UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of: *

ENBRIDGE - LINE 6B RUPTURE IN MARSHALL, MICHIGAN * Docket No.: DCA-10-MP-007

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Presentation by SCOTT IRONSIDE

Enbridge Headquarters
Edmonton, Alberta
Canada

Monday,
December 5, 2011

The above-captioned matter convened, pursuant to notice.

BEFORE: MATTHEW NICHOLSON
Investigator-in-Charge

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I N D E X

I N T E R V I E W

MR. NICHOLSON: Okay. We'll go ahead and start. We're on the record now recording. This is NTSB Pipeline case number DCA10MP007, Enbridge Energy July 2010 crude oil release in Marshall, Michigan. These are the Integrity Management Group interviews being conducted at the Enbridge headquarters in Edmonton, Alberta, Canada. Today is Monday, December 5th, 2011.

This interview is being recorded for transcription at a later date. Copies of the transcripts will be provided to the parties and the witness for review once completed.

Today's discussion is actually an overview of integrity management provided -- being presented by the Integrity Management Group of Enbridge.

To begin with, we'll go around the rooms and have each person introduce themselves for the record. Please include your name with spelling, employer's name, contact phone number and e-mail address.

I will start and we'll progress clockwise starting from my left. My name is Matthew Nicholson, M-a-t-t-h-e-w, N-i-c-h-o-l-s-o-n. I am the NTSB IIC. My number is [redacted] My e-mail is [redacted].

MR. FOX: I'm Matt Fox, M-a-t-t, F-o-x, with the NTSB. Phone number is [redacted] and e-mail is [redacted].

MR. IRVING: My name is Stephen Irving, S-t-e-p-h-e-n, I-r-v-i-n-g, and my title at Enbridge is director, pipeline compliance and risk management. My phone number is [redacted] and my e-mail address is [redacted]

MR. JOHNSON: Jay Johnson, [redacted] Cell: [redacted].

MR. VIGNAL: Geoff Vignal, Enbridge Pipelines, [redacted]. And e-mail is [redacted]

MR. SPORNS: Ryan Sporns, R-y-a-n, S-p-o-r-n-s. My employer is Enbridge Pipelines. My phone number is [redacted] My e-mail address is [redacted]

MR. KEANE: Sean Keane, employer is -- well, S-e-a-n, K-e-a-n-e. Employer is Enbridge Pipelines. Phone number is [redacted]. My e-mail is [redacted]

MR. IRONSIDE: My name is Scott Ironside, S-c-o-t-t, I-r-o-n-s-i-d-e. Employer is Enbridge Pipelines. My phone number is [redacted]. My e-mail is [redacted]

MR. THOMPSON: Matthew Thompson, M-a-t-t-h-e-w, T-h-o-m-p-s-o-n. My employer is Enbridge Pipelines. My phone number is [redacted] My e-mail address is [redacted]

MR. PIERZINA: Brian Pierzina, B-r-i-a-n, P-i-e-r-z-i-n-a. [redacted]. My phone number is [redacted] and my e-mail is [redacted]

MR. CHHATRE: Ravi Chhatre, R-a-v-i; last name, C-h-h-a-t-r-e. I'm with NTSB, and my e-mail [redacted] -- that's [redacted].

MR. NICHOLSON: Okay. Scott, if you want to begin, you're welcome to.

PRESENTATION BY SCOTT IRONSIDE

MR. IRONSIDE: Great. So what we'll do is run through a series of PowerPoint slides to assist in describing to you, firstly, a general overview of the development of our department historically, as well as getting into some detail in each of the three planning areas within our group in regards to managing threats on our pipeline system, including corrosion, cracking, mechanical damage, denting type scenarios.

So they'll be three -- sorry, four distinct sections within the presentation. So I'll lead through the first overview part and then pass it along to Sean, Ryan and Geoff here, maybe.

Okay. So for my introductory slides, what I've done is broken it into four areas. I will just do a quick pipeline system overview, moving along to how our pipeline integrity focus has been within the company and some historical overview of how we've developed over the life of the pipeline system. We'll get into the current organizational structure and also then talk about how we implement our pipeline integrity programs.

So this is just a geographical map of North America that shows the pipeline system under the Enbridge liquids pipelines that we have the responsibility for maintaining. You can see that we operate a pipeline up in the Norman Wells down to Zama area. The majority of the system is originating in Edmonton. There is also some original pipeline systems coming down from the oil sands in Fort McMurray. But the core of the system follows the corridor down from Edmonton through to Gretna, Manitoba, where we get to the U.S./Canada border, and then carries down through from there into the Clearbrook/Superior area, and onwards down into the Chicago market.

We also have a pipeline that goes north around the Great Lakes and also then meets up in Sarnia. From Chicago we also have the pipeline system moving up into the Sarnia area. And then once back into Canada we have a number of pipelines that move eastward towards the Toronto and Montreal area.

MR. NICHOLSON: Where is Line 3 on this map?

MR. IRONSIDE: Line 3 on this map would run from Edmonton in the main corridor, from Edmonton through to Gretna and then on from Gretna down into Superior.

MR. NICHOLSON: Okay.

MR. IRONSIDE: So Line 3 would effectively terminate at Superior. And I should also mention, then, of course, there's the system that connects up with Cushing, and so there's a pipeline system -- spearhead pipeline that connects with Cushing.

MR. FOX: Then does Line 6A, would that connect at Superior going down to Chicago?

MR. IRONSIDE: That's correct. So in this corridor here, Line 6A runs from Superior down to Chicago, and then 6B from Chicago up into Sarnia.

MR. FOX: Okay.

