Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal

Submitted by:

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Executive Summary

ICF International has been asked by American Petroleum Institute (API) to evaluate the cost and benefit impact of the PHMSA safety regulation proposal (Part 191 and 192) dated April 8, 2016, but does not consider information presented in webinars after this date. ICF's analysis includes validating the methodology and assumptions of the PHMSA cost and benefit calculations and making changes as necessary as well as determining any missing costs not included in the PHMSA cost analysis.

ES.1 Overall Summary of Gathering and Transmission Results

The table below displays ICF's overall results as a present value over 15 years with a discount rate of 7%. These results include ICF's estimates for missing costs in gathering and transmission as well as ICF's revisions to PHMSA's RIA calculations for costs and benefits in both sectors. In this analysis, the low estimate benefits have been reduced from $3,234 million to $306 million, the high estimate benefits from $3,738 million to $568 million. The overall costs have increased from PHMSA's $597 million to the ICF estimate of $33,416 million. The sections below provide the explanations behind these differences.

Table 1

Summary of 15 Year Net Present Value Benefits and Costs for Transmission and Gathering Lines (Millions; 2015$ 7% Discount Rate)

	Topic Area	ICF Missing and Revised Calculations[1]			PHMSA RIA[2]		
		Benefits - Low	Benefits - High	Costs	Benefits - Low	Benefits - High	Costs
1	Re-establish MAOP, Verify Material Properties, and Integrity Assessment Outside HCAs	$138.7	$401.0	$772.3	$2,953.5	$3,457.5	$267.0
2	Field Repair of Damages - (More Timely Repairs)	n.e.	n.e.	$3,578.2	n.e.	n.e.	$33.0
3	Management of Change Process Improvement	$16.4	$16.4	$12.3	$16.5	$16.5	$10.5
4	Corrosion Control	$96.1	$96.1	$114.6	$82.5	$82.5	$94.5
5	Pipeline Inspection Following Extreme Events	$4.7	$4.7	$63.2	$4.5	$4.5	$1.5
6	MAOP Exceedance Reports and Records Verification	n.e.	n.e.	$2.9	n.e.	n.e.	$3.0
7	Launcher/Receiver Pressure Relief	$6.7	$6.7	$0.4	$6.0	$6.0	$0.0
8	Expansion of Gathering Regulation	$43.3	$43.3	$28,872.2	$169.5	$169.5	$189.0
	Total for Gathering and Transmission Sectors	**$305.9**	**$568.2**	**$33,416.1**	**$3,234.0**	**$3,738.0**	**$597.0**

n.e. = not estimated

1. Figures for ICF Missing and Revised Calculations do not account for select costs as outlined in Section 4 of this report.

2. PHMSA RIA values displayed are the average annual values in Table ES-6 of the RIA multiplied by 15 to get the 15 year value. This may be slightly off due to rounding in Table ES-6.

ES.2 Summary of Gathering Sector

ICF determines that many of the costs associated with the gathering sector are completely missing from the PHMSA RIA calculations (a through o) or are incorrectly calculated (p through t), as follows:

(a) The RIA does not account for the up-front time and associated costs to interpret the rule and determine applicability to various pipe segments within each company's system.

(b) The proposal requires (192.607) all operators verify pipeline material that do not have "reliable, traceable, verifiable, and complete material documentation records" to conduct material testing of their pipe. The RIA does not calculate the cost of this requirement.

(c) The proposal requires (192.619, 192.624) that all operators determine or verify Maximum Allowable Operating Pressure (MAOP). This requirement creates substantial costs for operators who must determine MAOP. Some gathering operators either cannot utilize the five-year look-back period or do not already know MAOP. Of those operators that know the MAOP or can use the 5-year lookback option, all must verify if located in Class 3, Class 4, or Moderate or High Consequence Area (MCA or HCA, respectively) location. The RIA does not include the cost of MAOP determination for such operators.

(d) The proposal requires (191.23) operators to report safety-related conditions including the exceedance of MAOP. An operator must know the MAOP to know if this exceedance occurs, which requires the determination of MAOP. This applies to all pipeline, regardless of regulation. The RIA does not account for this cost.

(e) The proposal requires (192.163) operators to construct compressor buildings under certain standards. The RIA does not include this cost to build a noncombustible-material building for new compressor stations built in the future that would not have this requirement without the proposal.

(f) The proposal requires (192.706) operators perform periodic leak surveys and assessments. The RIA assumes that operators fix all conditions found during surveys. However, some operators may only monitor certain conditions and may not necessarily fix them within a set timeframe. The RIA does not consider the cost of fixing these monitored conditions. Additionally, the RIA does not take into account the incremental cost to fix a large number of conditions within an accelerated timeframe.

(g) The proposal requires (192.321) operators of above-ground plastic pipe in operation for greater than two years install such pipeline below ground with a specified minimum cover. The RIA does not include the cost for re-installing existing plastic pipe below ground.

(h) The proposal requires (192.105) operators to design newly installed pipeline under certain material standards. This might require higher grade steels, thicker walls, or the substitution of steel for plastic and composites. The RIA does not include the incremental costs for installing higher grade gathering pipe in the future than currently necessary to comply with the proposed design requirements for pipe.

(i) The proposal requires (192.183) operators to construct any installed vaults under certain design requirements. The RIA does not include the incremental costs to comply with specific structural design requirements for vaults on new gathering lines installed in the future.

(j) The proposal requires (192.619 and 192.624) operators to assess newly defined moderate consequence areas (MCA) for MAOP determination and verification. To determine whether a pipeline must comply, an operator must identify MCA areas, if any, using a Geographic Information System (GIS). The RIA does not account for the cost to identify these areas using GIS.

(k) The proposal requires (192.706) operators of Type A Area 2 to perform periodic leak surveys in order to maintain safe operation of a pipeline. The RIA does not consider this cost.

(l) The proposal requires (192.13) operators to perform a management of change process as well as reestablish records when gathering systems change hands. The RIA does not consider these costs.

(m) The proposal requires (192.478 and 192.465) operators adhere to internal and external corrosion requirements for operating gathering lines. This requires performing periodic surveys to monitor the condition of an operating pipe to ensure public safety. The RIA includes a cost for this requirement; however, these costs do not account for all specified requirements. Hence, ICF developed an estimate of additional costs for this requirement.

(n) The proposal requires (192.613) operators to conduct an inspection of all onshore pipeline and following an extreme weather event within 72 hours of cessation of the event. ICF considers this to include the cost to develop a process and perform inspection. The RIA does not consider these costs for gathering lines.

(o) The proposal requires (192.711, 192.713) operators to fix all conditions identified during leak surveys and assessments. Operators have historically monitoring conditions without necessarily fixing them. Therefore, a backlog of conditions exists that will need repair when the proposed rule comes into effect. The RIA does not consider the cost to address these backlog of conditions.

(p) The proposal requires (191.17) operators to complete and submit annual reports for all pipeline to PHMSA. The RIA provides an estimate of cost to submit these annual reports, but ICF considers these costs underestimated. We include a revision of these costs in our cumulative cost calculations.

(q) In the RIA, PHMSA assumes that 3% percent of newly regulated Type A Area 2 pipe is owned by a company not already regulated. ICF considers 80% of newly regulated Type A Area 2 pipe is owned by a company not already regulated.

(r) In the RIA, the pre-regulation occurrence of incidents were estimated incorrectly by taking the offshore incidents from 2001-2005 and applying them to Type A Area 2. ICF considers onshore incidents from 2001-2005.

(s) In the RIA, the post-regulation occurrence of incidents were estimated by taking the reported Type B incidents from 2010-2014 and applying them to Type A Area 2. ICF considers onshore incidents from Type A Area 1 to be a better estimate for the high stress Type A Area 2 pipeline.

(t) Finally in the RIA, Table 6-8 estimates the gas lost from onshore and offshore incidents. ICF considers onshore, natural gas, Type A and B pipelines for determining gas lost.

The following table shows ICF's new cost estimates for various parameters for gathering systems that impact operators based on the proposed safety regulation. For each cost parameter, ICF determines a net present value cost over a 15-year period using a 7% discount rate. (ICF has incorporated the revised benefit estimates discussed in items (r)-(t) in the overall table above, Table 1.) The total cost impact of the proposed rule on gathering line operations amounts to $27.1 billion.

Table 2

15 Year Net Present Value Costs for Gathering Lines (Millions; 2015$)	
Topic Area	**Total (NPV with discount rate 7%)**
a. Implementation of the Rule	$264.4
b. Material Verification	$315.0
c. MAOP Determination for Regulated Pipeline	$4,258.9
d. MAOP Determination for Unregulated Pipeline	$19,932.6
e. Compressor Stations	$14.4
f. Field Repair of Damages	$35.2
g. Construction	$86.9
h. Design Pressure	$499.2
i. Vaults	$1.6
j. Moderate Consequence Area Assessment	$543.5
k. Leak Surveys	$277.8
l. Management of Change	$778.4
m. Corrosion Control and Test Stations	$68.9
n. Pipeline Inspection Following Extreme Events	$49.1
o. Repairing Backlog of Conditions	$10.2
a-o. Subtotal Cost for Items Missing from the RIA	**$27,136.2**
p-q. Subtotal Cost for Revised Items	**$1,736.0**
Total Costs	**$28,872.2**

ES.2.1 Gathering Compliance Costs by Company Size

In order to estimate the impact of the regulation on companies of different sizes, ICF breaks the gathering compliance costs into costs incurred per company regardless of mileage versus those costs which are a function of mileage.

Table 3 shows gathering mile costs on an annual basis. ICF estimates each company will incur 7.6% of those costs creating a cost per company of $40,660. The remaining 92.4% of the costs lead to a per mile cost of $4,451.

Table 3

Annual Compliance Costs (7% NPV divided by 15 years)	
Total Annual cost for gathering	$1,924,810,153
Fraction of costs that are per-company and unrelated to mileage	7.60%
Annual cost allocated on per-company basis	$146,252,538
Annual cost allocated on per-mile basis	$1,778,557,615
Cost per company (unrelated to mileage)	$40,660
Regulatory compliance cost per mile	$4,451

Table 4 shows the approximate impact of the proposed regulation as estimated by ICF broken out by size of gathering company. The number of companies and the distribution of companies by size comes from the data analysis described in Section 2.1 of this report. ICF assumes the volumes gathered as equal to EIA estimates of onshore U.S. gross natural gas withdrawals in 2014 (the last full year of data). ICF also estimates revenues per Mcf of gas gathered. Additionally, ICF assumes total volumes gathered and revenues as proportional to mileage of gathering line among the three company-size segments.

For the gathering system as a whole, compliance costs average approximately 22% of revenues. However, for the smallest companies, the estimated annual compliance cost nearly equals estimated annual revenues from gathering fees. This disproportionate impact on small gatherers occurs because many of the costs incurred by the gatherers derive from regulatory analysis, set-up, and training costs which remain similar for each company regardless of its size.

Table 4

Impact of Gathering System Regulations by Company Size				
Size Segment Label	**Small Companies**	**Medium Companies**	**Large Companies**	**All Gatherers**
Minimum Miles per Company in Size Segment	0	10	100	0
Maximum Miles per Company in Size Segment	10	100	35,000	35,000
Company Count in Size Segment	2,223	921	453	3,597
Miles of Gathering Line in Size Segment	5,994	25,973	367,613	399,579
Miles of Gathering Line per Company	3	28	811	111
Approximate Annual Gas Volumes (Mcf) in Size Segment	435,187,050	1,885,810,550	26,691,472,400	29,012,470,000
Approximate Annual Gas Volumes (Mcf) per Company	195,770	2,047,942	58,892,711	8,065,741
Approximate Annual Gathering Fees per Company	$58,731	$614,383	$17,667,813	$2,419,722
Annual Compliance Cost in Size Segment (7% NPV /15 years)	$117,062,433	$153,046,895	$1,654,700,826	$1,924,810,153
Annual Compliance Cost per Company (7% NPV /15 years)	$52,661	$166,205	$3,650,972	$535,115
Annual Compliance Cost as % of Annual Gathering Revenues	90%	27%	21%	22%

ES.3 Summary of Transmission Sector

ICF determines that some of the costs associated with the transmission sector are completely missing from the PHMSA RIA calculations (a through d below) and determines that several key assumptions on estimating benefits and costs for the transmission sector are not representative of the current state of industry practices and the true cost impacts of the proposed rules (e through k below). The key assumptions and calculations requiring additions and revisions are as follows:

(a) The proposal requires (192.710 and 192.713) MCA mileage under pipeline assessment to repair conditions. These conditions are often times only monitored and not necessarily fixed within a set timeframe. The RIA does not adequately calculate the cost of this requirement.

(b) The proposal requires (192.713) operators repair pipeline under a specified timeframe. The RIA does not include repair costs for non-HCA and non-MCA mileage.

(c) The proposal modifies (192.3) the definition of gathering lines, requiring lines downstream of gas processing facilities (referred to as incidental pipe) that are now identified as gathering to comply with the entire transmission line regulation. This incidental transmission mileage is not accounted for in the RIA.

(d) The proposal requires (192.713) operators to fix all conditions identified during leak surveys and assessments. Operators have historically monitoring conditions without necessarily fixing them. Therefore, a backlog of conditions exists that will need repair when the proposed rule comes into effect. The RIA does not consider the cost to address these backlog of conditions.
(e) The RIA disregards operator feedback for the cost to upgrade pipeline to accommodate ILI, hence ICF modified the upgrade cost to reflect operator input more closely.
(f) The RIA estimates vendor costs but does not account for costs associated to the company for scheduling, implementing, supervising and verifying the work. ICF added a general and administrative cost to all vendor costs.
(g) The proposal requires (192.933) the repair of conditions immediately. The RIA assumes that all conditions found in an HCA during surveys are currently fixed. Many conditions currently are only monitored and not necessarily fixed within a set timeframe. The cost of fixing conditions that are only currently monitored is not a part of the RIA.
(h) The proposal requires (192.613) operators to conduct an inspection of all onshore pipeline and following an extreme weather event within 72 hours of cessation. ICF considers this as the cost to develop a process and perform inspection. The RIA does not consider this cost.
(i) The RIA underestimates the cost to conduct ILI, and so ICF made adjustments to the additional tools including Spiral MFL and crack tools.
(j) The RIA underestimates the cost to conduct a pressure test and so ICF made adjustments to these costs.
(k) The RIA underestimates the time to implement a management of change program in table 3-67.
(l) The RIA assumes a very large economic benefit associated with the reduced cost for tensile testing (192.107) which is added language in the regulation. ICF did not include this benefit because it does not comply with the “costs without new regulation” versus “cost with new regulation” concept that must be used for cost-benefit analyses of federal regulations.
(m) The RIA took a simple average of incidents in Table E-3 associated with incidents in HCA areas, which in turn over represents the true mean of these incidents. ICF took a power law distribution and applied it to the 23 incidents to achieve a more reasonable mean cost per incident.

The following table shows ICF’s new cost estimates for various parameters for transmission systems that impact operators based on the proposed safety regulation. For each cost parameter, ICF determines a net present value cost over a 15-year period using a 7% discount rate. (ICF has incorporated the revised benefit estimates discussed in items (l) – (m) in the overall table above, Table 1.) The total cost impact of the proposed rule on transmission operations amounts to $4.5 billion.

Table 5

15 Year Net Present Value Costs for Transmission Lines (Millions; 2015$)	
Topic Area	**Total (NPV with discount rate 7%)**
a. MCA Field Repair of Damages	$591
b. Non-MCA/Non-HCA Miles Field Repair of Damages	$1,594
c. Incidental Mileage	$270
d. Repairing Backlog of Conditions	$923
a-d. Subtotal Cost for Missing Items	**$3,377**
e-k. Subtotal Cost for Revised Items	**$1,167**
Total	**$4,543.9**

ES.4 Discussion of Benefits

During review of PHMSA's Preliminary Regulatory Impact Assessment, ICF found a number of inconsistencies in the calculations, with errors from Tables 6-1 and Tables 6-6 of the RIA having a significant impact on results. Table 6-1 is applying onshore and offshore incidents to onshore gathering line mileage. Removing offshore gathering incidents from onshore mileage over the same time period results in a change from 0.329 incidents per thousand miles to 0.144 incidents per thousand miles. Further, PHMSA pulled total costs when calculating Table 6-6's "other incident costs". This effectively double counted costs associated with fatalities, injuries and evacuations. By making the corrections to Table 6-1 and 6-6, the benefits from Topic Area 8 drops from $169.5 million to $43.3 million over the fifteen year period (Total NPV with discount rate 7%). ICF includes a complete listing of all inconsistencies in Appendix A.

ICF also takes issue with PHMSA's calculation of the average economic consequences for certain types of incidents related to HCAs in a table entitled "Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods Located in HCAs (2003-2015; 2015$)." This table takes a simple average of the consequences for 23 incidents that occurred over 13 years to compute an average of $23.4 million per incident. An analysis of the underlying data indicates that a single incident contributed 98.9% of the total consequences from the 23 incidents. Because the sample size is so small and so heavily skewed, it raises the question of how random factor commonly referred to as the "luck of the draw" might have influenced the calculated average and what a more sophisticated analysis of the data might reveal is a better estimate of the mean value for this variable. ICF conducts such an analysis assuming that consequences follow a power law distribution. This analysis suggests a better estimate of the average consequences to be expected from incidents in HCA areas from causes detectable by modern integrity assessment methods as approximately $6.7 million rather than the $23.4 million calculated by a simple average of the 23 incidents.

ES.5 Structure of Report

The structure of this report is as follows. The Background section provides the context to the analysis presented in this report. The Detailed Cost Discussion for Gathering section provides a detailed discussion of each cost parameter for gathering systems either missing or revised from the analysis shown in the RIA. The Detailed Cost Discussion for Transmission section provides a discussion of the cost parameters that were missing or required revisions, including the application of the power law distribution. The Significant Costs Lacking Data for Analysis section provides a discussion of known cost parameters without easily applicable methods of estimation from present data. Appendix A provides a listing of a variety of issues ICF determined when reviewing PHMSA's calculations. Appendices B, C, and D provide all recalculated tables from the RIA that relate to gathering systems, transmission systems, and the RIA appendix itself respectively.

1 Background

In this report, ICF discusses the results of analyzing PHMSA's proposed rules - 49 C.F.R. Parts 191 and 192. For this effort, ICF analyzes both the proposed rules and PHMSA's Regulatory Impact Analysis. ICF determines the magnitude of unaccounted for or underestimated costs based on our assessment, industry inputs, and expert opinion, following PHMSA's proposed methodology in the RIA where possible. ICF calculates all applicable pipeline mileage estimates revised using HPDI data using well mapping and company location. ICF considers cost for both existing pipeline that must now comply with regulation based on the revised definition of gathering pipeline in the proposal and newly installed pipeline that will require additional standards in the future. ICF developed this analysis by directly interpreting the language in the rule, without presumptions for any inconsistencies created by the proposed regulation.

2 Detailed Cost Discussion for Gathering

2.1 Estimation of Gathering Mileage

2.1.1 ICF Estimates for Miles of Gathering Line, Number of Gathering Companies, and "Incidental Gathering" Miles that will Shift from Gathering to Transmission Status

The cost-benefit analysis requires estimates for the number of miles of gathering line and the number of companies potentially impacted by the proposed regulations. ICF independently estimates those values and related statistics for its re-estimation of the economic costs and benefits of the proposed rules. This report discusses the methodologies employed by ICF for these estimates below.

2.1.2 Miles of Gathering Line

No comprehensive statistics exist for the number of miles of gathering line in the United States and only a few statistics related to gathering miles within any given state are available. To prepare the RIA, PHMSA estimated the number of gathering miles as 355,509. PHMSA computed the number of unregulated pipeline miles by taking a survey submitted by the American Petroleum Institute (Re: Pipeline Safety: Safety of Gas Transmission Pipelines, Docket No. PHMSA-2011-0023, October 23, 2012) representing data from 45 operators and assumed these operators to represent 70% of the total universe of unregulated gathering line miles. This PHMSA estimate includes both 344,086 currently unregulated miles (RIA Table ES-4) with an additional 11,424 regulated miles to give a value of 355,509 total gathering line miles.

ICF estimates gathering line miles through geographical information system (GIS) processing of gas-producing well data. ICF estimates 399,579 miles of gathering lines as of the end of 2015. Table 6 includes the ICF estimates for gathering line miles by type along with PHMSA's estimates.

The ICF methodology for estimating gathering system miles consist of the following steps.

1. Identify the latitude and longitude of all onshore wells producing gas in 2010 and 2015 using the Drilling Info Inc. HPDI database.
2. Use a "Euclidean minimum spanning tree" GIS algorithm to create minimum length straight-lines that link all wells within specific geographic areas together to create hypothetical production/gathering systems. Add up the miles of these links by state.
3. Adjust the miles to account for the fact that production/gathering lines do not follow straight lines and that redundant gathering systems sometime serve the same area.
4. Calibrate this adjustment factor of 17% to match the production/gathering line miles report by the Texas Railroad Commission.[1]
5. Separate production system miles from gathering line miles based on assuming a certain number of production line feet associated per well.
6. Add another 2,905 miles of gathering line to connect those GIS-estimated well gathering line networks to gas processing plants.

[1] See: http://www.rrc.texas.gov/pipeline-safety/reports/texas-pipeline-system-mileage/

ICF sums the number of miles by state into PHMSA cost regions so that the unit cost items can use appropriate region-specific cost factors. The "West (Except West Coast), Central, Southwest" region has 73.9% of the miles, the "South, West Coast" region has 2.2% and the "East" region has 23.9%.

Table 6

Estimation of Gathering Line

PHMSA Previous Designation	Proposed New PHMSA Designation	ICF Designation	PHMSA Estimate	Revised Estimate
Type A	Type A Area 1[1]	Type A Area 1[1]	7,844	7,844
Type B (includes Area 1 and Area 2)[1]	Type B (includes Area 1 and Area 2)[1]	Type B (includes Area 1 and Area 2)[1]	3,580	3,580
Unregulated	Type A, Area 2 (Class 1, high stress, ≥ 8")[1,3]	Type A, Area 2 (Class 1, high stress, ≥ 8")[1,3]	68,749	77,554
Unregulated	Unregulated	Type A -Unregulated (Class 1, high stress < 8)[2,3]	101,316	114,292
Unregulated	Unregulated	Type A -Unregulated (Class 1, high stress: with no diameter records were assumed to be less < 8.)[2,3]	19,346	21,823
Unregulated	Unregulated	Type B - Unregulated (Class 1 and some Class 2, low stress, all sizes)[2,3]	154,676	174,486
Total			**355,509**	**399,579**

1. Area 1 and Area 2 are defined individually for Type A and Type B pipe and are not consistent between the two designations of pipe

2. Pipe designated as unregulated in this table still is required to adhere to specific provisions in the proposed regulation.

3. Designations are based on GIS mapping for total miles of gas gathering pipe with each category determined based on ratios of each category estimated from a 2012 API survey

2.1.3 Number of Gas Gathering Companies

As shown in Table 7, ICF estimates 3,597 gathering companies potentially affected by the proposed rule compared to the PHMSA estimate of only 367. PHMSA's estimate of the number of operators currently reporting regulated Type A and Type B gathering lines to PHMSA appears in RIA Table 2-2. The RIA also used this number of reporters to compute compliance cost estimates. While PHMSA assumes operators that do not currently have regulated miles contribute 3% of Type A Area 2 miles, PHMSA does not add any newly regulated gathering line operators to drive cost estimates. Thus, PHMSA considers the number of regulated gathering operators subject to the new rule as the current number of regulated operators for the purpose of cost estimates.

ICF derives the estimate for gathering line operators by assuming that the average gatherer operates roughly 111 miles of onshore gathering line. ICF computes this average size using two methods. In the first method, ICF processes the GIS-estimated gathering line miles for the five states (Texas, Louisiana, New Mexico, Oklahoma and Kansas) that report the name of the gas gatherer in their state natural gas production data as compiled in the HPDI oil and gas well database. Adjusting for affiliated companies (that is, combining affiliated companies under a single parent name), a total of 1,576 gathering line operators exist in those five states with an average of roughly 130 miles of gathering line per gathering line operator. Table 7 below shows the size distribution of these companies by miles of gathering line. The distribution contains a large number of very small operators with approximately 60% of operators have 10 or fewer miles.

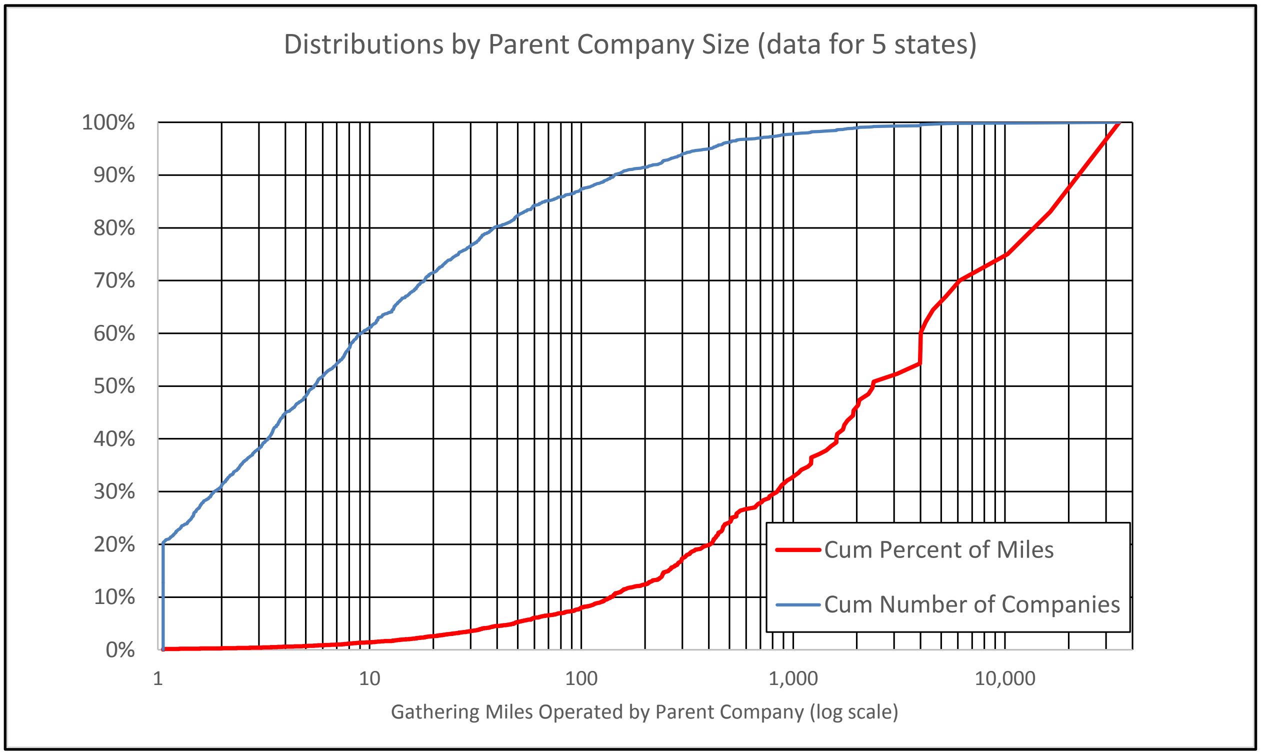
In a second method, ICF looks at the gathering line miles reported by the 104 gatherers reporting their mileage to the state of Pennsylvania[2] and computes an average miles per operator of approximately 110 miles.

Table 7

Estimation of Gathering Companies		
	PHMSA Estimate	**ICF Estimate**
Number of Operators	367	3,597

[2] Annual gatherer reports for the state of Pennsylvanian may be found at: http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_127_pipeline_act.aspx

Figure 1: Size Distribution Gathering Companies (data for TX, LA, NM, OK and KS)



2.1.4 Number of "Incidental Gathering" Line Miles

The term "incidental gathering" miles refers to gathering line that connect gas processing plants to gas transmission lines or to local gas distribution companies (LDCs). ICF expects such lines to change status under the proposed rule and become regulated as transmission lines. ICF estimates 1,628 miles of incidental gathering line exist using the following steps:

1. Compile the universe of gas processing plants from the Energy Information Administration,[3] excluding a few plants that process CO_2 only.
2. Identify processing plants directly connected to interstate gas transmission lines using the pipeline bulletin board data compiled in the PointLogic databases.[4]
3. Assume that the plants in PointLogic directly connects to interstate pipeline since the pipeline bulletin board receipt point is named for a gas processing plant. The processing plants have no associated incidental gathering miles.
4. Assume that some existing plants connect to intrastate pipeline and to LDCs. 86% of gas processing plants connect directly to transmission lines and 14% (or 81 plants) connect through incidental gathering line.
5. Assuming 20 miles of line from each plant, compute that 1,628 miles of incidental gathering line exist.

2.2 Missing Cost for Implementation of the Rule for Gathering Pipeline

2.2.1 Cost Basis

All gathering operators must evaluate the proposed regulation and determine whether they will need to comply with new requirements. To accomplish this, operators must provide qualified personnel enough time to understand regulation requirements and identify total applicable mileage. ICF considers this cost by determining the amount of personnel required and the number of hours needed to evaluate what an operator must provide in order to comply. ICF considers this as a one-time cost over the course of one year. PHMSA's proposed RIA does not account for this cost.

2.2.2 Major Assumptions and Caveats

- ICF considers 3,597 systems that must determine what information they need to comply.
- ICF considers that it will take 500 hours to understand and evaluate the rule.

2.2.3 Cost Results

The tables below show the results of ICF's estimates for the cost to implement PHMSA's proposed rule. ICF estimates a net present value cost over 1 year of $264.4 million at a 7% discount rate ($264.4 million, 3% discount rate) from understanding implementation requirements.

[3] See: http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=

[4] PointLogic is a commercial service providing energy data. See: http://www.pointlogicenergy.com/

Table 8

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 9

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)[3]				
	Type A, Area 1 Miles[1]	**Type B, Area 1 and Area 2 Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1 Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				
3. Regulated Miles are from 2014 as that was the most recent year when the analysis started				

Table 10

Total Gathering Mileage	
Gathering Pipeline Miles	399,579
Assumed Mileage per gathering system	111
Assumed Number of Systems	**3,597**

Table 11

Labor Rates

Occupation Code	Occupation	Industry	Labor Category	Mean Hourly Wage	Total Labor Cost [1]
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
13-1041	Compliance Officers	Oil and Gas Extraction	Compliance Officer	$41	$66
23-1011	Lawyers	Oil and Gas Extraction	Lawyers	$76	$101
	Contracted Compliance personnel[2]	Oil and Gas Extraction	Contracted Compliance personnel	$225	$250

Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).

1. Total Labor Cost is mean hourly wage plus mean benefits ($25.01 per hour worked).

2. Contracted compliance personnel was an assumption based on company input

Table 12

Total Hours for Evaluating Rule per System	
Total Hours	500

Table 13

Estimated Time to Evaluate and Implement Rule per System[1]				
	Percent of Time by Labor Category	**Total Labor Cost**	**Hours per Labor Category**	**Cost**
Sr. Engineer	20%	$99	100	$9,901
Project engineer	20%	$81	100	$8,101
Operator	20%	$55	100	$5,501
Contracted Compliance personnel	40%	$250	200	$50,000
Total	**100%**	**NA**	**500**	**$73,503**
1. All companies will have to evaluate if they must follow the existing regulation				

Table 14

Total Cost to Evaluate Rule	
Total Number of Systems	3,597
Cost for Each System	$73,503
Total Cost	**$264,391,015**

Table 15

Present Value Incremental Costs			
Total (NPV with discount rate 7%)[1]	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)[1]**	**Average Annual (NPV with discount rate 3% divided by 15)**
$264,391,015	$17,626,068	$264,391,015	$17,626,068
1. Since implementation of the rule would take place in year 1, assumed all costs were in year 1			

2.3 Missing Cost for Pipeline Material Verification for Gathering Pipeline

2.3.1 Cost Basis

For existing regulated pipeline with incomplete material documentation, operators must perform verification of material on both above and below ground pipeline locations according to 192.607. This regulation applies to pipeline that lacks reliable, traceable, verifiable, and complete material verification including documentation requirements for various aspects such as the line pipe itself, fittings, valves, flanges, and components. Gathering pipeline located in High Consequence Areas, or in Class 3 or Class 4, locations must comply with this regulation.

For pipeline lacking required documentation, operators must perform destructive or non-destructive testing. To test below ground locations, 192.607 requires a minimum number of excavations that an operator must perform to verify material properties. This minimum depends on either one excavation per pipeline mile up to, but not more than, 150 excavations. If an operator determines an inconsistency based on expectations from available information for a pipeline during testing, the minimum number of excavations required increases. For instance, if an operator determines more than 2 inconsistences exist, the minimum number of excavations required increases to 2.3 times the pipeline mileage or 350 excavations, whichever is less. To determine costs, ICF considers sampling costs for above ground locations, excavation/testing costs for below ground locations based on applicable mileage, the percentage of previously regulated pipe that do not know all material records, and the percentage of pipelines that will discover inconsistencies. PHMSA's proposed RIA does not account for this cost.

2.3.2 Major Assumptions and Caveats

- ICF considers Type A and Type B gathering mileage in HCAs or Class 3 or 4 locations.
- ICF considers that 99% of pipe will be below ground and 80% of those do not know all material records.
- ICF considers a cost of $75,000 to excavate for Class 3 locations and $100,000 for Class 4 locations.

2.3.3 Cost Results

The tables below show the results of ICF's estimates for the cost to verify pipeline material. ICF determines the applicable mileage and the number of tests for each pipeline system, and then multiples by a cost for material testing per mile. ICF estimates a net present value cost over 15 years of $315 million at a 7% discount rate ($397.5 million, 3% discount rate) not included in the RIA from material verification.

Table 16

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)

Type	Type A Miles[1]	Type B Miles[2]	Total Miles	Number of Operators	Average Size of System
Total Regulated Miles	7,844	3,580	11,423	367	31
Class 3 Miles	2,783	1,543	4,326	297	15
Class 4 Miles	29	11	40	15	3

Source: PHMSA Pipeline Data Mart

1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.

2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations

Table 17

Estimated Mileage that will be effected by 192.607				
Type	**Percentage of previously regulated pipe that do not know all material records[1]**	**Overall Percentage of Pipe that is Steel**	**Percentage of Pipe Below Ground/Above Ground[2]**	**Mileage that do not have records for underground pipe**
Type A, Class 3 and 4 Underground Miles	80%	95%	99%	2,120
Type A, Class 3 and 4 Above Ground Miles	1%	95%	1%	0.3
Type B Class 3 and 4 Underground Miles	80%	82%	99%	1,006
Type B Class 3 and 4 Above Ground Miles	1%	82%	1%	0.1
Total Underground Miles	**NA**	**NA**	**NA**	**3,126**
Total Above Ground Miles	**NA**	**NA**	**NA**	**0.4**
1. Made assumption that previously regulated Type A and Type B pipe had records for most of their pipe, but not all have what is required by the material verification requirements				
2. Assumed most pipe in class 3 and 4 categories would be underground. Furthermore, any pipe above ground would have reduced costs since they would not need to replace sidewalks, driveways, etc.				

Table 18

Number of Gathering Systems with Corresponding Inconsistencies for Below Ground Pipe

Average Mileage Per System	Average Mileage for System	Percent of Mileage in category	Number of Systems	Percentage of newly regulated lines with 0 inconsistency	Percentage of newly regulated lines with 1 inconsistency	Percentage of newly regulated lines with 2 inconsistency	Percentage of newly regulated lines with > 2 inconsistency	Number of systems with 0 inconsistency	Number of systems with 1 inconsistency	Number of systems with 2 inconsistency	Number of systems with >2 inconsistency
<50	25	93%	116	20%	30%	30%	20%	23	35	35	23
50-100	75	4%	1.7	15%	25%	25%	35%	0.3	0.4	0.4	0.6
100-150	125	2%	0.5	10%	20%	20%	50%	0.1	0.1	0.1	0.3
>150	200	1%	0.2	5%	15%	15%	65%	0.0	0.0	0.0	0.1

Table 19

Total Number of Excavations for Below Ground Pipe

Inconsistencies	0	1	2	>2	Total
Maximum Excavations	150	225	300	350	
Mileage times factor	1	2	2	2	
<50	581	1,308	1,744	1,337	4,971
50-100	19	47	63	101	229
100-150	6	19	25	72	122
>150	1.2	5	7	36	49
Total Excavations	**608**	**1,379**	**1,839**	**1,545**	**5,371**

Table 20

Number of Gathering Systems with Corresponding Inconsistencies for Above Ground Pipe											
Average Mileage Per System	**Average Mileage for System**	**Percent of Mileage in category**	**Number of Systems**	**Percentage of newly regulated lines with 0 inconsistency**	**Percentage of newly regulated lines with 1 inconsistency**	**Percentage of newly regulated lines with 2 inconsistency**	**Percentage of newly regulated lines with > 2 inconsistency**	**Number of systems with 0 inconsistency**	**Number of systems with 1 inconsistency**	**Number of systems with 2 inconsistency**	**Number of systems with >2 inconsistency**
<50	25	93%	0.01	20%	30%	30%	20%	0.0	0.0	0.0	0.0
50-100	75	4%	0.0	15%	25%	25%	35%	0.0	0.0	0.0	0.0
100-150	125	2%	0.0	10%	20%	20%	50%	0.0	0.0	0.0	0.0
>150	200	1%	0.0	5%	15%	15%	65%	0.0	0.0	0.0	0.0

Table 21

Total Number of Samples for Above Ground Pipe[1]					
Inconsistencies	**0**	**1**	**2**	**>2**	**Total**
Maximum Excavations	150	225	300	350	
Mileage times factor	1	2	2	2	
<50	0.02	0.06	0.07	0.06	0.2
50-100	0.00	0.00	0.00	0.00	0.0
100-150	0.00	0.00	0.00	0.00	0.0
>150	0.00	0.00	0.00	0.00	0.0
Total Excavations	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**

1. Assumed above ground pipe would do pipeline testing 1/3 as often as underground pipe

Table 22

Cost Breakdown for Excavations and Testing		
	Class 3	**Class 4**
Cost Per Excavation including removing of coupon plus repair[1]	$75,000	$100,000
Assumed Percentage of Cost Associated with Testing	50%	50%
Cost plus Testing of Underground Pipe	$75,000	$100,000
Cost of Testing of Above Ground Pipe	$37,500	$50,000
1. Assumed a cost for replacing sidewalks, driveways, and taking a sample and fixing pipe after.		

Table 23

Estimated Annual Cost				
	Underground Pipe		**Above Ground Pipe**	
	Class 3	**Class 4**	**Class 3**	**Class 4**
Percent of Pipe in Each Class	99%	0.9%	99%	0.9%
Number of Pipe Excavations	5322	49	0.2	0.0
Cost Per Excavation plus removing of coupon plus repair	$75,000	$100,000	$37,500	$50,000
Cost of Excavations	$399,167,991	$4,899,896	$8,400	$103
Annual Cost	$26,611,199	$326,660	$560	$7
G&A Cost	$5,322,240	$65,332	$112	$1
Total Annual Cost	**$31,933,439**	**$391,992**	**$672**	**$8**

Table 24

Present Value Incremental Costs			
7% Discount Rate		**3% Discount Rate**	
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$315,033,082	$21,002,205	$397,484,228	$26,498,949

2.4 Missing Cost for MAOP Determination for Regulated Pipeline for Gathering Pipeline

2.4.1 Cost Basis

All regulated gathering pipeline must determine the maximum allowable operating pressure (MAOP) in order to comply with regulations set forth in 192.619(e) and 192.624. Operators may determine MAOP using a number of different methods. An existing pipeline system may know MAOP prior to regulation or, if known, operators of a pipeline deemed in satisfactory condition based on maintenance history may consider pressure records for the past five years of the pipe and select the highest actual operating pressure as the MAOP (also known as a 'lookback period'). The date in which an operator must know previous operating pressure records depends on the classification of pipe.

Operators unable to implement the above methods (either through a known MAOP value or lookback period pipeline) may use pressure testing, pressure reduction, or direct assessment (ECA/ILI) as a method to determine MAOP. Each of these methods have a corresponding cost which impact the implementation of the requirements of 192.619. ICF considers an associated cost with each method which varies by pipeline diameter of applicable mileage. ICF distributes applicable mileage and costs to each test to determine the amount operators must spend to comply.

For all regulated gathering line, those that do not have adequate records or sufficient pressure records to fulfill the lookback period must determine MAOP. For existing regulated gathering lines, if the pipeline exists in a HCA or Class 3 or Class 4, the operator must verify MAOP using the proposed methods in 192.624 regardless of either the lookback period or known pressure records. PHMSA's proposed RIA does not account for this cost.

2.4.2 Major Assumptions and Caveats

- ICF considers 90% of Type A Area 2 gathering lines do not have adequate records and of those 56% cannot be grandfathered in.
- ICF considers 10% of Type A Area 1 and Type B gathering lines do not have adequate records and of those 56% cannot use the lookback period.
- ICF considers for Type A Area 2 gathering lines, 5% perform inline inspection, 90% perform pressure testing, and 5% perform upgrades to allow inline inspection.
- ICF considers for Type A Area 1 and Type B gathering lines, 5% perform inline inspection, 90% perform pressure testing, and 5% perform upgrades to allow inline inspection.

2.4.3 Cost Results

The tables below show the results of ICF's estimates for the cost to determine or verify MAOP for regulated pipeline. ICF determines the applicable mileage and the cost of each test for each pipeline system, and then multiples by the cost of testing per applicable mile. ICF estimates a net present value cost over 15 years of $4.3 billion at a 7% discount rate ($5.4 billion, 3% discount rate) not included in the RIA from determination of MAOP.

Table 25

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 26

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Class 3 and Class 4 Miles	2,812	1,499	4,312	301
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 27

Determining Previously Untested Pipe within Gathering Lines									
Type	**Estimated Mileage**	**Pipeline in Category that rule applies to**	**Mileage from the past 5 years that would be expected to have records**	**Percent of Gathering Lines that have MAOP records[1]**	**Percent of Gathering Lines that do not have pressure records to comply with the rule or do not meet the safety buffer criteria[1]**	**Pipelines that need to verify MAOP**	**Percent in Class 3 and 4**	**Mileage in Class 3, Class 4**	**Mileage not in Class 3, Class 4**
Type A, Area 2 (high stress, ≥ 8")	72,212	100%	5,341	10%	56%	33,435	0.0%	0	33,435
Type A, Area 1, and Type B Area 1 and Area 2	11,423	100%	0	90%	56%	635	38%	240	395
Total	**83,636**	**NA**	**NA**	**NA**		**34,070**	**NA**	**240**	**33,831**
1. Assumed mileage from the past 5 years have records. Of the remaining pipeline, assumed 20% don't have records and 50% of the remaining can use the pressure lookback period to comply.									

Table 28

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]			
	Type A, Area 2 (high stress, ≥ 8")		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8
Pipe thickness (inches)	0.4	0.4	0.3
Segment Miles	60	60	60
Number of Mainline Valves	3	3	3
Number of Bends	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583
Gas Released per Mile (MCF)[4]	286	78	19
Cost of Gas Released per Mile[5]	$1,203	$327	$79
Percentage of pipe that would have to be replaced	5%	5%	5%
Cost to replace per inch mile	120,000	120,000	120,000
G&A Cost[7]	45,161	24,992	12,532
Total Unit Cost (per mile)[6]	**$225,803**	**$124,960**	**$62,662**
HCA = high consequence area MCF = thousand cubic feet			
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.			
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.			
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.			

