based performance grants are appropriate because of: (i) the significant ownership of stock by many executives and the high rate of compliance with our share ownership guidelines; (ii) the belief that a cash-based program will increase the motivation of officers to achieve the goals included in the long-term incentive plan, as the rewards from the plan will be more immediate; and (iii) the fact that our officers typically hold net shares from vesting restricted stock grants until retirement.

Officers who have not achieved at least 50% of targeted share ownership received goal-based stock grants based on a stated dollar value. The number of shares awarded was determined by dividing the stated dollar value by the fair market value of Dominion's common stock on April 2, 2007. All officers are expected to hold any vested shares, net of shares used to cover taxes.

The 2007 performance grants for officers other than E&P officers, including Mr. Radtke, are denominated as a target award, with actual payout equal to 0-200% of the target based on the company's performance against two metrics:

- Total Shareholder Return (TSR) for the two year period ended December 31, 2008 relative to the TSR of a group of industry peers selected by the CGN Committee. TSR is the difference between the value of a share of common stock at the beginning and end of the performance period, plus dividends paid as if reinvested in stock. The TSR metric was selected to focus our management team on considering long-term shareholder value when developing and implementing their strategic plans and in turn, rewards management based on the achievement of total returns for our shareholders for defined periods of time as measured against our peer companies.

  The Peer Group for this grant is the same as the Peer Group used for 2007 compensation setting for non-E&P officers, with the exception of TXU Corp. TXU Corp. which was part of our peer group for 2007 compensation-setting purposes, was excluded as a peer company for the 2007 long-term awards because it announced its plans to become privately-held in 2007.
- Return on Invested Capital (ROIC) for the two-year period ended December 31, 2008. ROIC reflects the company's total return divided by average invested capital for the performance period. For this purpose, total return is the company's consolidated operating earnings plus its after-tax interest and related charges, plus preferred dividends. The ROIC metric was selected to reward the achievement of expected levels of return on the company's investments, with upside for returns exceeding those expectations. Having a ROIC measure encourages management to choose the right investments, and with those investments, to achieve the highest returns possible through prudent decisions, management and control of costs.

The grants are 100% performance-based with payouts ranging from 0-200%.

The performance period commenced on January 1, 2007 and will end on December 31, 2008. Each metric is equally weighted such that TSR performance shall determine 50% of the target amount and ROIC performance will determine the other 50% of the target amount.

Payouts for all officers, including officers who retire before the end of the performance period (who receive a pro-rata payout amount), will be made in February 2009.

The TSR Goal. The portion of the grant tied to the TSR goal will be paid out based on the following table:

Relative TSR Performance	Percentage Payout of TSR Percentage*
Top Quartile – 75 % to 100%	150% – 200%
2nd Quartile – 50% to 74.9%	100% – 149.9%
3rd Quartile – 25% to 49.9%	50% – 99.9%
4th Quartile – below 25%	0%

*TSR weighting is interpolated between the top and bottom of the percentages for that quartile. A minimum payment of 25% of the TSR percentage will be made if the TSR performance is at least 10% on a compounded annual basis for the performance period, regardless of relative performance.

The ROIC Goal. For the 2007 performance grants made to officers and employees (other than our Section 16 officers which includes our named executive officers), the CGN Committee approved the following ROIC goals, as modified in 2008 to reflect the 2007 budget as adjusted for E&P divestitures and for the approved 2008 budget. The ROIC targets and corresponding payout scores are as follows:

ROIC Performance	Percentage Payout of ROIC Percentage*
8.5% or greater	200%
8.3% – 8.49%	150% – 199.9%
8.1% – 8.29%	100% – 149.9%
7.9% – 8.09%	50% – 99.9%
Below 7.9%	0%

*ROIC weighting is interpolated between the top and bottom of the percentages for that quartile

Because of the uncertainty with pending E&P divestitures in 2007, the named executive officers other than Mr. Radtke and other Section 16 officers were given awards with ROIC percentages based on a 2007 budget that excluded any assumed earnings from the E&P business unit. In order to

EXHIBIT

OCC Ex. 16

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
Request to Produce - 3rd Set

Question Number: 67

Subpart:

Request Date: 01/17/2008

Due Date: 01/23/2008

Topic:
Section C - Operating Income

Question:
Please provide copies of all employee incentive plans for any employee whose labor expense is included in the test year and workpapers, data, source documents, and/or other information DEO relied upon in responding to OCC Interrogatory No. 110 pertaining to the employee incentive plans for any employee whose labor expense is included in the test year.

Answer:
PLEASE NOTE: This response and/or attachment(s) contains confidential documents or information. The source document may not contain a "Confidential" label or reference on the document itself. However, "CONFIDENTIAL DOCUMENT" has been included in the name of any file containing confidential material and, accordingly, the information included in such attachments should be considered confidential.

Descriptions included in the response to OCC Interrogatory No. 110 were provided by Dominion's Manager of Compensation Services. Please see the attached documents.

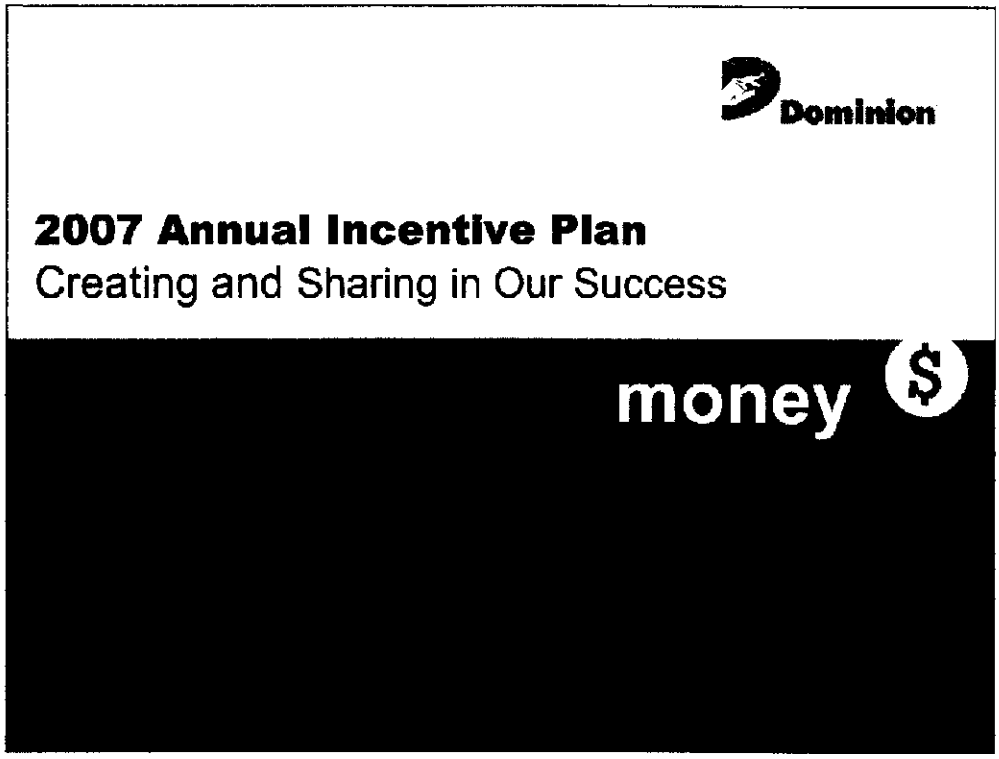
Preparer Of Response:
Vicki Friscic

Date Prepared:
01/18/2008 10:45:30 AM EST

Attachments:
Yes

Attachment Names:
CONFIDENTIAL DOCUMENT- Dominion 2007 AIP Employee Overview - Final.ppt
CONFIDENTIAL DOCUMENT- Incentive Compensation Plan.pdf
CONFIDENTIAL DOCUMENT - Leadership Stock Option Plan.pdf