MR. IRONSIDE: And, of course, that's a numbering system. The pipelines ultimately where we -- largely has to do with where the breakout of the oil is. So we have terminals that we would have full breakout where the oil goes into tankage and so then effectively the scheduling of movements out from that terminal would go on what's effectively a different line number. So that's the reasoning for the line numbering.

So the pipelines -- some of the characteristics might be similar as far as pipeline diameter or those types of things, but may have a different name just from a scheduling prospective.

MR. NICHOLSON: So it's a one number going into the tankage and then it gets a new number coming out, is that what you're --

MR. IRONSIDE: Potentially, yeah.

MR. NICHOLSON: Okay.

UNIDENTIFIED SPEAKER: In some cases it's just a -- you know, a 2A, 2B situation.

MR. IRONSIDE: Yeah. You'll see reference to --

MR. NICHOLSON: Yeah, I see that.

MR. IRONSIDE: -- Line 3A, 3B, or 2A, 2B at times but it just has to do with the scheduling.

Just some high level details of the system. So, over 20,000 kilometers of pipeline with a line fill capacity in the order of 6 million cubic meters of oil. The pipeline diameters range from 6-inch up to 48-inch in diameters. There's around 650 pumping units at around 225 pump stations, so typically you would see every 40 miles along the pipeline right-of-way a pumping station that reenergizes the crude oil to continue it moving down the system. So, in total, we're in that order of magnitude around 225 geographical station areas.

There's in the order of 35 custody transfer locations. So this would be a location where we're either receiving crude oil from a shipper or we're delivering crude oil to that same shipper, another refinery or that type of thing.

We have over 50 different shippers on the system, so customers of ours that own the oil that moves down our system -- we don't own any of the oil that's on our pipeline system; it's all customers of ours that they want to move crude oil. So we don't own oil, we just simply move it for the companies that want to get it from Point A to Point B.

There are in the order of 115 different commodities or crude oils that we move, so we ship crude oils, refined products, natural gas liquids. But within the definition of crude oil you would have many, many different -- what are considered commodities. So, whether it's a heavy crude oil, a light crude oil, medium crude oil, and all the variants within those would be defined as having a different commodity.

The oil is moved in a batch configuration, so the batches of oil are typically in the order of 10,000 cubic meters in size and would be tracked as such. So different customers have a different crude oil that they want to get to a certain location, and that batch of oil would be tracked as it moves through our system.

Generally speaking, it's not a batched -- or, sorry, a batch pig configuration. Normally the turbulent flow will provide an interface between one batch versus the other and contain the ability to keep that one batch contiguous.

There are some elements -- or, sorry, some pipelines on our system that do require a batch pig in the event that the pipeline may be flowing in laminar flow or slower speeds that require a batch pig. But, generally speaking on the system, we have no requirement for batch pig.

Looking at how the company developed the integrity management program where it is today, if I take us back to the '70s, we as a company began assessing the pipeline system at the time with magnetic flux leakage tools as well as caliper tools, looking for corrosion and denting. As the technologies were available at the time, we would consider those to be what were called a low resolution magnetic flux leakage tool. We continued to developed that strategy ever since. The tools, of course, have become much more sophisticated. But going back to the '70s, Enbridge was involved in the development of those types of techniques to assess the condition of our pipelines.

The pipeline system has always been built to be piggable, so we've generally speaking had all of our pipeline system piggable right from the -- from construction. As the development of technology continued, Enbridge was involved in the development, and whether it be in the research area or simply by the use of the technology in our system, to continue to understand it and allow the developers to learn.

As shown here, the magnetic flux leakage, as I said, was from the '70s to current. MFL is still a very important tool that we have in our tool box for understanding the corrosion condition on the pipelines.

Ultrasonics were developed alongside the MFL to assist in better understanding the corrosion condition on the pipeline and Enbridge has been involved from the '80s through till now, and continued to use ultrasonics from a -- as a tool to identify metal loss.

Similarly, ultrasonics in the '90s, late '80s, were developed to identify cracking on pipelines. Enbridge was instrumental in helping develop ultrasonic crack detection technology, starting with the elastic wave tool, which is a little bit different than the current technology, but ultimately looking for -- searching for different ways to utilize ultrasonics to better understand the cracking condition on pipelines.

As well, the caliper tools have evolved over time, so the caliper tools that have been used to identify pipe deformation and denting have evolved. Enbridge has been involved in the development of that and certainly in the use of caliper tools all along.

The last sub-bullet there, just to talk about variations in those technologies. So, there are a number of variants to the MFL and ultrasonics that have been developed over time. Circumferential MFL is, I think, a technology you would have heard of. It's the same technology, just using the magnetic field in a circumferential direction, as opposed to axially. It's an important change that was made to better characterize longer narrow corrosion.

As well as developing a tool for understanding the inertial data along a pipeline, so using GPS and high resolution spatial data to understand where the pipe may be bent or moving around within the pipeline system. So I guess -- the trade name would be the geo-pig that Baker Hughes owns, is a tool that Enbridge significantly contributed to the development of to understand the condition of pipelines and where they may have moved.

BY MR. NICHOLSON:

Q. When was that introduced, the geo-pig? When did were -- started to use that?

A. The geo-pig was introduced in the '80s actually.

Q. Okay.

A. We helped develop it for our Norman Wells pipeline. As I mentioned, the Norman Wells to Zama pipeline being in the permafrost. So we developed that tool with them to run on that pipeline system.

