UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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In the matter of: *

PUBLIC HEARING ON NATURAL GAS PIPELINE EXPLOSION AND FIRE, SAN BRUNO, CALIFORNIA SEPTEMBER 9, 2010

Docket No. DCA-10-MP-008

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Board Room and Conference Center
National Transportation Safety Board
490 L'Enfant Plaza
Washington, D.C. 20024

Thursday,
March 3, 2011

The above-entitled matter came on for hearing, pursuant to notice, at 9:00 a.m.

BEFORE: BOARD OF INQUIRY
National Transportation Safety Board

APPEARANCES:

NTSB Board of Inquiry

DEBORAH A.P. HERSMAN, Chairman
CHRISTOPHER A. HART, Vice Chairman
MARK R. ROSEKIND, Ph.D., Member
ROBERT L. SUMWALT, Member
EARL F. WEENER, Ph.D., Member

NTSB Technical Panel:

RAVINDRA CHHATRE, Investigator-in-Charge
MIKE BROWN, Transportation Safety Specialist
MIKE BUDINSKI, Chief, Material Labs
KARL GUNTHER, Chairman, Operations Group
MATT NICHOLSON, P.E., Pipeline Investigator
DANA SANZO, Chairman, Survival Factors Group
CARL SCHULTHEISZ, Ph.D., Materials Investigator
BOB TRAINOR, P.E., Chief, Pipeline and Hazardous Materials Division
FRANK ZAKAR, Materials Investigator
LORENDA WARD, Hearing Officer
MARK JONES, Audio/Visual

Interested Parties:

PAUL CLANON, Executive Director, California Public Utilities Commission (CPUC)
CONNIE JACKSON, City Manager, City of San Bruno, California
KIRK JOHNSON, Vice President, Gas Engineering Operations, Pacific Gas and Electric Company (PG&E)
DEBBIE MAZZANTI, Business Representative, International Brotherhood of Electrical Workers (IBEW), Local 1245
JEFF WIESE, Associate Administrator for Public Safety, U.S. Department of Transportation, Pipeline and Hazardous Materials Administration (PHMSA) Operations, Pacific Gas and Electric Company (PG&E)

Witness Panel 5:

CHARLES DIPPO, P.E., Vice President, Engineering Services and System Integrity, South Jersey Gas Company

APPEARANCES (Cont.)

Witness Panel 5 (Cont.):

FRASER FARMER, P.E., Owner, PipeLink Associates
GEOFF FOREMAN, Global Strategy Leader, PII Pipeline Solutions
JOSHUA JOHNSON, Materials Engineer, PHMSA
ALAN MAYBERRY, P.E., Deputy Associate Administrator for Field Operations, PHMSA
CHRISTINA SAMES, Vice President, Operations and Engineering, American Gas Association
ROBERT SMITH, Manager, Research and Development, PHMSA

I N D E X

I N D E X

P R O C E E D I N G S

(9:00 a.m.)

CHAIRMAN HERSMAN: Good morning and welcome back for the final day of our public hearing on the San Bruno pipeline accident. We'll begin with our fifth panel.

Ms. Ward, can you please swear in the witnesses?

HEARING OFFICER WARD: Thank you, Madam Chairman.

Can the witnesses please rise? Please raise your right hand.

(Witnesses sworn.)

HEARING OFICER WARD: Thank you. For the record, we have Mr. Geoff Foreman, Mr. Charles Dippo, Ms. Christina Sames, Mr. Fraser Farmer, Mr. Robert Smith, Mr. Joshua Johnson, and Mr. Alan Mayberry on the Panel. And we'll start with Mr. Geoff Foreman. If you could please state your full name, title, and a brief description of your duties and responsibilities?

MR. FOREMAN: My name is Geoffrey William Foreman. I'm the global strategy leader for GE PII Pipeline Solutions. I have 34 years experience in inline inspection. I've worked with pipeline operators around the world, and I have a degree in engineering.

HEARING OFFICER WARD: Thank you.

Mr. Dippo.

MR. DIPPO: Yes, good morning. My name is Charles Dippo. I am vice president of engineering services for South

Jersey Gas Company. I have 32 years experience with South Jersey Gas Company.

HEARING OFFICER WARD: And Ms. Sames.

MS. SAMES: I'm Christina Sames, vice president of operations for the American Gas Association. My responsibilities include pipeline safety and other safety initiatives, the AGA Best Practices Program, interaction with others, such as other stakeholders, like the Common Ground Alliance or regional, national and international gas associations, and about anything else they want to throw on my plate.

HEARING OFFICER WARD: All right, Mr. Farmer?

MR. FARMER: Thank you.

Good morning. My name is Fraser Farmer. I'm the owner of a small company called Pipelink Associates. My work history has been with TransCanada pipe for many years in engineering activities, then with a company called Pipetronics, which was in the IOI space. Pipetronics was acquired by the PII Company, which was acquired by GE. So, my background in inline inspection has been utilized since then in putting on workshops and web conferences in the SGA activities in inline inspection and integrity management. I hold a degree in electrical engineering. Thank you.

HEARING OFFICER WARD: Mr. Smith.

MR. SMITH: Good morning. I'm Robert Smith. I'm the R&D manager for PHMSA's Pipeline Safety Research Program. I'm involved with managing the strategic execution of the program and performance measurement. I'm proficient in all of our processes, and I have a pretty good background in all of the technology and things that are going on with our program.

HEARING OFFICER WARD: Mr. Johnson.

MR. JOSHUA JOHNSON: My name is Joshua Johnson. I'm a materials engineer with the Office of Pipeline Safety. I have nearly 15 years of experience as a regulator and as a consultant, primarily in the areas of metallurgy, inspection technology, failure analysis, and integrity management. I've also been the primary representative to the metallurgical group at NTSB over the last several years and have participated in a number of NTSB investigations, and I have a master's degree in material science and engineering from the University of Virginia.

HEARING OFFICER WARD: And Mr. Mayberry?

MR. MAYBERRY: Good morning. I'm Alan Mayberry with the Office of Pipeline Safety. I'm the deputy associate administrator for field operations for about the last year. In those responsibilities I cover our national inspection program through our five regional offices and also our emergency response and security functions. I've been with PHMSA for about 5 years. And then prior to my current position, I was the director of engineering.

HEARING OFFICER WARD: Thank you.

Madam Chairman, the witnesses have been sworn in and qualified, and they're ready to be questioned by Dr. Carl Schultheisz.

CHAIRMAN HERSMAN: Dr. Schultheisz, please proceed.

DR. SCHULTHEISZ: Thank you. Thank you all for participating in our panel today. I appreciate it.

I'd like to start with Mr. Mayberry. As the Chairman noted yesterday, PHMSA regulations require pressure testing for new construction, and pressure testing is also one of the possible methods identified for pipeline integrity management. How would a pressure test typically be performed for a large transmission line in a Class 3 location like San Bruno?

MR. MAYBERRY: Are you referring to a new pipeline?

DR. SCHULTHEISZ: Yes, a new pipeline.

MR. MAYBERRY: Okay, a new pipeline would be constructed, and upon completion of the construction process, there's the strength test requirement according to the regulations, what we call a sub-part J test for Class 3 pipeline, that would involve testing the pipeline at one-and-a-half times the anticipated maximum allowable operating pressure.

DR. SCHULTHEISZ: So, at that point you would expect to have a 50% margin of safety above the allowable operating pressure?

MR. MAYBERRY: Yes.

DR. SCHULTHEISZ: Okay, if you were replacing a segment of pipe, would you be expected to test, pressure test the entire line?

MR. MAYBERRY: If you're replacing a pipe, it depends. If you're replacing a short segment, say about a length of pipe or less, a pup perhaps, you're replacing an anomaly, a corrosion defect or that sort of thing, you would replace a section of pipe which would involve pre-testing a section, cutting out, stopping the line off, removing the product, whether it's natural gas in this case, making sure you have a safe environment, installing the new section of pre-tested pipe, inspecting the welds either through radiography or ultrasonics or some other appropriate method that's approved, and then placing the line back into service. If it's a longer section, it may require, say, a relocation perhaps; involve construction of an offset. A longer length would be constructed, buried, and then tested in place, similarly at one-and-a-half times the operating pressure.

DR. SCHULTHEISZ: Okay, thank you. And you would expect that newly installed pipe would have been pressure tested by the manufacturer to a much higher pressure level?

MR. MAYBERRY: Yes. The standard for line pipe that's referenced in pipeline safety regulations calls for a mill hydrostatic test.

DR. SCHULTHEISZ: Okay. And in some cases, PHMSA has required hydrostatic testing for other-than-new construction. Can you provide some examples of that?

MR. MAYBERRY: Certainly. Probably the main example would be post-failure. If there's been a pipeline incident where you have a release, it may be one of the requirements of a return to service to verify the integrity of the pipeline. It's one of many tools, mind you. There are other tools that I'm sure we're going to talk about, like inline inspection. There are other inspection methods, and it depends on the issue.

But we have had cases in corrective action orders, which are one of our enforcement actions when there is an incident, where we deem a pipeline to have perhaps an imminent hazard were it to continue operation without some sort of remedial action. We would issue what's called a corrective action order that could include provisions for further inline inspections or hydrostatic testing. I'll give you an example.

A couple of years ago, in 2007, actually, there was a failure on a natural gas pipeline in the Midwest. Failure was attributed to selective seam corrosion, a type of feature that is preferential to a certain type of pipe coated a certain way that we have corrosion that occurs along the seam of a pipe. In that situation, we required hydrostatic testing because there had been a couple of failures on that line. But then also we also included inline inspection. That's just one example.

We've also done it -- primarily it's common with say liquid pipelines where we would require it as a follow-up action. And also, I might add too that typically in a corrective action order or safety order, we would include a requirement for a long-term integrity verification plan, which requires the operator to determine the most appropriate method to assess the integrity of the pipeline.

DR. SCHULTHEISZ: Okay, thank you. We heard yesterday that one of the potential problems raised with regard to hydrostatic testing is the possibility of creating or propagating damage that might later cause a breach during normal operation. Does PHMSA have any documentation of cases where that has occurred?

MR. MAYBERRY: That is a factor that when you're considering pressure testing of vintage pipelines that would need to be considered. In reviewing our incident history on a phenomenon known as pressure reversal, which is a situation that happens when you hydrostatically test a pipeline and then a subsequent test is performed, and the pressure -- the pipeline may fail at a lower pressure than the first hydrostatic test. That's very simply put what is referred to as a pressure reversal. Those typically are done. Where those are experienced we may not know about those. However, I do have -- in 2008 there was a liquid pipeline failure that involved a pressure lower than a hydrostatic test that had been performed about 4 years earlier.

DR. SCHULTHEISZ: Okay.

MR. MAYBERRY: So, and there is some documentation available out there on this phenomenon. We have not seen it to be a significant issue, but yet, it's an issue that needs to be looked at.

DR. SCHULTHEISZ: Okay, thank you. Are there some operators that do choose to use routine hydrostatic testing as their method of ensuring pipeline integrity?

MR. MAYBERRY: Well, as you know with the integrity management program, which represented a paradigm shift in our regulations back when they were promulgated, it requires the operator to determine the best assessment method. That may include hydrostatic testing. It may also include inline inspection, but there are operators who do choose to do hydrostatic testing as an integrity verification method.

DR. SCHULTHEISZ: Okay, thank you.

I'd like to switch gears a little and address some questions to Mr. Johnson. Basically, well, PHMSA regulations also refer specifically to direct assessment methods as tools to ensure pipeline integrity. Could you give us an overview of the direct assessment methodology for external corrosion and internal corrosion?

MR. JOSHUA JOHNSON: Sure, direct assessment is one of the three assessment methods that are referenced in our code. When Congress and the 2002 Pipeline Safety Improvement Act, when they wrote that Act it was those three were put into that law when they asked us to create the Gas Integrity Management Rules.

Direct assessment, and particularly external corrosion direct assessment, came about in the early 2000's, and it's essentially a methodology that we took a number of measures that were already in place, some things that pipeline operators were already doing for integrity management and put them together to make it more of a practice and a program instead of just a hodgepodge of things. And so, all DA programs, all the direct assessment programs involve a four-step process.

The first process is a pre-assessment step where you gather in all the available data, and you come back and look and see what methodologies would be helpful and what your threats are and then also what your condition your line is in. And from that you then go out and look with direct inspection steps, which are tools in external corrosion direct assessment that you look for essentially places where coating has been damaged. And then by choosing the areas with the worst coating damage, you go up for the third step, the direct examination and dig up areas and look to see if there is actual corrosion at those areas instead of just coating loss. And finally, you bring it all back into a post-assessment and reevaluate everything, and then the process just keeps on rolling and rolling through.

DR. SCHULTHEISZ: And for the internal corrosion?

MR. JOSHUA JOHNSON: For the internal corrosion the big difference is that there are not tools to look for the coating damage, since we're looking inside. So, there's not a coating damage issue. So, what we're looking for instead is -- and internal corrosion direct assessment can only be used on lines that normally don't contain any water, but occasionally some might get into the system. So, we're looking for the areas that that water might have pooled. So, you're looking for angles where at the bottom of a hill the water could sit and cause internal corrosion. And then if you find those angles, you go out and dig at those areas and examine if there's corrosion in the pipe.

DR. SCHULTHEISZ: So, when you're looking in the external corrosion case, you're basically looking for leakage current or something of that sort to identify areas where there was a breakdown in the protective coating or possibly the cathodic protection?

MR. JOSHUA JOHNSON: Yeah, essentially you're looking for areas that between current gradience or other changes in a signal that you can read from the outside and an electrical signal that there is damage to the coating.

DR. SCHULTHEISZ: And as part of the assessment process, you need to test a random sample in order to check your methodology in effect?

MR. JOSHUA JOHNSON: Yes, the methodology that has been put in place has a number of digs that have to be done, including one at an area that you don't expect to have anything. So, you would look there and hopefully not have something. And if you do, then there's an obvious problem with how you've done your methodology.

DR. SCHULTHEISZ: Right, and that's part of the reassessment process is to --

MR. JOSHUA JOHNSON: It all feeds back into the reassessment process, yes.

DR. SCHULTHEISZ: So, you're checking your process and checking your assumptions and checking your results in effect?

MR. JOSHUA JOHNSON: Correct.

DR. SCHULTHEISZ: Is there any kind of a metric that might be used to quantify the effectiveness of the direct assessment? In a sense, you expect a hydrostatic test to, you know, identify 100 percent of the defects that would fail below the test pressure, but not give you any information about subcritical defects. Is there any kind of metric associated with the direct assessment methodology?

MR. JOSHUA JOHNSON: Well, there are a couple of things. One, and this is one of the advantages that direct assessment shares with ILI tools, is that they're data driven so that you can come back when you do your next one, and the data from the first one is still there. And so you can make a comparison to see if things have been changing.

The other thing that has been done, there are some industry groups in particular that have looked at areas where they've been doing direct assessment and that they've done ILI, and they've compared those to see how those match up, if the areas that you're finding the worst DA things, you're also finding the worst corrosion by ILI.

DR. SCHULTHEISZ: Okay, and I guess one possible problem would be if you had some disbonding of the coating that still provided an electrical insulation but allowed moisture or water to get to the pipe surface?

MR. JOSHUA JOHNSON: Yeah, certain coatings make this difficult. Rocky areas where you might have lots of rocks make it difficult. When we put pipes under roads it changes things. And these are all things that have to be looked at as part of the steps in the DA process to evaluate that. And in some areas, DA is not -- is either very, very difficult to do or might not be an appropriate tool because of that.

DR. SCHULTHEISZ: Okay, thank you.

I think that wraps up my questions for this morning for these witnesses. I'd like to pass the questioning to Frank Zakar.

MR. ZAKAR: Good morning. In this session I will be asking several questions on the capability of inline inspection tools. My first question will be directed to Mr. Geoff Foreman. Can you give me some examples of what type of flaws you're looking for in pipelines when you're sending your inline inspection tools?

MR. FOREMAN: Yes, the inline inspection tools look for internal and external corrosion, cracking, deformities, and pipeline movement.

MR. ZAKAR: And can you describe what inline inspection tools your company utilizes to detect these flaws?

MR. FOREMAN: I can. Can you bring up Exhibit 8-A, please?

Inline inspection can serve as a fundamental element of a pipeline operator's integrity management program. Fundamentally, it provides visibility and can identify pipelines that require additional investigation and response, provide a reference point for monitoring corrosion and crack growth, give 360 degree coverage for hundreds of miles in one pipeline inspection, and be tailored, as we said before, for various threats such as corrosion, cracking, deformities, et cetera.

MR. ZAKAR: Geoff, if you can, you do have the ability to change the slides if you would like to do that at this time. All right, okay, perfect.