CONFIDENTIAL

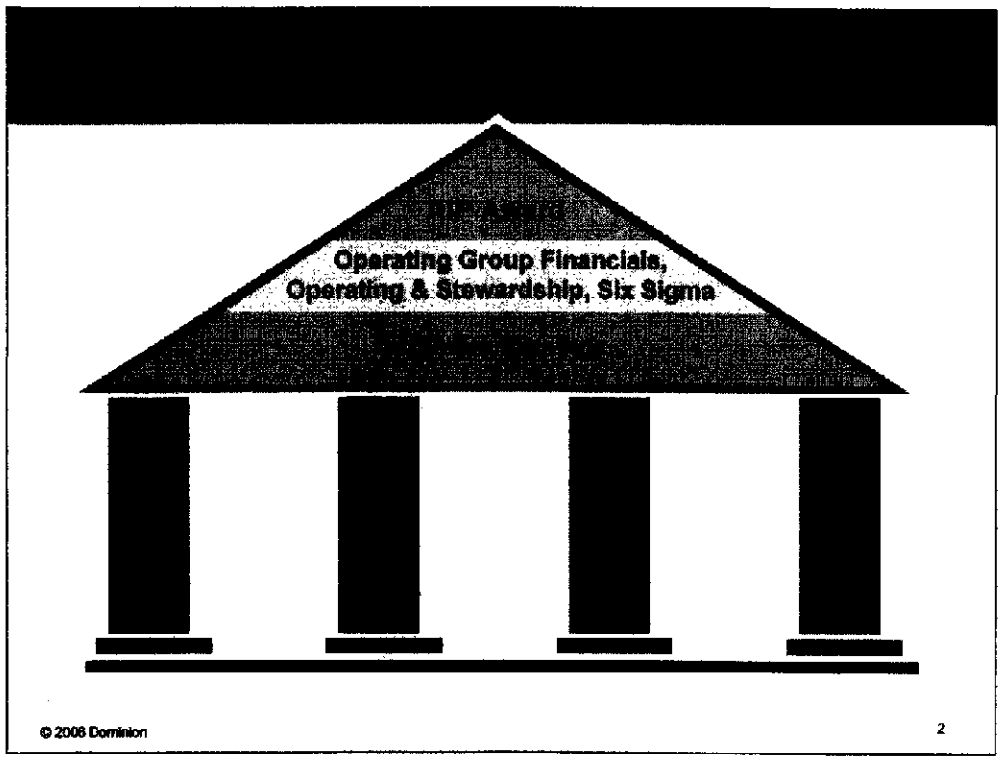


Welcome to the presentation on the Dominion Annual Incentive Plan for 2007, the AIP.

The information covered here will help you understand the plan and how you influence it, so you can help Dominion maximize performance and maximize your payout as a result.

It covers:

- The philosophy behind the AIP
- How the plan works
- Goals and goal weightings for 2007
- And some payout examples



• Let's start with the big picture. What is the purpose of the AIP? What does it take for Dominion to succeed? What does it take for AIP to pay awards?

• The purpose of the AIP is to make a strong link between the actions of individual employees, operating groups and business units, and the success of the company – and to reward that success.

•The three key elements of the AIP are:

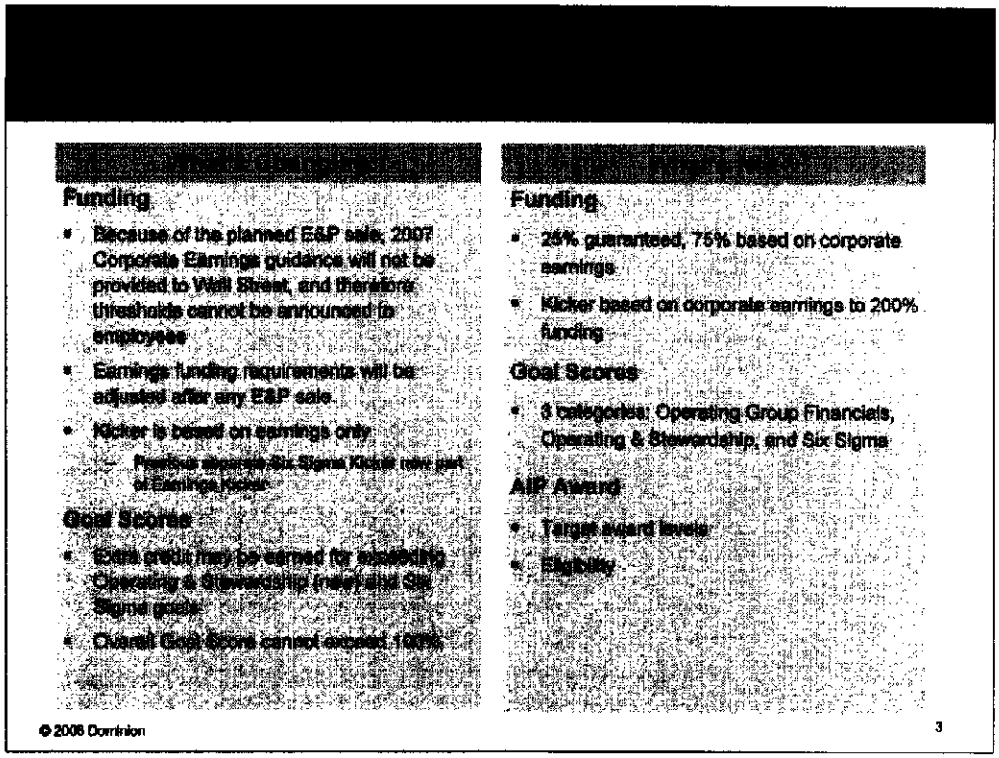
- Dominion's overall success in generating corporate earnings creates the funding for payouts.
- Business unit success with specific goals for operating group financials, operating and stewardship, and Six Sigma result in a "goal score" which represents the extent to which we achieved our goals. This determines how much of the funding is payable.
- Your AIP award payout incorporates the funding and your goal score. It's based on your target award percentage and plan compensation.

•Dominion's success starts with our four values – Safety, Ethics, Excellence, and One Dominion. These are the pillars which support our success.

• Managing our OSHA Recordable Incident Rates, living both the letter and spirit of the law, focusing continuously on what we can control, such as operational excellence and customer service, and behaving as a single organization with a shared mission, are fundamental. When we deliver on these, Dominion is positioned to succeed.

• When we add excellent business unit financial performance to the picture, which roll up to our corporate earnings target, we will have the funding we need to pay AIP awards.