Q. With who? Baker Hughes?

A. Yeah, it was -- well, it was Nowsco at the time, but currently Baker Hughes is the vendor.

Q. And who did Enbridge partner with for the ultrasonic development?

A. Well, GE would be the current name of the company.

Q. GE.

MR. IRONSIDE: So GE PII. So, in addition to knowing the condition of the pipeline from an in-line inspection perspective, you also need to know what does that really mean about the condition of the pipeline and how it's affecting the strength. We've been involved in and supported the development of fitness-for-purpose calculations that have been enhanced over time. So you're, I'm sure, familiar with the R string calculation. That's a development that the American Gas Association and, I guess, what's currently PRCI would say owns the technology there. But the understanding of how corrosion affects the strength of the pipeline is something that we've obviously had to transfer in from the knowledge of the pipeline condition to how that affects the in-line inspection data, and transferred those methods.

Similarly, there have been a number of developments on the crack strength calculations, so there have been a number of introductions of pipe strength calculations, whether it be through the API standards, some proprietary calculations done by DNV. We've researched and been involved with those organizations to fully understand the capabilities of those tools for understanding the pipeline strength.

And we continue to work with industry in a variety of forms. PRCI, which is Pipeline Research Council International, we're a member of that organization and continue to support the research that comes out of that and implementing that in our system.

API, American Petroleum Institute, has standards and work groups and committees that we're involved in. CEPA, is the Canadian Energy Pipelines Association. We have lots of involvement with that group to help direct research and understanding of issues with the pipeline industry.

Those are just to name a few. But ultimately we are engaged in these groups to continue to develop technology for implementation in the pipeline system. So --

BY MR. NICHOLSON:

Q. Can you go back? I'm sorry, Scott.

A. Yes.

Q. When you're talking about the standards, CEPA -- is there a CSA? What other Canadian --

A. Yeah, Canadian Standards, Canadian Standards Association we have a lot of involvement in. We have people that sit on the various subcommittees that write the standards, yes.

Q. Okay. But you follow API standards? There's no equivalent or --

A. So in Canada our regulator is the National Energy Board. In their regulations they specifically reference CSA.

Q. Oh, okay.

A. So we follow CSA standards on our Canadian System. And, of course, with the PHMSA regulations, they specifically reference certain standards throughout the regulations.

Q. Um-hum.

A. So we follow all the standards that are referenced there.

Q. Okay. So I'll -- in any B regs, I'll see CSA?

A. Absolutely.

Q. The API here is because of the PHMSA pipelines in the states?

A. Yeah. And API has a number of committees that do lots of good work in understanding issues that the pipeline industry has to manage and deal with, so we want to be involved in what they're doing.

Q. Okay.

A. So I have a slide here that shows -- not necessarily, I guess, a names organization structure but simply the roles of the groups in the current structure right now within our department. As I described, the evolution of the integrity program from the

'70s to current -- of course this structure didn't exist in the '70s but the group has grown over time.

For reference, in the 1990s there was in the order of 10 to 15 people that were focusing on running in-line inspection tools and the like. Through the 2000s the group grew to the order of 20 to 25 to 30 to 60, to where the point here you see this organization that the group has grown to. So there's been lots of development and evolution of the department that's focusing on the integrity of the pipeline system. Just quick --

MR. CHHATRE: This is Ravi from NTSB. Was it the same structure in place at the time of the accident or this is something different after the accident?

MR. IRONSIDE: This structure here is different. And what I'll say is -- well, I think Steve's getting an org structure from that time frame that we'll be able to provide to you. But, for now, the key differences would be -- at the time we didn't have this whole group over here called Infrastructure Management.

A lot of this work was being done within these groups here, the kind of the core original groups, or done by other departments. But we've brought an organization here that's going to bring together, I guess, an increased look at building reliability targets, looking at bringing together all the relevant stakeholders within our company to understand issues related to pipeline integrity to ensure that they get moved throughout the company at an appropriate pace.

BY MR. NICHOLSON:

Q. I guess I don't understand. Are you saying you move people from another reporting structure over into this pipeline integrity group or are these all new positions? Because it says risk management; that would have been part of integrity before, right?

A. That's right. There have been people somewhat moved in from other areas but also an expansion of the areas as well.

Q. Okay.

A. So when you say -- when we say risk management, this will be a group that links in with Steve's operational risk management group. Steve's operational risk management group still exists in the form that it was then and expanding to where it's going to be. This will be a dedicated group to assist in linking in with the risk management group.

Q. Okay.

MR. CHHATRE: Again, this is Ravi from NTSB. So risk management is part of integrity management at the time of the accident and now?

MR. IRONSIDE: Yes.

So under the programs area within pipeline integrity we have three manager areas. We have a planning group, a logistics group, and an integrity services group. We'll spend -- really the time in here in this presentation is focusing on the planning group, given that this area is responsible for the key technology that the department utilizes. So understanding what the conditions are on the pipeline system, recognizing what tools are required to understand that condition, and making decisions about how to go best about repairing and ensuring the pipeline is safe.

The logistics group then looks after the execution of those activities, as described by the planning area. So they would look after the actual physical program management -- or project management of running the tools, getting the information transitioned from our department to the execution in the field, all of the quality control of the data that comes into the department and leaves the department, as well as a lot of the annual tracking and interfacing with the budgeting groups and whatnot.

In integrity services, this group is looking after the quality management system for the department, so our integrity management system, ensuring the elements of the quality management system are implemented, such as lessons learned, management of change, doing audits of our internal processes, as well as owning the procedures and standards that the department has. So they wouldn't necessarily be the technical experts on those procedures and standards, but they would make sure that they're being updated appropriately and being managed.