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs

Table 29

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]

	Type A, Area 2 (high stress, ≥ 8")		
	26" - 48"	**14" - 24"**	**4" - 12"**[2]
Diameter (inches)	30	16	8
Segment Miles	45	45	45
Number of Mainline Valves	3	3	3
Number of Bends	6	6	6
Cost per Mainline Valve	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,856,000	$1,814,000	$923,000
Upgrade Costs per Mile	$63,467	$40,311	$20,511
Gas Released per Mile (MCF)[4]	286	78	19
Cost of Gas Released per Mile[5]	$1,203	$327	$79
Percentage of pipe that would have to be replaced	5%	5%	5%
Cost to replace per inch mile	120,000	120,000	120,000

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]			
G&A Cost[7]	48,934	27,328	13,718
Total Unit Cost (per mile)[6]	**$293,603**	**$163,966**	**$82,308**
HCA = high consequence area MCF = thousand cubic feet			
PHMSA = Pipeline and Hazardous Materials Safety Administration			
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.			
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.			
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.			
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.			
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.			
6. Upgrade cost plus cost per mile plus the cost of gas release per mile.			
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 30

Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools					
Type	**Pipeline Diameter**			**Weighted Average Cost per Mile**	
	> 26"	**14" - 24"**	**<12"**	**Class 1 and 2**	**Class 3 and 4**
Type A, Area 2 (high stress, ≥ 8")	3%	25%	72%	$82,973	$108,852
Type A. Area 1 and Type B Area 1 and Area 2	0.3%	12%	88%	$70,513	$92,592

Table 31

Estimated Unit Cost of ILI for 60 Mile Segments			
Component	**Cost from Interstate (60-mile) Segment used as a Proxy for Gathering**		
	26" - 48"	14" - 24"	4" - 12"
Mobilization[1]	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000
Additional combo tool (deformation & crack tools)	$340,000	$322,000	$304,000
Reruns	$63,000	$50,400	$37,800
Analytical and data integration services	$80,000	$80,000	$80,000
Operator preparation [3]	$27,000	$23,050	$19,100
G&A Cost[4]	$123,000	$111,990	$100,980
Total	**$738,000**	**$671,940**	**$605,880**
Source: PHMSA best professional judgment.			
1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.			
2. Typically $900 to $1,500 per mile.			
3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.			
4. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 32

Estimation of ILI Assessment Cost				
Segment Type	**Less than 12" Diameter**	**14" - 24"**	**Greater than 26" Diameter**	**Weighted Average Cost Per Mile**
Type A, Area 2 (high stress, ≥ 8")	72%	25%	3%	$10,436
Type A. Area 1 and Type B Area 1 and Area 2	88%	12%	0.3%	$10,235

Table 33

Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	$297,205	$325,730	$399,940	$877,272
24	$375,000	$420,000	$720,000	$1,160,769
36	$578,424	$738,787	$1,018,202	$2,053,359
Source: T.D. Williamson, Inc., Houston, TX - was used to determine 24 inch pressure test costs				
Source: Greene's Energy Group, LLC (2013), - Ratios from Green's Energy Group report were used to take T.D. Williamson's 24 inch diameter figures and determine 12 inch and 36 inch pipe				

Table 34

Volume of Gas Lost During Pressure Tests (MCF)				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	48	96	240	481
24	192	385	962	1,923
36	433	866	2,164	4,328
MCF = thousand cubic feet				
1. Estimated using Equation 1.				

Table 35

Cost of Lost Gas[1]					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1 Mile	**2 Mile**	**5 Mile**	**10 Mile**	**Average**
12	$274	$548	$1,370	$2,741	$1,233
24	$1,096	$2,193	$5,482	$10,964	$4,934
36	$2,467	$4,934	$12,334	$24,668	$11,101
1. Calculated based on volume lost (see Table Volume of Gas Lost During Pressure Tests (MCF)) times the cost of gas ($5.71 per thousand cubic feet).					

Table 36

Total Pressure Test Assessment Cost: Gathering Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12 inch				
Pressure test[1]	$356,646	$390,876	$479,928	$1,052,726
Lost gas[2]	$274	$548	$1,370	$2,741
Alternative supply	$0.0	$0.0	$0.0	$0.0
Total	$356,920	$391,424	$481,298	$1,055,467
24 inch				
Pressure test[1]	$450,000	$504,000	$864,000	$1,392,923
Lost gas[2]	$1,096	$2,193	$5,482	$10,964
Alternative supply	$0.0	$0.0	$0.0	$0.0
Total	$451,096	$506,193	$869,482	$1,403,887
36 inch				
Pressure test[1]	$694,109	$886,544	$1,221,843	$2,464,030
Lost gas[2]	$2,467	$4,934	$12,334	$24,668
Alternative supply	$0.0	$0.0	$0.0	$0.0
Total	$696,576	$891,478	$1,234,177	$2,488,698
1. Unit costs (see Table Estimated Cost of Conducting Pressure Test ($2015)) plus 20% G&A				
2. See Cost of Lost Gas				

Table 37

Per Mile Pressure Test Costs					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1	**2**	**5**	**10**	**Average**
Gathering					
12	$356,920	$195,712	$96,260	$105,547	$188,609
24	$451,096	$253,096	$173,896	$140,389	$254,619
36	$696,576	$445,738.97	$246,835.33	$248,869.85	$409,505

Table 38

Estimated Assessment Method for Gathering Pipe				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Type A, Area 2 (high stress, ≥ 8")	72%	27%	1%	$207,635
Type A. Area 1 and Type B Area 1 and Area 2	88%	12%	0.0%	$196,650

Table 39

Estimated Assessment Method for Gathering Pipe				
Location	**ILI**	**Pressure Test**	**ILI and Upgrade**	**Total**
Type A, Area 2 (high stress, ≥ 8")	5%	90%	5%	1
Type A, Area 1, and Type B Area 1 and Area 2 and Area 2	5%	90%	5%	1
Mileage Subject to Testing Type A, Area 2 (high stress, ≥ 8")	1,672	30,092	1,672	33,435
Mileage Subject to Testing Type A, Area 1, and Type B Area 1 and Area 2	32	571	32	635
Total Annual Cost - Type A Area 2	**1,163,109**	**416,542,604**	**10,410,524**	**428,116,237**
Total Annual Cost - Type A Area 1 and Type B Area 1 and Area 2	**21,651**	**7,487,999**	**188,446**	**7,698,096**

Table 40

Natural Gas Composition	
Gas	**Percent of Volume**
Methane (CH_4)	96%
Carbon dioxide ($C0_2$)	1%
Other Fluids	3%
Source: Estimated based on natural gas quality standards and operator reported measurements	
Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural- Gas	

Table 41

Proportion of Gas Gathering Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Type A, Area 2 (high stress, ≥ 8")	72%	27%	1%
Type A. Area 1 and Type B Area 1 and Area 2	88%	12%	0%
Source: 2014 Gas Transmission Annual Report			

Table 42

GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Natural Gas Composition Table lbs. = pounds			
MCF = thousand cubic feet			

Table 43

GHG Emissions from Pressure Tests per Assessment Mile[1]			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs.)**
Type A, Area 2 (high stress, ≥ 8")	202	193	300
Type A. Area 1 and Type B Area 1 and Area 2	151	144	224
lbs. = pounds			
MCF = thousand cubic feet			
1. Weighted average based on share of pipeline mileage by diameter.			

Table 44

Total GHG Emissions from Pressure Test Blowdowns				
Item	**PT Miles**	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
Re-establish MAOP: Type A, Area 2 (high stress, ≥ 8")	30,092	6,070,259	5,809,238	9,027,689
Re-establish MAOP: Type A. Area 1 and Type B Area 1 and Area 2	571	86,178	82,473	128,164
Total	**30,663**	**6,156,437**	**5,891,710**	**9,155,853**
PT = pressure test				
MCF = thousand cubic feet				

Table 45

Average Diameter in for Applicable Miles			
	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Type A, Area 2 (high stress, ≥ 8")	9.6	18.2	29.8
Type A. Area 1 and Type B Area 1 and Area 2	6.7	18.6	30.2

Table 46

Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)			
Location	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Type A, Area 2 (high stress, ≥ 8")	27.7	101.3	282.6
Type A. Area 1 and Type B Area 1 and Area 2	12.9	106.3	289.1
MCF = thousand cubic feet			
Source: See Equation 1 in Section 3.1.4.3			

Table 47

Proportion of Gas Gathering Mileage by Diameter			
Segment Type	≤ 12" Diameter	14"-24" Diameter	≥ 26"Diameter
Type A, Area 2 (high stress, ≥ 8")	72%	25%	3%
Type A. Area 1 and Type B Area 1 and Area 2	88%	12%	0%
Source: 2014 Gas Transmission Annual Reports			

Table 48

GHG Emissions from Blowdowns, ILI Upgrade (per Mile)			
Location	**Gas Released (MCF)**	**Methane Emissions (MCF)**	**$C0_2$ Emissions (lbs.)**
Type A, Area 2 (high stress, ≥ 8")	54	51	80
Type A. Area 1 and Type B Area 1 and Area 2	25	24	37

Table 49

Total GHG Emissions due to Blowdowns				
Item	**ILI Upgrade Miles**	**Gas Released (MCF)**	**Methane Emissions (MCF CH_4)**	**C02 Emissions (lbs.)**
Re-establish MAOP: Type A, Area 2 (high stress, ≥ 8")	1,672	89,642	85,787	133,315
Re-establish MAOP: Type A. Area 1 and Type B Area 1 and Area 2	32	787	753	1,170
Total	**1,704**	**90,428**	**86,540**	**134,485**
CO_2 = carbon dioxide CH_4 = methane				
GHG = greenhouse gas				
HCA = high consequence area ILI = inline inspection				
MAOP = maximum allowable operating pressure MCF = thousand cubic feet				
SMYS = specified minimum yield strength				

Table 50

Total Emissions Per Year			
Item	**Gas Released (MCF)**	**Methane Emissions (MCF CH4)**	**C02 Emissions (lbs.)**
Re-establish MAOP: Type A, Area 2 (high stress, ≥ 8")	410,660	393,002	610,734
Re-establish MAOP: Type A. Area 1 and Type B Area 1 and Area 2	5,798	5,548	8,622
Total	**416,458**	**398,550**	**619,356**
CO_2 = carbon dioxide CH_4 = methane			
HCA = high consequence area lbs. = pounds			
MAOP = maximum allowable operating pressure MCF = thousand cubic feet			
SMYS = specified minimum yield strength			

Table 51

Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)				
Topic Area 1 Scope	**Average Annual Methane Lost from Blowdown (MCF)**			**Average Annual**
	ILI Upgrade	**Pressure Test**	**Total**	**Social Cost [1]**
Previously untested in HCA	5,719	387,283	393,002	$11.6
HCA and Class 3 and 4 with inadequate records	50	5,498	5,548	$0.2
Subtotal	5,769	392,781	398,550	$11.7
MCF = thousand cubic feet				
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).				

Table 52

	2016	2017	2018	2019	2020	2021	2022	2023
Social cost of methane	25	25	26	26	26	27	28	29
Previously untested in HCA	$9,825,041	$9,825,041	$10,218,043	$10,218,043	$10,218,043	$10,611,044	$11,004,046	$11,397,048
HCA and Class 3 and 4 with inadequate records	$138,709	$138,709	$144,257	$144,257	$144,257	$149,806	$155,354	$160,902

Table 53

	2024	2025	2026	2027	2028	2029	2030
Social cost of methane	30	31	32	33	34	34	35
Previously untested in HCA	$11,790,049	$12,183,051	$12,576,053	$12,969,054	$13,362,056	$13,362,056	$13,755,058
HCA and Class 3 and 4 with inadequate records	$166,451	$171,999	$177,547	$183,096	$188,644	$188,644	$194,192

Table 54

Present Value Costs Discounted at 7%, Topic Area 1						
Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Type A Area 1, 2 and Type B Area 1 and Area 2	$4,247,214,635	$11,717,370	$4,258,932,005	$283,147,642	$781,158.0	$283,928,800

Table 55

Present Value Costs Discounted at 3%, Topic Area 1						
Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Type A Area 1, 2 and Type B Area 1 and Area 2	$5,358,804,921	$11,717,370	$5,370,522,291	$357,253,661	$781,158.0	$358,034,819

Table 56

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	Average Annual (NPV with discount rate 7% divided by 15)	Total (NPV with discount rate 3%)	Average Annual (NPV with discount rate 3% divided by 15)
$4,258,932,005	$283,928,800	$5,370,522,291	$358,034,819

2.5 Missing Cost for MAOP Determination for Unregulated Pipeline for Gathering Pipeline

2.5.1 Cost Basis

According to requirements under 191.23 and 191.25, an operator must report any malfunction that causes the pressure of a gathering pipeline to exceed the MAOP as this is a safety-related condition. Because of this, an operator must first determine the MAOP in order to know whether an exceedance has occurred. This requirement applies to all gathering line, regardless of whether the pipeline is regulated or not. ICF considers the cost to determine MAOP for all unregulated gathering pipeline in a very similar fashion as regulated gathering lines in the previous section, with revisions to applicable mileage and assumptions. PHMSA's proposed RIA does not account for this cost.

2.5.2 Major Assumptions and Caveats

- ICF considers 95% of unregulated gathering lines do not have adequate records and of those 63% cannot be grandfathered in.
- ICF considers for unregulated gathering lines 100% perform pressure testing.

2.5.3 Cost Results

The tables below show the results of ICF's estimates for the cost to determine MAOP for unregulated pipeline. ICF determines the applicable mileage and the cost of each test for each pipeline system, and then multiples by the cost for testing per applicable mile. ICF estimates a net present value cost over 15 years of $19.9 billion at a 7% discount rate ($25.1 billion, 3% discount rate) not included in the RIA from determination of MAOP.

Table 57

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines 1,2

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 58

Determining Previously Untested Pipe within Gathering Lines									
Type	**Estimated Unregulated Mileage**	**Pipeline in Category that rule applies to**	**New Mileage that would be expected to have records**	**Percent of Gathering Lines that have MAOP records**	**Percent of Gathering Lines that do not have pressure records to comply with the rule or do not meet the safety buffer criteria[1]**	**Pipelines that need to verify MAOP**	**Percent in Class 3 and 4**	**Mileage in Class 3, Class 4**	**Mileage not in Class 3, Class 4**
Type A -unregulated (high stress < 8)	106,420	100%	7,872	5%	63%	59,129	0.0	0	59,129
Type A -unregulated (high stress: with no diameter records- assumed to be less < 8)	20,320	100%	1,503	5%	63%	11,290	0.0	0	11,290
Type B - unregulated (low stress, all sizes)	162,469	100%	12,018	5%	63%	90,271	0.0	0	90,271
Total	**289,209**	**NA**	**21,392**	**NA**	**NA**	**160,690**	**NA**	**0**	**160,690**
1. Assumed mileage from the past 5 years have records. Of the remaining pipeline, assumed 20% don't have records and 50% of the remaining canuse the pressure lookback period to comply.									

Table 59

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]

	Type A, Area 2 (high stress, ≥ 8")		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8
Pipe thickness (inches)	0.375	0.375	0.25
Segment Miles	60	60	60
Number of Mainline Valves	3	3	3
Number of Bends	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583
Gas Released per Mile (MCF)[4]	286	78	19
Cost of Gas Released per Mile[5]	$1,203	$327	$79
Percentage of pipe that would have to be replaced	5%	5%	5%
Cost to replace per inch mile	120,000	120,000	120,000
G&A Cost[7]	45,161	24,992	12,532
Total Unit Cost (per mile)[6]	**$225,803**	**$148,960**	**$134,662**

HCA = high consequence area MCF = thousand cubic feet

1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4” generally cannot accommodate in-line inspection and will be exempt from requirements.

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs

Table 60

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]

	Type A, Area 2 (high stress, ≥ 8")		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8
Segment Miles	45	45	45
Number of Mainline Valves	3	3	3
Number of Bends	6	6	6
Cost per Mainline Valve	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,856,000	$1,814,000	$923,000
Upgrade Costs per Mile	$63,467	$40,311	$20,511
Gas Released per Mile (MCF)[4]	286	78	19
Cost of Gas Released per Mile[5]	$1,203	$327	$79

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]			
Percentage of pipe that would have to be replaced	5%	5%	5%
Cost to replace per inch mile	120,000	120,000	120,000
G&A Cost[7]	48,934	27,328	13,718
Total Unit Cost (per mile)[6]	**$293,603**	**$163,966**	**$82,308**
HCA = high consequence area MCF = thousand cubic feet			
PHMSA = Pipeline and Hazardous Materials Safety Administration			
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.			
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.			
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.			
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.			
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.			
6. Upgrade cost plus cost per mile plus the cost of gas release per mile.			
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 61

Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools					
Type	**Pipeline Diameter**			**Weighted Average Cost per Mile**	
	> 26"	**14" - 24"**	**<12"**	**Class 1 and 2**	**Class 3 and 4**
Type A -unregulated (high stress < 8)	0%	0%	100%	$134,662	$82,308
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	0%	0%	100%	$134,662	$82,308
Type B - unregulated (low stress, all sizes)	0%	6%	94%	$135,549	$87,047

Table 62

Estimated Unit Cost of ILI for 60 mile segments			
Component	**Cost from Interstate (60-mile) Segment used as a Proxy for Gathering**		
	26" - 48"	**14" - 24"**	**4" - 12"**
Mobilization[1]	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000
Additional combo tool (deformation & crack tools)	$340,000	$322,000	$304,000
Reruns	$63,000	$50,400	$37,800
Analytical and data integration services	$80,000	$80,000	$80,000
Operator preparation[3]	$27,000	$23,050	$19,100
G&A Cost[4]	$123,000	$111,990	$100,980
Total	**$615,000**	**$559,950**	**$504,900**
Source: PHMSA best professional judgment.			
1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.			
2. Typically $900 to $1,500 per mile.			
3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.			
4. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 63

Estimation of ILI Assessment Cost				
Segment Type	**Less than 12" Diameter**	**14" - 24"**	**Greater than 26" Diameter**	**Weighted Average Cost Per Mile**
Type A -unregulated (high stress < 8)	100%	0%	0%	$8,415
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	100%	0%	0%	$8,415
Type B - unregulated (low stress, all sizes)	94%	6%	0%	$8,468

Table 64

Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	$297,205	$325,730	$399,940	$877,272
24	$375,000	$420,000	$720,000	$1,160,769
36	$578,424	$738,787	$1,018,202	$2,053,359
Source: T.D. Williamson, Inc., Houston, TX - was used to determine 24 inch pressure test costs				
Source: Greene’s Energy Group, LLC (2013), - Ratios from Green's Energy Group report were used to take T.D. Williamson's 24 inch diameter figures and determine 12 inch and 36 inch pipe				

Table 65

Volume of Gas Lost During Pressure Tests (MCF)				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	48	96	240	481
24	192	385	962	1,923
36	433	866	2,164	4,328
MCF = thousand cubic feet				
1. Estimated using Equation 1.				

Table 66

Cost of Lost Gas					
Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$274	$548	$1,370	$2,741	$1,233
24	$1,096	$2,193	$5,482	$10,964	$4,934
36	$2,467	$4,934	$12,334	$24,668	$11,101
1. Calculated based on volume lost (see Table Volume of Gas Lost During Pressure Tests (MCF)) times the cost of gas ($5.71 per thousand cubic feet).					

Table 67

Total Pressure Test Assessment Cost: Gathering Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12 inch				
Pressure test[1]	$356,646	$390,876	$479,928	$1,052,726
Lost gas[2]	$274	$548	$1,370	$2,741
Alternative supply	$0	$0	$0	$0
Total	$356,920	$391,424	$481,298	$1,055,467
24 inch				
Pressure test[1]	$450,000	$504,000	$864,000	$1,392,923
Lost gas[2]	$1,096	$2,193	$5,482	$10,964
Alternative supply	$0	$0	$0	$0
Total	$451,096	$506,193	$869,482	$1,403,887
36 inch				
Pressure test[1]	$694,109	$886,544	$1,221,843	$2,464,030
Lost gas[2]	$2,467	$4,934	$12,334	$24,668
Alternative supply	$0	$0	$0	$0
Total	$696,576	$891,478	$1,234,177	$2,488,698
1. Unit costs (see Table Estimated Cost of Conducting Pressure Test ($2015)) plus 20% G&A				
2. See Tables 3-14.				

Table 68

Per Mile Pressure Test Costs					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1	**2**	**5**	**10**	**Average**
Gathering					
12	$356,920	$195,712	$96,260	$105,547	$188,609
24	$451,096	$253,096	$173,896	$140,389	$254,619
36	$696,576	$445,738.97	$246,835.33	$248,869.85	$409,505

Table 69

Estimated Assessment Method for Previously Untested Pipe				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Type A -unregulated (high stress < 8)	100%	0%	0%	**$188,609**
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	100%	0%	0%	**$188,609**
Type B - unregulated (low stress, all sizes)	94%	6%	0%	**$192,101**

Table 70

Estimated Assessment Method for Previously Untested Pipe				
Location	**ILI** [1]	**Pressure Test**[2]	**ILI and Upgrade**	**Total**
High stress, < 8"	0%	100%	0%	1
Type A (assumed < 8")	0%	100%	0%	1
Low stress, all sizes	0%	100%	0%	
Mileage Subject to High stress, < 8"	-	59,129	-	59,129
Mileage Subject to Type A (assumed < 8")	-	11,290	-	11,290
Mileage Subject to Low stress, all sizes	-	90,271	-	90,271
Total Annual Cost High stress, < 8"	**-**	**743,487,320**	**-**	**743,487,320**
Total Annual Cost Type A (assumed < 8")	**-**	**141,965,078**	**-**	**141,965,078**
Total Annual Cost Low stress, all sizes	**-**	**1,156,070,033**	**-**	**1,156,070,033**

Table 71

Natural Gas Composition	
Gas	**Percent of Volume**
Methane (CH_4)	96%
Carbon dioxide ($C0_2$)	1%
Other Fluids	3%
Source: Estimated based on natural gas quality standards and operator reported measurements	
Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural- Gas	

Table 72

Proportion of Gas Gathering Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Type A -unregulated (high stress < 8)	100%	0%	0%
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	100%	0%	0%
Type B - unregulated (low stress, all sizes)	94%	6%	0%
Source: 2014 Gas Transmission Annual Report			

Table 73

GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Natural Gas Composition Table lbs. = pounds			
MCF = thousand cubic feet			

Table 74

GHG Emissions from Pressure Tests per Assessment Mile[1]			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs.)**
Type A -unregulated (high stress < 8)	113	108	168
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	113	108	168
Type B - unregulated (low stress, all sizes)	130	125	194
lbs. = pounds			
MCF = thousand cubic feet			
1. Weighted average based on share of pipeline mileage by diameter.			

Table 75

Total GHG Emissions from Pressure Test Blowdowns				
Item	**PT Miles**	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
Re-establish MAOP: High stress, < 8"	59,129	6,681,589	6,394,281	9,936,859
Re-establish MAOP: Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	11,290	1,275,815	1,220,955	1,897,392
Re-establish MAOP: Type B - unregulated (low stress, all sizes)	90,271	11,750,939	11,245,649	17,475,997
Total	**70,420**	**7,957,404**	**7,615,236**	**11,834,251**
PT = pressure test				
MCF = thousand cubic feet				

Table 76

Average Diameter in for Applicable Miles			
	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Type A -unregulated (high stress < 8)	4.6	0.0	0.0
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	4.6	0.0	0.0
Type B - unregulated (low stress, all sizes)	6.1	17.7	30.1

Table 77

Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)			
Location	Diameter 12" or less	Diameter 14" to 24"	Diameter 26" and above
Type A -unregulated (high stress < 8)	5.7	0.0	0.0
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	5.7	0.0	0.0
Type B - unregulated (low stress, all sizes)	10.6	95.8	288.5
MCF = thousand cubic feet			
Source: See Equation 1 in Section 3.1.4.3			

Table 78

Proportion of Gas Gathering Mileage by Diameter			
Segment Type	≤ 12” Diameter	14"-24" Diameter	≥ 26"Diameter
Type A -unregulated (high stress < 8)	100%	0%	0%
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	100%	0%	0%
Type B - unregulated (low stress, all sizes)	94%	6%	0%
Source: 2014 Gas Transmission Annual Reports			

Table 79

GHG Emissions from Blowdowns, ILI Upgrade (per Mile)			
Location	**Gas Released (MCF)**	**Methane Emissions (MCF)**	**CO_2 Emissions (lbs)**
High stress, < 8"	6	5	8
Type A (assumed < 8")	6	5	8
Low stress, all sizes	16	15	23

Table 80

GHG Emissions from Blowdowns, ILI Upgrade (per Mile)			
Location	**Gas Released (MCF)**	**Methane Emissions (MCF)**	**CO_2 Emissions (lbs.)**
Type A -unregulated (high stress < 8)	6	5	8
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	6	5	8
Type B - unregulated (low stress, all sizes)	16	15	23

Table 81

Total GHG Emissions due to Blowdowns[1]

Item	ILI Upgrade Miles	Gas Released (MCF)	Methane Emissions (MCF CH_4)	CO_2 Emissions (lbs.)
Re-establish MAOP: High stress, < 8"	0	0	0	0
Re-establish MAOP: Type A -unregulated (high stress: with no diameter records- assumed to be less < 8)	0	0	0	0
Re-establish MAOP: Type B - unregulated (low stress, all sizes)	0	0	0	0
Total	**0**	**0**	**0**	**0**

CO_2 = carbon dioxide CH_4 = methane

GHG = greenhouse gas

HCA = high consequence area ILI = inline inspection

MAOP = maximum allowable operating pressure MCF = thousand cubic feet

SMYS = specified minimum yield strength

1. As 100% of Unregulated pipe would have to utilize pressure testing, there will be no miles under this category that will upgrade to ILI

Table 82

Total Emissions Per Year			
Item	**Gas Released (MCF)**	**Methane Emissions (MCF CH4)**	**CO_2 Emissions (lbs.)**
Re-establish MAOP: High stress, < 8"	445,439	426,285	662,457
Re-establish MAOP: Type A -unregulated (high stress: with no diameter records- assumed to be less < 8)	85,054	81,397	126,493
Re-establish MAOP: Type B - unregulated (low stress, all sizes)	783,396	749,710	1,165,066
Total	**1,313,890**	**1,257,392**	**1,954,017**
CO_2 = carbon dioxide CH_4 = methane			
HCA = high consequence area lbs. = pounds			
MAOP = maximum allowable operating pressure MCF = thousand cubic feet			
SMYS = specified minimum yield strength			

Table 83

Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)				
Topic Area 1 Scope	**Average Annual Methane Lost from Blowdown (MCF)**			**Average Annual**
	ILI Upgrade	**Pressure Test**	**Total**	**Social Cost [1]**
Type A -unregulated (high stress < 8)	0	426,285	426,285	$12.5
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	0	81,397	81,397	$2.4
Type B - unregulated (low stress, all sizes)	0	749,710	749,710	$22.0
Subtotal	0	1,257,392	1,257,392	$37
MCF = thousand cubic feet				
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).				

Table 84

	2016	2017	2018	2019	2020	2021	2022	2023
Social cost of methane	25	25	26	26	26	27	28	29
High stress, < 8"	10,657,135	10,657,135	11,083,420	11,083,420	11,083,420	11,509,705	11,935,991	12,362,276
Type A (assumed < 8")	2,034,925	2,034,925	2,116,322	2,116,322	2,116,322	2,197,719	2,279,116	2,360,513
Low stress, all sizes	10,695,955	10,695,955	11,123,793	11,123,793	11,123,793	11,551,632	11,979,470	12,407,308

Table 85

	2024	2025	2026	2027	2028	2029	2030
Social cost of methane	30	31	32	33	34	34	35
High stress, < 8"	12,788,562	13,214,847	13,641,132	14,067,418	14,493,703	14,493,703	14,919,988
Type A (assumed < 8")	2,441,910	2,523,307	2,604,704	2,686,101	2,767,498	2,767,498	2,848,895
Low stress, all sizes	22,491,298	23,241,008	23,990,718	24,740,428	25,490,138	25,490,138	26,239,848

Table 86

Present Value Costs Discounted at 7%						
Scope	**Total**			**Average Annual**		
	Compliance	**Social Cost of GHG Emissions**	**Total**	**Compliance**	**Social Cost of GHG Emissions**	**Total**
Unregulated Gathering Miles	19,895,591,486	36,967,334	19,932,558,821	1,326,372,766	2,464,489	1,328,837,255

Table 87

Present Value Costs Discounted at 3%						
Scope	**Total**			**Average Annual**		
	Compliance	**Social Cost of GHG Emissions**	**Total**	**Compliance**	**Social Cost of GHG Emissions**	**Total**
Unregulated Gathering Miles	25,102,709,119	36,967,334	25,139,676,453	1,673,513,941	2,464,489	1,675,978,430

Table 88

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$19,932,558,821	$1,328,837,255	$25,139,676,453	$1,675,978,430

2.6 Missing Cost for Compressor Stations for Gathering Pipeline

2.6.1 Cost Basis

According to requirements under 192.163, operators must house compressors in buildings made of noncombustible materials containing pipe more than 2 inches in diameter that is carrying gas under pressure or gas handling equipment other than utilization equipment used for domestic purposes. ICF considers newly regulated gathering line now subject to house compressors in the future to act as an additional cost over the current regulation. ICF considers a number of future compressor stations with a given cost to construct the required housing under the rule. PHMSA's proposed RIA does not account for this cost.

One other interpretation of this requirement could be that operators would only have to follow this requirement if a building is built. Under this interpretation, the costs presented here may be overstated.

2.6.2 Major Assumptions and Caveats

- ICF considers 1,815 future compressor stations with 19% requiring housing regulation based on newly regulated Type A Area 2 miles.
- ICF considers 25% of stations built as acceptable under the regulation.
- ICF considers $70,000 as the cost of housing.

2.6.3 Cost Results

The tables below show the results of ICF's estimates for the cost to compressor housing for newly regulated pipeline. ICF considers the applicable pipeline mileage, the number of future compressor buildings, and the cost of each building to determine the cost. ICF estimates a net present value cost over 15 years of $14.4 million at a 7% discount rate ($18.2 million, 3% discount rate) not included in the RIA from compressor housing requirements.

Table 89

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 90

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Class 3 and Class 4 Miles	2,812	7,873	7,844	301
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 91

Total Gathering Mileage	
Gathering Pipeline Miles	399,579

Table 92

Compressor Stations Newly Required to House Compressors Inside 192.163

Category	New Compression for Gathering Line Annual HP	Percentage of Pipe that will be expected to comply (Existing- retroactively and Future - upon new construction)	Count of Compressor Stations	Percent of gathering line that would have to follow the rule	Percentage of compressor stations that are not already housed in buildings that will have to be or were not planned to be housed in a building	Cost of Housing in Building	Cost to house compressors in building
Existing Compressor Stations	12,000,000	0.0%	4,000	NA	NA	NA	NA
Future Compressor Stations	5,445,000	100%	1,815	19%	75%	$70,000	$18,494,230
Total G & A Cost[1]	NA	NA	NA	NA	NA	NA	$3,698,846
Total	**17,445,000**		**5,815**				**$22,193,076**

Source: INGAA report: http://www.ingaa.org/File.aspx?id=27961&v=db4fb0ca

1. Assumed 20% G &A Cost

Table 93

Present Value Incremental Costs

Total (NPV with discount rate 7%)	Average Annual (NPV with discount rate 7% divided by 15)	Total (NPV with discount rate 3%)	Average Annual (NPV with discount rate 3% divided by 15)
$14,418,794	$961,253	$18,192,512	$1,212,834

2.7 Missing Cost for Field Repair of Damages for Gathering Pipeline

2.7.1 Cost Basis

Operators must now perform permanent field repair of imperfections and damages pending on discovered conditions under a required remediation schedule specified in 192.713. Although 192.9 states that Type A Area 1 gathering lines are excluded from this paragraph, 192.711(b)(1) states that if a discovered condition could adversely affect safe operation not covered under “Subpart O – Gas Transmission Pipeline Integrity Management”, an operator must correct the condition per 192.713. As such, ICF considers Type A Area 1 gathering lines to apply to the accelerated permanent repair condition requirements.

To interpret the cost to comply, ICF considers a similar estimation method in PHMSA's RIA used for Transmission miles. Operators assess applicable mileage for required repair conditions every seven years leading to a number of conditions discovered per year. ICF delineates discovered repairs into three regions and subsequently applies a cost per type of repair condition as specified by PHMSA to determine a total repair cost. Each type of repair has an associated cost based on the applicable region.

ICF then considers a percentage of conditions operators would repair under the accelerated time frame, with the cost being the difference in net present value of repairing the conditions immediately versus an expected average repair time of five years under normal business operation. ICF then determines the labor costs based on required personnel to monitor the remaining repairs over the lifetime of the condition. Finally, ICF determines the total cost to comply as the difference in net present values due to the accelerated timeframe plus the total cost to repair the remaining conditions minus the labor cost to monitor. This value is not accounted for in PHMSA's proposed RIA.

2.7.2 Major Assumptions and Caveats

- ICF considers Type A Area 1 gathering lines must follow accelerated repair procedures.
- ICF considers 0.2 scheduled repair conditions per mile assessed.
- ICF considers 67% of repairs will be done on an accelerated timeframe.

2.7.3 Cost Results

The tables below show the results of ICF's estimates for the cost of permanent repair to regulated gathering line conditions. ICF considers the applicable pipeline mileage, the number of repair incidents per region, the cost of each repair performed under the accelerated timeline, the cost to monitor the remaining repairs, and labor requirements to determine the cost to comply. ICF estimates a net present value cost over 15 years of $35.2 million at a 7% discount rate ($36.7 million, 3% discount rate) not included in the RIA for permanent field repairs.

Table 94

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 95

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 96

Table 3-60. Calculation of Mileage	
Scope	**Miles**
Type A, Area 1	7,844
Average assessed per year[1]	1,121
1. Assumed miles were assessed every seven years	

Table 97

Hazardous Liquid Scheduled Repair Conditions, 2004-2009		
Repair Condition	**Number**	**Percent of Total**
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%
Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2		

Table 98

Gathering Systems Repair						
	Fraction of Pipeline Assessed Using this method	**Repair Conditions Discovery Rate #/mile**	**Weighted Average Repair Conditions Discovered #/mile**	**BAU Fraction Repaired (remainder monitored)**	**BAU Conditions Repaired**	**BAU Conditions Monitored**
ILI/upgrade to ILI	0.10	1.0	0.1	50%	0.05	0.05
Pressure Test	0.90	0.1	0.1	85%	0.08	0.01
Direct Assessment	0.00	0.1	0.0	85%	0.00	0.00
Total	1.0		0.2	67%	0.13	0.06
1. Business as Usual (BAU) are repairs that would occur without regulation. Note, this does not mean they would have occurred with the same time schedule						

Table 99

Estimation of 180-Day Repair Conditions	
Component	**Value**
Miles assessed per year	1,121
Scheduled repair conditions per mile assessed[1]	0.2
Expected scheduled repair conditions per year	220
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	179
1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.	

Table 100

Number of Anomalies in each Location			
	West (Except West Coast), Central, Southwest	**South, West Coast**	**East**
Percent of anomalies in Location	74%	2%	24%
Number of anomalies in each Location	132	4	43

Table 101

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest1**	**South, West Coast**	**East2**
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$24,000	$30,000	$34,500
Sleeve (20’)	$28,800	$36,000	$41,400
Pipe Replacement (20’)	$76,800	$96,000	$110,400
Material Verification (20’)	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5’)	$21,600	$27,000	$31,050
Sleeve (5’)	$28,800	$36,000	$41,400
Pipe Replacement (5’)	$93,600	$117,000	$134,550
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$36,000	$45,000	$51,750
Sleeve (20’)	$43,200	$54,000	$62,100
Pipe Replacement (20’)	$115,200	$144,000	$165,600
Material Verification (20’)	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 102

Percent of Anomalies Repaired using Current Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
24-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
36-inch diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%

Table 103

Number of Repairs Done using Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	7	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	22	1	7
Composite Wrap (20’)	7	0	2
Sleeve (20’)	13	0	4
Pipe Replacement (20’)	2	0	1
Material Verification (20’)	22	1	7
24-inch Diameter			
Composite Wrap (5’)	7	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	22	1	7
Composite Wrap (20’)	7	0	2
Sleeve (20’)	13	0	4
Pipe Replacement (20’)	2	0	1
Material Verification (20’)	22	1	7
36-inch diameter			
Composite Wrap (5’)	7	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	22	1	7
Composite Wrap (20’)	7	0	2
Sleeve (20’)	13	0	4
Pipe Replacement (20’)	2	0	1
Material Verification (20’)	22	1	7

Table 104

Cost of Repairs				
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**	**Total**
12-inch Diameter				
Composite Wrap (5’)	$63,486	$2,372	$29,570	$95,429
Sleeve (5’)	$169,297	$6,326	$78,854	$254,476
Pipe Replacement (5’)	$91,702	$3,427	$42,712	$137,841
Material Verification (5’)	$44,088	$1,318	$14,285	$59,691
Composite Wrap (20’)	$105,810	$3,954	$49,283	$159,048
Sleeve (20’)	$253,945	$9,489	$118,280	$381,714
Pipe Replacement (20’)	$112,864	$4,217	$52,569	$169,651
Material Verification (20’)	$88,175	$2,636	$28,570	$119,381
24-inch Diameter				
Composite Wrap (5’)	$95,229	$3,558	$44,355	$143,143
Sleeve (5’)	$253,945	$9,489	$118,280	$381,714
Pipe Replacement (5’)	$137,553	$5,140	$64,068	$206,762
Material Verification (5’)	$44,088	$1,318	$14,285	$59,691
Composite Wrap (20’)	$158,716	$5,931	$73,925	$238,571
Sleeve (20’)	$380,917	$14,234	$177,420	$572,571
Pipe Replacement (20’)	$169,297	$6,326	$78,854	$254,476
Material Verification (20’)	$88,175	$2,636	$28,570	$119,381
36-inch diameter				
Composite Wrap (5’)	$142,844	$5,338	$66,533	$214,714
Sleeve (5’)	$380,917	$14,234	$177,420	$572,571
Pipe Replacement (5’)	$206,330	$7,710	$96,103	$310,143
Material Verification (5’)	$44,088	$1,318	$14,285	$59,691
Composite Wrap (20’)	$238,073	$8,896	$110,888	$357,857
Sleeve (20’)	$571,376	$21,351	$266,131	$858,857
Pipe Replacement (20’)	$253,945	$9,489	$118,280	$381,714
Material Verification (20’)	$88,175	$2,636	$28,570	$119,381
Total Cost	**$4,183,036**	**$153,341**	**$1,892,092**	**$6,228,470**

Table 105

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table 106

Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$6,228,470	$6,228,470
Percent of anomalies that are repaired	67%	67%
Cost of repairing anomalies on an accelerated schedule	$4,183,672	$4,183,672
Cost of repairs delayed 4 years	$3,191,704	$3,717,139
Difference for repaired anomalies (estimated cost of proposed rule)	$991,969	$466,534
Time to monitor one anomaly (hours)	1	1
Salary to monitor anomalies	$55	$55
Average Ongoing anomalies in a given time period	441	441
Cost for monitoring unrepaired anomalies	$24,255	$24,255
Annual cost of rule	**$3,012,511**	**$2,487,076**
G & A Cost	**$602,502**	**$497,415**
1. Over the fifteen year period the average lifetime of an anomaly is 7.5 years if they are not repaired. Used the fraction of anomalies not repaired and the 7.5 average lifetime to determine the number of anomalies to monitor annually		

Table 107

Present Value Costs			
7% Discount Rate		**3% Discount Rate**	
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$35,229,998	$2,348,667	$36,697,524	$2,446,502

2.8 Missing Cost for Construction for Gathering Pipeline

2.8.1 Cost Basis

Newly regulated new and existing gathering pipeline must comply with both installation and cover requirements under regulations 192.321 and 192.327. These requirements state that a plastic pipe may only operate above ground up to the manufacturer's recommended maximum period of exposure or two years, whichever is less. For all other plastic pipe, an operator must ensure the pipe is installed below ground. Additionally, an operator must ensure an installed pipeline has between 18 and 36 inches of minimum cover pending on class location and ground characteristics.

ICF considers a cost associated with following these requirements for both existing pipeline which now falls under regulation and regulated plastic pipeline that will be installed during the next 15 years (the time span of PHMSA's analysis). ICF considers these as a cost to bury existing pipeline that is now regulated and an incremental cost to bury and provide sufficient cover to installed plastic pipeline in the future. The 2014 INGAA study[5] provides ICF's estimate of future gathering pipeline mileage. ICF considers the average diameter[6] and an incremental cost per inch mile. PHMSA's proposed RIA does not account for this cost.

2.8.2 Major Assumptions and Caveats

- ICF considers both existing and newly installed Type A Area 2 gathering lines in this cost.
- ICF considers 12 inches as the average diameter of the pipe.
- ICF considers the operators incremental cost per inch mile of $5,000 for regulated pipeline installed in the future.

2.8.3 Cost Results

The tables below show the results of ICF's estimates for the cost to comply with construction requirements for newly regulated pipeline. ICF considers the applicable pipeline mileage and the cost to comply, pending on whether the pipeline is existing and now regulated or installed in the future. ICF estimates a net present value cost over 15 years of $86.9 million at a 7% discount rate ($109.7 million, 3% discount rate) not included in the RIA from these installation requirements.

5 http://www.ingaa.org/Foundation/Foundation-Reports/27958.aspx
6 Based on API Survey

Table 108

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 109

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Class 3 and Class 4 Miles	2,812	7,873	7,844	301
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 110

Total Gathering Mileage	
Gathering Pipeline Miles	399,579

Table 111

Gathering Pipe by Diameter										
	NPS 4' or less	**6"**	**8"**	**10"**	**12"**	**14"**	**16"**	**18"**	**20"**	**22"**
Proxy Diameter	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**
Type A Class 1	48,502	22,419	17,228	7,185	10,415	627	6,049	423	2,827	189
Type A Class 1 Unknown Pipe Diameter Apportioned using proportion of known pipe	5,517	2,550	1,960	817	1,185	71	688	48	322	21
Total	**54,019**	**24,969**	**19,188**	**8,002**	**11,600**	**698**	**6,737**	**471**	**3,149**	**210**

Table 112

Gathering Pipe by Diameter										
	24"	**26"**	**28"**	**30"**	**32"**	**34"**	**36"**	**38"**	**42"**	**48"**
Proxy Diameter	**24**	**26**	**28**	**30**	**32**	**34**	**36**	**38**	**40**	**48**
Type A Class 1	1,703	403	45	785	-	-	245	-	-	-
Type A Class 1 Unknown Pipe Diameter Apportioned using proportion of known pipe	194	46	5	89	-	-	28	-	-	-
Total	**1,897**	**449**	**50**	**874**	**-**	**-**	**273**	**-**	**-**	**-**

Table 113

Total Cost of New Regulation on Existing Plastic Pipes[1]

Category	Mileage of Plastic Pipe in Category from API data	Scaled Mileage to encompass non API sources	Percent of Pipe that falls into the diameter category to be regulated	Percent of Plastic Pipe 8 inches and above	Mileage of plastic pipe in diameter category	Percentage of Pipe that will be expected to comply upon new construction	Percentage of existing plastic pipe that has been in operation for more than 2 years and above ground	Mileage of Plastic pipe this applies to	Cost to Follow Regulation	Total Cost for Existing Pipe
Newly Regulated Existing Pipe (Type A, Area 2 (high stress, ≥ 8")	7,117	11,469	40%	20%	927	100%	1%	9	$75,000	**$695,446**
Total G & A cost[2]	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**$139,089**

1. Plastic pipe must be installed below ground except when installed on a bridge or if the pipe is located in an unlikely place that would experience physical damage

2. Assumed 20% G &A Cost

Table 114

Total Cost of New Regulation on Future Plastic Pipes								
Category	**Total Mileage of Existing Pipe for Type A Class 1**	**Miles of Plastic Pipe in Category**	**Percentage of Plastic Pipe**	**Future Pipe**	**Mileage of Future Plastic Pipe**	**Average diameter of affected pipe**	**Average additional Cost per inch mile**	**Total Cost of Added Regulation on Plastic Pipe**
Future (Type A, Area 2 (high stress, ≥ 8")) pipe	132,586	11,469	9%	20,767	1,796	12	$5,000	$110,776,922
Total G & A Cost[1]	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**$22,155,384**
1. Assumed 20% G &A Cost								

Table 115

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$86,908,032	$5,793,869	$109,653,792	$7,310,253

2.9 Missing Cost for Design Pressure for Gathering Pipeline

2.9.1 Cost Basis

PHMSA proposes design requirements in paragraph 192.105. These requirements entail manufacturing specification requirements including regulation which may require higher grade material costs. For example, according to 192.123, polyethylene plastic gathering pipe will not be able to operate over 125 psig regardless of the wall thickness. Operators will have to either purchase larger diameter plastic pipe in the future to achieve the same volume throughput and reduce the pressure in the pipe or purchase steel pipe and conduct corrosion control measures. The incremental cost per inch mile to upgrade from using lower diameter plastic pipe to using higher diameter plastic pipe amounts to a significant $5,000-$15,000 per inch mile.

Plastic pipe is oftentimes used in areas with sour gas as this gas has a higher propensity to corrode, thereby making corrosion control in these areas expensive. Adding to the additional expense is that lower pressure pipe would require more compressors to transport the gas. Furthermore under 192.59, pipeline companies are not allowed to utilize reworked pipe pipe (imperfect product and wastes that are recycled within the pipe manufacturing process) in the manufacturing of plastic gathering pipe which can comprise 20% of the finished pipe. This will increase pipeline manufactures operating costs.

Operators must comply with these more stringent requirements when installing new steel and plastic pipeline that is regulated in the future. ICF determines an incremental cost to meet this higher standard for future pipe by using an average diameter and cost per inch mile to comply with this requirement. PHMSA's proposed RIA does not account for this cost.

2.9.2 Major Assumptions and Caveats

- ICF considers newly installed Type A Area 2 gathering lines in this cost.
- ICF considers 50% of installed pipe will require the use of higher grade pipe.
- ICF considers 12 inches as the average diameter of the pipe.
- ICF considers a conservative incremental cost per inch mile of $5,000 to comply.