•If you aren't sure how you can affect our operational and financial results, please talk to your manager. We want you to recognize how important you are, and how you can create and share success.



There are some changes to the Annual Incentive Plan, let's review these.

Earning Guidance

•Since many factors (such as sale timing) related to the E&P divestiture will affect Dominion's 2007 corporate earnings, we are not providing guidance to Wall Street and will not have an announced earnings target to fully fund the AIP. After the year is completed, Dominion senior executive leadership and the Board of Directors will determine Dominion's 2007 financial performance and the associated funding level achieved.

Kicker Changes

•Last year, the kicker was based on two components – there was an earnings kicker, plus a Six Sigma kicker.

•This year, it's solely based on earnings, since Six Sigma is a crucial factor in building up our earnings. It's factored into earnings through the savings and productivity that it generates.

•This doesn't mean we have reduced the opportunity for a kicker. It's how we're defining the kicker that's changing.

•You'll see that there is a Six Sigma "credit" included in the performance goals. It's explained in that section.

Goal Scores

•We are adding the ability to earn extra credit within the Operating & Stewardship category, and keeping the ability for extra credit with Six Sigma goals.

•For 2007, your total goal score cannot exceed 100%. Since goal scores above 100% have to be incrementally funded to be paid out, we have moved that goal score upside (above 100% goal score) into the funding the plan kicker, which we will discuss on the next slide.

Many features remain the same.

Funding

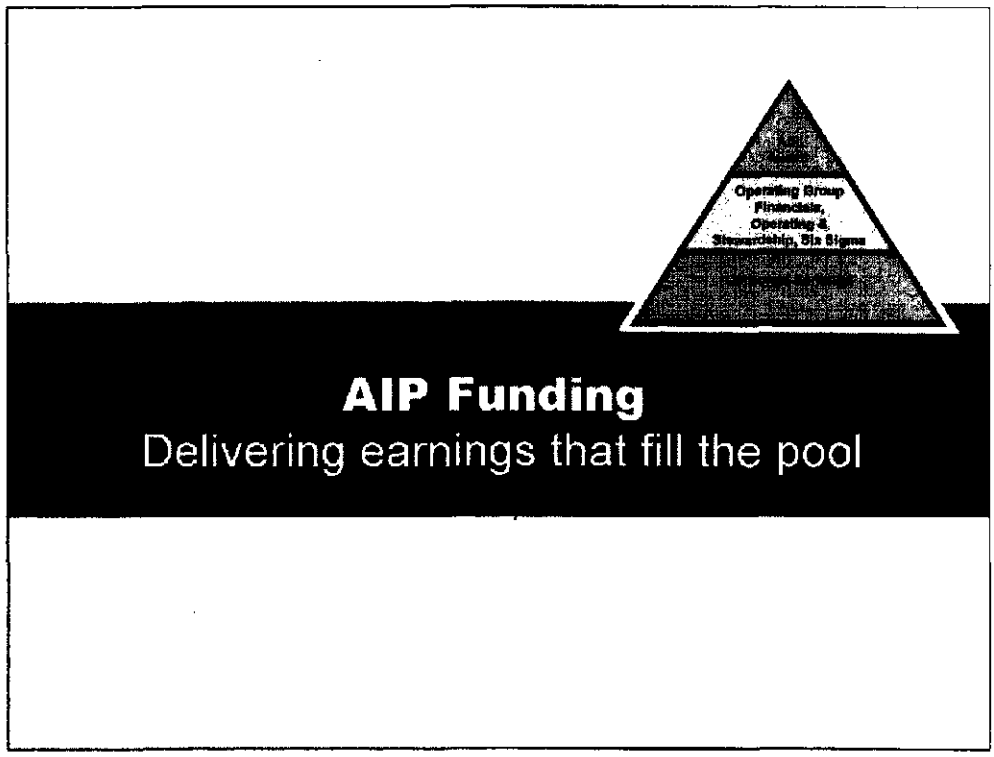
•The funding basics have not changed, and we review these on the next page.

Goal Scores

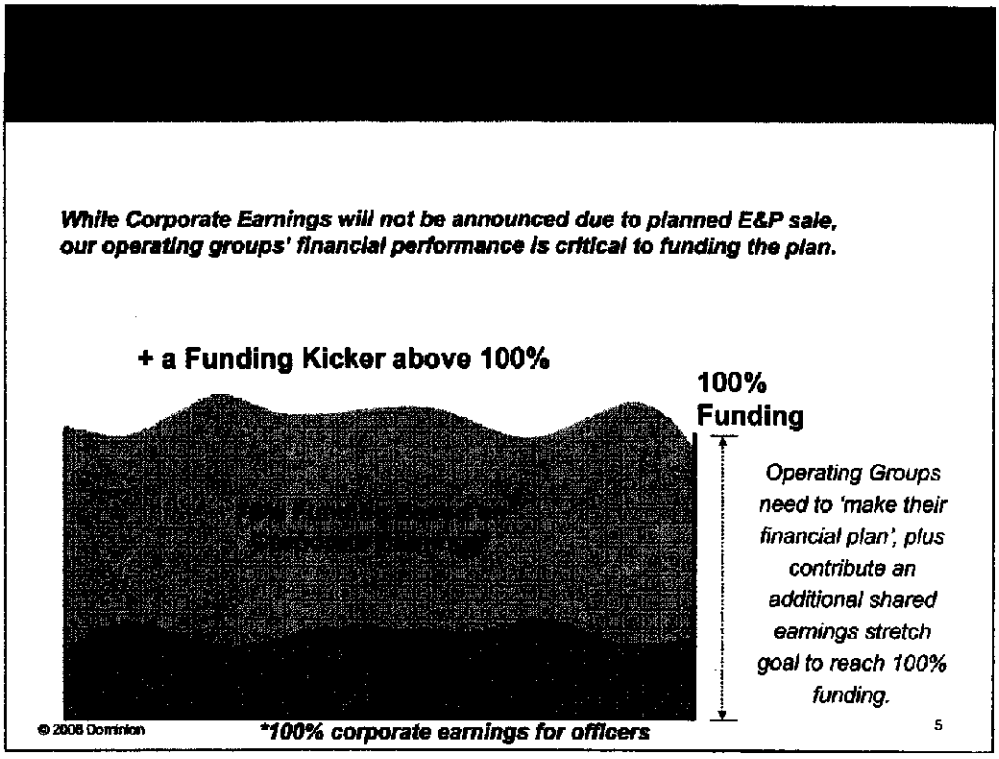
•We will still have 3 goal categories that provide balanced focus for success.