MR. FOREMAN: When we talk about ILI, there may be a tendency to focus on technology and tools, but it's important to recognize that this is a process, that the ILI vendor and the pipeline operator each play different and important roles. ILI requires a piggable and clean pipeline. The pipeline operator selects the appropriate ILI tool for a particular risk that he wants to evaluate. Example, he would not be looking for corrosion with a crack tool or vice versa. Then the inline inspection tool is run through the pipeline. A typical smart pig will take samples of a pipe every 1/8 of an inch along its entire length, and 360 degrees around its circumference in 1/4-inch intervals.

After the data has been collected on the tool and retrieved, complex data interpretation occurs. To understand this process, an analogy to medicine might help. Similar to an x-ray, CAT Scan or MRI, the quality of the data and the definition of the images supplied really depend on the type of equipment that is used. The ILI vendor, like a radiologist, uses his experienced proprietary software and seismograms to generate a report that identifies the dimensions of cracks, metal loss, and other physical features.

Then the pipeline operator, like the treatment physician, uses the ILI vendor's report to analyze the identified features against its own records, such as ASME, to develop responses including determining which defects require further action and which can be monitored for growth and revisited on subsequent inspections. Depending on the results of the analysis and per the regulation, the operator may have to undertake a dig program and make repairs. During a dig it is important that the operator should measure the defects and compare them to the inline inspection results. This comparison serves to validate the inline inspection work and enables continual improvement in the technology of inline inspection. But this can only occur if the results of the dig inspection are fed back to the inline inspection vendor.

Although the next two slides and charts are going to reference other risks such as densident (ph.) and pipeline movement, in the interest of time, I'm going to focus on cracks and corrosion. Each requires different tools. The ability of crack inspection to identify the presence of cracks has been well established. However, the industry has demanded that inline inspection vendors not only identify cracks but also provide dimensions. This requires very sophisticated and sensitive high technology tools which have been developed and are continually being refined.

The established crack evaluation technology is ultrasound because of the two dimensional nature of cracks, i.e. they don't have any width. While it is very suited for liquid pipelines, it isn't suited for inspection in dry gas pipelines. The most advanced ultrasonic tool is the phased array device, which I will explain in much more detail later.

For gas pipelines, gas crack detection historically has relied on the transverse field magnetic inspection tools. The newest technology suitable for crack detection and gas pipelines today is the EMAT tool, which I'll describe in more detail in a later slide.

Corrosion and other ILI tools cover over 80 percent of all inspections in the U.S. And the majority of those inspections are carried out with magnetic flux leakage tools. The capabilities of corrosion tools are generally well accepted, ultrasonic tools being the more accurate but only being used in liquid pipelines. Magnetic tools, such as MFL and TFI, which are less accurate, can operate in both gas and liquid environments. And again, the suitability of the tool depends on what pipe threat you wish to evaluate.

With this slide I wanted to try and show the difference of all the tools that are available today for both corrosion and crack. This slide identifies the various detection capabilities and accuracy specifications. Each needs to be considered in the tool selection process. For example, if you know that the higher accuracy of the EMAT tool for crack detection and sizing over that of TFI. As we've discussed, there's no single ILI tool that can identify every type of pipeline threat. To achieve the greatest degree of confidence, the use of moldable ILI tools may be the most appropriate approach.

From an emerging technology point of view, now I'd like to present the most promising technologies for the future. Let's concentrate on the left-hand side of the screen for the liquid solutions. I briefly mentioned phased array. I want to explain its vast capabilities. Unlike conventional measurement and crack detection tools, the phased array is a smart sensor that can be programmed to focus the rays of sensors to determine both corrosion and crack in a single run. We can also configure the sensor to give us better resolution for both.

Finally, we can adjust the angles to refine crack sizing. Today this tool can be multitasked and inspect for both corrosion and crack in a single fun, but however, it must be slowed down to a very slow speed compared to conventional tools. As electronics and physics are advancing, we are looking into smaller and faster elements and increasing both the resolution and the ability to remotely task at higher speeds. These elements combined with the many computers required to file them are at the leading edge of technology today. Going back to the medical analogy, this is your ultimate MRI machine versus and x-ray.

On the right-hand side of the screen we have the EMAT. EMATs in various forms have been around for 30 years but have never been successfully used inside of a pipeline. Very recently, however, after eight years of research, we have refined the technology to distinguish cracks in gas pipelines from the naturally occurring features associated with the manufacturing process. It is vitally important to get better crack sizing in gas pipelines, and this technology is the best solution available today. We are looking forward to working with the industry to adopt these technologies in the future.

There is a variety of conditions that may make a pipeline unpiggable, including the pressure, the flow, and the fittings. This slide identifies some of them. Determining whether a line is piggable requires an expert engineering assessment. No one solution fits all. Each pipeline is unique.

And finally, I want to conclude with a look at hydrostatic testing versus inline inspection. This diagram illustrates the typical limits and capabilities of an inline inspection tool, be it crack or corrosion. To see the defects in a pipeline varies those of the hydro test. Corrosion and cracks below the ILI detection limits are shown in the white areas adjacent to the X's. The large red dot shows the size of a defect that could fail the hydro test. A hydro test will find the single weakest defect, i.e. the weakest link in the chain. What it won't do is tell you how many more similar but not quite severe defects are present. Those other defects are depicted in the blue dots between the blue and red lines. Think of them as threats lurking around the corner. And the defect depicted in the green hatched areas are those that fall within the ILI tool specification and would be reported. So, this is what I mean when I talk about ILI provides more visibility. And with hydro testing, the pipeline must be taken out of service during the test. But if the pipeline isn't piggable, hydro test might be an appropriate method.

In conclusion and to reiterate, feeding the dig information back to the ILI vendor is essential in refining specifications and continuing advances in technology. Thank you.

MR. ZAKAR: Thank you, Mr. Foreman, for the presentation. The EMAT tool appears to be --

CHAIRMAN HERSMAN: Mr. Zakar, can you speak up just a little bit? I know people on the webcast were having a little bit of trouble hearing some people.

MR. ZAKAR: Okay.

Mr. Foreman, thank you for the presentation. EMAT tool appears to be a cutting edge technology. That's the electromagnetic acoustic transducer. Do all inline inspection companies have EMAT inspection capability?

MR. FOREMAN: Not all. There is two available in the U.S.

MR. ZAKAR: My next question is for Mr. Fraser Farmer. You saw Mr. Foreman's presentation. What key points are required to assure that an inline inspection is a success?

MR. FARMER: Thank you for that question. Just to elaborate on some of what Mr. Foreman has outlined, there is an established process to ensure success in an ILI project.

The first thing, and this has been discussed in this hearing, is to identify the relevant threats in the pipeline section of concern. And that's outlined very well in ASME B 31.8S, actually in article 2.2. And those are the so-called 22 threats, and we need to very clear about which threats exist or may exist in that pipeline section.

The next thing that is necessary to do is to choose the appropriate ILI technology. And here I'm not talking about particular vendors or particular vendor tools but the technologies, whether it's ultrasonics for metal loss, MFL for metal loss, or EMAT's, for instance, for crack detection in gas pipelines. So, choosing the appropriate technology is the next step. And there's good guidance in API 1163 Standard, NACE SP0102 and NACE report 35100. So, we have good guidance with respect to which technologies are appropriate.

The next stage is to choose the appropriate tool for that project. And here I'm thinking of the particular vendor, and vendors have a whole range of tools. So, which vendor and which tool is the next choice. And here the vendors provide really good guidance in their performance specifications, and they lay out in great detail the probability of detection of a particular tool finding a particular defect, and the whole range of those are expressed. Beyond probability of detection, they get into probability of identification. The first step is to detect the defect of concern. The second is to unambiguously identify that this is a crack. It's a mill defect, or it's some corrosion, for instance.

The third part of this stage is sizing the defects. One can detect defects and in some cases not be able to size them appropriately. If you can't size them, you can't assess their possible impact on predicted rupture pressure, for instance. So, once you've done that selection, you need to then have an operationally successful run. And that is described, all of the issues are described again in API 1163, and the personnel qualifications are described in ASNT ILI-PQ. So, the industry has pulled together to come up with common expected standards to assure that the field operation will be successful.

And Geoff alluded to a couple of the points. You need to have a clean pipeline. The definition of clean is challenging. You need to have a pipeline that's going to flow at a rate that's commensurate with the tool performance. And those are just a couple of the items that are needed to be managed.

The next stage you get into is the interpretation of the data that is collected, and that's done in a combination of ways. Some of the interpretation is done through rules-based software that evaluates the data on computers, and that's very good because it's predictable and it is highly productive in carrying that out. A lot of the defects, however, are complex and require human interpretation. So, the qualification of the people doing that work becomes significant.

The last step is the documentation of the results of one of these projects, and that's covered again in API 1163 and ILI-PQ. As several people have said in the past and currently, if it's not documented, it doesn't exist. If it's not documented well, it could be misleading. So, those guidelines are very important.

MR. ZAKAR: Thank you. I'd like to bring up Exhibit 8-E. This is an excerpt from the NACE Standard SP0102 standard practice in inline inspection of pipelines. Do you have any general comments regarding the thoroughness of this chart?

MR. FARMER: Yes, thank you for that. This is a very good early guidance on selection of the right tool against the potential threats in a pipeline section. So, down the left-hand side where it describes anomaly are the different kinds of defects that we could anticipate possibly occurring in a pipeline. Across the top are the different kinds of tools that are available from many vendors. And if you go down through that matrix, you're able to see in some cases where it states that a particular tool would not detect a particular defect. Obviously, that's an inappropriate choice. In other cases, it will show that it detects well, but sizing of that particular defect may be limited. So, as a starting point, and I emphasize as a starting point, that table provides very good guidance in selecting the right tool or technology for a particular anomaly.

MR. ZAKAR: Thank you. So, there's a little bit more to inline inspection than just sending the inline inspection tool through the pipe. By the way, that is an excerpt from the NACE document, and we did receive permission to use it for this session. So, we thank NACE for that permission.

The next question I have is Mr. Geoff Foreman. The origin of the fracture in the San Bruno pipe exhibited lack of wall penetration on the inside diameter of the pipe that extended between the inside diameter and approximately 50 percent of the wall thickness. My question to you is does and inline inspection tool exist that can detect such a flaw?

MR. FOREMAN: Yes, there is.

MR. ZAKAR: Thank you. Can you give us an idea which tool may be applicable?

MR. FOREMAN: It's a gas pipeline. EMAT technology would definitely see it and transverse fields. If we remember the chart I showed, the minimum detection is 25 percent through wall length 1 to 2 inches. So, the defect you described would be within that specification, so the tool would detect it.

MR. ZAKAR: Thank you.

My next question is in regards to the ability -- well, it would be a historical question. From the historical point of view, how far has inline inspection technology progressed in regard to the inspection of gas pipelines? We're looking at pipes that are 1950, 1960 vintage. Where does inline inspection tools come in? Is it very recent? Are we making any progress? And, Mr. Fraser Farmer, would you like to comment on that?

MR. FARMER: Thank you. The origin of inline inspection goes back to the mid to late 1960's. And the concentration at that time was on MFL technology for detection of internal and external corrosion. In the 1980's, those tools evolved to what are sometimes called high resolution MFL tools. And that is really a very mature technology now.

In the mid-'90s, the ultrasonic tools came on the market, initially for metal loss detection, in other words corrosion. And in the late '90s, the crack detection ultrasonic tools that Geoff referred to as being suitable for liquid pipelines or in a liquid batch in a gas pipeline, not a fun thing to do, but it's possible. They came on the market. Crack tools, initially there was an early British gas development for detecting cracks in gas pipelines. It used ultrasonics in a wheel configuration. Those tools have pretty much been retired now that

EMAT tools are on the market.

The ultrasonic crack detection tools, applicable in liquid systems in the late '90s, gained great popularity, particularly in liquid lines that had stress corrosion cracking. I think it's fair to say that the technology has been evolving more and more rapidly in the last few years, and it's reaching maturity in a few cases. But there are a lot of defects or anomalies that are still not amenable to inline inspection and worthy of further development or experimentation.

MR. ZAKAR: Thank you.

With all this technology that we have available, is it possible to miss the detection of a flaw? And, Mr. Foreman, can you address that?

MR. FOREMAN: Yes, it is.

MR. ZAKAR: And what conditions would cause you to miss that flaw?

MR. FOREMAN: It would depend on the size of the flaw. It would also depend on the type of technology that was trying to find the flaw. From a corrosion point of view, it's very rare. From a crack point of view, to my knowledge in anything that I've been involved in, from a forensics of a failure, a crack tool has always detected it but maybe not been able to evaluate it.

MR. ZAKAR: My next question is how do we improve the probability of detection?

MR. FOREMAN: So that, as I mentioned in my presentation, I think the more feedback we get with real defects, the better we are in understanding the capabilities of the technologies. The majority of the tools are, when we design and build them and test them, we test them with artificial defects. We build our expertise and our sizing algorithms based on artificial defects. Therefore, getting real defects from a pipe and a real pipe environment is invaluable to us. So, that's one way where we can improve.

And the other way is repeat inspections. You increase your probability of confidence -- sorry, you improve your confidence every time you run a tool. And the chances are that if you've missed something the first time, it will be caught in repeat inspections, and that's probably the best way of doing it.

MR. ZAKAR: What type of anomalies are not amenable to inline inspection detection?

MR. FOREMAN: The one anomaly that at the moment is impossible to be detected is a thing called pinholes or microbiological corrosion, and that's because of its very, very small diameter. Sometimes it's referred to as worm holes, and it's just because the physics that are available to us today don't allow us to detect it. However, the technology I did display, the phased arrays for liquid operation, we believe by using that kind of array we could provide a three-dimensional image of a worm hole sometime in the future, as an MRI machine does in a human body.

MR. ZAKAR: My next question would be who tracks the progress of inline inspection technology and its success rate? Yes, Mr. Foreman, if you could answer that?

MR. FOREMAN: Could you repeat that for me, please?

MR. ZAKAR: Who tracks the progress of inline inspection technology and its success rate?

MR. FOREMAN: Who tracks the projects?

MR. ZAKAR: Yeah, you know, you have so many companies that offer services. I guess maybe I should rephrase that question. How do you share that information among the different operators, and how does PHMSA get that information? How do you share that information and its ability of each tool to do the job?

MR. FOREMAN: Okay, I think most information sharing happens in conferences and also with pipeline agencies, bodies such as the PLCI, INGAA, wherever we get invited to present. But I think conferences, the National Pipeline Conference in Canada is a great one. So, that's where most new developments are shared.

MR. ZAKAR: My next question is when it comes to cost of this technology, once a pipe is constructed to run an inline inspection tool, which would become more costly to run? Is it the hydrostatic test or the inline inspection tool?

MR. FOREMAN: That's a very difficult question to answer. I could, you know, from an inspection point of view, it's the price of an inline inspection. I couldn't really comment on how much an operator pays for a hydrostatic test, plus the inconvenience of not being able to actually operate the pipeline.

So, really, it's a question you should really pose to an operator rather than to a pipeline vendor.

MR. ZAKAR: My next question would be to someone in PHMSA. How much of the U.S. pipelines are piggable? Is there anybody who could give an idea on the percentage, a rough estimate?

MR. MAYBERRY: We'll have to get that.

MR. ZAKAR: Somebody would like to give that a try?

MR. MAYBERRY: I'll give the microphone a try. We'll have to get that information.

MR. ZAKAR: Thank you. If you could do that, it would give us an idea of where we stand with pipelines in the U.S.

MR. MAYBERRY: Okay, perhaps someone from -- perhaps Christina from the AGA perspective may be able to shed some light.

MS. SAMES: The American Gas Association has done an industry survey. Based on that survey, about 61 percent of the pipe is not piggable.

MR. ZAKAR: Do you have any idea if the percentage of non-piggable lines are higher in gas lines versus liquid lines? Any idea on that?

MS. SAMES: Liquid lines are almost all piggable. And I'm not an expert in liquid, but if I recall some previous statistics, I want to say it's in the high 90's. PHMSA, do you want to take that one?

MR. MAYBERRY: Yes. Most liquid lines are piggable.

MR. ZAKAR: Thank you very much. That is all the questions I have for now. My next line of questions would be for Mr. Mike Budinski.

MR. BUDINSKI: Good morning. My first question is for Mr. Smith. Towards ensuring safety reliability and environmental protection, how does PHMSA develop technological advances in pipeline inspection?

MR. SMITH: If I could please have Exhibit 8-B brought up. Madam Chairman, I appreciate the opportunity to share our experience with improving pipeline safety through targeted research and to assist the NTSB in this investigation.

Before I begin, I'd like to point out that our program is addressing solutions for all pipeline types, not just for natural gas transmission. Could you please hand down the -- you should know that our program is there in support of the PHMSA mission in pipeline safety. We're focused on near-term solutions, that's one to three years, that improve the safety and reliability and the environmental impact, reduce the environmental impact from our nation's transportation system, pipeline transportation system.

