UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY

# INLINE INSPECTION PUBLIC MEETING

Galleria I and II
Westin Galleria Hotel
5060 West Alabama
Houston, Texas

Thursday, August 11, 2005
8:30 a.m.

Pipeline and Hazardous Materials Safety Administration and Office of Pipeline Safety Representatives

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Pipeline Industry and Inline Inspection Vendor Representatives

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Pipeline Industry and Inline Inspection Vendor Representatives (Continued)

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P R O C E E D I N G S

8:30 a.m.

Introduction of

PHMSA Acting Administrator Brigham McCown

Stacey Gerard

MS. GERARD: Good morning. It's a great day when you can get this many people in the room in Houston, Texas, this early in the morning to talk about pipeline safety. So we're off to a good start, and it's an even better start because the new Acting Administrator of PHMSA took time out of his schedule to come down and get a feel for this issue. And it isn't every day that somebody walks in on the job and will make a trip like this to be part of what's going on.

So I'm very proud to introduce my new boss, who is Brigham McCown. He has been in the Department as the counsel for the Motor Carrier Administration.

In order to describe Brigham, I have to say he's a cross between an energy lawyer and a Navy pilot, and so I think that's a good thing. I know one thing for sure is there's nothing he's afraid of and he takes the throttle very quickly. So I wanted to give you an opportunity to get to know Brigham McCown just a little bit.

Brigham?

(Applause)

Remarks by PHMSA Acting Administrator Brigham McCown

MR. McCOWN: Thanks, Stacey. It's a pleasure to be here today. It's always a pleasure, wanting to get outside of the Beltway, and it's a really special pleasure to be back home in Texas today.

As you may have heard from Joy, DOT underwent a reorganization last year where the former RSPA was split off into two separate operating administrations, RITA, which will concentrate on innovative technology research, and PHMSA, which is the marriage of the Offices of Pipeline Safety and Hazardous Materials Safety. And this consolidation brings a vast majority of the Department's energy transportation component into one single agency.

We have an exciting mission. Our mission, first and foremost, is safety, but at the same time we look forward to our consulting role with Homeland Security on the security component, as well as other parts of the government in the energy sector, our infrastructure, and protecting our communities as well.

DOT recognizes the importance of this industry, and I think it's very important that we share the practical knowledge and experiences and know-how through forums such as this. We need new initiatives, we need to refine our current initiatives, and we need to keep some initiatives that are working well as we address the national needs.

Secretary Mineta recently spoke to the CEOs of the oil industry, about two weeks ago in Annapolis, and I wanted to share a couple of thoughts that he had. I pulled his speech because when I'm talking about my boss I don't want to get it wrong.

And as he's talking to these CEOs, one of the things he said, it's like arteries carrying precious blood to the heart. Pipelines transport precious natural resources that are the lifeblood of our country.

He also said that today pipelines carry almost 66 percent of the energy products consumed in our country, and it is not surprising, therefore, that pipelines are by far the most important mode of transportation for energy products in the United States, and they are among the safest.

He noted that on average there had been about two fatalities and less than nine injuries per year during the last decade, and even though one death was too many, this record is clearly impressive compared to other forms of transportation. He said, for that I thank you, and please keep doing what you're doing.

He said the Department of Transportation, and it is his goal, that we help the companies be safer today than they were yesterday, and safer tomorrow than they are today.

He concluded by saying our ultimate goal is zero: no deaths, no injuries, no releases to the environment, no operating errors.

And I think when you have the Secretary of Transportation, who is, from his experiences on the Hill and his service to the government, is one who is keenly aware of the transportation sector and recognizes the vital importance that this sector plays. And so we at the Department of Transportation think that forums such as this are crucial to help us understand how to move forward and how to reach our goal, which is good for safety and good for the economy, to ensure safe and efficient and reliable service to all of the customers.

And in this day and age of questions regarding capacity, usage of energy products, an uninterrupted supply of energy is necessary if we're going to keep our economy growing and moving forward.

And just this morning, while watching CNN News, there was an article -- a story being run that pipelines are at capacity at several of the airports and that they are trucking supplies in because they're unable to meet current demands. And I think that's a telltale sign of how important it is not only to identify risks and issues, to fix the issues, and to keep the pipelines safe not only, again, for the safety of all of our citizens but for the economy.

So, with that, I thank you, and I look forward to sitting in the back of the room and listening to the discussions today. Thanks very much for your time.

(Applause)

MS. GERARD: Thank you, Brigham. And I think I forgot to say a Texas energy lawyer. Did I forget the Texas part? I'm so sorry. He adopted Texas as his home state. He was actually born in Ohio, but he likes Texas attitude, so I think that says a lot.

MR. McCOWN: I got here as quickly as I could.

MS. GERARD: We wanted to keep you just a little while in Washington.

Opening Remarks

Stacey Gerard

MS. GERARD: What we do together in settings like this and in other meetings and forums that you all sponsor and that we sponsor has always been important.

We've striven for continuous improvement just for the sake of safety, in addition to the other reasons that Brigham just mentioned.

We've had two goals. They've been our goals. They're going to be our goals for integrity management: improve protection in the high consequence areas and improve confidence in the safety of pipelines.

Now, more than ever, we must be sure that we're doing everything we can to reach these goals. The stakes are getting higher. The challenge of the growing economy is increasing demand for product, as you heard Brigham saying, stressing capacity. Population continues to encroach on communities. The population shifts continue to move population to places where there may not be supply, raising the issue of growth of the infrastructure.

In this environment of the Information Age, it's clear that communities' need for information about pipelines and communities' interest in monitoring the progress of pipelines becoming safer is getting to be a much bigger driver than it used to be. And we hope that local officials and state officials are positioning themselves to be better informed because they are going to increasingly be making siting decisions in their communities, whether it's moving more population near a pipeline or bringing a pipeline near a population. And so the issue of performance and tracking is increasingly an issue that we have to deal with.

I spoke about increased interest and awareness. The Secretary of Transportation speaking to the oil industry is one indicator. The Assistant Secretary and the Deputy Assistant Secretary for Policy have also had separate meetings in the past month dealing with the oil pipeline issue, infrastructure and the growth, as well as on the subject of the gas side. So we see an increasing interest at the Departmental level that is unprecedented.

And it's a relatively frequent occasion when we get a phone call first thing in the morning. The Secretary has been reading the newspaper, taking out his clips, and he calls us up upstairs to say, "How's it going?" That's not always how you want to start your day because it isn't usually a good thing.

The IG, the Inspector General, of the Department has just initiated a new audit on his own, not required by statute, to look at the process of how well you are identifying threats and repairing them. He has a lot of statutory requirements that he has to address, but of his own interest and choice he is starting a major audit this month, and many of you may have already been contacted.

On his own, he picked up the phone and called Baltimore Gas and Electric and said, "I'd like to come over and look at your operation." That's going on today. The Department is really paying attention.

In addition, the General Accounting Office is starting two audits this month focusing on the Gas Pipeline Integrity Regulation design, oversight, and implementation, and a separate audit on the issue of the reassessment interval.

Now, those two audits are required by statute in the Pipeline Safety Act. So that's three brand new audits starting this month.

The fact that the Highway Bill and the Energy Bill have just been passed leads us to expect that Congress' attention will be turning to pipeline safety and the reauthorization of our program very soon. That reauthorization environment is always kind of a different environment than, you know, the normal years, so we're expecting to have a very increased level of scrutiny on our performance.

We require operators to assess pipeline integrity. We intentionally encompass a broad array of technology and process in our regulatory structure. We expect you to use a variety of technology and processes in combination to get the best possible results, but the regulations do specify a minimum floor, a minimum capacity that you must meet.

From our unique vantage point as your overseers, we see each operator's level of performance. More specifically, we're seeing a range of performance. While we can say that all operators, every operator in this room, is emerging in its capability to be able to progress and improve and to assess the infrastructure and to repair it properly, we think that it is important to share information today on what we see as practices and procedures that we think are having the best results as the integrity regulation contemplated, as we expected as PHMSA.

This is an effort. What we're here to do today is to lead you to think and make decisions in a more robust manner about tool choice, about your expectation from your vendors, about how you verify the data that you get from vendors and your quality control.

The purpose of the meeting is to share information so that all operators know what our performance expectations are. The status quo is not acceptable.  Things are working right, but there are improvements that we need to see.  There is a lot that is going right, but there are improvements that we need to see to comply with the regulations and to improve performance.

All pipeline operators need to make better use of the assessments to understand pipe condition, how to address a condition, and how to make the right decision.  We hope that this meeting is very useful to you.  It was our agenda in PHMSA.  We established the agenda.

I know that you all have many questions and concerns about how we enforce.  The agenda is very busy.  I know there will be time for questions, but you may have questions that we may not be able to address today.  We believe in these kinds of settings, to be able to hash things out, if we can't get to all your questions today, we'll be happy to pitch another tent and have another meeting to discuss concerns that you may not be able to get answered today.

I have enormous confidence in the PHMSA staff who put this meeting together:  Joy Kadnar, Chris Hoidal, Bill Gute, Rod Seeley, Bruce Hansen.  There's no doubt in my mind that we have the very finest people with infinite capability looking at these issues and calling these questions for you. So I turn this meeting back over to them with the fullest confidence that they will deliver a program for you that is going to be useful.

And again, thank you so much for your attention, and we really do appreciate all the efforts. We ask a lot. Our standards are very high, and we will do everything we can to help you reach those standards. Thank you very much.

(Applause)

MR. KADNAR: Just like Mr. McCown adopted Texas as his home state and many of you may have changed states, the U.S. is my home country now. And I may sound unlike you; just bear with me.

(Laughter)

MR. KADNAR: I would like to now introduce you to the first panel. Beside Ms. Gerard is seated Mr. Bruce Hansen and Mr. Peter Lidiak.

Mr. Bruce Hansen is our senior program manager and an exceptional engineer. He was instrumental in launching the Integrity Management Rule and the subsequent inspections, and is responsible for the success of the Hazardous Liquid Integrity Management execution.

Mr. Hansen will brief you on the inline

inspection requirements of the Inline -- of the IM Rule and some of our findings pertaining to inline inspections.

I will follow Mr. Hansen. I will delve slightly into some data issues pertaining to inline inspection. I will show you some images and some quantitative and qualitative data that we have extracted by performing some investigations. I will then expose you to some best practices that we have gleaned over this time.

Immediately after me, Mr. Peter Lidiak, who is the director of the Pipeline Segment in API, will give you a brief presentation. For those of you who don't know, Mr. Lidiak has replaced Ms. Marty Matheson, who retired recently. Mr. Lidiak will describe to you some of the performance metrics that the API has culled since the IM Rule and subsequent inspections were launched.

Mr. Bruce Hansen.

Integrity Management and Inline Inspection Perspectives

Integrity Management: Background

Bruce Hansen

(PowerPoint presentation)

MR. HANSEN: Thank you, Joy. I appreciate it. I wasn't sure who you were talking about there for a second, but you kept using my name so I guess it was me.

I have kind of an interesting objective today. How many people in here have had or been associated with an integrity management inspection, either gas or hazardous liquid?

(Show of hands)

MR. HANSEN: Okay. I appreciate that. What I'm going to say next is probably going to cause a lot of disbelief, but I'm going to tell you everything there is to know about hazardous liquid and gas integrity management in 10 minutes.

(Laughter)

MR. HANSEN: Or something like that.

Just to start with the hazardous liquid; just for anybody that doesn't know, we have two basic programs for pipeline: hazardous liquid and gas integrity management inspection processes. The hazardous liquid program is basically in the regions now and is being conducted by the regions, and we have, looking at all inspections, somewhere around 150 inspections completed by now. On the other hand, on the gas integrity management side, we are just getting started with the inspections.

So, in that light, I'm going to tell you at a very high level kind of some of what we're looking at and some of the more focused -- the focused kind of results that we've seen.

On the hazardous liquid side, basically just to give you a just a little bit of feel for what the rule -- how long it took for it to get developed and so forth, we started off with the large operator rule. That basically -- because of the reactions and discussions related to that part of the rule, we reissued the rule in January of 2002 to include repair -- include the repair provisions. They took a little bit longer to develop.

And then, finally, the version of the rule that we're using right now -- there have been no changes to this yet -- is the January 16, 2002, and this basically extended all the requirements to all pipeline -- hazardous liquid pipeline operators.

Just -- this is basically the program elements that are inspected. Everybody that has had an inspection has been through these in a lot of detail. They take a while to get through. There is a lot of discussion about them, but this is the basis of our integrity management inspections for hazardous liquids.

One common thread throughout these elements is data, and data -- one of the main sources of getting the data is through inline inspections.

This is just some statistics, and these came right out of the 2004 annual reports. You can get a pretty good idea of what we're looking at as far as inspection results, and this is specifically for inline inspections. So there's been a lot of work done and there's also been a lot of activity as far as identifying and repairing conditions found.

I think it's very important to note that there has been a lot of this that has happened. This is not everything; I want to be clear about that. We're still sorting and looking at data that will be a more complete compilation of this, but for 2004, this is what it looks like.

One of the things you need to understand, too, for those of you that are either -- have had a reinspection on the hazardous liquid side or are scheduled for one, there is going to be more emphasis on field activities. Those will include, for -- well, for a great part, what you're doing from an assessment standpoint, and that will include inline inspections.

Some of the areas that we would be looking at would be the ILI run itself, the process you're using and so forth, but this is a field kind of activity. This is basically the inspector going to the field, looking at verification digs, perhaps even checking the actual run of the pig, that kind of thing.

The other things that are associated with that; there could be some HCAs, the high consequence areas, that would be reviewed and possibly even -- not possibly, would -- checked in the field.

The others that are likely to happen is that last bullet, the one about activities or implementation of preventive mitigative activities that you have said you're going to do or are doing.

A couple of issues -- and I want to be clear, too. This is not the whole issue set associated with hazardous liquid inspections, but two of the ones that jumped out at me when I was trying to do this presentation were, one, that we have a lot of emphasis, and we've had almost from the beginning of doing hazardous liquid inspections, looking at ILI vendor requirements. And this includes the tool tolerances and the time frames for completing ILI runs. These are all important things for the inspection team to understand what's happening for that particular operator for inline inspections.

The second part is -- notice how this is worded -- that the inspection team is looking for the qualifications of the people that are actually reviewing assessment results. Now, that can be -- and I don't know of an instance -- I hesitate to say this, but I don't know of an instance personally where we challenged the actual credentials or the qualifications of the person doing that result. I just don't know of one of those that happened.

However, what we saw a lot of was that there was no process in there to bring somebody else on board to do that activity at the same level of qualification.

Now we'll move on to gas. Basically, the final version of the Gas Rule that we're using is May 26, 2004. We have started some inspections. We have divided those up into intrastate and interstate inspections for the time being, and we have done exactly one intrastate, and I believe the interstate teams are on about their fourth inspection. So we're just getting started on the gas side. I want to be very clear that we've just kicked off the inspection process there.

Now, program elements. You note that there were eight for hazardous liquid. We'll keep going. There's a point I want to make. These are just the program elements that are going to be inspected for gas integrity management. You note there are a few more.

Now, the point I want to make is, all of these elements are going to be inspected during an integrity management inspection. The elements are, again, for the most part -- and I don't think there are any exceptions in here -- are going to have some thread of data that you're going to generate. One of the ways you're going to generate it is by doing inline inspections. So that's the basis of a lot of what you're going to be doing, the actual implementation of the integrity management requirements.

I got conflicted about this because I called it "Expectations" to begin with, but we've only done about five inspections yet. So we're guessing right now. But the guess is, if there's any correlation between what we did on the hazardous liquid side and what we're doing with the gas, we will see a lot of ILI assessments as the basis for a lot of what you're doing.

The direct assessment. We've had a little bit of experience with that. We're learning about direct assessment as we go through these inspections, and the operators -- the very few that we've looked at for the most part seem to be learning about direct assessment in a lot of areas also as we go through these inspections.

One of the interesting things that we've run into in this very small sample is that direct assessment gets really important for the smaller companies, more the LDC or the distribution companies that have their transmission lines so integrated into their systems. It really becomes a very important assessment tool.

And I guess we're going to hold off on questions? Okay.

Now I'll turn it back to Joy. Thanks very much.

(Applause)

MR. KADNAR: Thank you, Bruce, for so eloquently describing to us the rule requirements and the most salient findings pertaining to inline inspection. Like I said previously, I will go one step further in substance, but I cannot match Bruce in eloquence.

(Laughter)

Inline Inspection: Lessons Learned

Joy Kadnar

(PowerPoint presentation)

MR. KADNAR: Most of us recognize that inline inspection devices is a boon to the pipeline -- to pipeline operators. Thanks to these devices, pipeline operators can now collect copious amounts of data. But there's a lot more to the process than just launching the tool and acquiring the data.

Sorry. Here is a screen capture of some -- a vendor's log. Sorry.

This green, filled-in oval, symmetrical oval, is an aperture in the pipe. It could be a stopper fitting, a valve. You see two vertical lines, and those are the code words for the T piece, what could be called simply the T piece. We know the location, the meter reading of that feature. We know it is located right on top of the pipe at about the zero o'clock position.

There's a vertical red line that goes through it, down into the bottom half of the screen capture. Here we have a horizontal white line that gives us the wall thickness of the pipe. The wall thickness is about -- is 232 mils.

There's no -- the white line does not cross the red line and it does not cross the oval opening, and that's a clear indication that there's no wall thickness over here because there's no wall.

Just remember this picture. I'll come back to it later.

Here is another picture of a corrosion pit. Here you can see the corrosion pit on the pipe. And we have the field examination data and the inline inspection call-out data.

This picture is a metallographic section of -- at this location, at the pit. The yellow line -- right at the bottom, the yellow curve, is the intrados of the pipe. The one right on top is the extrados of the pipe. And the one in between is the beginning wall thickness at the scene.

You will see that there's a vast difference between the call-out -- the maximum depth of the pit called out by the inline inspection device and the actual ND examination.

An important fact that was not picked up by the device, for whatever reason, was it was located in the seam. This pit was located in the seam. This corrosion pit, by the way, leaked. That is why we performed this investigation.

Here are two more formal pictures. This is a group and this is a group. Here there is a cluster of pits. Here there is a single pit. You can see the wall loss in the metallographic section for this cluster of pits and this one here.

This is from the same pipe section. The largest -- the maximum depth of a pit in this pipe section was called out as 49 percent in the one I showed you previously, but it's clear from these metallographic sections that the wall loss on other pits was as high as the previous one, maybe in the 80 to 85 percent. Had the previous one not failed, not leaked, given time we believe these pits would have leaked.

Here is another picture showing a ruptured section in a pipe. As you all know, there are three ways to calculate the interaction distance among pits. The operator correctly used the relative distance method shown by the red squares. Disregard the green and the yellow squares.

Had the operator used the fixed distance method or the 3T criteria, specifically the 3T criteria -- I'm sorry, but the orange square does not show up properly. It's a much larger square on the outside.

Had they used the 3T criteria, they may have prevented this rupture by inquiring -- exposing the pipe and looking at it.

As I mentioned of why we do investigations, we collect data. Here is a table of 16 locations that we looked at from -- on a pipe. This is the difference in the location of the feature, the orientation of the feature along the pipe wall, along the circumference of the pipe, and the maximum depth of the feature. This is just an arithmetical difference. So if the inline inspection went and called it out as a 20 percent pit, we actually found a 90 percent pit. Ninety minus 20 gives us a 70 percent difference.

You can see that quite a few of the call-outs were undersized. For what reason we don't know yet. There is a possibility that some of the sensors were inoperative.

The distance from the upstream weld to the feature appears to be within tolerance, but the orientation, we see quite a bit of difference in some cases. By positive I mean clockwise; the feature was found farther clockwise. And negatively, it was found anticlockwise.

Over here is some other dig that we performed, and here this is just quality data I'm showing on the depth, length, and width of corrosion features and its orientation. You can see that the data is equally distributed among -- between the out-of-tolerance and within tolerance criteria.

This is the last picture, and here we have a pipe section. There's a buckle in the pipe with a crack. This is the image that we -- the inline inspection -- we captured from the inline inspection tool. This looks not unlike the first picture I showed you about the T piece, but this was called out as a T piece by the inline inspection vendor.

There are two issues here. One, the operator, had they not called it out as a T piece, we may have uncovered the pipe and investigated it. The inline inspection vendor may say that this definition is beyond the capability of the tool. So they'd want it pigged out.

But I think both of you should get together and ask, why did this happen? Why did you call it out as a T piece when it -- when you may have known it wasn't a T piece?

We have over time, in the past couple of years, through the IMP inspection and other investigations, found some good decision making, what we call the activity train. This is very basic. I believe some of your operators have much more elaborate flow charts.

From the pipeline operator, it would be nice to know -- the vendor would -- it would be nice for the pipeline operator to communicate to the inline inspection vendor the susceptibility of the pipe, how old the pipe is, what type of seam it has, what is its failure history, and of course the objectives of the inspection, too.

From the inline inspection vendor, the operator has several expectations. We expect the inline inspection vendor to pick out the correct tool, establish the performance specifications of the tool, and make sure it meets the performance specifications of the tools, segregate -- you know, signature is something that I don't know about, like the one previously I showed you.

We expect them to develop -- the inline inspection vendor to develop a dig list, verify it through the operator, and then develop a prioritized dig list.

Together I think the operator and the vendor need to look at other data that is collected by the pipeline operator. This is what we call data integration. It can be done independently by the operator, but it may be wise for both -- to have both the operator and the inline inspection vendor to look at it.

What have we learned? Here are just a few high points. We know the tools can't -- different tools are meant for different types of flaws. One does not substitute for the other.

A flaw can only be found after it has already happened. We cannot expect a tool to find something that may happen in the near future. A tool -- a corrosion tool cannot find -- cannot assess corrosion growth. That has to be -- you have to have two successive tool runs or you may have to integrate with CP data. And there are some features that an UT tool or an MFL tool or a geometric tool cannot find.

We have also learned that if an anomaly does not exist -- you cannot find an anomaly in a certain spot that was called out by the tool and look for it. The order meter could be wrong, the reading could be wrong, and it is very important to find it because we may be looking in the wrong place.

If the image signature appears strange, inquire as to its disposition. And we all know that patterns of echo loss are very important integrity management tools.

I have tried to show that there does not appear to be a problem with the physics of detection. Inline inspection devices find a lot. The problem, if there is one, resides in maybe the discrimination, confirmation, and integration process.

I want to also point out at this time that judgmental errors pale in comparison to the benefits of inline inspection devices. It has made the pipeline operator's job easier and, you know, we have --

incidents, accidents, leaks have gone down. In most cases, the intent of the rule is being met.

On this note, I would like to welcome Mr. Peter Lidiak.

(Applause)

Hazardous Liquid Pipelines: Industry Metrics and Impact of Integrity Management on Pipeline Safety

Peter Lidiak

(PowerPoint presentation)

MR. LIDIAK: On my screen this is a white background. I don't know why it's so yellow, but we'll see how that goes.

My name is Peter Lidiak, and I'm API's new pipeline director. I'm taking over for Marty Matheson, who held this job for quite a long while and who many of you knew. She has gone to a well-deserved retirement. Last time I talked to her, she was sitting on the top of a mountain in western Virginia sipping wine, so, you know, it sounds pretty good to me.

I'm here today representing liquid pipeline companies that are members of API and AOPL. API and AOPL are proud to support and promote the cooperation of this industry with the government and the public to make liquid pipelines safer and more environmentally friendly.

As many of you know, about four years ago the pipeline industry and the Office of Pipeline Safety, which is now known as PHMSA, or at least PHMSA, embarked on a cooperative effort to improve pipeline integrity management, adding to the industry's existing efforts to keep the public and the environment safer. Inline inspection tools have been an integral part of that effort and are the subject of today's workshop, as we all know.

I'm pleased to announce that the industry's latest contribution to improving inline inspection and integrity management, the API 1163 Inline Inspection Qualification Standard, was released last Friday. Talk about timing. This standard will move forward the use of this important technology to ensure pipeline integrity.

And, you know, I was struck by Stacey's comment earlier. Yes, things the way they are right now do need to improve, and I think this standard will help us move things forward.

I'd like to put today's discussions in context by sharing with you the results of our combined efforts and to demonstrate that while there remains room for improvement, great strides have been made in reducing releases from accidents associated with pipelines. Pipeline operators have already inspected and certified over 50 percent of the high consequence area miles.

Inline inspection, or ILI, technology has made these inspections possible to a large degree. ILI tools must be employed in a common sense manner. Operators understand that the right tool must be employed to inspect for appropriate conditions.

Some tools are good at detecting problems and are in widespread use. Tools to detect corrosion, for instance, are mature, and we're getting quite good at identifying corrosion-related problems. But some tools are developing. For example, tools for identifying cracks are coming into more widespread use. Nevertheless, the industry's record in reducing incidents of all sorts is impressive.

ILI is not the only tool, however, that's been employed to achieve these impressive results. The industry began to improve its record even before the implementation of the integrity management regulations, beginning with the safety initiative that began in 1998.

The industry has been and will remain actively engaged. The first step was the industry's voluntary reporting system, the PPTS. The PPTS captured more information and captured it eight times -- for eight times more spills than the then-existing OPS reporting system.

The lessons from that information resulted in the improvements to the record that we have seen. Add that to the later initiatives: operator training, standardizing operating practices, visual inspections, direct assessment, public outreach, and communication leading to greater public awareness of where pipelines exist, and safe practices around pipelines are all needed to keep incidents low and/or heading in a downward direction.

I'd like to share several slides with you that demonstrate some of these points, and the first one is up here already. As I said before, this information sets a good context for today's discussions. Other representatives from the liquid pipeline industry, people that are certainly much more knowledgeable than I am, will be discussing their experiences with best practices for the use of ILI tools later in the workshop.

One of the things you'll notice is that our goals are the same as Secretary Mineta's stated goals. These statements are really what our industry is striving for. They're what we're about. They're simple. They are heartfelt. Our leadership endorses these statements. We view the public's trust to operate our pipelines as a privilege and not a right, and we do expect to be questioned, criticized, investigated, and even enforced against when we don't perform adequately.

Let me turn to some of the accomplishments that have been achieved as a result of the long-term focus of the pipeline industry on managing its assets and the impacts of integrity -- of the integrity requirements.

As an industry, we felt that it was very important to know where we stood at the halfway point of the baseline assessment period under the rule in September 2004. We undertook a voluntary certification to the Office of Pipeline Safety. We -- API and AOPL's leadership asked our members to send OPS the following information. We undertook a voluntary certification to the Office -- excuse me.

Total miles of hazardous liquid pipelines was what was being reported. Companies operating about 80 percent of the total line pipe miles were -- actually participated in the certification.

Of those 130,000 miles that were actually involved, about 60,000 miles are in or could affect high consequence areas. Thus, about 46 percent of the U.S. mileage is directly subject to the rule.

As of September 30th in 2004, we've completed baseline assessments on 38,000 miles, which constitutes about two-thirds of the total operating miles that are in or could affect high consequence areas.

In addition to the assessments required under that, we have also -- under the regulations, we have also conducted assessments on 34,000 miles that are not on high consequence areas or areas that could affect high consequence areas. Thus, by the time September came last year, we were at about 72,000 miles, or 55 percent, of the U.S. total that's been assessed either directly or because of the rule and in addition to the requirements of the rule.

Now, many of you have seen this slide before. This is a picture of the industry's performance from 1999 through 2003. We're working on the 2004 data now, and we have every expectation that the results will continue in the same direction, and that is downward.