BY MR. NICHOLSON:

Q. So where are you on there, Scott?

A. I would be the director of --

Q. Okay.

A. -- programs.

Q. And Sean and Matt are manager level?

A. So then -- so currently this position is not -- is vacant.

Q. Okay.

A. And then there's three supervisor positions under here that are the three fellows you see across from you.

BY MR. FOX:

Q. So how does the interface work between, you know, the program management and the infrastructure management? I mean, there seems to be a lot that overlaps or maybe needs close, you know, working together between those two groups, particularly, you know, looking at some of the stuff under reliability, you know, risk management and understanding fracture mechanics, damaged metal, things of that nature, how does that tie into the, you know, the defect assessment and monitoring and planning side?

A. Well, so the individuals in this area will be linking very closely with the individuals in this area --

Q. Right.

A. -- because the -- this is effectively the users of the technology. This will be the evaluators of what the technology -- you know, of the --

Q. The data results?

A. Well, this is going to be evaluating the reliability of the program itself. So looking at when we do calculations, when we make decisions about the pipeline condition, it's going to be going back and looking at the reliability of those decisions, of the processes themselves.

Q. Okay.

MR. NICHOLSON: That's program evaluation or self-assessment of some sort?

MR. IRONSIDE: Yeah, that's certainly a part of it. Ultimately this group, as you'll see through the discussions, will evaluate the in-line inspection data, go out and do digs, assess that pipeline in the field, bring that information back and do comparisons to the in-line inspection data. All right.

And so this group here is going to be looking at how accurate was that process, how -- I guess, what safety factors were arrived at following that work. So when you can calculate a probability of a tool being wrong, so there's a bias associated with it, those are things that we've always kept track of and understood. This group is going to look at -- from a reliability based design prospective, what does that get us, as far as probabilities of failure going forward, and with various tools, with MFL tools, with ultrasonic tools, where the -- I guess, the linkages is between the two and how can we understand things better to make improved decisions.

MR. FOX: And then they'll also be linking closely with the pipeline operations and what, you know, effects operations may have on those factors as well?

MR. IRONSIDE: That's right. And so that's this group in here. So these people will be looking at the data generated from here as well as the information that's generated from other operational entities, bringing those groups together to better understand how changes to the pipeline operation affect the integrity of the pipeline system. And then looking for ways to improve and make change on the pipeline operations.

BY MR. NICHOLSON:

Q. So I know we're going to get an org chart at some point, but who are these people? Manager for reliability would be?

A. So this -- the individual's name is Wade Keller.

Q. Okay.

A. This manager of pipeline is Duane Evans. And manager of facilities is Brian Elstad. The director of this area's name is Trevor Grams.

Q. Okay.

A. Would you like me to spell their names or --

Q. Trevor Grams? I got that.

A. G-r-a-m-s.

Q. Oh.

MR. CHHATRE: Go ahead (indiscernible) --

MR. IRONSIDE: Okay. So this next slide is a -- kind of an overview of the development of our planning activities. I'll just quickly run through.

BY MR. CHHATRE:

Q. Excuse me. This is Ravi again. Can you go back to the previous slide? I think -- we didn't complete all the boxes before we interrupted you and -- what do the integrity services do? I know you explained the program logistics, what they do, but what do the integrity services --

A. So integrity services, that group will be responsible for our integrity management system, the quality management's approach to the integrity management system. So they'll be responsible for ensuring that our program has a lessons learned management of change, an internal audit process, will track the performance through a metrics process. So all of the elements of a quality management system, that group will be responsible for ensuring that that occurs in that manner, as well as looking after facilitating the procedures and standards that our department is responsible for. They won't be the technical experts, but they'll be facilitating those procedures and standards.

Q. So who develops the standards? Which group in here develops the standards?

A. Largely the integrity planning group will. So by standards, the -- if we look at how we would, for example, assess an in-line inspection data set and select digs, establishing a criteria for that, that procedure would be developed by this group as the technical experts, and the integrity services group would collate those procedures and ensure that they're developed in a standard format and meet the requirements of the quality management system.

MR FOX: So then where would -- who would check to ensure that any changes and whatever are -- meet regulation requirements or regulatory requirements?

MR. IRONSIDE: So the responsibility to ensure that it meets regulatory requirements would still be in this technical expert area, but this group would have a process to ensure that it's checked.

MR. FOX: Okay.

MR. IRONSIDE: So I'll just reiterate though that this structure is around a year old, that the functions largely were conducted within this original core group and that this is an expansion to add resources to continue to evolve what's already existing.

BY MR. NICHOLSON:

Q. But what's on the left, those three boxes were in place July 2010, right, to some extent?

A. To some extent. Not at the manager level --

Q. Oh, okay.

A. -- but at the supervisor level.

Q. Okay. So you've added managers now? You've added another layer of management since Marshall; is that the change?

A. Well, that's one of them, yes, so --

Q. Okay.

A. -- so now there's currently a vice president of pipeline integrity where previously there was not. So within all of our business units, liquids pipelines as well as the gas distribution, gas transmission, which we haven't talked about, but within Enbridge at -- there was a decision to have a vice president of pipeline integrity in all of those areas. And so from that there's now a new group of managers -- sorry, a group of directors and managers within the pipeline integrity group.

Q. Okay. And Walter Kresnic (ph.), he reports to Art Meyer?

A. That's correct.

Q. Okay. Also a new position since Marshall -- Art Meyer's position is new, right?

A. Yes, as a senior vice president. That's right.

So, I don't think we spoke of this one, Ravi, but the manager of facilities integrity, this is a group that actually was started in 2004. This group is focusing on all of the facilities inside the pump station. So the main-line pipelines, as I said, are all piggable. The trap-to-trap main-line pipeline system is all managed by this group. The facilities inside -- so tankage, piping, any of the rotating equipment, leak perspective is managed through this group here. So they establish programs for managing the reduction of leaks in the pump stations and tank facilities.