AIP Award

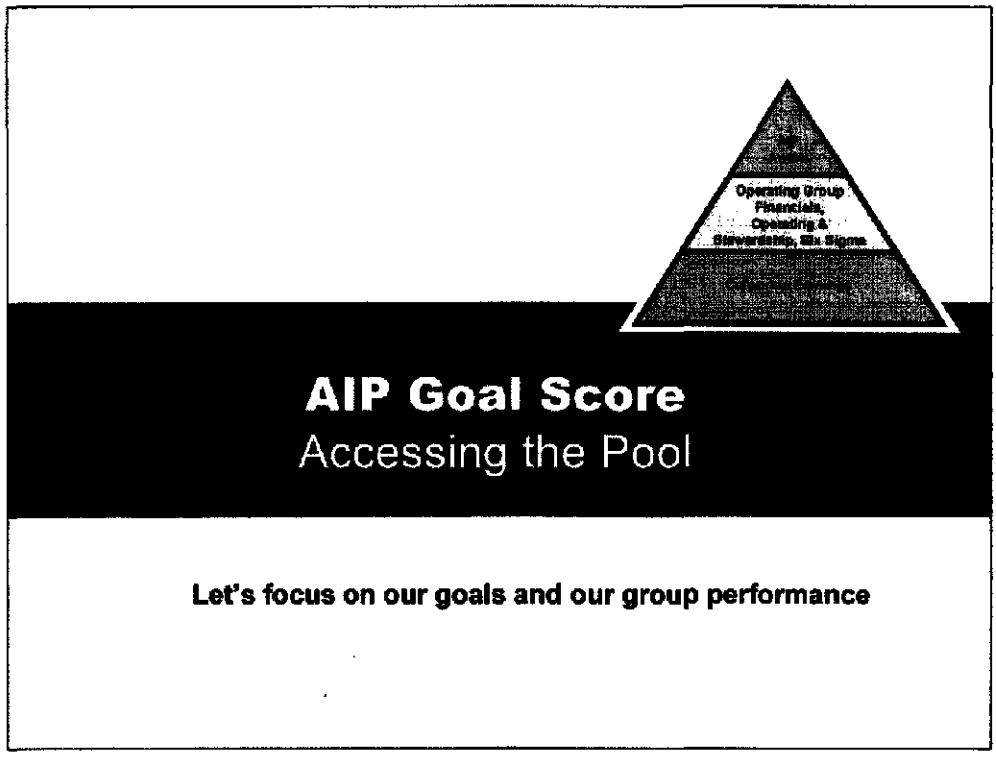
•The target levels, the eligibility, and the calculation methods are not changing. We will show you some payout examples later in this presentation.



- Here's an explanation of these three elements, one by one.
- The starting point is delivering earnings results that will fill a pool of money from which awards can be paid out.



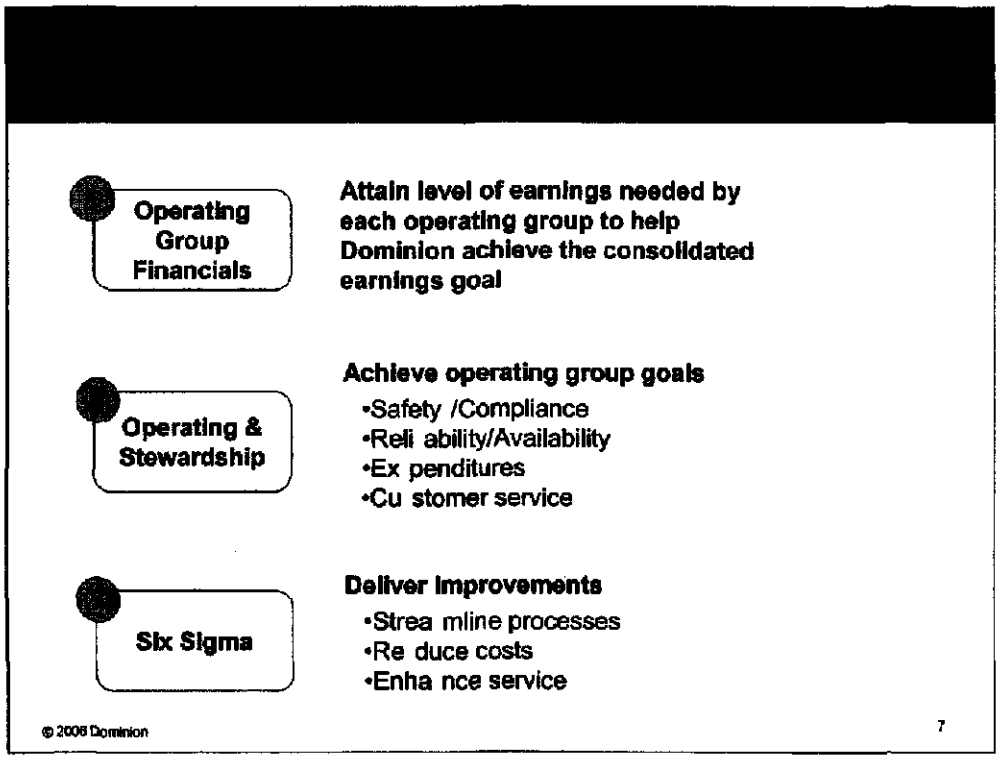
- For non-officers, the pool is funded in two "waves."
- 25% of funding is guaranteed, recognizing that earnings are variable. In other words, it will be funded whether or not we reach our consolidated earnings target. The funding is guaranteed, the payout is subject to your goal score.
- The remaining 75% is variable, based on our actual Consolidated Operating Earnings, or corporate earnings for short. Reaching full funding depends on two factors: all business units making their targets, plus reaching an additional shared stretch goal for earnings between them.
- For our CEO and Officers, AIP funding is based solely on corporate earnings, and depends wholly on our actual results.
- To give you some perspective, if the AIP is fully funded for 2007, Dominion will pay employees well over $100 million.
- We're not showing our actual corporate earnings target or stretch goal here, since they will be subject to adjustments related to any E&P sale.
- The plan also allows for a kicker to the pool. If we exceed our corporate earnings goal, then a "kicker" comes into play, adding dollars to the pool to recognize that additional success, above the 100% funding level.



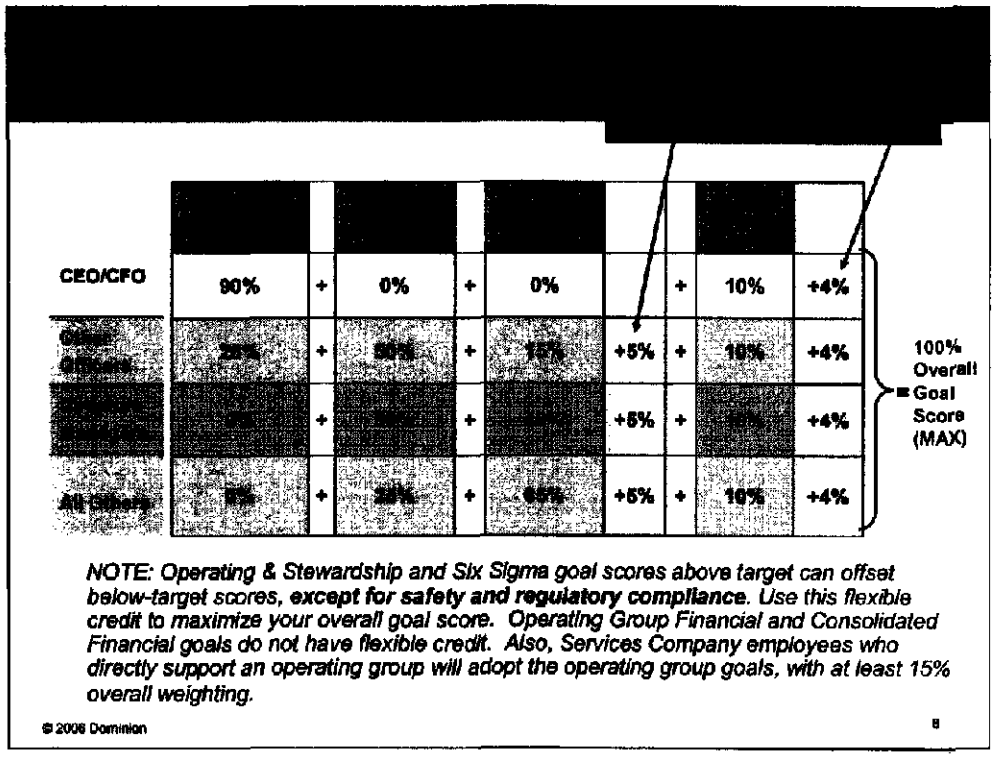
AIP Goal Score
Accessing the Pool

Let's focus on our goals and our group performance

• Now let's look at the 2007 goals – which is how you access your portion of the pool.