Each of these charts represents one major cause category and each incident is five gallons or more, yet the numbers are very small. All are one or two digits. Given that the net mileage of line pipe is 160,000 miles across the country, we think that's pretty phenomenal.

For those of you not into deciphering graphs, we just thought we'd put it up in words. Here are the words. Line pipe accidents are down in every category of incident. Line pipe -- the pipe that's in the right of way is where people are. This is the pipe that transects our communities, and that's where the focus should be.

IMP is a success story. I'm just going to run all these up on the screen. Otherwise, I'll -- okay. There we go.

The number and quality of the assessments has been great. The number of assessments exceeds the requirements of the regulations. They contribute significantly to the success story. The risk-based approach to addressing threats to integrity is a positive direction. Maximizing the access to utility of and the value of information, finding conditions and fixing them, and looking for emergency integrity issues -- emerging integrity issues are all important parts of what the success story has been.

Integrity management, though, is not just inspection and testing. Integrity management is all-encompassing, making maximum use of the information at the disposal of the operator. Lots of good work is going on in parallel with the implementation of the integrity rules and the enforcement of the integrity rules.

Operators have made broad commitments to improving the public awareness and communications along rights of way. We're in the early stages of assessing the effectiveness of industry efforts -- industry public outreach efforts. It appears that about 60 percent of those surveyed in our first pilot studies know that pipeline runs near their property or through their communities. We can and we will do better. We're going to continue this work.

Operators have increased security awareness for their employees and spend a great deal of time and resources on physical upgrades, sensors, cameras, control room access, access to all types of facilities, and much more than that has even been applied to pipelines that are part of port facilities.

We cannot let our guard down on seeking to prevent the incursion by third parties onto our lines. We are looking forward to a nationwide 811 to support One Call.

We have made investments in our performance, the Pipeline Performance Tracking System and the analytic work it engenders. We are seeking how to take even that a few steps further through our performance excellence analyses, and we're trying to basically use the data we've collected to figure out what the next big step will be.

And we are learning how to listen to our stakeholders and our critics. We don't know it all, sometimes we don't even know what we don't know, but we are listening.

Again, a little context. I just want to set this context. ILI is not the only part of IMP, of course. They are important, but they are not the only part of the successful integrity management. We must continue to address prevention, mitigation, and direct assessment.

I just want to end back on this page again because it tells a positive story of improvement. Based on the efforts of the pipeline industry, government, and others, we've been able to achieve these results.

Thank you.

(Applause)

MR. KADNAR: Guess what? We are already behind schedule, and I think you should keep your questions for the experts, the pipeline operators and the inline inspection vendors and the standards developers.

So now I would like to invite the next panel on the stage. They will be talking about their best practices, and Mr. William Gute, the OPS eastern region director, will moderate that panel.

Panel: Inline Inspection Practices and Data Management Strategies

William H. Gute, Moderator

MR. GUTE: Good morning. My name is Bill Gute. As Joy said, I'm the eastern regional director of Office of Pipeline Safety, and I'm the moderator for this panel, which is called Inline Inspection Practices and Data Management Strategies.

I think we have a real good panel today. We have a diverse panel. We have a liquid operator, we have gas operators, and we have a consultant. I'm going to introduce them and give them a little background, and then I'll call them up to speak. Our first -- and you can raise your hand, I think.

Dave Bowmaster is our first panel master -- panel master.

(Laughter)

MR. GUTE: That's a tricky name -- our first panel member. He's from El Paso. He's going to talk about ANR Pipeline Integrity Management Program.

He has been in the industry since 1978, and he's been the director of their integrity program and corrosion program and nondestructive testing program for the last few years.

Our next panel member is John Godfrey, who is now from Explorer Pipeline. Prior to working for Explorer, he had, I think, about 18 years with Colonial Pipeline, and he's had all sorts of experience with Colonial, from tanks to pipeline integrity management. So he's very good and very knowledgeable.

Next is Andy Drake from Duke Energy. Andy has been with Duke for I don't know how many years, but many years. And he's been involved with their integrity management program since it started, and he's been involved with many of the industry and government programs that have helped our standards and our rule.

Finally, we have Eydstein Egholm, and he is from -- well, it's DNV. I'll go with that.

(Laughter)

MR. GUTE: It's, I think, a company from Denmark or Netherlands -- where? Norway? Norway, I'm sorry.

And he -- most of his work has been in Europe, but now he's based in Houston, and he'll be our last speaker.

So, with that, I think they will cover a couple things. They will cover how they meet the requirements of the IMP rule, tool selection, discovery of flaws, confirmation of signatures, quality control and verification, data integration, and individual company practices.

So, with that, I'm going to turn it over to Dave Bowmaster.

(Applause)

ANR Pipeline: Inline Inspection Program History

Dave Bowmaster

(PowerPoint presentation)

MR. BOWMASTER: Hello. Let me get my blood pressure in order here.

I think it's probably no stretch to say that everyone -- all of the pipeline operators in this room probably had some form of pipeline integrity management program in place even prior to the passage of the Pipeline Safety Act of 2002. In fact, I was a little surprised and I was a little embarrassed when Joy asked for a show of hands on the people here who are pipeline safety advocates, that we should have all raised our hands, including me. I think we're all advocates of pipeline safety.

But those programs of all -- many of those programs relied on different aspects of -- had focused on different things. I know in the El Paso Pipeline Company we had some programs that relied heavily on internal inspection, other programs that relied heavily on our corrosion protection programs, and some programs that relied heavily on pipe replacement. Those have all been combined now into one consolidated pipeline integrity program.

What I've been asked to do today is talk briefly about the ANR Pipeline Integrity Program, and the primary reason for that is it's probably the most mature of all of the internal inspection programs that we have implemented at this time.

Let's see. Let me go to the next slide.

This is, you know, the obligatory map of the El Paso Pipeline systems. These are all the facilities that we have responsibilities for pipeline integrity management. Some of them we have direct responsibilities: Tennessee, CIG, ANR, El Paso, and Southern Natural Gas Company. Others we're joint venture -- we have joint venture interests with other pipeline companies.

The pipeline system that I'm going to be talking about today is the ANR pipeline system, which gathers gas in both the mid-continent and Gulf Coast areas of the United States, transports it to customers in -- primarily in Michigan and Wisconsin, and has a significant amount of storage activities in Michigan.

The ANR program -- the internal inspection portion of the ANR integrity management program formally began in 1984. This particular piece of the program and what I'm focusing my attention on today is that part of the program that was designed to address metal loss as a threat to the pipeline system.

At the time the pipeline -- at the time this program was put in place, it included all of the ANR system -- all of the ANR onshore system for internal inspection and pipelines greater -- 10-inch and greater in diameter. It did not focus specifically on HCAs, but instead they elected to inspect the -- all of the system that they were able to inspect with the tools that were available at the time.

The -- I was not at ANR at the time, but I have spoken with some of the individuals who participated in the formation and the development of this program, and they spent a great deal of time trying to determine what the best approach would be: would they install permanent launchers and receivers so that it would be easy to reinspect the pipeline at a later date; would they go with temporary launchers and receivers.

After a lot of discussion, they did decide that the best approach for them to take was to install permanent launchers and receivers and to develop reinspection intervals based on the findings of the inspections that they made.

As you might expect, a lot has changed since 1984, and so this program has evolved over the last 21 years to what it is today. And I bring that up -- you know, the obvious -- one of the obvious changes is that the tools have improved. We've gone from standard resolution tools to our -- the tool of choice today is high resolution tools.

But I went back and tried to spend a little bit of time thinking about what 1984 was like when I was putting this presentation together. Just to give you a little bit of an idea of, you know, data integration changes, I don't know about the rest of you in this room but when I go home tonight I'm going to have to turn on my computer, I'm going to have to do my e-mail, I'm going to have to prepare for some other presentation sometime.

In 1984, I bought my first PC. It was a Commodore 64. I had to pay a long-distance telephone bill. I lived in Midland, Texas. I had to pay a long-distance telephone bill in order to be able to connect to a telephone number in Lubbock so that I could get online with Compuserve to have my first online experience, which was the equivalent of a very slow, over a 75 bod modem. So there have been a lot of changes in what we're able to do with the data that we're collecting today.

The methodology that ANR applied at the time they put the program together, and it's much the same today. They did use a risk prioritization index to determine kind of the schedule of events, kind of the schedule of inspections that they were going to make.

And then, after they made inspections, they went over that information and established their own reinspection intervals. They did integrate all of the information that they had at the time, and as you can well imagine, in 1984 a lot of this was done on paper spreadsheets and from paper records, all of that which now is in GIS programs and large databases.

But they looked at all of the, you know, leak histories of the pipeline, what coating type the pipelines had, what the construction practices were at the time those pipelines were built, the CP records, the class locations, and hydrostatic test history. These are just a few of the things that they did incorporate in their initial risk prioritizations.

We believe that the remediation actions that have been taken on ANR Pipeline both historically and today were reasonably conservative.

The reinspection intervals -- again, the reinspection intervals were determined by the engineers who were working on the program and reviewing the data that was collected from the internal inspections, and then they established reinspection intervals that they felt were appropriate.  Those reinspection intervals were typically 12 to 14 years.

There were few pipelines -- and I'll show you a little bit here in just a moment.  There were a few pipelines that they felt like they needed to accelerate the reinspection intervals, and some of those were as short as -- recommendations were as short as five to six years.  They also used that information to determine whether or not there were any other actions that they felt they should take.

The progress to date on the ANR Pipeline system.  We've -- oh, and I failed to mention we have subsequently changed the -- from all pipelines 10-inch and greater onshore to all pipelines six-inch and greater onshore.

To date we've inspected about 93 percent of all of those onshore pipelines that are onshore -- yeah, about 93 percent of it is piggable. We haven't necessarily inspected all of the smaller diameter ones yet.

We've inspected over 8100 miles -- that's 93 percent of the onshore six-inch and greater -- has been inspected one time. We've inspected over 6400 miles of pipeline on ANR's system more than once, and 2100 miles of that system has been inspected more than twice.

We were looking at some of the data that have been collected over the years to try to see if we could show the continuous improvement that we think has occurred on the pipeline system, and we looked at 169 different pipeline segments that had been inspected at least once and in some cases as many as four times. Eighty-one of the segments were inspected once, 72 twice, 23 three times, and three of those 169 sections have been inspected four times since the beginning of the program.

In each case, in each one of these groupings, we have seen a reduction in the number of digs that have been done post inspection from the number of digs that were done in the first inspection. So we've seen a continuous improvement in the health of the pipeline system as we've progressed through the program.

The big punch line in all of this -- and I'm just superstitious enough. I'm always nervous when I talk about this last bullet. But the fact of the matter is, since ANR began this program in 1984 they have not had a corrosion-related leak from either -- caused by either internal or external corrosion on any pipeline that they've inspected and remediated. We feel like that's a clear indication that the program works and that we're finding potential leaks before they become leaks and that they're being corrected in a timely manner.

The conclusions that we drew when we were putting this presentation together is that internal inspection for the purpose of finding and controlling metal loss anomalies is an effective and proven technology. Our feeling is that the vendors that we use that supply data to us provide reports that are clear and that they provide us good and useful information.

We also believe that the reinspection intervals that ANR put together based on sound engineering judgment and knowledge of the -- of both the pipeline history and the results of the inspections was successful in dealing with the metal loss program at ANR.

We do this in every financial meeting I go to. While past performance is no guarantee of future success --

(Laughter)

MR. BOWMASTER: -- a well managed internal inspection program utilizing sound engineering practices we believe has been successful in addressing the internal and external corrosion threats on ANR's pipeline system.

I think that's it. That's it.

(Applause)

Quality Assurance: Hazardous Liquid Pipeline Perspective

John Godfrey

(PowerPoint presentation)

MR. GODFREY: Well, that's a fatal mistake, allowing me to introduce myself. We just ran over time again.

(Laughter)

MR. GODFREY: No, seriously, I'll keep it down.

Good morning. As Bill mentioned, my name is John Godfrey, with Explorer Pipeline. And what I want to talk to you about today is liquid operator pipeline experience and practices as it relates to internal line inspection.

You'll note on the left-hand side of my slides that we're repeating the graphs that Peter showed you earlier. This is on purpose. We want to emphasize that internal line inspection has contributed greatly to the liquid pipeline industry record both in the reduction in the number of leaks and incidents but also, to address Mr. McCown's comments earlier, it's helped to improve the reliability of the liquid pipeline system.

Safety is good business. You cannot transport refined petroleum products or crude oil safely -- or, reliably without doing it safely. So we want to make sure we make that connection, that safety really is core to our business. It is important to the liquid industry.

For the purpose of this presentation, I've simplified the ILI inspection process down into five steps. And these are my five steps, not to be confused with anybody else's.

But first in our process is to identify the risk factors or threats that the individual pipeline segment to be inspected faces. The second is to target the ILI technology, choose the right tool to fit those risk factors.

Third step, from an operator's perspective -- and this is an operator's role -- is, how do we receive and validate the ILI data. How do we make sure that the ILI data matches our expectations and meets the performance standards we set forth when we started the inspection process.

Finally, how do we integrate the data we receive from ILI. How do we combine it not just with previous inspections and other current inspections from a single tool or a suite of tools; how do we integrate it with other available data to get a more complete picture of the pipeline's integrity.

And final step is, provide performance feedback to drive continuous improvement both internally within our companies and externally with our vendors and with other agencies.

Before I discuss the internal inspection itself and the resulting data, we must understand the risks that individual pipeline systems face. Prior to any inspection, a pipeline operator should evaluate the risks to their system. This information may come from risk assessments, maintenance records, failure history, or the knowledge and experience of the personnel at the operating company.

Equally important to understand is the

industry experience. As pipeline operators, we are not trying to be reactive. ILI is not a reactive process. We need to understand what the potential threats are. We need to anticipate what the threats are. We need to learn from other operators' experiences through forums such as this and through other information that's publicly available to anticipate what the risks are, in addition to just reacting to what we've already seen.

Some of the most common threats that have been addressed by liquid operators through the ILI process include mechanical damage; third party damage and construction-related or outside force damage; deformations, buckles, dents, wrinkles; and also included in this, earth movement, subsidence or seismic activity that changes the orientation or the location of pipelines; and finally, certain types of seam integrity issues can be addressed through ILI.

In addition, and mentioned previously, internal and external corrosion, and as an evolving application, stress corrosion cracking and the ability to see certain types of SCC and -- in certain alignments has proven successful through the ILI process.

There is other valuable information that can also be obtained through ILI as well, and that's the alignment of your pipeline, center line alignment, as well as cataloging and documenting appurtenances, the features on the pipeline. Particularly with a lot of older systems and systems that may have changed hands through mergers or acquisitions, this provides a valuable tool to go back and update our construction records and update and validate where we happen to have branches, Ts, and other appurtenances on the line.

So now that an operator has gone ahead and assessed the risks and the risk factors associated with their segments, the operator needs to choose the best platform to identify those risks and to conduct the inspection. It's these risk factors that drive tool selection, and one of the most important factors here is a common understanding of tool performance.

And I'm happy to say that API 1163, which Peter mentioned was published just last week, provides operators guidance with how to choose the right tools for a particular inspection. More importantly, it provides some standardization around performance reporting. For an operator to choose the right tool for an inspection, we need to know how that tool is going to perform. We need to be able to compare apples to apples so that we know or can expect to get the most reliable data for the risk factors that we face.

We also need to consider excavation criteria and repair criteria. What is your corporate philosophy around excavation and repairs. To what extent are you going to remediate the pipeline above and beyond rule requirements. That also has a factor in choosing the right technology or the most appropriate technology for your inspection program.

We also need to consider reinspection intervals. Will this ILI run contribute to a body of knowledge that will help justify an analytical reinspection interval. Are you looking to measure the growth of anomalies. Are you looking to identify or validate your risk assessments. Are you using this data to feed back into your overall integrity program in a constructive way to assess when you need to go and look at that segment again, and are you choosing the right technology to support that. So these are all just considerations in choosing the right tool before you even put it in your launcher.

And finally, evaluate evolving technology. ILI technology continues to grow. New tools are available almost every year, and existing tools are enhanced either through improved sensors, improved data storage capacity, or through software that allows you to view the tool data and to better interpret the tool data. Evaluate that technology as you're assessing the risks and what you plan on getting out of your inspection.

And there's another consideration here that's just as serious but isn't included on this slide. Consider the operational impacts to your pipeline system as you choose your tool selections. It's important that we understand how tool -- required tool run speed, first run success rate, the range of tool, data acquisition, and/or specific product requirements impact your operation. Again, it's to provide a reliable supply to the marketplace and how does the ILI itself impact your pipeline operation.

Once the ILI is complete -- and this isn't to diminish the vendor's role in performing the inline inspection or how the tools operate. I believe we'll be hearing from a vendor panel later today to discuss that. But again, the focus is on the operator side.

What should the operator consider when receiving and validating ILI tool data. Well, we look to the vendors to provide consistent data interpretation and reporting. This is aided by the ongoing ASNT effort to qualify vendor personnel and personnel who review ILI logs and provide data output.

But it's important for the operator to get a good understanding with the vendor on consistency of data to ensure that we get accurate interpretations.

We also need to make sure that we accurately integrate pipeline data. Alignment sheets, AGM locations, other attributes and features that are known prior to the inspection should be integrated during the initial draft reports and prior to final reporting so that we know where those features are and we can align those with the data from the ILI.

And just as importantly, we need to work together with the vendors to resolve all discrepancies during this process. We need to be able to identify and have an open chain of communication. Identify where those variances exist. I see something here I don't see on your alignment sheets; help me understand. And we need to be able to work through them through this process so that we can get an accurate representation of what's out on the line.

From an operator's perspective during the receipt and validation of tool data, we have a role in that process as well. We need to go back and compare it to any previous inspections that we may have done. Is that repair sleeve in the ILI log? We repaired and recoated this feature over here. Is it accurately represented?

We also know -- we also need to go back and look at specific call-outs. Is there something in the initial data that doesn't look right. Nobody wants to leave immediate repair conditions on the pipeline. None of us want to be faced with a condition that's an imminent threat and wait for something to happen later. We want to know where that is and we want to be able to respond to it as a prudent operator.

A lot of that comes into specific experience and judgment. We cannot diminish the operator's role. They are the best people to know the condition of their systems. They know the operation of their system. Your experience and your judgment should play into the validation of the data. Take a critical look at that data when it comes in. Does it match your initial risk assessment, does it identify the specific threats you were looking for, and is the tool performing to the performance specifications you laid out to address those threats.

Data integration. We do not have time to go into more than one slide on data integration today. This could take an entire day's forum to discuss the various ways to integrate data from ILI and various sources that can be brought in, but I did want to mention a few specific things.

The data integration should focus on those risks that were previously identified in your pre-assessment. The list of potential data sources is large, but some of the things that can be brought in are corrosion data, either from annual surveys or close-interval surveys; GIS data, land use, population, foreign line crossings; additional right of way data, density of One Calls, recent activity along the right of way, aerial observation reports; and pipeline attributes not previously included in the validation process, but are there more features out on the pipeline that you need to integrate that give you a better understanding of the condition of the line.

Often it is the integration of ILI data that provides us the most complete picture of line condition. No single ILI run by itself gives you a complete and total picture of the condition of your system. It's an experienced operator working with a qualified vendor that provides good, accurate data that can be integrated across your full range of available information that gives you your most complete picture about the quality of your system and the threats that you happen to be facing.

Regardless of the type of tool you run, the number of tools that are run, or the vendors, an operator's data integration process is key to really understanding completely what the condition of the pipeline segment is.

I'm getting close to the end now. One of the last -- the last process step, or the fifth in my short process, is performance feedback. Guidance, again, is provided in 1163 on communicating back to your tool vendors and tool vendors communicating with the operators the actual results of the inspection.

It's important that we take this into account as a continuous improvement loop. As Joy's slides pointed out, we need to understand how well did the inspection meet the requirements we initially set forth; did we get the results that we were intending to get.

This is both internal communication and external. Our field crews need to communicate back to our ILI department. What are we finding in the field. We need to review and validate that information. We need to make adjustments into our excavation schedules as necessary to make sure that we capture all of those conditions that we're after.

Finally, in conclusion, as the graph on the left-hand side of the slide shows, current technology has produced significant performance improvement for the liquid industry. We have seen a decrease in the trend in the number of incidents and severity of incidents. We're seeing the pipeline systems becoming more reliable. We're seeing better business as a result of improved inspection techniques.

But technology enhancements will improve our capabilities. We recognize that there are new and evolving threats out on the pipeline system, and we need to evaluate new technology as it comes to market and we need to address those threats as we identify them.

We also note that developing standards such as 1163 help us improve the communication between operators and tool vendors. It helps to improve the standardization of tool performance reporting as well as data reporting, and it provides performance feedback both internally and externally to the vendors so that we can continue to understand the strengths and limitations of ILI and we can continue to apply ILI to address the threats that are most significant to our systems.

Thank you very much.

(Applause)

MR. GUTE: Our next speaker will be Andy

Drake from Duke Energy.

Quality Assurance of Inline Inspection Programs:
Natural Gas Pipeline Perspective
Andy Drake
(PowerPoint presentation)

MR. DRAKE: Good morning. It's good to see so many people here. I think that's just an indication of how much interest everybody's got in implementing these programs and the impact on our business and the regulatory involvement in this issue. I know that it's certainly probably an indication of how many of you are active in doing your programs, and I'm sure many of you are finding that Rolaids is now a food group in your diet but -- as you try to get these programs instituted and put into place and deal with your upper management on costs and trying to make good choices.

As I think about the programs that I just heard literally for the first time, it's amazing to me to see how much common ground there is between these three programs that were developed basically independent of one another. I think that bodes well for a process that we've been instituting in how we roll out integrity programs fundamentally.

We came together as an industry and we went through a rigorous process of trying to define best practices and instituting that knowledge and technology into standards that can be extrapolated into regulatory guidance and in an effort to try to help us see what is that elusive commodity of good judgment.

There we go.

The obligatory system map. That's the Duke Energy Gas Transmission U.S. operations map. It's comprised of several different systems of varying ages and varying different terrains. Constitutes a little less than 12,000 miles.

We have been active in inline inspection since 1968 and have about 15,000-plus miles inspected to date. Many of our pipelines have been inspected two, sometimes three, sometimes four times. Virtually all of our main line systems have been inspected, and we've got a -- obviously, we've been drug through the knot hole backwards on what you learn in going through that much data.

I, like Dave, remember sitting in the back of trucks reading logs on sheet tapes, trying to figure out what logs are. Now we sit down with computers that I don't even know how to turn on, sit next to technicians that are reading colored things that I don't even really understand, but they look like some sort of indication of a hole or something, and a change in oil thickness. But the technology has really, really changed radically, and the value that we can extrapolate that has changed radically, too.

We went through a rigorous program in the mid '80s and into the early '90s where we literally excavated thousands and thousands of anomalies and remediated those sites and got quite a learning curve on tools, tool availability, how to calibrate logs, how to run tools, how to work with vendors and how not to work with vendors.

In that time period and over the period that I've been involved in it, we've run all kind of different tools: I mean, caliper tools, geometry, slope deformation. We've run high- and standard res, MFL tools, hard spot tools. We've run the TFI IMAT tools, elastic wave tools in gas trying to look for cracks, all with varying degrees of success, all looking for different things, all with an intent and purpose of trying to make good choices about integrity.

And I think the interesting thing there is, with all these tools of choice, I think we do have to fall back to the standards that are in place to help us guide -- what are we looking for? -- to help us guide our tool choices as best we can.

There -- this isn't something we have to start from scratch in. I think the ASME documents and some of the new API and NACE documents help us in those regards, and if we use those criteria, we will make good choices. But I think fundamentally one of the underpinnings of this is that we don't take a minimalist approach and just look for metal loss. These tools generate all kinds of signals, and I think it behooves all of us to make the most out of those signals that are being generated.

In our program, the ILI objective is to foster well-educated decisions about integrity. I think that sounds like a lofty, nice thought, but it doesn't -- it really changes the course of our program, or sets our tack, and that is, it's not about just looking for metal loss. You see, it doesn't say that up there anywhere. It says, help us make good choices about integrity.

The tools are not a silver bullet. They don't find everything you run into. It doesn't magically heal the pipe and all of a sudden everything is great again and we can just go on about our merry way. We actually had to roll up our sleeves and really make these things work for us.

The vendors are there to help us, and I think fundamentally we need to synchronize with them. They are an integral part of how this works. And inside the minds of their technicians and their insights on their tools, capabilities, limitations, tolerances, and the insights of our folks' heads of operating issues and events that have happened in the field and where are foreign line crossings and where was so-and-so digging a couple years ago, a subdivision that was built, if we can integrate and synchronize all that information, we can really extrapolate a lot of value.

I think that's the key. It isn't really just about, "Show me where all my metal loss indications are." That's interesting. That's just the very minimalist of what it can accomplish.

I think we need, as the other speakers have said, to use tools appropriate -- use the appropriate tool given what you're looking for. Choose wisely, so to speak, and use the tool appropriately. They're great tools, and try to get as much information as you can out of them.

I think the bottom line, and this is a fundamental underpinning of the standards development process, is that pinned the foundation for the integrity rule itself. That is, try to be comprehensive, systematic, and integrated in the things that you do.  Those things will serve you well as you try to make choices on your programs.

Specifically, our program involves vendor qualification programs.  If these guys are going to be integral to our success, we need to know who they are and we need to know what they can do and that they have good processes and that they're capable of executing what the contract is going to obligate them to, literally.

We have established procedures on what we expect out of them in addition to the contract and try to communicate very clearly to them what are our expectations of them and what are our expectations of us in reporting, time frames, accuracy, validation, all those kind of things.

We also have pretty specific procedures on how we calibrate the log, how we mark the line, where we use AGMs to decide where we are accurately down the pipe, how we calibrate inside the AGMs where the findings are so that we don't just dismiss something as an anomaly that we couldn't find.

We try to get a comprehensive find report, as I said, to get as much information as we can out of that.  We're not just asking for metal loss indications.  We're actually asking for all indications of possible defects, that they give us that and then we try to decide. Things that they can't provide disposition on, then our folks, our engineers, roll up their sleeves and try to augment their insight to close disposition.

How we verify and calibrate logs. Typically, first-time runs we actually go out and excavate at least one, if not more, anomalies. That will depend on a communication with the vendor about tool speed, where they were, how they felt on their tolerances throughout the run, did we lose any channels, where were we, how many can we tolerate.

On subsequent runs, fortunately or unfortunately, we have typically had anomalies that have been investigated and recoated and back-filled, and we gauge off those anomalies. So we size off those, and oftentimes we don't need to make as many, if any, excavation validations.

The key really is looking back at data integration, looking back at old ILI information, operational data, vendor information, tool speed, tolerances, trying to make good choices about what that log and that extrapolation from that log is telling us.

Try to get as much feedback as we can from our vendors, and we try to give them feedback to them.

It really is a partnership, and it's a performance-based partnership. We're trying to work together to accomplish a goal, and we work well together as a team. And that team needs to synchronize and communicate with each other as well as they possibly can.

It's not just a contract: here, do this, send me a report when you're done, see you later, I'll bid to you next year. It doesn't work like that. At least it doesn't work very efficiently.

At the end of each year, we sit down -- actually, at the end of each run we sit down with them and gauge what they predicted based on what we find when we go out and excavate, and then they take that back in and use it to recalibrate their projections. So they're continually sharpening their algorithms, and that's worked very well over many years.