BY MR. CHHATRE:

Q. So when you refer to leaks, you're referring to the pump station's storage tanks, that kind of thing?

A. That's right.

Q. So pipeline leaks are handled differently? By a different group?

A. So pipeline leaks are the responsibility of this area.

Q. Okay, that's what I thought. Okay.

A. That's right.

Q. Okay. Thanks.

MR. IRONSIDE: Okay. So moving on then, I guess a high level look at how we do our planning. First of all, we -- you know, there's data gathering and integration of information about the pipeline -- whether it be the pipe characteristics, failure history, those types of things, generally speaking.

We then look at what the appropriate assessment method, based off of what we know about the pipeline system would be. We look at risk assessment results from the operational risk management group. They have a process of doing risk assessment.

We, of course, consider regulatory requirements and integrate those needs. We then would look at our high consequence area management plan and update that baseline assessment plan and reassessment plan, based off of this evaluation.

We have our budgetary and other factors that need to be considered. So looking at the economic needs of the company, whether, of course, ensuring the pipeline is safe and we're doing the actions that we need to, there can be opportunities to do work earlier, if required, for budgetary reasons.

We then link into the company's long range plan and provide information to all the relevant groups within the company to ensure that the assessment intervals and the corresponding costs and resource requirements for the inspections and the related dig programs and repair activities are understood by the people within the company that need to know, and then, of course, implement that assessment and do those activities.

That information then, of course, goes back into our data gathering and integration element of the planning and the learnings from that inspection or activity, whether -- integrity activity. It could be inhibition or some other kind of integrity activity that occurs. That information is then put back into the system.

So I'll get into this in a little bit more detail. And, of course, Ryan and Sean and Geoff will do the same.

MR. NICHOLSON: What's LRP?

MR. IRONSIDE: Long Range Plan.

MR. NICHOLSON: Oh, I'm sorry. Okay.

MR. IRONSIDE: That's the company long range planning process.

MR. NICHOLSON: Okay.

MR. IRONSIDE: So if we move down into the inspection and repair, as this makes up the majority of the activities that the department is involved in, when you look at an inspection and repair -- if we start at running the in-line inspection tool, of course, there are logistics around getting that work completed, including selecting the appropriate technology, getting that ILI vendor on board, getting the tool loaded into the pipeline system. But then once we get the information from the in-line inspection tool, we have the report come in from the vendor; we have specifications for them to meet when they report information to us.

The information is reviewed by a group within our department that quality controls that data. So looking at -- looking for errors in the report, making sure that it meets all our specifications. So we go through that process. Once the report's fully received, then we have a group that's going to look after technically assessing that data and determining whether we have to do digs to repair the pipeline.

That information is moved through to another group that looks after the creation and issuing of what we call dig packages. You'll hear reference to a dig package. A dig package is simply the relevant information that needs to be collated to send out to the field crews such that they can dig at the right spot, looking for the right information, and I guess ensuring that the appropriate requirements for information back to us are met. So that's a package of information that gets sent out to staff that excavate the pipeline and provide information.

That information then, from the field, of course, comes back in, in the form of non-destructive testing reports and other field reports. That information, once again, is looked at by a group that quality controls that. We specify what type of information needs to come back, and so we have a step where we ensure that that information is appropriately provided to us.

That information then, once approved, goes to the planning group folks again that initially had wanted to get the tool run completed. So now they've gotten a decision to do the inspection. Now they have the information about what the field said. So we get the in-line inspection data, get it out to the field, get the field data, and then that's where we look back at the in-line inspection data to compare the accuracy of the in-line inspection data and understand the condition of the pipeline.

All of that information gets reviewed and analyzed and we would then look at methods for determining when to re-inspect. So that would be looking at what is the exact pipeline condition now and depending on our knowledge about growth rates or other types of future conditions on the pipeline, then we would make decisions about reassessment.

MR. NICHOLSON: That's in that step there, trend NDE, that's the analysis?

MR. IRONSIDE: That's correct.

MR. NICHOLSON: Okay.

MR. CHHATRE: This is Ravi again. The question is, the select digs, who makes that decision? Do you do that in conjunction with a vendor or do you guys do it on your own?

MR. IRONSIDE: Well, largely that's done internally with Enbridge. We have developed an understanding of the in-line inspection tools with input from the vendors. Their information is presented to us in a format that we're in agreement with them on; we understand the feature classifications, how they present the data to us. So we've worked with them to understand what the data means, and then we would utilize our engineering staff internally to select the digs.

MR. CHHATRE: But the data interpretation is done by the vendor?

MR. IRONSIDE: Yes. So the data interpretation, the raw data interpretation is completed by the ILI vendor. We get the information largely in the form of, I would say, specific characteristics of a feature, whether it's a corrosion or a crack. They would give us the dimensional characteristics of it, whether that be shape, length -- in the form of length and width and depth, and then we evaluate based off of that.

So we're not conducting a raw analysis of the inspection raw data for the purpose of selecting these digs, although we have continued to develop our understanding of that element of the assessment. We do get some of that raw data for features that we're interested in, and we do, do our own additional review of that information. And we may make additional digs based off of concern about the data, but we don't go back and reassess the features themselves or change that.

BY MR. NICHOLSON:

Q. Okay. So you've been trained -- some of your people are trained to actually look at the raw data from the tool and make a determination or judgment call; is that what I heard you say?