2.9.3 Cost Results

The tables below show the results of ICF's estimates for the cost to comply with design requirements for newly regulated new pipeline. ICF considers the applicable pipeline mileage and the cost to comply to characterize the proposed higher standards. ICF estimates a net present value cost over 15 years of

$499 million at a 7% discount rate ($630 million, 3% discount rate) not included in the RIA from these design requirements.

Table 116

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 117

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Class 3 and Class 4 Miles	2,812	7,873	7,844	301
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 118

Total Gathering Mileage	
Gathering Pipeline Miles	399,579

Table 119

Gathering Pipe by Diameter										
	NPS 4' or less	**6"**	**8"**	**10"**	**12"**	**14"**	**16"**	**18"**	**20"**	**22"**
Proxy Diameter	**4**	**6**	**8**	**10**	**12**	**14**	**16**	**18**	**20**	**22**
Type A Class 1	48,502	22,419	17,228	7,185	10,415	627	6,049	423	2,827	189
Type A Class 1 Unknown Pipe Diameter Apportioned using proportion of known pipe	5,517	2,550	1,960	817	1,185	71	688	48	322	21
Total	**54,019**	**24,969**	**19,188**	**8,002**	**11,600**	**698**	**6,737**	**471**	**3,149**	**210**

Table 120

Gathering Pipe by Diameter										
	24"	**26"**	**28"**	**30"**	**32"**	**34"**	**36"**	**38"**	**42"**	**48"**
Proxy Diameter	**24**	**26**	**28**	**30**	**32**	**34**	**36**	**38**	**40**	**48**
Type A Class 1	1,703	403	45	785	-	-	245	-	-	-
Type A Class 1 Unknown Pipe Diameter Apportioned using proportion of known pipe	194	46	5	89	-	-	28	-	-	-
Total	**1,897**	**449**	**50**	**874**	**-**	**-**	**273**	**-**	**-**	**-**

Table 121

Total Cost for New Regulation on Pipe							
Category	**Mileage**	**Percent of gathering line that would newly fall under this rule**	**Percentage of mileage that operators that will be required to use a higher grade pipe due to regulation[1]**	**Future mileage affected by regulation**	**Average diameter of affected pipe**	**Average Additional Cost per inch mile**	**Incremental cost for upgraded pipe**
Future (Type A, Area 2 (high stress, ≥ 8")) pipe	20,767	100%	50%	10384	12	$5,000	$640,314,138
Total G & A cost[2]	NA	NA	NA	NA	NA	NA	$128,062,828
1. Assumed a combination of higher spec, thicker pipe, with more testing necessary on the pipe will cause companies to purchase a higher grade of pipe							
2. Assumed 20% G &A Cost							

Table 122

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$499,212,875	$33,280,858	$629,867,958	$41,991,197

2.10 Missing Cost for Vaults for Gathering Pipeline

2.10.1 Cost Basis

Both newly regulated new and existing gathering pipeline under the proposed rule must comply with requirements specified in 192.183 when installing vaults. This cost include design requirements such as pressure regulation to protect installed equipment including valves, PRVs, and pressure regulating stations. ICF considers the incremental cost to comply based on an applicable mileage and number of vaults installed. PHMSA's proposed RIA does not account for this cost.

2.10.2 Major Assumptions and Caveats

- ICF considers Type A Area 2 gathering lines in this cost.
- ICF considers vaults to exist every 50 miles.
- ICF considers $5,000 as the cost of housing.

2.10.3 Cost Results

The tables below show the results of ICF's estimates for the cost to comply with vault requirements for newly regulated pipeline. ICF considers the applicable pipeline mileage, the number of vault per mile, and the cost of each vault to determine costs. ICF estimates a net present value cost over 15 years of $1.6 million at a 7% discount rate ($2.0 million, 3% discount rate) not included in the RIA from vault requirements.

Table 123

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 124

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Class 3 and Class 4 Miles	2,812	7,873	7,844	301
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 125

Total Gathering Mileage	
Gathering Pipeline Miles	399,579

Table 126

Total Cost for New Regulation on Vaults								
Category	**Mileage**	**Percentage of Pipe that will be expected to comply (Existing- retroactively and Future - upon new construction)**	**Percent of Pipe that is Newly Regulated**	**Mileage of Pipe that will need to install Vaults**	**Vaults are assumed to be every XX miles**	**Number of Vaults needed to be installed**	**Incremental Cost of Vaults under new regulation**	**Costing of Vaults**
Future (Type A, Area 2 (high stress, ≥ 8")) pipe	20,767	100%	100%	20,767	50	415	$5,000	$2,076,749
Total G & A cost[1]	NA	NA	NA	NA	NA	NA	NA	$415,350
Total	**20,767**			**20,767**	**50**	**415**	**$5,000**	**$2,492,099**

1. Assumed 20% G &A Cost

Table 127

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$1,619,112	$107,941	$2,042,869	$136,191

2.11 Missing Cost for Moderate Consequence Area Assessment for Gathering Pipeline

2.11.1 Cost Basis

Defined in paragraph 192.3, a moderate consequence area (MCA) exists when an onshore area is within a potential impact circle containing five or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, or other principle 4-lane roadway. Sections 192.619 and 192.624 propose regulation for MAOP determination and verification, which apply to areas in moderate consequence areas. In order for an operator to know if a pipeline system must comply with these requirements, the operator must first identify if and where pipeline falls under the newly defined MCAs.

ICF considers the cost to identify MCAs by quantifying the purchase and implementation of a Geographic Information Systems (GIS). Currently under the proposed rule, GIS reporting requirements exclude gathering lines. As such, the cost to implement a GIS system to determine applicable MCA mileage would be a new cost for all pipeline. ICF considers a percentage of pipeline that do not have GISs and a cost to implement per mile. PHMSA's proposed RIA does not account for this cost.

2.11.2 Major Assumptions and Caveats

- ICF considers all regulated gathering lines in this cost.
- ICF considers 70% of pipelines do not have a GIS system for Type A Area 1, 90% of pipelines for Type A Area 2 and 70% of pipeline in Type B.
- ICF considers a cost of $7,000 per mile to add GIS.

2.11.3 Cost Results

The tables below show the results of ICF's estimates for the cost to assess a pipeline system for moderate consequence areas. ICF considers the applicable pipeline mileage and the cost to implement a GIS system per mile to determine costs. ICF estimates a net present value cost over 15 years of $543 million at a 7% discount rate ($686 million, 3% discount rate) not included in the RIA from MCA determination and assessment.

Table 128

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A -unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A -unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 129

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)						
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**	**Future Pipe Type A miles**	**Future Pipe Type B miles**
Total Regulated Miles	7,844	3,580	11,423	367	2,361	1,077
Class 3 and Class 4 Miles	2,812	1,499	4,312	301	NA	NA

Source: PHMSA Pipeline Data Mart

1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.

2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations

Table 130

Estimating Cost to add GIS Mapping to Determine MCA					
Type	**Estimated Mileage that would fall under this part**	**Percentage of Pipeline that do not have a GIS System**	**Mileage that need to add GIS**	**Cost to add GIS per Mile**	**Total Cost**
Type A, Area 2 (high stress, ≥ 8")	77,554	90%	69,798	$7,000	$488,588,769
Type A, Area 1	7,844	70%	5,490	$7,000	$38,433,371
Type B Area 1 and Area 2	3,580	70%	2,506	$7,000	$17,540,947
Total	88,977	NA	77,795	NA	$544,563,086

Table 131

Estimating Cost to add GIS Mapping to Determine MCA for future pipe					
Type	**Estimated Mileage that would fall under this part**	**Percentage of Pipeline that would not have had a GIS system anyway**	**Mileage that need to add GIS**	**Cost to add GIS per Mile**	**Total Cost**
Future Type A Area 1 and Area 2 and Type B Area 1 and Area 2	24,206	90%	21,785	$7,000	$152,495,608

Table 132

Estimating G&A Cost and the Total Cost of Determining MCA	
Total Cost	$697,058,694
G & A Cost	$139,411,739
Total Cost	$836,470,432
Annual Cost	$55,764,695
Note: Other costs associated with MCAs have been accounted for in the MAOP determination and the Corrosion	

Table 133

Present Value Costs			
7% Discount Rate		3% Discount Rate	
Total (NPV with discount rate 7%)	Average Annual (NPV with discount rate 7% divided by 15)	Total (NPV with discount rate 3%)	Average Annual (NPV with discount rate 3% divided by 15)
$543,453,055	$36,230,204	$685,686,774	$45,712,452

2.12 Missing Cost for Leak Surveys for Gathering Pipeline

2.12.1 Cost Basis

According to 192.706, all newly regulated gathering lines (Type A Area 2) must comply with leak survey requirements. These regulations require that operators perform surveys at intervals not exceeding 15 months but at least once a calendar year. Costs include implementing, conducting, and continuing a leak survey program. ICF applies an average cost to survey per mile, considers the cost to occur annually, and determines net present value over a 15 year period. PHMSA's proposed RIA does not account for this cost.

2.12.2 Major Assumptions and Caveats

- ICF considers Type A Area 2 mileage (newly regulated gathering lines).
- ICF considers 37.5% of pipeline were already conducting surveys and therefore do not incur additional costs to comply.
- ICF considers a $490 cost to conduct surveys per mile.

2.12.3 Cost Results

The tables below show the results of ICF's estimates for the cost to conduct leak surveys. ICF estimates a net present value cost of $278 million at a 7% discount rate ($350 million, 3% discount rate) not included in the RIA.

Table 134

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines [1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A - unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A - unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 135

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)[3]				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				
3. Regulated Miles are from 2014 as that was the most recent year when the analysis started				

Table 136

Cost to Conduct Leak Surveys Per Mile			
	Percent of Each Mile	**Unit Cost**	**Weighted Unit Cost**
Aerial Leak Survey	95%	$200	$190
Clearing Pipeline and Ariel Leak Survey	5%	$6,000	$300
Weighted Unit Cost	NA	NA	**$490**

Table 137

Estimating Cost of Gathering Lines that Now have to Conduct Leak Surveys						
Type	**Estimated Mileage that would fall under this part**	**Percentage of Pipeline that were already conducting leak surveys**	**Mileage that need to begin conducting leak surveys**	**Cost to conduct leak survey per mile**	**Total Annual Cost**	**G&A Cost**
Type A Area 2	77,554	38%	48,471	$490	$23,750,843	$4,750,169

Table 138

Present Value Costs			
7% Discount Rate		**3% Discount Rate**	
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$277,755,695	$18,517,046	$350,450,522	$23,363,368

2.13 Missing Cost for Management of Change for Gathering Pipeline

2.13.1 Cost Basis

Due to requirements in 192.13, Type A Area 2 and Type B gathering lines must create and implement a management of change program. The program must address technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline, whether permanent or temporary. Costs include total labor time, personnel requirements to set up a management of change program within the first year, and an annual implementation cost over the 15 year period. ICF determines the total time required, cost of personnel, and a net present value cost over 15 years to begin the program. PHMSA's proposed RIA does not account for this cost.

2.13.2 Major Assumptions and Caveats

- ICF considers 500 total hours for an operator to implement requirements where no program currently exists and 100 hours to implement required changes to an existing program.
- ICF considers 100 operators of the 3,597 total estimate as large, and therefore already have a management of change program in place, with the remainder of companies having to establish a management of change program.

2.13.3 Cost Results

The tables below show the results of ICF's estimates for the cost to implement a management of change program. ICF estimates a net present value cost over 15 years of $778 million at a 7% discount rate ($907 million, 3% discount rate) not included in the RIA from management of change.

Table 139

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A - unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A - unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 140

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)[3]				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				
3. Regulated Miles are from 2014 as that was the most recent year when the analysis started				

Table 141

Total Gathering Mileage	
Gathering Pipeline Miles	399,579
Assumed Mileage per gathering system	111
Assumed Number of Systems	**3,597**
Assumed Large System	**100**

Table 142

Labor Rates[1]					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[2]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
13-1041	Compliance Officers	Oil and Gas Extraction	Compliance Officer	$41	$66
23-1011	Lawyers	Oil and Gas Extraction	Lawyers	$76	$101
	Contracted Compliance personnel[3]	Oil and Gas Extraction	Contracted Compliance personnel	$225	$250
1. Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
2. Mean hourly wage plus mean benefits ($25.01 per hour worked).					
3. Contracted Compliance personnel was an assumption based on phone conversations					

Table 143

Total Hours for Implementing a Management of Change System per Company	
Total Hours	500

Table 144

Estimated Time to Create a Management of Change Program[1]				
	Percent of Time by Labor Category	**Total Labor Cost**	**Hours per Labor Category**	**Cost**
Sr. Engineer	17%	$99	83	$8,250.83
Project engineer	17%	$81	83	$6,750.83
Operator	17%	$55	83	$4,584.17
Contracted Compliance personnel	50%	$250	250	$62,500.00
Total	**100%**	**NA**	**500**	**$82,086**
1. All companies will have to evaluate if they must follow the existing regulation				

Table 145

Total Hours for Running a Management of Change system per Company	
Total Hours	100

Table 146

Estimated Time to Create a Management of Change Program[1]				
	Percent of Time by Labor Category	**Total Labor Cost**2	**Hours per Labor Category**	**Cost**
Sr. Engineer	17%	$99	17	$1,650.17
Project engineer	17%	$81	17	$1,350.17
Operator	17%	$55	17	$916.83
Contracted Compliance personnel	50%	$250	50	$12,500.00
Total	**100%**	**NA**	**100**	**$16,417**
1. All companies will have to evaluate if they must follow the existing regulation				

Table 147

Total Cost to Install a Management of Change Program			
	Large Systems	**Smaller Systems**	**Total**
Total Number of Systems	100	3,497	3,597
Cost for Each System	$16,417	$82,086	NA
Total Cost	**$1,641,717**	**$287,054,968**	**$288,696,684**

Table 148

Per Event Cost of Implementing Management of Change Processes				
Activity	**Labor Category**	**Labor Cost[1] ($/hour)**	**Hours**	**Cost**
Maintenance/operating personnel or engineer identifies a change, invoking the process	Operator	$55	1	$55
Obtain approval to pursue change	Manager	$86	1	$86
Evaluate and document technical and operational implications of the change	Sr. Engineer	$99	12	$1,188
Obtain required work authorizations (e.g., hot work and lockout-tag out permits)	Project Engineer	$81	3	$243
Formally institutionalize change in official "as-built" drawings, facilities lists, data books, and procedure manuals	Project Engineer	$81	8	$648
Communicate change to all potentially affected parties	Manager	$86	2	$172
Train and qualify involved personnel	Operator	$55	20	$1,100
Total	**NA**	NA	**47**	**$3,492**
1. See Table Labor Rate				

Table 149

Present Value Costs[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
Onetime process development	$288,696,684	$19,246,445.63	$288,696,684	$19,246,446
Annual implementation[2]	$489,707,778	$32,647,185	$617,875,167	$41,191,678
Note: Detail may not add to total due to rounding.				
1. Total is present value over 15 year compliance period; average annual is total divided by 15.				
2. Assumed each gathering company has four events per year, each with a cost of $3,492				

Table 150

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$778,404,462	$51,893,631	$906,571,851	$60,438,123

2.14 Missing Cost for Corrosion Control and Test Stations for Gathering Pipeline

2.14.1 Cost Basis

Operators must consider requirements to ensure operating pipeline has sufficient corrosion monitoring in order to ensure public safety. The proposed regulation includes both internal and external corrosion testing and monitoring requirements. These requirements propose which methods to use and the frequency in which to perform these methods to ensure the pipeline remains in a safe operating condition. Operators must use coupons or other suitable means to inspect a pipeline for evidence of internal corrosion where the pipeline transports corrosive gas. Operators must perform cathodic protection level testing using surveys or test station readings to monitor external corrosion. If a test station reading indicates protection levels below the requirement in the proposed rule, close interval surveys must be performed.

For this requirement, ICF considers performing coating surveys, internal corrosion monitoring, and the addition of test stations for cathodic protection monitoring as a means to determine the magnitude of the cost to comply with corrosion control. ICF considers the cost to perform each survey, the frequency of each survey, and the percentage of regulated pipeline already in compliance with these requirements. In paragraph 192.469, pipeline under cathodic protection must have sufficient test stations or contact points for electrical measurement to continually ensure levels remain adequate. As such, ICF also determines the number of test stations an operator must build based on applicable mileage and the cost to build a station. These costs apply to all regulated gathering miles. According to the RIA, costs for internal and external corrosion are indicated. ICF considers PHMSA's methodology for surveying and monitoring required in the regulation for corrosion control. ICF's estimates represent an additional cost for gathering lines.

2.14.2 Major Assumptions and Caveats

- ICF considers all regulated gathering lines must maintain corrosion control.
- ICF considers the cost and number of coating surveys based on class location.
- ICF considers the cost and compliance of internal monitoring based on class location.
- ICF considers the addition of 1 test station per mile at a cost of $540 per station.

2.14.3 Cost Results

The tables below show the results of ICF's estimates for the cost corrosion control and test stations. ICF considers the applicable pipeline mileage, the frequency and cost of each survey, and the cost of installed test stations to determine the cost to comply. ICF estimates a net present value cost over 15 years of $68.9 million at a 7% discount rate ($69.0 million, 3% discount rate) for corrosion control requirements.

Table 151

Reported Gas Gathering Incidents Due to Corrosion (Onshore and Offshore)				
Year	**Internal Corrosion**	**External Corrosion**	**Total Corrosion**	**Total All Causes**
2010	6	0	6	11
2011	7	0	7	14
2012	5	0	5	13
2013	4	0	4	8
2014	6	0	6	12
2015	2	3	5	10
Total	**30**	**3**	**33**	**68**
Source: PHMSA Incident Reports				

Table 152

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]						
Gathering Mile Designation	**PHMSA designation Type (Class 1 and Class 2)**	**2005**	**2010**	**2015**	**Miles from the past 5 years**	**Future Pipe over 15 years**
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A - unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A - unregulated (high stress: with no diameter records-assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**
1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.						
2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category						

Table 153

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Class 2	5,031	2,027	7,058	
Class 3	2,783	1,543	4,326	
Class 4	29	11	40	
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				

Table 154

Onshore Gas Transmission Mileage by Percent SMYS					
Location	**Total**	**<20% SMYS**	**20-30% SMYS**	**>30% SMYS**	**Percent >30% SMYS**
Interstate					
Class 1	160,029	6,750	7,977	145,301	91%
Class 2	17,805	1,460	1,436	14,909	84%
Class 3	13,927	1,302	1,307	11,318	81%
Class 4	28.539	3.616	9.264	15.659	55%
Total	191,789	9,516	10,729	171,544	89%
Intrastate					
Class 1	72,719	6,250	8,293	58,176	80%
Class 2	12,839	1,038	2,762	9,040	70%
Class 3	19,730	1,953	5,671	12,107	61%
Class 4	879.598	20.454	428.344	430.8	49%
Total	106,169	9,261	17,154	79,754	75%
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength					

Table 155

Estimation of Coating Survey Costs							
Class	**PHMSA Estimated Coating Survey Cost1**	**PHMSA Estimated Number of Surveys**	**Total Gas Transmission Lines**	**Total Gathering Mileage**	**Scaling Factor for total Cost**	**PHMSA Assumed Cost[1]**	**Gathering Cost1**
1	$200	100	232,748	77,554	33.32%	$20,000	$6,664
2	$400	70	30,645	7,058	23.03%	$28,000	$6,449
3	$3,000	50	33,657	4,326	12.85%	$150,000	$19,278
4	$5,000	20	908	40	4.39%	$100,000	$4,385
Total	**NA**	**240**	**297,958**	**88,977**	**73.59%**	**$298,000**	**$36,776**
Source: PHMSA Best Professional Judgment.							
1. Based on average survey length of 500 feet. Actual costs will vary depending on environment, traffic control, and survey length.							

Table 156

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table 157

Cost to Add Test Stations[1]							
Total Miles	**Percent of Pipe that will have to add test stations**	**Total Miles to add test stations**	**Stations Required per Mile**	**Baseline Compliance**	**New Stations Required**	**Cost per Test Station[2]**	**Total Cost**
77,554	30%	23,266	1	0%	23,266	$540.08	$12,565,572
HCA = high consequence area							
1. Source: PHMSA annual reports.							
2. Unit cost represents approximately $400 in labor (2 workers for half day) and $100 in materials.							

Table 158

Estimation of Costs for Internal Corrosion Monitoring							
Class	**Monitoring Equipment Cost**	**Total Gathering Mileage**	**Monitors Per Mile[2]**	**Total Number of Monitors Needed**	**% Current Compliance**	**Number of Monitors for Compliance**	**Gathering Cost[1]**
1	$10,000	77,554	0.2	15,511	75%	3,878	$38,776,886
2	$10,000	7,058	0.2	1,412	75%	353	$3,528,978
3	$10,000	4,326	0.2	865	75%	216	$2,162,776
4	$10,000	40	0.2	8	75%	2	$19,912
Total	**NA**	**17795.42057**	**NA**	**4449**	**NA**	**4,449**	**$44,488,551**
Source: PHMSA Best Professional Judgment							
1. Calculated as total number of monitors needed × (100% - % current compliance).							
2. Assumed gathering lines will have more sour gas and will need more monitors per mile for corrosion							

Table 159

Summary of Incremental Costs, Corrosion Control (Millions)		
Component	**One-Time**	**Annual**
External Corrosion Coatings	$0	$0.04
External Corrosion Monitoring	$13	$0
Interference Current Surveys	$0	$0
Internal Corrosion Monitoring	$44.5	$0
Total	**$57**	**$0.04**

Table 160

	PMT	2016	2017	2018	2019	2020	2021	2022
One Time Cost	NA	$57	0.0	0.0	0.0	0.0	0.0	0.0
Annual Cost	NA	$0	$0	$0	$0	$0	$0	$0
G & A in 7% case	NA	$11	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
G & A in 3% case	NA	$11.42	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total Cost 7%	**NA**	**$69**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Cost 3%	**NA**	**$69**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Table 161

	2023	2024	2025	2026	2027	2028	2029	2030
One Time Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Cost	$0	$0	$0	$0	$0	$0	$0	$0
G & A in 7% case	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
G & A in 3% case	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total Cost 7%	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Cost 3%	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Table 162

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$68,895,026	$4,593,002	$69,007,586	$4,600,506

2.15 Missing Cost for Pipeline Inspection Following Extreme Events for Gathering Pipeline

2.15.1 Cost Basis

According to requirements under 192.613, an operator must conduct continuing surveillance, and following an extreme weather event, must conduct an inspection of all onshore pipeline within 72 hours of the cessation of the event. This requirement applies to all regulated gathering line including Type A Area 1, Type A Area 2, Type B Area 1 and Type B Area 2. ICF considers this as the cost to develop a process and perform inspection following an extreme event. The cost to develop a process utilizes the same methodology as Topic Area 5 of the RIA, applied to gathering operators. ICF considers the estimated miles of pipe that would be effected by an extreme event and applies a cost for inspecting the pipe. PHMSA's proposed RIA does not account for this cost.

2.15.2 Major Assumptions and Caveats

- ICF considers a $1,188 to $3,069 cost to develop a program for extreme events.
- ICF considers 50% of gathering operators to have regulated pipe and have to comply with 192.613.
- ICF considers 380 to 760 miles per year affected by an extreme weather event with a cost between $350 to $500 dollars per mile.

2.15.3 Cost Results

The tables below show the results of ICF's estimates for the cost associated with pipeline inspections following an extreme weather event. ICF determines the applicable mileage and the cost of each test for each pipeline system, and then multiples by the cost of testing per applicable mile. ICF estimates a net present value cost over 15 years of $49.1 million at a 7% discount rate ($61.5 million, 3% discount rate) not included in the RIA from pipeline assessment due to extreme weather events.

Table 163

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A - unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A - unregulated (high stress: with no diameter records- assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 164

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)[3]				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1 Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				
3. Regulated Miles are from 2014 as that was the most recent year when the analysis started				

Table 165

Number of Regulated Gathering Operators	
Total Gathering Pipeline Miles	399,579
Assumed Mileage per gathering system	111
Assumed Number of Gathering Operators	**3,597**
Percentage of Operators that will have regulated pipe	**50%**
Assumed Number of Regulated Operators	1,799

Table 166

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost [1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
13-1041	Compliance Officers	Oil and Gas Extraction	Compliance Officer	$41	$66
23-1011	Lawyers	Oil and Gas Extraction	Lawyers	$76	$101
	Contracted Compliance personnel[2]	Oil and Gas Extraction	Contracted Compliance personnel	$225	$250
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Total Labor Cost is mean hourly wage plus mean benefits ($25.01 per hour worked).					
2. Contracted compliance personnel was an assumption based on company input					

Table 167

Estimation of Costs for Process Development for Extreme Events								
Activity	**Hours (Low)**	**Hours (High)**	**Cost per Operator (Low)[1]**	**Cost per Operator (High)[1]**	**Number of Regulated Operators**	**Total Cost (Low)[2]**	**Total Cost (High)[2]**	**Total Cost (Average)**
Review existing surveillance and patrol procedures to validate adequacy for extreme events	2	1	198	99	1,799	178,070	89,035	133,552
Revise surveillance and patrol procedures	5	20	495	1,980	1,799	445,175	1,780,700	1,112,937
Notify involved personnel of new procedures, providing implementation guidance and instruction	5	10	495	990	1,799	445,175	890,350	667,762
Total	**12**	**31**	**$1,188**	**$3,069**	**NA**	**$1,068,420**	**$2,760,085**	**$1,914,252**
Source: PHMSA best professional judgment								
1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).								
2. Calculated as cost per operator × number operators x 50% for assumed compliance								

Table 168

72-hour Post-Event Incremental Inspection Costs Per Event						
Inspection Method	**Base Cost**	**72 Hrs. Cost (Low)**	**72 Hrs. Cost (High)**	**Incremental Cost (Low)**	**Incremental Cost (High)**	**Incremental Cost (Avg.)**
Air patrol per Mile	$25	$38	$157	$13	$132	$72
Ground patrol per Mile	$100	$150	$800	$50	$700	$375
On- and Offshore Standup Test per Event	$500	$750	$800	$250	$300	$275
Depth-of-Cover Survey per Event	$500	$750	$2,381	$250	$1,881	$1,066
Underwater Depth-of-Cover Survey	$7,500	$11,250	$50,000	$3,750	$42,500	$23,125
Source: P-PIC compilation for API of Operator Base Costs. Low 72 hour cost based on 50% increase of baseline. High costs are based on operator high cost						

Table 169

72-hour Post-Event Incremental Inspection for Natural Gas Gathering Line			
	Low Estimate	**High Estimate**	**Average**
Events per Year	10	30	20
Miles Inspected per Event	380	760	570
Extra Cost per Inspection in $/mile	$350	$500	$425
Calculated Total Extra Cost in $/Year	$1,330,000	$11,400,000	$4,845,000
Source: Illustrative examples prepared by ICF to show approximate magnitude of costs.			

Table 170

Present Value Costs			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$49,131,045	$3,275,403	$61,488,727	$4,099,248

2.16 Missing Cost for Repairing Known Existing Conditions for Gathering Pipeline

2.16.1 Cost Basis

According to the proposed rule (192.711, 192.713), operators must repair pipeline conditions under a specified timeframe after the discovery of conditions. Under normal business as usual practices, companies have been making repairs to some conditions, while monitoring other conditions. The backlog of conditions that have not been repaired, but are being monitored, will now have to be repaired under the new rule.

ICF considers the percent of conditions that are repaired based on feedback from industry, and uses the percent of conditions not repaired to determine the backlog of conditions across the pipe (as determined in the field repair of damages for Type A Area 1 gathering lines). ICF then considers an average cost per repair based on the distribution of gathering pipe in the various regions and the costs per repair. This average cost per repair is attributed to each condition from the backlog. PHMSA's proposed RIA does not account for this cost.

2.16.2 Major Assumptions and Caveats

- ICF considers a backlog of 294 of conditions that would have to be repaired. This value is after PHMSA's assumption that 81% of conditions would have to conduct repairs across gathering line sections.
- ICF considers an average cost of $35 thousand dollars per repair

2.16.3 Cost Results

ICF estimates a net present value cost over 15 years of $10.2 million at a 7% discount rate ($10.2 million, 3% discount rate[7]) from non-HCA and non-MCA field repair of damages.

Table 171

Estimated 5 Year Backlog of Conditions			
Section	**Conditions**	**Percent repairs**	**Conditions not Repaired**
Type A Area 1	179	67%	59
		Estimated 5 year backlog	**294**

[7] The 7% and 3% discount value are the same because repairs would need to be done immediately under the existing rule.

Table 172

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$24,000	$30,000	$34,500
Sleeve (20’)	$28,800	$36,000	$41,400
Pipe Replacement (20’)	$76,800	$96,000	$110,400
Material Verification (20’)	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5’)	$21,600	$27,000	$31,050
Sleeve (5’)	$28,800	$36,000	$41,400
Pipe Replacement (5’)	$93,600	$117,000	$134,550
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$36,000	$45,000	$51,750
Sleeve (20’)	$43,200	$54,000	$62,100
Pipe Replacement (20’)	$115,200	$144,000	$165,600
Material Verification (20’)	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 173

Percent of anomalies Repaired using Current methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
24-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
36-inch diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%

Table 174

Number of Anomalies in each Location			
	West (Except West Coast), Central, Southwest	South, West Coast	East
Percent of anomalies in Location	74%	2%	24%

Table 175

Weighted Average Cost for 1 Anomaly per Region			
West (Except West Coast), Central, Southwest	South, West Coast	East	Total Cost Per Anomaly
$23,360	$856	$10,566	$34,782

Table 176

Cost of Repairs		
Number of Conditions	Average Cost Per Condition	Cost to Repair All Conditions
294	$34,782	$10,223,987

Table 177

Present Value Costs			
Total (NPV with discount rate 7%)	Average Annual (NPV with discount rate 7% divided by 15)	Total (NPV with discount rate 3%)	Average Annual (NPV with discount rate 3% divided by 15)
$10,223,987	$681,599	$10,223,987	$681,599

2.17 Revised Cost for Annual Reporting Requirements for Gathering Pipeline

2.17.1 Cost Basis

Due to requirements in 191.17, all gathering and transmission lines must submit annual reports to PHMSA. Operators must submit these reports each year, no later than March 15 for the preceding year. Annual reports include specific pipeline information from each operator and system including pipeline material, mileage, and incidents. ICF determines the total time required, cost of personnel, and a net present value cost over 15 years to create annual reports. ICF considers this cost to occur annually. PHMSA's proposed RIA represents this cost, but the values used are considered low.

2.17.2 Major Assumptions and Caveats

- ICF considers that 50% of systems have regulated miles with the remaining 50% having only unregulated miles.
- ICF considers 250 hours to complete the reports for companies with regulated miles and 150 hours to complete the reports for nonregulated miles.

2.17.3 Cost Results

The tables below show the results of ICF's estimates for the cost to create and supply annual reports. PHMSA reports this cost in the RIA to be \$0.8 million at a 7% discount rate (\$1.1 million, 3% discount rate). ICF estimates a net present value cost over 15 years of \$1.15 billion at a 7% discount rate (\$1.5 billion, 3% discount rate) from annual reporting requirements.

Table 178

Revised Estimates for Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines[1,2]

Gathering Mile Designation	PHMSA designation Type (Class 1 and Class 2)	2005	2010	2015	Miles from the past 5 years	Future Pipe over 15 years
Type A Area 2	Type A, Area 2 (high stress, ≥ 8")	60,746	72,212	77,554	5,341	20,767
Type A - unregulated (high stress < 8)	High stress, < 8"	89,522	106,420	114,292	7,872	30,605
Type A - unregulated (high stress: with no diameter records- assumed to be less < 8)	Type A (assumed < 8")	17,094	20,320	21,823	1,503	5,844
Type B - unregulated (low stress, all sizes)	Low stress, all sizes	136,671	162,469	174,486	12,018	46,724
Total		**304,034**	**361,422**	**388,156**	**26,734**	**103,941**

1. Estimate based on using GIS mapping, HPDI well data, and a count of processing plants to determine the mileage necessary for gathering lines.

2. The breakdown for categories of pipe uses the same ratio as presented in the API survey that was used by PHMSA, but this may be a conservative estimate, as much of the added pipeline from 2010 would be from shale reserves and could fall in the Type A Area 2, high stress, >8 inch category

Table 179

Pipeline Infrastructure - Regulated Onshore Gas Gathering (2014)[3]				
	Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
Total Regulated Miles	7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart				
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.				
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations				
3. Regulated Miles are from 2014 as that was the most recent year when the analysis started				

Table 180

Total Gathering Mileage	
Gathering Pipeline Miles	399,579
Assumed Mileage per gathering system	111
Assumed Number of Systems	3,597
Percent of Systems that will have Regulated Miles	50%
Number of Systems that have Regulated Miles	**1,799**
Number of Systems that Don't have Regulated Miles	**1,799**

Table 181

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost [1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
11-3071	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
13-1041	Compliance Officers	Oil and Gas Extraction	Compliance Officer	$41	$66
23-1011	Lawyers	Oil and Gas Extraction	Lawyers	$76	$101
	Contracted Compliance personnel[2]	Oil and Gas Extraction	Contracted Compliance personnel	$225	$250
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Total Labor Cost is mean hourly wage plus mean benefits ($25.01 per hour worked).					
2. Contracted compliance personnel was an assumption based on company input					

Table 182

Total Hours for Completing Annual Report with Regulated Miles	
Total Hours	250

Table 183

Estimated Time to Complete Annual Reports				
	Percent of Time by Labor Category	**Total Labor Cost2**	**Hours per Labor Category**	**Cost**
Sr. Engineer	17%	$99	42	$4,125.42
Project engineer	17%	$81	42	$3,375.42
Operator	17%	$55	42	$2,292.08
Contracted Compliance personnel	50.00%	$250	125	$31,250.00
Total	**100%**	**NA**	**250**	**$41,043**

Table 184

Total Hours for Completing Annual Report without Regulated Miles	
Total Hours	150

Table 185

Estimated Time to Complete Annual Reports[1]				
	Percent of Time by Labor Category	**Total Labor Cost**	**Hours per Labor Category**	**Cost**
Sr. Engineer	17%	$99	25	$2,475.25
Project engineer	17%	$81	25	$2,025.25
Operator	17%	$55	25	$1,375.25
Contracted Compliance personnel	50%	$250	75	$18,750.00
Total	**100%**	**NA**	**150**	**$24,625.75**
1. All companies will have to evaluate if they must follow the existing regulation				

Table 186

Total Cost to Complete and Submit Annual Reports		
	Number of Systems that have Regulated Miles	**Number of Systems that Don't have Regulated Miles**
Total Number of Systems	1,799	1,799
Cost for Each System	$41,043	$24,626
Total Cost	**$73,815,888**	**$44,289,533**

Table 187

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$1,150,992,594	$76,732,840	$1,452,232,888	$96,815,526

2.18 Revised Assumption for Percent of Type A Area 2 Miles from Currently Regulated Companies (Table 3-89)

2.18.1 Cost Basis

In Table 3-89, PHMSA classifies 97% of gathering miles as “existing regulated lines (group 2),” and that 3% of gathering miles as “no existing regulated lines (group 1),” based on PHMSA best professional judgment.

As described in Section 2.1, ICF develops a list of gathering pipeline operators and their gathering miles for five states, namely: Kansas, Louisiana, Oklahoma, New Mexico, and Texas. ICF filters PHMSA data to include onshore operators in the five aforementioned states and matches each PHMSA operator to an operator from the HPDI Database (if a match was possible). Out of the 217 unique onshore operators in the PHMSA database, 163 companies, or 73%, match operators in the HPDI database. These 163 companies in the five states that match between the PHMSA database and the HPDI database account for 6,259 miles in the PHMSA database. The total miles reported to PHMSA for gathering in the five states equaled 6,862 miles, indicating the mapping covers 91% of the miles reported to PHMSA.

The HPDI database includes a total of 192,907 miles and 1,576 unique gathering companies reported by the five states with data. Companies that report to PHMSA and mapped by ICF account for 34,323 miles or 18% of the total HPDI miles (ratio of miles associated with the five states reporting to PHMSA from the HPDI database and the total miles in the five states reported in the HPDI database). Because ICF mapped only 91% of PHMSA operator miles to the total HPDI miles, that percentage was scaled to 100% to adjust for the companies that were not matched. ICF then uses this ratio (100%/91%) to scale the

18% of miles from mapped companies in the five states to 20% to represent all companies reporting to PHMSA. Therefore, currently regulated companies account for 20% of existing unregulated gathering miles.

This analysis shows no basis in PHMSA's classification that 97% of Type A Area 2 miles would be from companies currently reporting. PHMSA states 367 reporting gathering companies with ICF estimating 3,597 unique gathering companies. Therefore 10% of existing companies report to PHMSA. The data indicates that the larger companies have a higher percentage of gathering miles, but doesn't support that 97% of miles will come from currently regulated companies. Rather ICF considers 20% of Type A Area 2 miles to come from existing reporting companies.

2.18.2 Major Assumptions and Caveats

- In Table 3-89: ICF considers 80% percentage of miles from the category "No existing regulated lines (group 1)" rather than 3%.
- In Table 3-89: ICF considers 20% percentage of miles from the category "Existing regulated lines (group 2)" rather than 97%.

2.18.3 Cost Results

ICF estimates a net present value cost of Topic Area 8 over 15 years of $585 million at a 7% discount rate ($699 million, 3% discount rate)[8]. This includes a combination of changes made throughout Topic Area 8, with the adjustment to Table 3-89 changing the unit cost for most gathering miles.

2.19 Revised Assumption of Utilizing Offshore Incidents to Represent Initial Incident Frequency from Newly Regulated Onshore Type A Area 2 Miles (Table 6-1)

2.19.1 Cost Basis

Table 6-1 lists the incident counts for offshore gathering pipelines in order to calculate an average pre-regulation incident rate for Type A Area 2 pipeline with a diameter of 8 inches or greater. ICF sees no reason to use the offshore incident rate as an estimate of onshore Type A Area 2 pipelines.

ICF revises Table 6-1 to obtain the counts for onshore gathering pipelines over the same time period. For onshore gathering pipelines, a total of 12 incidents occurred between 2001 and 2005 over a total of 84,476 gathering miles[9] over the 5 year period. This results in an average of 0.144 incidents per year per 1,000 miles, compared to 0.329 incidents per year per 1,000 miles for offshore gathering pipelines.

2.19.2 Major Assumptions and Caveats

- ICF considers onshore incidents as more representative of the pre-regulated incidents for Type A Area 2 pipelines. Therefore, ICF considers 0.144 incidents per year per 1000 miles as the existing incident rate for Type A Area 2 pipeline before regulation.

[8] This cost estimate excludes certain annual reporting costs as ICF considers specific annual report costs using a different approach.

[9] Each year, an average of 16,895 gathering miles exist over the 5 year period.

2.19.3 Cost Results

ICF estimates the net present value of benefits of Topic Area 8 over 15 years to equal $43 million at a 7% discount rate ($52 million, 3% discount rate). This includes a combination of changes made throughout Topic Area 8's benefits including adjustments to Table 6-1, Table 6-5, Table 6-6, and Table 6-8.

2.20 Revised Assumption of Utilizing Previously Regulated Type B Data to Model Type A Area 2 Miles (Table 6-5)

2.20.1 Cost Basis

Table 6-5 lists the incident counts for Type B pipelines and the onshore Type B pipeline miles in order to calculate an average incident rate for onshore Type B miles over the last 5 years. PHMSA makes the assumption that the newly regulated Type A Area 2 pipeline with a diameter of 8 inches or greater will behave most similarly to Type B Area 1 and Area 2 miles. ICF sees no reason that the high stress Type A miles in Class 1 locations would behave more like low stress pipelines in Class 2, 3, and 4 locations, and believes that Type A Area 1 pipelines (high stress in Class 2, 3, and 4 locations) to be a better approximation for the newly regulated Type A Area 2 pipelines.

ICF revises Table 6-5 to obtain the counts for onshore Type A natural gas gathering pipelines, which are high stress lines and susceptible to more incidents. For Type A pipelines, a total of two incidents occurred between 2010 and 2015 (both of which in 2012) over a total of 34,978 miles[10] over the six-year period. This results in an average of 0.06 incidents per year per 1,000 miles, compared to 0.04 incidents per year per 1,000 miles for Type B gas gathering pipelines.

2.20.2 Major Assumptions and Caveats

- ICF considers Type A Area 1 incidents to be more representative of the post regulated incidents for Type A Area 2 pipelines due to the high stress of Type A pipe. Therefore, ICF considers 0.06 incidents per year per 1000 miles for post regulation incidents.

2.20.3 Cost Results

ICF estimates the net present value of benefits of Topic Area 8 over 15 years to equal $43 million at a 7% discount rate ($52 million, 3% discount rate). This includes a combination of changes made throughout Topic Area 8's benefits including adjustments to Table 6-1, Table 6-5, Table 6-6, and Table 6-8.

2.21 Revised Assumption of Utilizing Onshore and Offshore Incidents to Represent Gas Lost from Newly Regulated Type A Area 2 Incidents (Table 6-8)

2.21.1 Cost Basis

Table 6-8 shows the total counts of gathering incidents and the quantities of gas released (MCF) from onshore and offshore incidents. The table lists out the incident counts for 2010 through 2015 and determines the average gas released per incident. Based on this data, each incident between 2010 and 2015 releases 3,351 MCF of gas on average. ICF revises Table 6-8 to only include incident counts and gas released for onshore, natural gas Type A and B gathering pipelines. For this type of pipe, five incidents have occurred over the six years, with 5,576 MCF of gas released on average per incident. Despite this

[10] Each year, an average of 5,830 gathering miles exist over the 5 year period.

small sample size, ICF considers this pipe to be more representative of the newly regulated Type A Area 2 pipe.

2.21.2 Major Assumptions and Caveats

- ICF considers an average gas released volume per incident of 5,576 MCF.

2.21.3 Cost Results

ICF estimates the net present value of benefits of Topic Area 8 over 15 years to equal $43 million at a 7% discount rate ($52 million, 3% discount rate). This includes a combination of changes made throughout Topic Area 8's benefits including adjustments to Table 6-1, Table 6-5, Table 6-6 and Table 6-8.

3 Detailed Cost Discussion for Transmission

3.1 Missing Cost for MCA Field Repair of Damages for Transmission Pipeline

3.1.1 Cost Basis

According to the proposed rule (192.933), PHMSA states HCA mileage must accelerate the timeframe for repair conditions under the integrity management program. Additionally, PHMSA states MCA mileage must perform pipeline assessment (192.710) and repair conditions under a proposed accelerated timeframe, similar to HCA mileage through integrity management. ICF considers this missing cost as the repair requirements specified (192.713) for MCAs. ICF follows PHMSA's RIA methodology under Topic Area 2 except where accounting for ICF's proposed revisions in the sections below. Field repair of damages for pipe in MCAs are not accounted for in PHMSA's proposed RIA.

3.1.2 Major Assumptions and Caveats

- ICF assumes 0.9 repair condition per mile for MCA mileage.

3.1.3 Cost Results

ICF estimates a net present value cost over 15 years of $591 million at a 7% discount rate ($668 million, 3% discount rate) from MCA field repair of damages.

Table 188

Estimated MCA Mileage						
	Onshore GT Miles[1]	**Non-HCA[1,2]**	**MCA % of Non-HCA[3]**	**MCA Miles[4]**	**Roadway MCA Miles[5]**	**Total MCA Miles[6]**
Interstate						
Class 1	160,029	159,374	2%	3,187	1,372	4,559
Class 2	17,805	16,774	50%	8,387	144	8,531
Class 3	13,927	7,378	100%	7,378	0.0	7,378
Class 4	29	10	100%	10	0.0	10
Subtotal	191,789	183,536	NA	18,962	1,516	20,478
Intrastate						
Class 1	72,719	71,692	2%	1,434	617	2,051
Class 2	12,839	12,396	50%	6,198	107	6,305
Class 3	19,730	10,224	100%	10,224	0.0	10,224
Class 4	880	156	100%	156	0.0	156
Subtotal	106,169	94,468	NA	18,012	724	18,736
Total						
Class 1	232,748	231,066	2%	4,621	1,989	6,610
Class 2	30,645	29,170	50%	14,585	251	14,836
Class 3	33,657	17,602	100%	17,602	0.0	17,602
Class 4	908	166	100%	166	0.0	166
Grand Total	**297,958**	**278,004**	**NA**	**36,974**	**2,240**	**39,214**
HCA = high consequence area MCA = moderate consequence area						
1. Source: PHMSA 2014 Gas Transmission Annual Report, Part Q. Total mileage shown for context only.						
2. Excludes mileage reported under inadequate maximum allowable operating pressure records.						
3. Source: PHMSA best professional judgment; based on homes and occupied sites in primary impact radius only.						
4. Non-HCA mileage multiplied by percentage MCA.						
5. 20% of total intersecting mileage. Total mileage based on overlay of Federal Highway Administration map with National Pipeline Mapping System pipeline data; 20% based on PHMSA best professional judgment.						
6. MCA miles plus additional roadway MCA miles.						