- AIP focuses us on the most critical measures of our performance. The blend of measures we use for AIP provides a balance between financial and operational goals. AIP is designed to reward our operating and stewardship goal achievements, such as safety and individual power plant performance, and Six Sigma, as well as our financial results.
- The financials are a given. We need to deliver operating group financials in support of Dominion's overall financial expectations for our shareholders.
- As you can see, although operating and stewardship goals aren't necessarily financial, they are focused on key areas of our business unit/operating group performance. Typical O&S goals include safety, compliance, reliability, expenditures and production, forced outages and service level requirements.
- Six Sigma helps us streamline processes, reduce costs and enhance customer service, producing both operational and financial results.
- Taken together, the goals for any given year will support our values of safety, ethics, excellence and One Dominion. And each person can have a direct influence on the goals for which they are accountable under AIP.

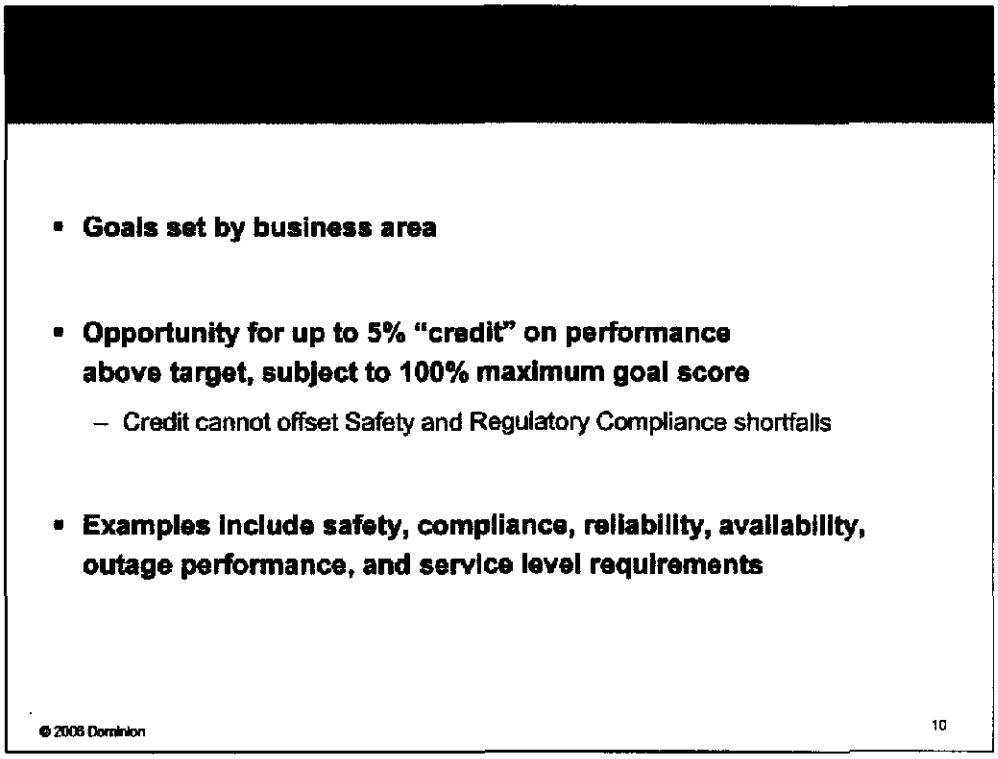


- This slide shows how each performance measure is weighted. The weightings reflect the degree to which different participants can influence results directly. For example, everyone impacts Six Sigma, so it's equally weighted for all.
- Consolidated Financial Earnings are a key accountability for our senior leaders, so that measure is most heavily weighted at those levels.
- Consistent with last year's plan, Service Company employees that directly support an operating group will align by sharing goals with that group.
- Each employee level has goal area weighting categories that correspond to the level of influence they can have on those areas.
- While the maximum goal score is 100%, note that Operating & Stewardship and Six Sigma show additional percentages. That's because those goal scores are designed to acknowledge exceptional performance through "credits."
    - Operating & Stewardship goals may be set to earn flexible "credits," up to 5% overall additional credit. This results in maximum scores for officers, directors and managers, and employees for this category of 20%, 45% and 70% respectively.
    - Six Sigma has a potential credit of 4%, for a maximum goal score of 14%.
- These flexible "credits" can offset any other operating group financials, operating/stewardship or Six Sigma payout goal that is not fully achieved, with an important exception -- safety and regulatory compliance goals cannot be offset.
- You will see some examples of earning and applying credits shortly.

Delivery	$397	$383	Less than $383
Energy	$296	$286	Less than $286
E&P	$659	$636	Less than $636
Generation	$703	$678	Less than $678
Services (expense goal)	$539	$560	More than $560

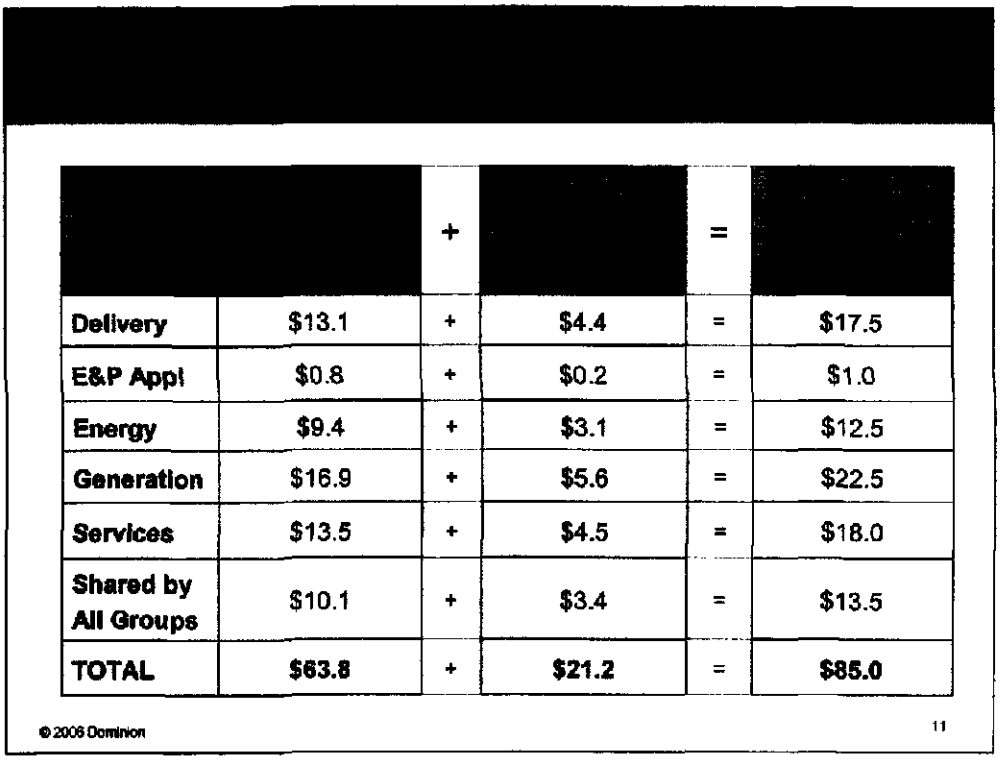
Note: Achievement that is better than the earnings target is needed to fully fund the plan, but Operating Group financial scores do not have flexible credit.