A. Yeah. So we have worked with the in-line inspection vendors to understand where, I would say, where there are conditions within the data that there's uncertainty, and we might make conservative decisions based off of the uncertainty within the data. We haven't sent our staff there to be trained as an analyst and get qualified as an Analyst 1, Analyst 2, Analyst 3, that they have within their facilities or within their staff. But where there are uncertainties within the raw data, we might make a more conservative decision about doing a dig, whereas, they've classified a feature as, you know, as a certain classification; we may look at that and make a more conservative decision.

Q. But how do you know it's -- how do you know the uncertainty in an analysis from a vendor? Do they give you a probability or how do you know there's -- I mean, they just tell you it's crack-like, crack field. How do you know if there's any uncertainty in their decision making? Do they provide that to you or --

A. Well, I guess I'm thinking more of a corrosion feature --

Q. Okay.

A. -- where the ILI vendor will be confident in their call of a certain depth and a certain length and characteristics. But specifically within the raw data there may be just a slight missing signal, for example, because of echo loss within an ultrasonic tool run.

Q. Oh, okay.

A. Right. Where they still have confidence in being able to characterize the feature.

Q. Okay.

A. But there might be a little bit of missing data there that we're not comfortable with, so we'll just go and do a dig.

Q. So they tell you there's missing data or we've got echo loss or --

A. That's right.

Q. Okay. I see.

BY MR. CHHATRE:

Q. What happens when you do your verification digs and they don't match, they don't jive with the ILI data, what happens then?

A. Well --

Q. If it happens. I mean, I do not know.

A. Yeah. In that case what we do is -- all of the field data is reviewed by the planning group. If there is field data that comes -- that's evaluated to be within a certain range outside of what the in-line inspection data had called, we call that an outlier. And so that would escalate a process to immediately send that information back and review that with our planning staff.

So if -- there's a certain range that the field data may be different than the in-line inspection data that gets evaluated on a routine basis. If it goes outside of a certain range that we've specified with the NDE field crews, then that would trigger an escalated process of evaluation.

So what we would do then is evaluate that and work with the in-line inspection vendor to then take that data back to them and say, here's what we found in the field, here's what the in-line inspection data said, and then work together to understand what the cause for that variation would be.

Q. That doesn't, that doesn't necessarily qualify for a reevaluation of the entire set of ILI inspection --

A. Well, it may. So the -- you know, if it's a single condition that is -- you know, if there's a, I guess, a unique characteristic that can be identified that describes why that occurred and it doesn't impact the rest of the tool run, then that may not change the rest of the tool run. But if there were multiples and it does result in an understanding of the in-line inspection data being inaccurate, for a particular reason, then they would evaluate that and modify the report.

Q. Okay. I guess my question was, are there -- looking at the, just as an example, your MFL tool, just for metal loss.

A. Um-hum.

Q. How many of those mismatches have a trigger for the validity of the entire data evaluation or run? I mean, do you guys have any parameter like 3 or 4 digs that don't match, then, gee whiz, you know, we question your tool data? Is there a cross-check or how many of those mismatches would trigger some kind of a questioning?

A. Well, just one would trigger questioning.

Q. Okay.

A. So we would -- if we have an outlier, then that's automatically we would go to the in-line inspection vendor to reassess. The decision about a full modification of the report would be based off of their understanding of the field feature and then, you know, a continued evaluation of the report.

I don't know if, Ryan or Sean, if you wanted to --

Q. Okay. Thanks.

MR. SPORNS: Yeah, I guess -- it's Ryan here. I guess -- I mean, there's a lot of history with ILI so there's a good understanding of what the causes are, what the limitations and strengths of the tools are, so often it's put into those categories of, yeah, that's a known limitation of that technology so that was why you were an outlier.

MR. CHHATRE: Okay.

MR. SPORNS: So it's not something that often surprises us, but sometimes it may and that may trigger more work.

MR. NICHOLSON: But an outlier could be something that's deeper than what was shown or something that's not as deep as was shown, right? Are both of those considered outliers?

MR. SPORNS: Yeah.

MR. IRONSIDE: Absolutely.

MR. SPORNS: Absolutely. Yeah, it goes both ways.

MR. NICHOLSON: And they're treated the same?

MR. SPORNS: Yeah. And also from a fitness for purpose standpoint. Right. So from a pressure prediction standpoint. From a length/depth --

MR. NICHOLSON: Um-hum.

MR. SPORNS: -- all the different parameters are like that.

MR. IRONSIDE: As well as a characterization.

MR. SPORNS: Right.

MR. IRONSIDE: So if it's characterized as -- incorrectly, even if it's a crack versus a -- not SCC or something, that mischaracterization is also an outlier.

MR. NICHOLSON: Okay, right. Okay.

MR. IRONSIDE: And just for -- this is one of the Phasor ray crack inspection tools in the picture behind.

So the next slide here I won't, I guess, get into all the boxes, but what I wanted to show is this is a linkage between the different departments within our area as well as outside of the group, some of the key areas that we talk with and interact with, as we go through our programs.

So the compliance group is always part of the support team for our program. They have a number of their own internal processes that we link in periodically, but certainly they're the keepers of the high consequence area management plan in the U.S., and so the rules and associated requirements for integrity, we interlink with them to understand quite often.

Our planning group, which we've been talking about, looks after, as we've described, the tool selection and the understanding of the pipeline condition to make decisions about how best to collect data on the pipeline, as well as doing the detail analyses that we've just been talking about with which features areas of interest that need excavation and whatnot in evaluating that field data.

The logistics group, this slide was really just for showing the detail that the logistics group needs to go through. So executing the inspection itself, they're the link between the ILI vendor and ensure that our field staff are aware of the work happening and ensuring that all the procedures are completed out in the field. They also are the link between -- the communication link between the in-line inspection vendors and our department. So if there's any information that's required through the data analysis process, they would be the communication link.