Table 189

Estimation of MCA Mileage Subject to Integrity Assessment Requirements						
Location	**MCA Mileage[1]**	**% Piggable[2]**	**Mileage Subject to Rule[3]**	**Mileage Subject to Rule less Overlap[4]**	**% MCA Currently Assessed[5]**	**MCA not Previously Assessed[6]**
Interstate						
Class 1	4,559	71%	3,237	2,622	50%	1,311
Class 2	8,531	70%	5,972	5,434	70%	1,630
Class 3	7,378	NA	7,378	6,490	80%	1,298
Class 4	10	NA	10	10	90%	1
Subtotal	20,478	NA	16,597	14,556	NA	4,240
Intrastate						
Class 1	2,051	53%	1,087	1,011	50%	505
Class 2	6,305	40%	2,522	2,371	70%	711
Class 3	10,224	NA	10,224	9,500	80%	1,900
Class 4	156	NA	156	155	90%	16
Subtotal	18,736	NA	13,989	13,037	NA	3,132
Total						
Class 1	6,610	66%	4,363	3,633	50%	1,817
Class 2	14,836	57%	8,457	7,805	70%	2,341
Class 3	17,602	NA	17,602	15,990	80%	3,198
Class 4	166	NA	166	165	90%	17
Grand Total	39,214	**NA**	**30,587**	**27,593**	**NA**	**7,372**
MCA = moderate consequence area						
1. See Table 3-24.						
2. Assumed equal to non-HCA percent piggable based on data from Part R of the annual report (see Table 3-3).						
3. MCA mileage times percent piggable.						
4. Excludes MCA mileage subject to MAOP verification provisions						
5. Assumed based on the overall reported assessed mileage and assessed mileage in HCAs						
6. Mileage subject to proposed rule less overlap with previous other topic areas multiplied by (100%-% not previously assessed).						

Table 190

Calculation of MCA Mileage, Topic Area 2	
Scope	**Miles**
MCA Mileage	30,587
MCA MAOP verification testing under Topic Area 1[2]	7,372
MCA less Topic Area 1 mileage	23,215
Average assessed per year[3]	3,316
1. Source: PHMSA Annual Reports	
2. See section 3.1.	
3. MCA miles less topic Area 1 divided by 7 years.	

Table 191

Hazardous Liquid Scheduled Repair Conditions, 2004-2009		
Repair Condition	**Number**	**Percent of Total**
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%
Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2		

Table 192

Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2014)				
Year	**ILI**	**Pressure Test**	**Direct Assessment**	**Total**
2014	45,454	1,815	3,632	50,900
Percentage	89.30%	3.56%	7.13%	
Source: PHMSA Gas Transmission Annual Reports: 2010-2014				

Table 193

Transmission Conditions Identification						
	Fraction of Pipeline Assessed Using this method	**Repair Conditions Discovery Rate #/mile**	**Weighted Average Repair Conditions Discovered #/mile**	**BAU Fraction Repaired (remainder monitored)**	**BAU Conditions Repaired**	**BAU Conditions Monitored**
ILI	0.89	1.0	0.89	50%	0.45	0.45
Pressure Test	0.04	0.1	0.00	85%	0.00	0.00
Direct Assessment	0.07	0.1	0.01	85%	0.01	0.00
Total	1.0		0.9	50%	0.46	0.45

Table 194

Estimation of 180-Day Repair Conditions	
Component	**Value**
MCA miles assessed per year	3,316
Scheduled repair conditions per mile assessed[1]	0.90
Expected scheduled repair conditions per year	3000
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	2442
1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.	

Table 195

Number of Anomalies in Each Location			
	West (Except West Coast), Central, Southwest	**South, West Coast**	**East**
Percent of anomalies in Location	75%	15%	10%
Number of anomalies in each Location	1,831	366	244

Table 196

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification[1] (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700

Range of Typical Repair Costs			
Material Verification1 (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$24,000	$30,000	$34,500
Sleeve (20')	$28,800	$36,000	$41,400
Pipe Replacement (20')	$76,800	$96,000	$110,400
Material Verification1 (20')	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5')	$21,600	$27,000	$31,050
Sleeve (5')	$28,800	$36,000	$41,400
Pipe Replacement (5')	$93,600	$117,000	$134,550
Material Verification1 (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$36,000	$45,000	$51,750
Sleeve (20')	$43,200	$54,000	$62,100
Pipe Replacement (20')	$115,200	$144,000	$165,600
Material Verification1 (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 197

Percent of anomalies Repaired using Current methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%
Pipe Replacement (5’)	2%	2%	2%
Material Verification (5’)	17%	17%	17%
Composite Wrap (20’)	5%	5%	5%
Sleeve (20’)	10%	10%	10%
Pipe Replacement (20’)	2%	2%	2%
Material Verification (20’)	17%	17%	17%
24-inch Diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%
Pipe Replacement (5’)	2%	2%	2%
Material Verification (5’)	17%	17%	17%
Composite Wrap (20’)	5%	5%	5%
Sleeve (20’)	10%	10%	10%
Pipe Replacement (20’)	2%	2%	2%
Material Verification (20’)	17%	17%	17%
36-inch diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%

Percent of anomalies Repaired using Current methodology			
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%

Table 198

Number of Repairs Done using Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	92	18	12
Sleeve (5')	183	37	24
Pipe Replacement (5')	31	6	4
Material Verification (5')	305	61	41
Composite Wrap (20')	92	18	12
Sleeve (20')	183	37	24
Pipe Replacement (20')	31	6	4
Material Verification (20')	305	61	41
24-inch Diameter			
Composite Wrap (5')	92	18	12
Sleeve (5')	183	37	24
Pipe Replacement (5')	31	6	4

Number of Repairs Done using Methodology			
Material Verification (5’)	305	61	41
Composite Wrap (20’)	92	18	12
Sleeve (20’)	183	37	24
Pipe Replacement (20’)	31	6	4
Material Verification (20’)	305	61	41
36-inch diameter			
Composite Wrap (5’)	92	18	12
Sleeve (5’)	183	37	24
Pipe Replacement (5’)	31	6	4
Material Verification (5’)	305	61	41
Composite Wrap (20’)	92	18	12
Sleeve (20’)	183	37	24
Pipe Replacement (20’)	31	6	4
Material Verification (20’)	305	61	41

Table 199

Cost of Repairs

Repair Method (Length)	West (Except West Coast), Central, Southwest	South, West Coast	East	Total
12-inch Diameter				
Composite Wrap (5’)	$879,119	$219,780	$168,498	$1,267,397
Sleeve (5’)	$2,344,318	$586,080	$449,328	$3,379,726
Pipe Replacement (5’)	$1,269,839	$317,460	$243,386	$1,830,685

Cost of Repairs				
Material Verification (5')	$610,500	$122,100	$81,400	$813,999
Composite Wrap (20')	$1,465,199	$366,300	$280,830	$2,112,328
Sleeve (20')	$3,516,477	$879,119	$673,992	$5,069,588
Pipe Replacement (20')	$1,562,879	$390,720	$299,552	$2,253,150
Material Verification (20')	$1,220,999	$244,200	$162,800	$1,627,999
24-inch Diameter				
Composite Wrap (5')	$1,318,679	$329,670	$252,747	$1,901,096
Sleeve (5')	$3,516,477	$879,119	$673,992	$5,069,588
Pipe Replacement (5')	$1,904,759	$476,190	$365,079	$2,746,027
Material Verification (5')	$610,500	$122,100	$81,400	$813,999
Composite Wrap (20')	$2,197,798	$549,450	$421,245	$3,168,493
Sleeve (20')	$5,274,716	$1,318,679	$1,010,987	$7,604,383
Pipe Replacement (20')	$2,344,318	$586,080	$449,328	$3,379,726
Material Verification (20')	$1,220,999	$244,200	$162,800	$1,627,999
36-inch diameter				
Composite Wrap (5')	$1,978,019	$494,505	$379,120	$2,851,643
Sleeve (5')	$5,274,716	$1,318,679	$1,010,987	$7,604,383
Pipe Replacement (5')	$2,857,138	$714,284	$547,618	$4,119,041
Material Verification (5')	$610,500	$122,100	$81,400	$813,999
Composite Wrap (20')	$3,296,698	$824,174	$631,867	$4,752,739
Sleeve (20')	$7,912,074	$1,978,019	$1,516,481	$11,406,574
Pipe Replacement (20')	$3,516,477	$879,119	$673,992	$5,069,588
Material Verification (20')	$1,220,999	$244,200	$162,800	$1,627,999
Total Cost	**$57,924,198**	**$14,206,325**	**$10,781,626**	**$82,912,149**

Table 200

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table 201

Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$82.9	$82.9
Percent of anomalies that are repaired	50%	50%
Cost of repairing anomalies on an accelerated schedule	$41.8	$41.8
Cost of repairs delayed 4 years	$31.9	$37.2
Difference for repaired anomalies (estimated cost of proposed rule)	$9.9	$4.7

Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions (Millions)		
Time to monitor one anomaly (hours)	1	1
Salary to monitor anomalies	$55	$55
Average Ongoing anomalies in a given time period	9,076	9,076
Cost for monitoring unrepaired anomalies	$0.50	$0.50
Annual cost of rule	**$50.5**	**$45.3**
G & A Cost	**$10.1**	**$9.1**

Table 202

Present Value Costs (Millions)			
7% Discount Rate		3% Discount Rate	
Total	Average Annual	Total	Average Annual
$591	$39	$668	$45

3.2 Missing Cost for non-HCA and non-MCA Field Repair of Damages for Transmission Pipeline

3.2.1 Cost Basis

According to the proposed rule (192.713), operators must repair pipeline under a specified timeframe based on the discovered condition. ICF considers this cost to repair under the specified timeframe for regulated pipeline outside of HCA and MCAs. As the proposed rule has less requirements for the amount of assessments for non-HCA and non-MCA pipeline miles, a smaller percentage of anomalies will be found. ICF follows PHMSA's RIA methodology of this cost estimate except where accounting for ICF's proposed revisions in the sections below. PHMSA's proposed RIA does not account for this cost.

3.2.2 Major Assumptions and Caveats

- ICF considers this mileage to be surveyed half as frequently as HCA or MCA mileage.
- ICF considers these miles to have 50% of the amount anomalies determined in HCA or MCAs as there are less assessment requirements.
- ICF assumes 0.45 repair condition per mile for non-HCA or non-MCA mileage.

3.2.3 Cost Results

ICF estimates a net present value cost over 15 years of $1.6 billion at a 7% discount rate ($1.8 billion, 3% discount rate) from non-HCA and non-MCA field repair of damages.

Table 203

Onshore Gas Transmission Mileage	
Location	**Total**
Interstate	
Class 1	160,029
Class 2	17,805
Class 3	13,927
Class 4	28.539
Total	191,789
Intrastate	
Class 1	72,719
Class 2	12,839
Class 3	19,730
Class 4	879.598
Total	106,169
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength	

Table 204

Mileage for Repairs[1]	
Total Miles	297,958
MCA Miles	30,587
HCA Miles	16,837
Total Miles not accounted for in repairs	250,533
1. Miles that were not accounted for by PHMSA in the RIA even though they are subject to Repair Criteria	

Table 205

Calculation of Mileage[1]	
Scope	**Miles**
Total Mileage	250,533
Average assessed per year[2]	17,895
1. Source: PHMSA Annual Reports	
2. Assumed non HCA, and non-MCA miles would be evaluated less frequently and for the purposes of the calculation assumed twice as long (14 years)	

Table 206

Hazardous Liquid Scheduled Repair Conditions, 2004-2009		
Repair Condition	**Number**	**Percent of Total**
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%
Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2		

Table 207

Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2014)				
Year	**ILI**	**Pressure Test**	**Direct Assessment**	**Total**
2014	45,454	1,815	3,632	50,900
Percentage	89.30%	3.56%	7.13%	
Source: PHMSA Gas Transmission Annual Reports: 2010-2014				

Table 208

Transmission Conditions Identification						
	Fraction of Pipeline Assessed Using this method	**Repair Conditions Discovery Rate #/mile[1]**	**Weighted Average Repair Conditions Discovered #/mile**	**BAU Fraction Repaired (remainder monitored)[2]**	**BAU Conditions Repaired**	**BAU Conditions Monitored**
ILI	0.89	0.5	0.45	50%	0.22	0.22
Pressure Test	0.04	0.1	0.00	85%	0.00	0.00
Direct Assessment	0.07	0.1	0.00	85%	0.00	0.00
Total	1.0		0.5	50%	0.23	0.22
1. Assumed that 50% of conditions per mile would be found						
2. Business as Usual (BAU) are repairs that would occur without regulation. Note, this does not mean they would have occurred with the same time schedule						

Table 209

Estimation of 180-Day Repair Conditions	
Component	**Value**
Miles assessed per year	17,895
Scheduled repair conditions per mile assessed[1]	0.45
Expected scheduled repair conditions per year	8,093
60-day conditions and 180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	6,588
1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.	

Table 210

Number of Conditions in each Location			
	West (Except West Coast), Central, Southwest	**South, West Coast**	**East**
Percent of anomalies in Location	75%	15%	10%
Number of anomalies in each Location	4,941	988	659

Table 211

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700

Range of Typical Repair Costs			
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$24,000	$30,000	$34,500
Sleeve (20')	$28,800	$36,000	$41,400
Pipe Replacement (20')	$76,800	$96,000	$110,400
Material Verification (20')	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5')	$21,600	$27,000	$31,050
Sleeve (5')	$28,800	$36,000	$41,400
Pipe Replacement (5')	$93,600	$117,000	$134,550
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$36,000	$45,000	$51,750
Sleeve (20')	$43,200	$54,000	$62,100
Pipe Replacement (20')	$115,200	$144,000	$165,600
Material Verification (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 212

Percent of Conditions Repaired using Current Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%

Percent of Conditions Repaired using Current Methodology			
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
24-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
36-inch diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%

Percent of Conditions Repaired using Current Methodology			
Material Verification (20’)	17%	17%	17%

Table 213

Number of Repairs Done using Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	247	49	33
Sleeve (5’)	494	99	66
Pipe Replacement (5’)	82	16	11
Material Verification (5’)	824	165	110
Composite Wrap (20’)	247	49	33
Sleeve (20’)	494	99	66
Pipe Replacement (20’)	82	16	11
Material Verification (20’)	824	165	110
24-inch Diameter			
Composite Wrap (5’)	247	49	33
Sleeve (5’)	494	99	66
Pipe Replacement (5’)	82	16	11
Material Verification (5’)	824	165	110
Composite Wrap (20’)	247	49	33
Sleeve (20’)	494	99	66
Pipe Replacement (20’)	82	16	11
Material Verification (20’)	824	165	110

Number of Repairs Done using Methodology			
36-inch diameter			
Composite Wrap (5')	247	49	33
Sleeve (5')	494	99	66
Pipe Replacement (5')	82	16	11
Material Verification (5')	824	165	110
Composite Wrap (20')	247	49	33
Sleeve (20')	494	99	66
Pipe Replacement (20')	82	16	11
Material Verification (20')	824	165	110

Table 214

Cost of Repairs				
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**	**Total**
12-inch Diameter				
Composite Wrap (5')	$2,371,853	$592,963	$454,605	$3,419,421
Sleeve (5')	$6,324,941	$1,581,235	$1,212,280	$9,118,457
Pipe Replacement (5')	$3,426,010	$856,502	$656,652	$4,939,164
Material Verification (5')	$1,647,120	$329,424	$219,616	$2,196,160
Composite Wrap (20')	$3,953,088	$988,272	$757,675	$5,699,036
Sleeve (20')	$9,487,412	$2,371,853	$1,818,421	$13,677,685
Pipe Replacement (20')	$4,216,627	$1,054,157	$808,187	$6,078,971
Material Verification (20')	$3,294,240	$658,848	$439,232	$4,392,320
24-inch Diameter				
Composite Wrap (5')	$3,557,779	$889,445	$681,908	$5,129,132

Cost of Repairs				
Sleeve (5')	$9,487,412	$2,371,853	$1,818,421	$13,677,685
Pipe Replacement (5')	$5,139,015	$1,284,754	$984,978	$7,408,746
Material Verification (5')	$1,647,120	$329,424	$219,616	$2,196,160
Composite Wrap (20')	$5,929,632	$1,482,408	$1,136,513	$8,548,553
Sleeve (20')	$14,231,118	$3,557,779	$2,727,631	$20,516,528
Pipe Replacement (20')	$6,324,941	$1,581,235	$1,212,280	$9,118,457
Material Verification (20')	$3,294,240	$658,848	$439,232	$4,392,320
36-inch diameter				
Composite Wrap (5')	$5,336,669	$1,334,167	$1,022,862	$7,693,698
Sleeve (5')	$14,231,118	$3,557,779	$2,727,631	$20,516,528
Pipe Replacement (5')	$7,708,522	$1,927,131	$1,477,467	$11,113,119
Material Verification (5')	$1,647,120	$329,424	$219,616	$2,196,160
Composite Wrap (20')	$8,894,448	$2,223,612	$1,704,769	$12,822,830
Sleeve (20')	$21,346,676	$5,336,669	$4,091,446	$30,774,792
Pipe Replacement (20')	$9,487,412	$2,371,853	$1,818,421	$13,677,685
Material Verification (20')	$3,294,240	$658,848	$439,232	$4,392,320
Total Cost	**$156,278,754**	**$38,328,485**	**$29,088,690**	**$223,695,929**

Table 215

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table 216

Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$223.7	$223.7
Percent of anomalies that are repaired	50%	50%
Cost of repairing anomalies on an accelerated schedule	$112.8	$112.8
Cost of repairs delayed 4 years	$86.1	$100.3
Difference for repaired anomalies (estimated cost of proposed rule)	$26.8	$12.6

Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions (Millions)		
Time to monitor one anomaly (hours)	1	1
Salary to monitor anomalies	$55	$55
Average Ongoing anomalies in a given time period	24,488	24,488
Cost for monitoring unrepaired anomalies	$1.35	$1.35
Annual cost of rule	**$136.3**	**$122.1**
G & A Cost	**$27.3**	**$24.4**

Table 217

Present Value Costs, (Millions)			
7% Discount Rate		**3% Discount Rate**	
Total	**Average Annual**	**Total**	**Average Annual**
$1,594	$106	$1,802	$120

3.3 Missing Cost for Incidental Mileage for Transmission Pipeline

3.3.1 Cost Basis

According to the proposed rule (192.3), PHMSA revises the definition of regulated gathering lines to now consider lines downstream of certain defined endpoints as transmission pipelines. Under the new rule, PHMSA proposes more stringent requirements for this applicable mileage as a transmission line. ICF considers additional costs for operators of this newly classified pipeline to comply to include determining MAOP, more timely repairs, and corrosion control with other requirements captured by other sections. ICF follows PHMSA's RIA methodology of each cost estimate except where accounting for ICF's proposed revisions in the sections below. ICF considers all added incidental mileage when determining this missing cost.

3.3.2 Major Assumptions and Caveats

- ICF estimates 81 processing plants to contain incidental transmission mileage, with each to have 20 applicable miles. Of these 20 miles, ICF considers the first as an MCA with the remainder of mileage as a Class 1 location.

3.3.3 Cost Results

ICF estimates a net present value cost over 15 years of $270 million at a 7% discount rate ($334 million, 3% discount rate) from incidental transmission mileage.

Table 218

Incidental Mileage	
	Miles
Total	1,628
Number of Processing Plants with Incidental Lines/Assumed number of Operators	81
Class 1-non MCA	1,547
Class 1- MCA	81

Table 219

Estimated Assessment Method				
Type	**Estimated Mileage**	**Pipeline in Category that rule applies to**	**Percent of Incidental Transmission Lines that have MAOP records**	**Mileage in Class 1**
Class 1-non MCA	1,547	100%	20%	1,237
Class 1- MCA	81	100%	20%	65
Total	**1,628**	**NA**	**NA**	**1,302**

Table 220

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]			
	Type A, Area 2 (high stress, ≥ 8")		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8
Pipe thickness (inches)	0.4	0.4	0.3
Segment Miles	60	60	60

Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]			
Number of Mainline Valves	3	3	3
Number of Bends	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583
Gas Released per Mile (MCF)[4]	286	78	19
Cost of Gas Released per Mile[5]	$1,203	$327	$79
Percentage of pipe that would have to be replaced	5%	5%	5%
Cost to replace per inch mile	120,000	120,000	120,000
G&A Cost[7]	45,161	24,992	12,532
Total Unit Cost (per mile)[6]	**$270,963**	**$149,952**	**$75,195**
HCA = high consequence area MCF = thousand cubic feet			
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.			
2. Pipelines below 4” generally cannot accommodate in-line inspection and will be exempt from requirements.			
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.			
<u>4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.</u>			
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.			
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.			
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 221

Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools[1]				
	Pipeline Diameter			**Weighted Average Cost per Mile**
Type	**> 26"**	**14" - 24"**	**<12"**	**Class 1 and 2**
Class 1-non MCA	11%	89%	0%	$163,408
Class 1- MCA	11%	89%	0%	$163,408
1. Assumed previously designated gathering lines after processing plants would typically be larger and so portioned line with 0% below 12 inches and the remainder following the same ratio as gathering class 1 locations				

Table 222

Estimated Unit Cost of ILI for 60 Mile Segments			
	Incidental Transmission Pipelines (60-mile) Segment		
Component	26" - 48"	14" - 24"	4" - 12"
Mobilization[1]	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000
Additional combo tool (deformation & crack tools)	$340,000	$322,000	$304,000
Reruns	$63,000	$50,400	$37,800
Analytical and data integration services	$80,000	$80,000	$80,000
Operator preparation[3]	$27,000	$23,050	$19,100
G&A Cost[4]	$123,000	$111,990	$100,980
Total	**$738,000**	**$671,940**	**$605,880**
Source: PHMSA best professional judgment.			
1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.			
2. Typically $900 to $1,500 per mile.			
3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.			
4. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs			

Table 223

Estimation of ILI Assessment Cost				
Segment Type	**Less than 12" Diameter**	**14" - 24"**	**Greater than 26" Diameter**	**Weighted Average Cost Per Mile**
Class 1-non MCA	0%	89%	11%	$11,321
Class 1- MCA	0%	89%	11.1%	$11,321

Table 224

Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	$297,205	$325,730	$399,940	$877,272
24	$375,000	$420,000	$720,000	$1,160,769
36	$578,424	$738,787	$1,018,202	$2,053,359
Source: T.D. Williamson, Inc., Houston, TX - was used to determine 24 inch pressure test costs				
Source: Greene’s Energy Group, LLC (2013), - Ratios from Green's Energy Group report were used to take T.D. Williamson's 24 inch diameter figures and determine 12 inch and 36 inch pipe				

Table 225

Volume of Gas Lost During Pressure Tests (MCF)[1]				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	48	96	240	481
24	192	385	962	1,923
36	433	866	2,164	4,328
MCF = thousand cubic feet				
1. Estimated using Equation 1.				

Table 226

Cost of Lost Gas[1]					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1 Mile	**2 Mile**	**5 Mile**	**10 Mile**	**Average**
12	$274	$548	$1,370	$2,741	$1,233
24	$1,096	$2,193	$5,482	$10,964	$4,934
36	$2,467	$4,934	$12,334	$24,668	$11,101
1. Calculated based on volume lost (see Table Volume of Gas Lost During Pressure Tests (MCF)) times the cost of gas ($5.71 per thousand cubic feet).					

Table 227

Total Pressure Test Assessment Cost: Incidental Transmission Pipeline Miles				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12 inch				
Pressure test[1]	$356,646	$390,876	$479,928	$1,052,726
Lost gas[2]	$274	$548	$1,370	$2,741
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$456,920	$491,424	$581,298	$1,155,467
24 inch				
Pressure test[1]	$450,000	$504,000	$864,000	$1,392,923
Lost gas[2]	$1,096	$2,193	$5,482	$10,964
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$551,096	$606,193	$969,482	$1,503,887
36 inch				
Pressure test[1]	$694,109	$886,544	$1,221,843	$2,464,030
Lost gas[2]	$2,467	$4,934	$12,334	$24,668
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$796,576	$991,478	$1,334,177	$2,588,698
1. Unit costs (see Table Estimated Cost of Conducting Pressure Test ($2015)) plus 20% G&A				
2. See Cost of Lost Gas				
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.				

Table 228

Per Mile Pressure Test Costs					
Pipe Diameter (inches)	Segment Length (miles)				
	1	2	5	10	Average
Incidental Transmission Pipelines					
12	$456,920	$245,712	$116,260	$115,547	$233,609
24	$551,096	$303,096	$193,896	$150,389	$299,619
36	$796,576	$495,738.97	$266,835.33	$258,869.85	$454,505

Table 229

Estimated Assessment Method for Incidental Transmission Pipe				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Class 1-non MCA	0%	98%	2%	$302,472
Class 1- MCA	0%	98%	2%	$302,472

Table 230

Estimated Assessment Method for Incidental Transmission Pipe				
Location	**ILI**	**Pressure Test**	**ILI and Upgrade**	**Total**
Class 1-non MCA	10%	85%	5%	1
Class 1- MCA	10%	85%	5%	1
Mileage Subject to Testing Class 1 -non MCA	124	1,052	62	1,237
Mileage Subject to Testing Class 1 - MCA	7	55	3	65
Total Annual Cost - Class 1-non MCA	**$93,385**	**$21,207,066**	**$720,631**	**$22,021,082**
Total Annual Cost - Class 1 - MCA	**$4,915**	**$1,116,161**	**$37,928**	**$1,159,004**

Table 231

Natural Gas Composition	
Gas	**Percent of Volume**
Methane (CH_4)	96%
Carbon dioxide (CO_2)	1%
Other Fluids	3%
Source: Estimated based on natural gas quality standards and operator reported measurements	
Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural- Gas	

Table 232

Proportion of Incidental Transmission Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Class 1-non MCA	0%	98%	2%
Class 1- MCA	0%	98%	2%
Source: 2014 Gas Transmission Annual Report			

Table 233

GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Natural Gas Composition Table lbs. = pounds			
MCF = thousand cubic feet			

Table 234

GHG Emissions from Pressure Tests per Assessment Mile[1]			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs.)**
Class 1-non MCA	434	415	646
Class 1- MCA	434	415	646
lbs. = pounds			
MCF = thousand cubic feet			
1. Weighted average based on share of pipeline mileage by diameter.			

Table 235

Total GHG Emissions from Pressure Test Blowdowns				
Item	**PT Miles**	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
Re-establish MAOP: Class 1 - non MCA	1052	456,568	436,936	679,008
Re-establish MAOP: Class 1 -MCA	55	24,030	22,997	35,737
Total	**1,107**	**480,598**	**459,932**	**714,745**
PT = pressure test				
MCF = thousand cubic feet				

Table 236

Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)			
Location	**Diameter 12" or less**	**Diameter 14" to 24"**	**Diameter 26" and above**
Class 1-non MCA	27.7	101.3	282.6
Class 1- MCA	12.9	106.3	289.1
MCF = thousand cubic feet			
Source: See Equation 1 in Section 3.1.4.3			

Table 237

Average Diameter in range for Onshore miles			
	Diameter 12" or less	**Diameter 14" to 24"**	**Diameter 26" and above**
Class 1-non MCA	9.6	18.2	29.8
Class 1- MCA	6.7	18.6	30.2

Table 238

Proportion of Incidental Transmission Mileage by Diameter			
Segment Type	**≤ 12" Diameter**	**14"-24" Diameter**	**≥ 26"Diameter**
Class 1-non MCA	0%	89%	11%
Class 1- MCA	0%	89%	11%
Source: 2014 Gas Transmission Annual Reports			

Table 239

GHG Emissions from Blowdowns, ILI Upgrade (per Mile)			
Location	**Gas Released (MCF)**	**Methane Emissions (MCF)**	**CO_2 Emissions (lbs.)**
Class 1-non MCA	122	116	181
Class 1- MCA	127	121	188

Table 240

Total GHG Emissions due to Blowdowns				
Item	**ILI Upgrade Miles**	**Gas Released (MCF)**	**Methane Emissions (MCF CH_4)**	**CO_2 Emissions (lbs.)**
Re-establish MAOP: Class 1 - non MCA	62	7,517	7,193	11,179
Re-establish MAOP: Class 1 -MCA	3	412	395	613
Total	**65**	**7,929**	**7,588**	**11,792**
CO_2 = carbon dioxide CH_4 = methane				
GHG = greenhouse gas				
HCA = high consequence area ILI = inline inspection				
MAOP = maximum allowable operating pressure MCF = thousand cubic feet				
SMYS = specified minimum yield strength				

Table 241

Total Emissions Per Year			
Item	**Gas Released (MCF)**	**Methane Emissions (MCF CH4)**	**CO_2 Emissions (lbs.)**
Re-establish MAOP: Class 1 - non MCA	30,939	29,609	46,012
Re-establish MAOP: Class 1 - MCA	1,629	1,559	2,423
Total	**32,568**	**31,168**	**48,436**
CO_2 = carbon dioxide CH_4 = methane			
HCA = high consequence area lbs. = pounds			
MAOP = maximum allowable operating pressure MCF = thousand cubic feet			
SMYS = specified minimum yield strength			

Table 242

Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)				
Topic Area 1 Scope	**Average Annual Methane Lost from Blowdown (MCF)**			**Average Annual**
	ILI Upgrade	**Pressure Test**	**Total**	**Social Cost 1**
Re-establish MAOP: Class 1 - non MCA	480	29,129	29,609	0.870
Re-establish MAOP: Class 1 -MCA	26	1,533	1,559	0.046
Subtotal	506	30,662	31,168	1
MCF = thousand cubic feet				
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).				

Table 243

	2016	2017	2018	2019	2020	2021	2022	2023
Social cost of methane	25	25	26	26	26	27	28	29
Re-establish MAOP: Class 1 - non MCA	740,215	740,215	769,824	769,824	769,824	799,432	829,041	858,650
Re-establish MAOP: Class 1 -MCA	38,985	38,985	40,545	40,545	40,545	42,104	43,664	45,223

Table 244

	2024	2025	2026	2027	2028	2029	2030
Social cost of methane	30	31	32	33	34	34	35
Re-establish MAOP: Class 1 - non MCA	888,258	917,867	947,475	977,084	1,006,693	1,006,693	1,036,301
Re-establish MAOP: Class 1 - MCA	46,783	48,342	49,901	51,461	53,020	53,020	54,580

Table 245

Present Value Costs Discounted at 7%, (Millions 2015$)						
Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Incidental Miles	$225,900,785	$916,340	$226,817,125	$15,060,052	$61,089.3	$15,121,142

Table 246

Present Value Costs Discounted at 3%, (Millions 2015$)						
Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Incidental Miles	$285,024,031	$916,340	$285,940,371	$19,001,602	$61,089.3	$19,062,691

Table 247

Present Value Incremental Costs			
Total (NPV with discount rate 7%)	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)**	**Average Annual (NPV with discount rate 3% divided by 15)**
$226,817,125	$15,121,142	$285,940,371	$19,062,691

Table 248

Calculation of Incidental Mileage	
Scope	**Miles**
Total Miles	1,628
Average assessed per year	233

Table 249

Hazardous Liquid Scheduled Repair Conditions, 2004-2009		
Repair Condition	**Number**	**Percent of Total**
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%
Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2		

Table 250

Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2014)				
Year	**ILI**	**Pressure Test**	**Direct Assessment**	**Total**
2014	45,454	1,815	3,632	50,900
Percentage	89.30%	3.56%	7.13%	
Source: PHMSA Gas Transmission Annual Reports: 2010-2014				

Table 251

Transmission Conditions Identification						
	Fraction of Pipeline Assessed Using this method	**Repair Conditions Discovery Rate #/mile**	**Weighted Average Repair Conditions Discovered #/mile**	**BAU Fraction Repaired (remainder monitored)**	**BAU Conditions Repaired**	**BAU Conditions Monitored**
ILI	0.89	1.0	0.9	50%	0.45	0.45
Pressure Test	0.04	0.1	0.0	85%	0.00	0.00
Direct Assessment	0.07	0.1	0.0	85%	0.01	0.00
Total	1.0		0.9	50%	0.46	0.45

Table 252

Table 3-62. Estimation of 180-Day Repair Conditions

Component	Value
Total miles assessed per year	233
Scheduled repair conditions per mile assessed1	0.9
Expected scheduled repair conditions per year	210
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	171
1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.	

Table 253

Number of Anomalies in Each Location			
	West (Except West Coast), Central, Southwest	**South, West Coast**	**East**
Percent of anomalies in Location	74%	2%	24%
Number of anomalies in each Location	126	3.8	41

Table 254

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
12-inch Diameter			
Composite Wrap (5’)	$9,600	$12,000	$13,800
Sleeve (5’)	$12,800	$16,000	$18,400
Pipe Replacement (5’)	$41,600	$52,000	$59,800
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$16,000	$20,000	$23,000
Sleeve (20’)	$19,200	$24,000	$27,600
Pipe Replacement (20’)	$51,200	$64,000	$73,600
Material Verification (20’)	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5’)	$14,400	$18,000	$20,700
Sleeve (5’)	$19,200	$24,000	$27,600
Pipe Replacement (5’)	$62,400	$78,000	$89,700
Material Verification (5’)	$2,000	$2,000	$2,000

Range of Typical Repair Costs			
Composite Wrap (20')	$24,000	$30,000	$34,500
Sleeve (20')	$28,800	$36,000	$41,400
Pipe Replacement (20')	$76,800	$96,000	$110,400
Material Verification (20')	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5')	$21,600	$27,000	$31,050
Sleeve (5')	$28,800	$36,000	$41,400
Pipe Replacement (5')	$93,600	$117,000	$134,550
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$36,000	$45,000	$51,750
Sleeve (20')	$43,200	$54,000	$62,100
Pipe Replacement (20')	$115,200	$144,000	$165,600
Material Verification (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 255

Percent of anomalies Repaired using Current methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%

Percent of anomalies Repaired using Current methodology			
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
24-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
36-inch diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%

Table 256

Number of Repairs Done using Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	6	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	21	1	7
Composite Wrap (20’)	6	0	2
Sleeve (20’)	13	0	4
Pipe Replacement (20’)	2	0	1
Material Verification (20’)	21	1	7
24-inch Diameter			
Composite Wrap (5’)	6	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	21	1	7
Composite Wrap (20’)	6	0	2
Sleeve (20’)	13	0	4
Pipe Replacement (20’)	2	0	1
Material Verification (20’)	21	1	7
36-inch diameter			
Composite Wrap (5’)	6	0	2
Sleeve (5’)	13	0	4
Pipe Replacement (5’)	2	0	1
Material Verification (5’)	21	1	7
Composite Wrap (20’)	6	0	2
Sleeve (20’)	13	0	4

Number of Repairs Done using Methodology			
Pipe Replacement (20')	2	0	1
Material Verification (20')	21	1	7

Table 257

Cost of Repairs				
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**	**Total**
12-inch Diameter				
Composite Wrap (5')	$60,714	$2,269	$28,279	$91,261
Sleeve (5')	$161,903	$6,050	$75,410	$243,362
Pipe Replacement (5')	$87,697	$3,277	$40,847	$131,821
Material Verification (5')	$42,162	$1,260	$13,661	$57,084
Composite Wrap (20')	$101,189	$3,781	$47,131	$152,102
Sleeve (20')	$242,854	$9,075	$113,115	$365,044
Pipe Replacement (20')	$107,935	$4,033	$50,273	$162,242
Material Verification (20')	$84,324	$2,521	$27,322	$114,168
24-inch Diameter				
Composite Wrap (5')	$91,070	$3,403	$42,418	$136,891
Sleeve (5')	$242,854	$9,075	$113,115	$365,044
Pipe Replacement (5')	$131,546	$4,915	$61,270	$197,732
Material Verification (5')	$42,162	$1,260	$13,661	$57,084
Composite Wrap (20')	$151,784	$5,672	$70,697	$228,152
Sleeve (20')	$364,282	$13,612	$169,672	$547,566
Pipe Replacement (20')	$161,903	$6,050	$75,410	$243,362
Material Verification (20')	$84,324	$2,521	$27,322	$114,168
36-inch diameter				
Composite Wrap (5')	$136,606	$5,105	$63,627	$205,337
Sleeve (5')	$364,282	$13,612	$169,672	$547,566

Cost of Repairs				
Pipe Replacement (5’)	$197,319	$7,373	$91,906	$296,598
Material Verification (5’)	$42,162	$1,260	$13,661	$57,084
Composite Wrap (20’)	$227,676	$8,508	$106,045	$342,228
Sleeve (20’)	$546,422	$20,418	$254,508	$821,348
Pipe Replacement (20’)	$242,854	$9,075	$113,115	$365,044
Material Verification (20’)	$84,324	$2,521	$27,322	$114,168
Total Cost	**$4,000,351**	**$146,645**	**$1,809,459**	**$5,956,454**

Table 258

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost[1]**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table 259

Present Value of Estimated Annual Cost of More Timely Repair of Non-Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$6.0	$6.0
Percent of anomalies that are repaired	50%	50%
Cost of repairing anomalies on an accelerated schedule	$3.0	$3.0
Cost of repairs delayed 4 years	$2.3	$2.7
Difference for repaired anomalies (estimated cost of proposed rule)	$0.7	$0.3
Time to monitor one anomaly (hours)	1	1
Salary to monitor anomalies	$55	$55
Average Ongoing anomalies in a given time period	637	637
Cost for monitoring unrepaired anomalies	$0.04	$0.04
Annual cost of rule	**$3.6**	**$3.3**
G & A Cost	**$0.7**	**$0.7**

Table 260

Present Value Costs (Millions)			
7% Discount Rate		**3% Discount Rate**	
Total	**Average Annual**	**Total**	**Average Annual**
$42	$2.8	$48	$3.2

Table 261

Reported Gas Transmission Incidents Due to Corrosion (Onshore and Offshore)				
Year	**Internal Corrosion**	**External Corrosion**	**Total Corrosion**	**Total All Causes**
2003	11	11	22	93
2004	14	9	23	103
2005	7	12	19	160
2006	11	12	23	130
2007	18	17	35	110
2008	8	11	19	122
2009	10	9	19	105
2010	19	10	29	105
2011	14	4	18	114
2012	14	13	27	102
2013	13	5	18	103
2014	9	9	18	129
2015	13	8	21	129
Total	**161**	**130**	**291**	**1,505**
Source: PHMSA Incident Reports				

Table 262

Onshore Gas Transmission Mileage					
Location	**Total**	**<20% SMYS**	**20-30% SMYS**	**>30% SMYS**	**Percent >30% SMYS**
Interstate					
Class 1	160,029	6,750	7,977	145,301	91%
Class 2	17,805	1,460	1,436	14,909	84%
Class 3	13,927	1,302	1,307	11,318	81%
Class 4	28.539	3.616	9.264	15.659	55%
Total	191,789	9,516	10,729	171,544	89%
Intrastate					
Class 1	72,719	6,250	8,293	58,176	80%
Class 2	12,839	1,038	2,762	9,040	70%
Class 3	19,730	1,953	5,671	12,107	61%
Class 4	879.598	20.454	428.344	430.8	49%
Total	106,169	9,261	17,154	79,754	75%
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength					

Table 263

Estimation of Coating Survey Costs[2]							
Class	**Coating Survey Cost[1]**	**Number of Surveys for Mileage PHMSA considered**	**Total Gas Transmission Lines**	**Total Incidental Mileage**	**Scaling Factor for total Cost**	**PHMSA Assumed Cost**	**Incremental Cost Associated with Incidental Miles**
1	$200	100	232,748	1,628	1%	$20,000	$140
G&A Cost	NA	NA	NA	NA	NA	NA	$27.98
Total	**NA**	100	**232,748**	**1,628**	**1%**	**$20,000**	**$168**
Source: PHMSA Best Professional Judgment.							
1. Based on average survey length of 500 feet. Actual costs will vary depending on environment, traffic control, and survey length.							
2. ICF took the incidental mileage divided by the total miles to determine the percentage of the cost to add for the incidental miles							

Table 264

Gas Transmission Close Interval Survey									
Class	**Close Interval Survey Cost ($/Mile)[1]**	**Mileage[2]**	**Current Compliance[1]**	**Out of Specification Test Station Readings (Annual)[1,3]**	**Total Gas Transmission Lines**	**Total Incidental Mileage**	**Scaling Factor for total Cost**	**PHMSA Assumed Cost**	**Total Costs[4]**
1	$2,000	232,635	15%	0.5%	232,748	1,628	1%	$1,977,398	$13,831
G&A Cost	NA	NA	NA	NA	NA	NA	NA	NA	$2,766.25
Total	**NA**	**232,635**	**NA**	**NA**	**232,748**	**1,628**	**1%**	**$1,977,398**	**$16,598**
1. Source: PHMSA best professional judgment									
2. Source: PHMSA 2014 Annual Report via PDM									
3. Reflects long-standing requirements for operators to have CP systems and check test stations annually, and PHMSA inspection experience.									
4. Calculated as the product of mileage, unit cost, out of spec rate, and (1-compliance rate).									

Table 265

Cost to Add Test Station in HCA						
Miles	**Stations Required per Mile**	**Baseline Compliance[1]**	**New Stations Required**	**Cost per Test Station[2]**	**G&A cost**	**Total Cost**
1,628	1	80%	326	$540.08	$35,170	**$211,020**
HCA = high consequence area						
1. Source: PHMSA BPJ						
2. Unit cost represents approximately $400 in labor (2 workers for half day) and $100 in materials.						

Table 266

Estimation of Costs for Interference Surveys										
Class	**Interference Survey Cost1 ($/mile)**	**Total Mileage[2]**	**Current Compliance[1]**	**Incremental Need for Surveys[1]**	**Compliance Mileage[3]**	**Total Gas Transmission Lines**	**Total Incidental Mileage**	**Scaling Factor for total Cost**	**PHMSA Assumed Cost ($7/years)**	**Total Costs[4] ($/7 years)**
1	$4,000	232,726	10%	1%	2,095	232,748	1,628	1%	$8,378,143	$58,602
G&A Cost	NA	NA	NA	NA	NA	NA	NA	NA	NA	$11,720
Total	**$4,000**	**232,726**	**NA**	**NA**	**2,095**	**232,748**	**1,628**	**1%**	**8,378,143**	**$70,323**
1. Source: PHMSA Best Professional Judgment										
2. Source: PHMSA 2014 Annual Report via PDM										
3. Calculated as total mileage × (100% - current compliance) × incremental need for surveys.										
4. Calculated as compliance mileage × unit cost.										

Table 267

Estimation of Costs for Internal Corrosion Monitoring									
Class	**Monitoring Equipment Cost**	**Total Number of Monitors Needed**	**% Current Compliance**	**Number of Monitors for Compliance**	**Total Gas Transmission Lines**	**Total Incidental Mileage**	**Scaling Factor for Total Cost**	**PHMSA Assumed Cost ($7/years)[1]**	**Costs**
1	$10,000	250	95%	13	232,748	1,628	0.7%	$125,000	$874
G&A Cost	NA	NA	NA	NA	NA	NA	NA	NA	$175
Total	**NA**	**250**	**NA**	**12.5**	**232,748**	**1,628**	**0.7%**	**$125,000**	**$1,049**
Source: PHMSA Best Professional Judgment									
1. Calculated as total number of monitors needed × (100% - % current compliance).									

Table 268

Summary of Incremental Costs, Corrosion Control			
Component	**One-Time**	**Annual**	**Recurring (7 years)**
External Corrosion Coatings	$0	$168	$0
External Corrosion Monitoring	$211,020	$16,598	$0
Interference Current Surveys	$0	$0	$70,323
Internal Corrosion Monitoring	$1,049	$0	$0
Total	**$212,069**	**$16,765**	**$70,323**

Table 269

Present Value Incremental Costs[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$502,621	$33,508	$557,007	$37,134
1. Calculated assuming one-time costs in year 1; annual costs in years 1-15; and 7-year recurring costs annualized over 7 years at the different discount rates. Total is present value over 15 years; average annual is total divided by 15.			