And obviously, we've been involved in pigging for 30-plus years. We've seen the technology change a lot. We've been pushing that. These guys down this table have been pushing that. Many of you have been pushing it. I know the vendors have been pushing it. And it has been changing and much, much, much to our value.

I think we've talked a lot about standards, and this -- maybe the use of these standards can help quell some of your need for the food group of Rolaids. But good judgment is a pretty elusive but much required commodity in this transaction. It's very subjective. We're trying to provide some clarity, and that's certainly why we're here today. We're just trying to find out, what are people doing that seems to be working for them. And then, how does everybody else take that home to do something with it that's actionable and consistent.

And I think, like I said, with the development of the integrity rule, the industry worked together with the vendors, the technical communities, the research community, the regulatory community, to extrapolate technology and science and practices into some kind of clear, executable in the form of a standard, and those standards have now started to pour out. Certainly, ASME B31.8S is one. There are many API documents. There are NACE documents on DA, yada yada yada.

Well, recently, the industry just released three new standards, literally just within the last couple weeks. These all relate to inline inspection. They are an amalgamation of discussions about practices and protocols, how to execute this kind of work. I think it behooves all of us to get fluent in these standards because they define what is good judgment on how to execute this kind of work, just like the S document did on integrity management.

I think there will be others that talk more in detail about these three standards, but I really think it just behooves us all to become fluent in them because this is going to be the benchmark of judgment.

My conclusions. I think to maximize the value of the ILI efforts, industry, including OPS and the vendors, has committed to these standards development processes. That's been very healthy, a very healthy exchange on all of our parts, to understand what is practicable, what is real, what is technical, what can tools do/not do, what causes these problems and how do we work on them. If we come to that common understanding, then solving this problem won't take nearly so many Rolaids.

I think national consensus standards on the ILI stuff are now just being released. But the industry as operators can only push that so far. I think the regulatory community has to, as they have in the past, help foster the dissemination of those standards to help communicate judgment, practicability. And I think that maybe that can be done through some kind of advisory bulletin to help disseminate it to the many operators.

The guys and gals that are here, we're the diligent ones. You're trying. We're all trying to find out what good judgment looks like, what is good practice. There are 700-and-some-odd interstate operators in the United States. There aren't 700 people here. I know there's three or four from some big companies right here altogether, so that probably means there's only a handful of operations here, really.

It's the ones who aren't in this room that cause a lot of the angst, and I think we have to figure out how to talk to that group. And I think we've got to really lean on the regulators to help us communicate with that group because I don't even know their phone numbers or addresses. They don't show up to the industry meetings.

Continue improvements of process. I think that we fundamentally have embraced this. These standards don't solve everything. They're a good starting point. There are some things left to do, sure, yeah, always are. It's a process, a systematic process of working off the biggest things, come back around and see what's not working, work on the next biggest thing. You're just taking performance evaluation and feeding it back in, and you keep turning the crank.

There are some expectations on good judgment. I'm certain there will be some issues and gaps clarified in these standards. There will also be some gaps identified in these things, and I think the key is that we just kind of work together to define how do we improve them and work together to close those gaps and mitigate any subjectivity on what good judgment looks like.

That's my presentation. Thank you.

(Applause)

MR. GUTE: Thank you.

And our next speaker will be Eydstein Egholm. That's DNV. We don't have to pronounce it, so. And that's how they actually do their business.

So he's getting set up, so while he's doing that, I think we're going to have time for questions after our panel. So maybe in 10 or 15 minutes, so start thinking.

ILI Results and Best Practices

Eydstein Egholm

(PowerPoint presentation)

MR. EGHOLM: Well, thank you. As he said, Eydstein Egholm with Det Norske Veritas, called DNV, yes, for easy reference. Thank you for the opportunity for us to present to you as well. We're not going to talk very much in detail about standards.

The focus here is on how to improve the use of ILI and get the most out of the good information that's collected in a pig run. I think you need a short introduction to DNV and what DNV does with ILI results. We are not a pigging operator or a pipeline operator or an ILI vendor. And then I'll talk a little bit about the concerns and challenges that we have notified -- noticed with the work that we have done on looking at ILI results and some of the best practices and suggestions of those that we can see.

I just want to point out that the majority of, you know, what this presentation is based on comes out of other places instead of the U.S. It's mainly Europe, Middle East, and South America. DNV does about 30 pipeline assessments per year.

It's a worldwide company. Our headquarters is based out of Oslo, Norway. We have offices around -- about 300 offices around the world in 100 countries and a total of about 6400 employees. We have four main business areas. Just briefly, those are certification, consulting, and technology services. Underneath the technology services part, we have a group, a small group, of pipeline experts that focus on design of pipelines and -- operation.

Our main focus until recently has been offshore pipelines; however, the focus has increased towards the onshore pipelines and particularly for the operational phase, which is in line with what the topic of today is.

We do author standards and recommend good practices and published several standards around the world which have been acknowledged by regulatory authorities. Typically, we develop these standards in cooperation with the international industry and use joint industry projects and research projects as the basis for developing knowledge and/or getting consensus around pertinent methodologies and technology and issues with these standards and practices for use in the industry.

We have membership of many international organizations, API and ASME and so forth. We find that several of our standards are actually used quite a lot around the world.

Now, what we use in ILI is the results for, as I guess most people use it for, is assuring the fitness for service and pressure-carrying capacity for pipelines as part of pipeline security control. We consider the ILI as one source of many information sources to control the condition of pipelines.

Now, the work that we do in looking through those results is typically in relation to the operators' work on the contract with operators. We review their ILI reports for correctness and data information correctness, consider the ILI results in relation to other kind of information elaborated in the presentations before: encroachment monitoring models and information, predictions, findings on that, as well as the process parameters and products, quality control, plus inline inspections that were done in the past, digs and any inspections that were done to verify the information.

We also evaluate the traceability of the anomalies that are found, location of defects, try to measure -- build the confidence in the measurements, take account of the measurements of error and classification of defects, assess defects according to our own recommended practice -- we'll go back to that in a second -- and look at the interacting and complexly shaped defects. It helps also to determine repair and remediation strategies that the operator chooses to follow. It depends on what tolerance they have towards risk and others, what kind of regulatory requirements they have to meet.

Look into the assessment intervals or inspection intervals, and they use very much a risk-based approach on that, and help assess the overall pipeline condition.

Just briefly, on the defect assessment, we use the Recommended Practice F11, Corroded Pipeline -- for Corroded Pipelines that was published in '99 initially, revised and updated in 2004 with the help of several companies, regulators, and ILI vendors.

Now, this code was actually developed to take account for measurement uncertainties that you inherently will have with the ILI tools, and take account of the benefits that you get if you have more accurate information. In the fact if you have more accurate sizing of your defects, you can tolerate a relatively higher pressure -- operating pressure.

We see this standard very much as an extent to the existing codes that are out there: ASME, Shell, and -- and the standard here was developed as a joint industry effort with contributions from operators, owner-operators, and vendors and regulators, as I mentioned.

We have a tool that we developed as part of that to capture -- we realized there's a lot of information, a lot of data to keep track on over time, and this tool is to capture and assess and manage inspection data.

The comments that we see in relation to ILI results -- I mean, there's a tremendous development that happened over the last many years, and the operators have emphasized that. I mean, more technologies have become available. It's now become a very trusted set of -- trusted way of doing inspection. So we see it as a very important source of information for the condition integrity control of both onshore and offshore pipelines.

The ILI results or data that's collected on offshore and onshore pipeline is very similar. There's very little difference in that.

We see also that the tools are very good, which is pointed out several times here. But the interpretation of the results may be less consistent or reliable. It is an indirect method, so it requires analysis interpretation -- realize that -- which again requires expertise for the personnel that interpret the data. The turnaround time that we normally see is a minimum of six to eight weeks, but mostly it's more than three months.

The main concerns that we want to point out for ILI results were the reports -- well, I'll split it in several categories. One is the report -- the quality of the reports. We find very many, or several inconsistencies and erroneous information reports incompatible with the existing ILI data which is given, past inspection reference points, et cetera.

There are issues with the calibration, travel speed that's used, the temperature, the operating temperature versus the temperature used with calibration, piping condition. I've touched upon that before. It kind of builds the confidence in the results that you get for the ILI vendor to have good conditions to run the pig under. Calibration towards the pipe dimensions, and sometimes we find inconsistencies between the operator specifications and what was actually done during the pig run.

Another concern that we have is the overall confidence in the ILI results. You see the validation data that shows inconsistent sizing and the anomalies. Erroneous indications, which are numerous I can say. Erroneous characterization of the anomalies, which Joy Kadnar mentioned very early on today.

Inconsistent results for the same pipe. We have reruns. We find one thing during one run and it appears slightly different for the second run.

And defect location, lack of traceability. It seems that the -- point system which sometimes is used by the ILI vendor is slightly different than what's used by the operator. A little bit of miscommunication there. Nevertheless, it turns out to be a problem.

So, overall, what we want to advocate is that you need to have a higher confidence in the uninvestigated anomalies that are left behind, that are not checked out further in detail.

The challenges in the -- or, what we see anyway, is to improving the -- in order to improve the results, you need to improve the inspection and interpretation of the ILI signals and improve the confidence in the results that are communicated to the user or the operator, as well as for the -- on the user side, I guess once the ILI vendor hands over the reports or the results, the work starts for the operator to assess the results and implement them, or follow the -- or derive the recommendation out of the results.

So you need, in our minds, an effective validation of the data you receive, integration of supplementary information, which was talked about earlier, also, and corrosion monitoring activities and so forth.

You need effective data assessment and integrity control. So, in our minds, you definitely need to incorporate the measurement or error which the tools have. It's a challenge to make the right informed -- and informed decisions about integrity management.

Now, the suggestions we put on the top of the list for best practice relate to integration of prior knowledge, and I think that seems to be the ongoing theme through the presentations here. We need to start out -- in our minds, the operate -- the ILI inspection vendor needs to start out with a clear understanding of the inspection objective, using the past information, validated data and so forth, and results to define the deliverable for the inspection they are about to line up for. It's good instructions.

In order to prove the generation of ILI data and present them as results and reports, communication -- communicate valid findings to vendors as it relates to the performance feedback. That was mentioned earlier. Now I assume it's in API 1160. I'm not familiar with that in detail.

And, should require the ILI vendor to explain how the inconsistency will affect the confidence in the overall results in the report. After all, the ILI vendor will have intimate knowledge to the ILI data which he's collecting, under which conditions they were collected, and so forth.

Best practice in relation to condition and monitoring activities. I want to reiterate, you integrate information. Again, the operating parameters and general pipeline data. Monitoring activities and efforts that were initiated in the past. Past and present ILI results across ILI vendors, not keep the results only with one vendor. It needs to reside with the operator.

Suggest a more open dialogue between the ILI team and the user of the results. Find that very important. Discuss special anomalies, so special findings, as was mentioned before, whether you call an indication a T or a hole because of corrosion.

Potential erroneous readings, elaborate on that. Investigate, you know, what could the reason for -- find an explanation, basically. Sizing accuracies, et cetera.

We need to recognize -- everybody, I guess, needs to recognize that ILI includes a level of uncertainties. Nothing is absolute. As mentioned before, it's an indirect method and highly depends on the expertise that resides with the ILI team and the tools they use to interpret the data.

Investigate critical anomalies, we suggest that, and sample non-critical anomalies out to optimize the confidence in the cases that are not investigated or left out, basically.

Last here, in relation to the reassessment intervals, we would suggest to use an engineering criticality assessment and probabilistic methods which are widely used for other purposes in industry to optimize assessment intervals. Of course, this may require some independent validation, preferably by a third party to the operation. And qualify recommendation intervals -- or, recommended intervals by using a risk assessment, so they have a risk-based approach for how to determine your next inspection period, so.

That was it.

(Applause)

Question-and-Answer Session

MR. GUTE: Well, that's all our panel members. Do we have any questions out in the audience?

(No response)

MR. GUTE: I don't see anybody rushing to the microphone here.

That's fine. I might have -- are these microphones now turned on on the table here? Okay.

One of the questions that I might ask the panel members to ask is, under what circumstances would you determine that the pig run would be invalid? What kind of criteria do you kind of use to make that judgment? If I could -- John, you may want to start with that, and go right down the panel.

MR. GODFREY: Well, if I start, I get to choose the easy one, right?

MR. GUTE: Sure.

MR. GODFREY: So things like loss of sensors, damage to the tool, running beyond its operational window in terms of data capacity, speed, or temperature or other factors, those would be easy.

Andy, do you want the tough ones?

MR. DRAKE: Thanks, John.

I think there are a lot of nuances inside the envelope. You know, if any of those are encroached upon, I think the run should be invalidated, and it can include whether the pig was rotated or not. You know, oftentimes we get in a place where the pig gets in a bind and it can't rotate, you know, back and forth and some contact can invalidate a log.

And I certainly agree with all the issues about speed and sensors and all those kind of things -- damage to the pig, those kind of things.

MR. BOWMASTER: I really don't have a lot to add to those. Andy mentioned the orientation. That's one of the criteria we used. You know, I think that a lot of it is looking at the data based on the information you already know about the pipeline, too. And if you see any obvious discrepancies, that would certainly be an indicator that you had a problem.

MR. EGHOLM: DNV really only looks at the reported results. Obviously, when we go through the report and the data which was reported, we're trying to build confidence in the ILI results, and we make recommendations based on that confidence level to the operator. Sometimes they can end up, you know, disqualifying the run because the confidence is basically too low.

MR. GUTE: Okay. So, now, I think there are some obvious ones, but I think what I did hear a little bit was that it is important to actually go out there and dig up some anomalies and see how they're measuring up on the predictions. And if they're not really measuring up, that is a criteria.

It gets back into the communication back with -- between the operators and the vendors, also. I mean, that's something that we've seen, and we think it's very, very important. I believe the standard, 1163, which we'll talk about later, talks about that.

The other -- nobody up for questions yet?

The other question I might have is, you know, we have -- I think Andy mentioned that we have a very diverse size of operators. I mean, we have -- we use the term maybe improperly -- the mom-and-pop guys. They may only have like 10 miles of pipeline. And then we have 12,000, 20,000 miles of operator.

And I kind of wonder, I mean, the large corporations, they have -- usually have the expertise to help take a look at the logs and make some judgments. But I'd like to sort of hear, maybe, from the panel members on any recommendations they might have for the smaller guys out there on how to evaluate, select, and maybe that kind of feedback.

MR. DRAKE: Certainly there are -- engineering service companies out there. I mean, there are engineering service companies that come in and look at an operator's, you know, operating background, you know, certainly the lay of the pipe, the operating characteristics of the pipe, and how they interface with the vendor as a surrogate. They communicate the operating side of the picture to the vendor to help the vendor interlock with the operating attributes of the pipeline better.

It doesn't have to necessarily be the operator themselves. There are many excellent engineering firms out there with knowledge of that.

MR. GODFREY: I think another thing to consider with small operators is participation in forums such as this and other industry forums. This is a good way to gain information from other operators, from tool vendors, from engineering services companies to identify areas where you may improve your own processes and to network with people and identify resources to help people with those issues.

MR. GUTE: Any other comment? We do have a few individuals. Please state your name and your company.

AUDIENCE MEMBER: My name is (Name) from (Name). My question is, more than one speaker talked about choosing the right tool to get some reliable result. I think we need some more information about what we mean by choosing the right tool.

MR. GUTE: Okay. Who wants to try to answer that one?

MR. GODFREY: I guess I'll start. I'll start with the area of deformations because that has an impact on the large liquid lines, large -- liquid lines which I'm most familiar with.

If one of your largest threats are damaged buckles and other sorts of deformations, you need to look for a deformation tool that has a number of channels, the accuracy to be able to report across a wide range of geometries. You want a tool that can operate within the speed envelope of your pipeline system, your predicted flow rates, and also one that will operate well with your products to get transport that has the necessary wear capability and endurance to work through a system. A gas -- natural gas.

So when you're looking at -- if you're looking at a large line -- T ratio and you're really looking at complex geometry or deformations, you want to go out and you want to find a tool that can interpret all those things and give you enough data back that you can make informed judgments.

AUDIENCE MEMBER: So that's most likely the vendor's responsibility, other than the operator or the owner of the pipeline?

MR. GODFREY: No, I think the operator or owner needs to know what they expect to get out of the assessment. Are you susceptible to denting; do you want to know as much as you can about the dents. I mean, you have to build that into your specification.

And when you review the quotes that you receive back from your tool vendors, you need to be able to look into their standards performance, their performance specifications, and verify that it does meet your specifications.

It's always buyer beware. The operator always has to make sure that what the services they are procuring -- because we are buying data. That's what we do in this process -- is make sure that the data we buy meets our original intent.

AUDIENCE MEMBER: Okay.

MR. GUTE: We have another question.

AUDIENCE MEMBER: Pat (Name) with CC Technologies. First of all, I'd like to start off by saying that everybody in this room is willing to do everything that they can to avoid the next failure. There's no doubt about that.

The second thing is, is that we've seen a long progression of the use of inline inspection tools over the last 30 years, the use of deformation tools to find dents, MFL and ultrasonic tools to find corrosion-caused metal loss, and we've learned a lot from that and significantly reduced failures associated with those integrity threats.

We're now moving into a stage where we're extending the use of these available technologies to find other types of defects -- for example, the wrinkle that was shown up there earlier -- potential for finding existing mechanical damage.

We're now moving into the next stage, where we're getting new technologies. That is, the ultrasonic crack detection tools, EMAT, et cetera.

My question is, is the development or the evolution of the regulations and the current legal environment, does it suppress the development and use of any of these technologies?

MR. GUTE: Go ahead.

(Laughter)

AUDIENCE MEMBER: You know, I'm not sure if that's even a question that can be answered in five minutes, but I think as we go through the next couple of days discussing this that being involved in a number of programs with operators, we're dealing with information where we don't always have the tools to support that.

For example, with corrosion tools, we have the evolution or development of B31.G and other corrosion assessment tools. What criteria do we have whether or not a wrinkle or wrinkles may be acceptable in a pipeline, whether or not corrosion of -- is an issue. There are a lot of issues like that.

My only comment would be that I hope the regulations don't suppress the development of these technologies.

MR. GUTE: Well, I can comment. That certainly would not be our goal. I mean, we want the technology to develop. We are big believers in technology, and in fact, we have quite a bit of research money which we are jointly working with industry on some technology to improve pigging technology.

So that's not our goal, and hopefully we're not doing that.

AUDIENCE MEMBER: I agree, but I think there's -- I certainly support that OPS has certainly provided a lot of funding to further address these issues, but I think that there's more immediate concerns than there are long-term concerns. That is, we've had 30 years of development on metal loss tools. We have certainly learned a lot from that, and my point is, it's still going to take a little bit of time to start being able to fully utilize the new technologies.

MR. GUTE: I think we recognize that.

Any other questions? Let's start with the gentleman back here first.

AUDIENCE MEMBER: Charles Steadham (ph) with (Name). I had a question about -- is there a standard for pre-run cleaning of pipelines prior to ILI inspections? Have you thought of that? There has been debris when the MFL tool runs in our pipeline, and we want to know basically if you guys have criteria that you utilize before you launch your tools.

MR. DRAKE: We've got some books that are very tuned in on the standards themselves, but I know that -- many of the vendors we deal with have a pre-cleaning requirement for us prior to even sticking their tools in the pipe. They're even obligated to run dummy tools in front of their tools to make sure that they can pass.

But I know that inside the standard it does identify an issue that you have to have the pipe passable and clean to accommodate the pig. Now, what does that judgment mean I think is going to be a discussion between the vendor with regard to what they can accommodate.

MR. GUTE: Yes, sir.

AUDIENCE MEMBER: I'd like to ask a question of the panel. I'll excuse DNV because I already know that you take into consideration tool tolerance. But in your IM programs, do you take into consideration the tool tolerance in developing your dig program or do you take into consideration corrosion growth?

MR. BOWMASTER: What was the second part?

AUDIENCE MEMBER: The tool tolerance or corrosion growth.

MR. BOWMASTER: I'm not sure that I really know the answer to the tool tolerance question specifically. We -- as you heard the other panelists mention, we do everything we can do to validate the data that we receive back from the tool vendor by doing validation digs and comparing what we actually find to what was reported by the vendor. So I'm not sure if that answers your question.

MR. DRAKE: We actually -- in the verification dig, we use that to calibrate the duration of the log, and then we, in addition to that, consider a certain envelope of the tolerance, not 100 percent because it's sort of -- curve on their tolerance. We work with them to define where are we on the 90th percentile and then work in that range to consider the tolerance of the tool, and finally, make sure we're conservative. And we do consider corrosion in setting the excavation schedule.

MR. GODFREY: The short answer is yes.

MR. DRAKE: There you go.

MR. GODFREY: The longer answer is, we do consider tool tolerances in three different ways. First off is in the specification, of course, for the tool itself, to make sure that the tolerances that the vendor provides in their performance spec meet our expectations for the run.

The second is in our excavation criteria and dig list criteria. What are you going to excavate in the field, taking into account the tool tolerances there for broadening your range of excavations to make sure you capture everything within the envelope.

The third is really in the performance feedback period, the post assessment, or integrity assessment as we call it, where we go back and develop unity curves and plot field excavation results versus the call-out from the ILI vendor to make sure that the tool performed within its range or to adjust the dig list and go back and make sure you've captured what you're after.

And again, a lot of that information is very useful in going into your post assessment because it helps develop things such as corrosion growth rates, where you can substantiate it and roll it into your overall integrity management program, as I mentioned, to consider your reassessment interval as part of this process.

MR. GUTE: I think we have time for one more question. Then we're going to have to go on break, so.

AUDIENCE MEMBER: Two questions. I'm sorry. (Name) with (Name) Quality Services.

The first question is, there was a little bit of discussion about invalid runs. Just for curiosity, what's the ratio of valid to invalid runs which --

(Laughter)

AUDIENCE MEMBER: And the second question that sort of relates to this is, I'm sure, you know, there are many factors that can invalidate a run. How many of those are actually related to the data validation in terms of when you verify using the field data, and second, how do you consider the inconsistencies that might exist within the field data itself in that process? So, if you could please throw a little light on that?

MR. BOWMASTER: I don't know what the statistics are on the actual success rate on runs. I know it's a topic of discussion almost every time we meet with a vendor or any of our operating people or, for that matter, any of our commercial people concerning why we have to adjust the flow schedule on our pipeline system. I will say this. It feels to me that it's been pretty good and that it's proven.

What were the rest of the pieces of the question?

MR. GODFREY: I think another one of the questions, the two other parts, were around data validation and qualification, and the second one was considering inconsistencies in field data collection. And I'll touch on the inconsistencies in field data collection briefly.

Yes, it is important. It is important that an operator has processes, procedures, and practices in place for the collection of field data because garbage in is garbage out. You can't do an analysis of the quality of your ILI run if your field data is suspect.

Obviously, measuring the depth of the corrosion pit is one thing. Trying to assess the depth of a crack is another. So it is important that operators take that into consideration and that you do a thorough job of evaluating your field collection techniques, digging and collecting from the field, make sure you have qualified people there to do it so that you are getting a very good comparison. That needs to be part of an IM program.

MR. GUTE: Well, I think we -- Joy is coming here, and we're a little bit over the time limit. And we will have questions at the end of the day, so save those up, and the panel members will be around to answer them.

I want to thank the panel members very, very much for participating.

(Applause)

MR. KADNAR: I've got an announcement please. If there's any speaker who hasn't given his presentation to -- yet, could you please do it at noon?

And we'll meet back in 15 minutes. That will be 11:04.

(Brief recess)

MR. KADNAR: I'd like to introduce to you Mr. Chris Hoidal, PHMSA/OPS western region director. Mr. Hoidal is a veteran of the Pipeline and Hazardous Materials Safety Administration, and he will moderate a panel consisting of inline inspection vendors.

Chris?

Panel: Good Decision Making: Inline Inspection Vendors' Perspective

Chris Hoidal, Moderator

MR. HOIDAL: Good morning, everyone. Like Joy said, I'm Chris Hoidal. I'm the western region director for the Office of Pipeline Safety out of Denver. I have the pleasure of moderating the panel, the ILI vendor panel.

Over the last few years, there has been a lot of public dialogue between the operators, the operator associations, industry associations, and regulators, but not too often do we get the opportunity to listen to the perspective of the ILI vendors, particularly in the area of good decision making and how it relates to integrity management.

We're very fortunate today to have such an accomplished panel of experts from the ILI industry. I know they will provide a lot of good insight and recommendations on what ILI vendors and operators should consider when testing and assessing their pipelines.

Starting to my immediate left we have -- well, here's a change to your program. I'm sorry. Ken Maxfield has replaced Mark Harris, but Ken is from TD Williamson/Magpie Industries. Then we have Garrett Wilkie, moving down the line, from BJ Pipeline Inspection Services, Lisa Barkdull with Tuboscope Pipeline Services, Shahani Kariyawasam from GE Energy, and at the end, Bryce Brown from Rosen North America.

I believe that these presentations are going to be very interesting. In order to get them done and provide enough time for everybody to speak, we will be splitting this panel around lunch. Three of the speakers, Ken, Garrett, and Lisa, will speak before lunch, and the last two will speak right after lunch. So don't eat too much because I want you guys awake for the last two presenters.

Each of the presenters will cover an area of consideration that must be addressed by vendors and operators alike to ensure good assessment of their pipeline systems. Like the last thing -- like the last panel, there will be an opportunity for questions after all five panelists have presented.

The first person that will be speaking today is Ken Maxfield. He is vice president of operations with TD Williamson Magpie Systems. He has degrees from BYU and the University of Wyoming. He has 19 years of work experience in the pipeline inspection industry. He is co-founder of Magpie Systems. They were created in 1997, and in 2002, Magpie was acquired by TD Williamson.

Ken?

Data Quality Assurance and ILI Personnel Operator Qualifications

Ken Maxfield

(PowerPoint presentation)

MR. MAXFIELD: Thanks, Chris. It's a pleasure for me to be here with you this morning to be able to talk about something that I'm quite passionate about, and that is putting instruments on a pig and running it through a pipeline. I've spent the last 19 years working with pigs, and it's something that I enjoy doing. And this industry gets under your skin and it's hard to leave this industry.

So I've been assigned to talk about a specific topic dealing with data quality and inline inspection personnel. We could probably cover this topic in a couple of days if we dove into it in detail, but I have 15 minutes so we're just going to cover some highlights and hopefully just give you an overall presentation.

I want to cover four points when we talk about data quality. First we're going to talk about how data is collected in an instrumented pig, talk about how the data is analyzed, how we can use other sources of information, combining it with information collected by the inspection tools and putting that all together, and then talk about designing pipelines and the conditions that would allow you to collect data needed to do an assessment of a pipeline.

So, first, let's talk about collecting data. We as service providers are in the business of providing information. We sell very expensive data sets to pipeline operators. That is our main product.

Now, a lot of things go into being able to provide this information. We have to be designers, manufacturers. We have to be skilled in the mechanical engineering discipline, electronics, to put these types of systems together. Most of the service providers up here design and build their own equipment, and so we're very passionate about coming up with systems to provide information that is necessary to pipeline operators.

Let me say right up front that we are all driven by the free market system. We see needs and we go out and fill those needs, and that's what we do with these inspection systems.