The department has been conducting research since 1969 but at a very limited level, paper studies, and really not addressing technology development. This all changed in 2002 with the passage of the Pipeline Safety Improvement Act which authorized our program up to $10 million a year. And it also put a strong focus on technology development and deployment and coordinating and collaborating with all pipeline safety stakeholders, federal, state, and private. Essentially, Congress charged our program with creating more tools in the industry toolbox so they can more safely meet and exceed integrity management regulations.

Keeping in mind our mission and Congressional direction, we've crafted and are executing a time tested process that incorporates stakeholder input that is transparent, competitive, collaborative and co-funded, leveraging the appropriations given to this program with our stakeholder community. We feel that this process works very well with the type of research we seek and award, meeting federal guidelines for quality, transparency, and because we've been independently reviewed, favorably closing audits by the Inspector General and the Government Accountability Office.

Our program strives for outputs and impacts from these three objective areas, developing technology, strengthening consensus standards, and generating and promoting new knowledge to decision makers. We've awarded 171 projects with $62 million in PHMSA funds as well as $79 million of industry and other federal co-funding worldwide since 2002. The graphic illustrates the relevance of these 171 awards, projects, noting that one project can be relevant to more than one of our objectives.

Just to give you a feel of how that investment populates our program categories, this represents our initial program structure identified in our first strategic plan. It's currently in revision for the period 2011 through 2015. The figure will drastically change to illustrate how our investment addresses many of these pipeline challenges. Currently, our drafts new programmatic areas are threat prevention, leak detection, anomaly detection and characterization, anomaly remediation and repair, design materials welding and jointing, and alternative fuels, climate change, and others.

The next couple of slides depict just some of the impacts that our program has brought to bear on natural gas transmission pipeline challenges. We've seen improvements to guided wave ultrasonics, a technology that may be used in difficult to inspect areas, such as cased pipelines that go under roads and railroad crossings.

We've seen the first ever tool that can map an entire pipeline current demand from inside the pipeline. Areas of higher current demand may indicate challenges with the effect of this of a cathodic protection system in a given pipeline segment.

We've also seen deployment of an innovative robotic inspection tool for natural gas pipelines considered unpiggable by traditional inline inspection technology. The tools shown in the bottom left has cameras on both ends, can be deployed remotely and has a sensor on it addressing metal loss corrosion.

We've also had an impact with leak detection. We've been able to integrate state-of-the-art leak detection on helicopter and fixed-wing aircraft capable of addressing and identifying small leaks before they become larger ones and over a wide area.

The following next couple of slides depict some of the anticipated technology impacts that we see entering the market in the next one to three years, once again addressing natural gas transmission pipeline challenges. Working with the same sponsors supporting the six to eight-inch robotic tool, we've seen big advances in technology to inspect larger diameter unpiggable pipelines.

The picture shows another innovative robotic inspection technology still in the research phase but going under numerous technology demonstrations to ensure that the technology will reliably perform in the challenging environments it needs to. The picture shows this tool. It has cameras once again on both ends. It has a MFL sensor capable of looking at metal loss corrosion. Not depicted in the picture, it has a gas turbine on it that will allow the robot to recharge in the pipe, allowing it to go further distances of inspection. And we're very excited about this tool, and we think it's definitely a leap in the ability to look at some of these unpiggable systems that we've been talking about.

We also anticipate major improvements to handheld technology which is used once pipelines are uncovered exposing segments for closer investigation. These tools will address anomaly detection of a wide array of pipeline threats, providing for clear decision making on repairing the damage.

And finally, we're not done improving upon existing technology such as magnetic flux leakage sensors used in inline inspection. Research underway is demonstrating that this technology traditionally used for metal loss corrosion can be applied to other threats, such as mechanical damage and identifying areas of despondent coding from inside the pipe.

As I mentioned earlier, we're also focused on improving nationally recognized consensus standards. We have a memorandum of agreement with the Pipeline Standard Developing Organization Coordinating Council. This council represents the Pipeline Standard Developing Organization to have interest in pipeline safety standards and specification standards. We make them aware of the research targeting their standards. We invite them to peer review our projects annually that are relevant. We share the project results with committees representing these standards, and we ask them to report if the project results are used to help revise these standards.

In our initial data call, we determined that three standards were improved from our program's focus on standards, one with API and one with NACE International. We also determined that a number of project results were shared with these committees for addressing whether or not they would be used to help revise these standards. We're currently in another data call underway. We hope to better reflect how our program is keeping these critical standards relevant to their purpose.

We were also asked to talk about direct assessment and how our program is broadening applicability, validating, and further standardizing the direct assessment process. Let me first say that direct assessment, and starting with external corrosion direct assessment, has been improving since its release in 2004, both from its usage and from targeted research. Direct assessment is moving from exterior threats like external corrosion to interior threats such as internal corrosion in dry and wet gas systems and liquid systems. We now see direct assessment expanding into and addressing complex threats coming from stress corrosion cracking, mechanical damage, and possibly systems carrying ethanol or other biofuels. Our program will continue finding and securing projects capable of developing new and further refining existing direct assessment and other standards.

And finally, we really believe that the future is bright and promising. We spent the early years of our program crafting the best results-driven process possible and aligning it to the type of research we fund and the stakeholders we partner with. We feel our program has the right type of credentials and hallmarks necessary for a federal research program addressing these ever changing pipeline challenges. Deploying technology via our program is growing in its success, and we believe it can be accelerated with additional resources. I urge you to please visit our program website. It documents and disseminates much more information than I was able to present to you today on the projects that I mentioned as well as many other projects not mentioned. Thank you.

MR. BUDINSKI: Thank you, Mr. Smith. I have a few other questions in follow up to your presentation. Thank you very much for a nice presentation. It appears that from what I understand the PHMSA research roadmap, shall we say, is managed by kind of a gap closure process whereby you have collective information that you get from industry and, you know, regarding problems and issues. And then, you know, you take a look at the priority of projects and you try to close those gaps. What gaps have been closed so far? What are sort of the key accomplishments to date that we have based on the research work done since inception of the current phase of research?

MR. SMITH: I'll try to do my best on that answer. But I'd first like to say that process that I showed in the slide is really the process that works well for our program and our stakeholders to identify what the right priorities are. We come together periodically to look at all the ongoing research that we're not duplicating. We want to be able to identify what research is ongoing on the challenges that we know we still have. We meet in working groups to identify what challenges we still need to address, and we come out of that event with a report and recommendation that we solicit for research addressing those topics and then finding the best researchers to address those to a competitive review process.

To exactly answer your question, of course, we've talked about some of the technological impacts that we brought to bear. I think I would first try to echo the comments made about technology that we need to focus on both the people process and tools when we're looking at threats. And the reliance just on technology -- we need to focus as much on the people who use the technology, training them, certifying them, and the process of pulling that all together.

MR. BUDINSKI: Okay, thank you. To just probe a little bit more there, what do you consider probably your top win? What have you really, you know, something you're really proud of that's been accomplished so far in this area, one good example?

MR. SMITH: Well, the program, like I said, started in 2002, and with the appropriations necessary to address some of these technological challenges. I would have to speak towards some of the robotic technology being really the major improvement that the program has been able to partner with mutual challenges to get solutions out there for unpiggable systems.

MR. BUDINSKI: So, these are tethered robots rather than pigs going through the pipeline?

MR. SMITH: These are untethered, battery operated robots that can be launches and retrieved.

MR. BUDINSKI: Oh, untethered, okay. Thank you. You talked a little bit about direct assessment, but I had a question regarding how -- is there any work you're doing on pulling together data as you're developing new technology, and how effective is direct assessment becoming? Is it really increasing in effectiveness, and do you have any metrics or ways of documenting that?

MR. SMITH: Not that the research program can provide. I mean, we're trying to mainly provide new data sets and new processes that can be integrated into these standards, not really addressing research. Even in our general knowledge type research to say that, you know, one process is better than another, this is really not a goal in our program to collect that type of knowledge about improvements.

MR. BUDINSKI: Is anybody recording that sort of information within PHMSA?

MR. SMITH: It might be addressed outside of our program in looking at other means that we have to address that, but I would maybe defer it to Alan.

MR. BUDINSKI: Alan?

MR. MAYBERRY: If applied appropriately it is effective. Operators are required to report the results of their integrity management program. And as you well know, the direct assessment is an assessment method that's relied upon heavily for distribution companies for intrastate transmission companies where they're not piggable. Again, it has to be used appropriately. If you're looking for external corrosion and you have say a seam threat, that would not be the appropriate use of external corrosion direct assessment, for instance. But it is an effective tool for finding external corrosion, assuming that the line also meets the other aspects of the regulations related to corrosion control.

MR. BUDINSKI: Thank you.

A few more questions for Mr. Smith with regard to your presentation. Is there research on hydrostatic pressure testing underway, and in what would we maybe expect in the next two or three years in terms of technological advances?

MR. SMITH: Yes, we are currently looking at hydrostatic testing with one active project that is due to complete this summer. That actually is getting to some of the discussions that we talked about over the last couple of days on customizing hydro testing, the parameters involved in hydro testing, to not grow some cracks but grow other threats, and to be able to look at the stress corrosion cracking threat in particular.

MR. BUDINSKI: Okay, thank you. One last question regarding your presentation. But the integrity management program is still relatively young. What has been learned so far? What is the main thing you've learned to far out of this whole integrity management program from a research perspective?

MR. SMITH: From a research perspective, and I'll probably pass some of that question on, we know that we can effectively target research program solutions towards some of these challenges that we're seeing out in the field. We're partnered very well in the engineering program at PHMSA, and our field personnel and our state partners and as well as coordinating with other federal agencies in the industry to know that we need to be addressing these type of challenges and develop those type of tools to be able to help meet and exceed regulatory requirements. And if there's a question about data and metrics, that would be maybe something for Alan to answer.

MR. BUDINSKI: Are you able to chime in, Alan or Mr. Mayberry?

MR. MAYBERRY: Well, certainly, since the inception of the program for gas, there have been about 1,052 conditions repaired that required immediate attention, and then over 2,239 conditions that were repaired on a scheduled basis. And these were issues that were found during the, or in conjunction with, integrity management.

MR. BUDINSKI: Great, thank you.

With regard to technological development, again this is for Mr. Smith, what is the greatest threat not being adequately addressed in pipeline integrity management today?

MR. SMITH: I would believe that we are addressing most of them, if not all, of the known threats that we see out there. We have, like I said, that process that really gets to the heart of the gaps that we see out there, and then finding good research to address that, and then getting those tools out into the market or information to stand and developing organizations. I think that the biggest gap that we do see still is to have the same suite of tools that we see in traditional inline inspection into some of these robotic platforms that can address these unpiggable challenges.

MR. BUDINSKI: I see, okay. I was thinking that an unpiggable situation might be towards the top of the list of some concerns. As we've covered in the first two days of the hearing, successful integrity management is predicated largely on successful inspection of identified threats. Are there new approaches or technologies to more accurately identify threats in a pipeline system, Mr. Smith?

MR. SMITH: When I had the slide talking about how our investment has broken into out programmatic areas, you might have seen that there was not much investment going on in risk management, and that's really because directly, that's because risk management is something that is involved with pretty much every project that we're dealing with. Because of integrity management and because of the reliance on data and risk management to know what tools that we should be looking at in development and what tools that need to be deployed.

MR. BUDINSKI: Okay, it just seems as though, you know, having to know really the threats before you start to inspect them is sort of an unending loop. You almost need to inspect your pipeline first so that you can figure out what threats to identify, then you start to monitor those threats. And it seems like this is an area where there's assumptions made for operators, and so I was just wondering is there more work being done in this area? I'm not sure if somebody else from PHMSA is able to comment on this. Mr. Mayberry?

MR. MAYBERRY: If I might add, Mr. Budinski, my colleague Linda Daugherty yesterday referred to a couple of workshops that are coming, one specifically related to risk assessment and how operators are identifying risk.

If you look over the last year or so at the incidents that have occurred in the U.S., you know, they're quite varying causes, causal factors involved. However, a common thread that we could pick out there, if you will, is the identification of threat, appropriate identification of threat, and in many cases, just using information that's already in the hand of the operator. So, that's why we felt a need to have a workshop, which is coming up in July.

In addition, we're also issuing, as my colleague Ms. Daugherty mentioned yesterday as well, an advance notice of proposed rule making related to the gas integrity management program. We've already done that for liquid, and the comment period just closed. But we expect that to be coming out late spring to further ask the public and industry, the stakeholders, where improvements need to be made in our integrity management regulations.

MR. BUDINSKI: Okay, thank you.

On the same subject, I'd like to ask Mr. Dippo a question. In older or legacy pipeline systems, have industry best practices been developed to identify pipeline threats with the highest level of confidence?

MR. DIPPO: Yes, I actually have a presentation, Exhibit 8-C. Would now be the right time to bring that up?

MR. BUDINSKI: I don't believe so. If you're able to just answer this briefly, and then maybe you could comment more thoroughly later.

MR. DIPPO: Sure, could you repeat the question, please?

MR. BUDINSKI: Yes, in older or legacy pipeline systems have industry best practices been developed to identify pipeline threats with the highest level of confidence? In other words, is there sharing going on in the industry around the best way to get at the assumed threats for pipeline system, and is that being shared effectively?

MR. DIPPO: I believe so. As both Mr. Foreman indicated and others have indicated on the panel, the best place to learn about these industry best practices and what other operators have experienced and found is at industry conferences. And the American Gas Association does have an excellent program for local distribution companies who are participating in their best practices program to share information and lessons learned.

MR. BUDINSKI: Thank you.

Next question is for Mr. Smith. Do you have any examples of newer pipeline inspection technologies that are underused due to economics or logistics? In other words, are operators using what you've developed?

MR. SMITH: I think this gets to the question of how you measure the impact of research, and sometimes that's a difficult endeavor. We try to stop at the idea that we're able to bring new tools out into the market. Going beyond that to look at economic issues, we don't have economics in our mission. And I do believe just the requirements about how we maybe ask the industry to report back. Since we regulate them, I think there's a burden that we may be putting on industry to try to go out there and do that from our point of view. But we try to get tools out.

We try to measure that they've been commercialized. We measure what the net improvement of those tools are. We're measuring that we're providing information to standards developing organizations. We're measuring that it was used or not, and we're measuring from promoting general knowledge. You know, how many files are being downloaded, website hits, patents, a number of other things to try to show that our program is effective in at least getting this information out there. It's once again hard to go beyond that step, I think.

MR. BUDINSKI: Thank you. The next question also to Mr. Smith. How does the pipeline inspection, new pipeline inspection technology impact data collection, management, and the determination of actions to take? The thinking is that as we get, for example, an inline inspection or direct assessment, we're getting better data, more effective data, more precise data. Are we able to use this in better models? Are we able to use this for better predictions? Do we have some more predictive capabilities? Where is that going? What kind of work are you doing in this area, and how do you see that going forward?

MR. SMITH: Well, I think you partially already answered some of that with the idea that we have had advances in tools and more tools out there, creating more data. We've been looking hard at data over the last few years in our solicitations, trying to make researchers look at the idea of what data they're creating and what could be done with this data. We had this as part of a discussion in one of our R&D forums a few years back. We've kept that type of ideals in the contracts that we issue with the researchers.

One particular project and example is we're trying to put some of these low MFL sensors on cleaning pigs, something that hasn't really been done before. And we're trying to just get more data, since cleaning pigs are run on a higher frequency than pigs for smart pigs are.

MR. BUDINSKI: Okay, thank you. I'm going to switch gears a little bit in terms of moving from inspection technology to another form of technology. This question is for Mr. Smith, but I'm also going to ask the same question to Ms. Sames as well. Given the impact of gas release during a pipeline rupture event, what new automatic shutoff valve or excess flow valve technology is being developed to quickly terminate gas flow during a pipeline breach? So, is there any new work that's being done in this area, Mr. Smith?

MR. SMITH: I guess I'll quickly say that I'm just not aware of work. Obviously, I mean, we're not looking at that issue right now on valves. It might be something we look at in the future, but nothing that I'm aware of right now.

MR. BUDINSKI: Okay, thank you.

And, Ms. Sames, do you have any comments in this area? I know you poll the industry as a whole, so you may have some perspective on this.

MS. SAMES: You mentioned excess flow valves; I'll start with it. So, for excess flow valves we know what we have seen is an expansion of that technology over time. When they first were developed they had some issues. Right now, they're pretty -- they work really well for single family homes. There are still some challenges when you expand that to small businesses, because excess flow valves are a relatively stupid device. They only look at a loss of pressure. But if you have an increase in load, the device could assume that that loss of pressure is due to an incident, not an increased load and will shut down. That creates safety problems, which has been discussed throughout the hearing.

So, work is still being developed to make them a little smarter, and industry is pilot testing these to see where they work and where they don't.