Table 270

Summary of Present Value for 15 year period Benefits and Costs[1,2,3] (Millions; 2015$)						
Topic Area	**7% Discount Rate**			**3% Discount Rate**		
	Benefits - Low	**Benefits - High**	**Costs**	**Benefits - Low**	**Benefits - High**	**Costs**
1	$0	$0	$227	$0	$0	$286
2	$0	$0	$42	$0	$0	$48
3	$0	$0	$0	$0	$0	$0
4	$0	$0	$0.50	$0	$0	$0.56
5	$0	$0	$0.0	$0	$0	$0.0
6	$0	$0	$0.0	$0	$0	$0.0
7	$0	$0	$0.0	$0	$0	$0.0
Total	**$0**	**$0**	**$270**	**$0**	**$0**	**$334**
n.e. = not estimated						
1. Total present value over 15-year study period divided by 15. Additional costs to states estimated not to exceed						
$1.5 million per year. Range of benefits reflects range in estimated defect failure rates.						
2. Break even value of benefits, based on the average consequences for incidents in high consequence areas, would equate to approximately one incident averted over the 15-year study period.						
3. Did not calculate any benefits associated with Incidental Miles. Also did not capture costs from Topic Area 3,5,6,and 7 as felt they were either captured, small, or if there was not enough time to evaluate						

3.4 Missing Cost for Repairing Known Existing Conditions in Transmission

3.4.1 Cost Basis

According to the proposed rule (192.713), operators must repair pipeline conditions under a specified timeframe after the discovery of conditions. Under normal business as usual practices, companies have been making repairs to some conditions, while monitoring other conditions. ICF interpretation is that a portion of this backlog of conditions that have not been repaired, but are being monitored, will have to be repaired immediately under the new rule.

ICF considers the percent of conditions that are repaired (as determined in the field repair of damages for HCAs, MCAs, Incidental Mileage, and other pipe sections) based on feedback from industry, and uses the percent of conditions not repaired to determine the backlog of conditions across the various segments of pipe. ICF then considers an average cost per repair based on PHMSA's distribution of conditions and the costs per repair. This average cost per repair is attributed to each condition from the backlog. This cost for repairing the backlog of conditions is not accounted for in PHMSA's proposed RIA.

3.4.2 Major Assumptions and Caveats

- ICF considers a backlog of conditions that would have to be repaired. This backlog is after PHMSA's assumption that 81% of conditions would have to conduct repairs across HCAs, MCAs, Incidental Mileage, and other pipe sections.
- ICF considers an average cost of $34 thousand dollars per repair

3.4.3 Cost Results

ICF estimates a net present value cost over 15 years of $923 million at a 7% discount rate ($923 million, 3% discount rate[11]) from non-HCA and non-MCA field repair of damages.

Table 271

Estimated 5 Year Backlog of Conditions			
Section of Pipe	**Conditions**	**Percent repairs**	**Annual Conditions not Repaired**
HCA	1,771	50%	878
MCA	2,442	50%	1,210
Non-MCA/Non-HCA	6,588	50%	3,265
Incidental Miles	171	50%	85
		Annual backlog	**5,438**
		Estimated 5 year backlog	**27,189**

Table 272

Range of Typical Repair Costs			
Repair Method (Length)	**West (Except West Coast), Central, Southwest[1]**	**South, West Coast**	**East[2]**
12-inch Diameter			
Composite Wrap (5')	$9,600	$12,000	$13,800
Sleeve (5')	$12,800	$16,000	$18,400
Pipe Replacement (5')	$41,600	$52,000	$59,800
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$16,000	$20,000	$23,000
Sleeve (20')	$19,200	$24,000	$27,600
Pipe Replacement (20')	$51,200	$64,000	$73,600

[11] The 7% and 3% discount value are the same because repairs would need to be done immediately under the existing rule.

Range of Typical Repair Costs			
Material Verification (20')	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5')	$14,400	$18,000	$20,700
Sleeve (5')	$19,200	$24,000	$27,600
Pipe Replacement (5')	$62,400	$78,000	$89,700
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$24,000	$30,000	$34,500
Sleeve (20')	$28,800	$36,000	$41,400
Pipe Replacement (20')	$76,800	$96,000	$110,400
Material Verification (20')	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5')	$21,600	$27,000	$31,050
Sleeve (5')	$28,800	$36,000	$41,400
Pipe Replacement (5')	$93,600	$117,000	$134,550
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$36,000	$45,000	$51,750
Sleeve (20')	$43,200	$54,000	$62,100
Pipe Replacement (20')	$115,200	$144,000	$165,600
Material Verification (20')	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 80% of South/West Coast.			
2. 115% of South, West Coast.			

Table 273

Percent of Conditions Repaired using Current Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
24-inch Diameter			

Percent of Conditions Repaired using Current Methodology			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%
36-inch diameter			
Composite Wrap (5')	5%	5%	5%
Sleeve (5')	10%	10%	10%
Pipe Replacement (5')	2%	2%	2%
Material Verification (5')	17%	17%	17%
Composite Wrap (20')	5%	5%	5%
Sleeve (20')	10%	10%	10%
Pipe Replacement (20')	2%	2%	2%
Material Verification (20')	17%	17%	17%

Table 274

Number of Conditions in each Location			
	West (Except West Coast), Central, Southwest	**South, West Coast**	**East**
Percent of anomalies in Location	75%	15%	10%

Table 275

Weighted Average Cost for 1 Anomaly per Region			
West (Except West Coast), Central, Southwest	**South, West Coast**	**East**	**Average Cost Per Anomaly**
$23,720	$5,818	$4,415	$33,953

Table 276

Weighted Average Cost for 1 Anomaly per Region		
Number of Conditions	**Average Cost Per Condition**	**Cost to Repair All Conditions**
27,189	$33,953	$923,141,201

Table 277

Present Value Costs			
Total (NPV with discount rate 7%)[1]	**Average Annual (NPV with discount rate 7% divided by 15)**	**Total (NPV with discount rate 3%)[1]**	**Average Annual (NPV with discount rate 3% divided by 15)**
$923,141,201	$61,542,747	$923,141,201	$61,542,747
1. Since repairs of backlog would take place in year 1, assumed all costs were in year 1			

3.5 Revised Cost of Upgrading to ILI for Transmission Pipeline

3.5.1 Cost Basis

In the RIA, PHMSA calculates a cost for estimating the Class 1 and Class 2 non-HCA pipelines to upgrade to In-line Inspection in Table 3-6 and a cost for Class 3 and Class 4 HCA pipeline miles in Table 3-7. PHMSA states that stakeholders provided inputs on the average cost for upgrading to in-line inspection (ILI) testing as follows:

Stakeholder	**Cost Estimate to for Average Pipeline to Upgrade to in-line inspection per Mile (Thousand $ per mile)**
Pacific Gas and Electric (PG&E)	$153
Southern California Gas Company and San Diego Gas $ Electric Company (SoCal)	$4,400-$4,700
Interstate Natural Gas Association of America (INGAA)	$50-$1,000

PHMSA then provides the methodology to determine the cost to upgrade to ILI in Tables 3-6 and 3-7 where the costs range from $14.6 to $168.7 thousand dollars depending on the diameter. When factoring in an average reported transmission diameter, the cost ranges from $31.9 to $86.2 thousand dollars which varies pending on each class location. This range of costs is not consistent with any approximation provided by stakeholders for the average cost to upgrade to ILI. ICF follows PHMSA's proposed methodology with one addition; an operator must replace a percentage of pipeline per mile.

ICF considers a cost to replace the pipe per inch mile, multiplied by the applicable diameter of the pipe listed in the Tables 3-6 and 3-7 of the RIA.

3.5.2 Major Assumptions and Caveats

- ICF assumes that 5% of pipe would have to be replaced in a mile segment.
- ICF considers a cost of $120,000 per inch mile for replacement of pipe.

3.5.3 Cost Results

ICF's modification results in costs ranging from $68.6 to $348.7 thousand dollars. By using a weighted average pipeline diameter, the costs range between $145.3-$179.2 thousand dollars per mile for the various class locations. This range is more consistent with some costs provided in the RIA by PG&E and INGAA. However, these costs do not represent locations requiring replacement of significant portions of their pipeline to upgrade to ILI.

3.6 Revised Cost of Vendors for Transmission Pipeline

3.6.1 Cost Basis

Throughout the RIA, PHMSA assumes vendor costs for items like repairs and corrosion testing. These vendor costs must have an associated cost to the company for scheduling, implementing, and verifying the work. To account for these additional general and administration costs, ICF considers an additional factor to increase proposed vendor cost appropriately. ICF includes this revision throughout all applicable cost parameters estimated in this report.

3.6.2 Major Assumptions and Caveats

- ICF considers 20% of the total cost as general and administration costs in Topic Area 1, Area 2, and Area 4.

3.6.3 Cost Results

ICF's modifications result in the costs for each topic area to increase by 20%.

3.7 Revised Cost for Field Repair of Damages for Transmission Pipeline

3.7.1 Cost Basis

According to the proposed rule (192.933), PHMSA states HCA mileage must accelerate the timeframe for repair conditions under the integrity management program. Because an operator must now repair a condition on a timeframe, an additional cost now exists to comply with this requirement. For the consideration of this cost, PHMSA assumes an operator's current practice as repairing a condition in five years on average rather than immediately as under the proposed rule. Through discussion with companies, ICF identifies that operators monitor conditions over the lifetime of the condition, but do not repair all conditions. ICF considers the cost of the proposed regulation in two parts. First, for all conditions companies would repair under normal business practices, ICF considers the cost for the proposed rule as the difference between the net present value from completing repairs five years from discovery and completing repairs immediately. Secondly, for conditions not repaired under normal business practices, ICF considers the cost of the proposed regulation as the cost to repair those conditions minus the cost to monitor those conditions.

3.7.2 Major Assumptions and Caveats

- ICF assumes 50% of conditions identified in PHMSA's RIA Table 3-62 as monitored only and not repaired over the lifetime of the condition.
- ICF considers the cost for monitoring as 1 hour of labor per condition at $55 dollars per hour.
- ICF follows PHMSA's proposed cost methodology for repair conditions and assumes immediate repair rather than a five year average.

3.7.3 Cost Results

ICF estimates a net present value cost of Topic Area 2 for HCA miles over 15 years of $428 million at a 7% discount rate ($484 million, 3% discount rate) not included in the RIA from pipeline assessment due to extreme weather events.

3.8 Revised Cost for Pipeline Inspection Following Extreme Events for Transmission Pipeline

3.8.1 Cost Basis

According to requirements under 192.613, an operator must conduct continuing surveillance, and following an extreme weather event, must conduct an inspection of all onshore pipeline within 72 hours of cessation of the event. Under Topic Area 5 of PHMSA's RIA, a cost for developing processes to deal with an extreme event is included. PHMSA's RIA does not consider the cost associated with inspections on the associated miles of pipe that would be effected by an extreme event. PHMSA's proposed RIA does not account for this cost.

3.8.2 Major Assumptions and Caveats

- ICF considers 200 to 400 miles per year could be affected by an extreme weather event with a cost between $350 to $500 dollars per mile.

3.8.3 Cost Results

ICF estimates a net present value cost of Topic Area 5 over 15 years of $63.2 million at a 7% discount rate ($79.5 million, 3% discount rate) not included in the RIA from pipeline assessment due to extreme weather events.

3.9 Revised Cost of In-line Inspection

3.9.1 Cost Basis

In the RIA, PHMSA calculates a cost for conducting an In-line Inspection test. Table 3-9 calculates this cost for transmission pipelines, taking into account mobilization, base MFL tools, additional tools, reruns, analytical and data integration services, and operator preparation. ICF applies this same calculation for In-line Inspection cost to gathering miles. Based on discussions with industry partners, PHMSA's estimations underrepresent the true cost of additional tools such as spiral MFLs or crack tools. As such, ICF adjusts the cost of these two tools upward.

PHMSA is currently assuming that ILI technology can be used to determine the MAOP for the majority of transmission pipe now subject to the rule. Concerns have been raised on whether the ILI technology is advanced to the point where it can be used to determine the MAOP. If it is not possible to use ILI to determine the MAOP, then pressure testing would be used and the cost to determine the MAOP would be approximately 15-25 times larger. ICF has applied PHMSA's assumption for the breakdown of ILI and pressure testing, but this assumption is dependent on the technology existing and being acceptable for companies to utilize.

3.9.2 Major Assumptions and Caveats

- ICF considers a different value for the cost of additional tools necessary when completing an ILI test as outlined in the table below.

Table 278

Component	Component	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
		26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"
PHMSA RIA	Additional combo tool (deformation & crack tools)	$45,000	$36,000	$27,000	$22,500	$18,000	$13,500
ICF Adjustment	Additional tools (Spiral MFL, Crack Tools, etc.)	$340,000	$322,000	$304,000	$340,000	$322,000	$304,000

3.9.3 Cost Results

The cost adjustment applied to ILI testing changes the range of ILI testing from $121,550-$297,000 to $515,820- $738,000 for a segment. After taking into account transmission pipe diameters and adjusting for a per mile basis, the cost per mile changes from $4,324-$4,594 to $11,350-$18,216.[12] ICF estimates a net present value cost of Topic Area 1 over 15 years of $546 million at a 7% discount rate ($684 million, 3% discount rate). This includes a combination of changes made throughout Topic Area 1 including adjustments to upgrading to ILI, ILI, and Pressure Testing. ICF also applies these values to the gathering segment.

3.10 Revised Cost of Pressure Testing

3.10.1 Cost Basis

In the RIA, PHMSA calculates a cost for conducting a pressure test in Table 3-11. PHMSA then adjusts this calculation for transmission pipelines in Table 3-16 and Table 3-17. The three tables account for "mobilization; safety training; equipment setup; fill and stabilize pipeline; 8-hour hydrostatic test; dewater pipeline with carbon media filtration; clean and dry pipeline; disassemble equipment; clean up and de-mobilize" with the adjustment in 3-16 and 3-17 accounting for "operator costs for engineering test plan, procurement of pipe materials, right of way and agent costs, manifold installation costs, engineering and operational oversight, right of way clean up, and return the line to service."

ICF adjusts the approach by using industry feedback for the cost of a pressure test. ICF then utilizes the ratio of costs from 12 inch to 24 inch and 36 inch to 24 inch pipe from the Greene study (from PHMSA's

[12] Cost range includes both interstate and intrastate costs

RIA) to estimate the cost from 12 inch and 36 inch pipe. ICF then applies a 20% G&A cost rather than the 75% multiplier that PHMSA considers.

3.10.2 Major Assumptions and Caveats

- ICF considers a different cost for pressure testing as outlined below with the revised Pressure testing cost.

Table 279

Table 3-11. Estimated Cost of Conducting Pressure Test ($2015)

PHMSA RIA Estimate

Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	$156,550	$159,706	$191,114	$286,355
24	$197,528	$205,927	$344,057	$378,893
36	$304,680	$362,229	$486,555	$670,248

Source: Greene's Energy Group, LLC (2013), updated to 2015 dollars using the Bureau of Labor Statistics US All City Average Consumer Price Index (2013=233.5; 2015=237.8). Includes mobilization; safety training; equipment setup; fill and stabilize pipeline; 8-hour hydrostatic test; dewater pipeline with carbon media filtration; clean and dry pipeline; disassemble equipment; clean up and de-mobilize.

Table 280

Table 3-11. Estimated Cost of Conducting Pressure Test ($2015)				
Revised Estimate				
Pipe Diameter (inches)	Segment Length (miles)			
	1	2	5	10
12	$297,205	$325,730	$399,940	$877,272
24	$375,000	$420,000	$720,000	$1,160,769
36	$578,424	$738,787	$1,018,202	$2,053,359
Source: T.D. Williamson, Inc., Houston, TX - was used to determine 24 inch pressure test costs				
Source: Greene's Energy Group, LLC (2013), - Ratios from Green's Energy Group report were used to take T.D. Williamson's 24 inch diameter figures and determine 12 inch and 36 inch pipe				

- ICF then applies a 20% G&A cost rather than the 75% multiplier that PHMSA's RIA uses for the values presented in Tables 3-16 and 3-17.

3.10.3 Cost Results

The cost adjustment applied to Pressure Testing changes the weighted by diameter pressure test cost from $203,556-$226,939 to $270,444-$305,543 per mile. ICF estimates a net present value cost of Topic Area 1 over 15 years of $546 million at a 7% discount rate ($684 million, 3% discount rate). This includes a combination of changes made throughout Topic Area 1 including adjustments to upgrading to ILI, ILI, and Pressure Testing. ICF also applies these values to the gathering segment.

3.11 Revised Cost for Management of Change for Transmission Pipeline

3.11.1 Cost Basis

In the RIA, PHMSA calculates a cost for implementing a management of change program as well as a per event cost of implementing the management of change process. ICF adjusts the approach by using industry feedback to estimate the necessary time to implement a management of change program. ICF utilizes PHMSA's 70 companies that would need to implement a management of change program as well as 4 events per company. ICF determines the total time required, cost of personnel, and a net present value cost over 15 years to begin the program.

Industry feedback indicates that every company would be required to make adjustments to their management of change program and therefore incur a substantial cost associated with the time spent to adhere to the new requirements. Additionally, the number of events is estimated to be in the tens of thousands which is substantially higher than the 280 that PHMSA has accounted for. ICF did not have time to evaluate these two issues, but anticipates the Management of Change provision may have even more cost associated (than shown below) with it based on these two additional factors.

3.11.2 Major Assumptions and Caveats

- ICF assumes the time to implement a management of change program would vary between 187 and 813 hours.

- ICF assumes the 70 operators that PHMSA considered having to establish a management of change program.

3.11.3 Cost Results

ICF estimates a net present value cost of Topic Area 3 over 15 years of $12.3 million at a 7% discount rate ($14.8 million, 3% discount rate).

3.12 Revised Benefits of Proposed Material Documentation Requirements for Transmission Pipeline

3.12.1 Basis

In Table 4-6 of the RIA, PHMSA proposes a cost benefit analysis for newly added regulation. In this analysis, benefits include considerations for newly proposed methods in the regulation to determine MAOP. One method for determining MAOP requires the excavation and testing of a pipeline for yield strength (192.107) as part of design pressure requirements. This requires operators to excavate to perform testing of the pipe. However, as PHMSA previously required operators to determine MAOP, any proposed method to avoid costs incurred by further regulation requirements does not truly constitute a benefit.

PHMSA assumes all pipeline miles must determine material records through excavation, with consideration of a cost of $75,000 per coupon and a coupon taken every 400 feet. PHMSA assumes that all pipeline miles must excavate for testing, requiring a cost of $75,000 per coupon and a coupon taken every 400 feet. This new regulation now requires a total cost to the operator to excavate as $288 million dollars to comply. PHMSA then considers the difference between this value and the cost estimated for determining the MAOP evaluated under Topic Area 1 as a benefit ($273.7 million over 15 years). As this is a new requirement, ICF does not believe it appropriate to claim any benefit associated with this portion of the regulation.

3.12.2 Major Assumptions and Caveats

- ICF removed this calculation for benefits entirely.

3.12.3 Results

ICF's modification results in benefits decreasing by $273.7 million over the 15 year period.

3.13 Power Law Recalculation of HCA Cost

3.13.1 Cost Basis

In the RIA on page 176, PHMSA calculated the average economic consequences (a.k.a. damages) for certain types of incidents related to HCAs in a table entitled "Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods Located in HCAs (2003-2015; 2015$)." This table takes a simple average of the consequences for 23 incidents that occurred over 13 years to compute an average of $23.4 million per incident. An analysis of the underlying data indicates that a single incident contributed 98.9% of the total consequences from the 23 incidents. Because the sample size is so small and so heavily skewed, it raises the question of how random factor commonly referred to as the "luck of the draw" might have influenced the calculated average and what a more sophisticated analysis of the data might reveal is a better estimate of the mean value for this variable. Such an analysis was conducted by ICF assuming that consequences follow a power law distribution.

3.13.1.1 Use of the Power Law Distribution for Consequences

The power law distribution is commonly used to analyze the distribution of consequences from natural disasters and accidents wherein a few occurrences account for the majority of the economic losses. An example of such analysis was published by Jana, a consulting company that provides performance validation and risk modeling services to the North American pipeline industry.[13] The authors say "In this paper, the form of the distribution of consequences arising from pipeline incidents is examined and it is seen, in a variety of industries (gas distribution, pipelines, gas transmission pipelines, hazardous liquid pipelines and gas gathering pipelines), to follow a power law or Pareto type distribution."[14]

Table 281 shows the 23 HCA incidents that appear in RIA Table E-3 as recently extracted by ICF from the PHMSA incident database and converted to 2015 dollars. Although the average consequence is $23.4 million, the distribution shows that 16 of the 23 incidences or 70% had consequences of approximately $100,000 or less. The importance of the one outlier event is evident in that by excluding the highest cost event, the average of the remaining 22 incidents would be just $0.3 million. This suggests that had that one random event not occurred, then the computed average would have been much different. The Jana authors warn of such a possibility by saying:

> "… a history of only low consequence events is not an indication that only low consequence events will continue to occur. In fact, Power Law behavior implies that, with a significant number of low consequences events, there will be some associated number of higher consequence events that will eventually occur. This has been repeatedly observed in the pipeline industry where the same type of failure mode (e.g., corrosion, third party damage, etc.) that has previously resulted in only moderate incidents, results in an incident that causes significant damage, injuries or fatalities. Mapping the Power Law behavior of small incident in terms of frequency and severity can actually be used to develop this specific relationship and allow prediction of the likelihood of the low probability-high consequence events."[15]

Hence the authors suggest fitting the historical consequence data to power law distributions to help avoid incorrect conclusion that might be drawn if the particular sample of consequence which is available just happens to not contain a representative number of low probability-high consequence events.

Table 281

[13] "Managing Low Probability – High Consequence Pipeline Risks," W. Bryce, P. Eng., K. Oliphant, Ph.D. P. Eng, Jana, Aurora Ontario. http://www.betterpiping.com/pdf/Managing-Low-Probability-High-Consequence-Pipeline-Risk.pdf

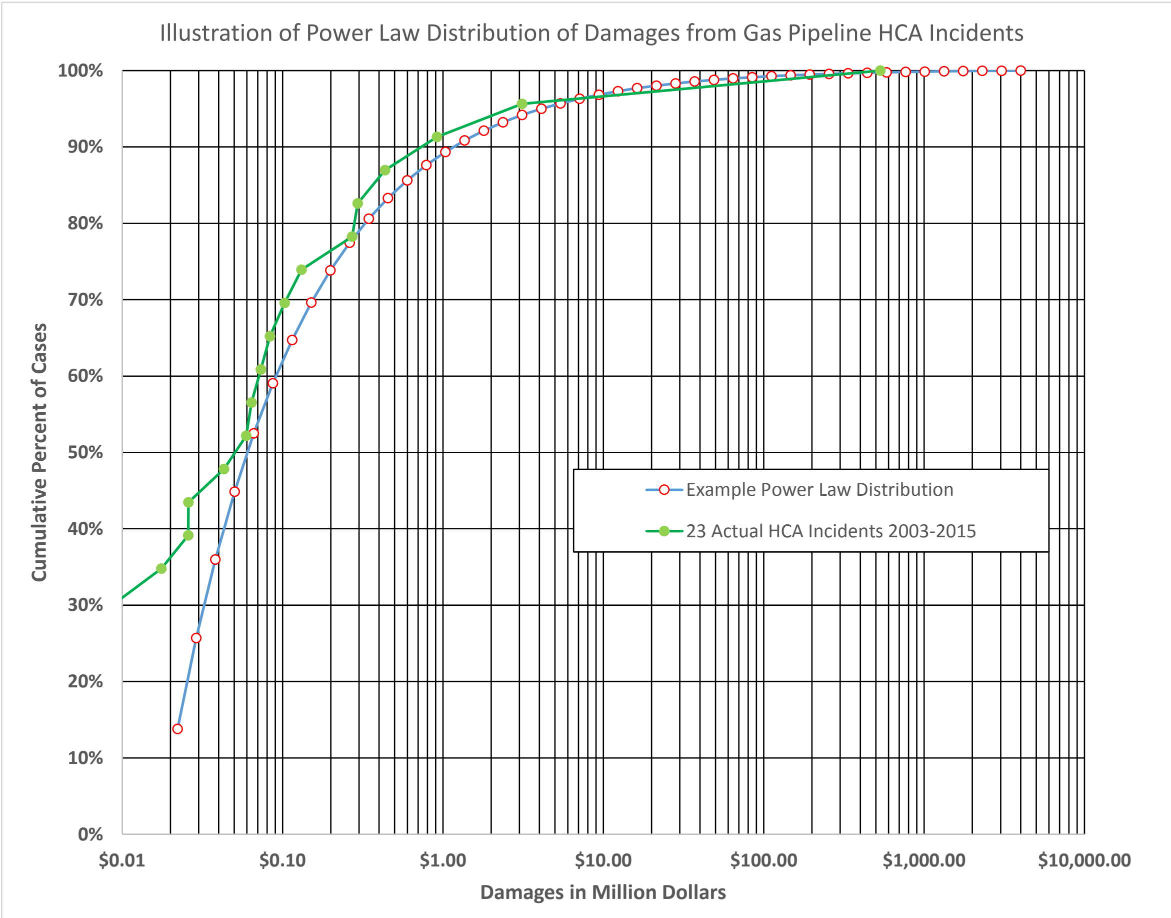
[14] Ibid., page 1

[15] Ibid., page 6.

The 23 HCA Incidents Contained in RIA Table E-3 as Recently Extracted from PHMSA Incident Database (consequences in 2015 million$)		
Rank	**Consequences ($million)**	**Cumulative %**
1	$0.0000	4%
2	$0.0001	9%
3	$0.0012	13%
4	$0.0019	17%
5	$0.0038	22%
6	$0.0038	26%
7	$0.0093	30%
8	$0.0176	35%
9	$0.0258	39%
10	$0.0259	43%
11	$0.0432	48%
12	$0.0593	52%
13	$0.0642	57%
14	$0.0732	61%
15	$0.0834	65%
16	$0.1032	70%
17	$0.1314	74%
18	$0.2713	78%
19	$0.2946	83%
20	$0.4351	87%
21	$0.9187	91%
22	$3.1119	96%
23	$532.9626	100%
Sum	$538.6413	
Average of All 1 to 23	**$23.4**	
Average 1 to 22 Only	$0.3	

The distribution of consequences for these 23 HCA incidents is shown graphically in Figure 2 as a green line. Also shown in Figure 2 is a hypothetical power law distribution that was selected to approximate the shape of the distribution of the 23 actual incidents. This hypothetical distribution has a high end that is about eight times larger than any of the 23 incidents (that is, the hypothetical high end is $4.0 billion versus $533 million for the largest consequences among the 23 actual cases). Even so, the average of the hypothetical distribution is only $6.7 million versus the $23.4 million because the hypothetical distribution “fills in” the large number of small- and moderate-cost incidents that would be expected to accompany the few high-cost incidents.

Figure 2: The Distribution of Consequences for the 23 HCA Incidents and a Hypothetical Power Law Distribution with a Similar Pattern



The hypothetical power law distribution of the consequences in HCA areas is shown in tabular form in Table 282 where the number of incidents in each cost category are represented by the rows in the table. The number of incidents of each cost category sum to the arbitrary number of 1,000 so that the number of incidents at the high-cost end would be around 1 and the table easier to interpret. At 1.8 incidents per year (the value implied by RIA Table E-3 for 23 event over 13 years), the 1,000 incidents depicted in Table 282 would require more than 500 years to occur. The sum of the cost for the 1,000 incidents would be $6.7 billion or an average of $6.7 million per incident.

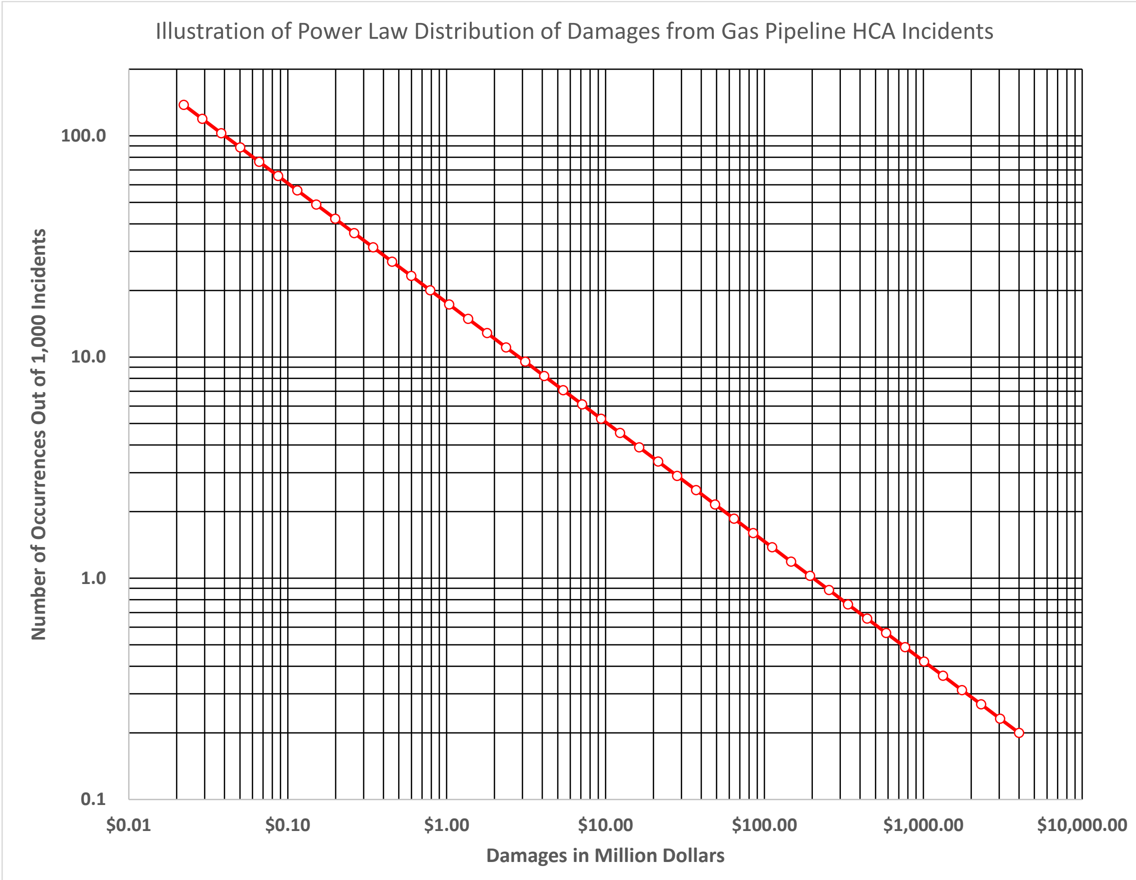
Table 282

Hypothetical Power Law Distribution of HCA Consequences in Tabular Form			
Consequences per Incident ($million)	**Number of Incidents Out of 1,000**	**Total Damages for This Number of Incidents ($million)**	**Cumulative Probability**
$0.02	137.9	$3	13.8%
$0.03	119.2	$3	25.7%
$0.04	102.8	$4	36.0%
$0.05	88.6	$4	44.8%
$0.07	76.3	$5	52.5%
$0.09	65.8	$6	59.1%
$0.11	56.7	$7	64.7%
$0.15	48.9	$7	69.6%
$0.20	42.1	$8	73.8%
$0.26	36.3	$10	77.5%
$0.34	31.3	$11	80.6%
$0.45	27.0	$12	83.3%
$0.60	23.2	$14	85.6%
$0.79	20.0	$16	87.6%
$1.04	17.3	$18	89.3%
$1.37	14.9	$20	90.8%
$1.80	12.8	$23	92.1%
$2.37	11.1	$26	93.2%
$3.12	9.5	$30	94.2%
$4.11	8.2	$34	95.0%
$5.41	7.1	$38	95.7%
$7.12	6.1	$43	96.3%
$9.38	5.3	$49	96.8%
$12.35	4.5	$56	97.3%
$16.26	3.9	$64	97.7%
$21.42	3.4	$72	98.0%
$28.21	2.9	$82	98.3%
$37.14	2.5	$93	98.6%
$48.91	2.2	$105	98.8%
$64.41	1.9	$120	99.0%

Hypothetical Power Law Distribution of HCA Consequences in Tabular Form			
Consequences per Incident ($million)	**Number of Incidents Out of 1,000**	**Total Damages for This Number of Incidents ($million)**	**Cumulative Probability**
$84.82	1.6	$136	99.1%
$111.69	1.4	$154	99.3%
$147.09	1.2	$175	99.4%
$193.69	1.0	$199	99.5%
$255.07	0.9	$225	99.6%
$335.89	0.8	$256	99.6%
$442.32	0.7	$290	99.7%
$582.47	0.6	$330	99.8%
$767.04	0.5	$374	99.8%
$1,010.08	0.4	$424	99.9%
$1,330.14	0.4	$482	99.9%
$1,751.61	0.3	$547	99.9%
$2,306.63	0.3	$621	100.0%
$3,037.52	0.2	$704	100.0%
$4,000.00	0.2	$799	100.0%
$6.7	1,000	$6,699	

An import characteristic of a power law distribution is that it appears as a straight line when both the number of occurrences (Y-axis) and the consequences (X-axis) are depicted in a log scale. This is shown in Figure 3 for the hypothetical power law distribution of the consequences in HCA areas.

Figure 3: Hypothetical Power Law Distribution of HCA Consequences in Log-Log Graphical Form



3.13.1.2 Sensitivity to Assumptions for Upper-End Consequence

As was discussed above, the hypothetical power law distribution of HCA consequences was created with the assumption that the highest-cost event would have consequences of $4 billion or about 8 times the actual highest-cost event from 2003 to 2015. This $4 billion value is equivalent to 200 fatalities (at $9.4 million per fatality) plus $2,120 million in property and other damages. This assumption for the highest-cost event yields the average of $6.7 million per incident used in the recalculation of the cost-benefits.

If we were to have assumed that the highest cost event were only $2 billion (100 fatalities plus $1,060 million in property and other damages), then the average consequence would have been $4.9 million per incident. On the other hand, an assumption that the highest-cost event that could be expected was $8 billion (this about 16 times the historical maximum and equivalent to 400 fatalities plus $4,240 million in property and other damages) would yield an average damage of $9.2 million per incident, a number still well below the $23.4 million produced by using a simple average of the 23 incidents.[16]

[16] To create a hypothetical power law distribution with an average consequence of $23.4 million would require assuming that the most catastrophic gas pipeline incident in an HCA would be over $62 billion for that single highest-cost event.

3.13.2 Major Assumptions and Caveats

- ICF utilized the power law analysis to estimate of the average consequences to be expected from incidents in HCA areas from causes detectable by modern integrity assessment methods. ICF considers the average per incident to be equal to \$6.7 million rather than the \$23.4 million calculated by a simple average of the 23 incidents.

3.13.3 Cost Results

ICF estimates a net present value benefit over 15 years of \$97-275 million at a 7% discount rate (\$122-347 million, 3% discount rate) based on the power law average in Table 4-7. PHMSA's estimate for the net present value benefit over 15 years calculated in Table 4-7 was \$245-667 million at a 7% discount rate (\$310-842 million, 3% discount rate).

4 Significant Costs Lacking Data for Analysis

Through discussions with API Partners, ICF recognizes remaining costs for operators to comply with this regulation which could influence this analysis further. ICF does not include the parameters given here in the analysis outlined in this report, however further revisions could allow for a more complete and verifiable response to the proposed regulation. ICF discusses these further parameters below.

For compliance with excavation requirements, operators may inadvertently increase the risk of causing damage through testing of the pipe. This increased risk of damage creates further costs to repair. Operators would need to consider additional costs created by the action of complying with requirements. Through inspection and repair requirements, operators may need to shut in systems in order to comply. This creates a loss of revenue by decreasing production volumes. Due to this, operators of small systems may experience very high costs, forcing them to shut down or sell operations rather than pay the expenditure required to comply.

For operators of composite pipe (approximately 20,000 miles), if a line becomes relocated, replaced, or otherwise changed, the pipeline must comply with specified requirements under the rule. Because PHMSA does not specify design requirements for composite pipeline, operators would require the replacement to steel pipeline. This causes two impacts for operators. Existing plastic pipe will have to retire as changes occur over the next several years and operators must install steel pipe rather than composite in the future, with the cost difference being an additional burden. Considering replacement of 20,000 miles of existing composite pipe, operators may replace 50% up to a cost of $120,000 per inch-mile.

PHMSA's incident reporting has a section entitled storage gathering, separate from Type A and B miles. If the revised definition of a regulated gathering line captures these miles under the new rule, this additional mileage of pipeline must comply with all specified requirements. The proposed rule also requires fracture mechanics modeling for failure stress analysis where a pipeline segment contains or may be susceptible to cracks. This cost includes performing an analysis using computer modeling and incorporating some year to year changes. This issue would include all pipeline, with HCA pipeline mileage requiring the testing every calendar year. Further, for operators of transmission lines, industry partners state substantial additional costs to identify MCAs even with an existing GIS system in place.

PHMSA's Topic Area 4 entitled corrosion control has a variety of assumptions for the percent already complying, the number of surveys that would be necessary, and the unit cost for a survey or monitor. ICF did not evaluate these assumptions for transmission but industry representatives state that PHMSA's corrosion costs are underestimated due to these factors.

Appendix A: Inconsistencies in Regulatory Impact Analysis

Throughout replicating the calculations, ICF determined a variety of issues with PHMSA's calculations. These issues include arithmetic, cross-reference and conceptual mistakes. ICF also identified some inconsistencies in the text that vary from what is displayed in the tables. Lastly, ICF could not replicate the values presented in the RIA for a variety of tables which could be because of incomplete documentation of PHMSA's methodology or arithmetic errors. The various errors ICF identified are displayed below:

Calculation Issues with PHMSA's RIA

1) Table 2-1 and Table 2-2 state they are using 2015 values, but the values reflect the 2014 values. Additionally, the 2015 values only came out midway through the comment period.
2) Table 3-2:
    a. Class 1 HCA > 30 SMYS does not match with the value presented in Appendix A-1. The value should be 56 instead of 59.
    b. The percentage presented as the total percentage is misleading as it is not the percentage being used. This percentage should be the weighted average of Class 1-4.
3) Table 3-6 and Table 3-7 are not using the blowdown conditions stated in the table footnotes, but rather the ones displayed in Equation 1.
4) Table 3-12 and Table 3-13 are not using the inside pipe diameter to estimate gas loss from a pipe and are instead using the outside diameter.
5) Table 3-18 did not include the gas lost in interstate pipelines as they did in intrastate pipelines.
6) Table 3-39 subtotal is not of Class 1 and 2 as displayed but rather of all miles in Table 3-33.
7) Table References:
    a. Table 3-33 states to "See Table 3-24" when it is referencing Table 3-32.
    b. Table 3-35 states "based on Table 3-25 and 3-26" when actually referring to 3-33 and 3-34
    c. Table 3-39 states "(Table 3-24)" when it is referring to either 3-32 or 3-33
    d. Table 3-40 states "See Tables 3-30, 3-31, and 3-32" but using Tables 3-37, 3-38, and 3-39
    e. Table 3-43 states "from Table 3-30" but using 3-37
    f. Table 3-105 says "See Table 3-83" and "See Table 3-75" but actually using 3-99 and 3-104
8) Table 3-54 is incorrectly using Table 3-49's value for gas lost due to Pressure Testing instead of Table 3-53's value for gas lost due to upgrading to ILI.
9) Table 3-73 is assuming a labor cost of $50 dollars per hour which is lower than the lowest cost presented in Table 3-66 on labor rates.
10) Table 3-78: Review existing surveillance and patrol procedures to validate adequacy for extreme events has 1 hour as the high and 2 hours as low. This appears to be a mistake.
11) Table 3-85: PHMSA did not apply the Consumer Price Index factors stated in the footnotes correctly to update 2006 dollars to 2015.
12) Table 3-90 states calculated as 0.5% in the footnotes, but is using 5% instead.
13) Table 3-92 does not include damage prevention costs outlined in Table 3-86.
14) Table 3-103's cost per operator is inconsistent with what is displayed in Table 3-66.
15) Table 3-104 is not capturing the total costs in Table 3-102.

16) Table 4-12: The average cost per incident listed in Table E-5 is not the same as what is listed in Table 4-12.
17) Table 6-1 pulled both onshore and offshore incidents and applied this to onshore miles.
18) Table 6-5 has pulled the incorrect value for 2014 Type B miles.
19) Table 6-6 has pulled the total cost and applied it as the other incident cost.
20) It is unclear why Table 7-2 varies from the value calculated in Table 3-106.
21) Appendix A-1: The sum of Class 1-4 does not add up to the total for HCA >30% SMYS interstate, intrastate and total.
22) Table B-3:
    a. PHMSA pulled the total gas emissions for methane emissions
    b. PHMSA calculated the SCM (3%) and utilized the 2015 value for the year 2016. Therefore, the social cost of methane was off by one year for all years.
    c. PHMSA is using the 2007 social cost of carbon instead of the 2015 social cost of carbon.

Identified Text Inconsistencies

Throughout replicating the calculations, ICF identified a variety of issues with PHMSA's calculations including

1) Page 45: In the Total Cost to Re-establish MAOP work, PHMSA uses the average cost of one, two, five and eight miles but the tables display one, two, five and ten miles.
2) Page 62: "Error! Reference source not found."

Tables Unable to Replicate

1) ICF was unable to replicate Tables 3-20, 3-28 and 3-42. ICF replicated the mileage, the percentages of each test applied, and the costs per mile, but were unable to replicate the total costs per class. This is particularly relevant for upgrading to ILI.
2) ICF was unable to replicate Table 3-48. It is unclear why the gas released would be different than Tables 3-12 and 3-13 as they are using the same equation without specifying different conditions.
3) ICF was unable to replicate the intrastate pressure test miles stated in Tables 3-50.
4) ICF was unclear why Table 3-41 not match Table 3-40 mileage for Class 3 and 4 miles. It is our understanding that Table 3-41 is just allocating what test would occur for the mileage stated in Table 3-40.
5) ICF could not replicate the cost for repairs stated in Table 3-64.

Questionable Calculation Assumptions Made by PHMSA that ICF Did Not Address

1) Table 3-60 excludes the mileage from Topic Area 1. The mileage accounted for in Topic Area 1 would also have to accelerate their repairs. It is not clear why PHMSA justified the removal of this mileage from Topic Area 2 as the only cost being evaluated is the cost of repair, and not an assessment cost.
2) Table 3-4 uses historical data for the miles of pipe that utilized various integrity assessment methods. It is not clear why PHMSA only considers ILI that utilize corrosion or metal loss tools and not dent or deformation tools, crack or long seam defect detection tools or other tools. It is also not clear why PHMSA only consider ECDA for Direct Assessment methods and not ICDA or SCCDA.

3) Equation 1's compressibility factor of 0.88 appears to be low compared to what would be expected on transmission and gathering lines under the average conditions in each of these respective industry segments.
4) The social cost of methane used in Table B-2 and throughout calculations inherently has a 3% discount rate associated with it. This social cost was used for both the 7% and the 3% discount rate.

Appendix B: All Recalculated Tables from the RIA for Gathering

Table B- 1

Table 2-2 Pipeline Infrastructure - Regulated Onshore Gas Gathering (2015)			
Type A Miles[1]	**Type B Miles[2]**	**Total Miles**	**Number of Operators**
7,844	3,580	11,423	367
Source: PHMSA Pipeline Data Mart			
1. Metal gathering line operating at greater than 20% specified minimum yield strength or non-metallic line for which maximum allowable operating pressure is greater than 125 pounds per square inch in a Class 2, Class 3, or Class 4 location.			
2. Metallic gathering line operating under 20% specified minimum yield strength or non-metallic pipe for which maximum allowable operating pressure is less than 125 pounds per square inch in a Class 3, Class 4, or certain Class 2 locations			

Table B- 2

Table 3-85. Unit Cost of 2006 Expanded Safety Provisions ($ per mile)				
Component	**Initial Capital Cost Component**	**Operating (Recurring) Costs (2006$)[1]**	**Initial Capital Cost (2015$)[2]**	**Operating (Recurring) Costs (2015)[2]**
Population survey	$588	$118	$691	$139
Corrosion control	$17,183	$449	$20,200	$528
Line markers	NA	$153	NA	$180
Damage prevention	NA	$259	NA	$304
Public education	NA	$198	NA	$233
1. Source: IPAA, as cited in PHMSA, 2006, Final Regulatory Evaluation, Regulated Natural Gas Gathering Lines.				
2. Updated from 2006 dollars using the BLS All-City Consumer Price Index, averaged through November (2006 CPI: 201.6; 2015 CPI: 237.0)				

Table B- 3

Table 3-86. Summary of Estimated Unit Costs, Unregulated Onshore Gas Gathering Pipelines			
	Operators of Currently Unregulated Lines (Group 1)	**Operators of Currently Regulated Lines (Group 2)**	**Operators of Lines with Cathodic Protection Subject to Damage Prevention Laws**
One-Time Capital			
Corrosion Control	$17,183	$12,887	$0.0
Recurring (7 years)			
Population Surveys	$118	$29	NA
Recurring – Annual			
Corrosion control	$449	$337	$22
Line markers	$153	$76	NA
Damage prevention	$259	$129	$13
Public awareness	$198	$20	NA
MAOP	$0.0	$0.0	NA
Design, installation, testing	$0.0	$0.0	NA
Emergency plan	$325	$20	NA
Source: PHMSA best professional judgment percentage adjustment (see text) of inflation-adjusted IPAA (2006) cost information.			