These tools are designed to collect information about pipelines, and there's all sorts of different features of a pipeline that you can collect information about. There are mapping tools and deformation tools and metal loss tools and crack tools. These tools collect literally billions of pieces of information as they travel down a pipeline, and so these systems are very sophisticated and the advancement of electronics over the last 10 to 20 years has allowed these systems to continue to evolve until they are very sophisticated.

Another trend we're starting to see in the industry is combining technologies so that we can collect more than one piece of information about a pipeline as a tool travels through a pipeline. And so we try to design the tool to look at a specific piece of a pipeline, and we put that in a pig and run it down a pipeline.

We always strive to continue to improve our tools so that we can provide more information and better information. So we as service providers like to team up with pipeline operators. You have problems, we like to solve problems. The best customers that I have are the ones where we're actively engaged in solving problems and making it a win-win between an operator and a service provider.

And as we go down the road, we are constantly improving these tools. A question I'll often ask is, you know, how -- if we run a tool now and we run it in three years, are we going to get the same data; what happens if the tool changes? Our tools are always evolving.

I look back over our history, and we're updating electronics, we're adding more sensors all the time, and these have an impact on the data quality. We're hoping that we're increasing our accuracy, increasing the quality of the data year after year as we go through the process.

We like to talk with our customers about how we can make our service better, how we can provide better information. We're also noticing that sometimes we're hitting the ceiling on certain technologies. We've taken it to a level where we can make the quality of the data better but we can't make the quantification of the data better. And so we're communicating that with operators as well as we design these systems.

Our world is changing. We as service providers are about to have all these industry standards come out, and they will impact on us and how we conduct our business and how we design these systems, how we qualify these systems, how we run these systems through pipelines, and how we verify these systems. So our industry is at a crossroads right now, but I think it's for the better and I think going forward over the next few years that it will be a very interesting time.

So we have a couple of new regulations, API 1163 and there's a couple of documents associated with that, that are just coming, and they will impact us.

Let's talk about how we analyze data. We collect data on a tool. It's digitized in some format. Some tools are just data acquisition systems. They just collect data from sensors and store it digitally. Other systems are designed to do on-the-fly processing as they go down the pipe. But most information collected from inline inspection tools has to be evaluated by either computer or by a human being sitting at a computer. Most information now is digital, and most of the analysis is done on computer.

It is incumbent on us as service providers to hire and train analysts to look at this information. We're trying to extract parameters from this data and provide information about operating conditions of a pipeline.

So we as service providers have training where we'll bring somebody in and go through steps, evaluations, make sure that these analysts have the necessary skills to start looking at data. So as we go through that training process, they acquire more experience and are able to do higher and higher levels of data analysis.

We as service providers want to put out consistent information so that one pipeline segment has consistent features versus another. So we try to standardize. We try to put this information, this data analysis, through many quality checks so that our systems are -- so that the information we're providing to the pipeline operators is consistent.

Probably our most experienced analysts are the ones doing the final check. I can't speak for the other service providers, but our specific company, we put all of our data through three different passes or three quality checks as we go through the analysis process to make sure that we're doing things in a consistent format.

We also like a partnership with the pipeline operators. We like to make sure that our tools are providing the information that we say that they're capable of providing. We want to make sure that the information we provide is within specifications that we publish for our inspection tools. So a critical part of this process is to make sure that the information we provide meets the tolerances or the specifications.

That requires feedback from the operator. Many times we will not even be in sight, we won't know what is done with this information. But it's critical to make this system -- to have continuous improvement to get feedback so that we can improve the system. If we see that there are trends that we need to take corrective action on, we can do that. So feedback is a critical component of the data analysis process.

Our world is about to change with the passage of this ILI-PQ 2005 for data analysts. This is a document published by SNT that specifically deals with people looking at inline inspection data.

This is a double-edged sword. With this document, we as providers of inline inspection data are held to a higher standard. What I mean by that is, this new document is going to require analysts to have a lot of experience before they're capable of making judgment calls on anomalies in pipelines. The level of standard is above and beyond any other area of nondestructive testing in any other industry.

And so, as an example, the person looking at the X-rays on a pipeline weld needs about a year of experience to say whether that weld is acceptable or not. With this new standard, somebody looking at an MFL data set needs two years of experience to make calls on MFL data. So with this new document, we are holding ourselves up and applying a higher standard.

So it will change our industry as we go forward over the next few years as we implement these new recommended practices.

The third area is data mining. It's helpful to look at the big picture of a pipeline. I find it's interesting reading the news because it seems like merger mania is alive and well in the pipeline industry. As we inspect pipelines, the ownership of those pipelines changes hands on a regular basis.

Some of the older pipelines, the documentation is not very complete, and so we -- when we look at data quality, we like to gather as much information as we can about the pipeline from as many different sources and put all those pieces together. Combining all that information together helps evaluate more about what's going on in a pipeline.

So things we like to do, we like to look and see, has this pipeline had an inspection tool run before. If so, what technology was used; what was the results of the data; what is the condition of the pipeline.

Nowadays, many people are running multiple technologies through a pipeline. The inspection cycle is up, but they might be running three or four different technologies to get information about the pipeline. It's helpful to combine those different data sets together to help figure out what's going on with the pipeline.

Look at the repair history about the

pipeline. There are some repair techniques now that some inspection tools are blind to, so we don't know whether the anomalies have been repaired or not. And so looking at repair history is important as we piece together this puzzle of what's going on inside a pipeline.

And also, relying upon service providers' experience. As we inspect pipelines year after year, we generate huge databases of knowledge that we can apply as we look at new pipeline segments. It's always fun and challenging for analysts to go through a pipeline for the first time. It's always -- that next screen of information can sometimes knock your socks off of what you find. It's always a challenge to see a signal and try and figure out what's going on with a pipeline.

The fourth area about helping with data quality is pipeline design and condition. Before a pipeline can accept an inline inspection tool, it has to be designed to be able to insert it into the pipeline and get it out the other end and traverse the pipeline without damaging the inspection tool.

So there has to be some homework before an inspection tool is run through a pipeline. We have to decide can the pig or the inline inspection device get into the pipeline safely, go through, carry out the inspection, and get the required information that's necessary.

Repairing a pipeline has a huge impact on data quality and also first run success, so the more homework that is done up front, the better odds or chances of getting a good data set the first time.

We also have to look at operating conditions of a pipeline. This has a huge impact on data quality. Most inspection tools have specifications that are -- operating specifications that are necessary to meet. These might include temperature, speed. They might include the type of product the pipeline is running in, the pipeline material, the wall thickness, bend configuration. There's a host of different pipeline configurations that needs to be evaluated.

The other thing is the cleanliness of a pipeline. One of the questions we're often asked as a service provider is "How clean does my pipeline have to be?" That's a very difficult question to answer. It's easy to answer after you've run the pig, but it's hard to answer before you run the pig. So cleanliness can have an impact on data quality, and so we will look at that.

So, to summarize, our world is about to

change. These new specifications, industry documents, are coming. They will change the way we do things going forward. I think it is good change. I think it will help us elevate the quality of data in the future.

Our data collection is an ongoing enhancement process. I often lay awake at night trying to figure out how I can detect an anomaly in a pipeline using a new type of sensor. That's just the fun part of being in this business.

Our data analysts are qualified and they're matched with their area of expertise. All of our analysts are qualified in all the different sensor technologies that are used to inspect pipelines, and so we will continue to train and to meet industry standards with that.

Data mining is critical. It helps you understand the big picture: what is going on in the pipeline; how the pipeline is configured.

And, pre-job preparation is necessary if you want quality data.

So that's my presentation.

(Applause)

MR. HOIDAL: Thanks, Ken.

Our next speaker is going to be Garrett Wilkie from BJ Pipeline Inspection Services. Mr.

Wilkie is going to be talking about tool selection and proper application of the technology. Garrett has eight years of pipeline operator experience with Enbridge Pipelines and joined BJ about one year ago.

And, Garrett?

Operation Considerations: Tool Selection and Proper Application of the Technology

Garrett Wilkie

(PowerPoint presentation)

MR. WILKIE: Thank you, Chris. Good morning, everyone. Let me just get set up here.

So, as Chris mentioned, I guess I've got both sides of the fence and some experience working with an operator, and the bulk of my career has been on the operational side, both in operations and -- as well as pipeline integrity. And I joined the inline inspection service provider side of things here about a year ago and find it very interesting being on -- having that perspective from both sides of the fence. And hopefully, I want to share that with you today.

So I was asked to talk about operational considerations, tool selection, and technology application. I first wanted to recognize and acknowledge -- and others have said it here today as well -- that inline inspection is an optimized means of managing integrity. It's -- there are a number of tools to manage integrity, but it's one of our best tools.

And I think it's a proactive industry. It's moving ahead. We're all involved with the development of all these new recommended practices and standards that are coming out, and it is a highly competitive and highly technical service. So it needs to stay that way. It's a service industry. It shouldn't be treated as a commodity type industry, so.

A question was asked of how do we reduce the errors and miscall, and I'll attempt to go through that here with my presentation. But a key function to all of it, and we've heard it again this morning through other presentations, is improved planning and understanding. Just open up those communication lines between the operator as well as the ILI service provider and everyone who is involved with the integrity management process.

So, operational considerations. Talking about a pipeline questionnaire. That seems a bit boring. We've all heard it time and time again, but I felt it relevant because it still is maybe taken for granted somewhat. I was guilty of it myself. You would put your summer student on to putting together a pipeline questionnaire, and that's not a bad thing, but it needs to be taken seriously.

What is happening there is the transition of the information of, why are you running a tool, and all of that specific pipeline's history and information is being passed along from the operator to the service provider. That's the key start to this whole process, to understand what are the goals.

So, in speaking to goals, obviously there's typically a primary inspection goal that you're trying to achieve and will ultimately factor in your tool selection, but there are also other things -- other goals that you hope to achieve with running a tool. These tools and inspections don't come cheap, so you're hoping to maximize that and do it in the most economic way.

There are a number of documents. Again, it's been mentioned a lot today and will be the topic of later discussions this afternoon. The NACE recommended practices as well as the new API 1163. These documents, again, for reference go into this in a lot more detail and help you with working through selection of tools, how to run the tools, how to qualify a system.

I just wanted to talk a little bit and work through an example, I guess, on tool selection and technology application. I'm going to use an MFL example, and it's been talked about today, standard res or low res and high res.

To me, anyhow, it used to be quite clear in black and white, and today it's not. I don't think there's -- we talk about high-, medium-, and low res. It used to be that it was purely magnetic saturation that was the distinction between a standard res and a high res, and that was, did you have enough magnetic horsepower on the tool to saturate the pipe to optimize sizing.

And I think as an industry there are still standard res tools available, but we have evolved into the bulk of the tools being utilized are what we would have called years ago high res tools.

But there are a number of other factors to consider. All these tools -- like I mentioned, we're a highly competitive industry and we're all striving to outdo each other and compete for your business. There are different types of sensors, hall effects, coils, number of axes, single-, dual-, tri-axial fields, number of sensors, electronics, the software packages. All this plays a factor in ultimately the data quality, and so it's quite a rigorous process to go through and evaluate us and determine what best suits your needs.

So that's, I guess, the key statement there. Understand what you want to inspect for and then understand clearly the capabilities of the service providers as well as their tools to achieve the results you're looking for.

So, a little bit more into ILI and some of the potential errors or sources of errors and feature sizing, tool tolerances. There are performance specifications, and API 1163 does get into that quite a bit to work through that and essentially understand a performance spec and what you as an operator are holding the ILI service providers to.

There are other sources of errors, though, as well. Positional errors. Is the tool equipped with only odometers or is there also an inertial mapping or an inertial navigation system on board to provide center line and GPS coordinates.

And what plays into a factor with that is also the type of repair work that you do. Are you doing an entire -- exposing an entire joint of pipe along with the adjacent joint ends to verify joint length as well as three long-seam positions, or are you just digging a bell hole, in which case you need to be more precise.

So there have been and are errors out there, and you have to understand that sometimes these things can go astray. You need to be aware of that and check into that. Often -- I know I've experienced myself where a field crew will call in and say, "Yeah, we're at the right spot. We dug it up and we found nothing. That stupid ILI tool."

Well, the first question asked back, "Okay. Well, let's work through the process. Let's step it out. How did we get to that position?" And quite often there are positional errors.

Data quality. Ken touched on it. Obviously, the operational considerations in your pipelines with speed, line cleanliness, all this plays into a factor on data quality, and you need to be aware of that. So, is the inspection tool capable of finding what you're looking for.

Just, on feature sizing, I wanted to talk a little bit about sizing tolerances. This is just a high level example. Defect assessment codes use length and depth. And these two examples; the one on the left with the red shows an example of a tool with maybe looser tolerances, larger tolerances, than the one on the right.

And what can happen there is, obviously, with those tolerances and being aware of those tolerances and potentially factoring them into your decisions can take you across that threshold into -- from an acceptable feature to an unacceptable feature. So be aware that tighter tool tolerances can lead to optimized decision making.

I know that in this inline inspection services, often we hear the complaint that it's too much money and we're all striving to do things cheaper and all the time being better. But also factor in the cost of your repairs. Integrity management is the whole picture, and I know myself it's -- I've spent a lot of money on repairs, and so keep that in mind in selecting the tools and being able to optimize your program.

Just quickly talk about determination of sizing accuracy. In sizing accuracy we need both the sizing tolerance as well as the percent confidence or, in other words, the standard deviation of the error. So I know we're all familiar with plus or minus 10 percent on depth with 80 percent confidence. Well, I'm not a big lover of stats, and you can make stats say what you want. So in this example, this plus or minus 5 percent depth with 47.8 percent confidence is the exact same thing.

So there's our generic, standard distribution, plus or minus 10 percent 80 percent of the time. That same distribution, plus or minus 5 percent, is 47.8 percent of the time. So be aware of that.

One thing I did also want to mention; the question of 80 percent, where did that come from, why isn't it 90 percent, why isn't it 100 percent of the time? Well, steel is imperfect. The line conditions -- we're running these tools in non-ideal situations, often. This isn't a laboratory setting, so there are other considerations to take into account and essentially that's the main driver for the 80 percent.

I've talked a lot about the tools. Something also to consider is the in-the-ditch considerations. Errors can and do occur in the ditch. Just because they've got the pipe opened up and they're in the ditch taking some measurements, quite often that's believed to be the most accurate and often there are large variations in errors that can occur in the ditch. So a comment there is, qualify your field personnel similar to the qualification of an ILI service provider.

Ultimately, with that, from tool and field you're looking to achieve the state of validation that is being talked about today and comparing the tool versus field to determine performance. And that's essentially, I guess, leading into Lisa's talk here.

But to conclude, errors do exist. Be aware of them. There are tolerances on the measurements. Just, again, throughout the day I think we're going to continue to hear that there is always the increase in communication between all those involved and understanding of the problems and understanding of the issues as well as the services that can be provided. In strengthening that, we're just going to continue to improve as an industry.

Thank you.

(Applause)

MR. HOIDAL: Thank you, Garrett.

Our next speaker is going to be Lisa Barkdull. She is going to be talking about field data verification, feedback loop, and importance of accuracy on advanced analysis and risk management methods.

Lisa works for Tuboscope Pipeline Services. She's the manager of the UT Data Analysis Section. She has 13 years of experience with Tuboscope in engineering, quality assurance, and data analysis, and she has a master's in statistics from the University of Houston, Clear Lake.

Lisa?

Field Data Verification, Feedback Loop, and Importance of Accuracy on Advanced Analysis/Risk Management Methods

Lisa Barkdull

(PowerPoint presentation)

MS. BARKDULL: Okay. I've been asked to talk about evaluating inline inspection results. In presenting this, I was presented with several questions, frequently asked questions. Some of them are, what is the process of evaluating -- is there a process and what is it for evaluating the results; are verification digs necessary; if so, how many; what type of information is the service providers looking for whenever excavations are performed and how is this information used; and how important is it to understand these errors and the accuracies of ILI survey data.

What is the process to evaluate ILI survey results? There are several standards and references. You've heard the standard API 1163 mentioned quite frequently today, and in fact my presentation is using that as the guideline. There's also NACE recommended practices. Each ILI service provider probably has their own standard operating procedures to verify ILI survey results, and most operators that I've worked with internally have their own systems in place. So there are several references that you can use.

In API 1163, Section 9 of that standard specifically addresses system results verification, and it's called "Systems," it's not called "ILI Verification Results." That's because they understand that this is a system. It's the tool, it's the personnel that run the tool, it's the analysts that analyze the data, and it's the software that is used in this process.

The process of evaluating results is a three-step process. The first step is called process validation, which I'll talk about in depth. Also, it involves the comparison of the current data set with historic data from the pipeline being inspected. That has sort of been a common theme throughout these presentations and an important part of the system.

It also includes comparison of historic data or large-scale test data from the ILI system being used because there is a history with that tool, also, not just with your pipeline.

The Section 9 also has some criteria to

determine whether verification measurements are recommended or not.

During the process validation part of this process, the one thing that's key to understand is that it is a responsibility -- this is the responsibility of the ILI service provider and it's the responsibility of the operator. This is a dual responsibility process here.

The first step in this process would be confirmation of the data analysis process, and this can be anything as simple as checking out line links; are the line links correct. Checking out -- we talked about survey exception criteria. Were the survey exception criteria met. Were the QC checks in the field done correctly. Were the QC checks during the data analysis process done correctly.

You can also look at the pipeline parameters that were utilized for both the tool run during the analysis portion and also during any subsequent assessment of the data. Were the right pipeline parameters used.

You would want to check the report just to make sure you're launching traps correct, your -- you know, the section that's being run. Just check for errors through this overall process.

You also want to compare the recorded data with any previous data. Do you have previous excavations or previous repair information. You can use this to do this process validation.

Maybe you've never -- maybe this particular section of pipeline has never been run but you've used this 12-inch tool to run many other sections in your pipeline system. Look at that; is it consistent. Are you expecting -- are you seeing similar results.

An important aspect of process validation is the comparison of reported locations and type of pipeline components to the actual areas. As an operator, this is information you know already, or for the most part you'll know where are your Ts, where are your taps at, where are your valves at. So do a comparison. Make sure what's getting reported inside the ILI survey report is matching up to what you expect. Likewise, service providers can use the alignment maps that are provided by the operators to them to do this comparison.

So the question is, do we have to do verification digs. API 1163 has a guideline to determine if verification measurements are recommended. You'll notice there's a difference. There's verification digs. There's verification measurements.

When you open up a hole in excavation, one bell hole can render several, if not many, verification measurements, so take advantage of those holes that are being opened up. Don't just go up to your target anomaly. Go ahead and take the time to gather all that information, because it starts counting towards your measurements and in statistics. We're not going to have it lessen statistics, but the larger number you have, the better it is. So you want to, when you open up a hole, take advantage of that and get as many measurements as possible.

So, to determine if you're going to do verification measurements or not, one of the guidelines -- one reason you may have to do it is just that there's no historic data available on that line. Or, perhaps it's a new technology. It's a new technology that hasn't been ran very much addressing a specific threat. You may want to do some verification digs.

Or perhaps you've found discrepancies during that process validation. You may want to do some verification digs.

Another reason that I don't have listed here is the ILI service provider themselves may go to you and say, "Hey, listen. You know, we had some indications on this log. We'd like you to do a dig.

Take a look at it for us." Maybe it's something they don't understand. Maybe there's an unusual signal. So that's a likely scenario.

This last bullet point probably says it all. The reality -- it's the integrity management protocol within the operator's domain that warrants digs. More often than not operators are digging because it's the protocol within their own companies. But when you do those digs, if you're going after your immediate or whatever you're going after, take advantage of that hole being open. Get all those other measurements.

Once you decide to do a verification dig, before you go out there you need to understand detection thresholds, measurement thresholds, reporting thresholds, and interaction criteria. In fact, in API 1163, Chapter 10 deals with reporting, and that's one of the recommended -- these are some of the features that an ILI service provider is going to provide in the report. Because, if you don't understand those, as soon as you dig and find some discrepancy, it could be related to some of these issues, and it just helps you be more informed when you go out to the field.

You also want to consider errors associated with ILI measurements and field measurements. Garrett talked about this. Any measurement system has errors.

Typically what happens is that the ILI measurement is weighed against the field measurement, which is considered the baseline.

But the reality is that field measurement has an error with it, too. Depending on what type of field measurement you're doing, the error, you know, can vary. If you're looking for external corrosion, that's one error. If you're looking for a crack and measuring that, that's a totally different error. So that needs to be considered when you're looking at this information.

The comparison between measured and reported characteristics should be statistically valid and based on sound engineering practices. Like I said, there is not time to have a statistics lesson here, and I doubt anybody would want one, but it does have to have some sort of sound engineering practice.

One of the easiest ways -- everything I'm speaking about is lined out in API 1163. There are guidelines set forth in there. There are appendices that give examples of these different methods.

One of the methods would be simply -- the simplest, most often used is compare dig results to the tool specification. If the tool says, say, for the depth of extended corrosion we expect to be plus or minus 10 percent with an 80 percent certainty -- and I'm going to -- is this the laser here? Yes.

This is just a simple unity graph right here. All you do is plot the -- in this case, the X-axis is the field measurements. The Y-axis is the ILI measurement. You put in your expected error bars. In this case, it is listed at plus or minus 10 percent. If this was going after external corrosion, I would probably want to add in -- you would consider the error of the field, too. It would change it a little bit, not very much.

That is one way to quickly establish or verify your data, or 80 percent of your calls within here.

Another method is the histogram. What is good about the histogram method is you are able to see the distribution of your errors. You would expect in this middle bin for the majority of your data -- 80 to 90 percent -- to be sitting inside there, but you can see if it is skewed one way or the other to get a feel for the distribution of how your errors are falling.

Other methods. For example, if you don't have a large sample size and maybe a total of 80 percent is not falling within that error band, you can look at some other statistical methods. One would be using distribution functions to find out if the dig results are statistically consistent with the tool specifications. You can use binomial distributions, normal distributions.

Another example that you can use would be to build confidence intervals. These are intervals that will determine the true performance capability. For example, if you are testing for a certainty of 0.80, you can build a confidence interval that tells based on your data set what range that certainty actually falls in.

The next question is, okay, we are going to do these verification digs, we are going to analyze this data in a sound manner. So, how many do we need to do? There is not a magic number out there. Unfortunately, there is not a magic number, but you can look at some guidelines. You can look at the amount of historical data associated with the pipeline or the ILI system itself.

Something you want to do to save you a dig is, do you have excavation information where you went out, dug, sandblasted, recoated the pipe. Use that information as a verification measurement without ever having to dig up that piece of pipe again.

Do you have repairs that you made? As long as the repair doesn't interfere with the technology you are running, you can use that information. You have documented it. You know what it is. Use it and you don't have to open up a ditch but you can use it as one of your verification measurements.

You could also use results from surveys with similar pipeline and survey characteristics. Is there a history with that tool? Do you understand how that tool has performed in other sections of other pipelines and under the same operating conditions as in your pipeline? Use that information.

If your confidence levels associated with tool specifications, say with your tolerance or your certainty, is low, you may want to do some digs or do more digs than you normally would. If it is a new technology, you may want to do more digs than you normally would.

The feedback loop portion of evaluating ILI survey results is an important part, and it has been talked about by the operators and other people. It is a part that allows us as an industry to become more informed and improve.

The information from verification measurements should be forwarded to the service provider. The format can be agreed on between the service provider and the operator. There are a lot of best practices out there. There have been presentations at NACE conferences. API 1163 has a best practice. So there is a lot of information about how information needs to come from the field to the service provider.

Also, the quality and accuracy of the information is very important. This information is going into databases that we are using to make inferences, both the service provider and the operator. So you want to make sure the accuracy and the quality of the data that you gather in the field meets those requirements. This is as important as the accuracy that you expect from the ILI service provider.

The third point is an important point. The measurements -- the information that you give back should include both measurements that are within and not within tolerance, because a service provider is going to hear pretty quickly when something is not in tolerance. That is a call that is common. But we also need the information back about those that are in, and I want to demonstrate why this is so important real quick, if I can.

If you imagine this graph right here and we removed all this area right here and this is all you hear about or this is all you hear about, that can really skew your database. It skews the actual capabilities of the system. So we want to make sure that we get both good -- the measurements that are within and without tolerance.

Any discrepancies between the reported inspections and the field measurements that are outside tool specification should be reviewed and discussed. There should be a meeting and a communication between the service provider and the operator to find the source of these.

Sometimes it is simply, you know, you would review the field verification process, you would review your data analysis process, you review the operating parameters at that time in the survey: was the tool speeding at that time. You just want to go in and try to identify where the source of these errors. Is the anomaly that you are after out of the specification of the tool. Is it not qualified by that tool, perhaps.

Once you have verified or you have done these verification digs, the tool specifications can be confirmed or perhaps even reestablished based on the information provided during the feedback loop. This allows for the continual improvement of the data analysis process.

So, why is it important to go to all this trouble to verify an ILI survey? Because once you understand the data you have in hand, you can be smarter. You can make better decisions. So it allows the operators to implement an optimal repair and mitigation program and do it more smartly.

It allows service providers to offer advanced analysis methods. Shahani is going to talk a little bit after lunch about some of this, but you can implement more accurately pressure-based anomaly assessment, growth analysis, fitness for purpose, or the failure assessment diagram anthology.

This is just a quick example and I'm not pretending to be a mechanics person at all, but this is a diagram that most people are used to seeing. But it shows, when you understand the errors associated with the data you have -- if I have a point here for a deterministic model, I have a point on a graph. But once I understand errors associated with that information, you can create a probabilistic model and you can actually estimate failure probabilities. So these are just some of the things that you can do with this understanding of the data set you have in hand.

It also allows -- when you understand the accuracies of your ILI survey data, it allows for modeling the remainder of the data set. Because the reality is, on most lines -- not all lines -- you are not going to dig everything. You are going to dig a sample. You are going to -- or, you are going to do your process validation and understand the specifications are being met, and you have to make an assessment or have a story to tell about the remainder of the data set. This process will allow you to do it when you understand your ILI -- the accuracy of the results.

In conclusion, successful evaluation of ILI survey results is possible, using a systematic approach and communication between all parties involved. Understanding the accuracy of these results aids in implementation of an optimal repair and mitigation program. It also enhances the ability to implement advanced analysis methods.

Thank you.

(Applause)

MR. HOIDAL: Thank you very much, Lisa. I think I need a class in statistics now.

But we are going to be breaking. We are back on schedule. We are going to be breaking from 12:00 to 1:30. Joy was pretty generous in the lunch break.

Please use the opportunity to think of some questions, you know, over lunch, maybe with your coworkers, on a question you want to ask the entire panel.

We have two more presenters. We have Shahani and Bryce. They will be presenting immediately after lunch. We are going to start promptly at 1:30. Go have at it and go eat.

(Whereupon, at 12:00 p.m., the proceedings were adjourned for lunch, to reconvene at 1:30 p.m., the same day.)

A F T E R N O O N S E S S I O N

1:30 p.m.

Good Decision Making: Inline Inspection Vendors' Perspective (Continued)

Chris Hoidal, Moderator

MR. HOIDAL: The first speaker is Dr. Shahani Kariyawasam. Dr. Kariyawasam will be talking about advanced analysis methods for ILI interpretations. She has a Ph.D. in structural engineering, and the last five years -- or, for five years she was with Seifert Technologies, developing pipeline integrity management software and consulting. She has been with GE Energy for the past two and a half years, and she is responsible for developing and improving integrity services.

I'm just going to call you Shahani. Shahani, come on up.

Advanced Analysis Methods

Shahani Kariyawasam, Ph.D.