For automatic shutoff valves and remote control valves, automatic shutoff valves are very similar to an excess flow valve. It just indicates if there is a pressure loss, which means that you have to be pretty certain about your pressure, have pretty consistent pressure in order to use that type of device. A remote control valve, a little different, has a little bit of intelligence. I think we've seen a progression of that technology. I believe that more work needs to be done to make them just a little smarter, hopefully a little cheaper and better utilized.

MR. BUDINSKI: Thank you. I guess in your opinion, and I'll throw this out to both of you, do you feel that this is an area that needs more attention technologically to be able to get it to a point where they might be more commonplace and maybe be smarter about when they work and don't work and so forth?

MS. SAMES: Okay, I'll jump in first.

MR. SMITH: Yes, please.

MS. SAMES: I'm not sure if it's more of the technology as more of an understanding of where they should be applied and where they shouldn't be applied. GOT does have regulations for operators to consider this. We know that operators are considering them, but there are a number of factors that have to be taken into consideration.

So, what I would like to see, and one of the things that the American Gas Association is currently working on -- I'll speak to it a little bit later -- is a document that helps to pull together where they work, where they don't work, and things that have to be considered. For example, if you are trying to install one of these valves in an urban environment, you may not be able to put it above ground. If you put it below ground, you need to have the real estate, a vault. You have to get the permits.

The vault has to be big enough to put that valve, plus the electricity, plus somebody working around that. So, you may be talking a 20- to 30-foot valve vault. Now, if you're talking of trying to put something like that here, let's just use a local example, D.C., I don’t know if you can find real estate underground that big to put one of those valves. Those are the types of things that have to be considered. I do think more research needs to be done to make these a little bit more effective, especially on the remote control valves. And hopefully we can work together to do that.

MR. BUDINSKI: Mr. Smith, any comments on that at all?

MR. SMITH: Actually, no.

MR. BUDINSKI: Or Mr. Mayberry?

MR. MAYBERRY: At one of the foundations of the integrity management program is to integrate data. And in complying with the preventive and mitigative measures required in the program, the operator must look at data of his system, his operating data, to see if automation of a valve may be necessary. You've kind of covered a broad spectrum here. I know we've gone from excess flow valves on a customer's service line to an automation of a mainline valve. Certainly, the technology is there to automate mainline valves, and we have, for instance, in our alternate MAOP regulation we have mandated automated valves or line break sensors at valve stations to control operation or control the flow of gas on those types of pipelines.

MR. BUDINSKI: Thank you. This concludes my questioning at this point in time, and I'll turn the microphone over to Dr. Schultheisz.

DR. SCHULTHEISZ: Thank you.

Mr. Dippo, you mentioned that you have a presentation to present the industry perspective on this. I guess we could proceed with that. It's Exhibit 8-C, I believe.

MR. DIPPO: Thank you, Dr. Schultheisz.

Good morning, Madam Chairman, Vice Chair, Board members, technical panel members and analysts. My name is Charles Dippo. I am here today as the 2011 Operating Section Chair of the American Gas Association representing the natural gas distribution industry. I am vice president of engineering services and system integrity for South Jersey Gas Company, a local distribution company which supplies natural gas service to the lower one-third of New Jersey. I've been with South Jersey Gas for 32 years, and my responsibilities include the areas of engineering, design, planning, transmission and L&G operations, gas supply, gas control, and system integrity.

I have been asked to provide an operator's perspective on how to address threats to pipeline safety, focusing on inline inspection and hydrostatic pressure test assessments. The first step in managing integrity is the identification of the potential threats to a pipeline's integrity. This chart, taken from ASME B 31.8, categorizes the root causes of threats to pipelines into three time-related defect types of behavior, those that are time dependents, those that are stable unless activated by a change in conditions, and those that are time independent or random. Based on the type of threat behavior, either periodic assessments or one-time inspection assessment, or ongoing prevention and surveillance is required to mitigate these threats.

This flow chart, taken from a 2005 report prepared for the INGAA Foundation on evaluating integrity characteristics of vintage pipelines, demonstrates how an operator can manage historic anomalies most likely to threaten a pipeline's integrity. In this particular example, which is addressing seam weld and variable weld quality, guidance is provided to identify when a defect may exist for a particular pipe type and vintage, conditions that may activate a defect and practices used to mitigate the potential threat.

One method of mitigating the risk due to cracking near seam welds is to pressure test. Another is to perform inline inspection with a tool designed to detect cracks. The bottom line is that operators have to make decisions based on specific pipeline threats as each assessment technique has limitations.

As described in detail by Mr. Foreman and others, there are numerous different ILI technologies. Again, the tools are selective, and operators must know the defect they are searching for and use the specific tool. As stated, certain tools have better abilities for seams and cracks, but no tool is 100 percent fool proof, and there are limitations. In order to run inline inspection tools, the pipeline must be piggable, both physically and operationally. And what I mean by operationally is that pipeline flow rates and operating pressures must match the tool speed requirements.

Inline inspection can detect corrosion, mechanical damage, material defects and cracks. Operators support the technology but acknowledge the limitation that it is never 100 percent. Also, it should be pointed out that just because a pipeline segment is not piggable does not mean that it has bad pipe within it.

It has been estimated that the cost to retrofit all intrastate transmission pipeline to be piggable is approximately $12 billion. I think a question was asked earlier about the estimated percentage of LDC transmission pipe that is not piggable, and that is shown as the first bullet as 61 percent.

Hydrostatic pressure testing is a standard practice now done by operators as a post-construction, pre-commissioning strength test for the as constructed facility. It serves as a final validation of the integrity of the constructed system.

Hydrostatic mill pressure tests are performed at the pipe manufacturer at pressures now significantly higher than operational pressures. This chart, taken from API 5L -- or excuse me, the INGAA 2005 report shows maximum test pressures for large diameter pipe increasing from 50 percent of specified minimum yield in 1928 to 90 percent of specified minimum yield in 1983 when the API 5L and 5LX specifications were combined.

The use of hydrostatic pressure testing for in service pipe does have limitations. First, the pipeline has to come out of service for a hydrostatic pressure test, which may not always be feasible. For example, the pipeline may be a single directional feed to a downstream area which may represent two large of a load for utilizing either a temporary supply or a bypass of the effected section. Second and of equal importance is that incomplete dewatering can lead to future internal corrosion.

It should be pointed out that a hydrostatic pressure test has no predictive value. It is a snapshot in time, and there is no data available for other defects which may exist. It finds the weak link defect which fails below the test pressure.

There is also the possibility that a hydrostatic pressure test can cause subcritical defects to grow and possibly fail upon subsequent pressurization at a level below that of the first test in a phenomena previously referred to by Mr. Mayberry as a pressure reversal.

While it makes sense to hydrostatically pressure test new pipelines prior to their being placed in service, if time dependent defects can be located reliably by an inline inspection tool, utilizing the inline inspection tool is usually preferable to the hydrostatic pressure testing of an in service pipeline. If hydrostatic testing is to be conducted to validate the serviceability of a pipeline that is suspected to contain defects that are becoming larger with time, the highest feasible test pressure should be used. The higher the test pressure, the smaller will be the defects, if any, that survive the test.

There are over 187,000 miles of pressure-1970 transmission pipeline, and this is out of a total of approximately 300,000 miles. But just because a pipeline was constructed pressure-1970 does not mean that it was not subjected to a pre-commissioning hydrostatic strength test. As stated earlier, the state of California required pressure testing earlier than the 1970 federal regulations requirement.

Other considerations for operators include assessments of low stress pipelines or pipelines operating at less than 30 percent of specified minimum yield strength. Low wall stress pipelines have different failure characteristics than pipelines operating at high stress levels. They tend to leak rather than rupture, and it is unlikely that a fracture in a low stress pipeline will propagate. These differences significantly reduce the potential likelihood and consequences for such pipelines in comparison to the higher stress lines. As such, these differences are recognized for pipelines that operate below 30 percent of yield in both ASME B 31.8S and 49 CFR 192.

In summary, operators need the flexibility to use all tools to address the threats to pipeline safety. There is no single silver bullet. Inline inspection and pressure tests each have both benefits and limitations, and operators must carefully weigh the benefits and risks associated with hydrostatic pressure testing of in service pipe. Thank you.

DR. SCHULTHEISZ: Thank you very much for the presentation. I appreciate that. Is it possible, can you give us a rough estimate of the costs of hydrostatic testing versus inline inspection or direct assessment methods? Is there a rule of thumb like a cost per mile, or can you give me an order of magnitude estimate maybe?

MR. DIPPO: I don't have that information. A rule of thumb might be very difficult to apply there. Of course, there are costs associated with inline inspection that include not only making the pipeline piggable, but the utilization of an inline inspection tool. Those costs vary significantly based on the diameter of the line being inspected and based on the tool being applied. Likewise, hydrostatic pressure testing also requires for the most part a pipeline being made piggable, because that's the only way to ensure removal of water from the pipeline. If you were going to go to that trouble and expense of making a pipeline piggable to remove the water, it may be preferable to perform inline inspection at that point.

DR. SCHULTHEISZ: Okay, I guess I'll anticipate Member Rosekind's question and ask if the industry has developed metrics of some sort to measure the level of success of the pipeline integrity management programs.

MS. SAMES: Maybe I'll rephrase the question just a bit. Integrity management is relatively new, as was pointed out. So, it's still an evolving process, and it was always meant to be an ever growing process. We're just now finishing the baseline assessments on transmission integrity management. We're learning from those baselines, and that will move into the next phase, the reassessments.

As far as lessons learned, if I take it to a very high level, I would say the lessons learned are we're finding some things that we weren't expecting. We're also finding things that we were expecting. That's good. And hopefully as we move forward, and the prediction is that by finding these issues, we will be improving pipeline safety over time. But this is an ever growing process. So, stay tuned.

DR. SCHULTHEISZ: Okay, thank you.

I guess I'd like to ask the same question I asked to Mr.

Mayberry as to whether you have any documentation of these kinds of pressure reversal problems with hydrostatic testing?

MR. MAYBERRY: A lot of the pressure reversals typically we may not hear about because they may happen in conjunction with the hydrostatic test, and it's experienced before placing the pipeline into service. There are methods to -- and quite honestly, we haven't seen a big failure history or major issues related to that phenomenon. One way to manage it is we do require on existing lines from time to time what's called the spike test, which may address, suitably address the concern over a pressure reversal. And that still involves an eight hour test; however, you're not holding the pressure up at the yield or close to yield quite as long, maybe a half hour just to validate the integrity of the seam, and then you bring the pressure back down for the remainder of the test. And that's been demonstrated to address that concern.

DR. SCHULTHEISZ: Okay, thank you very much. I guess I'd like to allow Mr. Ravi Chhatre to ask a few questions.

MR. CHHATRE: I have a question for Mr. Mayberry going back to the pressure reversal.

CHAIRMAN HERSMAN: Mr. Chhatre, can you speak up just a bit?

MR. CHHATRE: Okay.

This is a question for PHMSA, Mr. Mayberry. Can you elaborate on the test that PHMSA sometimes refers to as spike test to, I guess, eliminate the phenomenon of pressure reversal?

MR. MAYBERRY: It's a test that we have required of operators on occasion, whether it's a concern over the integrity of a line, in particular to address potential defects in the seam. It involves, like I was saying earlier, applying pressure to the pipeline, hydrostatic pressure with water, tests with water. The test is an eight hour test. The pressure is raised to close to 100 percent of the specified minimum yield strength of the pipe of the steel. And just for everyone's benefit, that's the point at which the pipe goes from elastic deformation or the steel goes from elastic to plastic deformation. And a good example would be if you were to take a paperclip and bend it, you bend it a little bit, and it comes back to its original shape. At some point, you bend it so far it's not going to come back to its original shape. That point at which that happens is 100 percent of SMYS essentially. It's not the tinsel strength. The tinsel strength is the point at which the pipe or the steel would break or you'd have a rupture. It's below that point.

But to address the concern, a pressure reversal involves, as I mentioned earlier, where you have a hydrostatic pressure test, for instance, at a certain level. You test the line at a later date or you put it into service at a later date, and it fails at a lower pressure. It's because of a defect that perhaps has grown to failure after you took the pressure off and then repressurized it.

MR. CHHATRE: Thank you for that.

This question is for Ms. Sames. This is regarding the manufacturing defects or flaws. The particular flaw that seems to have caused the San Bruno rupture appears to be a manufacturing flaw which has turned out not to be stable. And the question is what about the manufacturing flaws that may not be stable?

MS. SAMES: When I look at DOT statistics on incidents, I am not seeing that as an issue. I'm seeing what happened in San Bruno as an anomaly. And what we in the industry are hoping is that through your investigation you find out why that anomaly occurred. Why did that what we perceived to be a stable defect become instable? I'm looking forward to your findings.

MR. CHHATRE: And I'm running out of time, so I'll pass it on to Mr. Trainer for one last question.

MR. TRAINER: I would direct this question to Ms. Sames and also perhaps Mr. Dippo. Ms. Sames, you just stated that an unstable fabrication defect is an anomaly. With this accident and our investigation of the Carmichael Mississippi accident that occurred in 2007, which also led to two fatalities -- within the last 5 years we've had two accidents that have claimed ten lives. I question whether these two accidents should be considered anomalies. I'd like you to address that. Thank you.

MS. SAMES: So, if I look at the DOT statistics, and you look at the history from the time they've collected incident data, which has been I know more than 20 years, you're talking about two incidents out of hundreds. To me that is still an anomaly. My perspective, of course, but to me that is still an anomaly. What our big question in the industry is what is causing those anomalies to occur? But I still feel pretty assured to say that that's an anomaly. That is my belief based on the DOT information.

MR. TRAINER: One last question for Mr. Mayberry. What percentage of reported incidents approximately are attributed to mechanical or fabrication defects of the pipe?

MR. MAYBERRY: You know, I don't have that. We have that data, Mr. Trainer, but I don't have it with me. But I'd be glad to get that to you separately, or it's available on our website as well.

MR. TRAINER: Okay, thank you.

I know we have one last presentation from Ms. Sames discussing data collection and benchmarking and data transmission to their member companies. So, if you could go ahead with that.

MS. SAMES: Thank you. And I do appreciate the opportunity to speak at this hearing about safety. I can tell you that I and my colleagues are pretty passionate about this. I also am very happy that I am the last presenter of the last panel of the last day of a long hearing. So, let's see if we can wrap this up. I promised Dr. Schultheisz I would do this in five minutes or less, and I'm sure he will pull in the hook if I'm not.

Just to give you a quick understanding of who the AGA is and who we represent, about 200 companies, energy companies. Primarily we represent distribution. Many of these distribution companies have transmission, so these would be your intrastate transmission lines. All in all our members deliver about 91 percent of the gas that's delivered in the U.S.

And let me just right into our best practices program. It's one of the topics that has come up. How does the industry benchmark itself? The AGA has three areas that we cover and three topics within each of those areas. We cover benchmarking that allows companies to benchmark themselves against others, their peers and figure out who's best in class. We do round tables, and we also do questionnaires. I'll cover each of those in a little bit more detail. But what we're looking for is those procedures that help move the industry forward, whether they be the procedures of the top companies or those unique procedures that can be utilized.

This is just a little bit -- okay, so one of the areas we cover for benchmarking is distribution. You can see some of those topics right there that we've covered in the past. We do change our topics each year. There is not really a need to benchmark each topic. I'm just going to keep clicking until I get to the end of this. There's not really a need to benchmark every topic every year, but what you want to look for are trends, and that's what the program does.

So, three areas, transmission, distribution, and supplemental gas. With transmission, that is done in conjunction with the Southern Gas Association. I think I mentioned earlier when I was being introduced that we do work and partner with others. This is just one example. The benchmarking process is really ever growing. What you start off with are the identification of topics. This is done by looking at what issues need to be addressed within the industry. We create data packets, collect the data. That data is analyzed by subject matter experts within the industry.

That moves on into leading and identifying those top cortel (ph.) companies and those top performances. That feeds into roundtables. We look to the leaders to explain to others in the industry how they got to that top cortel. What are the procedures that they're using? We also look for those unique instances that may not have been considered by other companies, because you want to bring those forward also. Those go into the roundtable discussions. The roundtable does two things. Actually, let me hold that. I'll get to more details in a minute. All of this comes about with identification of best practices that can be utilized by the industry.

So, let me get into the benchmarking in just a little bit more detail. I mentioned that we collect statistical data for each of the topics, that the topics change year by year depending on the needs of the industry. I'm not going to read through all of the bullets because they're available in the exhibit. There we go.

Roundtables, I mentioned that we bring the procedures that were identified from the top cortel companies into the roundtables along with some of the unique identifying characteristics that we're finding. What we're looking at are a few things. First, what are the challenges for that topic? So, the topic may be damage prevention or integrity management. If it were transmission integrity management, one of the topics that may come up as a challenge is how do you address historical data. In the roundtable, the participants of the roundtable then identify their company's leading practices from their perspective of how they are addressing that particular issue. From that, the participants at the roundtable identify out of everything that's been discussed what are the best practices for that particular operational challenge. This is all captured and shared with the industry. I didn't mention, but I should have, that in the benchmarking that data is also shared by all of participants.