Table B- 4

Table 3-87. Currently Regulated Onshore Gas Gathering Infrastructure		
Type A Miles	**Type B Miles**	**Total Miles**
7,844	3,580	11,423
Source: 2014 Gas Gathering Annual Report		

Table B- 5

Table 3-88. Estimation of Total Currently Unregulated and Proposed Newly Regulated Onshore Gas Gathering Pipelines			
Type (Class 1 and Class 2)	**2012 API Member Estimate[1]**	**Revised Estimate based on GIS Mapping**	**Difference[2]**
Type A, Area 2 (high stress, ≥ 8")	48,124	77,554	29,430
High stress, < 8"	70,921	114,292	43,371
Type A (assumed < 8")[3]	13,542	21,823	8,281
Low stress, all sizes	108,273	174,486	66,213
Total	**240,860**	**388,156**	**147,296**
1. Source: Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, Re: Pipeline Safety: Safety of Gas Transmission Pipelines (Docket No. PHMSA-2011-0023), October 23, 2012. Data from 45 operators.			
2. Calculated as total mileage minus group 1 operator mileage.			

Table B- 6

Table 3-89. Estimation of Newly Regulated Mileage by Operator Group			
Operator Type	**Percent of Total Mileage[1]**	**Newly Regulated Type A Area 2 Miles**	**All other Unregulated Miles**
No existing regulated lines (group 1)	80%	62,419	249,986
Existing regulated lines (group 2)	20%	15,135	60,616
Total	**100%**	**77,554**	**310,602**
1. Source: PHMSA best professional judgment			

Table B- 7

Table 3-90. Estimation of One-Time Costs for Corrosion Control for Newly Regulated Gas Gathering Line				
Operator Type	**Newly Regulated Mileage**	**Mileage without Cathodic Protection[1]**	**One-Time Corrosion Control Unit Cost per Mile[2]**	**Total One-Time Corrosion Control Cost**
Group 1	62,419	3,121	17,183	53,627,059
Group 2	15,135	757	12,887	9,752,260
Total	**77,554**	**3,878**	**NA**	**63,379,319**
1. Calculated as 0.5% of newly regulated mileage.				
2. Source: see Table 3-86				

Table B- 8

Table 3-91. Estimation of Total Costs for Right-of-Way Surveillance for Newly Regulated Gas Gathering Lines				
Operator Type	**Newly Regulated Mileage**	**Periodic Right-Of- Way Surveillance Unit Cost[1]**	**Periodic Surveillance Costs (every 3 years)[2]**	**Annualized Surveillance Cost[3]**
Group 1	62,419	$118	7,365,411	$2,455,137
Group 2	15,135	$29	438,916	$146,305
Total	**77,554**	**NA**	**$7,804,327**	**$2,601,442**
1. Source: see Table 3-86				
2. Unit costs times mileage.				
3. Periodic costs divided by three.				

Table B- 9

Table 3-92. Estimation of Recurring Costs for Newly Regulated Gas Gathering Lines							
Mileage Type	**Mileage**	**Unit Costs[2]**					**Total Annual Cost[1]**
		Corrosion Control	**Line Markers**	**Damage Prev.**	**Public Awareness**	**Emergency Plan**	
Operator Group 1							
Total	62,419	0.0	153	0.0	198	325	42,195,067
Steel lines; cathodic protection	59,298	22	0.0	13.0	0.0	0.0	2,075,423
Steel lines; no cathodic protection	3,121	449	0.0	259.0	0.0	0.0	2,209,623
Operator Group 2							
Total	15,135	0.0	76	0	20	20	1,755,664
Steel lines; cathodic protection	14,378	22	0.0	13.0	0.0	0.0	503,240
Steel lines; no cathodic protection	757	337	0.0	129.0	0.0	0.0	352,646
Total	**77,554**	**NA**	**NA**	**NA**	**NA**	**NA**	**49,091,664**
1. Calculated as mileage times the sum of applicable unit costs.							
2. See Table 3-86							

Table B- 10

Table 3-93. Present Value of Compliance Costs, Gas Gathering Safety Provisions[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
One-time	$63,379,319	$4,225,288	$63,379,319	$4,225,288
Annualized periodic	$25,352,273	$1,690,152	$31,987,526	$2,132,502
Annual	$478,421,237	$31,894,749	$603,634,687	$40,242,312
Total	**$567,152,829**	**$37,810,189**	**$699,001,531**	**$46,600,102**
1. Total is present value over 15 year study period; average annual is total divided by 15.				

Table B- 11

Table 3-94. Gas Gathering Pipeline Reporting Requirements		
Regulation	**Description**	**Timing**
191.5	Immediate notice of certain incidents	Upon event
191.15	Incident report	Upon event
191.17	Annual report (i.e., pipeline summary data)	Annually
191.22(a)	Operation identification request	Once
191.22(c)	Notification of changes	Upon event
191.23	Safety-related condition report	Upon event

Table B- 12

Table 3-95. Proposed Reporting Requirements			
Regulation	**Description**	**Type A, Area 2 Lines**	**All Other Currently Unregulated Lines**
191.5	Immediate Notice of certain incidents	√	√
191.15	Incident Reports	√	√
191.17	Annual Reports (i.e., pipeline summary data)	√	√
191.22(a)	OPID Request	√	√
191.22(c)	Notification of Changes	√	NA
191.23	Safety-Related Condition Reports	√	NA
NA = not applicable			

Table B- 13

Table 3-96. Estimates of Unit Cost for Reporting Provisions (Per report)					
Component	**Group 1 One-Time**	**Group 1 Per Event**	**Group 2 One-Time**	**Group 2 Per Event**	**Group 1,2 Annual**
Immediate notice	$1,300	$100	$100	$100	NA
Incident report	$2,580	$1,400	$180	$1,400	NA
SRC report	$2,900	$340	$180	$340	NA
Annual report	$1,780	NA	$620	NA	$280
OPID request	$520	NA	NA	NA	NA
Notification of change	$980	$85	$180	$85	NA
Source: PHMSA best professional judgment Group 1 = operators without pre-existing lines.					
Group 2 = operators with pre-existing regulated lines.					
See Table 3-98 for reporting requirements applicable to Group 1 and Group 2 mileage					

Table B- 14

Table 3-97. Summary of Mileages by Operator Group			
Type A, Area 2 Lines		**All Other Currently Unregulated Lines[1]**	
Group 1	**Group 2**	**Group 1**	**Group 2**
62,419	15,135	249,986	60,616
Group 1 = operators without existing regulated lines. Group 2 = operators of existing regulated lines.			
1. Total estimated currently unregulated mileage minus Type A, Area 2 currently estimated unregulated.			

Table B- 15

Table 3-98. Reporting Requirements by Operator Group					
Regulation	**Description**	**Type A, Area 2 Lines**		**Group 1 Group 2**	
		Group 1	**Group 2**		
191.5	Immediate notice	√	√	√ √	Upon event
191.15	Incident report	√	√	√ √	Upon event
191.17	Annual report	√	√	√ √	Annually
191.22(a)	OPID request	√	√	√ √	Once
191.22(c)	Notification of changes	√	√	NA	Upon event
191.23	Safety-related condition report	√	√	NA	Upon event
Group 1 = operators without existing regulated lines Group 2 = operators of existing regulated lines					
NA = not applicable					

Table B- 16

Table 3-99: One Time Compliance Costs of Gathering Line Reporting Requirements			
Category	**Miles**	**Cost per Mile**	**Total One-Time Costs**
Type A, Area 2 Lines[1]			
Group 1	62,419	$174	$10,846,504
Group 2	15,135	$5	$76,583
Subtotal	77,554	NA	$10,923,087
All Other Currently Unregulated Lines[2]			
Group 1	249,986	$27	$6,662,133
Group 2	60,616	$0	$4,849
Subtotals	310,602	NA	$6,666,983
Total	**388,156**	**NA**	**$17,590,070**
Source: PHMSA best professional judgment Group 1 = operators without existing regulated lines Group 2 = operators of existing regulated lines			
1. Immediate notice, incident, SRC, annual, OPID request, notification of change reporting.			
2. Immediate notice, incident, annual, and OPID request reporting.			

Table B- 17

Table 3-100. Cost of Incident Reporting for Newly Regulated Gas Gathering Pipelines				
Year	**Incidents per 1,000 Miles[1]**	**Cost per Incident[2]**	**Annual Cost per 1,000 Miles**	**Costs per Year[3]**
1	0.2	$1,500	$300	$23,266
2-5	0.1	$1,500	$150	$11,633
6-15	0.0	$1,500	$60	$4,653
1. Source: PHMSA best professional judgment. See benefits analysis.				
2. Table 3-86, $1,400 for incident report, $100 for immediate notification per incident				
3. Cost per 1,000 miles × 68.749 thousand Type A Area 2 miles.				

Table B- 18

Table 3-101. Annual Costs for Safety Related Condition Reports			
Reports per 1000 Miles[1]	**Unit Cost per Report[2]**	**Cost per 1000 Miles[3]**	**Total Annual Costs[4]**
0.2	$340	$78	$6,065
1. Source: Estimated based on historical reporting levels.			
2. Source: PHMSA best professional judgment.			
3. Calculated as reports times unit cost.			
4. Calculated as cost per 1000 miles times thousands of Type A Area 2 miles (Table 3-96).			

Table B- 19

Table 3-102. Costs for Annual Reporting[1]			
Group	**Miles**	**Annual Cost Per 1000 Miles**	**Total Annual Costs**
Type A Area 2	77,554	$0	$0
All other regulated	310,602	$0	$0
Total	**388,156**	**NA**	**$0**
1. Zeroed Values as this cost is being accounted for as a separate item with a different methodology			

Table B- 20

Table 3-103. Recurring Incremental Compliance Costs for National Registry Reporting			
Operator Group	**Number of Operators[1]**	**Annual Costs per Operator[1]**	**Total Annual Costs**
Constructing 10 or more miles of pipelines	92	$86	$7,913
Acquisition, divestiture, merger, and entity changes	31	$86	$2,666
Total	**123**	$86	**$10,579**
1. Source: PHMSA best professional judgment			

Table B- 21

Table 3-104. Present Value of Recurring Reporting Costs				
Provision	**7% Discount Rate**		**3% Discount Rate**	
	Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
Incident reporting	$87,603	$5,840	$101,774	$6,785
SRC reporting	$59,103	$3,940	$74,572	$4,971
Annual reporting[3]	$0	$0	$0	$0
National Registry Reporting	$103,100	$6,873	$130,083	$8,672
Total	**$249,806**	**$16,654**	**$306,429**	**$20,429**
1. Represents 15-year study period.				
2. Total divided by 15.				
3. Accounted for annual portion of annual reporting as a separate cost item				

Table B- 22

Table 3-105. Present Value of Reporting Provision Costs				
Type of Provision	**7% Discount Rate**		**3% Discount Rate**	
	Total	**Average Annual**	**Total**	**Average Annual**
Recurring[1]	$249,806	$16,654	$306,429	$20,429
One-time[2]	$17,590,070	$1,172,671	$17,590,070	$1,172,671
Total	**$17,839,876**	**$1,189,325**	**$17,896,499**	**$1,193,100**
1. Source: See Table 3-99.				
2. Source: See Table 3-104.				

Table B- 23

Table 6-1. Safety Performance Baseline Calculation			
Year	**Corrosion and Excavation Damage Incidents[1]**	**Onshore Gathering Miles[2]**	**Incidents per 1000 Miles[3]**
2001	1	17,516.0	0.1
2002	3	16,994.0	0.2
2003	2	16,414.0	0.1
2004	2	17,401.0	0.1
2005	4	16,151.0	0.2
Total	**12**	**84,476.0**	**0.1**
1. Source: Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage			
2. Gas Gathering Annual Report			
3. Incidents divided by mileage times 1,000 miles.			

Table B- 24

Table 6-2. Baseline Incident Rate		
Estimated Corrosion and Excavation Damage Incident Rate (per 1,000 miles per year)	**Unregulated Higher-Stress, Larger-Diameter Onshore Gas Gathering Mileage**	**Estimated Corrosion and Excavation Damage Incidents per Year on Unregulated Lines (incidents per year)**
0.1	77,554	11

Table B- 25

Table 6-3. Average Consequences per Incident on Gas Transmission Systems in Class 1 and 2 Locations from Corrosion or Excavation Damage		
Category	**Number**	**Value**
Fatalities[1]	0.03	264,375.00
Injuries[1]	0.06	61,625.00
Evacuations[2]	11.68	17,517.19
Other	NA	175,447.19
Total	NA	518,964.38
Source: See Appendix E (Table E-7)		
1. DOT VSL guidance, $9.4M VSL, factor .105 for serious injury.		
2. Based on estimate of approximate cost of $1,500 per evacuation.		

Table B- 26

Table 6-4. Estimated Baseline Consequences Per Year					
Incidents	**Fatalities[1] (Count)**	**Injuries[2] (Count)**	**Evacuation Cost (Count)**	**Other Incident Costs**	**Total Costs**
11	$2,944,555	$686,367	$195,103	$1,954,095	$5,780,120
	0.3	1	130		
VSL= Value of Statistical Life					
1. Valued using a VSL of $9.4M per Departmental guidance (https://www.transportation.gov/sites/dot.gov/files/docs/VSL2015_0.pdf).					
2. Valued using 0.105 times the VSL ($987,000), also per Departmental guidance.					

Table B- 27

Table 6-5: Safety Performance of Type A Gas Gathering Pipelines			
Year	**Corrosion and Excavation Damage Incidents[1]**	**Type A Miles[2]**	**Incidents per 1000 Miles[3]**
2010	0.0	6,297.0	0.0
2011	0/0	6,781.0	0.0
2012	2.0	6,633.0	0.3
2013	0.0	7,624.0	0.0
2014	0.0	7,643.2	0.0
Total	2.0	34,978.2	0.1
1. Gas Transmission and Gas Gathering Incident Reports, onshore gathering lines corrosion and excavation damage.			
2. Gas Gathering Annual Report.			
3. Incidents divided by mileage times 1,000 miles.			

Table B- 28

Table 6-6. Calculation of Safety Benefits, Topic Area 8 (Millions 2015$ per year)							
Period	**Incidents per 1000 Miles Assumed**	**Incidents Avoided per year**	**Value of Avoided Fatalities[1]**	**Injuries[2]**	**Evacuations[3]**	**Other Incident Costs[4]**	**Average Benefits Per Year**
Year 1	0.10	3	$0.80	$0.19	$0.05	$0.53	$1.56
Years 2-5	0.07	5	$1.41	$0.33	$0.09	$0.94	$2.78
Years 6-15	0.06	7	$1.77	$0.41	$0.12	$1.18	$3.48
1. Calculated as incidents avoided times VSL ($9.4 million in 2015$).							
2. Calculated as incidents avoided times VSL ($9.4 million in 2015$) times 0.105.							
3. Calculated as number of evacuations times $1,500 (PHMSA best professional judgment).							
4. Calculated as average other incident damages times incidents averted (see Table E-7).							

Table B- 29

Table 6-7: Summary of Safety Benefits for Expanded Gathering Line Regulations[1]			
Average Annual (7%)	**Total (7%)**	**Average Annual (3%)**	**Total (3%)**
$2	$30	$3	$38
1. Based on expected stream of benefits from Table 6-4. Average annual is total discounted benefits divided by 15 years.			

Table B- 30

Table 6-8. Type A and Type B Gathering Line Incidents			
Year	**Incidents**	**Gas Released (MCF)**	**Average per Incident**
2010	0	0	0
2011	2	14,311	7,156
2012	3	13,570	4,523
2013	0	0	0
2014	0	0	0
2015	0	0	0
Total	**5**	**27,881**	**5,576**
Source: PHMSA Gas Transmission and Gas Gathering Incident Reports for onshore, natural gas, Type A and Type B incidents.			

Table B- 31

Table 6-9. Estimate of Reductions in Natural Gas, Methane, and Carbon Dioxide Released1			
Period	**Annual Releases Averted**		
	Natural Gas (MCF)[1]	**Methane (MCF)[2]**	**Carbon Dioxide (MT)[3]**
Year 1	16,801	15,121	26
Years 2-5	29,825	26,843	46
Years 6-15	37,379	33,642	58
15-Yr Total	**84,006**	**75,605**	**131**
MCF = thousand cubic feet MT = metric tons			
1. Calculated as average incidents avoided per year times historical average natural gas releases from gas gathering incidents.			
2. Calculated as natural gas released times 0.90.			
3. Calculated as natural gas released times 0.03 times 114.4 lbs./MCF carbon dioxide.			

Table B- 32

Table 6-10. Calculation of Benefits Per Year Based on Reductions in Volumes Emitted (3% Discount Rate)					
	Methane		**Carbon Dioxide**		**Average Benefits Per Year**
Period	**MCF**	**Average Benefit**	**Metric Tons**	**Average Benefit**	
Year 1	15,121	$378,027	26	$1,125	$379,152
Years 2-5	26,843	$691,204	46	$2,159	$693,363
Years 6-15	33,642	$1,052,979	58	$3,078	$1,056,058
MCF = thousand cubic feet					
Emissions calculated as expected incidents avoided times emission per incident. Values are the average of the product of emissions and the SCC/SCM value over the identified year range					

Table B- 33

Table 6-11. Total Environmental Benefits		
Pollutant	**Emissions**	**Social Benefit (3%)**
Methane (MCF)	458,908	$13,672,639
Carbon dioxide (MT)	794	$40,543
Total	**NA**	**$13,713,182**
MCF = thousand cubic feet MT = metric ton		

Table B- 34

Table 7-1. Summary of Benefits for Topic Area 8 (Millions 2015$)[1]				
Benefit	**Average Annual (7%)**	**Total (7%)**	**Average Annual (3%)**	**Total (3%)**
Safety benefits[2]	$2	$30	$3	$38
GHG emissions reductions	$1	$14	$1	$14
Total	**$3**	**$43**	**$3**	**$52**
1. Total is over 15-year study period; annual is total divided by 15 years.				
2. Sum of expected incidents averted times average incident consequence (see Table E-7).				

Table B- 35

Table 7-2 Summary of Compliance and Reporting Costs for Topic Area 8 (Millions 2015$)[1]			
Average Annual (7%)	**Total (7%)**	**Average Annual (3%)**	**Total (3%)**
$39	$585	$47	$699
1. Total is over 15-year study period; annual is total divided by 15 years.			

Table B- 36

Table 8-1. Mileages, Inspection Units, and New Operators for the Newly-Regulated Gathering Lines		
Mileage Group Descriptions	**Estimate of Miles**	**Estimated of Inspection Units**[1]
Type A, Area 2	77,554	388
Operator group 1	62,419	312
Operator group 2	15,135	76
1. Calculated as miles divided by 200.		

Table B- 37

Table 8-2. Unit Cost for State Pipeline Safety Programs in 2012		
Total State Program Expenses	**Estimated Number of Inspection-Days**	**Unit Cost per Inspection-Day**
$50,209,656	39,473	$1,272
Source: State reports		

Table B- 38

Table 8-3. Estimated Routine Field Inspection Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions (Type A, Area 2)			
Estimated Inspection Units	**No. of Inspection-Days per Unit**	**Total Field Inspection-Days**	**Total Field Inspection Costs ($ / 2 years)**
356	5	1,780	$2,264,160

Table B- 39

Table 8-4. Company Headquarter Inspection Costs to the States for Newly-Regulated Operators Subject to Safety Provisions					
No. of Operators	**No. of Inspection-Days per Operator**	**Total HQ Inspection-Days**	**Total HQ Inspection Costs[1]**	**Cost per Year, Initial 3-Year Cycle[2]**	**Cost per Year, Recurring 5- Year Cycle[3]**
75	7	525	$667,800	$222,600	$133,560
100	7	700	$890,400	$296,800	$178,080
125	7	875	$1,113,000	$371,000	$222,600
HQ = headquarters					
1. Inspection-days times unit cost per day ($1,272, see Table 8-2).					
2. Total divided by 3.					
3. Total divided by 5.					

Table B- 40

Table 8-5. Total Annual Costs to the States for Newly-Regulated Gathering Lines Subject to Safety Provisions, First Three Years (Millions)					
Field Inspections -Low	**Field Inspections -High**	**Company HQ Inspections1-Low**	**Company HQ Inspections1 -High**	**Total-Low**	**Total-High**
$1	$1	0.2	0.4	1	1
1. Based on between 75 and 125 newly regulated operators, for example.					

Appendix C: All Recalculated Tables from the RIA for Transmission

Table C- 1

Table 2-1 Pipeline Infrastructure - Gas Transmission (2015)			
System Type	**Onshore Miles**	**Total Miles**	**Number of Operators[1]**
Interstate	191,813	195,621	160
Intrastate	106,165	106,254	892
Total	297,979	301,875	1019
Source: PHMSA Pipeline Data Mart			
1. Entities may operate both inter- and intrastate pipelines. There are 1,019 total operators.			

Table C- 2

Table 3-1. Onshore Gas Transmission Mileage by Percent SMYS

Location	Total	<20% SMYS	20-30% SMYS	>30% SMYS	Percent >30% SMYS
INTERSTATE					
Class 1	160,029	6,750	7,977	145,301	91%
Class 2	17,805	1,460	1,436	14,909	84%
Class 3	13,927	1,302	1,307	11,318	81%
Class 4	28.539	3.616	9.264	15.659	55%
Total	191,789	9,516	10,729	171,544	89%
Intrastate					
Class 1	72,719	6,250	8,293	58,176	80%
Class 2	12,839	1,038	2,762	9,040	70%
Class 3	19,730	1,953	5,671	12,107	61%
Class 4	880	20.454	428.344	430.8	49%
Total	106,169	9,261	17,154	79,754	75%
Source: 2014 PHMSA Gas Transmission Annual Report SMYS = specified minimum yield strength					

Table C- 3

Table 3-2. Estimate of Previously Untested Onshore Gas Transmission Mileage in HCAs Operating at Greater than 30% SMYS

Location	Previously Untested HCA[1]	Percent >30% SMYS	HCA ≥ 30% SMYS[2]
Interstate			
Class 1	62	91%	56
Class 2	23	84%	19
Class 3	439	81%	357
Class 4	0	55%	0.0
Total	524	83%	432
Intrastate			
Class 1	13	80%	10
Class 2	18	70%	13
Class 3	749	61%	460
Class 4	5	49%	2
Total	785	62%	485

HCA = High consequence area

SMYS = specified minimum yield strength

1. Source: PHMSA 2014 Annual Report
2. See Appendix A.

Table C- 4

Table 3-3: Percent of Miles Capable of Accepting an Inline Inspection Tool

Class Location	HCA	Non- HCA
Interstate		
Class 1	95%	71%
Class 2	94%	70%
Class 3	89%	60%
Class 4	94%	56%
Intrastate		
Class 1	68%	53%
Class 2	66%	40%
Class 3	55%	33%
Class 4	49%	62%

Source: PHMSA 2014 Gas Transmission Annual Report

Table C- 5

Table 3-4. Miles of Onshore Gas Transmission Pipeline for which Integrity Assessment was Conducted (2010-2014)

Year	ILI	Pressure Test	Direct	Other	Total
Interstate					
2010	15,308	567	177	85	16,137
2011	17,366	829	157	29	18,381
2012	18,656	846	126	42	19,670
2013	15,687	739	106	144	16,676
2014	15,820	1,008	116	11	16,954
Total	82,837	3,989	682	311	87,818
Percentage	94%	5%	1%	0.4%	
Intrastate					
2010	4,792	826	1,539	1,191	8,348
2011	3,920	858	1,842	1,046	7,666
2012	5,041	1,232	2,085	2,570	10,928
2013	5,663	763	1,894	782	9,102
2014	5,801	807	1,641	750	8,998
Total	25,217	4,486	9,001	6,339	45,042
Percentage	56%	10%	20%	14%	

Source: PHMSA Gas Transmission Annual Reports: 2010-2014

Table C- 6

Table 3-5. Estimated Assessment Method for Previously Untested Pipe in High Consequence Areas (Percent of Mileage)

Location	ILI [1]	Pressure Test [2]	ILI Upgrade [2]
Interstate			
Class 1	95%	5%	0.0%
Class 2	94%	5%	1%
Class 3	89%	5%	6%
Class 4	94%	0.0%	6%
Intrastate			
Class 1	68%	10%	22%
Class 2	66%	20%	14%
Class 3	55%	20%	25%
Class 4	49%	21%	30%
1. Source: PHMSA 2014 Gas Transmission Annual Report			
2. PHMSA best professional judgment based on historical piggability and assessment methods (Tables 3-3 and 3- 4).			

Table C- 7

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]						
	Interstate Segment			**Intrastate Segment**		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**	**26" - 48"**	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)	30	16	8	30	16	8
Pipe thickness (inches)	0.38	0.38	0.25	0.38	0.38	0.25
Segment Miles	60	60	60	30	30	30
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	3	3	3	3	3	3
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,676,000	$1,718,000	$875,000	$2,338,000	$1,498,000	$786,000
Upgrade Costs per Mile	$44,600	$28,633	$14,583	$77,933	$49,933	$26,200
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,202.78	$326.95	$79.08	$801.86	$217.96	$52.72
Percentage of pipe that would have to be replaced	5%	5%	5%	5%	5%	5%
Cost to replace per inch mile	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
G&A Cost[7]	$45,161	$24,992	$12,532	$51,747	$29,230	$14,851

Table 3-6. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 1 and Class 2 Non-HCA Pipelines[1]						
Total Unit Cost (per mile)[6]	**$270,963**	**$149,952**	**$75,195**	**$310,482**	**$175,382**	**$89,103**
HCA = high consequence area MCF = thousand cubic feet						
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.						
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.						
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.						
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.						
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.						
6. Upgrade costs per mile plus cost of gas released during blowdown per mile.						
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs						

Table C- 8

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]

	Interstate Segment			Intrastate Segment		
	26" - 48"	**14" - 24"**	**4" - 12"[2]**	**26" - 48"**	**14" - 24"**	**4" - 12"[2]**
Diameter (inches)[2]	30	16	8	30	16	8
Segment Miles	45	45	45	15	15	15
Number of Mainline Valves	3	3	3	2	2	2
Number of Bends	6	6	6	6	6	6
Cost per Mainline Valve	$338,000	$220,000	$89,000	$338,000	$220,000	$89,000
Cost per Bend	$60,000	$32,000	$16,000	$60,000	$32,000	$16,000
Cost of Launcher	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Cost of Receiver	$741,000	$481,000	$280,000	$741,000	$481,000	$280,000
Total Upgrade Cost[3]	$2,856,000	$1,814,000	$923,000	$2,518,000	$1,594,000	$834,000
Upgrade Costs per Mile	$63,467	$40,311	$20,511	$167,867	$106,267	$55,600
Gas Released per Mile (MCF)[4]	286	78	19	190	52	13
Cost of Gas Released per Mile[5]	$1,203	$327	$79	$802	$218	$53
Percentage of pipe that would have to be replaced	5%	5%	5%	5%	5%	5%
Cost to replace per inch mile	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
G&A Cost[7]	$48,934	$27,328	$13,718	$69,734	$40,497	$20,731
Total Unit Cost (per mile)[6]	**$244,669**	**$136,638**	**$68,590**	**$348,669**	**$202,485**	**$103,653**
HCA = high consequence area MCF = thousand cubic feet						
PHMSA = Pipeline and Hazardous Materials Safety Administration						

Table 3-7. Estimated Average Unit Cost of Upgrade to Accommodate In-line Inspection Tools, Class 3 and Class 4 Pipelines and Class 1 and Class 2 HCA Pipelines[1]
1. Based on best professional judgment of PHMSA staff, and includes excavation, permitting, construction, and cleanup costs. Unit cost of gas released based on incident reports.
2. Pipelines below 4" generally cannot accommodate in-line inspection and will be exempt from requirements.
3. Total upgrade cost calculated as cost of launcher plus cost of receiver plus cost per bend multiplied by number of bends plus cost per mainline valve and number of mainline valves.
4. Based on Equation 1 using temperature (70 degrees F), pressure (14.7 PSIA at standard conditions; 50 PSI at blowdown conditions), and compressibility (factor of 0.88 at packed conditions) assumptions.
5. Assumes a natural gas cost of $4.21 per MCF, based on the cost of gas released intentionally during a controlled blowdown as part of a response to an incident (median of costs based on data for 294 incidents). Does not include the social cost of methane released.
6. Upgrade cost plus cost per mile plus the cost of gas release per mile.
7. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs

Table C- 9

Table 3-8. Calculation of Weighted Average Unit Cost to Accommodate Inline Inspection Tools

Type	Pipeline Diameter[1]			Weighted Average Cost per Mile[2]	
	> 26"	14" - 24"	<12"	Class 1, 2, Non-HCA	Class 3, 4, HCA
Interstate	41%	32%	27%	$179,175	$162,369
Intrastate	14%	29%	57%	$145,308	$166,827
1. Source: PHMSA 2014 Gas Transmission Annual Report					
2. Based on Tables 3-6 and 3-7.					

Table C- 10

Table 3-9. Estimated Unit Cost of ILI

Component	Interstate (60-mile) Segment			Intrastate (30-mile) Segment		
	26" - 48"	14" - 24"	4" - 12"	26" - 48"	14" - 24"	4" - 12"

Table 3-9. Estimated Unit Cost of ILI

Mobilization[1]	$15,000	$12,500	$10,000	$15,000	$12,500	$10,000
Base MFL tool[2]	$90,000	$72,000	$54,000	$45,000	$36,000	$27,000
Additional tools (Spiral MFL, Crack Tools, etc.)	$340,000	$322,000	$304,000	$340,000	$322,000	$304,000
Reruns	$63,000	$50,400	$37,800	$63,000	$50,400	$37,800
Analytical and data integration services	$80,000	$80,000	$80,000	$40,000	$40,000	$40,000
Operator preparation[3]	$27,000	$23,050	$19,100	$16,250	$13,650	$11,050
G&A Cost[4]	$123,000	$111,990	$100,980	$103,850	$94,910	$85,970
Total	**$738,000**	**$671,940**	**$605,880**	**$623,100**	**$569,460**	**$515,820**

Source: PHMSA best professional judgment.

1. Mobilization is the cost for mobilization and demobilization of the construction work crew, material and equipment to and from the work site. Regional differences may apply.

2. Typically $900 to $1,500 per mile.

3. Includes analysis, specifications, cleaning pigs, fatigue crack growth analysis, etc. Estimated as 10% of cost of ILI and related data analysis.

4. G&A costs for record keeping, reporting, scheduling, working with vendors, etc. equal to 20% of all costs

Table C- 11

Table 3-10. Estimation of ILI Assessment Cost[1]				
Segment Type	**Less than 12" Diameter**	**14" - 24" Diameter**	**Greater than 26" Diameter**	**Weighted Average Cost Per Mile**
Interstate (60-mile segment)	27%	32%	41%	$11,350
Intrastate (30-mile segment)	57%	29%	14%	$18,216
1. Weighted average based on unit costs (see Table 3-9) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.				

Table C- 12

3-11 Estimated Cost of Conducting Pressure Test ($2015)				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	$297,205	$325,730	$399,940	$877,272
24	$375,000	$420,000	$720,000	$1,160,769
36	$578,424	$738,787	$1,018,202	$2,053,359
Source: T.D. Williamson, Inc., Houston, TX - was used to determine 24 inch pressure test costs				
Source: Greene’s Energy Group, LLC (2013), - Ratios from Green's Energy Group report were used to take T.D. Williamson's 24 inch diameter figures and determine 12 inch and 36 inch pipe.				

Table C- 13

Table 3-12. Volume of Gas Lost During Pressure Tests (MCF): Interstate Pipelines[1]				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	44	88	221	442
24	181	361	903	1805
36	415	830	2075	4149
MCF = thousand cubic feet				
1. Estimated using Equation 1.				

Table C- 14

Table 3-13. Volume of Gas Lost During Pressure Tests (MCF): Intrastate Pipelines[1]				
Pipe Diameter (inches)	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12	29	59	147	294
24	120	241	602	1,203
36	271	542	1,354	2,708
MCF = thousand cubic feet				
1. Estimated using Equation 1.				

Table C- 15

Table 3-14. Cost of Lost Gas: Interstate Pipelines[1]					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1 Mile	**2 Mile**	**5 Mile**	**10 Mile**	**Average**
12	$252	$504	$1,261	$2,522	$1,135
24	$1,031	$2,061	$5,154	$10,307	$4,638
36	$2,369	$4,738	$11,846	$23,692	$10,662
1. Calculated based on volume lost (see Table 3-12) times the cost of gas ($5.71 per thousand cubic feet).					

Table C- 16

Table 3-15. Costs of Lost of Gas: Intrastate Pipelines[1]

Pipe Diameter (inches)	Segment Length (miles)				
	1 Mile	2 Mile	5 Mile	10 Mile	Average
12	$168	$336	$841	$1,681	$756
24	$687	$1,374	$3,436	$6,871	$3,092
36	$1,546	$3,092	$7,730	$15,461	$6,957

1. Based on volume lost (see Table 3-13) times the cost of gas ($5.71 per thousand cubic feet).

Table C- 17

Table 3-16. Total Pressure Test Assessment Cost: Interstate Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12 inch				
Pressure test[1]	$356,646	$390,876	$479,928	$1,052,726
Lost gas[2]	$252	$504	$1,261	$2,522
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$456,898	$491,380	$581,189	$1,155,248
24 inch				
Pressure test[1]	$450,000	$504,000	$864,000	$1,392,923
Lost gas[2]	$1,031	$2,061	$5,154	$10,307
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$551,031	$606,061	$969,154	$1,503,230
36 inch				
Pressure test[1]	$694,109	$886,544	$1,221,843	$2,464,030
Lost gas[2]	$2,369	$4,738	$11,846	$23,692
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$796,478	$991,283	$1,333,689	$2,587,723
1. Unit costs (see Table 3-11) plus 20% G&A.				
2. See Tables 3-14.				
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.				

Table C- 18

Table 3-17. Total Pressure Test Assessment Cost: Intrastate Pipelines				
Component	**Segment Length (miles)**			
	1	**2**	**5**	**10**
12 inch				
Pressure test[1]	$356,646	$390,876	$479,928	$1,052,726
Lost gas[2]	$168	$336	$841	$1,681
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$456,814	$491,212	$580,768	$1,154,407
24 inch				
Pressure test[1]	$450,000	$504,000	$864,000	$1,392,923
Lost gas[2]	$687	$1,374	$3,436	$6,871
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$550,687	$605,374	$967,436	$1,499,794
36 inch				
Pressure test[1]	$694,109	$886,544	$1,221,843	$2,464,030
Lost gas[2]	$1,546	$3,092	$7,730	$15,461
Alternative supply[3]	$100,000	$100,000	$100,000	$100,000
Total	$795,655	$989,636	$1,329,573	$2,579,491
1. Unit costs (see Table 3-11) plus 20% G&A.				
2. See Tables 3-15.				
3. Approximation of cost of temporary supply (up to $1 million) for 10% of tests.				

Table C- 19

Table 3-18. Per Mile Pressure Test Costs					
Pipe Diameter (inches)	**Segment Length (miles)**				
	1	**2**	**5**	**10**	**Average**
Interstate					
12	$456,898	$245,690	$116,238	$115,525	$233,588
24	$551,031	$303,031	$193,831	$150,323	$299,554
36	$796,478	$495,641	$266,738	$258,772	$454,407
Intrastate					
12	$456,814	$245,606	$116,154	$115,441	$233,503
24	$550,687	$302,687	$193,487	$149,979	$299,210
36	$795,655	$494,818	$265,915	$257,949	$453,584
Source: Tables 3-16 and 3-17 divided by miles per segment.					

Table C- 20

Table 3-19 Weighted Average Unit Pressure Test Assessment Cost Per Mile[1]				
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**	**Average Cost**
Interstate	27%	57%	16%	$305,543
Intrastate	57%	37%	6%	$270,444
1. Weighted average based on unit costs (see Table 3-18) and percentages of gas transmission mileage by diameter for inter and intrastate pipe from the 2014 Gas Transmission Annual Report.				

Table C- 21

Table 3-20. Annual Costs to Re-establish MAOP, Previously Untested Pipe Operating at Greater than 30% SMYS in a HCA

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	40,466	57,334	0.0	97,800
Class 2	13,698	19,615	2,230	35,543
Class 3	240,253	363,351	247,904	851,508
Class 4	0.0	0.0	0.0	0.0
Subtotal	**294,417**	**440,300**	**250,134**	**984,851**
Intrastate				
Class 1	8,588	18,751	28,226	55,565
Class 2	10,158	45,699	21,887	77,744
Class 3	306,968	1,657,232	1,417,384	3,381,585
Class 4	1,457	9,272	9,063	19,792
Subtotal	**327,172**	**1,730,954**	**1,476,560**	**3,534,686**
Total				
Class 1	49,054	76,085	28,226	153,365
Class 2	23,856	65,313	24,118	113,287
Class 3	547,221	2,020,583	1,665,288	4,233,093
Class 4	1,457	9,272	9,063	19,792
Grand Total	**621,588**	**2,171,254**	**1,726,695**	**4,519,537**
ILI = inline inspection				
HCA = high consequence area				
MAOP = maximum allowable operating pressure PT = pressure test				
SMYS = specified minimum yield strength				

Table C- 22

Table 3-21 Estimated Unit Cost of Direct Assessment ($ per mile)			
Phase	**Low Estimate**	**Mid Estimate**	**High Estimate**
Pre-assessment	$5,000	$7,500	$10,000
Indirect inspection	$2,500	$10,250	$18,000
Direct examination	$15,000	$17,500	$20,000
Post-assessment	$5,000	$7,500	$10,000
Total	**$27,500**	**$42,750**	**$58,000**
Source: PHMSA best professional judgment			

Table C- 23

Table 3-22. Integrity Assessment Methods			
Location	**Inline Inspection**	**Pressure Test**	**Direct Assessment and Other Methods**
Interstate	94%	5%	1%
Intrastate	56%	10%	34%
Source: 2010-2014 PHMSA Annual Report part F.			

Table C- 24

Table 3-23. Estimated Annual Baseline Assessments of HCA Segments Operating at Greater than 30% SMYS

Location	Total HCA	ILI Miles	PT Miles	DA and Other Miles
Interstate	29	27	1	0.3
Intrastate	32	18	3	11
HCA = high consequence area				
SMYS = specified minimum yield strength				
Source: Total mileage from Table 3-2 divided by 15 and multiplied by rates shown in Table 3-22.				

Table C- 25

Table 3-24. Estimated Baseline Costs Per Year on Previously Untested HCA Segments Operating at Greater than 30% SMYS

Annual Cost	Inline Inspections	Pressure Tests	Direct Assessment and Other Methods	Total
Interstate	$308,560	$399,987	$13,925	$722,472
Intrastate	$329,824	$871,018	$470,834	$1,671,676
Total	$638,384	$1,271,005	$484,759	$2,394,148

Table C- 26

Table 3-25. Net Average Annual Costs to Assess Previously Untested HCA Segments Operating at Greater than 30% SMYS

Component	Interstate	Intrastate	Total
Compliance costs	$984,851	$3,534,686	$4,519,537
Baseline integrity management costs	($722,472)	($1,671,676)	($2,394,148)
Net costs	**$262,379**	**$1,863,009**	**$2,125,388**
HCA = high consequence area			
SMYS = specified minimum yield strength			

Table C- 27

Table 3-26. Mileage of Pipe for which Records are Inadequate

Location	HCA	Class 3 and Class 4 Non-HCA	Total
Interstate			
Class 1	79	0.0	79
Class 2	97	0.0	97
Class 3	437	672	1,109
Class 4	1	0.2	1
Subtotal	613	673	1,286
Intrastate			
Class 1	32	0.0	32
Class 2	34	0.0	34
Class 3	1,044	1,841	2,886
Class 4	125	1	126
Subtotal	1,235	1,843	3,077
Total			
Class 1	111	0.0	111
Class 2	130	0.0	130
Class 3	1,481	2,514	3,995
Class 4	125	2	127
Grand Total	**1,848**	**2,515**	**4,363**
HCA = high consequence area			
Source: PHMSA 2014 Gas Transmission Annual Report: Part Q Sum of "Incomplete Records" columns by class location and HCA status			

Table C- 28

Table 3-28. Annual Costs to Re-establish MAOP, Segments with Inadequate Records Located in HCAs and Class 3 and 4 Non-HCAs

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$56,747	$80,402	$0.0	$137,148
Class 2	$68,741	$98,432	$11,193	$178,365
Class 3	$599,584	$1,129,921	$3,029,037	$4,758,543
Class 4	$570	$0.0	$1,353	$1,923
Subtotal	$725,642	$1,308,754	$3,041,583	$5,075,979
Intrastate				
Class 1	$26,572	$58,014	$87,327	$171,913
Class 2	$26,979	$121,375	$58,133	$206,487
Class 3	$1,435,387	$10,405,262	$13,896,904	$25,737,552
Class 4	$75,199	$477,109	$464,171	$1,016,479
Subtotal	$1,564,137	$11,061,760	$14,506,534	$27,132,431
Total				
Class 1	$83,318	$138,415	$87,327	$309,061
Class 2	$95,719	$219,807	$69,326	$384,852
Class 3	$2,034,972	$11,535,183	$16,925,941	$30,496,095
Class 4	$75,769	$477,109	$465,524	$1,018,402
Grand Total	**$2,289,778**	**$12,370,514**	**$17,548,117**	**$32,208,409**
ILI = inline inspection				
HCA = high consequence area				
MAOP = maximum allowable operating pressure PT = pressure test				
SMYS = specified minimum yield strength				

Table C- 29

Table 3-29. Estimated miles of HCA Segments with Inadequate MAOP Records Assessed per Year by Baseline Assessment Method				
Miles	**Total HCA**	**ILI Miles**	**PT Miles**	**DA and Other Miles**
Interstate	41	39	2	0.5
Intrastate	82	46	8	28
Source: HCA miles from Table 3-26 divided by 15 years and multiplied by the HCA assessment rates in Table 3-22.				

Table C- 30

Table 3-30. Estimated Annual Costs for Baseline Assessments of HCA Segments: Inadequate Records				
Location	**Inline Inspections**	**Pressure Tests**	**Direct Assessment and Other Methods**	**Total**
Interstate	$437,785	$567,503	$19,757	$1,025,044
Intrastate	$839,443	$2,216,846	$1,198,330	$4,254,618
Total	$1,277,227	$2,784,349	$1,218,087	$5,279,663

Table C- 31

Table 3-31. Net Average Annual Costs to Assess HCA Segments: Inadequate Records			
Component	**Interstate**	**Intrastate**	**Total**
Compliance costs	$5,075,979	$27,132,431	$32,208,409
Baseline integrity management costs	($1,025,044)	($4,254,618)	($5,279,663)
Net costs	**$4,050,934**	**$22,877,812**	**$26,928,747**

Table C- 32

Table 3-32. Estimated MCA Mileage						
	Onshore GT Miles[1]	Non-HCA[1,2]	MCA % of Non-HCA[3]	MCA Miles[4]	Roadway MCA Miles[5]	Total MCA Miles[6]
Interstate						
Class 1	160,029	159,374	2%	3,187	1,372	4,559
Class 2	17,805	16,774	50%	8,387	144	8,531
Class 3	13,927	7,378	100%	7,378	0.0	7,378
Class 4	29	10	100%	10	0.0	10
Subtotal	191,789	183,536	NA	18,962	1,516	20,478
Intrastate						
Class 1	72,719	71,692	2%	1,434	617	2,051
Class 2	12,839	12,396	50%	6,198	107	6,305
Class 3	19,730	10,224	100%	10,224	0.0	10,224
Class 4	880	156	100%	156	0.0	156
Subtotal	106,169	94,468	NA	18,012	724	18,736
Total						
Class 1	232,748	231,066	2%	4,621	1,989	6,610
Class 2	30,645	29,170	50%	14,585	251	14,836
Class 3	33,657	17,602	100%	17,602	0.0	17,602
Class 4	908	166	100%	166	0.0	166
Grand Total	**297,958**	**278,004**	**NA**	**36,974**	**2,240**	**39,214**
HCA = high consequence area MCA = moderate consequence area						
1. Source: PHMSA 2014 Gas Transmission Annual Report, Part Q. Total mileage shown for context only.						
2. Excludes mileage reported under inadequate maximum allowable operating pressure records.						
3. Source: PHMSA best professional judgment; based on homes and occupied sites in primary impact radius only.						
4. Non-HCA mileage multiplied by percentage MCA.						
5. 20% of total intersecting mileage. Total mileage based on overlay of Federal Highway Administration map with National Pipeline Mapping System pipeline data; 20% based on PHMSA best professional judgment.						
6. MCA miles plus additional roadway MCA miles.						