(PowerPoint presentation)

DR. KARIYAWASAM: I have been asked to talk about advanced methods, so I thought first I will define my categories. I think we all quite agree that ILI is essential to ensure pipeline integrity and safety. We know the ILI methodologies -- the two ILI methodologies that are covered here -- or, the services that are covered are detection and sizing and dig verification.

However, to ensure safety, we all know that assessments have to go beyond ILI. To ensure safety, we have to go into secondary assessments of the pipeline, both before the ILI and after the ILI. We also have to -- integrating all these solutions is essential to preventing failures.

For the convenience of this presentation, I have broken it into three categories: the different kinds of assessments, the primary assessments, the secondary assessments, and the tertiary. And I have given a very high level process diagram here to show the interrelatedness of these different kinds of assessments.

The primary assessments that I name here are essentially the services that ILI provides directly or traditional ILI servicers have provided: the detection, the sizing, the dig verification and run validation around the inline inspection.

The second reassessments as defined in this presentation are the assessments that use the ILI data as well as the assessments that are pre-ILI, that qualify the ILI or provide the right guidance for the ILI.

So these different assessments -- the pre-assessments looked at the tool selection which Garrett talked about. Many aspects have already been talked about.

We also have to consider what threats we are facing, so the risk assessment comes into it. We have to do the risk assessment to know what kind of threats we are expecting our pipeline to have or know that our pipeline has. That will define what kind of types of defects we are looking for.

The pre-ILI tool selection also includes aspects like looking at what kind of defect we have, will our tool be able to see these defects, and also to consider your pipeline, see what kind of critical sizes of pipeline -- defect critical sizes are relevant to your pipeline, and then find out whether the tool that you are expecting to run can actually see that size of defect.

This kind of analysis -- we have found through our experience that even though we expect the operator to do the tool selection that we need to give the guidance to the operator to do so. I will talk about some of those methodologies.

The post assessment can be of different types. Here the post assessment -- I have mentioned feature assessment and maintenance optimization. Now, this can go into different levels. It can be done on a deterministic level, it can be done on a probabilistic level. There are many levels that we can do it at. I think some of the previous speakers alluded to some of the probabilistic methods, and we can do these at different levels. But what is important is that it is using the data generated by the ILI data and providing solutions to ensure safety and integrity.

So it is essential that these assessments are also correct and accurate and done appropriately so that we can integrate the ILI data appropriately.

The tertiary methods that I defined here are the different assessments that we provide almost as a feedback loop. So that, we take all the data that these assessments generate, we find -- we organize that data and manage the data so that we can mine the data. We can find the trends, we can learn from our mistakes, we can learn from what the data is telling us and improve each of these assessment methodologies.

And the main point is that we have to integrate all of these solutions to ensure reliability of a pipeline. We need to have good detection, good sizing going hand in hand with good assessment, what kind of defects we have, and predict the life cycle of a defect.

In this -- because I have a very short time, what I will do is give you a couple of examples of each different kind of assessment. Each assessment methodology we have used because we have quite a lot of data in our company. We have been able to gather this data, and by using this data we have been able to improve each of these assessment methodologies. So I will give you a couple of examples of each of these different kinds of assessments.

First of all, I've got the primary analysis, which is of course the ILI services, what we provide, and the strengths. I think we all acknowledge the strengths of our ILI methodologies and technologies. We know that they have a proven detection capability unparalleled by any other assessment to assess a whole pipeline. The detection capability has not only been able to prevent a lot of failures but it assures pipeline safety throughout the pipeline as opposed to many other assessment methods.

Now, the multiple technologies also help us, and this is a strength that we have. I think, again, a couple of the previous speakers have talked about the different technologies available and that there are different technologies available for the different kinds of defects.

We also have a strength of now having these ILI standards, the latest standards we have for quality control, and we can leverage these to improve and prevent failures. I think we haven't quite fully harnessed those capabilities yet.

Some of the improvements that we have been providing in the primary analysis are streamlining the analysis process. In streamlining the analysis process what we really focus on is doing the mundane, everyday, simple activities, automating those activities so that we can put the analysis effort in the right place, where the attention of the expert analysts is required. That improves the process as well as it improves the time of delivery because we can do it much faster.

We have also, I think, done a lot of consolidating of data streams from the tools and databases. We have seen within the last few years quite a few dual tools coming out, and these dual tools have been able to consolidate the data much better.

With those tools we will be able to consolidate the data much better and leverage these databases.

Another area of continuous improvement that we see among many of the ILI providers is the defect sizing algorithms. This is a continuous improvement that we see. The different ones that are ongoing or needed further enhancement is the dig verification process. Again, I think Lisa spoke to that, and others have spoken to the fact that we do need a feedback loop. We need a better feedback loop. We need better communication to improve this.

We need better data management. We need also mechanical damage. We have been able to harness technologies to improve corrosion and also our crack assessment methodologies. But we are in the process right now of developing improved mechanical damage analysis methodologies.

As an example of secondary assessments, now this can be done pre- and post. And this -- I'm giving you one example here of a pre-ILI assessment because we find that operators need guidance and help in finding the right tool and also verifying that your tool will be able to see the different critical defects that are available.

So this is an example of a service we provide with the crack tool. Because the crack tool -- in the pipeline there are critical crack sizes, we have to ensure that the critical crack sizes are within the tool's spec with adequate confidence.

The other objective here is to also provide an adequate reinspection interval, ensure adequate inspection intervals within the appropriate corrosion growth rate.

Now, in doing this, we use this kind of graph, and this is one example of how we do it. The graph looks at the critical crack sizes for a certain length of crack and an MAOP. And for your particular pipeline we could draw different critical crack size lengths. For the different wall thicknesses, we have three lines plotted here.

Now, the Y-axis would give you the crack depth. If we mark on this our tolerance, then we know that below this we will not see the defects. So we are acknowledging the defects that we will not be able to see in our tool.

If we know our toughness, we can see what is the largest depth we will not be able to see through this inspection -- through this tool. So we know that this defect will not be able to be seen by the ILI and therefore we have to assure that the defect that is left in the pipeline, using the appropriate corrosion growth rate, will be able to grow at that growth rate for a certain number of years, and that number of years we can calculate through that process. This will ensure a retesting to it.

Of course, in this process we do take conservative values. We take the 90th percentile depth. We take a very conservative growth rate.

This is one example of a pre-ILI assessment and an assessment that will ensure the right usage of the tool and of course prevent failures because of that.

This is one example of a secondary analysis in the assessment. Now, if your assessment is poor and we don't assess our pressure -- our failure pressure properly, then we will not be able to know which defects are the most critical, or we might have miscalls or false digs. So the better your assessment methodology, the better dig program you can have and better economy as well.

This is a methodology called length adaptive pressure assessment. It is an improved failure pressure assessment methodology using ILI box data. The ILI box data you can see here. It follows the same pattern as the op strength. It is an op strength approximation, and instead of the field measurements, we use the inspection box data.

This process has been validated against dig and burst data. There are some IPC papers on this methodology, which has shown to be a very good methodology to assess the pressure of the pipeline -- failure pressure. These results have been found to be more accurate to give burst pressure predictions rather than conventional methods. This is available both with MFL and DP technology as well.

So this will improve the dig program and prevent failures, and that's why this kind of assessment has to go hand in hand with ILI to prevent the failures.

If you look at pipeline reliability and look at the sensitivity of the pipeline reliability to different aspects of the pipe, the aspects that it's most sensitive to are depth and depth growth rate. So if you were to get the best bang for your buck, you would put your effort in refining your depth measurement and your growth rate measurements. That is why we have taken lots of effort in getting -- assessing and quantifying our depth as well as quantifying our growth rates.

Our corrosion growth rates we can get from repeat ILI data. There are different methods to do this. Again, many people do it with feature matching from spreadsheet data. This can be done on a number basis, but it has the problem of not having -- the benefit of not having -- not knowing what sizing algorithms were used and also it doesn't consider the clustering because the clustering can be different for the two ILI runs.

The feature matching using visual display software and box matching is also prevalent in here. Because you use the box data, you are avoiding the clustering problems but yet the sizing algorithms -- the different sizing algorithms, the errors that that brings, is not overcome.

The best method that is available is the signal matching. The signal matching is also called run comparison, and you compare the two runs -- the signals of the two runs so that you look at actual physical point to point and therefore, also, because you are looking at the signal and not the box data, you eliminate the extra error that comes into play because of the sizing, the two different sizing algorithms. Very often, because there is a time lag of about five or six years between the two runs, there is a difference in sizing algorithms because we are constantly improving our sizing algorithms.

An example of the tertiary assessments and continuous improvement is given here. Here we would -- we consolidate all the different kinds of data. This is very important. I think many people alluded to this as well, to get our right of way information, our contour information, our ILI data, pipeline attributes all in one paper and have a smart current alignment sheet. Because it is current and we know exactly where the pipeline parameters correlate to each other, we can assess features by correlating the ILI data with the right kind of pipeline attributes.

It also aids in mobilizing remediation crews so that they will be able to reveal -- these methods would reveal the right of way access issues right at the beginning so that they will not have -- they will have less false digs.

We also aid data mining, and it enables improvement of the process -- of the different assessment processes, as I talked about earlier.

This is an example of a tertiary method because this is a method that was developed using our past data. We have about 15,000 kilometers of crack detection data, and we have been able to use this data, look at the data, look at the trends, and find out certain characteristics and predictions. Because looking at the data we found that we had very good detection capability, we could find -- we could make sure that we would be able to detect SCC.

Here is where you don't know whether you have SCC or not in a pipeline, in a case where you are trying to find out -- validate the presence of SCC. You would use this methodology just to be able to validate either the absence or the presence of SCC. This is done through the database of crack detection used to provide necessary -- the data has been used to provide the necessary reliability and the confidence level.

In conclusion, I would like to talk about effective decision making because this is all about decision making. One of the speakers earlier said, what does good decision making look like, and I would like to say that good decision making has to always think about the probability of failure and look at all the different assessments that come into preventing failures. The ILI services, which is a snapshot of the pipeline at one particular time, but how we predict what happens in the next few years. We need advanced assessment methods for -- to integrate and learn from our past history. We need to integrate our data and keep improving our dig program.

And with that, I will leave you with the thought that integrated solutions ensure reliable pipeline integrity.

Thank you.

(Applause)

MR. HOIDAL: Thank you, Shahani.

Our last presenter in this panel is Bryce Brown from Rosen North America. He is manager of the Integrity and Compliance Department. He is in his 14th year with the company and is responsible for pipeline regulations and integrity as they relate to the company's pipeline inspection business.

He has a B.S. in civil engineering from Texas A & M. He is a member of ASME and NACE. He is a past president of Inline Inspection Association, and he is also the current president of the Pigging Products and Services. And you were also the vice chair on the API 1163 Working Committee.

Welcome, Bryce.

Inspection Technologies: Ensuring Confidence in ILI Methodologies

Bryce Brown

(PowerPoint presentation)

MR. BROWN: Thanks, Chris.

I have been asked to present on the subject of ensuring confidence in ILI methodologies. First of all, I would like to say that this is one forum that we can all, as all stakeholders involved and interested, this is one method to start to understand and gain confidence. And, appreciation goes out to the federal and the state regulators for organizing such events in that we can all sit together and hear the same pieces of information, take that back, and implement those together.

So, with that, moving on, ensuring confidence in ILI methodologies. ILI methodologies are well established and well proven techniques and tools, processes, procedures. They have been helping pipeline operators to ensure safe, reliable, and economic operation of their pipelines and pipeline systems. That was emphasized this morning by Stacey on safety as well as during our last panel.

Some of the general information. As we heard this morning, ILI dates back to the mid '60s, coming on 40 years of being applicable to pipelines. ILI is a mature industry. There are technologies that are in place: for example, high res MFL, which has been mature for some time. There are other technologies, new, evolving technologies, that because you, the pipeline operator industry, are helping us to make those mature and get those further developed so that they can meet your needs in those areas.

Vast strides have been made over the past 15 years in this industry. That has to do with electronic sensor techniques, general learning of physics, and so forth. Also, the development and introduction of new and more advanced technologies and techniques have come about over the last 15 years. And of course, as you know, the R & D efforts continue in our own facilities and in your industry to provide for the industry what you're looking for as far as the requirements and demands.

We do have a major stake in the proper implementation and use of ILI methodologies. This is our business. We want to make sure with you, together, that you're getting what you are requiring from our services.

We want to be successful -- we are successful -- in helping the operator, again, ensure safe, reliable, and economic operation of their pipelines. As stated in the previous panel, once again there is a success story out there, and working together has only proven that to be the case.

Ensuring confidence in ILI methodologies has to be at the forefront, and that is the, of course, subject of this talk. We do have confidence in the methodologies that we employ. We have the expertise, we have the know-how, and we have the track records.

You, the operators, you have the expertise, you have the know-how in your operations and pipeline integrity. You know your pipelines best.

There are operators that have mature programs; that's for sure. We realize that. We have relationships with you on that, and it is when we both have understanding about what we can provide to each other is when we are going to gain confidence in the methodologies. So this is a key.

So, how do we achieve understanding? Through timely, open, and effective communication.

So, how can one achieve understanding of ILI methodologies? Well, again, I said that earlier, as I started. Through forums like these. But basically, ask us. In today's industry and marketplace, all of us represented on this panel here today have to be obligatory to answering your questions, making you understand what our capabilities are, our limitations, and the methodologies that we offer.

I'm going to give you some ideas of industry guidance. These are three publications that most of you are aware of. If you're not, these are a good starting point. There are others out there, but once again, these are good reference documents and publications that could be shelved to look into further.

As you know, there are a number of workshops out there, and schools and conferences. An observation was made this morning that nobody can remember the last time, or if ever, a pigging conference was so well attended as this is. So that goes out to the group here in their appreciation for the attention you give this.

But, yes, there are a number of workshops and conferences that you can leverage to understand these methodologies and start to gain confidence. These workshops and conferences offer up real-world applications of the technology by customers, by pipeline operators. I think that it's important that we hear from you what you're learning in the field of application of these methodologies.

On the other side, you also get information about evolving and emerging technologies. I can think of about six papers presented this year alone on that subject of result validation of ILI technologies.

Standards. There are existing standards and recommended practices that we as inline inspection service providers utilize already today. One of those you may be aware of is the European Pipeline Operator Forum Reporting Standard. That is a document that originated in Europe by pipeline operators in Europe. It has come across the Atlantic and been adopted by inline inspection companies as well as some of you.

NACE publications on inline inspection. NACE TR 35100 talks to the capabilities and expectations from ILI technologies that are offered, and NACE RP0102, published in 2002, offers a very good insight to ILI process.

So this new environment with IMP means news and enhanced standards. So, yes, I will also mention these three new standards. What do these standards offer all of us in this room? Improved communication. These will offer us a means to look at the same documents and start to talk effectively about the particular subjects covered.

Improved transparency. I think that is a key these days in the industry, is the fact that you need to understand what we do and vice versa. So that will be something that you will gain from these documents.

Improved understanding. Once again, that is a key here in order to improve our confidence in these technologies and techniques.

Once again, we answered your call here on these three documents. This was driven by you, the pipeline operator industry, and we worked on the first two in particular over the last three years together to provide consensus and usable information in these subject areas.

Of course, there are associations to help you improve your understanding. These groups are out there for you. The Pigging Products and Services Association, they offer up a group of members that have a wide variety of applicability and applications, products, and services. You have the Inline Inspection Association, which you will hear about shortly. These are items that -- and associations that you can leverage and ask us questions and hopefully you will get some consensus response from these groups.

I call this recognized gaps, or more so, probably action items moving forward. As technologies and techniques advance and we introduce new processes and so forth to you, then we need to make sure that you understand what it is that we are providing. That is one of these action items for us as industry providers, is that we play a more active role in that understanding.

We, of course, do that with you and make sure that when we're in a relationship with you that you do understand what you're getting from us.

And you do this as well, but again, we need to make sure that we're clear on your expectations, that you clearly spell out your expectations and as early in the process as possible. The more information that we understand that you require, the better it is at the end of this process. We are going to be successful together.

Improved and more timely feedback between all stakeholders. I think you've heard that a couple of times already today. That is a key. We need more feedback from you, the operator. You are out there verifying our results. You are out there making your repairs based on our reports and data. We need that information back. Again, we want to put that back into our loop for continuous improvement and we want to learn from that.

Improved communications among all stakeholders, again, everybody in this room. I think, again, this is a good avenue to start that communication. It's very difficult in such a short time to go into much detail, but again, we need to understand each other and each other's requirements from all views. I think that is something moving forward that we should try to take advantage of.

A simple schematic to conclude, but working together, again, everybody in this room, all the stakeholders, to ensure this confidence in these ILI methodologies and to ensure safe, reliable, and economic operation of pipelines. That is what we need to try to accomplish, and we can do that. It has been proven that it has been done. So there's -- we just need to recognize together, operator to service provider to stakeholder, in particular in that relationship what are those gaps.

Thank you.

(Applause)

MR. HOIDAL: Well, thanks, Bryce. I appreciate it. They were great presentations, all five of them.

Question-and-Answer Session

MR. HOIDAL: We have a unique opportunity here, a rare opportunity, to get five of the -- five major ILI vendors up here that you guys can ask questions of. I was wondering if -- you know, there is somebody back there already.

Joy, how much time do we have for questions? Where is Joy? What time is it now? Fifteen minutes, okay.

Go ahead and identify yourself and pose your question. Make sure you direct it to one person, or if it's for the whole panel, let them know.

AUDIENCE MEMBER: Larry (Name), (Name) Pipeline. What measurable criteria do you use to determine if a pipeline is clean enough to run your tool?

(Laughter)

PARTICIPANT: It's like deja vu.

MR. MAXFIELD: I'll jump in. It varies from technology to technology. I think MFL tools are a little more tolerant of dirt or debris than like a UT tool. Deformation tools might be a little more tolerant than an MFL tool. So it depends a lot on the type of technology.

But like I said in my presentation, it's hard to tell you ahead of time, but after we run the tool I'll let you know whether it was clean or not. It's a very subjective thing.

MR. HOIDAL: Does anybody else have anything to add?

(No response)

MR. HOIDAL: All right. Up front here.

AUDIENCE MEMBER: (Name) My question is,

when you run your pig, how do you actually calibrate, before or after your operations? Do you have like a device with a low-interference -- pig?

MR. HOIDAL: Are you directing that to one vendor or all five?

AUDIENCE MEMBER: All five.

MR. HOIDAL: All right. Go ahead. We'll let Bryce take this one first.

MR. BROWN: I'll try and understand the question. To me, it sounds like, do we calibrate our tools?

AUDIENCE MEMBER: Exactly. Between running your pig.

MR. BROWN: Yes, we do. We do calibrate our tools against known, typically artificial anomalies implemented to find the ones -- the known wall thickness inspected, maximum wall thickness inspected -- expanded, and run multiple tests against those defect populations to generate a database and, upon that, to test our algorithms against sizing to establish a calibration curve, if you will. That's typical.

AUDIENCE MEMBER: So you calibrate your instruments -- my question is, do you calibrate off site, before you come to pig?

MR. BROWN: Okay. Real quick. We continue that process with bench tests, standard tests, and sensitive tests to ensure that the tool is functioning in the way that it was calibrated, yes.

MR. HOIDAL: Go ahead.

AUDIENCE MEMBER: (Off mike) (Name) with (Name). I think most of the presenters talked a little bit more in terms of improving the communication between the operators and the providers so that it is synchronized and so we get better results. Why do you think there has -- doesn't it seem that we are...Why hasn't...from the service provider's point of view?

MR. HOIDAL: What's your short question? I don't mean to be disrespectful, but.

AUDIENCE MEMBER: There was a gap in communication mentioned. What is missing there on both hands? Why hasn't this communication improved over the years?

MR. HOIDAL: I think that is a very clear question. I guess starting -- maybe Garrett or Lisa could attack this one. What has been, in your idea, the perceived or what you perceive as the most common gap in expectations, I guess.

MR. WILKIE: Maybe just in relation to what I talked about in my presentation and starting right from the beginning of the process with the questionnaire.

It may seem like the questionnaire is somewhat taken for granted, but it's that initial communication step of relating the information from an operator and their system and what they're looking for to that vendor.

I still think, in seeing it from both sides of the fence, that some are done very well but there are a lot that are poorly done. So it is that initial step of transferring that knowledge of the pipeline history and what you're looking for to the service provider. If that takes place, then everything can fall into place from there because you've opened the communication.

MS. BARKDULL: And also, I don't think necessarily that there has been a lack of communication over the last 40 years between ILI providers and operators. I think the communication has been there. Just because a standard comes out that emphasizes we need communication doesn't necessarily mean there was none to start with. I think there has been a good communication.

The fact is, though, with the regulations and the industry today, more operators that in the past haven't pigged before are in this business now. So there is an education process and a communication that needs to take place that hasn't been there before. It may be more to address those situations.

AUDIENCE MEMBER: (Off mike) -- for a long time that communication was not there...partnership.

MS. BARKDULL: There is quite a bit of partnership.

DR. KARIYAWASAM: (Off mike) I think the communication that we were talking about that we have been lacking or can improve is more under the certification, where operators are going and digging and...but we very often don't find out about that. For us to be able to find out what kind of...we need to know all of the digs. That communication can improve. The general communication is good because we know our operators.

MR. HOIDAL: Any other questions? Yes, Mr. Flanders.

AUDIENCE MEMBER: My question would be, the vendors are all now producing an estimated repair factor or comparisons of the ruptured capacity of the pipe to what the defect would allow as safe operating pressure. Now, as you are producing this data, does anyone give to the operators that data, that estimated repair factor, with tool tolerances both in depth and in axial plane as a standard course? Do you report that to the operators?

MR. WILKIE: I guess for -- speaking on behalf of BJ Pipeline Inspection, we do provide the RPRs or ERFs to our clients, and as far as the tolerances, they are posted on our performance specification. It essentially becomes an operator's decision of how to use those tolerances and factor that into their program. So, how are they doing the repair program to determine whether or not how and when they would use those tolerances.

DR. KARIYAWASAM: (Off mike) We do provide these with the tolerance numbers, but if they require...very often we do it in consultation with the operator. So if they want a probabilistic number, we can provide that as well, and we can provide, again, the RPR or the ERF factor. That again depends on the operator . Some prefer RPR, some prefer...some prefer...

AUDIENCE MEMBER: Does anybody add in the tolerance or axial competency -- not competence, but the axial length tolerance level also in the strength of the -- combine those figures to provide one failure path?

DR. KARIYAWASAM: (Off mike) If you -- we have a lot more error and we have a wider error band than the depth. When we call out the pressure, we call the number...but to give the error band. If you were to put the error band on the depth and the length, that would call out an extremely conservative pressure and that wouldn't be reasonable.

AUDIENCE MEMBER: As long as the operators know how you're doing it, that's what I'm trying to drive at. You need to be up front and tell the limitations of your data set because some of the newer operators are taking this data and saying this is all we do. We don't do any further analysis of it. That's my comment.

MR. HOIDAL: Anybody else want to add anything? I have another question here that came from the webcast.

(No response)

MR. HOIDAL: Okay. I'm going to direct this one to Lisa.

"It was noted that vendors should provide feedback after the operator completes the field investigation or their direct inspections. What specific action will vendors take to reestablish the tool specifications when the field data is out of tolerance?" Basically, what do you do after you find out that the field data doesn't match up with what the tool said?

MS. BARKDULL: Once a significant sample set is evident, the tool on that particular survey, the survey results, are out of specification, we'll take a look at that data. Again, this was covered in API 1163. We'll take a look at that data, and there are several options available.

First, we're going to investigate, as I discussed, why is it out of tolerance? It may be something in the process of analyzing the measurements in the field to the ILI survey results that is the problem itself. So you are going to investigate all possible options with the tool -- were the survey operational parameters at that time out of the limits of the tool. Was it speeding at that time or the wall thickness, you know, thicker than the tool can handle.

But the choices, once you understand that, are to take that information and to reanalyze the data, looking at that information. Another choice would be to reestablish the tool specifications for that particular survey or in that particular area. Once again, once you understand that, you are able to make your analysis and continue with your mitigation program.

The other one would just be simply to say the data is not verified for that particular area.

MR. HOIDAL: Does anybody else have something to add? Bryce, Shahani, Garrett?

(No response)

MR. HOIDAL: All right. Any other questions?

(No response)

MR. HOIDAL: Well, I have one question I want to ask, if that's okay with you. My question is -- and this applies -- this kind of alludes to what Andy Drake was saying earlier about the small companies. Many of the small liquid operators we have seen -- I expect the same thing will happen on the gas side -- maybe has one or two engineers on staff. In a practical sense, you know, how would a small company know what or when an exposed anomaly should be provided back to the ILI vendor?

What I heard earlier is you would prefer that all information is provided back to the vendor; is that what I heard? Is that correct? So you know the good story as well as the bad story. All right.

All right. Well, if there are no other questions, we will move on to the next panel. Oh, okay. One more. Hold on. Another webcast question. This is from Sun Core Energy.

"The members of the panel have indicated two-way data sharing between the vendor and operator is very important in developing an accurate ILI final report and ultimately developing a high degree of confidence in pipeline integrity. Some service providers are very cooperative in integrating verification and correlation data into the final report. What is each panel member's respective company philosophy on data sharing and how do you integrate?"

That must be data sharing between companies, I assume; is that right?

PARTICIPANT: Company and vendor.

MR. HOIDAL: Oh, between company and vendor.

So, "What is each panel member's respective company philosophy on data sharing, and how do you integrate?"

Bryce, you look like you're ready to take this on.

MR. BROWN: Well, basically, you know, what Lisa said as far as the information that we get back from you, the customer, we want to have the amount of data required back to us on -- the good things, the bad things. Again, we hear about the bad things. That is what we hear about, and that is normal. But again, we want to hear about the good things.

Again, if you want to understand performance as a tool, then we have to have all the detailed information possible so that we can then go back into our data, into the process and procedures, look at signals, look at how they were analyzed and so forth, to then make a decision does something need to be integrated or not.

Typically, the customer is going to let you know right offhand what their expectations are, and that goes to the relationship. They are out there digging these things that we agreed on as a result of feedback. Now, once the customer understands what they're seeing in that information of measured, in-the-ditch anomaly, then they're going to have a pretty good idea of what they would like for us to do with it as far as, please take it back, review it, go through your procedure or your methodology, and then give us a response.

So, at a minimum, we will -- if that's what they want, then we will respond to it. As far as recognizing a need to integrate it based on that review process, then we will recognize that work with the customer to decide on which type of methodology to take to integrate that. We submit a report. We submit the specifications. A finding in the particular area of pipelines is not going to be meaningless facts based on data quality. It is a good process.

But we are open to that. We do perform those activities.

MR. HOIDAL: Thanks, Bryce.

Anybody want to add something?

MR. MAXFIELD: It's a unique relationship between a pipeline operator and a service provider. I mean, there's a contractual obligation, and you can handle this feedback loop through that contract. It's not very often dealt with, but it's a great place to deal with it.

We react to providing the service and keeping you happy so that we get paid. It's kind of a win-win situation. Now, with these new recommended practices coming down and if they somehow get incorporated into a contractual obligation, then we're both obligated to provide this feedback. But that's coming in the future. In the past, it's kind of been hit and miss.

The newer the technology, the more we're interested in receiving feedback to make sure that the tools are meeting their specifications. As we get more and more comfortable with this technology, then we as service providers might not necessarily need as much feedback.