The last area that we cover in the best practices is the questionnaires. This allows us to look for trends, to look for other areas that you can't put a number to. You have the benchmarking that you can put a number to. For the questionnaires, it's more of a touchy, feely, how are you doing this. How are you working about this procedure? So, you need all three. You need the benchmarking. You need the roundtables. And you need the questionnaires to really get a better feel, a better handle on each of these topics. That's just a high level overview of the best practices program. I'm sure you'll have questions later. I'll be glad to answer them.

A second area that we are utilizing to improve the industry are publications. We spend a -- we have about 16 technical committees just within operations, each focused on a particular topic such as corrosion or engineering. We utilize these technical committees to create publications, and some of them are formal publications, nice, thick documents. Others are papers that can be used to move the industry forward. This is just an example, and this is an additional example. I did mention earlier that we -- or I think I mentioned earlier that we are working on a paper on automatic shutoff valves and remote control valves. I don't have that list because it's not final yet. That is being done through our technical committee, our distribution and transmission engineering committee. We hope to have that finalized this fall.

What we're doing now is pulling the things together that have to be considered, such as I mentioned earlier on automatic shutoff valves you have to have pretty consistent flow pressure because if you have fluctuations, that valve will shut down, and then you have the repercussions. For remote control valves, you need to make sure you have the real estate, the area to put that device in. You have to have electricity if the flow is not fast enough through the line so that that device runs. Many things that have to be considered. We did a statistic on -- I know Ms. Daugherty yesterday mentioned that one of the costs -- I think you estimated the cost for automatic shutoff valves, remote control valves, to replace half the valves with remote control was about $600 million. That was actually for one company. When we look at this nationally, you're talking $13 billion for the nation to just put these in a high consequence area. I won't go into some of the issues I see with that, but I'll just move on.

There is a many a variety of other ways that we're trying to improve the industry. What I have captured here is just some of the things that have been done within AGA's operations and engineering group. Multiply this by what's done by the Interstate Natural Gas Association, by the American Petroleum Institute, by the Association of Oil Pipelines, by the American Public Gas Association, by the Southern Gas Association, by the, and I can continue for probably another ten minutes. So, I'm only highlighting what's done within AGA's operation and engineering.

For 2010 we conducted 65 topical forums. These are events where we're pulling together the industry to share knowledge. And when I did a capture of how many people we pulled together, that was about 2,700. I mentioned that we have 16 technical committees. You see just a few of those listed. We did complete nine publications plus a variety of other documents. All of that is to help improve the knowledge of the industry.

SOS's, it's really short surveys. When somebody within the industry has an issue that needs to be solved, we will put out an SOS for that company to say how are you addressing this issue? How have you combated this issue? What are you finding that can improve or that can solve this? Also, we did 80 of those. And then we have a board safety committee that was put into existence about 5 years ago. There are a number of priorities. We have a safety implementation plan that's revised at every meeting. And we completed about 90 of their priorities. We also hold, just as an FYI, an executive leadership safety summit. Our fifth one will be held this November in D.C. And I'm sure some of you will be invited to that. With that, thank you, and I'm open for any questions.

DR. SCHULTHEISZ: In the interest of time, I think we'll defer questions. That concludes the technical panel's questioning of the witnesses.

CHAIRMAN HERSMAN: Thank you very much. I know there's quite a few people that are in need of a break, and so, we will take a break until 11:10. So, we'll have a 20 minute break.

(Off the record.)

(On the record.)

CHAIRMAN HERSMAN: If everyone could take their seats, we're about to begin.

(Pause.)

CHAIRMAN HERSMAN: We will resume with some additional questions from the tech panel.

MR. CHHATRE: Madam Chairman, the technical panel is ready to ask questions, first with Mr. Zakar.

MR. ZAKAR: I have a question. This is towards PHMSA. Does PHMSA have a program that validates inline inspection tools? Basically what I'm looking for is who's checking whether or not the inline inspection companies are delivering the detection capabilities that they are advertising? Who is doing the checks and balances?

MR. JOSHUA JOHNSON: We do not have a formal program to look at that. But as part of our integrity management inspections we do look at what tools are reporting and then what vendors go out and see. But the, you know, the primary check on that is going to be the operating companies, because if they are not getting good data back from their inspection companies, they can really not do their integrity management work. So, that relationship is there. There was at one time a push to try to kind of benchmark the tool companies kind of as a third party organization was going to do it, but that really didn't go anyplace.

MR. DIPPO: Yeah, I might just add from an operator's perspective that when inline inspection reports are received, of course, there are digs and validation digs associated with those reports. And as Mr. Foreman indicated, that information is very -- the inline inspection tool vendor is very interested in the results of that. And we're also very interested in it as well, because we have predicted anomalies, and then we have as found. So, we do make those comparisons.

MR. ZAKAR: Okay, we have pipes in the ground that predate 1970, and we've had issues with low frequency electric resistant welds. Do we have the capability, or do we continue to have challenges to find those seams and cracks or any problems associated with those seams? Somebody in PHMSA would like to address that?

MR. MAYBERRY: Because of the incident history, low frequency or W-pipe by name is one of the --

MR. ZAKAR: Your mic is not on.

MR. MAYBERRY: Okay, we do call out low frequency or W-pipe specifically related to the integrity management program and when you need to assess for that. There is a large population of that type of pipe still present in use. Most of it is safely operating. There are techniques that are available to assess the integrity of the seam and to look for the defects in those types of seams.

MR. ZAKAR: Do we still continue to have -- is it challenging with -- are we having difficulty finding them? Is it still a challenge or something easy to detect?

MR. MAYBERRY: Well, I wouldn't characterize it as easy to detect. I think inline inspection techniques have come a long way giving options for detecting anomalies such as cracks that are one type of issue associated with low frequency or W-pipe.

And then, of course, the other method would be hydrostatic testing. But it's still evolving, but I think there's much improvement that's been gained. I don't see data that warrants as far as an incident history or prevalent incident history currently that would warrant or specifically targeting it for say some sort of replacement, wholesale replacement. All pipelines are different. All operating environments are different. Pipelines tend to be buried, and so there's a lot of variability there. So, you have to assess each system would probably do the variable specific to that system.

MR. ZAKAR: And then I have the same question concerning girth welds.

MR. MAYBERRY: Girth welds, there are detection techniques for girth welds related to inline inspection. That's a technology that's improved recently. We've seen some success in being able to identify anomalies or issues with girth welds. We've also seen some pipeline failures related to girth welds, in particular with vintage pipe. Is it a significant instant history? I would say not. It tends to be -- it has not been that prevalent. The hydrostatic testing method is probably not the method to look for girth weld anomalies because of the orientation of the stress that you're putting on the pipe is 90 degrees off from what you need, the way you need to stress it for a girth weld.

MR. ZAKAR: Okay, thank you. My next question is does

PHMSA have any regulations that require newly constructed lines to be made piggable?

MR. MAYBERRY: Yes, we do. Back in the early 2000's, mid-'90s we issued regulations, required new pipelines to be piggable to accept inline inspection devices.

MR. ZAKAR: And do you have a program to validate?

MR. MAYBERRY: To validate whether or not -- that would be picked up in our inspection program whether or not the -- it would be part of our inspection whether or not the line was piggable.

MR. ZAKAR: Okay, that's my last question.

MR. CHHATRE: I wanted to ask a couple of quick questions. And my first question goes to Mr. Foreman and Mr. Farmer in that order. Is there a minimum pressure that a pipeline should have before any ILI tool can be passed through a gas transmission line?

MR. FOREMAN: Yes, there is.

MR. CHHATRE: And what that will be?

MR. FOREMAN: It would be -- I'm trying to convert here from bar to PSI. It's probably 300 PSI.

MR. CHHATRE: Mr. Farmer?

MR. FARMER: I would concur.

MR. CHHATRE: Thank you. Again the question goes to Mr. Foreman and Mr. Farmer in that order. Probability of detection and probability of identification for the tools that are currently available, is there a rule of thumb that you can tell me like 35 percent, 90 percent?

MR. FOREMAN: The probability of detection we like to try to achieve is 90 percent or greater. The P of I, the probability identification is sometimes more challenging, so that tends to be around about the 80 percent.

MR. CHHATRE: Mr. Farmer?

MR. FARMER: It's going to depend on the particular tool, particular vendor. Generally, the numbers that Mr. Foreman quoted are correct, but not necessarily uniform or universal.

MR. CHHATRE: Does that mean that some critical flaws may get undetected using the ILI tool?

MR. FOREMAN: I'll take that question. The probability of detection and probability of impedance is really aimed at the lower end of the specification. That's what drives that number. So, what I'm saying really is large defects are much easier to detect and discriminate than small ones. So, it's the smaller end of the capability of the tool that drives that probability.

MR. CHHATRE: Mr. Farmer?

MR. FARMER: Yes, I would concur with that. But statistically, to have 100 percent is very ambitious.

MR. CHHATRE: I understand that. The reason I was asking that because we had a couple of accidents in the recent past where I like to (indiscernible), and in both cases, the flaw was not detected. In fact, the segment that ruptured did not have any flaws identified. That's where I was coming from.

Mr. Mayberry, would a hydro test or pressure test conducted at 150 or 135 percent, would it detect all the flaws that are likely to cause a rupture at that given time?

MR. MAYBERRY: It's likely to detect critical flaws that would be subject to rupture. So, yes, if it's performed at a high level at 90 to 100 percent of specified minimum yield strength. It would not -- and perhaps where you're going with this, it does not tell you any remaining flaws or characterize any remaining issue with the pipe. It's a test that demonstrates the integrity and the leak tightness, if you will, of the pipeline at that moment and until the next assessment interval.

MR. CHHATRE: And my last question, you mentioned that maybe an array of tools may be necessary depending upon the flaws that the operator may identify as a threat. And considering the ILI tools, there were many you need to identify depending upon stress or cracking or corrosion damage. Does hydro test have a place in those, since hydro can detect the flaws that are critical now, where ILI can detect all the possible flaws?

MR. MAYBERRY: Hydrostatic testing is one tool in the toolbox. Inline inspection is another. There are other inspection techniques. For instance, if you're dealing with case pipe, you may use SCADA wave ultrasonic testing. There's no perfect test. Generally, the standard detection I normally think of or ability for inline inspection is sort of the least common denominator, which is about an 80 percent probability of detecting within plus or minus 10 percent. Sometimes we've had, depending on the line, again it's driven by the threats and what we observe say post incident. It might be warranted to do a combination of both tests, both speaking in terms of inline inspection and hydrostatic testing. We may also add other appropriate tools, such as indirect inspection methods to look for corrosion issues, active corrosion issues perhaps or coating issues.

MR. CHHATRE: Thank you. I'll just stretch my luck and ask one more question. How critical the dehydration problem once you do a hydro test?

MR. MAYBERRY: It's very critical. There are techniques to perform that function because water, residual water in a pipeline creates an issue with internal corrosion potentially down the road. From an operational standpoint, it also will create issues with freezing perhaps. Say in a distribution system perhaps there could be -- if residual water has caused freeze ups at say service regulators at the house, it's also caused blockages in low pressure systems as well.

Most recently, we had a failure in the Salt Lake City area. This was on a liquid pipeline that was caused by residual hydrostatic test water that was remaining in the line and wasn't suitably removed. Actually, there was residual water, and it wasn't suitably treated with antifreeze to ensure that it didn't freeze. It did freeze and causing -- the water expands when it freezes, and it caused a breach of a valve and a release of crude oil in this case.

MR. CHHATRE: Thank you much.

Madam Chairman, the technical panel has concluded their questions for the witnesses.

CHAIRMAN HERSMAN: Thank you, and we'll begin with the parties. CPUC?

MR. CLANON: Thank you, panel. I'm Paul Clanon, and I'll be representing the CPUC. Just a couple of questions.

Mr. Farmer, I wanted to follow up on an exchange you had about the existence of inline inspection technology, that had the line in San Bruno been piggable that technology that might have picked up the defect that we're talking about here. What were those technologies?

MR. FARMER: The technology for that particular defect, that's a crack that has opened up, so it has some volume. So, magnetic flux leakage will work in that case, but it's not the standard magnetic flux leakage which magnetizes in the axial direction. So, to detect that flaw, the magnetization would have to be circumferentially oriented, and there are several companies that supply that technology.

MR. CLANON: How long ago was that technology developed? Is that a longstanding technology or relatively recent?

MR. FARMER: Oh, that's probably 10 years, so it's a pretty mature technology.

MR. CLANON: Thank you.

And Mr. Mayberry, I'm going to start with you, but others on the panel might want to chime in on this as well. I want to focus in on pipe that's pre-1970, so grandfathered pipe that's never been hydro tested and that may have an unstable defect or about which we have concerns that there may be an unstable defect. Let's just assume those three things without saying anything more specific about that. Given all the plusses and minuses of the kinds of testing that you've been talking about this morning, what would you recommend for a situation like that?

MR. MAYBERRY: For which type of defect? I'm sorry.

MR. CLANON: Any kind of unstable manufacturing defect, for example, or a pipeline about which we have suspicions there may be an unstable manufacturing defect.

MR. MAYBERRY: As I was mentioning, there are a variety of tools in the toolbox to assess the integrity of a line. Specifically if you have a manufacturing defect, say a seam defect, there are the inline inspection tools. There are tools that will detect those types of defects. Hydrostatic testing is also a tool that's been used, that is used effectively to address those types of defects. Those are the primary two tools that would be used.

MR. CLANON: And so, if we're dealing with an infrastructure that's not piggable, for example, does that leave us only with hydro testing?

MR. MAYBERRY: Not necessarily. I mean, if you were to do nothing, perhaps hydro testing would be the option. And obviously, that would require cutting in test sections and hydro-ing a line that's currently not piggable. The other option is to make it piggable. The other option is to, and this is again assuming that you've gone through the proper scenario of identifying the threats which we've discussed is an area that we're discussing with ourselves and industry. You need to make sure you've identified the threats so that you can use the proper tools for this.

MR. CLANON: Thank you. And I just want to ask whether anyone else on the panel would like to chime in on this question.

(No response.)

MR. CLANON: Nobody wants to bite on that one. Okay, and that's all I had. Thank you.

CHAIRMAN HERSMAN: PG&E?

MR. KIRK JOHNSON: I just want to direct a question to Mr. Foreman. Specific to the EMAT tool you spoke to in your presentation, are there any restrictions on that tool? Can it handle a multi-diameter pipeline, for example?

MR. FOREMAN: We only have one tool at the moment. It's only in 30-inch to 36-inch diameter. It's a single diameter tool that can be used in 30, 34, and 36-inch, but we haven't got a multiple diameter adaptation for that tool yet. It could be perhaps adapted. But as it stands today, there is only one prototype tool.

MR. KIRK JOHNSON: So, just so I understand, what you talked about is we have one prototype of that tool. We don't have a fleet of these tools. And the availability of this tool is relatively limited. Is that true?

MR. FOREMAN: That's true from GE, yes.

MR. KIRK JOHNSON: Are you aware of other vendors that had that exact same tool?

MR. FOREMAN: Other vendors have got an EMAT tool. It does not operate at exactly the same way that our tool operates, and it's a very different methodology that they use with the same technology, but it doesn't actually work in exactly the same way.

MR. KIRK JOHNSON: Okay, thank you. I have no further questions.

CHAIRMAN HERSMAN: City of San Bruno?

MS. JACKSON: Yes, thank you, Madam Chair.

I have a short question for Ms. Sames. One of your slides indicated that you have a publication or a program related to alarm management for control room operations. I'm just curious whether that is a -- if you could just give us a brief comment about whether that is related to operating procedures or to technologies?

MS. SAMES: If I remember correctly, and I am going by memory, it covers both. That publication is available through the AGA website at the link that's on the one slide. The description will provide more information as to what exactly is in that document.

MS. JACKSON: Great, we'll take a look at it. Thank you.

This is a question for Mr. Mayberry and Dippo, Mr. Dippo first. In your presentation, one of your bullet points stated that the operator and regulator need to decide whether to place pipe under the high stress of a pressure test or to maintain the stability of a historically low operating pressure. Could you comment, please, on an existing practice that would utilize pressure increases to maintain a historically high MAOP, a maximum allowable operating pressure, and whether this practice might impact the integrity of a legacy pipeline?