- These are the earnings goals and scores for each business unit. Note that the Services Company has an expense goal rather than an earnings goal.
- The 100% column shows the earnings required for a 100% goal score – the target.
- The threshold column shows the minimum amount a business unit can earn to achieve partial credit for its earnings goal. The goal score for threshold results is 80%. Anything below that is a goal score of 0%.
- If the actual performance is between the Threshold and the 100% level, the score will be proportional between 80% - 100%.
- For officers, directors and managers, earnings make up 80% of the operating group financial goal score, while the other 20% reflects their accountability for capital expenditures goals.
- For employees below the manager level, typically earnings are 100% of the operating group financial goal score measured at the Operating Group level, where employees can have the most direct impact. Operating Groups do have the discretion to include capital expenditure goals below the manager level.



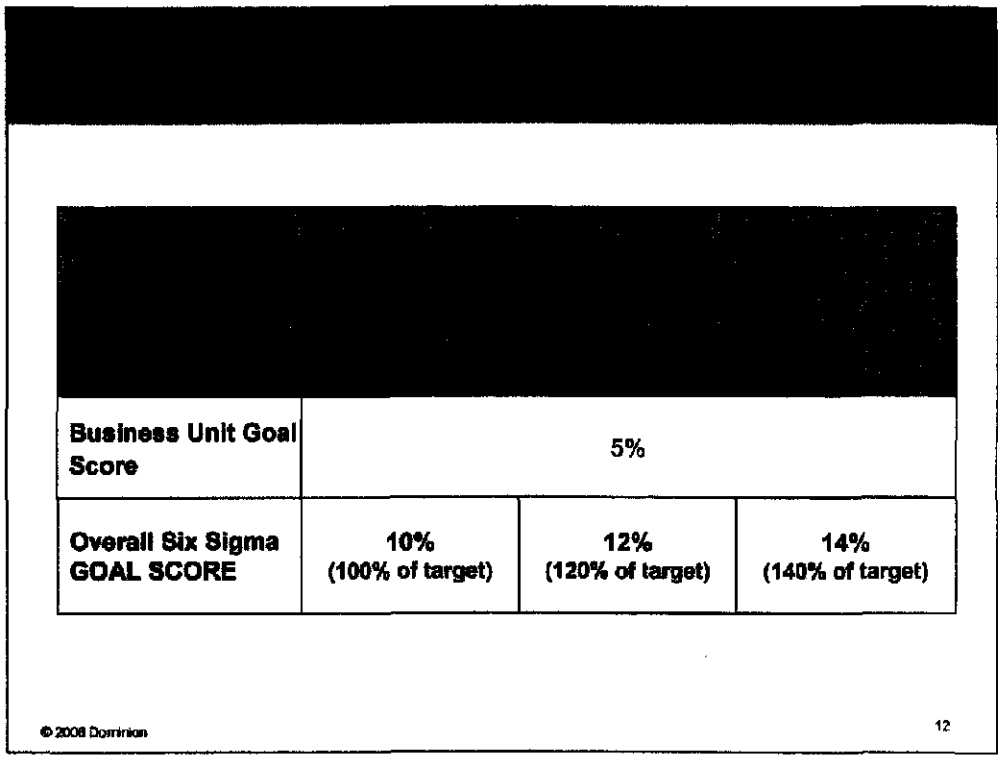
•Operating and Stewardship results can add up to 5% credit to the goal score.

•Typically, these goals include safety, compliance, reliability, availability, outage performance (or forced outage goals), and service level requirements, for example, and are set by business area.



		+		=	
Delivery	$13.1	+	$4.4	=	$17.5
E&P Appl	$0.8	+	$0.2	=	$1.0
Energy	$9.4	+	$3.1	=	$12.5
Generation	$16.9	+	$5.6	=	$22.5
Services	$13.5	+	$4.5	=	$18.0
Shared by All Groups	$10.1	+	$3.4	=	$13.5
TOTAL	**$63.8**	+	**$21.2**	=	**$85.0**

- Here are the Six Sigma goals. All these figures are pre-tax.
- Looking at the slide, you can see that each business unit has been assigned a hard profit and loss or "P&L" savings goal (left column). Then there's a shared additional goal of $10.1 million, bringing the total 2007 corporate P&L target to $63.8 million.
- In addition, moving to the middle column, there's a further target that can be met through P&L and/or CapEx. For example, reading from left, Delivery needs to attain its $17.5 million target. $13.1 million must come from P&L, while $4.4 million can be achieved through additional P&L, through CapEx, or through a combination of the two.
- The business unit score is based on achievement against the total number – for example, if Delivery achieves $17.5 million, then the full 5% business unit portion of the Six Sigma goal score is earned.
- At the bottom of the far right column, these goals add up to our total financial target savings of $85 million, which earns the 5% corporate score.



Business Unit Goal Score	5%		
Overall Six Sigma GOAL SCORE	10% (100% of target)	12% (120% of target)	14% (140% of target)

•As mentioned on the previous slide, the total Six Sigma goal score is 10%. 5% is based on corporate results and 5% on business unit results.

•Similar to the Operating & Stewardship goal category, credit can be earned if we surpass our Six Sigma corporate target of $85 million.

- If we reach $100 million, we earn 2% of additional credit.
- If we reach $120 million, we earn 4% of additional credit.

•The business unit portion of the Six Sigma goal score is 5%, so the Six Sigma goal score can be as much as 14% in total.

•The business unit goals may include Financial targets, as listed on the previous slide, and Improvement targets. The full 5% cannot be put into the Improvement target. Improvement targets can get a general target such as the number of non-financial projects completed or a more focused business target such as improving reliability by x% through Six Sigma projects.

• Like the Operating & Stewardship credit, this can be applied against any goal shortfall except safety and regulatory compliance – up to a maximum overall score of 100%.