But when we do get feedback, at least our company's position is we will incorporate that data.

We will include that as notes in the final report. If we get feedback back in time, we will put that right into the final report so that there is some documentation there about what happened in the field and what was reported back to us.

DR. KARIYAWASAM: (Off mike) I'd like to add one thought on that note. On the verification, we do sometimes have to go and retest based on the verification. But recently we have been... working with the operator. They do the digs. They give us the data. They...we go back and forth recategorizing two to three...

MR. HOIDAL: So what I'm hearing is this kind of feedback is important to the whole industry, not just that specific operator.

DR. KARIYAWASAM: Right.

MR. HOIDAL: That's great. Any other questions?

(No response)

MR. HOIDAL: All right. Well, let's get -- I'm sorry. Go ahead.

DR. JEGLIC: I'm Franci Jeglic. I am from the National Energy Board, Canada. I would like that each member of the panel outline the improvements and innovations you are looking for.

MR. HOIDAL: Are you asking specifically to --

DR. JEGLIC: I would like it if each of them would take this.

MR. HOIDAL: Okay. Hardware or in the analysis?

DR. JEGLIC: Whatever is their preference.

MR. HOIDAL: Okay. Why don't we just move down the line here.

MR. MAXFIELD: I'll start. Our priority is, there has been an explosion of pipeline inspection over the last five years. So that puts more and more demands on us as a company. With these new regulations and recommended practices and training people, qualified people, to look at this information, we're going to be focusing a major effort on trying to automate this process as much as possible, take the human factor out of this and be more productive with the trained people we have.

So I think as technology improves you will see more and more automation take place.

MR. WILKIE: From BJ's perspective, I think when we introduced ourselves into the market with our product lines back originally in the late '80s and early '90s with the drill pig and then, in the mid

'90s, with our vector tool, that is our market niche.

We are looking to be an advanced inspection company, and we are always looking to improve electronics, such as your computers and hand-held devices are always getting better, faster, faster sample rates. We are always continuously improving. I guess that is from a technology side of it.

As well, improvements. We always look to improve on the service side of it. We feel we are very strongly a service company and look to continuously improve our service and provide more to our clients.

MS. BARKDULL: Tuboscope feels the same. Our goal would be to provide services to our clients that are useful and allow them to help meet their objectives. So pretty much the market is going to dictate what we do.

In a general concept, we have key indicators that have been around for a long time. Somebody sort of asked, what is the percentage of good runs to bad runs. You always want to make sure your first run success rate is good. You want to make sure you have timely turnarounds in your data analysis. So you are constantly looking at ways to improve those types of issues.

DR. KARIYAWASAM: (Off mike) GE, every year we spend money...improvements in the pipeline. We have many initiatives right now on improving. I think I talked to a couple of them in my presentation.

On the...side, we are working on a tool which is...We are also...feedback and confidence and specification improvement...and another important one is...damage assessments...

We are also, on the assessment side, the other...assessment methodologies that are talked about of data integration and providing more integrated solutions...ILI for pre-inspection, post inspection, and providing integrated solutions...performance and screening methodologies, and that is to verify...So these are some of the initiatives that we are working on right now.

MR. BROWN: (Off mike) At Rosen, we have a research facility of about 250-plus people that are constantly working on improving current technologies. We look at MFL. I mean, as I pointed out, advances in electronics, such as cameras and sensors, is a...based on...analysis and so forth, based on your needs. What are your requirements, what are your demands.

Piggability situations, operating situations...tools. That is something that we want to see develop. We've developed...field MFL. That is the latest technology that for us has now matured over the last five years, since 2000, 2001. XGP, Extended Geometry Inspection, is an enhancement of our current geometry device.

The next release for us will be an EMAT for SCC. And again, we need to understand together, or with you, the industry, what appears to be critical. I mean, is it mechanical damage? Is that the hot topic which will be coming up in the next month or two? SCC, critical mechanical damage. What is critical about SCC that you need from us as an inspection company.

We need that type of feedback as well to develop these tools. We have the opportunity with you to work on these developments, and that is key to these developments being put into practice, is having the opportunity to put these into pipelines, run them against real anomalies, and then show you what these tools can do. I think we benefit from that.

But those are some of the initiatives. Any time we can turn out a report quicker. We're looking at data routines, processing, and so forth to turn those out. So those are some of the highlights there.

MR. HOIDAL: Great. I see that somebody else is standing back there.

AUDIENCE MEMBER: I'm Don (Name) with Exxon

Mobil Pipeline.

MR. HOIDAL: Hey, Don.

AUDIENCE MEMBER: (Off mike) I noticed when the first notice of this meeting came out, there were certain -- four or five case histories and so on where lines have been pigged and then have failed very close afterwards.

I'm not asking for whose method and whose pipelines, but from the notes that I took on this panel, I detect there are like three areas where we can have, let's say, a column. First of all, you could have an operator's pipeline not -- again, the parameters: the measurements of the pipe, the speed of the pig going through it, the cleanliness. That's all one factor.

Basically, as you're running the tool, does it actually...I heard some comments about the rotation of the tool as it's going through the line.

And the third of which is, if that data stayed in for analysis, for evaluation.

I'm just curious, from the whole group, of those three major areas -- again, the pipeline parameters you know before the run, running the tool with its sensors, and then getting the data analysis analyzed by your own people -- the problems we have had, although they are small, can you tell us is there one area or the other which is the majority of the problems or can it evenly be split between them?

MR. HOIDAL: That's directed at everybody?

AUDIENCE MEMBER: Yes.

DR. KARIYAWASAM: (Off mike) I couldn't tell you the strength of those because I don't have...but I would like to add there are two other areas that we have seen failures happening. One of them is because it is not within the tool specs. Our...tool has very good specs and is very good at...performance, but it cannot see -- there are indications of what it can't see in very big dents. Small dents it could be able to see some cracks, but if it's a very...then we get...and we do not...inside that dent...that is an example of a characteristic being beyond the tool spec. We cannot...that is all you can report.

The other error is the assessment. Sometimes we give the sizing of the crack. We had a case where we had even the sizes of the crack, and the assessment done by a third party called out a life that was about 15 years. But when -- and it did fail. But what was wrong with the assessment, because we went and assessed it and found out it was a very shallow and long crack. That certain methodology became very conservative...it was a much smaller crack, and therefore it was the assessment that led to the failure and not the sizing of the crack.

MR. HOIDAL: Anybody else want to take a shot at that? Go ahead, Bryce.

MR. BROWN: (Off mike) Just a general comment. I think -- pointing to such incidents, I think what does happen is that we learn how...from our customers. As soon as we learn about these situations, we go into a procedural mode to then go back and work with the customer to hone in to the location in the data where this exactly happened, and that's key. We need to know as quick as possible. We would like to have back exactly, you know, what footage from a dirt well did this occur, what happened there, what's the assessment from the failure site, and so forth.

We need to clear as much information as possible about that type of situation in order to do an effective review of the procedure or process that we go through, and that's looking at data quality, that's looking at signals recorded at that location, if any.

And then we work with the customer to get to the bottom of it, to find out exactly at which point is there anything to determine. Is it a detection issue with a tool; was it the way the data was analyzed; was it the way the data was treated. We want to get to the bottom of it just like you, the operator, would like to, as well as the regulator. The regulator comes and looks at the data as well.

So that is a very detailed process that we go through to try to get to the bottom of it. We need to know that because, again, we don't want to see that thing happen again. If it's detection limit issues, that's one thing. But if it's something the tool didn't see or something that we didn't analyze properly, then we need to understand those things so we can take a more advanced look.

Just a general comment.

MR. HOIDAL: Garrett, did you want to add something?

MR. WILKIE: The only one thing I was going to add. When that first announcement came out and it had those five or six examples, right away, obviously, you can't get a full appreciation for what's happened because there's probably a 100-page failure investigation report that is also behind the scenes and all that.

But my consensus with most of those after reading them was, well, that was the wrong tool for that problem. So, if anything, from a high level I was going to say, is there a gap. I think there's, maybe, a gap on understanding what some of the technology can do. I'd just go back to what I was talking about previously.

AUDIENCE MEMBER: Good afternoon. Jeanette Jones with (Name) Services. My first question is, operators are extremely seeing problems where the pipe wall thickness conditions and the tool is being hung up on that. Are you doing any kind of research or tool development to take into consideration improving that so that if we didn't transition correctly during construction that the tool won't be hung up?

The second question I have is, what kind of tool development are you doing for the gap gatherers where we have multi-diameter pipes who are transitioning into this?

MR. HOIDAL: Lisa, you've been quiet for a few seconds.

MS. BARKDULL: Actually, I'd prefer to defer that question to our head of our Engineering Department. I'll be honest; as far as the transitioning between the wall thickness, I know there's an issue with that. Typically, the customer will come back and discuss it with our Engineering Department and take a look at what the cause is and maybe even do a root cause analysis, make adjustments to the tool if necessary, or understand the limitations of the tool, as far as the new technologies and developments.

MR. HOIDAL: All right. So you could maybe direct that person to your engineering manager.

Ken, do you have an answer for that?

MR. MAXFIELD: Dual diameter inspection is a unique challenge depending on which technique you use, especially when you're talking about MFL technology. It's very hard. The smaller the diameter, the harder it is to build a dual diameter tool that would adequately saturate the pipe wall in the larger diameter. So there's a physics problem you have to overcome.

Ultrasonics might be a little easier, but you have to put a lot of sensors into a small space as well.

So we constantly struggle with trying to meet your needs. The thing I always struggle with is telling somebody no, but there is some pipelines there is just no physical way to inspect it in one pass. You'd like to get the engineer's hands who designed that pipeline and slap them a time or two, but, you know, what's done is done. We just have to go forward and try and build tools that meet your needs. But sometimes we're limited by the advancement of electronics and physics.

MR. HOIDAL: Shahani?

DR. KARIYAWASAM: On the wall thickness changes, I mean, you can tell how much of a change there is. If there is an extreme change, then we would recommend something like smart scanning or -- scan, which are other tools that we are developing for pipelines. We do have dual tools that we have developed that they are using right now.

MR. BROWN: I think it's all in the preparation. If you know that those things exist in the pipeline, which sometimes you don't, you know, the more information we know about those, you will see that these tools can be modified just by changing out and using a different type of cup.

But, yes, if the wall thickness change is too significant, then that becomes an issue, unless it's been beveled or hammered or something along those lines.

Dual diameter inspection. We have capabilities for doing them for that type of situation. Low-pressure, low-flow brings us into equipment that is self-propelled, crawling. High MFL tools, for example, that crawl through a pipeline bidirectionally. Or your unpiggable situations. As you know, there are companies out there working on providing solutions. We work closely with our customers in that arena, and again, we -- that's how we build our business, is looking at your needs and delivering a product that you can use.

MR. HOIDAL: Thank you, everyone.

I think we had better get moving on to the next panel. The next panel is going to be on Guidance Provided by Inline Inspection Standards. It is going to be moderated by Richard Sanders, who is director of our Training and Qualifications Division.

A few questions have come in during the course of this, but we will save them 'til the end.

I think we ought to all thank the five presenters here, though.

(Applause)

MR. HOIDAL: Here's Richard Sanders.

Panel: Guidance Provided by Inline Inspection Standards

Richard Sanders, Moderator

(PowerPoint presentation)

MR. SANDERS: All right. Let's go ahead, since we're already behind. We'll get this thing cranked off and see if we can't get through some of these standards so that if there are any questions toward the end we will have an opportunity to ask them.

I'm going to be covering the OQ, operator qualification, and some comments on the ASME B31.Q area. Certainly I've already been asked can we make comments at the end of your presentation, so I'm afraid some of you think I'm going to say something wrong.

Qualification of pipeline personnel. Is there anybody in this room that has not heard of OQ?

(Laughter)

MR. SANDERS: Don't show me your hand.

(Laughter)

MR. SANDERS: OQ.1, OQ.2, B31.Q, and on and on it goes. But we hope we're reaching a point where it's going to be stagnant for a few years.

Looking at the history, again I think everybody has heard this time and time again. But if you look at the history of the industry all the way back to 1968, when we got started in this, we've always had some general requirements for training. It's not like we're just now getting into the ball game. So don't lose that perspective.

The other thing I want to mention as I go through this; for those of you that have good, robust OQ programs, any of the changes that may be coming down the tube are not going to affect you that much, if any. So keep that in mind.

Also, looking at some of the reasons that precipitated us to get into this requirement is the 1987 NTSB recommendations for training. In '92 we had legislature telling us to get into the game. The '94 proposed rule on training, which had everybody upset. I don't know about your background, but from adult education areas, if you look at the training requirements, training is a means to an end. We're trying to get qualified people, so this training in itself, where I come from, is not going to get the job done.

I know quite often we use training and qualification side by side, together. But when you start looking at it from an educational standpoint, it does have a different meaning, so keep that in mind. A lot of educational type folks that are in our industry got concerned when we started talking about repetitive training and not using the term "qualification."

Again, NTSB had additional issues with training and testing that, you will see here in a little bit, that we took care of here just recently with a mini rule.

Of course, in '99 the final rule came out.

It established Part 192, 800 series, and 195, 500 series.

Need for additional work, or at least perceived needs. Maybe some of the things that we're going to talk about are already taken care of, and you'll have an opportunity to comment on that a little bit later on.

Development of protocols. We feel like, from an inspection standpoint, we've gotten the protocol questions taken care of. We think that we have answered the need to NTSB with the mini rule. We addressed the word "training" where appropriate. Additional requirements that NTSB felt like as far as the reevaluation intervals that needed to be addressed have been done.

Congress gave us a mandate that we've got to generate a report here very shortly on our efforts in the OQ. Public meetings were held, and we identified 13 areas that we could not reach consensus on. In doing so, it was decided that we thought the best process to go forward with this was to look at a standard. Thus, ASME B31.Q was established to look at and develop a detailed standard that was all-inclusive. Keep that in mind as we go forward talking about B31.Q.

Qualification program in place in '99. Many of you, or all of you, should be well into your OQ programs. The direct final rule, as indicated previously, hopefully, at least in my expectations, has met NTSB's needs. I have not heard anything other than the fact that it was acceptable.

B31.Q, though, is likely not to be completed before next fiscal year. A problem has arisen that Stacey talked about earlier this morning. There are questions coming about. We're in the time cycle to looking at reauthorization, and one of the commitments that we had on the table is that we'd have OQ taken care of. We anticipated that the ASME B31.Q standard would be passed and we'd be moving along to reference in an update in the regulation that standard.

There were a few negatives in the B31.Q standard. The group has gotten together and worked through that and I believe has reached consensus with those negative votes and are now ready to go forward. But still, it's probably going to be into the first part of next year before this hits the street.

So, depending on the reauthorization issues that we've got within OPS and the time cycle that we've got to go through with B31.Q, there may be some data put out for you to start looking at prior to that given time. That's not to say that we won't eventually go back, reference the B31.Q standard, and incorporate it into the regulations as required.

I mentioned there were 13 areas. Just to show you the work that has gone on in the ASME B31.Q area. There were 13 areas that we referenced that we were having problems meeting consensus on, and out of those, I've listed them so that you can look at and get the information as far as the B31.Q is concerned.

In red to the right, you will see the chapter that addresses that particular 13th issue that came up. I'll just click through these for the time, but again, each area is addressed except for the -- one of the problems that we were going through and addressing some of these was the noteworthy practices.

This one in particular we had discussions and it was determined that this was a regulatory issue and, if needed, it should be addressed by OPS/PHMSA when the time was appropriate. So out of the 13, all were addressed through the standard except for that particular one.

Let me propose some questions to you. Whether you want to stand up and give me your response at the mikes or whether you want to write on the three-by-five cards or whether you want to send in your information on an e-mail or what have you, let me propose some questions that we have been asked through the reg writers in headquarters.

When is training appropriate for qualification?  Right now we're saying you've got to have training where appropriate.  And certainly, if it was a new employee coming in for a given covered task, training would be something you should be looking at. But what are the other areas that we need to be considering?  What will you as an operator be considering?  What will you as a vendor recommend that the operator require?

How does an operator provide sufficient objectivity and evaluation of knowledge, skills, and ability.  When we look at qualification, just a written test may not get the job done.  There are skills and abilities that need to be tested, time cycles for accomplishing of a task that need to be looked at.  How are we going to establish what is or is not acceptable.

Assuming some flexibility in the requalification intervals, should there be a difference based on infrequency and critical work, such as abnormal operating conditions?

Also, there is a note, presently -- but I think we're going to see here shortly as we get other standard presentations where this question may be answered. Tasks that impact integrity of pipelines but are performed off the pipeline, such as pig log inspections.

Presently, under 192 and 195, if you go to the definitions section, there is an area that talks about pipeline facility. That definition would be a limiting factor in my opinion for OQ in that it limits it to the pipeline right of way, the appurtenance of the pipeline, et cetera. So there would not be justification within the regulation presently, unless we reference some of these new standards, to go outside of that area.

So, with that said, let me give you the opportunity to ask any quick questions that you might have before we move on to the next standard issue. Anybody got a question they want to propose at this time? Going once, going twice, sold.

AUDIENCE MEMBER: I have a question.

MR. SANDERS: I knew it had to come.

AUDIENCE MEMBER: This question is also a comment. It is true OPS is modifying its OQ regulations to meet the Pipeline Safety Improvement Act recommendation in the draft final rule to require operator programs to satisfy training -- attend training as appropriate and prescribe defensible reevaluation intervals for qualification.  I guess the B31.Q standard, when it's final, will provide more detail on this.

The companies I represent in the liquid industry had some problems with the draft standard that existed at an earlier time, primarily with the prescriptiveness of the standard, not the requirements that were addressed:  training, evaluation.  We understand that Congress has decreed that and we're of course going to comply with that.

But we felt that a performance-based approach was really preferable and that was the key to ensuring improvement over time and that we incorporate new methods as we went along and that the problem of when to set requirements would focus on results, not on how to achieve results.

I understand that the new version of this guidance effort that is available to some folks addresses these problems in a positive way, so we will be looking at that.

But, however, as you indicated, the final has to be signed off, all the I's dotted and T's crossed. Performance standards may not be available in a timely way for consideration in the rulemaking prior to congressional reauthorization.  We hope it is, but if it isn't, I guess our observation is that we think it would be possible to extract from the standard any type of performance-based training and reevaluation language that could be adopted or proposed to be adopted into the new regulations in a timely way so that we would have a rulemaking in progress at least contemporaneously with the reauthorization process.

In any event, we will work with INGAA on a schedule that works for you all and works for industry.

MR. SANDERS:  Thanks, Ben.

Anybody else got a comment?

(No response)

MR. SANDERS:  All right.  Moving along so we can try to make up some time, our next speaker, Pam Moreno, is with Tuboscope, has been with them some 21 years.  She has worked in the analysis area, in sales, and in management.

Please welcome Pam.

Overview of ILI Standards and ILIA's Contribution to Standards Development

Pam Moreno

(PowerPoint presentation)

MS. MORENO:  Get all my operational devices working here.

This is a little different hat for me today. I'm here to speak to you on the Inline Inspection Association. Most of you that I've been working with through the years have seen me talk about all the great things that Tuboscope can and does on a daily basis, and so this is a little different. So, a little different hat.

But we've had a lot of talk already about standards, and what I want to speak with you about is the Inline Inspection Association and how they've been involved in standards generation. There have been some questions about whether the ILIA is supportive of the standards that have been coming out in various levels of completion here through NACE, ASNT, and API, and I just wanted to give you a feel for our involvement in that and so forth, and some of the other things we're doing.

With respect to that, a few folks have reflected back to the mid '80s and the earlier days of pigging and so forth. I was trying to think of what the operator qualifications for a data analyst must have looked like back then. It was probably something like strong wrists, because those 400-foot logs took a long time to get to the other end of. And probably something about holding a grade one, grade two, and grade three stamp in your hand all at once as you went through grading the joints of pipes.

So we've come a long way. Don't -- we shouldn't sell ourselves short or think that because we're having a meeting like this today to talk about some of the concerns that we haven't come a long way in what we do and how we accomplish it.

This pictorial, this is sort of the whirlwind of regulations for the past couple of years. There has been a lot of --

(Laughter)

MS. MORENO: -- standards involvement going on. It's been hard to get your hands around it. I know that operator qualifications is difficult to get your hands around sometimes, as well will be 1163 and some of the others. It's actually Hurricane Ivan in the Gulf last September or so. I'm an avid fisherwoman, so I kind of keep an eye on that and see how the water looks.

I'm going to talk a little bit about the introduction of the ILIA Association. We were founded in April of 2002. There were five charter members at the time that got together and decided that maybe if we worked together in some sort of a format that we could help regulations or recommended practices come out in a more meaningful way for our operators and more meaningful for the inline inspection companies themselves.

And so that was the beginnings of it. You see there the website.

The founding members were BJ Services, GE -- back then PII -- and Rosen, TDW, and of course, Tuboscope. Our newest members that have just signed on in the last couple of years here have been CPIG, NDT Systems and Services, and Weatherford.

So it's not a big organization. It's not a huge meeting; it's a pretty small meeting. I will tell you we meet basically quarterly to talk about issues. We usually get involved in certain types of classes and try to help train OPS inspectors or other avenues that need training. And so we welcome anybody that wants to bring or address an issue at one of our quarterly meetings to come.

We usually meet in the Galleria area, and it's quite easy to get to, at least for those of you here in Houston, or to call in and address an issue that you might want us to look at, like standardized -- I call them Lionel Log survey questionnaires, but I guess survey questionnaires. That has been a common theme. Can we have a standardized one that we all use, and I think they did come out with one in 1163 to address that issue.

In our beginnings, our primary focus was to support the pipeline industry, to enhance pipeline integrity. We wanted to raise the awareness of the ILI industry, of all the products and services we offer, the new things, the old things, the capabilities, the limitations, best practices, and so forth.

We also wanted a legitimate format with which we could liaise with industry associations and regulatory bodies. In other words, when any of us individually went to a regulatory body or an industry association, it was all about Tuboscope, and we needed to get in a forum where we could speak and it wasn't so specific to one particular service provider, as we call them; vendors as some of you call them.

So that's how we moved forward. We began participating in the development of standards very quickly, best practices, and we also wanted to raise awareness of R & D initiatives as well. So there we moved forward.

I will say on behalf of the ILI companies, and I hope the rest of them agree. I heard a quote earlier in the day, and as companies, we're all emphasizing communication so strongly. And this morning -- and it was with regards to a different subject -- Peter Lidiak's presentation, he said, we do expect to be questioned, informed, educated, and even acted against when we don't perform adequately.

I think that's the most serious statement we have to make from the ILIA companies. We want the feedback. We expect the feedback. We need it. We want to continue to improve. We need operators' help on that.

With regards to the standards writing and involvement, there were a couple of industry drivers for that. One was, as we tried to become more and more efficient and as new technologies and processes were coming on board to improve data accuracy and reliability, we found that, you know, of course, that introduced new types of errors or new types of issues to our groups.

Also, the competitiveness that came across the market as the regulatory involvement became stronger created some new market forces, some new -- old players in various stages of development in their R & D processes with regards to equipment and with regards to analysis systems. And so those were important driving forces.

And within the U.S. specifically, as I said, the new regulations have increased the demand for our products and services a great deal. The market demand issues became capital equipment, having enough of it, being able to run enough pigs to keep up with what was going on. Right behind that became trained personnel to do all those things. And then robust systems, and of course, the quality assurance side of things at the tail end of the process there.

Clarity and commitment to the future is required to manage growth. What I mean by that is, we definitely need to understand where the operators want us to go and how we need to move forward to do the things you want us to do.

And then, the main topic here, the recommended practices and standards are being published as we speak.

What is required in a standard. We found that a lot of the operators were looking for some transparency among providers. In other words, help us use your data more easily by providing it in formats that are easier to integrate into our other systems and so forth. We began immediately to engage in the generation of consensus among the providers and the operators so that we could come together on what standards would look like.

We wanted to provide a platform to improve and maintain quality in a growth market, and we wanted to respond to all of the industry expectations that very quickly were coming on board.

In a lot of these slides you will see the commonality of the operator, the regulator, and the service providers coming together.

The first thing the ILIA did with regards to standards was to start trying to figure out, how do we write a recommended practice. How do we do this. We got together some really good folks from the different inline inspection companies, and they began the process of writing a recommended practice. This was deemed ILIA RP 5302 Draft for the date that was it was originally drafted. It never became an actual standard in itself because what we found was being a standards organization is quite an undertaking, as NACE and ASNT and API could tell you more about.

So we merged -- went on forward with it anyway and started writing a recommended practice. We figured, we'll get it as far along as we can and then we'll find out who we can hand this off to. So we wrote basically a 62-page document. What you see here is the table of contents from that document and some of the things that were encompassed in it.

This is the first page and the second page, and you can see we go into measurement analysis improvement, management responsibilities, personnel resource management, in other words operator qualifications, and really, a very, very detailed document.

We then, at completion of that document, started working with several groups to try to help continue along the standards-writing. By that time, we were able to get in together with ASNT and with API. The NACE standard had pretty much been completed at that point, the initial version of it. But we got together with the ASNT and API and started a more wide-ranged effort at doing these standards.

And so when people ask do we support the standards, are we involved, much of what we've written are in the standards. So we're very involved, we're very supportive, and it is a place that we want to continue to move forward in.

In summary, I have to give you my obligatory pig picture because I can't do a whole presentation without a pig, without some data, or without some pipe. So this is what we're all talking about. We're talking about pulling all that together and having standards that make sure that that happens in the manner that it's supposed to happen.

Those are -- again, the participation has been and will continue to be threefold. We need all those groups working together. They have worked together very, very well. We want that message out there. We've worked together very, very well to establish these standards. None of it has happened in a vacuum. It's been a very large effort. I know most of the operators know that, but I just want to make sure that everyone knows that.

The regulations have and will continue to increase the demand for more ILI-related products and services; we know that. We've seen the idea of turnkey work take off like crazy this past couple of years. We're no longer just running a pig, and none of the ILI vendors are just running a pig. Everything is starting from the very basics all the way through integrity management, risk analysis, fitness for purpose, and all the way through.

We have a significant time investment in writing these standards, and in refining these standards and we will continue to be involved. We need balanced and cooperative standards, standards that will allow companies to operate their pipelines and meet the standards and still make a profit and go forward from there.

Our future challenges. To increase the pace of acceptance and implementation of the standards I think is a huge challenge for us. Sometimes these standards come out and it takes a lot of time before they're recognized by regulatory agencies and so forth, or given credence, and we need that to happen faster. I'd be willing to say that the very -- just because of this meeting happening, we got 1163 out about four days ago. I think that might have been a little bit of a push because of this meeting coming on, and I think that's awesome.

We want to utilize the standards in a way that is effective, consistent, auditable, and efficient. We need cooperative efforts, as I said before, to improve and update the standards as they mature.

We need to evaluate and adjust the standards in a way that allows operators to make sound integrity decisions to maximize the benefit versus cost ratio of their maintenance dollars. We don't need folks spending money in the wrong places because a standard has been poorly written or hasn't been revised in a timely manner. We need to make sure that dollars are spent smartly, and I'm sure I'm singing to the choir on that one.

With that, I'll pass it on to the others.

(Applause)

MR. SANDERS: Has anybody got a quick question for Pam before we move on to the next speaker?

(No response)

MR. SANDERS: All right. At this time, I'd like to introduce Dave Culbertson. Dave has got some 36 years with El Paso. I've known Dave for a number of years. Matter of fact, I won't tell you all the stories that I know about Dave, but in introducing Dave today, I couldn't resist reading one of the areas that's on his resume.