MR. DIPPO: Yes, I think that was briefly touched on earlier. The potential for a pressure reversal in an existing pipeline that is being pressure tested with or hydrostatically pressure tested because you don't know what may exist in that line in terms of subcritical defects that may not necessarily fail the pressure tests. They can be exposed or grown during the pressure test process such that sometime subsequent to the pressure testing and after the pipeline is back in service the potential exists for these defects to then turn critical. So, that has to be recognized on the front end, and I think the point of the operator and the regulator must know that there are decisions that have to made here as you progress through this process of integrity management and you can only go with the -- you have to be driven by the characteristics and the specifics in terms of what it is you think you're looking for and go look for it and then determine whether or not -- again, it's a continuous improvement process.

So, one assessment is not the way to complete a complete integrity program. Baseline assessments get done, and then future reassessments are mandated by the regulations to address just that.

MS. JACKSON: Thank you.

MR. MAYBERRY: Related to the practice of raising the pressure, I've not seen that in my observations of the national inspection program for the lines we regulate. I can't say that -- would say that it was not the intent when the regulation was written that it would warrant the raising of pressures to avoid a certain assessment. If you're adjusting the pressure periodically, you need to assess that or make that part of your overall assessment of the risk on that pipeline and perhaps it may, that act in itself may create the need to assess for construction or material defects. I might add too that part of our issuance of an advanced notice of proposals we're making, I'm sure we'll be asking the question about that area.

MS. JACKSON: Okay, thank you.

This is a question for the entire panel, anybody who's able to comment on this. We've heard today about exciting new technologies and their potential for operators to detect and resolve defects. We're certainly anxious and looking forward to their widespread deployment within the industry.

That said, I need to take, respectfully take, strong exception to a supposition that an undetected, unstable manufacturing defect, such as may have contributed to the tragic incident that the community of San Bruno experienced is an anomaly. I'm confident that the citizens of San Bruno would find this very difficult position or conclusion to accept, if only because it could diminish the urgency with which the various issues under discussion these last three days are fully addressed.

With that said, an understanding that many areas of our older infrastructure for financial gas transmission based on the statistics you cited today may actually be currently unpiggable, my question for the entire panel is whether the conclusion we're left with is that replacement of the pipeline infrastructure is at least in the near term the most viable strategy in order to address the problem?

MR. MAYBERRY: I might add from PHMSA's perspective our agency is deeply saddened by the event that occurred in San Bruno. We take incidents like this seriously, and we learn from them, and I can assure you that we will apply learning of this incident to our program and to the national program. And whatever we learn from it, it will be applied to our program. We don't accept -- accidents are unacceptable. They do happen, unfortunately. Fortunately, there's a low probability of there happening, but when they do happen, there is a high consequence. We look for the issues that happen or that contributed to the cause, and we do take action based on that.

MS. JACKSON: Thank you.

MS. SAMES: And if I could just jump in to echo Mr. Mayberry's comments. While I still believe that this is an anomaly, that does not diminish the magnitude of this incident or the lessons that can be learned. Replacement is one of the options that should be considered for some of these lines, just like other options should be considered.

I think what needs to be done is an analysis on these various pipelines looking at what can -- how can we identify the risk to these lines, how can we make sure that they're safe, that they continue to be maintained safely, that we are looking at the issues that may exist within these lines, and it's decision tree. Replacement may be part of that decision tree. Reducing pressure may be a part of the decision tree. Making the line piggable may be part of that decision tree -- hydrostatically testing.

But with each of these, other things have to be considered, including the impact to replace the unpiggable lines. And I would like to make one clarification. I mentioned -- I was asked earlier about the percent of liquid lines that are piggable, and it's the vast majority. I mentioned that about a 1/3 of the transmission lines were unpiggable that were only -- I'm sorry, about 1/3 were currently piggable. That is intrastate transmission. For interstate it's about 2/3, maybe a little higher. I would defer to my associates for that. But what we are seeing is more of these lines becoming piggable for a variety of reasons. It is an option that has to be considered. I think we need to look at all the options.

MS. JACKSON: Thank you.

CHAIRMAN HERSMAN: IBEW?

MS. MAZZANTI: Yes, Madam Chairman, I do have a couple of questions.

My questions are going to be directed to Mr. Foreman and Mr. Farmer. Do you have any data that talks about the daily costs associated with the technologies you've described today?

MR. FARMER: I'm sorry, about which costs?

MS. MAZZANTI: The daily operational costs in the technology that you're describing.

MR. FOREMAN: In operating the technology or developing and doing the research for the technology?

MS. MAZZANTI: No, in operating if an operator were to utilize these technologies, do you have a sense of what that daily cost would be to that operator utilizing your tools?

MR. FOREMAN: It was mentioned before. It really depends on the tool, the technology that's being adopted, and it's not easily translated to a daily fee, because the actual running of the pig might take a few hours or a couple of days. But then there's several months of interpretation and analysis that goes on with the data following that. But I can furnish you with some ideas of prices of inspection if you would like.

MS. MAZZANTI: Thank you.

MR. FARMER: I would support those comments.

MS. MAZZANTI: Okay. My next question is what operational issues have you encountered using these technologies? Have you encountered, have you heard of any or gotten any feedback that there are some difficulties with the technology?

MR. FOREMAN: In its functionality or in its results?

MS. MAZZANTI: Yes, both.

MR. FOREMAN: From the functionality point of view, I think Fraser touched on it, and I mentioned, you know, the preparation of the pipelines, making sure the pipeline is clean, the correct pressure and flaws is an essential part of making sure that you get a good inspection. And then from that, making sure that we get a good interpretation of the data that to make sure that the accuracy of the report.

MR. FARMER: Some other things that operators need to be very cognizant about is things like the fittings that Geoff described, there are some fitting that the tools just don't like going past, so they don't. They stop, jam, and that's an operational problem. It's unpleasant for both parties. So, being very prudent about what's in the pipe and sharing that information with the vendor is pretty significant.

Operationally, one of the things that's important is that the valves, all the valves in the pipeline, be fully open. And if a mistake is made in operation and a valve is not fully opened, again the tool may stop and jam, and now you may have to cut out that whole section. So, that can be a problem. So, effective planning beforehand, knowing your system, which is an integrity management concept as well, knowing your system for a pigging project is really important.

MR. FOREMAN: I agree and reiterate that the record keeping on some of these older pipelines, especially the unpiggable pipelines are essential. At the end of my presentation I said an expert engineer in assessment needs to be taken on each and every unpiggable pipeline, because there are some engineering solutions that you can actually apply if it's just because you can't put a pig in because it hasn't got a pig trap. You can apply some techniques.

We've had success in New York where we used a 45 degree hot tap to put a 24-inch to 26-inch tool and went across the river in Manhattan with it. But we knew what was in the pipeline. Some of the fittings that we show like that intrude into the pipeline, as Fraser said, the last thing you want to do is stick a pig in the pipeline.

So, the mission is to find out what's in there. So, good record keeping is important. We mentioned grandfathering old pipelines. For me, the first part of an engineering study would be to look at the oscilids (ph.) and see what kind of detail and confidence the operator has on what's actually in his pipeline.

MS. MAZZANTI: Okay.

MR. FARMER: One last parting comment. Geoff referred to the fact that the speed has to be within a certain range in order to gather good data. One of the recent innovations, let's say last five to 10 years, has been speed control on some of these tools. So, they actually have a bypass that controls the speed to less than the flow speed, and that's typical of the innovation in the last 10 years.

MS. MAZZANTI: Okay, and I know I'm running out of time, and I had two -- actually three more questions, but two of them that are very dear to my heart. Do you have any instances of failures on pipes after you've used these tools, after you've used the technology? Have there been any examples of there was then failure on the pipe?

MR. FOREMAN: Yes, there has. I think Ravi asked the question. That there has been, unfortunately, some failures after pigs have been run through pipelines. And the occasion, I think how I answered it last time was the crack tool will see defects, and to my knowledge, on all of the forensics following the failure, the point of origin was clearly identified except for one. And in all those cases, the tool did detect something. But we've learned from those instances on the analysis and the interpretation of the signals to change our processes to a more conservative approach.

MR. MAYBERRY: I might add from a PHMSA approach, we've seen some failures post inline inspection run, and that is part of the basis for why we're going to have a workshop is usually the case is that the wrong pig perhaps was run, looking for the wrong issue, using the wrong tool. The other might be say an incorrect corrosion growth rate assumption, those types of things, but that will be the subject of our workshop.

MS. MAZZANTI: I have one more question.

CHAIRMAN HERSMAN: Sure, one more question.

MS. MAZZANTI: Okay, do the vendors supply or do you offer any guarantees or assurances regarding the effectiveness of your technology?

MR. FOREMAN: No, only the -- we look after providing the operator with dimensions. The operator then decides what to do with those dimensions.

MR. FARMER: Yeah, I think that's basically the cut off situation. The tool vendor supplies information about the defect and doesn't necessarily warrant the pipeline. What they do warrant is that the results of the survey are in accordance with their performance specification.

MR. FOREMAN: That's why it's so important to do the dig verification and validate the inspection.

MS. MAZZANTI: Thank you.

CHAIRMAN HERSMAN: PHMSA?

MR. WIESE: Thank you very much. Very interesting, panel, my compliments to everyone. It's really very interesting. I wish we could continue this, but I'd like to explore just a couple of things with you. One of them is research and development. I think Mr. Smith raised a very good point. He said the challenges were set in the early 2000's with the integrity management roles. They were pretty aggressive challenges, but technology has played a key role in helping operators meet those challenges. I'd like to know, really like to get at the level of R&D funding, and is it adequate. So, I'm just curious if any of you, maybe start with Ms. Sames, could talk to us about any publicly available studies that would talk about funding levels and research and development for pipeline safety only.

MS. SAMES: Thank you for that question. The American Gas Foundation and the INGAA Foundation concluded its study 2005, 2006. It's available on, I believe, both websites that looks at funding levels for research for pipeline safety. And if you look at it from a very high level, it shows that compared to other industries like the computer industry or the medical industry, there is less funding that is done by this industry, but the funding that is done is done to pull all available resources to address the biggest risks, and I think that's one of the keys of the success of the industry collectively, whether it be the industry comprised of the government and industry looks at the priorities. We think PHMSA does a great job at your R&D forums, where you pull all of the stakeholders together to identify what particular elements need research. And that is then put into your solicitations. So, we're looking at the priorities and putting research funding towards those. Can more funding be added? Absolutely.

MR. SMITH: Thanks for that question. I think it's an important question to keep in mind for the type of research that this program executes. We have a requirement for a 50/50 cost share with other federal agencies and private research and trade organizations. We're funding a lot with agencies and the Department of Interior. We funded and work with the Department of Energy, the Department of Commerce, so many industry organizations, Pipeline Research Council International, Northeast Gas Association, Nisearch Operations Technology Development, and even the American Waterworks Association trying to crossbreed across different industries and learn from what's working there and also share with them what's working well in the oil and gas industry.

In the federal example, since 2002, it's been about a 44 percent federal investment and a 56 percent private investment on some of the challenges that we talked about and solutions that I mentioned. The federal funding is down about $5 million since 2005 with the loss of the Department of Energy's program that was addressing some technology for gas transmission. And like I said, I think we believe that the process that we have in place is the right type of process for the short term research that we address.

And our story is growing and the technology that we can deploy.

MR. WIESE: Okay, thank you very much. I was really just trying to get at a question I think that one of the technical panel members had asked about road mapping, so both of those were very helpful. The point of it is only short to mid-term research is done. All of the long-term research is dried up and gone, is that correct?

MS. SAMES: There is some long-term research that's being done, but it is not to the level that was done historically.

MR. WIESE: My numbers will probably be wrong here, but I believe that it was closer to $50 million at one point in time. We might be under 10 collectively at about this point in time.

Okay, second question really maybe go to Fraser I thought did an excellent job in describing the overall process of inline inspection, and Geoff as well. It is more than a tool. It's a process with many stages, and each stage has a quality control. The one I'd just invite comments on is the human side of this. Humans play a significant role, both in the deploying of the technology and the analysis of the results. I just wondered if either of you would care to comment on the training and qualifications involved.

MR. FARMER: Maybe I'll lead off, and Geoff can follow on that one. There is the ASNT Standard ILI-PQ which means personnel qualification. And that talks to the qualification of the field staff from the vendor going into the field, and it talks to the qualification of the data analysts who review and make calls on the data. That standard talks to the minimum levels of training in terms of how many months of training, and it's then left up to the individual vendors to implement that training and to implement training that's consistent with their technology. And maybe, Geoff, you'd like to comment on what GE does?

MR. FOREMAN: We've always had a training policy of various, and it's a career structure, so it's time oriented. Each technology we have every technology, so we have a broad base of analysts. And we have some of the most experienced in the industry. So, yeah, we have annual tests. An analyst, for instance, can't progress to the next level until they pass a written and a blind test on data. Any instances that come from learning in the industry we incorporate those kind of data into the test material, so we keep our analysts very current and well trained.

CHAIRMAN HERSMAN: CPUC, did we start with you? That's right, I'm sorry. My track record was pretty good for the hearing. This was the first time I've messed it up.

Member Sumwalt?

MR. SUMWALT: Thank you.

Ms. Sames, you talked about some of the best practices that AGA does. In my preparation for this hearing and my research, listening and talking to people, one thing that I'm hearing is that the industry as a whole could do a better job with sharing information, sharing best practices, sharing information about accidents, incidents, and near misses. And what are your comments regarding that?

MS. SAMES: I think there are a variety of ways that the industry does share information on incidents and near misses. I forgot you're a former pilot. There are a variety of ways that the industry shares information on incidents and near misses. I'll give you a few examples, but I will preface everything to say with everything we've discussed, communication is the key to learning. So, the more we can communicate, the more that we can share, the better off we're going to be.

But to give you a few examples within the American Gas Association, I mentioned the technical committees. Within the technical committees, there's roundtables at each meeting. Typically those meetings are held two to three times per year. Within the roundtables is the sharing of problems that we are seeing within the industry.

Within the operations managing committee that oversees those technical committees, we also have a roundtable which allows companies to share incidents, accident information, problems that they're encountering. When I take it up another level at the board we have an executive leadership safety summit that we hold every year. We also have roundtables within the board safety committee. Dedicated time on every agenda, and the board safety committee meets three times a year where we specifically ask for issues that the industry is encountering. With the roundtable following of how those are being addressed elsewhere.

On the AGA website we have an information resource, safety information resource website. This is for just members only. It's not available to the public, because we want to get pretty solid information without the issue of having to mask some of the data. But what we have there is a sharing of the particular incidents. What occurred? What exactly happened? What were the lessons found? I'll go back. Can more be done? Absolutely. And I'm hoping that this leads, this discussion leads to other ways that we can improve that.

MR. SUMWALT: Well, in fact, I thank you for that answer and for your candor. And that just sets me up for the next question. We are here to determine facts and to learn. This is a fact finding hearing. So, given that you've said that there are ways, that there's room for improvement, how can the industry at large better share information?

MS. SAMES: I think continuing on the path that we've set. I don't think some of the communication paths are broken. I think they can be enhanced. So, continuing, and I'm just speaking for the American Gas Association, continuing the interactive discussions that we are holding within the industry, those candid discussions is absolutely critical.

I can guarantee that we will be taking the findings from the NTSB, the discussions from this hearing into our next meeting which is in May. We will be discussing what we've learned. I've already been sending out to the AGA members tidbits from this hearing to give them here are some of the things that you should be thinking of. The more we can communicate, the more we can share information, I truly believe that's how we're going to improve.

I also think it's critical that this is not just industry talking, that it's industry talking to other stakeholders. So, the workshops that Mr. Wiese and Ms. Daugherty and Mr. Mayberry mentioned earlier, where you're bringing together the collective stakeholders to talk about a particular issue that's critical. And you hope that you -- we always encourage candid discussion at those. You hope that you have candid discussion.

MR. SUMWALT: So, what can the NTSB do to help facilitate that?

MS. SAMES: I would love for the -- you're already helping. The reports that you are providing allows us to get a better picture of what occurred. We are not privy to information until it's made public for this particular instance. So, as you're releasing information, we're learning from that information, and that's when we can take it into our technical committees, our managing committee and to our board.

Other ways you can help, active dialog with the industry. We will be sending an invitation to the NTSB to participate in our executive leadership safety summit. We would love for you all to join us to talk about what you can. If this case isn't closed, talk about how you are learning from these incidents and how we can work together. Really, I've said for years that pipeline safety is a shared responsibility. We all have a part to play, and the more we can work together, the better we can play our parts.

MR. SUMWALT: Thank you very much. I appreciate your answers.

CHAIRMAN HERSMAN: Member Weener?

DR. WEENER: We've had a lot of discussion about how to operate systems with essentially untested pipe, and we've got a lot of untested pipe because grandfathering pipe before 1970. I believe it was Mr. Mayberry who made the comment that de-rating the operating pressure to 30 percent of yield strength or yield pressure would yield a stable pipe, is that correct?

MR. MAYBERRY: I think we were speaking of hydrostatic testing. Testing up to at or close to the yield point would address near critical threats and remove them from or they would be discovered because pipe would burst at that level. And then any remaining threats in the pipe would not be at that point. They would be subject to inspection down the road, if there were an issue with other defects perhaps that were remaining would be assessed or subject to a future integrity assessment.