Table C- 33

Table 3-33. Estimation of MCA Mileage Subject to Integrity Assessment Requirements						
Location	**MCA Mileage[1]**	**% Piggable[2]**	**Mileage Subject to Rule[3]**	**Mileage Subject to Rule less Overlap[4]**	**% MCA Currently Assessed[5]**	**MCA not Previously Assessed[6]**
Interstate						
Class 1	4,559	71%	3,237	2,622	50%	1,311
Class 2	8,531	70%	5,972	5,434	70%	1,630
Class 3	7,378	NA	7,378	6,490	80%	1,298
Class 4	10	NA	10	10	90%	1
Subtotal	20,478	NA	16,597	14,556	NA	4,240
Intrastate						
Class 1	2,051	53%	1,087	1,011	50%	505.429518
Class 2	6,305	40%	2,522	2,371	70%	711.204
Class 3	10,224	NA	10,224	9,500	80%	1900
Class 4	156	NA	156	155	90%	15.5
Subtotal	18,736	NA	13,989	13,037	NA	3,132
Total						
Class 1	6,610	66%	4,363	3,633	50%	1,817
Class 2	14,836	57%	8,457	7,805	70%	2,341
Class 3	17,602	NA	17,602	15,990	80%	3,198
Class 4	166	NA	166	165	90%	17
Grand Total	39,214	**NA**	**30,587**	**27,593**	**NA**	**7,372**
MCA = moderate consequence area						
1. See Table 3-32						
2. Assumed equal to non-HCA percent piggable based on data from Part R of the annual report (see Table 3-3).						
3. MCA mileage times percent piggable.						
4. Excludes MCA mileage subject to MAOP verification provisions						
5. Assumed based on the overall reported assessed mileage and assessed mileage in HCAs						
6. Mileage subject to proposed rule less overlap with previous other topic areas multiplied by (100%-% not previously assessed).						

Table C- 34

Table 3-34. Estimated MCA Integrity Assessment Methods			
Location	**ILI[1]**	**PT[2]**	**DA and Other Methods[3]**
Interstate			
Class 1	100%	0%	0.0%
Class 2	100%	0%	0.0%
Class 3	60%	5%	35%
Class 4	55%	5%	40%
Intrastate			
Class 1	100%	0%	0.0%
Class 2	100%	0%	0.0%
Class 3	33%	10%	57%
Class 4	62%	10%	28%
1. PHMSA assumed operators will use ILI where possible.			
2. 2010-2014 PHMSA Annual Report part F. Historical rates of pressure testing in integrity assessments. The proposed rule requires assessment of pipelines in Class 1 and Class 2 locations only if piggable.			
3. PHMSA assumed direct assessment of remaining pipelines.			

Table C- 35

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)				
	ILI	**PT**	**DA & Other**	**Total**
Interstate				
Class 1	1,311	0.0	0.0	1,311
Class 2	1,630	0.0	0.0	1,630
Class 3	779	65	454	1,298
Class 4	1	0.1	0.4	1
Subtotal	3,721	65	455	4,240
Intrastate				
Class 1	505	0.0	0.0	505
Class 2	711	0.0	0.0	711
Class 3	627	190	1,083	1,900
Class 4	10	2	4	16
Subtotal	1,853	192	1,087	3,132
Total				
Class 1	1,817	0.0	0.0	1,817
Class 2	2,341	0.0	0.0	2,341
Class 3	1,406	255	1,537	3,198
Class 4	10	2	5	17
Grand Total	**5,574**	**257**	**1,542**	**7,372**

Table 3-35. Estimated Assessment Methods for MCA Integrity Assessments (Miles)
Source: Based on Table 3-33 and Table 3-34. DA = direct assessment
ILI = inline inspection
MCA = moderate consequence area PT = pressure test

Table C- 36

Table 3-36. Estimated Annual Costs for Expansion of Integrity Assessments Outside of HCAs

	ILI	PT	DA & Other	Total
Interstate				
Class 1	$992,044	$0.0	$0.0	$992,044
Class 2	$1,233,567	$0.0	$0.0	$1,233,567
Class 3	$589,289	$1,321,981	$1,294,755	$3,206,025
Class 4	$416	$1,018	$1,140	$2,575
Subtotal	$2,815,316	$1,323,000	$1,295,895	$5,434,211
Intrastate				
Class 1	$613,796	$0.0	$0.0	$613,796
Class 2	$863,690	$0.0	$0.0	$863,690
Class 3	$761,432	$3,425,625	$3,086,550	$7,273,608
Class 4	$11,670	$27,946	$12,369	$51,985
Subtotal	$2,250,589	$3,453,571	$3,098,919	$8,803,079
Total				
Class 1	$1,605,840	$0.0	$0.0	$1,605,840
Class 2	$2,097,257	$0.0	$0.0	$2,097,257
Class 3	$1,350,721	$4,747,607	$4,381,305	$10,479,633
Class 4	$12,087	$28,964	$13,509	$54,560
Grand Total	$5,065,905	$4,776,571	$4,394,814	$14,237,290
DA = direct assessment ILI = inline inspection				
HCA = high consequence area PT = pressure test				

Table C- 37

Table 3-37. Estimated Mileage of Previously Untested Pipe Operating at 20-30% SMYS in HCAs			
Location	**Previously Untested HCA Miles[1]**	**Percent of all Pipe Operating at 20-30% SMYS[1]**	**HCA Miles 20-30% SMYS[2]**
Interstate			
Class 1	62	5%	3
Class 2	23	8%	2
Class 3	439	9%	41
Class 4	0.0	32%	0.0
Subtotal	524	NA	46
Intrastate			
Class 1	13	11%	1
Class 2	18	22%	4
Class 3	749	29%	215
Class 4	5	49%	2
Subtotal	785	NA	223
Total			
Class 1	75	7%	4
Class 2	41	14%	6
Class 3	1,188	21%	256
Class 4	5	48%	2
Grand Total	1,309	**NA**	**269**
HCA = high consequence area.			
SMYS = specified minimum yield strength.			
1. Source: 2014 PHMSA Gas Transmission Annual Report.			
2. Calculated as untested HCA mileage times percent of all pipe operated at 20-30% SMYS.			

Table C- 38

Table 3-38. Previously Untested Non-HCA Pipe in Class 3 and 4 Locations	
Location	**Mileage**
Interstate	
Class 3	888
Class 4	0.0
Subtotal	888
Class 3	724
Class 4	1
Subtotal	725
Total	
Class 3	1,612
Class 4	1
Grand Total	1,613
Source: 2014 PHMSA Gas Transmission Annual Report.	

Table C- 39

Table 3-39. Estimation of Piggable MCA Mileage in Class 1 and 2 Locations			
Location	**Piggable MCA[1]**	**Percent of Non-HCA Mileage Previously Untested[2]**	**Previously Untested Piggable MCA Mileage[3]**
Interstate			
Class 1	3,237	0.2	615
Class 2	5,972	0.1	537
Subtotal	9,209	NA	1,153
Intrastate			
Class 1	1,087	0.1	76
Class 2	2,522	0.1	151
Subtotal	3,609	NA	227
Total			
Class 1	4,324	NA	691
Class 2	8,494	NA	689
Grand Total	**12,818**	**NA**	**1,380**
MCA = moderate consequence area.			
1. Estimated as MCA (Table 3-33) times % piggable non-HCA (Table 3-3).			
2. Source: 2014 PHMSA Gas Transmission Annual Report.			
3. Calculated as piggable MCA mileage multiplied by percent untested non-HCA mileage.			

Table C- 40

Table 3-40. Summary of Applicable Previously Untested Mileage

Location	HCA Operating at 20-30% SMYS	Class 3 and 4 Non- HCA	Piggable Class 1 and 2 MCA	Total
Interstate				
Class 1	3	0	615	618
Class 2	2	0	537	539
Class 3	41	888	0.0	929
Class 4	0.0	0.0	0.0	0.0
Subtotal	46	888	1,153	2,087
Intrastate				
Class 1	1	0.0	76	78
Class 2	4	0.0	151	155
Class 3	215	724	0.0	939
Class 4	2	1	0.0	3
Subtotal	223	725	227	1,175
Total				
Class 1	4	0.0	691	696
Class 2	6	0.0	689	694
Class 3	256	1,612	0.0	1,868
Class 4	2	1	0.0	3
Grand Total	**269**	**1,613**	**1,380**	**3,262**
Source: See Tables 3-37, 3-38, and 3-39. HCA = high consequence area				
MCA = moderate consequence area SMYS = specified minimum yield strength				

Table C- 41

Table 3-41. Miles by Estimated Assessment Method				
Location	**Total ILI**	**PT**	**Upgrade and ILI**	**Total**
Interstate				
Class 1	618	0.0	0.0	618
Class 2	539	0.0	0.0	539
Class 3	558	46	325	929
Class 4	0.0	0.0	0.0	0.0
Subtotal	1,715	46	325	2,087
Intrastate				
Class 1	78	0.0	0.0	78
Class 2	153	0.4	2	155
Class 3	582	94	263	939
Class 4	0.0	0.0	0.0	0.0
Subtotal	813	94	265	1,172
Total				
Class 1	696	0.0	0.0	696
Class 2	692	0.4	2	694
Class 3	1,140	140	588	1,868
Class 4	0.0	0.0	0.0	0.0
Grand Total	**2,527**	**141**	**590**	**3,259**

Table C- 42

Table 3-42. Annual Costs to Re-establish MAOP, Previously Untested Segments Other than HCA Operating at Greater than 30% SMYS

Location	ILI	PT	Upgrade and ILI	Total
Interstate				
Class 1	$467,688	$0.0	$0.0	$467,688
Class 2	$408,074	$0.0	$0.0	$408,074
Class 3	$421,852	$946,361	$3,766,438	$5,134,652
Class 4	$0.0	$0.0	$0.0	$0.0
Subtotal	$1,297,613	$946,361	$3,766,438	$6,010,413
Intrastate				
Class 1	$94,198	$0.0	$0.0	$94,198
Class 2	$185,316	$6,981	$24,060	$216,356
Class 3	$707,217	$1,693,495	$3,244,413	$5,645,125
Class 4	$0.0	$0.0	$0.0	$0.0
Subtotal	$986,731	$1,700,476	$3,268,473	$5,955,679
Total				
Class 1	$561,885	$0.0	$0.0	$561,885
Class 2	$593,389	$6,981	$24,060	$624,430
Class 3	$1,129,069	$2,639,856	$7,010,851	$10,779,777
Class 4	$0.0	$0.0	$0.0	$0.0
Grand Total	$2,284,344	$2,646,837	$7,034,911	$11,966,092
ILI = inline inspection				
HCA = high consequence area				
MAOP = maximum allowable operating pressure PT = pressure test				
SMYS = specified minimum yield strength				

Table C- 43

Table 3-43. Estimated Miles of Previously Untested HCA Segments Operating at 20%- 30% SMYS Assessed per Year by Baseline Assessment Method

Location	Total HCA	Inline Inspection	Pressure Test	Direct Assessment and Other Methods
Interstate	3	3	0.1	0.0
Intrastate	15	8	1	5
HCA = high consequence area.				
SMYS = specified minimum yield strength.				
Source: HCA mileage from Table 3-37 divided by 15 and multiplied by the baseline HCA assessment rates from Table 3-22.				

Table C- 44

Table 3-44. Estimated Baseline Costs Per Year on HCA Segments Operating at 20%-30% SMYS Assessed per Year by Baseline Assessment Method

Location	Inline Inspections	Pressure Tests	Direct Assessment and Other Methods	Total
Interstate	$32,880	$42,623	$1,484	$76,987
Intrastate	$151,667	$400,530	$216,509	$768,705
Total	**$184,547**	**$443,153**	**$217,993**	**$845,693**

Table C- 45

Table 3-45. Net Average Annual Costs to Assess HCA Segments Operating at 20-30% Specified Minimum Yield Strength

Component	Interstate	Intrastate	Total
Compliance costs	$6,010,413	$5,955,679	$11,966,092
Baseline integrity management costs	($76,987)	($768,705)	($845,693)
Net costs	**$5,933,426**	**$5,186,974**	**$11,120,399**

Table C- 46

Table 3-46. Natural Gas Composition

Gas	Percent of Volume
Methane (CH_4)	96%
Carbon dioxide ($C0_2$)	1%
Other Fluids	3%
Source: Estimated based on natural gas quality standards and operator reported measurements	
Enbridge Estimates: https://www.enbridgegas.com/gas-safety/about-natural-gas/components-natural-gas.aspx Spectra Estimates: https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural- Gas	

Table C- 47

Table 3-47. Proportion of Gas Transmission Mileage by Diameter			
Segment Type	**<12" Diameter**	**14"-34" Diameter**	**36"+ Diameter**
Interstate	27%	57%	16%
Intrastate	57%	37%	6%
Source: 2014 Gas Transmission Annual Report			

Table C- 48

Table 3-48. GHG Emissions from Pressure Test Blowdowns			
Diameter (inches)	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
12	113	108	168
24	424	406	631
36	974	932	1,449
Source: See Equation 1 and Table 3-46 lbs. = pounds			
MCF = thousand cubic feet			

Table C- 49

Table 3-49. GHG Emissions from Pressure Tests per Assessment Mile			
Location	**Gas Released per mile (MCF)**	**Methane Released per Mile (MCF)**	**Carbon Dioxide Released per Mile (lbs.)**
Interstate	424.3	406.1	631.0
Intrastate	277.7	265.8	413.0
lbs. = pounds			
MCF = thousand cubic feet			
1. Weighted average based on share of pipeline mileage by diameter.			

Table C- 50

Table 3-50. Total GHG Emissions from Pressure Test Blowdowns					
Item	**PT Miles (Interstate)**	**PT Miles (Intrastate)**	**Gas Released (MCF)**	**Methane (MCF)**	**Carbon Dioxide (lbs.)**
Re-establish MAOP: HCA > 30% SMYS[1]	2	48	14,086	13,480	20,949
Re-establish MAOP: Inadequate Records[2]	36	491	151,687	145,164	225,589
Integrity Assessment: Non-HCA[1]	65	192	80,758	77,285	120,103
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable[1]	44	72	38,850	37,180	57,778
Total	**148**	**802**	**285,381**	**273,109**	**424,418**
PT = pressure test.					
MCF = thousand cubic feet.					
1. Miles pressure tested for compliance with MAOP reverification requirements minus baseline HCA pressure test miles.					
2. MCA miles pressure tested for compliance with MCA integrity assessment requirements.					

Table C- 51

Table 3-51. Natural Gas Lost due to Blowdowns per Mile (MCF/Mile)			
Location	**Diameter 12" or less**	**Diameter 14" to 24"**	**Diameter 26" and above**
Interstate	18.6	130.3	332.3
Intrastate	19.9	114.3	344.3
MCF = thousand cubic feet. Source: See Equation 1 in Section 3.1.4.3.			

Table C- 52

Table 3-52. Proportion of Gas Transmission Mileage by Diameter			
Segment Type	**≤ 12” Diameter**	**14"-24" Diameter**	**≥ 26"Diameter**
Interstate	27%	32%	41%
Intrastate	57%	29%	14%
Source: 2014 Gas Transmission Annual Reports			

Table C- 53

Table 3-53. GHG Emissions from Blowdowns, ILI Upgrade (per Mile)			
Location	**Gas Released (MCF)[1]**	**Methane Emissions (MCF)[2]**	**$C0_2$ Emissions (lbs.)[3]**
Interstate	183	175	272
Intrastate	93	89	319
CO_2 = carbon dioxide CH_4 = methane			
GHG = greenhouse gas			
HCA = high consequence area ILI = inline inspection			
ILI = inline inspection			
lbs =pounds			
1. Weighted Average based on natural gas emissions due to upgrade by diameter and annual report diameter data			
2. Gas emissions multiplied by 95.7% methane			
3. Gas Emissions multiplied by 1.3% CO^2 and 114.4 lbs/MCF CO^2			

Table C- 54

Table 3-54. Total GHG Emissions due to Blowdowns

Item	ILI Upgrade Miles (Interstate)	ILI Upgrade Miles (Intrastate)	Gas Released (MCF)	Methane Emissions (MCF CH_4)	C02 Emissions (lbs.)
Re-establish MAOP: HCA > 30% SMYS	22	120	15,078	14,429	44,073
Re-establish MAOP: Inadequate Records	263	1,176	157,344	150,578	446,704
Integrity Assessment: Non-HCA	0	0	0	0	0
Re-establish MAOP: HCA 20- 30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	325	265	84,073	80,458	173,004
Total	**609**	**1,561**	**256,495**	**245,466**	**663,781**
CO_2 = carbon dioxide CH_4 = methane					
GHG = greenhouse gas					
HCA = high consequence area ILI = inline inspection					
MAOP = maximum allowable operating pressure MCF = thousand cubic feet					
SMYS = specified minimum yield strength					

Table C- 55

Table 3-55. Total Emissions Per Year			
Item	**Gas Released (MCF)**	**Methane Emissions (MCF CH4)**	**C02 Emissions (lbs.)**
Re-establish MAOP: HCA > 30% SMYS	1,944	1,861	4,335
Re-establish MAOP: Inadequate Records	20,602	19,716	44,819
Integrity Assessment: Non-HCA	5,384	5,152	8,007
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	8,195	7,843	15,385
Total	**36,125**	**34,572**	**72,547**
CO_2 = carbon dioxide CH_4 = methane			
HCA = high consequence area lbs. = pounds			
MAOP = maximum allowable operating pressure MCF = thousand cubic feet			
SMYS = specified minimum yield strength			

Table C- 56

Table 3-56. Average Annual Social Cost of Gas Lost due to Blowdown (Millions 2015$)				
Topic Area 1 Scope	**Average Annual Methane Lost from Blowdown (MCF)**			**Average Annual**
	ILI Upgrade	**Pressure Test**	**Total**	**Social Cost[1]**
Previously untested in HCA	962.0	898.7	1,860.6	0.1
HCA and Class 3 and 4 with inadequate records	10,038.5	9,677.6	19,716.2	0.6
Applicable MCA	0.0	5,152.4	5,152.4	0.2
Previously other HCA and non-HCA	5,363.9	2,478.6	7,842.5	0.2
Subtotal	16,364.4	18,207.3	34,571.7	1.0
MCF = thousand cubic feet				
1. Based on the values for social cost of methane and social cost of carbon calculated using a 3% discount rate (see Appendix B).				

Table C- 57

Table 3-57. Present Value Costs Discounted at 7%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance Cost	Social Cost of GHG Emissions	Total Cost	Annual Compliance Cost	Annual Social Cost of GHG Emissions	Average Annual Cost
Re-establish MAOP: HCA > 30% SMYS	$21	$1	$22	$1	$0.1	$1
Re-establish MAOP: Inadequate Records	$262	$9	$271	$17	$1	$18
Integrity Assessment: Non - HCA	$139	$2	$141	$9	$0.2	$9
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$108	$3	$112	$7	$0.2	$7
Total	**$530**	**$15**	**$546**	**$35**	**$1**	**$36**

GHG = greenhouse gas.

HCA = high consequence area.

MAOP = maximum allowable operating pressure. SMYS = specific minimum yield strength.

1. Total is of the 15 year compliance period; average annual is total divided by 15.

Table C- 58

Table 3-58. Present Value Costs Discounted at 3%, Topic Area 1 (Millions 2015$)[1]

Scope	Total			Average Annual		
	Compliance	Social Cost of GHG Emissions	Total	Compliance	Social Cost of GHG Emissions	Total
Re-establish MAOP: HCA > 30% SMYS	$26	$1	$27	$2	$0.1	$2
Re-establish MAOP: Inadequate Records	$331	$9	$340	$22	$1	$23
Integrity Assessment: Non - HCA	$175	$2	$177	$12	$0.2	$12
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$137	$3	$140	$9	$0.2	$9
Total	**$669**	**$15**	**$684**	**$45**	**$1**	**$46**

HCA = high consequence area

MAOP = maximum allowable operating pressure SMYS = specific minimum yield strength

1. Total is of the 15 year compliance period; average annual is total divided by 15.

Table C- 59

Table 3-60. Calculation of HCA Mileage, Topic Area 2

Scope	Miles
HCA[1]	19,872
HCA MAOP verification testing under Topic Area 1[2]	3,035
HCA less Topic Area 1 mileage	16,837
Average assessed per year[3]	2,405

1. Source: PHMSA Annual Reports.
2. See section 3.1.
3. HCA miles less topic Area 1 divided by 7 years.

Table C- 60

Table 3-61. Hazardous Liquid Scheduled Repair Conditions, 2004-2009

Repair Condition	Number	Percent of Total
60-day conditions	4,673	19%
180-day conditions	20,468	81%
Total	25,141	100%

Source: 2004-2009 Hazardous Liquid Annual Reports; see Table C-2.

Table C- 61

Table 3-62. Estimation of 180-Day Repair Conditions

Component	Value
HCA miles assessed per year	2,405
Scheduled repair conditions per mile assessed[1]	0.9
Expected scheduled repair conditions per year	2176

Table 3-62. Estimation of 180-Day Repair Conditions	
180 conditions (% of scheduled conditions)	81%
Expected 180-day conditions per year	1,771
1. 2004-2009 Gas Transmission scheduled repair rate, see Table C-2.	

Table C- 62

Table 3-63. Range of Typical Repair Costs

Repair Method (Length)	West (Except West Coast), Central, Southwest	South, West Coast	East[1]
12-inch Diameter			
Composite Wrap (5')	$9,600	$12,000	$13,800
Sleeve (5')	$12,800	$16,000	$18,400
Pipe Replacement (5')	$41,600	$52,000	$59,800
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$16,000	$20,000	$23,000
Sleeve (20')	$19,200	$24,000	$27,600
Pipe Replacement (20')	$51,200	$64,000	$73,600
Material Verification (20')	$4,000	$4,000	$4,000
24-inch Diameter			
Composite Wrap (5')	$14,400	$18,000	$20,700
Sleeve (5')	$19,200	$24,000	$27,600
Pipe Replacement (5')	$62,400	$78,000	$89,700
Material Verification (5')	$2,000	$2,000	$2,000
Composite Wrap (20')	$24,000	$30,000	$34,500
Sleeve (20')	$28,800	$36,000	$41,400
Pipe Replacement (20')	$76,800	$96,000	$110,400

Table 3-63. Range of Typical Repair Costs			
Material Verification (20’)	$4,000	$4,000	$4,000
36-inch diameter			
Composite Wrap (5’)	$21,600	$27,000	$31,050
Sleeve (5’)	$28,800	$36,000	$41,400
Pipe Replacement (5’)	$93,600	$117,000	$134,550
Material Verification (5’)	$2,000	$2,000	$2,000
Composite Wrap (20’)	$36,000	$45,000	$51,750
Sleeve (20’)	$43,200	$54,000	$62,100
Pipe Replacement (20’)	$115,200	$144,000	$165,600
Material Verification (20’)	$4,000	$4,000	$4,000
Source: PHMSA best professional judgment			
1. 115% of South, West Coast.			

Table C- 63

Percent of Conditions Repaired using Current Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%
Pipe Replacement (5’)	2%	2%	2%
Material Verification (5’)	17%	17%	17%
Composite Wrap (20’)	5%	5%	5%
Sleeve (20’)	10%	10%	10%
Pipe Replacement (20’)	2%	2%	2%
Material Verification (20’)	17%	17%	17%
24-inch Diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%

Percent of Conditions Repaired using Current Methodology			
Pipe Replacement (5’)	2%	2%	2%
Material Verification (5’)	17%	17%	17%
Composite Wrap (20’)	5%	5%	5%
Sleeve (20’)	10%	10%	10%
Pipe Replacement (20’)	2%	2%	2%
Material Verification (20’)	17%	17%	17%
36-inch diameter			
Composite Wrap (5’)	5%	5%	5%
Sleeve (5’)	10%	10%	10%
Pipe Replacement (5’)	2%	2%	2%
Material Verification (5’)	17%	17%	17%
Composite Wrap (20’)	5%	5%	5%
Sleeve (20’)	10%	10%	10%
Pipe Replacement (20’)	2%	2%	2%
Material Verification (20’)	17%	17%	17%

Table C- 64

Number of Repairs Done using Methodology			
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**
12-inch Diameter			
Composite Wrap (5’)	66	13	9
Sleeve (5’)	133	27	18
Pipe Replacement (5’)	22	4	3
Material Verification (5’)	221	44	30
Composite Wrap (20’)	66	13	9
Sleeve (20’)	133	27	18
Pipe Replacement (20’)	22	4	3

Material Verification1 (20')	221	44	30
24-inch Diameter			
Composite Wrap (5')	66	13	9
Sleeve (5')	133	27	18
Pipe Replacement (5')	22	4	3
Material Verification1 (5')	221	44	30
Composite Wrap (20')	66	13	9
Sleeve (20')	133	27	18
Pipe Replacement (20')	22	4	3
Material Verification1 (20')	221	44	30
36-inch diameter			
Composite Wrap (5')	66	13	9
Sleeve (5')	133	27	18
Pipe Replacement (5')	22	4	3
Material Verification1 (5')	221	44	30
Composite Wrap (20')	66	13	9
Sleeve (20')	133	27	18
Pipe Replacement (20')	22	4	3
Material Verification1 (20')	221	44	30

Table C- 65

Cost of Repairs				
Repair Method (Length)	**West (Except West Coast), Central, Southwest**	**South, West Coast**	**East**	**Total**
12-inch Diameter				
Composite Wrap (5')	$637,614	$159,404	$122,209	$919,227
Sleeve (5')	$1,700,305	$425,076	$325,892	$2,451,273

Cost of Repairs				
Pipe Replacement (5’)	$920,998	$230,250	$176,525	$1,327,773
Material Verification (5’)	$442,788	$88,558	$59,038	$590,384
Composite Wrap (20’)	$1,062,691	$265,673	$203,682	$1,532,046
Sleeve (20’)	$2,550,457	$637,614	$488,838	$3,676,909
Pipe Replacement (20’)	$1,133,537	$283,384	$217,261	$1,634,182
Material Verification (20’)	$885,575	$177,115	$118,077	$1,180,767
24-inch Diameter				
Composite Wrap (5’)	$956,422	$239,105	$183,314	$1,378,841
Sleeve (5’)	$2,550,457	$637,614	$488,838	$3,676,909
Pipe Replacement (5’)	$1,381,498	$345,374	$264,787	$1,991,659
Material Verification(5’)	$442,788	$88,558	$59,038	$590,384
Composite Wrap (20’)	$1,594,036	$398,509	$305,524	$2,298,068
Sleeve (20’)	$3,825,686	$956,422	$733,256	$5,515,364
Pipe Replacement (20’)	$1,700,305	$425,076	$325,892	$2,451,273
Material Verification (20’)	$885,575	$177,115	$118,077	$1,180,767
36-inch diameter				
Composite Wrap (5’)	$1,434,632	$358,658	$274,971	$2,068,261

Cost of Repairs				
Sleeve (5’)	$3,825,686	$956,422	$733,256	$5,515,364
Pipe Replacement (5’)	$2,072,247	$518,062	$397,181	$2,987,489
Material Verification (5’)	$442,788	$88,558	$59,038	$590,384
Composite Wrap (20’)	$2,391,054	$597,763	$458,285	$3,447,102
Sleeve (20’)	$5,738,529	$1,434,632	$1,099,885	$8,273,046
Pipe Replacement (20’)	$2,550,457	$637,614	$488,838	$3,676,909
Material Verification (20’)	$885,575	$177,115	$118,077	$1,180,767
Total Cost	$42,011,700	$10,303,671	$7,819,779	$60,135,150

Table C- 66

Labor Rates					
Occupation Code	**Occupation**	**Industry**	**Labor Category**	**Mean Hourly Wage**	**Total Labor Cost1**
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table C- 67

Table 3-64. Present Value of Estimated Annual Cost of More Timely Repair of Non- Immediate Conditions (Millions)		
Estimate	**7% Discount Rate**	**3% Discount Rate**
Cost of repairs	$60.1	$60.1
Percent of anomalies that are repaired	50.4%	50.4%
Cost of repairing anomalies on an accelerated schedule	$30.3	$30.3
Cost of repairs delayed 4 years	$23.1	$27.0
Difference for repaired anomalies (estimated cost of proposed rule)	$7.2	$3.4
Time to monitor one anomaly (hours)	1.0	1.0
Salary to monitor anomalies	$55.0	$55.0
Average Ongoing anomalies in a given time period	6,583.0	6,583.0
Cost for monitoring unrepaired anomalies	$0.4	$0.4
Annual cost of rule	**$36.6**	**$32.8**
G & A Cost	**$7.3**	**$6.6**

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Table 3-65. Present Value Costs, Topic Area 2 (Millions)[1]			
7% Discount Rate		**3% Discount Rate**	
Total	**Average Annual**	**Total**	**Average Annual**
$428	$29	$484	$32
1. Total is of the 15 year compliance period; average annual is total divided by 15.			

Table C- 69

Table 3-66. Labor Rates

Occupation Code	Occupation	Industry	Labor Category	Mean Hourly Wage	Total Labor Cost[1]
17-2141	Mechanical Engineers	Oil and Gas Extraction	Sr. Engineer	$74	$99
Nov-71	Transportation, Storage, and Distribution Managers	Oil and Gas Extraction	Manager	$61	$86
17-2111	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors	Oil and Gas Extraction	Project engineer	$56	$81
47-5013	Service Unit Operators, Oil, Gas, and Mining	Pipeline Transportation of Natural Gas	Operator	$30	$55
Source: Bureau of Labor Statistics Occupational Employment Statistics (May 2014) and Employer Cost of Employee Compensation (September 2015).					
1. Mean hourly wage plus mean benefits ($25.01 per hour worked).					

Table C- 70

Table 3-67. Onetime Cost of Management of Change Process Development[1]

Activity	Low Estimate		High Estimate	
	Hours	Cost[2]	Hours	Cost[2]
Review existing MoC procedures for IMP- and Control Center-related changes	24	$2,415	0	$0
Revise and expand scope of procedures	130	$12,879	0	$0
Establish procedures	0	$0	650	$52,689
Notify personnel and provide implementation guidance and instruction	33	$3,220	163	$8,945
Total	**187**	**$18,514**	**813**	**$61,634**
1. Source: PHMSA best professional judgment. Low estimate reflects nominally formal existing processes and high estimate reflects only minimal existing processes.				
2. Feedback from partners indicated the time to set up a management of change program would be closer to 500 hours and so made adjustment				

Table C- 71

Table 3-68. Per Event Cost of Implementing Management of Change Processes				
Activity	**Labor Category**	**Labor Cost[1] ($/hour)**	**Hours**	**Cost**
Maintenance/operating personnel or engineer identifies a change, invoking the process	Operator	$55	1	$55
Obtain approval to pursue change	Manager	$86	1	$86
Evaluate and document technical and operational implications of the change	Sr. Engineer	$99	12	$1,188
Obtain required work authorizations (e.g., hot work and lockout-tag out permits)	Project Engineer	$81	3	$243
Formally institutionalize change in official "as-built" drawings, facilities lists, data books, and procedure manuals	Project Engineer	$81	8	$648
Communicate change to all potentially affected parties	Manager	$86	2	$172
Train and qualify involved personnel	Operator	$55	20	$1,100
Total	**NA**	NA	**47**	**$3,492**
1. See Table 3-66.				

Table C- 72

Table 3-69. Present Value Costs, Topic Area 3[1]				
Component	**Total (7%)**	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
Onetime process development	$2,805,187	$187,012	$2,805,187	$187,012
Annual implementation1 ($977,760)	$9,530,011	$635,334	$12,024,227	$801,615
Note: Detail may not add to total due to rounding.				
1. Total is present value over 15 year compliance period; average annual is total divided by 15.				

Table C- 73

Table 3-70. Reported Gas Transmission Incidents Due to Corrosion (Onshore and Offshore)				
Year	**Internal Corrosion**	**External Corrosion**	**Total Corrosion**	**Total All Causes**
2003	11	11	22	93
2004	14	9	23	103
2005	7	12	19	160
2006	11	12	23	130
2007	18	17	35	110
2008	8	11	19	122
2009	10	9	19	105
2010	19	10	29	105
2011	14	4	18	114
2012	14	13	27	102
2013	13	5	18	103
2014	9	9	18	129
2015	13	8	21	129
Total	**161**	**130**	**291**	**1,505**
Source: PHMSA Incident Reports				

Table C- 74

Table 3-71. Estimation of Coating Survey Costs			
Class	**Coating Survey Cost[1]**	**Number of Surveys**	**Cost[1]**
1	$200	100	$20,000
2	$400	70	$28,000
3	$3,000	50	$150,000
4	$5,000	20	$100,000
G &A Cost	NA	NA	$59,600
Total	**NA**	240	**$357,600**
Source: PHMSA Best Professional Judgment.			
1. Based on average survey length of 500 feet. Actual costs will vary depending on environment, traffic control, and survey length.			

Table C- 75

Table 3-72. Gas Transmission Close Interval Survey

Class	Close Interval Survey Cost ($/Mile)[1]	Mileage[2]	Current Compliance[1]	Out of Specification Test Station Readings (Annual)[1,3]	Total Costs[4]
1	$2,000	232,635	15%	0.5%	$1,977,398
2	$3,000	30,631	10%	0.5%	$413,519
3	$25,000	33,652	5%	0.5%	$3,996,175
4	$50,000	908	5%	0.5%	$215,650
G &A Cost	NA	NA	NA	NA	$1,320,548
Total	**NA**	**297,826**	**NA**	**NA**	**$7,923,289**

1. Source: PHMSA best professional judgment
2. Source: PHMSA 2014 Annual Report via PDM
3. Reflects long-standing requirements for operators to have CP systems and check test stations annually, and PHMSA inspection experience.
4. Calculated as the product of mileage, unit cost, out of spec rate, and (1-compliance rate).

Table C- 76

Table 3-73. Cost to Add Test Station in HCA

HCA Miles[1]	Stations Required per Mile	Baseline Compliance[2]	New Stations Required	Cost per Test Station[3]	G&A cost	Total Cost
19,872	2	80%	7,949	$540	$858,599	**$5,151,592**

HCA = high consequence area
1. Source: PHMSA annual reports.
2. Source: PHMSA BPJ
3. Unit cost represents approximately $400 in labor (2 workers for half day) and $100 in materials.

Table C- 77

Table 3-74. Estimation of Costs for Interference Surveys						
Class	**Interference Survey Cost[1] ($/mile)**	**Total Mileage[2]**	**Current Compliance[1]**	**Incremental Need for Surveys[1]**	**Compliance Mileage[3]**	**Total Costs[4] ($/7 years)**
1	4,000	232,726	10%	1%	2,095	$8,378,143
2	5,000	30,645	10%	1%	276	$1,379,005
3	10,000	33,657	70%	3%	303	$3,029,158
4	10,000	908	90%	3%	3	$27,244
G &A Cost	NA	NA	NA	NA	NA	$2,562,710
Total	**NA**	**297,936**	**NA**	**NA**	**2,676**	**$15,376,260**
1. Source: PHMSA Best Professional Judgment						
2. Source: PHMSA 2014 Annual Report via PDM						
3. Calculated as total mileage × (100% - current compliance) × incremental need for surveys.						
4. Calculated as compliance mileage × unit cost.						

Table C- 78

Table 3-75. Estimation of Costs for Internal Corrosion Monitoring

Class	Monitoring Equipment Cost	Total Number of Monitors Needed	% Current Compliance	Number of Monitors for Compliance[1]	Costs
1	$10,000	250	95%	13	$125,000
2	$10,000	50	80%	10	$100,000
3	$10,000	150	95%	8	$75,000
4	$10,000	200	95%	10	$100,000
G &A Cost	NA	NA	NA	NA	$80,000
Total	**NA**	**650**	**NA**	**40**	**$480,000**

Source: PHMSA Best Professional Judgment

1. Calculated as total number of monitors needed × (100% - % current compliance).

Table C- 79

Table 3-76. Summary of Incremental Costs, Corrosion Control (Millions)

Component	One-Time	Annual	Recurring (7 years)
External Corrosion Coatings	$0.0	$0.4	$0.0
External Corrosion Monitoring	$5.2	$7.9	$0.0
Interference Current Surveys	$0.0	$0.0	$15.4
Internal Corrosion Monitoring	$0.5	$0.0	$0.0
Total	**$5.6**	**$8.3**	**$15.4**

Table C- 80

Table 3-77. Present Value Incremental Costs, Topic Area 4[1]

Total (7%)	Average Annual (7%)	Total (3%)	Average Annual (3%)
$114,137,670	$7,609,178	$137,800,566	$9,186,704

1. Calculated assuming one-time costs in year 1; annual costs in years 1-15; and 7-year recurring costs annualized over 7 years at the different discount rates. Total is present value over 15 years; average annual is total divided by 15.

Table C- 81

Table 3-78. Estimation of Costs for Process Development for Extreme Events

Activity	Hours (Low)	Hours (High)	Cost per Operator (Low)[1]	Cost per Operator (High)[1]	Total Cost (Low)[2]	Total Cost (High)[2]	Total Cost (Average)
Review existing surveillance and patrol procedures to validate adequacy for extreme events	2	1	198	99	100,693	50,347	75,520
Revise surveillance and patrol procedures	5	20	495	1,980	251,733	1,006,932	629,332
Notify involved personnel of new procedures, providing implementation guidance and instruction	5	10	495	990	251,733	503,466	377,599
Total	**12**	**31**	**1,188**	**3,069**	**604,159**	**1,560,744**	**1,082,452**

Source: PHMSA best professional judgment

1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).
2. Calculated as cost per operator × 50% × 1,017 operators.

Table C- 82

72-hour Post-Event Incremental Inspection for Natural Gas Transmission Line			
	Low Estimate	**High Estimate**	**Average**
Events per Year	25	75	50
Miles per Event	200	400	300
Extra Cost per Inspection in $/mile	$350	$500	$425
Calculated Total Extra Cost in $/Year	$1,750,000	$15,000,000	$6,375,000
Source: Illustrative examples prepared by ICF to show approximate magnitude of costs.			

Table C- 83

Table 3-79. Present Value Costs, Topic Area 5[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
63,209,810	4,213,987	79,469,918	5,297,995
1. Total is present value over 15 year study period; average annual is total divided by 15 years.			

Table C- 84

Table 3-80. MAOP Exceedance Reports from Gas Facilities	
Year	**MAOP Exceedance Reports**
2012	5
2013	21
2014	21
2015	17
Source: PHMSA Safety Related Condition Reports: MAOP exceedance reports on gas transmission pipelines	

Table C- 85

Table 3-81. Previously Incurred Compliance Costs (2015$)				
Year	**MAOP Exceedance Reporting[1]**	**Records Verification[2]**	**Total at Current Labor Rates**	**Estimated Cost Incurred[3]**
2012	$2,970	$2,851,488	$2,854,458	$2,765,332
2013	$12,475	$0.0	$12,475	$12,265
2014	$12,475	$0.0	$12,475	$12,459
2015	$10,099	$0.0	$10,099	$10,099
Total	$38,020	$2,851,488	$2,889,508	$2,800,155
NA = not applicable				
1. Reports from Table 3-80 times six hours times $99/hour labor rate from Table 3-66.				
2. 1,440 reports times 20 hours times $99/hour labor rate from Table 3-66.				
3. Cost at labor rates in year occurred approximated using the Bureau of Labor Statistics Consumer Price Index – All Urban Consumers (average annual value for 2015: 237.0; 2014: 236.7; 2013: 233.0; 2012: 229.6).				

Table C- 86

Table 3-82. Present Value Costs, Topic Area 6 (2015$)[1]			
Total (7%)	**Average Annual (7%)**	**Total (3%)**	**Average Annual (3%)**
$2,898,575	$193,238	$2,930,815	$195,388
1. Total is present value over 15 year study period; average annual is total divided by 15 years.			

Table C- 87

Table 3-83. Estimation of Costs for Creating Launcher and Receiver Pressure Specifications				
Activity	**Hours**	**Cost[1]**	**Number of Systems**	**Total Cost**
Review existing design, installation, and testing specifications for launcher/receiver facilities.	1	$99	10	$990
Revise specifications to comply with new §192.750.	24	$2,376	10	$23,762
Total	**25**	**$2,475**	**20**	**$24,753**
Source: PHMSA best professional judgment				
1. Calculated as hours × labor cost for senior engineer ($99; see Table 3-66).				

Table C- 88

Table 3-84. Estimation of Costs for Launcher and Receiver Safety Device Installation					
Component	**Cost per Small Line[1] (<16")**	**Cost per Large Line[2] (>16")**	**Incremental Number of Devices, Small Lines**	**Incremental Number of Devices, Large Lines**	**Total Cost**
Closure	$7,000	$25,000	5	5	$160,000
Trap	$10,000	$25,000	5	5	$175,000
Total	**$17,000**	**$50,000**	**10**	**10**	**$335,000**
Source: PHMSA best professional judgment					
1. Pressure relieving closure for 8" line size with 12" trap including installation and testing.					
2. Pressure relieving closure for 30" line size with 36" trap including installation and testing.					

Table C- 89

Table 3-106. Summary of Present Value Compliance Costs (Millions 2015$)[1]				
Topic Area	**7% Discount Rate**		**3% Discount Rate**	
	Total	**Average Annual**	**Total**	**Average Annual**
1	$546	$36	$684	$46
2	$428	$29	$484	$32
3	$12	$1	$15	$1
4	$114	$8	$138	$9
5	$63	$4.2	$79	$5
6	$3	$0.2	$3	$0.2
7	$0.4	$0.0	$0.4	$0.0
8	$585	$39	$699	$47
Total	**$1,752**	**$117**	**$2,103**	**$140**
1. Total present value over 15 study period; average annual calculated by dividing total by 15.				
2. PHMSA analyzed this component with a pre-statutory baseline, however most operators are expected to be in compliance with the Act				

Table C- 90

Table 3-107. Summary of Present Value Total Costs (Millions 2015$)[1]

Component	7% Discount Rate		3% Discount Rate	
	Total	Average Annual	Total	Average Annual
Compliance costs	$1,737	$116	$2,088	$139
Social cost of methane[2]	$15	$1	$15	$1
Total	**$1,752**	**$117**	**$2,103**	**$140**

1. Total present value over 15 study period; average annual calculated by dividing total by 15.
2. Based on 3% value. See Appendix B for discussion of other estimated values.

Table C- 91

Table 3-108. Breakdown of Present Value Costs, Topic Area 1 (Millions 2015$)

Subtopic Area	7% Discount Rate		3% Discount Rate	
	Average Annual	Total	Average Annual	Total
Re-establish MAOP: HCA > 30% SMYS	$1	$22	$2	$27
Re-establish MAOP: Inadequate Records	$18	$271	$23	$340
Integrity Assessment: Non - HCA	$9	$141	$12	$177
Re-establish MAOP: HCA 20-30% SMYS; Non-HCA Class 3 and 4; Non-HCA Class 1 and 2 piggable	$7	$112	$9	$140
Total	**$36**	**$546**	**$46**	**$684**

HCA = high consequence area

MAOP = maximum allowable operating pressure SMYS = specific minimum yield strength

Table C- 92

Table 4-1. Summary of Estimated Defect Discovery Rates (per Mile)				
Requirement	**Defect Discovery Rate ILI, DA (immediate)**	**Defect Discovery Rate ILI, DA (scheduled)**	**Defect Discovery Rate PT**	**Description**
Integrity verification, previously assessed pipe (HCA)[1]	0.0	0.4	0.0	Represents difference between hazardous liquid and gas transmission discovery rates (see Appendix C) since proposed gas transmission requirements resemble existing requirements for hazardous liquid pipe.
Non-HCA integrity verification and MCA assessments of previously unassessed pipe[2]	0.1	0.5	0.0	Represents hazardous liquid baseline discovery rate since proposed repair criteria and assessment requirements are similar.
1. Re-establishing MAOP for previously untested pipe and pipe for which records are inadequate.				
2. Includes requirements addressing previously untested pipe, inadequate records, and integrity assessments outside of HCAs.				

Table C- 93

Table 4-2. Estimated Percent of Defects Which Would Have Resulted In Failure		
Method	**Low**	**High**
Inline and direct assessment (immediate repair)	3%	13%
Inline and direct assessment (scheduled repair)	0.3%	1%
Pressure test	33%	50%
Source: PHMSA best professional judgment considering that immediate repair criteria represent a calculated failure pressure less than 1.1 times operating pressure or pipe wall lost greater than 80% loss, and other factors including overpressure protection, safety margin for combined stresses, and 180 days for results to represent immediate discovery. Pressure tests are very effective at finding defects (wall loss, dents, or cracking) that would not otherwise have been abated.		