Dave is a past president for the American Society for Nondestructive Testing, an ASNT fellow, ASNT professional level three in RT, UT, MT, and PT. Now, don't give me a hard time about acronyms in the federal government anymore.

(Laughter)

MR. SANDERS: So, at this time, I'd like to welcome Dave Culbertson.

(Applause)

Genesis of ASNT and API Standards and Details of ASNT ILI-PQ Standard, "ILI Personnel Qualification"

David Culbertson

(PowerPoint presentation)

MR. CULBERTSON: Thank you, Richard.

Before I address the ASNT standard, and as Pam eloquently put it together as far as the cooperation from a number of people to end up developing these particular standards, I'll give you sort of a brief history of the development of how we sort of got here today.

I see Bernie over here smiling. He was one of the fire starters for this.

But back in November of 2001 -- so everyone remembers 9/11, so it was just a couple of months after this horrific incident -- we got together here in Houston as an ad hoc group just made up of pipeline operators both from the liquid and gas side. We had the ILI service providers, representatives from the Office of Pipeline Safety, we had independent consultants, and research laboratories. They actually met at my office up at the Intercontinental Airport, which was convenient for those coming in from out of town because they didn't have to go very far.

It was out of that particular meeting that we looked at the standards development process, what would it take to put together standards, what would we need for inline inspection. From that, if I can figure out which way we go, Richard, with the pointer here.

MR. SANDERS:  There's the pointer.

MR. CULBERTSON:  No, I mean the slide.

(Pause)

MR. CULBERTSON:  >From that particular meeting we came out with a mission, and that ad hoc group worked out the mission to develop a nationally recognized consensus standard and/or recommended practices that will provide the pipeline industry, liquid and gas, with qualified personnel and systems that perform inline inspection activities, including the acquisition and analysis of the data.  So that was the overall put-together of our mission to go about how to do that.

The ILI Oversight Committee was then put together, and its responsibility was for coordinating activities and the outputs of the three different standards that we've been talking about today, that being the one on personnel qualification from ASNT, the recommended practice from NACE, and the systems qualification from API.

The American Society for Nondestructive Testing has been developing American national standards in the area of nondestructive testing personnel qualification and certification since 1987.  ASNT is accredited by the American National Standards Institute, ANSI, as a standards-developing organization.

ASNT's Standards Development Committee within ASNT -- again, we use these acronyms, Richard -- SDC, it was established by the ASNT board of directors to develop and maintain ASNT's national standards. The Standards Development Committee and its subcommittees handle ASNT standards activities.

Some of the standards that ASNT has, as we see here. The one, of course, that we're interested in today is the one at the bottom. The following standards are either presently published or they're in the process of being in development.

As Pam mentioned, it was sort of timely that these various standards sort of come out and are being published around the same time. The NACE recommended practice has been out for some time and has been available. This whole process has taken a couple years, and it's putting together the initial draft for a particular standard. Then you've got to go through the standards approval process.

Anyone that understands this industry consensus process, it's not something that's just done overnight. Not only does it have to get approved by the initial committee that's developing this, it has to go back to the regular standards body. That one has to approve it. Then the ANSI has to publish that out to the industry for comments. If any comments come back, then those comments have to be addressed, positive or negative. Send it back out again. If there are any changes, get published again, and go through this same process over and over.

So even though we started in November of 2001, we sit here today in August of 2005 and we now have the two standards and the recommended practice out for public consumption.

Okay. What's the scope of the ASNT ILI-PQ 2005 standard. The ILI Personnel Qualification Standard was drafted in just a little over a two-year time period by the ILI Personnel Qualification Subcommittee, which was a subcommittee of the ASNT's Standard Development Committee.

Following an industry consensus process on the standards developing -- development, the composition of the ILI Personnel Qualifications Subcommittee that wrote the ASNT standard was again made up of members from a cross section of groups, from pipeline operators, ILI service vendors, regulators, consultants, research organizations, and third party consultants.

The ASNT standards specify the qualification and certification of ILI personnel, and it says that that shall be the responsibility of the employer. So this isn't saying that ASNT is going to go out there and certify -- qualify and certify these personnel. ASNT has developed the standard for industry to follow and it will be the responsibility of the employer of the ILI personnel.

Within the standard, it says that the employer will establish a written practice. The written practice is for the control and administration of ILI training, examination, and certification. So Richard spoke just a while ago about training, what does that mean, and so on. What the standard is saying is the ILI vendor shall tell us what it's going to be by placing that in their particular written practice.

The written practice is a documented procedure developed by the employer that details the requirements for the qualifications of their personnel.

The employer's written practice shall be reviewed and approved by designated management personnel. So it's not just some engineers go over here and write some nice gobbledy-gook words and say we're going to end up doing it. Management has to buy into this and support the activity.

The employer shall maintain the written practice on file and it shall be made available for auditing. So be it the regulators, be it the operators that want to come in and audit the particular program, it has to be maintained on file and made readily available to those.

The employer's written practice shall describe the responsibilities for each level of ILI personnel. There are basically three levels. The standard talks about four levels. There is a trainee, which is basically someone who is starting out and has to gain experience and training in the needed technology to become certified as either a level one, a level two, or a level three.

So those of you that are familiar with the NDT certifications, it follows along that same guidelines. A level one has less experience than a level two. A level two has more experience and is probably the worker bee of the particular group. Then we have the level three, someone who has a lot of experience in the technology, is capable of doing training, writing procedures, and performing the examinations of the level one and level two personnel.

The experience is cumulative. Training hours are cumulative. Training shall be outlined in the employer's written practice. Experience can be shared between ILI technologies. So it doesn't necessarily say that, oh, well, if I start with a new technology, do I have to start all over again. No, you put the two together and that counts as part of that.

The standard presently identifies seven technologies. There is geometry, axial magnetic flux, transverse magnetic flux, ultrasonic compression wave, ultrasonic sheer wave, EMAT, and mapping.

The standard defines two categories of ILI personnel qualification in its present format. That is, the ILI tool operator -- so again, there are three certification categories, level one, level two, and level three, for tool operator -- and ILI data analyst, level one, level two, and level three.

The employer shall be responsible for the administration and grading of examinations specified within the written practice. Now, they may delegate that out to a third party to perform some of those particular responsibilities of administering the exams and grading it, but the written practice shall specify how that's done.

The employer's examination shall address the basic principles of the applicable tasks to be performed and identify abnormal conditions. So, what happens when we come up with something that just didn't go right, okay? You need to address that in how you go about putting together your particular examination.

Certification shall be based on the satisfactory completion of the following qualification requirements as defined in the employer's written practice: education, training, experience, and then examination. So it takes those four pieces in order to become certified.

So, again, there is a difference between qualification and certification. Qualification is identifying what attributes do I have to achieve to get to the point of certification. Certification says that all four of these attributes have been completed successfully.

Once certified, there's a recertification period identified in the ASNT standard, and it basically specifies that every three years this individual shall be recertified. And it will specify in there and give guidance to the employer how they want to identify this. This could be by reexamination in all of the areas, could be reexaminations in some critical areas, or combinations of those factors.

Okay. Termination of certification. Because the way the standard is put together and it says that the employer shall develop this written practice, it's the employer's certification. So once an individual has terminated employment with that employer, their certification is null and void.

Okay. Now, there is a way of going back and getting recertified with a new employer, and it doesn't necessarily mean, oh, I've got to start from ground zero and start all over again with getting hours of classroom training and experience. No. As long as that's documented, you can carry on work and go to a new employer and the new employer's written practice will then address how they can go about recertifying personnel that have been terminated from another employer.

Okay. What are some of the future directions that we see in the ILI-PQ standard. Some of those are looking at, do we need to expand the categories beyond the two that we already have: the tool operator and the data analyst.

Another criteria that has come up is auditing criteria. Some people have asked as we developed this, well, Dave, who is going to qualify or certify the third party consultants that are going to come in and audit these particular programs?

There already are some guidelines out there in the industries in the ASTM standards for how you go about auditing NDT service laboratories. So what we are looking at is possibly the next generation of this particular standard, is that we would write some criteria for auditing ILI qualification and certification criteria within the particular written practice.

Okay. This is the new standard. As with the API, I have been coordinating closely with the ASNT headquarters about when is this document coming out. It was approved back in May of this year, but it just hasn't hit the particular newsstand. I was sent a proof copy of this particular -- not a proof copy but a sample copy of this particular document, and ASNT has assured me that they're on the bookshelves and they're ready to be ordered.

So if anyone is interested in that, I'm going to leave some pamphlets and folders up here for you to pick up if you want to end up ordering that document.

Another quick way -- you don't have to fill out the particular document. You can go to www.asnt.org. That's their website. And go in and actually order this particular standard from them.

There are two pricing schemes on it. One is, if you're an ASNT member, you get a reduced rate compared to a non-member.

And that's all I have.

(Applause)

MR. SANDERS: Has anybody got any questions for Dave; short questions?

(No response)

MR. SANDERS: Okay. Our next presenter, Linda Goldberg, is with NACE. Linda is the director of Technical Activities at NACE International, where she manages the development of standards and technical committee reports and other activities of the NACE Technical Committee.

So, at this time, let me present Linda.

NACE State of the Art ILI Report and RP0102-2002

"Recommended Practice: Inline Inspection of Pipelines"

Linda Goldberg

(PowerPoint presentation)

MS. GOLDBERG: Thank you.

Okay. As Richard said, I'd like to provide you some information about NACE publications and other activities on inline inspection. As some of the other speakers have said, ILI technology has been around for a lot of years, but it wasn't until the 1990s that a committee was formed at NACE to write a technical committee report. They published the report, which is NACE Publication 35-100, in 2000.

If you know any -- if you'd like to know about the numbering scheme, this publication was done by Specific Technology Group 35. It was the first report they published in 2000. So that's how you can tell when a report was published and what committee it was published by.

At the same time, another committee was working on a standard, and later a standard was published.

This report is pretty comprehensive. It covers all the different types of tools, the new technologies and existing technologies. And during the development of this report, there was a lot of input from other groups. I know that our committee met with an API committee and probably other committees, because their objective was to get the most and best information they could from across the industry to put into the report.

This is a list of the sections in the report. As you can see, it covers the different kinds of tools and how you analyze what tool to use and how you manage the data.

There's a very long reference list. I think it's three or four pages, and it's divided according to topic, for those who want to look up more information about inline inspection. It also has several appendices. Some people may not be familiar with all of the terminology used in the inline inspection industry, so there's a glossary of terms and a list of acronyms and abbreviations and specifications that are used.

The last couple of things that are in the appendices are items that we wouldn't normally put in a technical committee report because they are procedures. So they are put in appendices as examples for people to use if they would like to.

The reason for that is that in NACE technical committee reports we don't allow recommendations or requirements. So if a committee wants to include some of those or a typical procedure, which they would like to do a lot of times, we put that in an appendix. The reports just give results of research or results of a survey, the state of the art of a particular technology. They're informational reports. We leave it to the standards to give requirements.

A lot of times when a committee is working on a report, that information in the report will lead to a standard. Usually the report gets a lot of input.

There's a lot of research done, and it may be very comprehensive. A committee will frequently decide to develop a report first for that reason, and then they'll develop a standard.

That's kind of what happened with this report and standard. There was another task group, Task Group 212, that developed the standard that you've heard mentioned several times today, RP0102-2002, Inline Inspection of Pipelines. This was published in 2002, and it gives the process for the ILI and the data management and data analysis. It's for carbon steel pipeline systems transporting all of these various gases and liquids.

This is a list of the sections in RP0102. It gives definitions and data analysis requirements and all of these other things that you can see. It also has a short list of references, not like the report. If you really want the long list of references, you'll need to go to the report.

It includes a sample pipeline inspection questionnaire that you can use. You can adapt it or use it as it is. It has a good figure in it. There is also a table that lists the ILI tools and their various applications.

NACE is an American National Standards

Institute-accredited developer, like most of the other organizations that are here today. One thing about the ANSI process is that it's an open and transparent process, which means that we have to solicit input from all interested parties. It's sort of like OPS in the public meetings. They're trying to get everyone's input so that they can produce the best regulations. Well, ANSI standards developers try to get input from interested and affected parties so that they can produce the best standards.

We advertise ballots that are going out, standards that are being developed. If you check the NACE website, we'll have a list of ballots that are going out soon. Even if you're not a NACE member or if you're not a member of the committee that's developing that particular standard, you can call and request a ballot and vote on that ballot. You can also go to the meetings. All of the meetings are open.

If you're a non-member, you can set up a password and vote online using the online balloting system. There's a way for members to vote using their member number, but you can also do that if you're a non-member, and the committee considers all of the comments and votes that they receive.

Sometimes other organizations will get

together and send one response from that organization, which is one way that it's done. But also, if you're an individual member of another organization, you can register to vote and send in your vote, also.

Now, the ANSI standards and other standards -- this was already part of NACE's procedures, but standards are required to be revised or reaffirmed every five years, which means that the committee has to look at the standard and decide whether they think that the technical information is still good and they just want to keep it as is, without making technical changes. In that case, they would recommend that it be reaffirmed.

The committee can reaffirm it in a meeting. They can send a letter ballot, but most often it's done in a meeting, as long as the committee is notified ahead of time and the standard goes out with the agenda for that committee.

But since they have to get this done every five years, it's best that they start a few years ahead, which is what they're doing with RP0102. That revision is due in 2007, so this committee is already working on the revision. Pam happens to be the chair of that committee, so if you'd like to talk to her about that, feel free.

The committee can start a revision right after a standard is published, if they want. Sometimes the committee works very hard on a standard and, because of new information coming out, or sometimes new safety information comes out for some reason, they will decide to revise it immediately after it's published. That doesn't happen that often, but it's best to start two or three years ahead of the revision because the revision is supposed to be complete at the end of five years, not started at the end of five years.

Usually, we reactivate a task group that published a standard originally. Just to keep the continuity, they can keep the same task group number. Usually the chairman will be different and some of the members will be different, but they will still keep that task group number and reactivate it.

NACE committees meet usually twice a year, although they can meet more often if they have a lot of work to do. And on some of these pipeline integrity standards that have been published recently, they've met many more times than just twice a year. But the official NACE meetings are twice a year at the NACE Annual Conference and Corrosion Technology Week.

Corrosion Technology Week is in Calgary this year in September, from September 18th to the 22nd.

Task Group 212, which is working on the ILI standard, will meet at that meeting, and I've given the date and time on the slide. Feel free to come to that meeting and provide your input if you would like.

This year, for the first time, NACE members don't have to pay to go to this meeting. But even if you're not a NACE member, you're still welcome to come.

NACE also has a second type of committee called a technology exchange group. Usually these committees have information exchanges in their meetings. Sometimes they have planned presentations like we're having in this meeting. Sometimes they just have an open discussion where people can come in and post questions and discuss problems they're having and other people will respond and give solutions that they've had to those various problems.

This Technology Exchange Group 267X is on the same topic as the inline inspection standard, so they'll be discussing topics related to inline inspection. Sometimes these TEGs provide suggestions to the task group that's developing a standard. TEGs don't develop standards, but they often do a lot of research. They have presentations sometimes that are solicited from very knowledgeable people.

We have another technology exchange group on the direct assessment process, in fact, that has a list server going, and people respond to the list server with suggestions. They're going to provide input to that task group. So this is another way that industry provides input to the standards development process.

The task group that develops the standard is very small. It's usually maybe 10 to 15 people. So those people develop a draft, but then there's a much wider group that votes on the standard and there's a much wider group that can have input. There are usually several sponsoring STGs, one or more sponsoring committees, that can vote on it, along with anyone else from industry who wants to.

So if you would like to come to the Corrosion Technology Week meeting, and you would like more information, please see me after the break or at the break or after the meeting and I'll give you some information.

The last thing that I wanted to mention is that NACE is developing a course on inline inspection. This is just under development, so I really don't have details on this course. I'm sure that it will use the standard on inline inspection and possibly the report, too. But I -- it's just under development, so it's not -- there's not any information yet.

But I would suggest watching the NACE website for information on the courses. If you're a NACE member and get Materials Performance Journal, it will also be described in there. But usually the most up-to-date information on technical committee activities and course activities will be on the website, and the URL is given here.

Of course, please feel free to call me if you have any questions. If I can't answer it, I'll be happy to direct you to the right person.

Richard?

MR. SANDERS: Linda, thank you, ma'am. Appreciate it.

(Applause)

MR. SANDERS: Any questions for Linda?

(No response)

MR. SANDERS: Our next speaker, Bryan Melan, is system and integrations leader for Marathon Pipeline, LLC in Houston, Texas. He is responsible for pipeline structural integrity of Marathon's assets in Texas, Louisiana, Wyoming, and the Gulf of Mexico.

Mr. Melan has over 15 years' experience. He is present vice chair of the NACE Task Group TG 212, which developed the RP0102, and is presently chairman of the NACE ILI Committee TEG 267X. He is also co-chair of the API 1163 Work Group, which developed the 1163 Inline Inspection Systems Qualification standards.

Bryan?

(Applause)

Inline Inspection Association

API 1163, "ILI Systems Qualification"

Bryan Melan

(PowerPoint presentation)

MR. MELAN: Thank you. I know I'm the only thing standing between you and the break, and I also know how comfortable those chairs are out there, so we're going to get through this fairly quickly.

It feels a little bit today, with all the announcements about API Standard 1163, that this is kind of a coming out party. Standard 1163 is getting a lot of mention and attention here for a standard that probably the vast majority of you haven't even seen yet. So we encourage you to get it, to read it, to use it. It's an attempt to standardize across the industry on processes used for inline inspections.

I'd like to take this opportunity right now; since this is the first time since it's been published I've been able to address folks, I want to thank all the members of the 1163 Work Group, a lot of whom are here today. I especially want to recognize my co-chair, Jerry Rau of Panhandle Energy. Bryce Brown was vice chair; Bryce from Rosen Inspection. And a special recognition to Mr. Bernie Selig, who was kind of the catalyst that put all this together and kept us focused as we went through the process of developing the standard.

The first thing to mention is this is API 1163's first edition. We want to give this thing a chance to be used and to be matured and developed. Other standards API have published -- API 1104, for example, is going into its twentieth revision. We don't envision that this standard is perfect by any means, and there are going to be problems, there are going to be gaps, and there will be revisions.

But pretty much it's a good first step, establishes a good path forward for the industry, both operators and ILI vendors, and it's kind of an organization of best practices. The work group consisted of a wide array and a wide diversity of individuals with various experience.

API 1163 provides requirements for the qualification of inline inspection systems. The standard ensures that inspection service providers make clear, uniform, verifiable statements describing inline inspection system performance.

It also ensures that pipeline operators select an inspection system suitable for the conditions under which the inspection will be conducted. This includes pipeline material characteristics, pipeline operating conditions, and the types of anomalies expected to be detected and characterized.

It ensures that the inline inspection system operates properly under the conditions specified. It ensures that inspection procedures are followed before, during, and after the inspection. Also, the anomalies are described using a common nomenclature as described in the standard.

The standard is non-technology specific. It covers all inspection technologies. It's performance-based. It tells you what's required, what needs to be done. It does not tell you how to do them.

It provides requirements for qualification processes. It defines the documentation of the processes for system qualification. It fosters continuous improvement in ILI quality and accuracy, and you've heard that several times this morning about the feedback between service providers and operators and vice versa. We'll see that.

It standardizes ILI terminology, and this was a particular concern of ours in the work group and something that got a lot of attention because ILI has developed kind of haphazardly over the years, the use of ILI, and people were calling different things -- the same anomalies different things. They were defects, they were anomalies, they were features; what's the difference?

This is a figure from 1163, and it kind of takes you through the steps of when an indication becomes an anomaly, when an anomaly becomes a defect. When an anomaly doesn't become a defect, it's a feature or an imperfection. It's kind of hard to read right here, but it's in the standard and you can go through those steps and see how the terminology evolves.

We also encourage in the standard to use the terminology in the definitions section, calling metal loss, metal loss, and deformations, and the difference between deformations and dents, the difference between validation and verification.

Under Preparation, this slide is called "Operator Responsibilities." But it also mentions that while service providers have the responsibility to identify inline inspection system capabilities, their proper use and applications, the operators also have responsibilities. These are to identify the specific threats to be investigated, to choose the proper inspection technology, to maintain operating conditions within the ILI system performance specification limits, to confirm the inspection results, and to provide feedback from the verification results to the ILI service providers.

Under the Goals and Objectives, the goals and objectives of an inline inspection shall be defined. The procedures used to define the goals and objectives are not part of the standard. If you need help, if you need a reference, there are other standards out there that will help you define the goals and objectives of an inspection. Some of those are API 1160 and ASME B31.8S.

This is one of the keystones to the entire standard, the performance specification. The performance specification shall define the capabilities of the inline inspection system to detect, locate, identify, and size anomalies.

The service provider must statistically validate the system performance when generating this performance specification in terms of the types of anomalies or characteristics covered by the performance specification, the detection thresholds and probabilities of detection, probabilities of proper identification, sizing or characterization accuracies, the linear distance and orientation measurement accuracies, and any limitations of the system. The service provider is required to submit a qualified performance specification to the operator which will define these parameters.

Under the Execution phase of the standard, this is where the other two standards tie in. Personnel and equipment used to perform inline inspections and analyze the results shall be qualified according to API 1163 and the companion standards ASNT ILI-PQ and the NACE RP0102.

Combined, these three standards provide the requirements and processes for the qualification of inline inspection systems, including inline inspection tools, their software, and the personnel to operate the systems and analyze the results.

Under Reporting, only feature and anomaly identifications and characterizations that are within the performance specification and can confidently be called within the performance specification may be reported. Other features that the service provider is not comfortable saying are within the performance specifications may be identified, but they must be reported and identified as unqualified.

This is where I've heard the term used before, "undecipherable type signals." If they're not confident they can be put into terms of the performance specification, they may be reported but have to be identified.

Under Verification, I think Lisa touched on a lot of this earlier, so we're not going to go into it in very much detail. But the process must be validated. That's the first step of verification. Data -- comparison with historical data for the pipeline inspected or, also, you could compare the data with historical data from a similar pipeline system that was inspected. Data comparison with any large-scale data used to qualify the ILI system, such as from pull tests.

Verification digs may or may not be required, and we'll look at Figure 4 in just a second to see what we're talking about there.

Regulatory- or operator-required investigation digs are an additional consideration beyond the scope of this standard. In other words, we're just talking verification digs here to verify that the tool performed within the performance specification. You may be digging a lot of other things for regulatory or your own requirements.

This is Figure 4. Again, a lot of detail, but take a look at it in the standard. Basically, we'll start on the left-hand side, where we completed the ILI data and the process is validated. If we cannot validate the process and account for discrepancies, we cannot validate the results and therefore verification measurements are suggested.

If we don't have good comparison with historical data, if something looks amiss, then it's also recommended that verification digs be performed.

However, if everything lines up and all the planets align and you've got just a few anomalies and they were all reported pretty close to what happened during the last inspection, we can verify the results without digs. The standard allows that.

Under continuous improvement, when verification digs are performed, information from the measurements shall be given to the service provider to confirm and continuously refine the data analysis processes. Any discrepancies between the reported inspection results and verification measurements that are outside the performance specifications shall be documented.

I think I'm going to repeat one more thing I believe came up in a question earlier. What happens when your data and your verification measurements are outside the performance specification? And again, to repeat, there is communication that has to happen between the operator and the service provider to sit down and review that data.

The inspection data may be reanalyzed altogether, depending upon how serious and prevalent the discrepancies are. All of part of the inspection results may be invalidated, or the performance specification may be revised for all or part of the results.

Finally, the last slide. This is another figure within Standard 1163. It shows you how everything progresses from the ILI to be conducted and starts the steps -- the real meat of it starts in Section 6. Everything else before that is pretty much boilerplate references, the definitions sections.

Section 6 starts where you select a system. It also links with NACE RP0102. Linda mentioned the table of ILI tool selection in RP0102. That is an excellent reference to use to help select the right tool for the threat that you're looking for in the pipeline.

Section 7 specifies performance. This is where the performance specification comes in that the operator receives from the service provider to tell what's expected of the tool.

Preparing and running the tool is covered in Section 8, and validating the operation of that tool is also in Section 8, to validate that you've got a good run and you've got good data.

And then, down at the bottom is where ASNT actually ties in with the data analysis and also preparing and running the tool, in Section 8, because of the two different classifications of personnel that are being qualified.

And at the bottom is the feedback loop. That's where data is analyzed, reports issued, the verification takes place, and the feedback occurs, and maybe the report has to be modified or issued or the specifications changed. But again, we're emphasizing the feedback loop.

Thank you very much for your attention.

(Applause)

MR. SANDERS: Has anybody got any questions at this time? Everybody is wanting to go to break.

(No response)

MR. SANDERS: Let's go ahead and take our break. We've got a couple of questions we'll answer when we get back in and get started again.

(Brief recess)

Question-and-Answer Session

MR. SANDERS: As everybody is taking their seats, there was a question -- matter of fact, got a couple of questions I think I can answer with one fell swoop.

The question is, "Sanders stated OPS would not be issuing final rules on OQ since B31.Q is not being published on time." I hope I didn't say that. If I did, I apologize because OPS is moving to write a final rule on B31.Q, certainly utilizing the information that's been generated in ASME B31.Q. But it may be late in arriving due to the fact there were negatives that had to be worked through and had to be sent back out through the committee to get final votes on.

Even if it gets published at the end of the -- at the beginning or the first of the year, certainly there will be the opportunity for OPS to be petitioned to adopt the ASME B31.Q, or at least those applicable parts in it.

But as Stacey indicated earlier, we feel like we're required, based on the reauthorization and commitments that we've made, that we've got to go forward with this rewrite to broaden the scope based, again, as ASME B31.Q indicated.

The other question was, "Would the direct final that was published in March be retracted?" Absolutely not. That was accomplished to meet the requirements of NTSB, and as I stated, I believe that we met and accomplished what NTSB was asking us to do.

Not only that, if you go into the law, it specifically required us to address some of those areas. You as an operator were already required to meet it whether it was in the regulations or not. So all we did is took wording and all from the regulations and put it into the codes under 192 and 195.

And then, the last one again addressed the direct final rule of March 31. It's a final rule. It's out there. It's applicable. Matter of fact, the inspection protocols were changed in the headquarters inspection and field verification forms to reflect that it's mandatory that you address those requirements. So anybody that's undergoing an OQ audit today should in fact have those questions proposed to you and should be audited accordingly.

Any other questions that we need to answer on the B31.Q issues? If not, I would like to turn the program back over to Joy.

(No response)

Panel: How can Assessments be Improved to Carry Out the Intent of the Regulations?

Joy Kadnar, Moderator

MR. KADNAR: Thank you, Richard.

This is the last panel, and in this panel, it will be more interactive, more informal. We would like to have some ideas on how we move forward, what needs to be done, what we need to do, what the standards organizations could do to improve the process and improve the education of the pipeline industry at large.

I would like to introduce the panel we have here. On my extreme right is Dr. Franci Jeglic. Dr. Franci Jeglic is with the National Energy Board in Canada. He has 35 years of pipeline experience. He is presently with the National Energy Board, and he's a member of the ASME and Canadian Standards Association and others.