DR. WEENER: Okay, perhaps I misunderstood then. There was a reference to a 30 percent SMYS.

MR. MAYBERRY: Okay, I believe that was related to the leak rupture boundary. Lines operating above 30 percent of the specified minimum yield strength tend to exhibit a behavior where they rupture as opposed to leak. Lines below that level have shown over time that if there is a through wall breach of the steel, the metal that would tend to leak as opposed to rupture. Rupture in terms of having a rapid decompression and an opening of a seam perhaps and ejection of the segment, such as occurred as San Bruno.

DR. WEENER: Okay, so then operating a line at 30 percent of SMYS is not necessarily then a stable operation, is that correct?

MR. MAYBERRY: No, operating a line at -- well, lines can operate up to 80 percent of specified minimum yield strength. And the issue of defects and addressing defects, what we're after is any anomaly that could cause an issue with the operation, with the integrity of the line. So, to address those, one of the methods that we're talking about was the hydrostatic test which involves bringing the pressure up in the line before you put product in it to a level above what it would operate, where it will operate in service. And doing so, and then in approaching the SMYS of the steels, you would detect any or it would rupture any defects that were in the line.

I must say that that doesn't happen with modern construction. You rarely see that happening. You don't see it all that often with existing either; it's just an issue that you have to address and have to be mindful of when you develop a program to assess the integrity of an existing line. Because of the vintage pipelines and variability there, there can be issues like what we've discussed related to growing a flaw to failure or pressure reversal phenomenon. But they're not that prevalent.

DR. WEENER: Okay, so that rule of thumb is really based on having a pipe with a good weld, because SMYS is probably meaningless if you've got a bad weld in the pipe?

MR. MAYBERRY: Well, if you have a bad weld, in this sense we're talking about the weld, the longitudinal weld as opposed to the girth weld, the test is designed to detect issues with that weld. Inline inspection tools are able to find issues with that weld as well. But it's critical to find issues with the longitudinal seam to ensure that you don't have an in service failure.

DR. WEENER: All right, thank you.

Another question for Mr. Foreman. We were talking about robotics in terms of inline inspection tools. How far along are robotics in terms of actually being able to utilize them operationally?

MR. FOREMAN: I really can't comment on that because GE aren't actually engaged in any of the robotic programs at this moment. We've concentrated all our research and development on existing transmission pipeline crack detection.

DR. WEENER: I guess it was Mr. Smith then that brought up robotics?

MR. SMITH: Yes, please allow me to elaborate. The smaller diameter tool that I showed addressing the 6 to 8-inch range for unpiggable natural gas pipelines is now a commercial tool being used by industry and being used -- allowed to be used by industry that meet or exceed the requirements.

The larger diameter tool is still under research and development. It's being further demonstrated in pipelines and real pipelines to understand if it will be able to assess and identify and traverse due to the unpiggable nature of the pipelines, whether it be a plugged valve, a diameter change, a 90 degree bend, or a miter bend or other type of obstructions that Geoff talked about in his presentation. That's with the demonstrations occurring, we anticipate it in the early 2012 time frame to be a potential tool for industry to use. And then additional diameter sizes have to be made by the vendor to address that market.

DR. WEENER: So, basically, technical feasibility then is validated next year, and it's just a matter of then adapting it to different applications, is that correct?

MR. SMITH: That's correct. Like I also mentioned, we'd be interested in partnering with industry to try to get additional sensors on these type of robotic devices. More time in these unpiggable systems may identify some of the things that we've been talking about over the last couple of days. So, we want to get as many tools or sensors on these robotic platforms now that we have these platforms to integrate sensors on them.

DR. WEENER: All right, thank you, Mr. Smith.

CHAIRMAN HERSMAN: Member Rosekind?

DR. ROSEKIND: We've already acknowledged how clear and cogent Mr. Farmer's description was of the process to inspect and test. And you cited some standards. There were questions about the training as well. I'm curious, is that the model? You know, if we were to go out to any property around the country, would we see, you know, that's kind of the certification, the approved model, or is there a variance around that and how people actually apply what you described?

MR. FARMER: I'm not sure if I follow your question.

DR. ROSEKIND: What you described the standard, if I go to any property, am I going to see what you just described being used, or are you like, you know, you're in the A category, and there's a whole bunch of B's and C's, or you're in the middle and there's some people that have a totally different process? Is what you've described the model, or is it all over the place?

MR. FARMER: Okay, yes, I think I do understand. That model of the standards and the process is pretty universally applied by all operators these days. It's not mandated, but the API 1163 Standard, by example, is something that all of the vendors, GE and all of the other vendors are totally familiar with. So, if I was an operator and I was specifying my project totally differently from that, it's going to be strange. So, because it's a standard and it's accepted by all the vendors, and it's now accepted by many of the operators, that's what they write into their specifications. So, it's very universally applied.

DR. ROSEKIND: Great. And I'm curious for the whole panel, just how much of these inspection and testing capabilities are internal to companies versus contracted out or other external parties that are involved in these processes?

MR. SMITH: I would say it's very highly let out to service companies. I know of one company in the United States that -- operator who has their own tools.

DR. ROSEKIND: And are those going to be for all of it, different pieces of it?

MR. SMITH: That company purchased tools from one of the vendors, and they do the field operation. I believe they rely on the vendor for the data interpretation.

DR. ROSEKIND: And so, just to clarify, in the industry then, most companies will have third parties that are involved in this process. And can you just give me some sense of is it all inspection and testing is outsourced, or 50 percent, just some sense of how much external involvement is involved?

MR. SMITH: I would say it's 95 percent service providers.

DR. ROSEKIND: Okay, Mr. Smith, one of the questions we often ask is wouldn't it be nice if there was research going on to actually look at some of these issues and look to the future and how nice to be able to talk about a program that's been in place for awhile, highly structured. And you did describe a bit some industry input with your stakeholders, so you have a sense of what's relevant. Can you talk a little bit more about your transfer process and how you take your findings and technology into practice? You started a little bit with your previous answer, but if you could give us a little more sense of you got great results or really promising piece of technology. How does that get out to the industry?

MR. SMITH: Thanks. That's a great question and a great opportunity to follow up. We talk about long-term research. You know, that pretty much starts at the university and academic level, and there has been a lot of partnering with the gas industry and the industry as a whole with academics to bring forth new sensors. You know, our program gets more involved once we're past the proof of concept, that's how we've been directed by Congress to be more short-term.

One of the ways that we can accelerate these tools out into the market are through technology demonstrations. We stage these throughout the research project timeline. We integrate our regional offices, our state partners, the industry co-funding it, the vendors that may offer the service. We invite them to these demonstrations. They're a part of the demonstrations. They see that the technology is performing the way it was designed at these R&D forums or other events that we said that we need to have a technology that addresses this threat and that kind of pipeline. And we really believe that these demonstrations are working well to understand how much time and how much issues need to still be addressed before this technology can be in the marketplace and something that we could see industry using to comply or exceed regulations.

DR. ROSEKIND: Is there anything that would facilitate that even more? You know, you've got a great product. What's going to really help that get out and into practice sooner? Are there things that would help with that?

MR. SMITH: Well, as I mentioned before, we're addressing challenges for all pipeline types, and so, we have a number of situations where projects come to a point where it's time to get out there in the field in real pipelines, and it's challenging to be able to associate our resources towards all of these challenges at the same time when they're all very good projects. And so, if we're able to have additional technology demonstrations, maybe at a higher frequency and intensity, it would aid in bringing these tools to market. And that was the point I made about additional resources. It's kind of a linear relationship. If you're having more demonstrations, you're having more people in front of them, everybody is aware, and we're able to get that out there.

DR. ROSEKIND: And from the industry side, any comment just about the actual implementation and deployment of these new technologies?

MR. DIPPO: No, I would agree with Robert that as these technologies are developed, I mean, we've been running inline inspection for -- well, since the type line integrity regulations came into place, and we've even seen, you know, developments and progression in the tools and the sensitivity and their abilities to locate anomalies, defects, whatever it might be within the particular pipeline segments. So, we're very interested in knowing the capabilities of the tools, the limitations of the tools, what they're designed to do because we are the ones as operators that are required to select the tool for the defect that we're trying to analyze.

DR. ROSEKIND: I have a couple of quick ones. I'm going to try to wrap it up in this, okay. There's a lot of focus on the technologies. I'm curious what industry or research efforts are going on on the modeling side. There's a lot of data coming in now, etcetera, and there's a lot of sort of folks that are working on, you know, failure analysis and prediction kinds of things. That's another side of this to get those numbers sort of moving a little bit. Can you just --

MR. FOREMAN: I can maybe take that one. From our point of view, these tools are generating a lot of information. And as we mentioned, not only for defects in the pipeline but also the position of the pipeline, straying and movement in the pipeline, and also that the history, the records of everything that's on the pipeline. So, one of the things that we were looking at at the moment is software solutions that you can actually overlay multiple inspection sets. You can overlay multiple data sets so that operators have got better access to data and real time rather than having to have records all over the place. That's one of the initiatives that we're currently undertaking.

MR. SMITH: Just a quick comment to that illustration about other than just detection. We have a lot of work going on looking at the codes that are out there that use the data that comes from inline inspection or other assessment methods to understand if the defect is severe and needs to be replaced, what's the remaining integrity of the system? What's the remaining pressure? A lot of work going on in materials to try to understand that blowing up pipe, destructive testing, and working with the right type of team environment in our research projects to bring that to fruition.

DR. ROSEKIND: And my last question is Mr. Sallas (ph.) on Tuesday brought up the idea of actually replacing old pipeline. No one said let's go out and replace the whole system. So, clearly, if you're going to focus on an aging system and identifying where that's even a consideration, I'm curious if anyone has done analysis to understand where the economic justification point is when you look at the amount of operating at a lower pressure, cost of testing? Do people have models for sort of for where that aging pipe is better replaced giving its life cycle as opposed to just keeping it there and the testing process going on?

MR. DIPPO: I can speak to that from an operator's perspective. And again, for us it would be done on a case by case basis. So, there is considerable cost to replacing, obviously, a line segment in its entirety. But, you know, there's a point there where making the line piggable and then running the inline assessment inspection with that is going to be perhaps a more economical solution to address the threats to that line. In some cases, depending on what it is you know about that particular pipe, the specifications, the inherent threats that are with it, it may not make sense to do all of the retrofitting for the smart pigging and then to run the assessment just to find out you needed to replace it anyway.

DR. ROSEKIND: And so, again that is a model that people run to get a sense that they can make that decision based on some economic justification point?

MR. DIPPO: Absolutely.

DR. ROSEKIND: Great, thank you.

CHAIRMAN HERSMAN: Vice Chairman?

MR. HART: Thank you.

I'd like to touch on two areas, employee information programs and the SOS program that you mentioned. I'd like to address that to the American Gas Association if I could. In many industries that are trying to develop proactive information programs to find out about problems and fix them before they hurt anybody, the fuel for those programs is information from the front line because it's the people on the front line who see it and live it and breathe it every day, and they know what's not working as well as it should, and they probably have a good sense of how to make it better. So, I'm just wondering -- correct me if I'm wrong, but I assume that structural model is appropriate also for this industry as well?

MS. SAMES: Absolutely.

MR. HART: If so, then I'd like to ask do you have any sense of the prevalence of employee reporting programs amongst your members?

MS. SAMES: I would say that I don't know the single member that doesn't have it.

MR. HART: Okay, and then going to your excellent presentation about sharing and best practices and various areas, do you also share best practices in employee information programs and what works and what doesn't work and how to get the most information and get, you know, the employees to be responsive and to trust that this information won't be used against them and all of those kinds of issues that are addressed with those programs?

MS. SAMES: Those are the type of elements that come out in the secure roundtables that are done with in the technical committees, the managing committee, the board level. What you find is that as employees are identifying issues, they're brought to different levels within a company. So, depending on the level that it's brought to, if it's say you're seeing a corrosion issue, something that's occurring on the system, what you expect is that the company brings that to AGA's corrosion committee or one of the other corrosion committees that exist in one of the other organizations. In a secure roundtable behind doors with only members of the industry, because you want an honest discussion to occur, so those elements that you brought up on the employee programs, that's brought to the technical committees, the managing committee, the board, at least within AGA.

MR. HART: Okay, thank you. That's very helpful. Now, let me move on to the SOS program that you mentioned. There are also some analogs to that in other industries I've seen. I just wonder do you have any success stories, recent success stories? I'm not looking for naming names or anything, but just success stories especially related to safety that have resulted from your SOS program?

MS. SAMES: I would say every SOS is -- I can't say it fast. I would say that every SOS is a success story, but let me explain why. When an SOS comes in, it's a problem that a particular company is encountering. That SOS, that problem is sent out to every technical committee within AGA that could respond in a valid fashion, usually it's multiple committees. You then have collectively nationwide a number of companies that are giving you solutions for your particular problem. The company pulls together a summary of that SOS that's shared with the rest of the industry, and then that's put on the AGA website for others to see. Personally, I think each SOS is a success story. I don't recall ever having an SOS where we did not receive responses.

MR. HART: Well, let me take that questioning to the semi-controversial term anomaly. In many industries again we've seen where things were reported that people thought were anomalies, but then when it got into the system, other people said gee, I've seen that too and found out gee, this wasn't an anomaly after all. This is actually more prevalent than I thought. Or else, with time it's becoming a trend. We're seeing that where as technology is changing, new things happen. And somebody saw it first, so then it's anomaly, but then when they start spreading the word and other people see it. I'm just wondering was this event, now that the NTSB has put this out in the public docket about what happened here, was this distributed through your SOS system as an anomaly and asking other people how are they seeing -- are they aware of similar situations as what we've seen here?

MS. SAMES: I have not seen, and I see the operational SOS's. I see every one that goes out. I have not seen an SOS on this particular issue. That said, I'm pretty sure that what we will be looking for, now that we have more information, is gathering that for the industry, has anyone else seen this particular type of issue?

MR. HART: If you do get some feedback on that, I think -- I don't want to interfere with the investigative process, but I would think any information you get to that effect that tells how prevalent this problem is out there in the rest of the world could certainly be useful to our investigators. I hope you would share that.

MS. SAMES: We would be happy to share that.

MR. HART: Okay, thank you.

MS. SAMES: You're welcome.

CHAIRMAN HERSMAN: Can I just follow up on that line of questioning? The Vice Chairman just asked you if any SOS's have gone out following this accident on a particular issue. But I want to ask a more generic question. Have any SOS's gone out since this accident?

MS. SAMES: We have probably put out -- we average anywhere from 80 to -- within operations, there are other SOS's from other departments, so I'm only going to speak within operations.

CHAIRMAN HERSMAN: Can you limit your focus to the circumstances of this accident though? I'm not talking about general SOS's. I'm talking about information that's come out about this accident, have you put any out?

MS. SAMES: No.

CHAIRMAN HERSMAN: What about based on the recommendations that were issued in early January about the record keeping problems?

MS. SAMES: We've had previous SOS's that have gone out about how companies keep records, how they are able to use that information. We have prior to this incident collected information. I don't recall putting out an SOS on that specific topic.

CHAIRMAN HERSMAN: When you collected information previously, did you identify that people had problems with their underlying records?

MS. SAMES: With integrity management we know that it's a challenge to gather information into one place to do an analysis on it. We've had a number of discussions about how as an industry, as a company, look at your records, pull together the best information you possibly can on each segment of line, determine if --

CHAIRMAN HERSMAN: Just trying to focus you, did you get any responses back that people had problems with their data, that they had bad underlying data? It's more of a yes or no.

MS. SAMES: I would say yes because of the historical nature of many of these documents.

CHAIRMAN HERSMAN: Okay. And do you all have any recommendations or solutions about how to identify that situation and address it?

MS. SAMES: The solutions that have come up are looking at each -- looking at the data from a variety of ways. For example, if you're missing information on a particular line, it's do you have manufacturing records that can help with filling in the blanks. Is there information out there from other sources that you can utilize? So, it's gathering if you have this particular issue with this data, what are some of the ways you can get better information on your system? You can't create historical data, but what you can do is look out to others to say do you have similar information that can be shared.

CHAIRMAN HERSMAN: Okay, there were questions asked earlier from the tech panel, and I kind of want to go back to them. If you all can't provide answers today, then if you could provide them for the record. I think it's very important for us to understand the cost factor associated with many of the different safety devices that we're talking about.

Valves, is there a difference between remote shutoff valves and automatic shutoff valves as far as cost for installation, valves and other mitigation actions? And then I think when it comes to preventative, needing to understand the factor of cost between ILI, hydrostatic testing, and a replacement of the line. Not specific dollars, because we understand each line, each segment is going to be very different, but factors, cost factors. Can anybody speak to that now? Mr. Mayberry?