We have established conditions on the pipeline system that if an ILI vendor sees a feature over a certain magnitude, whether it's a depth or predicted failure pressure level, that would require an immediate reporting to us. And I know that we need to change this immediate reporting name to priority or something like that, because not to confuse with the HCA rule or use of the term. But, ultimately, when we have our in-line inspection vendors doing their analysis, we don't wait for them to complete their final analysis before, if they had something really serious, to call us about. So we have a set of criteria for them to identify priority features.

BY MR. NICHOLSON:

Q. And where is that? I'm sorry, that's under logistics?

A. Yeah. And it's there because they're the initial link between the in-line inspection vendors and us. Well, and Enbridge.

Q. But is this a new work flow? This was in place prior to 2010?

A. Yes, that's right.

Q. So the delayed -- that whole 2007 to 2009 self-imposed pressure restriction --

A. Yes.

Q. -- this was -- this process was in place?

A. Yep.

Q. Okay. Wasn't there an issue there with getting information back, raw data analyzed from the vendor?

A. Yeah. There's a lot of information there and it has to do with a variety of different aspects to the program at the time.

Q. Okay.

MR. IRONSIDE: So the -- this group then, of course, receives the ILI report and goes through the quality control process that we spoke about, performs some data integration. That has to do with ensuring that all the girth welds are labeled properly, that all the previous inspection information is integrated as required. Pulls together all of the logistical information, gets that over to the planning group, who then does the detailed analysis.

They then select the features for excavation, and we have a process whereby we implement a pressure restriction on our pipelines for all features that require such per our procedures. So the logistics group then would implement those activities. So for a specific feature on the pipeline that's discovered through an inspection that requires a pressure restriction, then this group would -- the planning group would define what that level of pressure restriction would be and the logistics group is our link to the rest of the company to ensure that that happens.

They also then do some prioritization and implementation of the dig program and work with the appropriate resources in the company to get the digs completed. As well they -- as stated earlier, they are linking to the vendor, the NDE vendor, to get the data back from the field and turn that back around to the planning group for their review and implementation of any changes that are required from the NDE data.

One of the links here is in our services group. Integrity services, we have an in-line inspection technology, small group, where that area is responsible for keeping up with all of the in-line inspection technology that exists available to us in industry, what we term is our ILI expert, that assists these folks here in understanding what technology is available for certain features. This would be where if we had a certain condition on a pipeline that may require an additional inspection technology to be included, he would be tracking with the in-line inspection vendors to understand all of the available technologies and where they can be used better for certain conditions.

MR. NICHOLSON: Is that Greg Zinter? Who's that?

MR. IRONSIDE: The name of that individual is Garry Sommer (ph.).

MR. NICHOLSON: Oh, okay.

MR. IRONSIDE: And I think actually on your note last week you had identified him as well as a potential for interviewing. So Garry works with the ILI vendors to understand what developments are being made, which tools we may want to be doing some additional testing on, whether it's at their facilities or bringing a tool into our pipeline to do a test. So he's involved in all those activities.

MR. CHHATRE: Is he a one person group or he has other people helping him?

MR. IRONSIDE: In this new organization he has two staff underneath him that are just currently being hired.

MR. CHHATRE: They are technical, not the administrative folk?

MR. IRONSIDE: That's correct, technical, yeah.

The last column here is the linkage with our operational risk management group. So the operational risk management group conducts their assessments and information from there is linked in as we integrate that data as far as the consequence side of the equation when we're looking at integrating into our overall analysis, as well as looking at prioritization and implementation of the dig programs.

MR. NICHOLSON: Where's that chart located, Scott? Is that in the ACA plan, that figure that you're talking to right there?

MR. IRONSIDE: Yes, I believe so. If you're unable to find it in there, it would be -- this was pulled from a presentation at a PHMSA audit and it may have been modified for the PHMSA audit for ease of presenting the process.

MR. NICHOLSON: Okay.

MR. FOX: The compliance regulation workflow, is that -- do those folks fall under -- in that org chart that you showed in the prior slide?

MR. IRONSIDE: No. The compliance -- that organization is under Steve Irving.

MR. FOX: And what's -- Steve Irving is? What was his title?

MR. IRONSIDE: Steve's the --

MR. IRVING: That's me. I'm Steve Irving.

MR. FOX: Yeah.

MR. IRVING: And I was the director of system integrity and compliance pre-Marshall. So I had the integrity group, the compliance group in the U.S. and Canada, and then the facilities integrity and operational risk management group was a separate group, and actually Matt, who at the time of Marshall was the manager of that group.

MR. FOX: Okay.

MR. IRVING: And in the present structure, the compliance group in Canada and the U.S. both report to me now.

MR. IRONSIDE: So my last slide, before I'll move it off to Sean, Ryan and Geoff, is just to talk about the new group, the infrastructure integrity side and some of the strategic planning that that group is going to be continuing to conduct.

First thing is, of course, the safe operation is the first priority. So their work is going to be looking at enhancing decision making around how we optimize the operation of the pipeline, but their first priority will be making sure that what they do doesn't compromise the safe operation of the pipeline.

However, the long range plan for the operation of the line will drive investment decisions. So what I mean by that is, as I said earlier, we don't own the oil; we just move the oil for the people that do own it. And their needs will drive where we invest in new pipelines and the throughput needs that they have will drive what we do with the pipeline system. Of course, ensuring -- our responsibility is making sure that the pipeline is always operating safely. Where it ends up going to is driven by our customers.

The discrete repair versus pipe replacement. What I mean by that is, currently our programs, which we've been talking about here, have been doing in-line inspections and making discrete repairs based off of the results of those inspections. Our operational model for a number of years have been that that is a safe way of going out and repairing the pipeline and, generally speaking, is the most economical method of keeping the pipeline safe.