Beside him, on his left, is Mr. Brian Sitterly. He is the integrity and regulatory services manager of Shell Pipeline Company. Mr. Sitterly has 19 years of pipeline experience. Over the last five years, he has led the development of Shell Pipeline's integrity management programs. He has held many positions in engineering, operations, community safety, and regulatory services.

In addition to Shell Pipeline's Integrity Management Program and Risk Program, he leads the public awareness and damage prevention efforts and Operation Qualification Program.

Mr. Sitterly is a graduate of the University of Texas at San Antonio, and he has a B.S. in civil engineering. He is also a registered professional engineer in Texas.

On my right is Mr. Shamus McDonnell. He is the CEO of Hunter-McDonnell Pipeline Services. He has worked extensively on pipeline integrity since 1990. Hunter-McDonnell specializes in advanced pipeline integrity data analysis and management, improving inline inspection and pipeline protection, and GPS survey data.

And on my left is Mr. Bernie Selig. Many of you know him. He has over 40 years of experience in the power, insurance, and pipeline industries. Lately he has been concentrating on standards for the pipeline industry, including ASME B31.8S, API 1163, and ASME B31.Q.

Mr. Selig has a flight at 6:30, so he would like to make a short statement. We will start off with him. Immediately after Mr. Selig, we'll go to Mr.

Sitterly, who would like to make a very short presentation, and then we'll talk amongst ourselves and invite questions.

Thank you.

Remarks by Bernie Selig

MR. SELIG: Joy, thank you very much. I guess the question for us all is, how can assessments be improved to carry out the intent of the regulations. At least that's the title for this section.

Assessments, since IMP initiation, are on the whole okay. Some of the examples given in the public announcement occurred before IMP began in regulation. If there are companies gaming the system, that is a regulatory problem. Find them and deal with them appropriately. Don't make the rest of the industry do additional things because of the inappropriate behavior of a few.

I want you to remember that ILI is not an assessment. Assessment requires a comprehensive, integrated, and systematic approach to acquiring and integrating data and then assessing it. ILI is one piece of that assessment.

I'm known in the industry for speaking my mind, and as you can see, I'm doing that now. And then

I'm going to cut out of town, so.

(Laughter)

MR. SELIG: One of the things I'm seeing -- and I've gotten to see an awful lot in the industry over the last 10 or 12 years that I've been very nicely associated with the pipeline industry. I just want to make one comment, and if the shoe fits, you've got to wear it.

You cannot subcontract out your integrity management approach. That's what all these people here have been telling you about communications, the reason we need the communications. It can't be one way; getting a vendor or service provider and saying, "Do an ILI. Tell me what I have to fix, and I'm done." That will not work. It's got to be a cooperative venture.

Now, the new standards that we've been talking about today address many of the issues mentioned in the public announcement. As a matter of fact, when I went through the six or eight bullets that show those, there was only one that the standards did not address, and that was because of tool limitations or incorrect tool use, and even that could be covered.

What I'd like to advise OPS to do is to let industry take some time to implement these. I'd like OPS to assist in disseminating them by issuing an advisory for all three of these standards out to the entire industry and recommending that they try them. Let's see how that works.

And I have some thoughts for OPS and NTSB. Is there anybody from NTSB here?

(No response)

MR. SELIG:  Okay.  It'll be on the record, and I'll hear about it.

(Laughter)

MR. SELIG:  OPS has and continues to be actively involved and participate in the development of these industry standards, and we are very much appreciative of that.  We wouldn't be where we are today without their involvement.

Working on standards and then incorporating them into regulations, such as the diagram that was shown earlier, is actively trying to resolve open NTSB issues.  Standards are one way of doing that.  OPS, take credit for your efforts and explicitly communicate them to NTSB and tell them how you're anticipating that particular standard will take care of an issue that NTSB has raised.

Now I have a comment for NTSB.  NTSB should provide comments during the open comment period on standards when standards go through the ANSI review process. These technically based standards do cover many of the issues NTSB raises, and they need to be more aware of them and perhaps a lot more involved.

And I know they have a particular scope, but the way they get dragged into this is we as an industry tell them we're going to take -- we agree with your concern and the way we're going to take care of it is through a standard. Then they get dragged into it, and they should be somewhat actively involved. I'm not suggesting they should be on the committees, but they should clearly review the standards and understand how those standards are going to take care of some of the issues they have.

Those are the only comments I wanted to make. Thank you.

MR. KADNAR: Thank you.

(Applause)

Remarks by Brian Sitterly

(PowerPoint presentation)

MR. SITTERLY: I just have a few slides I wanted to run through. I think you'll find that they, to a large degree, summarize some of the points you've heard today, but I also hope they prompt some questions from you all for the discussion that's supposed to take place later.

But this first slide up here, four years of continuous improvement. The message I want you to take away from this slide is, we've not been at this very long, but there has been a lot of significant work that has been done. It was just in 2001 that the rule was issued, or became effective, rather. That same year, API 1160 was printed.

In 2002, we started seeing the first written integrity management programs among liquid operators, and they've continued to improve ever since.

By the end of 2004, the liquid industry had completed more than 50 percent of their HCA mileage in terms of being assessed.

And just here in 2005, API 1163 and its associated documents are coming out. That should take us to another level.

Now, API 1163 has gotten a lot of air time here today, but we shouldn't forget some of the other significant work that's gone on over this time frame: documents like B31.8S, the suite of NACE direct assessment documents, and we shouldn't forget API 1162 on public awareness, so.

Just a quick slide on some of the results we've achieved. As a result of the rulemaking, there's been a significant increase in the miles inspected and therefore anomalies repaired. Data integration is identifying additional injurious conditions. Technology and our knowledge related to how to do this work is continuing to improve. The new consensus documents are educating and setting standards for process rigor across the industry.

The performance metrics show that there has been a significant improvement in release performance since the implementation of the rules and things like API 1160. With 1163 and the supporting documents coming out, with more mileage yet to be assessed for the first time, with improvements in technology, with additional R & D that's taking place, the stage is certainly set for continuing improvement down the road.

In preparation for this public meeting, I participated in some conversations with other pipeline operators, trying to identify, you know, what do we think we ought to be taking into consideration looking forward on this road to continuous improvement. This list here represents the consensus of that group and items that we can mutually agree upon.

The first thought is, allow the rule, the protocols, in industry documents to continue delivering results. They clearly are delivering the results. It shows up in the performance metrics. These items have set a great framework for continuing to improve. Operators and everybody has a lot of room for improvement within the framework that exists today.

A thought about the incidents that were referenced in preparation for this public meeting. The thought here is, analyze incidents in context with overall performance. Overall there is clear improvement. There is not a lot known about the incidents that were referenced. The causal findings have not been broadly shared. So it's difficult to know whether or not we have a trend developing or we have a new learning developing.

But in the absence of a new trend, in the absence of a new learning, the recommendation is we ought to stay the course. Now, stay the course doesn't mean don't continuously improve, but one thought we wanted to capture here is we need to resist the temptation to make sudden course corrections that may be counterproductive. They may take away resources from focusing on these methods that are clearly working and we're still trying to incorporate to a higher level in our programs.

Knowledge sharing is a huge opportunity for continuing improvement at this point. Forums like this work very well. They're not the best forum for developing detailed learnings about how operators are doing this business, what's working well. We need smaller, more intimate forums where there's more detail that we dig down into, and I think through that process we'll identify additional best practices, proven practices, and be more effective in moving the whole industry towards improving.

Obviously, we all want to strive for continuous improvement. The people resources we use in this business are relatively highly specialize. They're slow to develop. We can't address everything at once. Whether you're an operator, a vendor, or a regulator, we don't have all the people we need to be as effective as possible. So the point here is, let's just make sure we focus those resources on delivering the greatest improvement over time.

And the last slide I'll show up there is one you've seen several times now. What we're doing is working. Let's keep heading that direction.

Thanks.

(Applause)

MR. KADNAR: Thank you, Brian.

Would you like to add something? You just told me you wanted to add something.

(No response)

Panel Discussion

MR. KADNAR: (Off mike) Having gone through this entire day, one very important thing that struck me was what Andy Drake said. Here we have maybe the best pipeline operators, and maybe just one -- you know, 3 percent of the pipeline operators in the country. Most of the operators...I believe, good. How do we educate the other pipeline operators?

And it then struck me...to tell pipeline operators what we can expect of them would be a good idea. Another idea would be...pipeline operators to take a look at all these standards that have been issued, that have been reviewed and implemented, integrate them into their programs, and implement program operating.

Another option we have is -- I had something in mind. I'm sorry.

(Laughter)

MR. KADNAR: (Off mike) There are options of standards and regulations. I'm not...process. We can speak to counsel and Director of Regulations, Florence Hamm, as to what can be done, but the option that we would take -- I don't know the process how it would work or can it be done, you know.

And the third option we have at present is to make the industry at large aware of these standards.

I had a few questions in the interim. Dr. Jeglic, since you work with the National Energy Board, can you tell us -- can you shed some light; is there anything being done differently by the Canadians than what is being done by us in the U.S.?

DR. JEGLIC: Well, I listened today and I observed what you are doing in the States. What I realized is that you said you have all the same goals, so we have the same goals. What we are talking about is performance indicators, the integrity performance indicators. And we are formulating a few indicators that would be established on a yearly basis so we can compare the average performance and then see who is above and who is below.

Then, again, coming back to the goals, since we have all the same goals we have decided to have goal-oriented regulations. So what the goal-oriented regulations say, it's the same goals: no ruptures, no injuries, no fatalities, high safety standards, high integrity standards.

And what the operator has to do is, he has to develop an integrity management standard program. So all our operators, they have programs and they are programs that they feed their systems.

And I heard today that there would be audits. We have, also, audits. Very similar; what you are doing we are doing. But we also have audits but we don't have too many audits per year. We regulate approximately 110 companies. And we also realize that we have large companies and not so large companies, so we divided the companies in Group 1 and Group 2.

And so those audits cannot cover all the companies in the cycle of five years. So what we did, we went and had a meeting with the pipeline operators and we talked to them. The staff talked to them, and they held a presentation on what they did in the last year and what they will do the next year. We hold one or two meetings per year with the operators, and the operators generally like this kind of one-to-one approach.

And there are a few other things. There is one other thing I want to mention. I don't want to elaborate too, too long.

What we are looking today at is the pipelines in service. It happens that, first of all, I want to mention that most -- not most, but many pipelines that you operate in the States start in Canada and maybe they have a different name. But basically, there is -- they will originate in Canada and it would show perfect integrity on your side.

But we are also looking at the new pipelines, pipelines from the north, and there are some challenges, I understand, for the vendors if the tools will operate at verified pressures. We are looking at pipelines up to 3000 PSI and we are looking at pipelines that we are operating in sub-freezing temperatures. These are all gas pipelines, and the future operators tell us that there are no pigs that would withstand those circumstances. But they also tell us that they work with vendors to develop those pigs.

There are a few other small things, but for now I think I should give a chance to other members here at the podium.

MR. KADNAR: This question is for Shamus. You told me that you've worked a lot overseas. Are there any good practices that you have seen deployed overseas that, you know, maybe we could absorb over here in the inline inspection industry? I think we always believe we are right on top on the face, but is there something that you have seen adopted by companies overseas that could help us improve?

MR. McDONNELL: For the most part, most of us out in North America in a lot of ways is starting to becoming industry-leading. There were times not that far in the past when practices were quite a bit different. There was a fast, low-budget approach to pipeline integrity and it wasn't taken as seriously.

There were stronger and more comprehensive standards and so forth developed in other regions where failures had greater consequences. Now that those consequences have started to increase here, there's no question that the bar has been raised here and has come to the forefront. Some of the stuff that is happening right here is leading for other companies in other parts of the world.

So nothing specific comes to mind.

MR. KADNAR: Okay. Is there anything, being a practical person, being someone who works with pigs, evaluates logs, and does other tasks, other activities, is there anything that you think can be something that as a regulator we should be looking at, or that an operator should be looking at? You've seen the pig logs, you've seen how the operators flag it, you know our regulations, you know what the operators' plan is. You see the entire picture.

MR. McDONNELL: The biggest one that comes to mind; it came up today, or the comment came in several of the discussions, with the feedback loop. When the operator receives the data from the vendor and goes out to do his excavation and repair program, there has still been some reluctance on the operators' part to collect enough data to give good feedback back to the vendor.

This relates back to the low-resolution tools as they've evolved. It wasn't that many years ago -- 15 years ago, you'd get a log and it was graded one, two, or three, meaning it had less than 25 percent wall loss, less than -- or, 25 to 50 percent wall loss, or greater than 50 percent. So you'd go out there with a pit gauge and confirm that, yes, we did find a 60 percent wall loss pit in that joint. That meant that there was good correlation.

Today these tools are calling out thousands of individuals calls or anomalies in a single joint, and we can't begin to collect that data efficiently in the ditch. It's a big problem. There are some automated tools, but it's time-constrictive and there are limitations to what the pipeline operator is willing to absorb at this point in time to collect enough data to close that feedback loop in a resolution and reliable fashion that can be used by the ILI vendor to improve their records.

It's something that we need to work on, but there are practices and stuff being developed and there has been a lot of improvement there. But it's still one of the weaker areas.

When the operator can confirm that the anomaly does or does not require repair, once he has the pig excavated, in most cases sufficiently, they make their repair, they can move on. They do not need to stay there for 10 hours collecting data to validate the log at that point. They confirm they have to repair it; they're going to cut it out. That's where they want to stop.

The low-resolution field data, though, is typically collected in those instances. It is completely inadequate to the ILI vendors. Even if supplied back to them, they're going to look at it and go, well, it shows a very poor correlation because in the field they measured at a much lower resolution than the tool did. So that's one major area that would probably help that and probably make it easier for the ILI vendors to receive that feedback from the operators.

MR. KADNAR: Interesting. Brian, you're familiar with the code, the ASNT standard, right?

MR. SITTERLY: I'm not particularly familiar with the ASNT ILI-PQ standard, if that's the one you're

--

MR. KADNAR: Okay. I'd like someone to answer this question on the standard. It came to my attention -- and I'm not familiar with the standard, too -- that there appears to be a significant difference in how the inline inspection analysts are qualified and, you know, with respect to how NDT personnel are qualified.

Supposedly, NDT qualification is recognized worldwide and there's a testing program. Inline inspection qualification is in-house, so it can vary from company to company. If this is so, is there a need to reconcile the differences?

MR. CULBERTSON: Dave Culbertson from El Paso Corporation. As far as the ASNT standard, it was developed using the same boilerplate that the NDT standard has today. The guidance was from having input from the ILI vendors of what they felt were equivalency to what the present NDT standards are.

Now, you bring up a good question on that particular point. That is, we now have a benchmark to start from and we have to percolate through this and see how it comes up. Yes, the next edition may be changed to be more specific and identify those areas for qualification, but right now it's a starting point.

It's an agreement among those who participated in writing the standard.

MR. KADNAR: Thank you very much, David.

AUDIENCE MEMBER: Scott (Name) with GE. I co-chaired the ASNT standard with Dave. One of the things across the inline inspection analysis process is different focus areas depending upon the flow processes that are automated. Some areas are more automated in some companies than are others.

So what you find through the inspection providers is various needs for various expertise. So when we developed the standard, we allowed that to reflect which operators or which suppliers have different requirements.

So the recommended hours of training that are in the standard itself are recommended based on a selected group but not written to be prescriptive across the board. So a little bit of, I think, what's being perceived is the numbers that are in the standard are actually hard numbers, but they were baseline projections from the consensus group. But those need to be reflected within your written practice of in those areas that you've identified as key process steps and taken into account.

So it's there for a guideline, but specific -

- each inline inspection provider should have those key tasks and the training required to be competent in those tasks reflective of the nature of the work.

So you'll see a little bit of variation, but it's contributable to the process.

MR. KADNAR: Thank you, Scott.

Shamus, this question is for you. It is my understanding from the previous investigations that we have done that some operators request only features beyond a certain threshold to be reported. Do you think -- like, for example, they'll say, "Give me all pigging above 30 percent wall loss."

Do you think this is a good approach, and should all features within tolerance for that particular tool be reported?

MR. McDONNELL: There would likely be -- I'm trying to think of an instance where a pipeline operator would not want to know everything that's on their pipeline. They're in the transportation business. They have to have product running through their pipeline in order to make their money. The last thing they want is to have interruptions to that production.

So to start cutting parts of data off and not want to know what's out there is not a good approach.

That's like putting your head in the sand. It's best to confront it and see what's out there.

There are -- I suppose if you get a line with a great deal of data on it and you're trying to focus on particular regions of the pipeline, that's probably a better approach than to start not wanting to know what might be there.

As far as anomalies that meet the threshold criteria of the tool, provided they can be sized they should be. I believe there was a terminology in the last presentation about an API 1163 for unqualified calls. If it's a defect that can be seen by the tool but it cannot be sized accurately, then to identify it at least to make the operator aware of it I think is something that should be done. It's not something that they should be held to, of course, from a standpoint of the operator has to address it or so forth. It's a difficult thing to do.

It's just something they should be aware of. There should be a validation from the standpoint of confirming it. If it looks like a T -- as in your earlier presentation, if it's something that looks like a T and from all the records -- construction records on the pipeline there's no record of there ever being a T at that location, it's something that should be investigated.

MR. KADNAR: (Off mike) Let me ask you another question on data and on defects. Are there any tools that can pick up combined defects: corrosion, pitting, and other defects, for example? Will we be able to define the size -- eventually extract the size of the...and the corrosion?

MR. McDONNELL: To the best of my knowledge, only the tools that combine different kinds of technologies can size and accurately detect both. So it would take a combination tool that can use MFL for wall loss and also have caliper sensors on it, for instance.

There are tools that have secondary effects. MFL tools, especially transverse tools, are sensitive to pipe geometry, so they will pick up the change in shape of the pipe; however, they cannot size that. So what they will see is they can confirm that there is what appears to be wall loss in an area where the pipe is no longer round or has been deformed. They cannot size the deformation.

It's not necessary that that is critical at that point. If you have a combined defect, it becomes very difficult to assess that. So there's value in knowing that there is more than one type of defect there. Typically it requires running more than one tool, combining those two logs, layering them, correlating them together properly, and then looking for whether it's overlap or combination defects.

MR. KADNAR: Thank you.

Dr. Jeglic, do you have any ideas how we can improve performance beyond what has been done today?

DR. JEGLIC: Who is "we"?

(Laughter)

MR. KADNAR: Including you.

"We" meaning the industry and the standards organizations.

DR. JEGLIC: Okay. That's --

MR. KADNAR: Loaded question. I'm sorry.

DR. JEGLIC: It's a good question. Well, I think you are -- or, we are on the way. We have a standard now. Lots of people were asking for a standard, so we have one now. I think vendors started doing their best.

What I haven't heard today, and I think this was a good development, is that some operators had specific requirements for their pipeline and they would get together with the vendor and the vendor and operator would develop a pig that would suit the vendor's pipeline.

So that's something. I'm aware of two or three cases in Canada, and I think this is a good development. Definitely there were -- lots of people talked about understanding or communication, and so there was lots of communication.

If I can summarize what I've heard today, I think vendors are doing their best, operators are doing their best, standard-writing organizations are on the ball.

Qualification of the people. What I kind of detected; I think if the vendor has a very qualified person and understands the pipeline system and the operator has a very qualified and experienced person that understands the inline inspection technologies, I think both kinds of -- there is just not a kind of contact required but it's a required contact for understanding on a higher technological level.

So I think, as you see, you have a large attendance today, even as late as now in the day. Maybe there should be also smaller meetings, if somebody can organize them, you know, where people can exchange day-to-day experiences. Or, there is a good experience where we have in Canada that a group of knowledgeable regulators goes and visits the knowledgeable operators.

Now, we do talk to operators and we kind of get information from the vendors on presentations to us, especially with new developments. But we regulators are operators, so we require the operators that they have the right inspection techniques on their pipelines and so on and so forth.

So we are not entering into contractual arrangements because -- contractual arrangements are very important because you can buy from the vendor all kinds of services or you can buy only a few services. And this depends. If you are willing to pay, if the operator is willing to pay, I guess we'll get lots from the vendor. Sometimes the operator is restricted in funds that are available for these services. So I always ask when we go to visit the other operators, "What's your budget?" This tells me something.

Questions

MR. KADNAR: (Off mike) Thank you, Dr. Jeglic.

I'd like to open the questions to the floor. In some cases, you may not have the right choice to answer the question, so, you know, if you know who your question is directed at, a morning speaker who is still in the audience maybe can do that. I know that...would like to leave by 5:00, and Bill still has to give a closing statement. So we can take a couple of questions.

AUDIENCE MEMBER: I'll be brief then, Joy.

MR. KADNAR: Okay, Christina.

AUDIENCE MEMBER: Christina (Name) from OPS. Actually, this isn't a question, it's a comment, and it's a comment on how do you get to the smaller operators and better educate them. I think that this type of forum is a great start. However, most operators, especially the smaller operators, don't have the resources to attend these kind of events, which is why you see the bigger operators.

I know that the trade associations supply information to the members: American Gas Association, American Petroleum Institute, Association of Oil Pipelines, Interstate National Gas Association, and American Public Gas Association. I think I've covered all the American ones. We provide information.

So as these events come out, we can distribute -- there will be webcasts so people can tie in remotely. That helps. It also helps if you post the proceeding and the presentations on your website.

I agree with Brian and with Franci that smaller workshops, preferably around the country, on specific topics would help.

And I'll make one more suggestion. There's a lot of information currently out there. It's very difficult for even large operators and trade associations to summarize the information for people. It would be fabulous if we could have sort of a Cliff's Notes version of the various standards that are currently out there which trade associations can then supply to the smaller operators. You can post it on your website.

I think that will provide people a better perception of what's currently out there that can assist them when it comes to inline inspections. That's just my comment.

MR. KADNAR: Nice comment. Thank you.

(Applause)

MR. KADNAR: Any other questions or comments?

AUDIENCE MEMBER: John Zurker (ph) with Process Performance. I appreciate what Christina said, but Cliff's Notes have an inherent nature and that's something interpreting what the standard says. So I'd have to object just a little bit, Christina.

The other thing I'd like to say is, industry, government, service providers identified 15 standards being developed about three years ago. Thirteen of those are now published. There are two remaining: one is on IPGA and the other one is on pressure testing, and those will be out soon, I hope.

But let's give these standards a chance to work before we start doing something stupid. They're new. They will evolve. They will improve. We will learn lessons and we will make modifications.

The second point I'd like to make is there are about 900 operators of approximately 1200 transmission pipeline systems in the United States, liquid and gas. Probably 100 are represented here. You may have another 100 on the website, like Christina said, but I think the Office of Pipeline Safety stopped woefully short of fulfilling their obligation to notify these operators of what is out there and what their expectations are.

Yes, you post on your website that this meeting is going on and, yes, you invite people to attend. But you do it on your website. You do not contact people individually to tell them that you're going to hold this meeting. There are a lot of small operators with just a couple miles of pipe, and trust me, they do not have the ability to find this out.

I also know that every pipeline company in the United States is required to report to OPS at some point in time something about their system, either through integrity management, through annual reports, or through incident reports. OPS is the only organization that has that complete list. There is nothing wrong with you sending letters to these people advising them, if you will -- I don't want to use the word "advise," but notify them these standards are available, you know. That may be an expectation that we think you ought to look at, okay, something on that order.

You are the only ones that know who all those people are. The 200 here are fine. The other 700, like Danny said this morning, they're the ones I'm worried about. Those are the one we need to have an outreach program for.

So, thank you.

MR. KADNAR: Thank you very much.

(Applause)

MR. KADNAR: Any more comments?

(No response)

MR. KADNAR: No questions, too? Thank you.

I'd like to now hand over the stage to Bill Gute, who will make closing remarks.

Closing Remarks

William H. Gute

MR. GUTE: Thank you, Joy.

It's been a long day and so I'm sure everyone is tired, so I'm not going to spend a lot of time up here, you know, rehashing all the stuff that has been said today. There has been a tremendous amount of information that's been given by the panel members. You know, we really appreciate it. This is a huge turnout, so it was certainly an area of interest for everybody.

I think some of the comments we just heard at the end here are some good ideas. I mean, we are trying to outreach and reach people. We can take a look at how we do it, if there's a better way. We have some ideas. We can consider how to do them and, if we can do it, we can do it. Maybe even e-mails to some of these people, if they're sending e-mails to us, we can use that way. Letters generated and so on, you know, takes quite a bit of work.

But anyway, we can look at how to do that, and we want to do it. I think that's the most important thing.

I think a couple key points are communication. We heard that all day long. I think, you know, it goes between the regulator, the vendors, the operators, and the public. Let's not forget the public. They're interested in how we're doing.

But one of the things I heard was, you know, the vendors and operators have to have -- understand their goals and expectations, the capabilities, and they have to have a feedback loop.

Also, I think the field verification aspect and understanding and reporting in standard ways between the vendor and the operators certainly has come out loud and strong. I think it's an important aspect which I think probably, when we're looking at operators' IMP plans and programs, we'll probably start taking a look at that closer than we have in the past.

I don't see a sudden change in course. That came up a couple times. But, you know, we're quite proud of our IMP rules. I think Stacey mentioned that. We spend a lot of time on public outreach and feedback, and I think the results are showing. We saw a lot of slides about -- and the liquid industry is very proud, and I think they should be -- that downward trend. We're proud of that, too. That's how we're judged.

So I don't see a change of course, but we do want the continuous improvement. But we can't do it alone. I think that's the other thing that I want to say, and I know Stacey wants to say it. It's got to be a collaborative effort, and that's with the industry, the vendors, and the public. I think this is a good example.

I'm very impressed with all the panel members that came up here and spent the time and effort and made their slides, and all the people that came out to hear it. So thank you very much for that.

Let's see. I had a note about trying to get to the smaller companies. I think I've talked about that.

And I want to acknowledge the work the standards committees have done. John Zurker just got up and talked about the number of standards that have been developed, and they have -- that is quite -- that is a huge amount of work that's been done, and I think they're extremely useful. And I think we will give them the test of time. I'm not sure what the comment meant, you know, "Don't do something stupid."

(Laughter)

MR. GUTE: But anyway, hopefully we won't do that. But we want to test them, and they have to be field tested. We realize that, you know, when a new standard comes out, that's the first standard. They have to be used. They have to be field tested and there are revisions as they come along. So we recognize that, and I think the standards will help us make better judgments on how we look at companies and how they're applying their procedures and applying their IMP programs.

So I think they're extremely useful to us, as was pointed out. We all agreed that they had to be created, and they've been created, so now we want to test them and utilize them.

So, with that, I don't have much more to say, other than, again, thank you very much. I think Joy has something here.

MR. KADNAR: I'd like to make an announcement unrelated to this meeting. It's about a mechanical damage workshop that Jeff Wiese, our program development director, will be hosting in the month of October. There will be a Federal Register notice. I think the date hasn't been fixed yet because they're going to get together in Houston. But I think Jeff is working on it.

So look for that. Look for that Federal Register notice. There is a website, and I think (Name), she left, but she had a website address where we are requesting information on mechanical damage. I don't know the website; I'm sorry.

MR. GUTE: Yeah. I guess two more things, then, Joy. You know, the results -- the transcripts will be posted -- of this meeting will be on our website in a few weeks. You'll be able to get that.

And if you have additional questions, you know, we want the feedback. Please give us feedback. That's important for us to know what the issues are or, you know, ideas on how to do things better.

So, with that, I think -- thank you very much for attending, and this meeting is adjourned.

(Applause)

(Whereupon, at 4:55 p.m., the meeting was concluded.)