MR. MAYBERRY: We don't have cost factors related to those issues. You acknowledged there are differences of getting a magnitude or order of magnitude difference between or the difference ratio-wise between the two is something we would have to look into. When you're speaking of valves, you know, valves can be retrofitted with devices. Some valves aren't suitable for that, so that would be a variable there. But that would be something we'd have to look into and get back.

CHAIRMAN HERSMAN: Okay, and it would be great if people want to get back to us for the record if they have some information about cost. I think it's very difficult. How can we expect a regulation to be promulgated or how can we expect a business to make a decision if we don't understand what the costs are? It seems unreasonable for me that the industry doesn't have a sense of these costs.

MS. SAMES: If I may?

CHAIRMAN HERSMAN: Sure.

MS. SAMES: For remote control valves when we've surveyed the industry, what we found is those valves will to install them will cost somewhere normally between $100,000 to well over a $1 million depending on a number of factors.

CHAIRMAN HERSMAN: Is that per location?

MS. SAMES: That's per location, and the location has a lot to do with the cost. The specifics of the pipe have a lot to do with the cost. We can provide a range, and we can try to possibly break down the range. I'm not sure we can do that, but I can provide a range. We do have some of those numbers.

CHAIRMAN HERSMAN: Sure, and obviously, we have some providers of inspection services. I'm looking for a range, not specifics, but for a range of costs. If I could ask just to follow up, because there was a question earlier, and I'm not sure I quite got it down in my head, how much does the industry spend annually on safety efforts? And I don't know if you were differentiating between safety and R&D. That might be two different pots for you or a subset of, you know, one is a subset of the other. So, do you have numbers on how much the industry spends annually?

MS. SAMES: Our survey is a little historic. I believe the last time we did a survey was about $7 billion annually. It does not include research and development.

CHAIRMAN HERSMAN: $7 billion annually on safety.

MS. SAMES: On safety.

CHAIRMAN HERSMAN: Not including R&D or R&D is a part of that?

MS. SAMES: I'm not sure to be honest. I don't believe it includes R&D. I believe it's a separate issue.

CHAIRMAN HERSMAN: And is that just AGA, or is that INGAA, AGA, Liquid lines as well?

MS. SAMES: We do have some joint members, so it would include some of those joint members. I'll defer to INGAA on their costs.

CHAIRMAN HERSMAN: Okay, and the last question I have before I'll pass it around again is obviously this accident was a gas accident, but we're also investigating a number of accidents that involve liquid lines. I want to make sure that we understand the information that's been provided. Do you all differentiate between the effectiveness for these services and technologies on liquid versus gas? And if I could get yes or no answers, that would be great, but if you need more detail, that's fine.

MR. FOREMAN: From our point of view, yes.

CHAIRMAN HERSMAN: You differentiate between the effectiveness?

MR. FOREMAN: Yes, the liquid pipeline the maturity of the technology and the liquid pipelines is way in advance on gas.

CHAIRMAN HERSMAN: The technologies available for safety and inspection are more advanced on the liquid lines than gas, is that what you just said?

MR. FOREMAN: Yes.

CHAIRMAN HERSMAN: Okay.

MR. FOREMAN: Because of the use of ultrasonic equipment in liquids, yeah.

CHAIRMAN HERSMAN: Okay, anyone else have a different opinion?

MR. MAYBERRY: The two products are different, so there are different risks associated with each. As was pointed out, with liquid lines there are options for using ultrasonics that you don't have with gas lines. But the goal is the same, to address the risk, and the techniques to assess risk are similar. It's just the risks and the relative value for one versus the other may be different depending on what you're dealing with.

CHAIRMAN HERSMAN: Two of the primary risks cited with hydrostatic testing for gas lines were low pressure conditions where pilot lights might go out and residual water left in the pipe. Are those issues not of a concern with liquid lines and hydrostatic testing?

MR. MAYBERRY: Well, those would be a concern in either case. Usually with a line that's already accepts pigging or inline inspection it is more conducive for water removal than say an interconnected intrastate pipeline, just from a practical point of view. But the concern over leaving water, there's an equal concern over removing the water to address potential internal corrosion issues, for instance.

CHAIRMAN HERSMAN: Thank you.

Do we have additional questions from the tech panel?

MR. CHHATRE: Madam Chairman, the technical panel has no additional questions at this time.

CHAIRMAN HERSMAN: How about from the parties? Do we have additional questions from the parties? San Bruno, any questions?

MS. JACKSON: No.

CHAIRMAN HERSMAN: IBEW?

MS. MAZZANTI: No.

CHAIRMAN HERSMAN: CPUC?

MR. CLANON: No, thank you.

CHAIRMAN HERSMAN: And, of course, I knew that PHMSA would have questions, so I saved you for last.

MR. WIESE: Hey, it's our life, you know, this is what we do. So, thank you very much for your patience. I just have one, and we have tons of questions which we've offered to talk with your technical panel about offline. But I'm just interested in one concept that really for the panel anyone, feel free to comment on this.

Clearly this is private infrastructure, you know, run by private companies, with the exception of the municipal gas operators. So, that's sort of an outlier there. I just would invite your comments really for the public who may be watching about what are the constraints, financial constraints here? I mean, no operator that I've ever met wants to have a pipeline failure with a tragic consequences like you've seen in San Bruno. Clearly, so you're constrained in some way, and I assume that somewhere in there is the rate setting environment. So, I would just -- I would welcome comments. And if you can give a concrete example, I'd welcome it where operators go in for a replacement and then what happens after that. So, thank you.

MR. DIPPO: Yes, Jeff, as an operator I can comment on that. While we are a private company, we are a regulated public utility, and we're regulated in New Jersey by the Board of Public Utilities. We've been successful in the last couple of years in terms of getting approval from our commission to spend incremental dollars associated with system replacement and system upgrades of aging infrastructure. And to that end, we are also looking at extending that program currently with our regulatory commission, and we have a filing pending for that.

MR. WIESE: Maybe before anybody else goes in, can I just ask you, Chuck, since you're very familiar with this is that a fairly universal reaction across the country?

MR. DIPPO: I don't think so. I know it varies state by state, commission by commission. Some operators have been more successful. We were not the first ones to get such treatment on these types of expenditures, and there's many others that have not yet received that from their state commissions.

MS. SAMES: Looking at it from a national perspective, and this was brought up by Mr. Metro yesterday, there is a balance within the state of keeping rates low for the customers and ensuring pipeline safety. What we see in some states is a rate mechanisms that allow for quicker replacement of pipe. Other states it's a bit more of a challenge. So, it really does vary from state to state.

MR. WIESE: Any comments from Mr. Mayberry about the interstate systems?

MR. MAYBERRY: Well, the interstate systems are for natural gas anyway are subject to jurisdiction, and there is a rate factor there involved with obtaining approval to replace lines. Certainly they have the ability to maintain them, but when it comes to replacement, there is that added economic justification balanced with the safety concern to seek and obtain approval to replace pipelines.

MR. WIESE: Okay, thank you very much.

CHAIRMAN HERSMAN: Member Weener?

DR. WEENER: Yeah, I'd like to just follow up with Mr. Smith on the robotics which you described as a top win a little earlier. You said that for a 6 to 8-inch pipes it was operational, is that correct?

MR. SMITH: Yes.

DR. WEENER: Is it in commercial production or commercial use?

MR. SMITH: Correct, yes, it is.

DR. WEENER: And what kind of defects, since we talked about you have to decide what kind of defects you're going to go looking for, what kind of defects is this technology set up to look for?

MR. SMITH: In the smaller tool it is metal loss corrosion.

DR. WEENER: So, it's a corrosion tool?

MR. SMITH: Correct.

DR. WEENER: It would not have been useful then in the process of trying to find bad welds?

MR. SMITH: Not to my knowledge, no.

DR. WEENER: Okay, thank you.

CHAIRMAN HERSMAN: I have a couple of clean-up questions. Mr. Dippo, can you tell me what percent of your system is HCA's?

MR. DIPPO: What percentage of our system? Yeah, Setra is a gas company operates only 122 miles of transmission system, and approximately 10 percent of our mileage is, or a little over 12 miles, is located within HCA's today. Now, that being said, there are requirements within New Jersey, and we have in terms of the state pipeline safety regulations which overlay the federal pipeline safety regulations for us as operators. They basically became effective -- well, they've been effective for a long while, but they became much more stringent after the 1994 Edison pipeline explosion. So, to that end, we are working with our regulator who has requested of us that they would like to see all of our transmission mileage be assessed within New Jersey, and they would like to see that done on an accelerated schedule, prior to the end of 2013. And we are working to try to meet that goal presently.

CHAIRMAN HERSMAN: Okay, so that's one of those examples of a state having more stringent regulations or expectations than the federal government?

MR. DIPPO: Absolutely.

CHAIRMAN HERSMAN: Okay, and do you have any automatic or remote shutoff valves on your line on your transmission line?

MR. DIPPO: We don't, but referencing those state pipeline safety regulations again, after that terrible incident in Edison, the regulations have changed over the years, and we are required to perform as local distribution company and operators within the state, we are required to perform annual drills and an annual valve assessment of our transmission system, such that we have to revisit all of our valves. And based on the drill and audit of that drill, the success of how that emergency drill was responded to, then go back through the system and look at all of our valving and determine whether or not those valves would be suitable for being ranked as either a low, medium, or high priority for retrofitting either into automatic or remote. To that end today, we don't have any remote --

CHAIRMAN HERSMAN: When would that assessment be completed? Would it be this year of looking at adding additional valves?

MR. DIPPO: Yes.

CHAIRMAN HERSMAN: Okay, if you wouldn't mind, once that's completed and submitted, if you would share that with our investigative team?

MR. DIPPO: Yes.

CHAIRMAN HERSMAN: Thank you. And you mentioned earlier that the estimate for pigging the entire intrastate system was approximately $12 billion. Did that include distribution as well as transmission lines, or is it just transmission?

MR. DIPPO: No, that is just transmission, and that is just transmission within the distribution sector.

CHAIRMAN HERSMAN: Okay, thank you for clarifying that.

PHMSA, can you tell me how many miles of pipe were pigged pre-mandate for the baseline assessments and how many miles have been pigged post-mandate for the baseline assessment? And if you don't have that information, if you could provide it for the record.

MR. MAYBERRY: I can provide that for the record. I do have some current information related to post-integrity management. About 140,000 miles of gas transmission pipelines have been inspected using one or more assessment methods that are specified in the IM rules. And this includes mileage outside of HCA. It's about six-and-a-half percent of all pipeline. Transmission pipelines are considered in HCA's.

CHAIRMAN HERSMAN: And what I'm trying to understand is what was the increase post-mandate. And so, before there was this requirement in the law, what percentage of pipe did they pig? And then post-mandate, did that increase, or did it stay the same? The second question I have with respect to that is are there any instances that you know of of pipeline operators that have not been able to conduct required assessments because of a scarcity of equipment, not having enough pigs or companies that operate inline inspections to provide that service for them?

MR. MAYBERRY: I'm not aware of any, but let me refer to Joshua to see if there's any that I missed.

MR. JOSHUA JOHNSON: I have not heard of any on an ongoing basis. There are some tools where there might only be one or two in a certain size, so if they are in use in some place, GE and the other companies will send these tools sometimes all over the world. So, sometimes someone else might be using them. So, you might not be able to get them next week or the week after, but I have not heard of someone having a problem getting one eventually, you know, within the time frames of the rule.

CHAIRMAN HERSMAN: Okay, and I was curious if any of you all had heard any new problems identified in this hearing that you hadn't been aware of prior to the hearing?

MS. SAMES: I think the one problem that I had not heard prior was the discussion between joiners and pups, that there potentially was an issue with the joiners that was at the mill, potentially at the mill. I hadn't heard that before the hearing.

MR. MAYBERRY: You know, on that note, from my perspective, I guess related joiners I heard a theory related to why that's probably the type of pipe involved. This one involved a joiner or a pup installed or connected to a -- or a series of pups connected to another length of pipe to form one length of pipe. I think that's still under investigation is what it appears to be from our standpoint. It's not conclusive that those actually a joiner situation versus the situation where it was perhaps a pup welded to the end of another pipe separately from the pipe manufacturing process. I think there's some theories related to that, but it's not conclusive.

CHAIRMAN HERSMAN: Thank you. And I guess, you know, for me I was reviewing a transcript of a hearing before the Senate Commerce Committee in May 2000, and there were recommendations and some opposition to repealing grandfather clauses at the time. Some discussion of public awareness, community awareness of safety inspection requirements and new technology and tools, discussion of high populated areas and valves. And I was struck that there really weren't any new problems. What we need are some new solutions. Many of these issues are fields that have been plowed before. But here we are in 2011, and we still had a community that wasn't aware of the pipeline that ran through the neighborhoods, and we still have pipe that is older that is not subject to higher standards or inspections. These are issues that have been discussed before. Are there any questions from the tech panel?

MR. CHHATRE: Madam Chairman, no questions at this time.

CHAIRMAN HERSMAN: Any final questions from the parties before we conclude, board members?

We have no other witnesses to testify, so this portion of the NTSB's investigation into the pipeline accident in San Bruno is concluded. The record will remain open for additional materials requested during the hearing.

On behalf of my fellow board members and the NTSB staff, we extend our appreciation to all of the participants in this hearing. In particular, I'd like to thank the two dozen witnesses for their participation and the parties and the parties' spokespersons for their cooperation not only at this hearing, but throughout the investigation.

We look forward to completing our investigation and sharing our final report with you in the coming months. I'd like to acknowledge our staff from the Pipeline Division and the Office of Research and Engineering. From the on scene investigation to all of the lab work that was done and the urgent safety recommendations that were crafted over the December holidays, you have worked tirelessly to document the evidence and develop the facts so that they are known and that preventative actions can be taken.

I'd like to note that everyone in the pipeline division, and it's a very small division, there's four investigators and a chief, was involved in this accident investigation, and each and everyone of them is involved in other accident investigations as well. We actually poached some staff from other offices in the agency. Our hearing office, Loernda Ward, is one of our most experienced aviation investigators in charge, and she has lent her services to the division, and specifically provided a great deal of help to this hearing, so we thank you.

And I'd like to acknowledge that we've put a real challenge out for our staff, not only to complete a public hearing on this accident investigation, but also to complete a final report and bring that to the board in less than a year. Obviously, that will depend on many things as far as technical information to be developed and potential government shutdowns that might be looming and other things. But I have every confidence in our staff that they will continue to work as hard as they can to meet that goal, and I am very much appreciative to the managing director's office for putting on loan a great attorney and one of the best writers that we have at this agency, Karen Burry (ph.). And I know if anybody can help to write this report quickly and do it thoroughly, it's Karen.

The past three days have shined an additional light on the facts and circumstances of the September 9th accident. And they afforded the public and the pipeline industry a window into this investigation, and I thank everyone in the audience for lasting with us. This has been quite a marathon, and I'd like to recognize Congresswoman Speier who has been with us throughout the three days, and we very much appreciate her interest and support in our investigation.

We've talked about safety policies and procedures and how operators evaluate the integrity of their pipelines and mitigate the risk. We discussed emergency response plans and how to evaluate the public's awareness so that communities are better informed and better prepared when there is an emergency. We've also discussed how federal and state entities regulate the pipeline industry and ensure compliance. We touched on the type of technologies that are available to industry to monitor and test the pipes. All of these discussions will assist us as we move forward in our investigation. All of the materials from the presentations to the exhibits are available on the NTSB's docket on our website.

For the parties, the next steps for you all will be the completion of the fact finding portion of our investigation. And then we'll have a technical review. Following the technical review, you will have the opportunity to submit written submissions regarding your conclusions and recommendations about this accident. I invite and encourage you to do that. It's beneficial to the board in our analysis to have that perspective, and it offers the parties an opportunity to share their views for the record.

The NTSB is committed to finding out how this accident happened, but that's only half the job. The other half is prevention. It's never too late to work to prevent future accidents. The information developed during this hearing will result in some of the attendees taking actions in advance of the completion of our report, and that's as it should be. The lessons learned from this hearing and the San Bruno rupture can prevent another community from having to experience a similar tragedy. Already we have heard that PG&E has committed to greater awareness for the community and providing more information to the public and that they are committed to expanding their use of shutoff valves.

Thank you all very much for your participation in this hearing, and this hearing now stands adjourned.

(Whereupon, at 1:00 p.m., the hearing was adjourned.)

CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

IN THE MATTER OF:	PUBLIC HEARING ON NATURAL GAS PIPELINE EXPLOSION AND FIRE SAN BRUNO, CALIFORNIA SEPTEMBER 9, 2010
PLACE:	Washington, D.C.
DATE:	March 3, 2011

was held according to the record, and that this is the original, complete, true and accurate transcript which has been compared to the recording accomplished at the hearing.

Timothy Atkinson, Jr.
Official Reporter