Example 1

Operating Group Financials	84%	X	25%	=	21%
Operating & Stewardship	103%	X	65%	=	67%
Six Sigma	120%	X	10%	=	12%
OVERALL GOAL SCORE					**100%**

- Let's look at how the overall AIP goal score is determined when a credit is earned.
- Once results for the year are in, we evaluate goal achievement percentage and multiply it by the weighting to determine the goal score.
- For example, here we assume that we've achieved 84% of operating group financial goals, 103% of operating and stewardship goals and 120% of Six Sigma.
- The respective goal scores are 21%, or 4% below the full score; 67% and 12%. Both of these are 2% over goal, for a total of 4% additional credit.
- This 4% additional credit that's generated by above-target Operating & Stewardship and Six Sigma results makes up the 4% shortfall in Operating Group Financials for an overall goal score of 100%.
- Going above and beyond target matters.

Example 2

Operating Group Financials	100%	X	25%	=	25%
Operating & Stewardship	103%	X	65%	=	67%
Six Sigma	100%	X	10%	=	10%
Total					102%
OVERALL GOAL SCORE					**100%**

[redacted]

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- Here's another way to look at the credit potential.
- This example reflects a very strong year, where we hit our financial and Six Sigma targets and exceeded our operating & stewardship goals.
- The operating & stewardship goal credit is applied against the weighting, raising that goal score by 2% to 67%.
- Added to the financial and Six Sigma scores, this raises the combined goal score to 102%. However, the maximum goal score recognized by the plan is 100%.

Example 3

Operating Group Financials	100%	X	25%	=	**25%**
Operating & Stewardship	97%	X	65%	=	**63%**
Six Sigma	120%	X	10%	=	**12%**
Total					***100%***
Safety shortfall					-2%
OVERALL GOAL SCORE					**98%**

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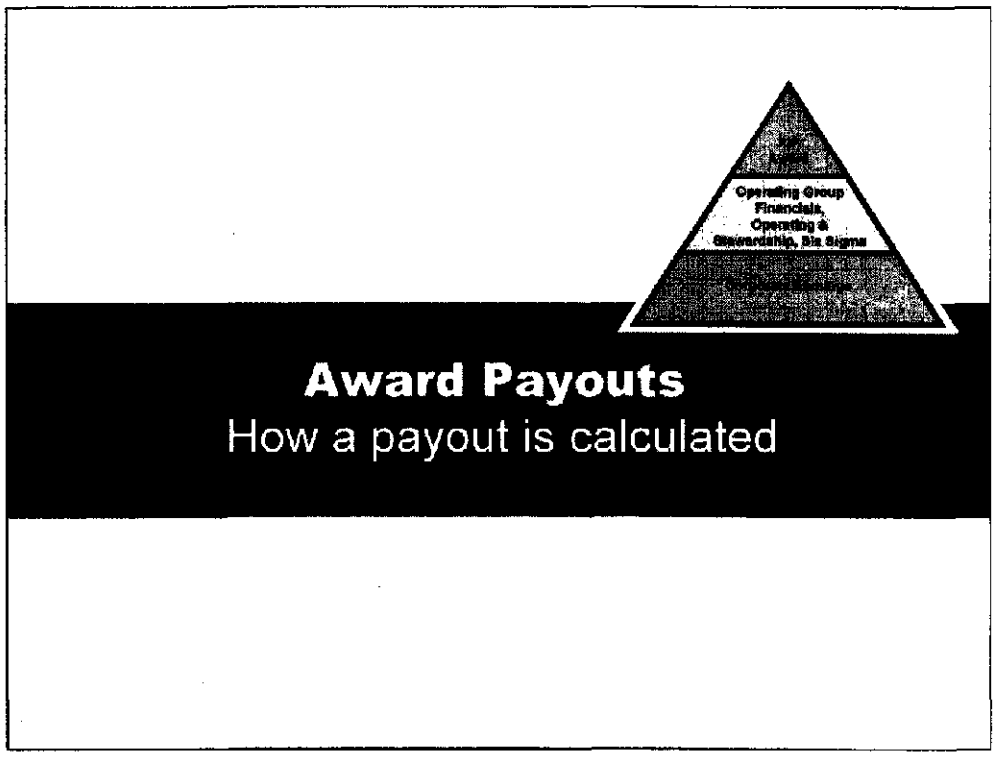
- One more example of a credit situation that reinforces how critical safety and compliance are to our success.
- In this example,
  - Operating group financials are on target
  - However, our operating & stewardship score is under-target, is 63% due to 2% deduction caused by falling short on safety.
- We did achieve 2% credit for 120% Six Sigma goal performance.
- But since we cannot offset safety or regulatory compliance results, we must reduce our Total by the 2% caused by the Safety shortfall.
- The result: the overall AIP goal score is 98%.



Now let's look at how funding, performance scores and your individual award opportunity come together for award payouts.

Plan Compensation	→	**$50,000**
Target Award Level	X	**10%**
Target Award Amount	=	**$5,000**
Funding Level*	X	**100%**
Funded Amount	=	**$5,000**
Goal Score	X	**90%**
Actual Payout	=	**$4,500**

**Funding Level: 25% Guaranteed + 75% for Corporate Earnings*

	Accomplishment	Weighting	Score
Operating Group Financials	86%	25%	21.5%
Operating & Stewardship	90%	65%	58.5%
Six Sigma	100%	10%	10.0%
			90.0%

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- Here is an example of a potential incentive payout for an employee. The example assumes we reach 100% funding by meeting our corporate earnings target. The sample employee has plan compensation of $50,000 and a target award level of 10%, for a target award amount of $5,000.
- The funding level is 100% -- 25% from the guaranteed contribution and 75% from Dominion's earnings goal. Thus the funded award amount is the full $5,000.
- Looking at the goal scores, note that the operating group achieved 86% of its financial goal. This means the group achieved 86% of the target amount, above the threshold amount.
  - The group also achieved 90% of its operating/stewardship goal
  - The Six Sigma business unit and corporate goals were fully achieved
- By multiplying the accomplishments on the left times the goal weighting in the middle, we get a goal score on the right for each of the three goals. Those scores sum to 90%.
- To calculate the payout, multiply the goal score of 90% times the funded amount of $5,000. The resulting payout is $4,500.

Plan Compensation	→	**$50,000**
Target Award Level	X	**10%**
Target Award Amount	=	**$5,000**
Funding Level*	X	**25%**
Funded Amount	=	**$1,250**
Goal Score	X	**90%**
Actual Payout	=	**$1,125**

**Funding Level = 25% Guaranteed + 0% for Corporate Earnings*

	Accomplishment	Weighting	Score
Operating Group Financials	86%	25%	21.5%
Operating & Stewardship	90%	65%	58.5%
Six Sigma	100%	10%	10.0%
			90.0%

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- This example assumes the same employee and the same overall goal score. The difference is that earnings were not sufficient to fund the Corporate earnings portion of the pool. However, the 25% guaranteed contribution to the pool is available.
- The calculation process is the same, but now just $1,250 of the employee's $5,000 target award is funded rather than the full award. Multiplied by the 90% goal score, the payout is $1,125.