Table C- 94

Table 4-3. Estimated Incidents Averted, Topic Area 1

	Mileage		HCA %		Incidents Averted[1]							
Scope	**ILI and DA**	**PT**	**HCA**	**Non- HCA**	**ILI and DA, Immediate - Low**	**ILI and DA, Immediate -High**	**ILI and DA, Scheduled - Low**	**ILI and DA, Scheduled - High**	**PT - Low**	**PT - High**	**Total - Low**	**Total - High**
HCA >30% SYMS	800	118	1	0.0	1	5	1	2	1	2	3	9
HCA; Class 3 and 4 non-HCA	3686	678	0.4	1	9	37	5	8	8	12	22	57
MCA Class 3 and 4; MCA Class 1 and 2 (piggable)	7116	257	0.0	1	22	92	10	17	3	4	35	114
HCA 20-30% SMYS; non-HCA Class 3 and 4; MCA Class 1 and 2 (piggable)	3118	141	0.1	1	9	38	4	7	2	2	15	48
Total	**14,719**	**1,193**	**NA**	**NA**	**41**	**173**	**21**	**34**	**14**	**21**	**76**	**228**

DA = direct assessment

HCA = high consequence area ILI = inline inspection

MCA = moderate consequence area PT = pressure test

SMYS = specified minimum yield strength

1. Based on multiplying estimated mileage by defect discovery rate and range of percentage of defects that would have resulted in failure absent the proposed rule.

Table C- 95

Table 4-4. Causes of Incidents Detectable by Modern Integrity Assessment Methods

2003-2009	2010-present
External corrosion	External corrosion
Internal corrosion	Internal corrosion
Rupture of previously damaged pipe	Previous damage due to excavation activity
Body of pipe; pipe seam weld	Original manufacturing-related (not girth weld or other welds formed in the field)
Joint; butt weld; fillet weld	Construction-, installation-, or fabrication-related
NA	Environmental cracking-related
Source: PHMSA Incident Report Form	

Table C- 96

Table 4-5. Estimated Average Per Incident Consequences, Topic Area 1 (2015$)

Subtopic Area	HCA	Non-HCA
MAOP verification for segments within HCA	$6,699,452	NA
MAOP verification for segments with inadequate records within HCA and Class 3 and Class 4	$6,699,452	147,800
Integrity assessments for segments within MCA in Class 3 and Class 4, and Class 1 and Class (piggable)	N/A1	$1,085,614
MAOP verification for segments within HCA (operating between 20%-30% SMYS) and MCA (Class 3 and Class 4; Class 1 and Class 2 piggable)	$6,699,452	$1,085,614
Source: PHMSA Gas Transmission Incident Reports summarized in Tables E-3 through E-6. HCA = high consequence area		
MCA = moderate consequence area		
MAOP = maximum allowable operating pressure NA = not applicable		
PT = pressure test		
SMYS = specified minimum yield strength		
1. Based on HCA incidents from 2003-2015 (see Table E-3).		
2. Based on Class 3 and 4 non-HCA incidents from 2003-2015 (see Table E-8).		
3. Based on estimate of incidents that may represent MCA incidents (see Table E-4).		

Table C- 97

Table 4-6. Estimation of Average Annual Cost Savings of Proposed Material Documentation Requirements[1]	
Component	**Average Annual Cost (Millions 2015$)**
Existing requirements (cutouts)[2]	0
Proposed rule (IVP)[3]	$0.00
Cost savings (over 15 years)	$0.00
IVP = integrity verification program NA = not applicable	
1. Based on 291 miles of pipe for which there are incomplete, missing, or inadequate records to substantiate maximum allowable operating pressure as indicated in the 2014 Gas Transmission Annual Report. The proposed requirements would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non- destructive methods.	
2. Calculated as mileage multiplied by 13.2 cutouts per mile and $75,000 per cutout.	
3. Average annual cost to re-establish MAOP for segments with inadequate MAOP records using methods permitted in the proposed rule (see Section 3.1.5).	

Table C- 98

Table 4-7. Present Value of Safety Benefits, Topic Area 1 (Millions $2015)

Component	7% Discount Rate				3% Discount Rate			
	Total[1] -Low	Average Annual[2] =-Low	Total[1] -High	Average Annual[2] - High	Total[1] - Low	Average Annual[2] =-Low	Total[1] - High	Average Annual[2] - High
MAOP verification for segments within HCA	15	1	37	2	19	1	47	3
MAOP verification for segments with inadequate records within HCA + Class 3 & 4	41	3	108	7	52	3	136	9
Integrity assessments for segments within MCA in Class 3&4 and Class 1&2 (piggable)	25	2	80	5	32	2	101	7
MAOP verification for segments within HCA(20%-30% SMYS) + MCA (Class 3&4,Class 1&2 piggable)	16	1	50	3	20	1	63	4
Total	**97**	**6**	**275**	**18**	**122**	**8**	**347**	**23**
MAOP = maximum allowable operating pressure								
1. Present value over 15-year study period.								
2. Total divided by 15.								

Table C- 99

Table 4-8. Present Value of Cost Savings Benefits, Topic Area 1 (Millions, 2015$)[1]			
7% Discount Rate		3% Discount Rate	
Total	Average Annual	Total	Average Annual
$0	$0	$0	$0
MAOP = maximum allowable operating pressure			
1. Associated with MAOP verification for segments for which records are inadequate within high consequence area and Class 3 and 4 locations. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times MAOP and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods. Total is present value over 15-year study period; average annual is total divided by 15.			

Table C- 100

Table 4-9. Breakeven Analysis, Topic Area 2			
Scenario	Annual Cost[1]	Average HCA Incident Consequences[2]	Break-Even Number of Incidents per Year[3]
7% interest rate	$30,333,999	$6,699,452	$5
3% interest rate	$30,333,999	$6,699,452	$5
1. See Table 3-43. Annual cost represents the change in time value of money of expedited repairs for the given interest rate			
2. See Table E-3.			
3. Calculated as annual cost divided by average incident consequences.			

Table C- 101

Table 4-10. Calculation of Safety Benefits, Topic Area 3 (Millions 2015$)		
Incidents Averted per Year[1]	Average Cost per Incident[2]	Annual Benefits[3]
1	$0.8	$0.8
1. Source: PHMSA best professional judgment		
2. See Table E-1		
3. Calculated as incidents averted × average cost per incident.		

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Table 4-11. Present Value of Benefits, Topic Area 3 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$8	$1	$10	$1
1. Present value over 15-year study period.			
2. Total divided by 15.			

Table C- 103

Table 4-12. Calculation of Safety Benefits, Topic Area 4 (Millions, 2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident[2]**	**Annual Benefits[3]**
7	$0.5	$4
1. Source: PHMSA best professional judgment (4.0 + 0.2 + 3.0)		
2. See Table E-5.		
3. Calculated as incidents averted × average cost per incident.		

Table C- 104

Table 4-13. Present Value of Benefits, Topic Area 4 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$36	$2	$46	$3
1. Present value over 15-year study period.			
2. Total divided by 15.			

Table C- 105

Table 4-14. Calculation of Safety Benefits, Topic Area 5 (2015$)		
Incidents Averted per Year[1]	**Average Cost per Incident[2]**	**Annual Benefits[3]**
0.5	$114,077	$57,039
1. Source: PHMSA best professional judgment		
2. See Table E-6.		
3. Calculated as incidents averted × average cost per incident.		

Table C- 106

Table 4-15. Present Value of Benefits, Topic Area 5 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$555,869	$37,058	$701,352	$46,757
1. Present value over 15-year study period.			
2. Total divided by 15.			

Table C- 107

Table 4-16. Calculation of Safety Benefits, Topic Area 7		
Total Incidents Averted[1]	**VSL (millions)[2]**	**Total Benefits (millions)[3]**
1	$9	$9
VSL = value of statistical life		
1. Source: PHMSA best professional judgment		
2. Approximately $9.4 million (2015$; per Department of Transportation internal guidance).		
3. Over the 15-year study period. Calculated as incidents averted × VSL.		

Table C- 108

Table 4-17. Present Value of Benefits, Topic Area 7 (Millions 2015$)			
7% Discount Rate		**3% Discount Rate**	
Total[1]	**Average Annual[2]**	**Total[1]**	**Average Annual[2]**
$6	$0.4	$8	$1
1. Present value over 15-year study period.			
2. Total divided by 15.			

Table C- 109

Table 4-18. Summary of Estimated Incidents Averted, Topic Areas 1-7										
	Topic Area									
Estimate	**1 - Low**	**1-High**	**2**	**3**	**4**	**5**	**6**	**7**	**Total Low**	**Total High**
Annual	5	15	n.e.	1	7	1	n.e.	0.1	14	24
Total[1]	76	228	n.e.	15	108	8	n.e.	1	207	359
Note: detail may not add to total due to independent rounding.										
n.e. = not estimated										
1. Calculated as annual estimate times 15 years.										

Table C- 110

Table 4-19. Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)			
Year	**Incidents**	**Natural Gas Released (MCF)**	**Average per Incident (MCF)**
2010	105	2,351,022	22,391
2011	114	2,718,692	23,848
2012	102	2,105,292	20,640
2013	103	1,688,265	16,391
2014	129	2,467,085	19,125
Total	**553**	**11330356**	**20,479**
Source: Gas Transmission Incident Reports. MCF = thousand cubic feet.			

Table C- 111

Table 4-20. Ignition or Explosion of Gas Released During Gas Transmission Pipeline Incidents (2010 – 2014)

Year	Ignition or Explosion	No Ignition or Explosion	Ignition or Explosion	No Ignition or Explosion
2010	19	86	NA	
2011	13	101		
2012	15	87		
2013	11	92		
2014	16	113		
Total (%)	74	479	13%	87%
Source: Gas Transmission Incident Reports				

Table C- 112

Table 4-21. Greenhouse Gas Emissions per MCF of Natural Gas Released

Gas	Methane (MCF)	Carbon Dioxide(lbs.)
No ignition or explosion[1]	1.0	1.5
Ignition[2]	0.6	41.7
lbs. = pounds		
MCF = thousand cubic feet CH_4 = methane		
CO_2 = carbon dioxide		
1. MCF CH_4 = 1 MCF gas × 96% methane; lbs. CO_2 = 1 MCF gas × 1.3% $C0_2$ × 114.4 lbs./MCF.		
2. MCF CH_4 = 1 MCF gas × 96% methane ×1-0.35 combustion efficiency factor); lbs. CO_2 = (1 MCF gas × 1.3% $C0_2$ × 114.4 lbs./MCF) + (1 MCH methane × 96% methane × 0.35 combustion efficiency factor).		

Table C- 113

Table 4-22. Greenhouse Gas Emission Reductions Per Year				
Scenario[1]	**Natural Gas Combusted (MCF)[2]**	**Natural Gas Not Combusted (MCF)[3]**	**CH_4 Emissions Reduction (MCF)[4]**	**$C0_2$ Emissions Reduction (lbs.)[5]**
Low	$37,895	$245,293	$258,318	$1,944,306
High	$65,658	$425,005	$447,573	$3,368,788
MCF = thousand cubic feet CH_4 = methane				
CO_2 = carbon dioxide				
1. Low scenario reflects low assumption of defect failures and avoided incidents; high scenario reflects high assumption of defect failures and avoided incidents.				
2. Gas released × 13%				
3. Gas released × 87%				
4. (Combusted × 0.62) + (not combusted × 0.96); see tables 4-19 and 4-20.				
5. (Combusted gas × 116 lbs. $C0_2$/MCF gas) + (not combusted gas × 1.5 lbs. $C0_2$).				

Table C- 114

Table 4-23. Summary of Total Climate Benefits, Topic Areas 1-7 (Millions 2015$)[1]				
Pollutant	**Avoided Emissions -Low**	**Avoided Emissions - High**	**Social Cost (3%) - Low**	**Social Cost (3%) - High**
Methane (MCF)	$3,874,768	$6,713,590	$114	$197
Carbon dioxide (MT)	$13,229	$22,921	$1	$1
Total	**NA**	**NA**	**$115**	**$199**
MCH = thousand cubic feet MT = metric tons				
1. Total over 15-year period calculated as emissions from Table 4-22 multiplied by 15 years and valued using the estimates in Appendix B.				

Table C- 115

Table 4-24. Present Value of Safety Benefits, Topic Areas 1-7 (Millions 2015$)								
	7% Discount Rate				**3% Discount Rate**			
Topic Area	**Total[1] - Low**	**Total[1] - High**	**Annual[2] - Low**	**Annual[2] - High**	**Total[1] - Low**	**Total[1] - High**	**Annual[2] - Low**	**Annual[2] - High**
1	$97	$275	$6	$18	$122	$347	$8	$23
2	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
3	$8	$8	$1	$1	$10	$10	$1	$1
4	$36	$36	$2	$2	$46	$46	$3	$3
5	$1	$1	$0.0	$0.0	$1	$1	$0.0	$0.0
6	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
7	$6	$6	$0.4	$0.4	$8	$8	$1	$1
Total	**$148**	**$326**	**$10**	**$22**	**$187**	**$412**	**$12**	**$27**
n.e. = not estimated								
1. Present value over 15-year study period.								
2. Total divided by 15.								

Table C- 116

Table 4-25. Climate Change Benefits, Topic Areas 1-7 (Millions 2015$)				
	Total[1] -Low	**Total[1] -High**	**Annual[2] - Low**	**Annual[2] - High**
1	$42	$126	$3	$8
2	n.e.	n.e.	n.e.	n.e.
3	$8	$8	$1	$1
4	$60	$60	$4	$4
5	$4	$4	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.
7	$1	$1	$0.0	$0.0
Total	**$115**	**$199**	**$8**	**$13**
n.e. = not estimated				
1. Total value over 15-year study period.				
2. Total divided by 15.				

Table C- 117

Table 4-26. Present Value of Total Benefits, Topic Areas 1-7 (Millions 2015$)[1]

	7% Discount Rate				3% Discount Rate			
Benefits Category	**Total -Low**	**Total - High**	**Average Annual - Low**	**Average Annual - High**	**Total - Low**	**Total - High**	**Average Annual - Low**	**Average Annual - High**
Safety	$148	$326	$10	$22	$187	$412	$12	$27
Cost savings	$0	$0	$0	$0	$0	$0	$0	$0
Climate change	$115	$199	$8	$13	$115	$199	$8	$13
Total	**$263**	**$525**	**$18**	**$35**	**$301**	**$610**	**$20**	**$41**

1. Total is present value over 15-year study period; average annual is total divided by 15.

Table C- 118

Table 5-1. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)

Topic Area	**Compliance**	**Social Cost of Methane[1]**	**Total**
1	$35.4	$1.0	$36.4
2	$28.6	$0.0	$28.6
3	$0.8	$0.0	$0.8
4	$7.6	$0.0	$7.6
5	$4.2	$0.0	$4.2
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0
Total	**$76.8**	**$1.0**	**$77.8**

1. Using 3% discounted values (see Appendix B).

Table C- 119

Table 5-2. Summary of Average Annual Present Value Costs, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)

Topic Area	Compliance	Social Cost of Methane	Total
1	$44.6	$1.0	$45.6
2	$32.3	$0.0	$32.3
3	$1.0	$0.0	$1.0
4	$9.2	$0.0	$9.2
5	$5.3	$0.0	$5.3
6	$0.2	$0.0	$0.2
7	$0.0	$0.0	$0.0
Total	**$92.6**	**$1.0**	**$93.6**

Table C- 120

Table 5-3. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 7% Discount Rate

Topic Area	Safety-Low	Safety - High	Cost Savings[1]	Climate[2]-Low	Climate[2]-High	Total - Low	Total - High
1[3]	$6.5	$18.3	$0.0	$2.8	$8.4	$9.2	$26.7
2	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
3	$0.5	$0.5	$0.0	$0.6	$0.6	$1.1	$1.1
4	$2.4	$2.4	$0.0	$4.0	$4.0	$6.4	$6.4
5	$0.0	$0.0	$0.0	$0.3	$0.3	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
7	$0.4	$0.4	$0.0	$0.0	$0.0	$0.4	$0.4
Total	**$9.9**	**$21.8**	**$0.0**	**$7.6**	**$13.2**	**$17.5**	**$35.0**

n.e. = not estimated

1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty.
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3. for Topic Area 1 Safety and Climate

Table C- 121

Table 5-4. Summary of Average Annual Present Value Benefits, Topic Areas 1-7, 3% Discount Rate (Millions 2015$)

Topic Area	Safety-Low	Safety - High	Cost Savings[1]	Climate[2]-Low	Climate[2]-High	Total - Low	Total - High
1[3]	$8.1	$23.1	$0.0	$2.8	$8.4	$10.9	$31.5
2	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
3	$0.7	$0.7	$0.0	$0.6	$0.6	$1.2	$1.2
4	$3.1	$3.1	$0.0	$4.0	$4.0	$7.0	$7.0
5	$0.0	$0.0	$0.0	$0.3	$0.3	$0.3	$0.3
6	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
7	$0.5	$0.5	$0.0	$0.0	$0.0	$0.6	$0.6
Total	**$12.4**	**$27.5**	**$0.0**	**$7.6**	**$13.2**	**$20.1**	**$40.7**

n.e. = not estimated

1. Material verification cost savings would provide comparable safety with a pressure test at or above 1.25 times maximum allowable operating pressure and with all anomaly dig-outs pipe properties confirmed through either destructive or non-destructive methods.
2. Using 3% discounted values. TA 1 includes range for uncertainty in incidents averted rates (see Table 4-2 and Table 4-3).
3. Range reflects uncertainty in incidents averted rates, see Table 4-2 and Table 4-3.

Table C- 122

Table 5-5. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 7% Discount Rate (Millions 2015$)

Topic Area	Average Annual Benefits-Low	Average Annual Benefits-High	Average Annual Costs	Benefit: Cost Ratio - Low	Benefit: Cost Ratio - High
1[1]	$9.2	$26.7	$36.4	$0.3	$0.7
2[2]	n.e.	n.e.	$28.6	n.e.	n.e.
3	$1.1	$1.1	$0.8	$1.3	$1.3
4	$6.4	$6.4	$7.6	$0.8	$0.8
5	$0.3	$0.3	$4.2	$0.1	$0.1
6	n.e.	n.e.	$0	n.e.	n.e.
7	$0.4	$0.4	$0.0	$18.5	$18.5
Total	**$17.5**	**$35.0**	**$77.8**	**$21.0**	**$0.4**

n.e. = not estimated.

1. Reflects uncertainty in incident averted rates for topic area 1. See Tables 4-2 and 4-3.

2. Break even value of benefits would equate to approximately one incident averted over the 15-year study period.

Table C- 123

Table 5-6. Summary of Average Annual Present Value Benefits and Costs, Topic Areas 1-7, 3% Discount Rate (Millions $2015)

Topic Area	Average Annual Benefits - Low	Average Annual Benefits - High	Average Annual Costs	Benefit: Cost Ratio - Low	Benefit: Cost Ratio - High
1[1]	$10.9	$31.5	$45.6	$0.2	$0.7
2[2]	n.e.	n.e.	$32.3	$0.0	$0.0
3	$1.2	$1.2	$1.0	$1.3	$1.3
4	$7.0	$7.0	$9.2	$0.8	$0.8
5	$0.3	$0.3	$5.3	$0.1	$0.1
6	n.e.	n.e.	$0.2	$0.0	$0.0
7	$0.6	$0.6	$0.0	$23.0	$23.0
Total	**$20.1**	**$40.7**	**$93.6**	**$25.3**	**$0.4**

n.e. = not estimated.

1. Reflects uncertainty in incident averted rates. See Tables 4-2 and 4-3.

2. Break even value of benefits would equate to less than one incident averted over the 15-year study period.

Appendix D: All Recalculated Tables from the RIA Appendix

Table D- 1

A-1. Calculation of HCA Mileage Operating at Pressure Greater than 30 Percent SMYS

Location	Onshore Gas Transmission Miles[1]	HCA Mileage[2]	Total >30% SMYS	% >30% SMYS	HCA >30% SMYS
Interstate					
Class 1	160,029	62	145,301	91%	56
Class 2	17,805	23	14,909	84%	19
Class 3	13,927	439	11,318	81%	357
Class 4	29	0.0	16	55%	0.0
Total	191,789	524	171,544		432
Intrastate					
Class 1	72,719	13	58,176	80%	10
Class 2	12,839	18	9,040	70%	13
Class 3	19,730	749	12,107	61%	460
Class 4	880	5	431	49%	2
Total	106,169	785	79,754		485
Total Onshore					
Class 1	232,748	75	203,477	89%	67
Class 2	30,645	41	23,949	78%	32
Class 3	33,657	1,188	23,424	69%	816
Class 4	908	5	446	49%	2
Total	297,958	1,309	251,297		917
Source: 2014 PHMSA Annual Report					
1. Part K					
2. Part Q GF HCA					

Table D- 2

A-2. Calculation of HCA Mileage Operating at Pressure 20-30% SMYS					
Location	**Onshore Gas Transmission Miles[1]**	**HCA Mileage[2]**	**Total 20-30% SMYS**	**% >30% SMYS**	**HCA >30% SMYS**
Interstate					
Class 1	160,029	62	7,977	5%	3
Class 2	17,805	23	1,436	8%	2
Class 3	13,927	439	1,307	9%	41
Class 4	29	0.0	9	32%	0.0
Total	191,789	524	10,729		46
Intrastate					
Class 1	72,719	13	8,293	11%	1
Class 2	12,839	18	2,762	22%	4
Class 3	19,730	749	5,671	29%	215
Class 4	880	5	428	49%	2
Total	106,169	785	17,154		223
Total Onshore					
Class 1	232,748	75	16,270	6%	5
Class 2	30,645	41	4,198	14%	6
Class 3	33,657	1,188	6,978	22%	256
Class 4	908	5	438	49%	2
Total	297,958	1,309	27,883		269
Source: 2014 PHMSA Annual Report.					
1. Part K					
2. Part Q GF HCA					

Table D- 3

Table B-1. Social Cost of Carbon Based on IWG (2015)[1]

Year	SCC (per metric ton CO2; 2007$)	SCC (per metric ton CO2; 2015$)
2015	$36	$41
2016	$38	$43
2017	$39	$45
2018	$40	$46
2019	$41	$47
2020	$42	$48
2021	$42	$48
2022	$43	$49
2023	$44	$50
2024	$45	$51
2025	$46	$53
2026	$47	$54
2027	$48	$55
2028	$49	$56
2029	$49	$56
2030	$50	$57

Source:

1. Based on 3% discount rate. CO_2 = carbon dioxide

IWG = The Interagency Working Group on Social Cost of Carbon

SCC = social cost of carbon

Table D- 4

Table B-2. Social Cost of Methane Based on Marten et al., (2014)		
Year	**SC per metric ton methane (2007$)**	**SC per MCF methane (2015$)**
2015	$1,100	$24
2016	$1,120	$25
2017	$1,140	$25
2018	$1,160	$26
2019	$1,180	$26
2020	$1,200	$26
2021	$1,240	$27
2022	$1,280	$28
2023	$1,320	$29
2024	$1,360	$30
2025	$1,400	$31
2026	$1,440	$32
2027	$1,480	$33
2028	$1,520	$34
2029	$1,560	$34
2030	$1,600	$35
Source: Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH_4 and N_20 Mitigation Benefits Consistent with the US Government's SC-CO_2 Estimates. Climate Policy. Inflated to 2015 based on 2015 average CPI of 237.0		
SC = Social cost		
MCF = 1,000 ft^3 of a gas at standard temperature and pressure		

Table D- 5

Table B-3. Total Social Cost of GHG Emissions due to Pressure Test and ILI Upgrade related Blowdowns (3%)

Year	Methane Emissions (MCF)	SCM (3%)	C0₂ Emissions (lbs.)	C0₂ Emissions (metric tons)	SCC	Social Cost of GHG Emissions
2016	34,572	$864,292	72,547	33	$1,414.98	$865,707
2017	34,572	$864,292	72,547	33	$1,480.80	$865,772
2018	34,572	$898,863	72,547	33	$1,513.70	$900,377
2019	34,572	$898,863	72,547	33	$1,546.61	$900,410
2020	34,572	$898,863	72,547	33	$1,579.52	$900,443
2021	34,572	$933,435	72,547	33	$1,579.52	$935,014
2022	34,572	$968,007	72,547	33	$1,612.42	$969,619
2023	34,572	$1,002,578	72,547	33	$1,645.33	$1,004,224
2024	34,572	$1,037,150	72,547	33	$1,678.24	$1,038,828
2025	34,572	$1,071,722	72,547	33	$1,744.05	$1,073,466
2026	34,572	$1,106,293	72,547	33	$1,776.96	$1,108,070
2027	34,572	$1,140,865	72,547	33	$1,809.86	$1,142,675
2028	34,572	$1,175,437	72,547	33	$1,842.77	$1,177,279
2029	34,572	$1,175,437	72,547	33	$1,842.77	$1,177,279
2030	34,572	$1,210,008	72,547	33	$1,875.67	$1,211,884
Total	518,575	$15,246,104	1,088,200	494	$24,943	$15,271,047

CO_2 = carbon dioxide GHG = greenhouse gas lbs. = pounds

MCF = thousand cubic feet MT = metric ton

SCC = social cost of carbon SCM = social cost of methane

Table D- 6

Table B-5. Social Benefits of Avoided Gathering Line GHG Emissions (3%)						
Year	**Avoided CH_4 emissions (MCF)**	**SCM (3%)**	**Avoided CO_2 Emissions(lbs.)**	**CO_2 Emissions (MT)**	**SCC**	**Social Cost of GHG Emissions**
2016	15,121	$378,027	57,662	26	$1,125	$379,152
2017	26,843	$671,072	102,361	46	$2,089	$673,161
2018	26,843	$697,915	102,361	46	$2,136	$700,051
2019	26,843	$697,915	102,361	46	$2,182	$700,097
2020	26,843	$697,915	102,361	46	$2,229	$700,144
2021	33,642	$908,321	128,286	58	$2,793	$911,114
2022	33,642	$941,962	128,286	58	$2,851	$944,814
2023	33,642	$975,604	128,286	58	$2,909	$978,513
2024	33,642	$1,009,245	128,286	58	$2,968	$1,012,213
2025	33,642	$1,042,887	128,286	58	$3,084	$1,045,971
2026	33,642	$1,076,529	128,286	58	$3,142	$1,079,671
2027	33,642	$1,110,170	128,286	58	$3,200	$1,113,370
2028	33,642	$1,143,812	128,286	58	$3,259	$1,147,070
2029	33,642	$1,143,812	128,286	58	$3,259	$1,147,070
2030	33,642	$1,177,453	128,286	58	$3,317	$1,180,770
Total	458,908	$13,672,639	1,749,968	794	$40,543	$13,713,182
CH_4 = methane						
CO_2 = carbon dioxide GHG = greenhouse gas lbs. = pounds						
MCF = thousand cubic feet MT = metric ton						
SCC = social cost of carbon SCM = social cost of methane						

Table D- 7

Table C-1. Estimated Immediate Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Immediate Repair Rate			Gas Transmission Integrity Management Immediate Repair Rate			GT Estimated Immediate Repair Rate for Previously Assessed Pipe
	Total HL Assessment Miles	HL HCA Immediate Repairs	HL Immediate Repair Rate[1]	Total GT Assessment Miles	GT HCA Immediate Repairs	GT HCA Immediate Repair Rate	
2004	65,565.0	1,701.0	0.0	3,998.0	104.0	0.0	0.0
2005	17,501.0	1,369.0	0.1	2,906.0	261.0	0.1	0.0
2006	12,411.0	941.0	0.1	3,500.0	158.0	0.0	0.0
2007	9,240.0	880.0	0.1	4,663.0	258.0	0.1	0.0
2008	5,916.0	888.0	0.2	2,858.0	181.0	0.1	0.1
2009	3,372.0	660.0	0.2	3,288.0	144.0	0.0	0.2
Average rate[2]	NA	NA	0.1	NA	NA	0.1	0.0

Source: Gas Transmission and Hazardous Liquid Annual Reports GT = gas transmission

HCA = high consequence area HL = hazardous liquid

NA = not applicable

1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

Table D- 8

Table C-2. Estimated Scheduled Condition Repair Rates for Previously Unassessed Pipe and Previously Assessed Pipe

Year	Hazardous Liquid Integrity Management Scheduled Condition Repair Rate						Gas Transmission Integrity Management Scheduled Repair Rate			GT Estimated Scheduled Repair Rate for Previously Assessed Pipe
	Total HL Assessed Miles	HL HCA 60-Day Repairs	HL 60-day Repair Rate	HL HCA 180-day Repairs	HL 180-day Repair Rate	HL Total HCA Scheduled Repair Rate[1]	Total Assessed Miles	Total Scheduled Repairs	Scheduled Repair Rate	
2004	65,565	647	0	3,178	0	0	3,998	599	0	0
2005	17,501	1,109	0	5,278	0	0	2,907	378	0	0
2006	12,411	861	0	2,748	0	0	3,501	344	0	0
2007	9,240	580	0	2,139	0	0	4,663	452	0	0
2008	5,916	1,022	0	4,037	1	1	2,858	252	0	1
2009	3,372	454	0	3,088	1	1	3,288	266	0	1
Avg. rate[2]	NA	NA	0.1	NA	0.4	**0.5**	NA	NA	0.1	**0.4**

Source: Gas Transmission and Hazardous Liquid Annual Reports GT = gas transmission

HCA = high consequence area HL = hazardous liquid

NA = not applicable

1. Assumed gas transmission repair rate for previously unassessed pipe.
2. Average of 2004-2009 rates

Table D- 9

Table C-3. Pressure Test Failures 2010-2013			
Year [1]	**Miles Pressure Tested**	**Failures both in and out HCA**	**Test Failure Rate per Mile**
2013	1,502	54	0.04
2012	2,078	52	0.03
2011	1,687	71	0.04
2010	1,393	51	0.04
Average Rate[2]	NA	NA	0.03
1. Operators were not required to report pressure test failures prior to 2010.			
2. Average of 2010-2013 rates			

Table D- 10

Table D-1. Summary of Consequences Associated with the 2010 San Bruno Pipeline Incident		
Consequence	**Value**	**Source**
Deaths, injuries, and property damage	$565,000,000	PG&E Annual Reports
Cost of gas lost	$263,000	PG&E Incident Report
Emergency response (PG&E)	$250,000	NTSB Report, PHMSA estimate
Emergency response (public)	$50,000,000	NTSB Report, University of Delaware, PG&E Annual Reports
Disaster relief and evacuations	$64,987,210	PG&E Annual Reports, University of Delaware, American Red Cross
Mandatory pressure reduction	Not quantified	California Public Utilities Commission
Total	$680,500,210	See above

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Table E-1. Historical Consequences of Onshore Gas Transmission Incidents Due to All Causes (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	81	1	$9,400,000	8	$7,888,000	$26,002,183	439	$658,500	$43,948,683	$542,576
2004	83	0	$0	2	$1,972,000	$4,027,541	1,036	$1,554,000	$7,553,541	$91,007
2005	106	0	$0	5	$4,930,000	$110,676,449	1,996	$2,994,000	$118,600,449	$1,118,872
2006	108	3	$28,200,000	3	$2,958,000	$8,419,432	995	$1,492,500	$41,069,932	$380,277
2007	86	2	$18,800,000	7	$6,902,000	$14,434,410	1,174	$1,761,000	$41,897,410	$487,179
2008	93	0	$0	5	$4,930,000	$12,154,890	635	$952,500	$18,037,390	$193,950
2009	92	0	$0	11	$10,846,000	$7,767,011	727	$1,090,500	$19,703,511	$214,169
2010	82	10	$94,000,000	61	$60,146,000	$418,615,646	265	$397,500	$573,159,146	$6,989,746
2011	101	0	$0	1	$986,000	$22,200,196	870	$1,305,000	$24,491,196	$242,487
2012	87	0	$0	7	$6,902,000	$13,710,727	904	$1,356,000	$21,968,727	$252,514
2013	93	0	$0	2	$1,972,000	$13,876,259	3,103	$4,654,500	$20,502,759	$220,460
2014	116	1	$9,400,000	1	$986,000	$14,867,441	1,445	$2,167,500	$27,420,941	$236,387
2015	117	6	$56,400,000	14	$13,804,000	$11,885,205	503	$754,500	$82,843,705	$708,066
Total	1245	23	$216,200,000	$127	$125,222,000	$678,637,390	$14,092	$21,138,000	$1,041,197,390	$836,303

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

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Table E-2. Historical Consequences of Onshore Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods1 (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	33	0	$0	0	$0	$15,854,155	171	$256,500	$16,110,655	$488,202
2004	26	0	$0	0	$0	$1,108,283	229	$343,500	$1,451,783	$55,838
2005	27	0	$0	0	$0	$105,697,938	384	$576,000	$106,273,938	$3,936,072
2006	44	0	$0	0	$0	$2,802,314	52	$78,000	$2,880,314	$65,462
2007	38	1	$9,400,000	3	$2,958,000	$11,941,122	263	$394,500	$24,693,622	$649,832
2008	30	0	$0	1	$986,000	$8,200,877	331	$496,500	$9,683,377	$322,779
2009	32	0	$0	3	$2,958,000	$2,494,681	278	$417,000	$5,869,681	$183,428
2010	28	8	$75,200,000	51	$50,286,000	$412,056,506	29	$43,500	$537,586,006	$19,199,500
2011	29	0	$0	0	$0	$8,020,221	66	$99,000	$8,119,221	$279,973
2012	26	0	$0	0	$0	$7,585,658	524	$786,000	$8,371,658	$321,987
2013	27	0	$0	2	$1,972,000	$8,124,268	451	$676,500	$10,772,768	$398,991
2014	31	0	$0	0	$0	$5,359,479	598	$897,000	$6,256,479	$201,822
2015	28	0	$0	0	$0	$3,961,837	366	$549,000	$4,510,837	$161,101
Total	399	9	$84,600,000	60	$59,160,000	$593,207,339	3,742	$5,613,000	$742,580,339	$1,861,104

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
5. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

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Table E-3. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods1 Located in HCAs (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	2	0	$0	0	$0	$3,065,772	0	$0	$3,065,772	$1,532,886
2004	3	0	$0	0	$0	$90,612	28	$42,000	$132,612	$44,204
2005	1	0	$0	0	$0	$1,056	0	$0	$1,056	$1,056
2006	2	0	$0	0	$0	$20,187	0	$0	$20,187	$10,094
2007	2	0	$0	0	$0	$267,564	200	$300,000	$567,564	$283,782
2008	1	0	$0	0	$0	$15,577	30	$45,000	$60,577	$60,577
2009	0	0	$0	0	$0	$0	0	$0	$0	$0
2010	2	8	$75,200,000	51	$50,286,000	$407,516,568	0	$0	$533,002,568	$266,501,284
2011	2	0	$0	0	$0	$302,089	0	$0	$302,089	$151,045
2012	3	0	$0	0	$0	$280,668	500	$750,000	$1,030,668	$343,556
2013	0	0	$0	0	$0	$0	0	$0	$0	$0
2014	4	0	$0	0	$0	$141,019	18	$27,000	$168,019	$42,005
2015	1	0	$0	0	$0	$58	0	$0	$58	$58
Total	23	8	$75,200,000	51	$50,286,000	$411,701,170	776	$1,164,000	$538,351,170	$23,406,573
Power Law Average										**$6,699,452**

HCA = high consequence area VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs

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Table E-4. Historical Consequences of Gas Transmission Incidents due to Causes Detectable by Modern Integrity Assessment Methods1 Located in Proposed MCA (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	11	0	$0	0	$0	$12,977,374	13	$19,500	$12,996,874	$1,181,534
2004	7	0	$0	0	$0	$216,205	0	$0	$216,205	$30,886
2005	5	0	$0	0	$0	$102,653,637	240	$360,000	$103,013,637	$20,602,727
2006	14	0	$0	0	$0	$926,494	33	$49,500	$975,994	$69,714
2007	16	1	$9,400,000	3	$2,958,000	$8,312,698	63	$94,500	$20,765,198	$1,297,825
2008	13	0	$0	0	$0	$6,913,847	298	$447,000	$7,360,847	$566,219
2009	9	0	$0	3	$2,958,000	$873,649	207	$310,500	$4,142,149	$460,239
2010	10	0	$0	0	$0	$2,651,682	0	$0	$2,651,682	$265,168
2011	11	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$1,470,556
2012	11	0	$0	0	$0	$3,334,972	22	$33,000	$3,367,972	$306,179
2013	12	0	$0	2	$1,972,000	$8,702,995	451	$676,500	$11,351,495	$945,958
2014	27	0	$0	0	$0	$2,534,887	27	$40,500	$2,575,387	$95,385
2015	27	0	$0	0	$0	$2,177,212	27	$40,500	$2,217,712	$82,137
Total	173	1	$9,400,000	8	$7,888,000	$168,399,266	1,416	$2,124,000	$187,811,266	$1,085,614

MCA = moderate consequence area (five building in the potential impact radius criterion) VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Inline inspection, pressure testing, direct assessment, and other technology.
2. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
3. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
4. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs

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Table E-5. Historical Consequences of Gas Transmission Incidents due to Corrosion (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$986,000	$10,202,074	171	$256,500	$20,844,574	$992,599
2004	26	0	$0	1	$986,000	$1,171,118	262	$393,000	$2,550,118	$98,081
2005	26	0	$0	1	$986,000	$1,958,592	44	$66,000	$3,010,592	$115,792
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,958,000	$5,538,624	138	$207,000	$27,503,624	$808,930
2008	25	0	$0	1	$986,000	$7,808,619	295	$442,500	$9,237,119	$369,485
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,902,000	$5,372,531	6	$9,000	$31,083,531	$1,295,147
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,972,000	$6,509,273	12	$18,000	$8,499,273	$424,964
2013	25	0	$0	2	$1,972,000	$4,820,896	2567	$3,850,500	$10,643,396	$425,736
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,972,000	$2,904,165	46	$69,000	$14,345,165	$597,715
Total	320	9	$84,600,000	20	$19,720,000	$56,143,102	3,737	$5,605,500	$166,068,602	$518,964

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

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Table E-6. Historical Consequences of Gas Transmission Incidents due to External Natural Force Damage Events (2003- 2015; 2015$)										
Year	**Number of Incidents**	**Number of Fatalities**	**VSL[1]**	**Number of Injuries**	**VSL Serious Injury[2]**	**Other Costs of Accident[3]**	**Number of Persons Evacuated**	**Estimated Cost of Evacuations[4]**	**Total Cost of Incidents**	**Average Cost per Incident**
2003	3	0	$0	0	$0	$124,874	0	$0	$124,874	$41,625
2004	5	0	$0	0	$0	$240,779	0	$0	$240,779	$48,156
2005	22	0	$0	0	$0	$1,151,038	0	$0	$1,151,038	$52,320
2006	4	0	$0	0	$0	$108,107	10	$15,000	$123,107	$30,777
2007	6	0	$0	0	$0	$236,541	206	$309,000	$545,541	$90,924
2008	12	0	$0	0	$0	$695,379	0	$0	$695,379	$57,948
2009	9	0	$0	0	$0	$605,516	138	$207,000	$812,516	$90,280
2010	6	0	$0	0	$0	$340,174	0	$0	$340,174	$56,696
2011	16	0	$0	0	$0	$3,566,551	141	$211,500	$3,778,051	$236,128
2012	5	0	$0	0	$0	$1,129,508	30	$45,000	$1,174,508	$234,902
2013	7	0	$0	0	$0	$279,537	0	$0	$279,537	$39,934
2014	13	0	$0	0	$0	$3,026,390	510	$765,000	$3,791,390	$291,645
2015	10	0	$0	0	$0	$404,247	0	$0	$404,247	$40,425
Total	118	0	$0	0	$0	$11,908,641	1,035	$1,552,500	$13,461,141	$114,077
VSL = value of statistical life										
Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files										
1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).										
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).										
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs										
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).										

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Table E-7. Historical Consequences of Gas Transmission Incidents due to Pipe Failure due to Corrosion and Excavation Damage in Class 1 and Class 2 Locations. (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	21	1	$9,400,000	1	$986,000	$10,202,074	171	$256,500	$20,844,574	$992,599
2004	26	0	$0	1	$986,000	$1,171,118	262	$393,000	$2,550,118	$98,081
2005	26	0	$0	1	$986,000	$1,958,592	44	$66,000	$3,010,592	$115,792
2006	32	3	$28,200,000	0	$0	$2,458,396	33	$49,500	$30,707,896	$959,622
2007	34	2	$18,800,000	3	$2,958,000	$5,538,624	138	$207,000	$27,503,624	$808,930
2008	25	0	$0	1	$986,000	$7,808,619	295	$442,500	$9,237,119	$369,485
2009	17	0	$0	0	$0	$1,246,324	83	$124,500	$1,370,824	$80,637
2010	24	2	$18,800,000	7	$6,902,000	$5,372,531	6	$9,000	$31,083,531	$1,295,147
2011	24	0	$0	0	$0	$3,935,920	65	$97,500	$4,033,420	$168,059
2012	20	0	$0	2	$1,972,000	$6,509,273	12	$18,000	$8,499,273	$424,964
2013	25	0	$0	2	$1,972,000	$4,820,896	2567	$3,850,500	$10,643,396	$425,736
2014	22	0	$0	0	$0	$2,216,570	15	$22,500	$2,239,070	$101,776
2015	24	1	$9,400,000	2	$1,972,000	$2,904,165	46	$69,000	$14,345,165	$597,715
Total	320	9	$84,600,000	20	$19,720,000	$56,143,102	3,737	$5,605,500	$166,068,602	$518,964

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

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Table E-8. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods1 Located in Non-HCA Class 3 and Class 4 (2003-2015; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	0	0	$0	0	$0	$0	0	$0	$0	#DIV/0!
2004	2	0	$0	0	$0	$13,506	1	$1,500	$15,006	$7,503
2005	3	0	$0	0	$0	$40,964	100	$150,000	$190,964	$63,655
2006	2	0	$0	0	$0	$93,107	0	$0	$93,107	$46,554
2007	1	0	$0	0	$0	$48	0	$0	$48	$48
2008	3	0	$0	0	$0	$6,409	2	$3,000	$9,409	$3,136
2009	3	0	$0	0	$0	$147,752	99	$148,500	$296,252	$98,751
2010	1	0	$0	0	$0	$8,907	0	$0	$8,907	$8,907
2011	0	0	$0	0	$0	$0	0	$0	$0	$0
2012	2	0	$0	0	$0	$4,188	0	$0	$4,188	$2,094
2013	1	0	$0	0	$0	$1,540,149	175	$262,500	$1,802,649	$1,802,649
2014	2	0	$0	0	$0	$652,110	20	$30,000	$682,110	$341,055
2015	1	0	$0	0	$0	$1,152	0	$0	$1,152	$1,152
Total	21	0	$0	0	$0	$2,508,292	397	$595,500	$3,103,792	$147,800

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).

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Table E-9. Historical Consequences of Gas Transmission Incidents due to Causes Detectible by Modern Integrity Management Methods (ILI, Pressure Testing, Direct Assessment, Other Technology) Located Alternate 1 Structure PIR MCA (2003-2013; 2015$)

Year	Number of Incidents	Number of Fatalities	VSL[1]	Number of Injuries	VSL Serious Injury[2]	Other Costs of Accident[3]	Number of Persons Evacuated	Estimated Cost of Evacuations[4]	Total Cost of Incidents	Average Cost per Incident
2003	26	0	$0	0	$0	$13,155,941	13	$19,500	$13,175,441	$506,748
2004	17	0	$0	0	$0	$219,159	0	$0	$219,159	$12,892
2005	23	0	$0	0	$0	$103,043,595	280	$420,000	$103,463,595	$4,498,417
2006	27	0	$0	0	$0	$1,063,038	42	$63,000	$1,126,038	$41,705
2007	28	1	$9,400,000	3	$2,958,000	$8,478,907	263	$394,500	$21,231,407	$758,265
2008	18	0	$0	0	$0	$6,921,409	300	$450,000	$7,371,409	$409,523
2009	24	0	$0	3	$2,958,000	$923,407	207	$310,500	$4,191,907	$174,663
2010	25	0	$0	0	$0	$3,359,001	0	$0	$3,359,001	$134,360
2011	25	0	$0	0	$0	$16,123,614	35	$52,500	$16,176,114	$647,045
2012	23	0	$0	0	$0	$4,506,211	24	$36,000	$4,542,211	$197,487
2013	26	0	$0	2	$1,972,000	$8,702,995	451	$676,500	$11,351,495	$436,596
2014	10	0	$0	2	$1,972,000	$11,240,623	10	$15,000	$13,227,623	$1,322,762
2015	6	0	$0	2	$1,972,000	$3,732,419	6	$9,000	$5,713,419	$952,237
Total	278	1	$9,400,000	12	$11,832,000	$181,470,319	1,631	$2,446,500	$205,148,819	$737,945

VSL = value of statistical life

Source: Incident data from PHMSA gas transmission incident reports, 2003-2015, see http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

1. Based on DOT 2015 Guidelines for Value of Statistical Life (VSL; $9.4 million in 2015 dollars).
2. Based on DOT 2015 Guidelines for VSL (serious injury value; $0.986 million in 2015 dollars).
3. Converted from $2013 to $2015 (2013 Consumer Price Index- 233.5; 2015 Consumer Price Index-237.0). Includes all reported operator incident expenses (3rd party damage, operator emergency response, lost gas, etc.) less operator property damage and repair costs
4. Based on multiplying the number of persons evacuated by a best professional judgment estimate of per person evacuation cost (approximately $1,500).