Plan Compensation	→	**$50,000**
Target Award Level	X	**10%**
Target Award Amount	=	**$5,000**
Funding Level*	X	**109%**
Funded Amount	=	**$5,450**
Goal Score	X	**90%**
Actual Payout	=	**$4,905**

Funding Level: 25% Guaranteed + 75% Based on Earnings + 9% Earnings Kicker

	Accomplishment	Weighting	Score
Operating Group Financials	86%	25%	21.5%
Operating & Stewardship	90%	65%	58.5%
Six Sigma	100%	10%	10.0%
			90.0%

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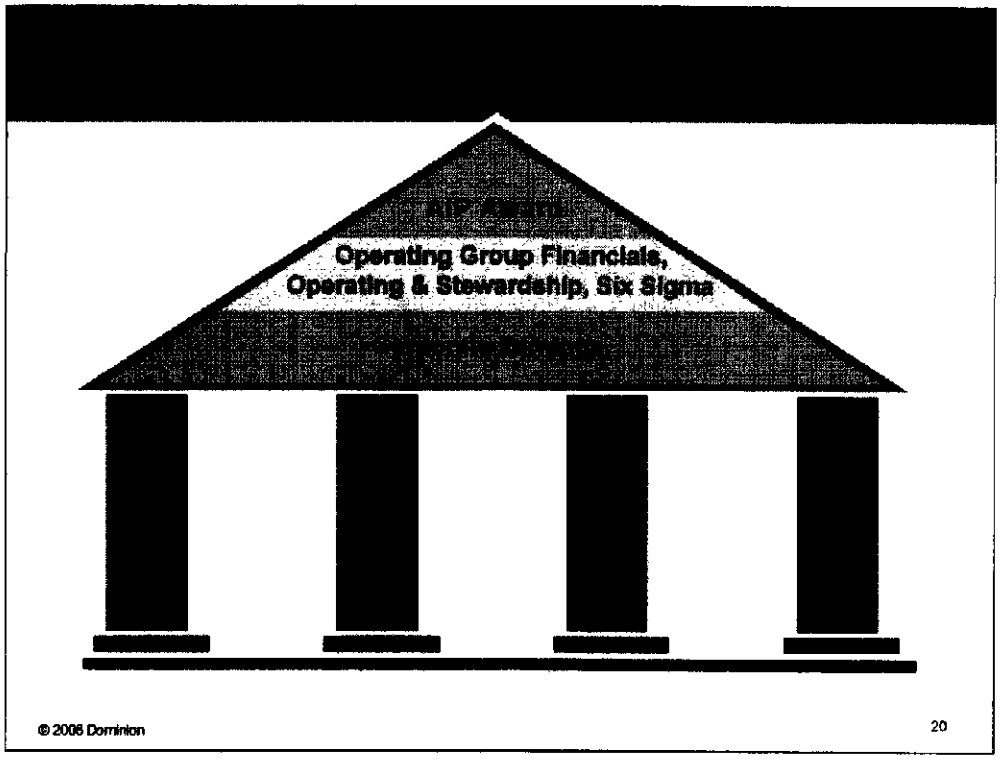
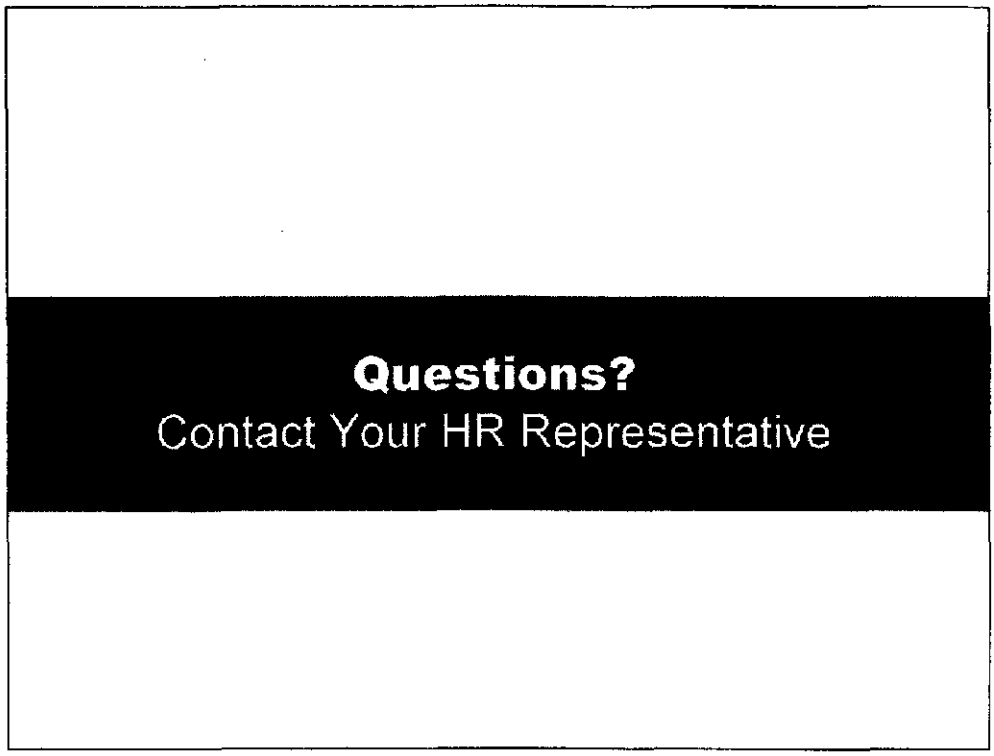
- Funding can be on the other end of the spectrum as well. In this example, the combination of 25% guaranteed funding, another 75% funding based on corporate earnings plus the 9% kicker based on above-target earnings creates 109% funding for the pool.
- The goal score is 90%.
- Following the same employee, the funded award amount is above target at $5,450. With a goal score of 90%, the payout is $4,905.
- As you see from these few examples, there's real value in maximizing all our results in order to maximize your AIP payout.



•Everything you do that touches these goal areas influences our overall AIP goal score and our earnings. Our desire is to reach performance levels that provide 100% payouts or more. That would be a sign that we really are creating and sharing in success.

•And to go back to the beginning, that's what AIP is about. It connects what you do, what your operating group/business unit does and the company's overall performance and earnings and ultimately, your AIP payout.

•Be sure you know what your own goals are, and how you can deliver your best against each one. If we all continue to work safely and ethically, with the interests of Dominion and shareholders in mind, we will have the greatest chance of reaching or exceeding our corporate goal. Then we'll all enjoy the rewards of the jointly created success.



- This concludes the presentation on the 2007 Dominion Annual Incentive Plan.
- Please contact your HR representative if you have questions.

EXHIBIT

OCC Ex. 17

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Response to Data Requests

Requesting Party:
OCC

Data Request Set:
PIR - INT Set 2 08-169-GA-ALT

Question Number: 77
Subpart:

Request Date: 06/17/2008
Due Date: 07/08/2008

Topic:
Distribution Infrastructure

Question:
Referring to the Pipeline Replacement Program testimony of Mr. Murphy, p. 4. Mr Murphy states that the Pipeline Replacement Program "will result in fewer rate cases." Please identify the number of rate cases the Company plans to file in the next 25 years if the Pipeline Replacement Program is approved.

Answer:
The Company has not performed that calculation. The company will file rate cases as necessary to recover its operating expenses and to earn a return of and on its investments made to provide service.

Preparer Of Response:
Jeff Murphy

Date Prepared:
06/18/2008 01:49:59 PM EDT

Attachments:
No