There are certain pipelines on our system where the density of discrete repairs is such that there are enough discrete repairs required that a pipe replacement may be an appropriate economical way of dealing with the situation. So if you had a 10-mile segment, for example, that had a very large number of repairs required, it would make more sense to just replace the entire pipeline segment as opposed to doing discrete repairs.

BY MR. NICHOLSON:

Q. Well, 6B was that way, wasn't it?

A. That's correct.

Q. Okay. The company had made a decision to replace it, I think, when the (indiscernible) came out and said there was a 2012 plan to replace 6B; is that correct?

A. Yes, segments of it, yeah.

Q. And that was because it had so many discrete repairs; is that right?

A. That's correct.

Q. Okay.

A. Yep. So those types of thoughts and decisions have been part of what we do for a long time. That's always been part of our thoughts. But this new group here, this infrastructure integrity group, is going to take a lot of that planning and pushing forward of those plans throughout the company and throughout our stakeholders external to the company to ensure that we can improve our decision making process in that area.

So that's really this last point. We've got now a group of people that are focusing on linking the technical information that's generated within the department about the condition of the line, and working with our business development folks, who are working with our shippers in understanding where the oil needs to get to, and making a more informed decision throughout the company about some of these repair versus replacement decisions.

Q. Okay. So this is your new group. Prior to this, the decision for this sort of thing would have been where?

A. Well, the decision would have been, I guess, still within the development of a company decision through our long range planning processes. The development of the technical support to each of those would be generated through the specific stakeholder areas.

Q.   Okay.

A.   What this group is going to do is be -- I'll say the glue that pulls that all together now. So trying to add more resources to spending more time on understanding those factors that go into that type of decision.

Q.   Okay.

BY MR. PIERZINA:

Q.   Scott, what about the probability of failure if -- let's say if a consequences of missing a defect are so great, you know, at such a level, is there a process by which you'd select a different tool for assessment?

You know, we talked about replacement versus repair, you know, being essentially an economic decision. If -- getting back to the assessment level, you know, if the issues with ILI are such that, you know, there's a risk of missing a defect, is there a way -- is there a process, I guess, for analyzing when you might, say, select a different tool, hydro test, for instance?

A.   There's -- I think that's where we link in with the overall operational risk management group. So the ORM group is looking at bringing a lot of the -- all of those company conditions into their model.

Our linkage through our department is around that probability side and, as you saw in the slides, the reliability group is going to further enhance our understanding of that probability of failure and assist in allowing the operational risk management area to better evaluate that scenario.

Q. Okay. So the input comes from operational risk management, is that --

MR. IRVING: Maybe I could jump in. It's Steve Irving.

MR. PIERZINA: Sure.

MR. IRVING: The operational risk management group, of course, looks at risk in its whole, you know, the consequence, time and probability of failure occurring. We get the information on the probability of failure from the pipeline integrity group. We then have a model that gives us the consequence so that we're then able to generate a risk number. That number would, in turn, go back to the integrity group, and they may take that information and prioritize the dig program, for instance. They may even take a look at their program in its totality as it relates to possibly ILI intervals and whatnot. So we would, you know, take that information, give it back to them; they'd then do an evaluation on whether they need to make any changes to their integrity program.

MR. IRONSIDE: I think, Matt might -- you can walk through a couple of the ways that we evaluate things.

MR. THOMPSON: So certainly when we're running our programs, the ILI programs, as was discussed earlier, we're looking for cases where the ILI tool is not providing us the information that we need to manage the integrity of the pipeline.

So one example of that would be if we do -- if we conduct an integrity dig and we find a significant feature that wasn't identified by the tool. So that's something that we have to pay a lot of attention to clearly.

In those types of situations, we would -- we need to investigate the current ILI data set, and we may find that the current ILI data set isn't of the right quality for the purposes. So we have a number of options there. One is we can reanalyze or have the vendor reanalyze the data set to see if that can improve the data that we have to work with. That may not be the solution. The next step can be to rerun the same tool. So possibly it was something like a data degradation issue, why we couldn't see that particular feature.

If it's a technology limitation, so if that particular tool can't actually see that type of feature -- and that can happen with -- as you know, with magnetic tools, they can't see certain types of features and ultrasonic tools can fill the gap and so on. So the next option, of course, is to run a different tool to see if we can see the -- find these features.

If those types of steps can't identify the features that we're looking for and we're still left with a pipeline that we cannot find the significant features with the ILI technology and the data processing at hand, then hydro testing becomes a management option for us. We haven't found ourselves in that situation in recent times because we've got the ILI tools that can generally see these features we're looking for, and certainly features of less significance than a hydro test would identify. But certainly we have a process that we'd step through that ultimately can lead to hydro testing.

MR. NICHOLSON: And how many times have you hydro tested Line 6B or any of the link end systems? Have you ever gone to that tier in your logic diagram you've laid out there?

MR. THOMPSON: Typically when Enbridge has hydro tested in recent time, it's been to change the MOP of a pipeline. So we've had -- we were actually just talking about a case -- I think it was 2006 -- where we tested a section of Line 3 in Canada. It was about -- I think it was about 23 kilometers. And we wanted to increase the MOP. I think it was -- I'm not sure what the percent SMYS it was running at but we -- I think we took it up to 80 percent SMYS in operating pressure. And in that case it was simple to raise the MOP, but it did show our ILI program to be valid in that we didn't have any failures during that pressure test. So that was a positive program because we had to, you know, run the crack, corrosion and geometry programs beforehand, so --

MR. NICHOLSON: But you've never done it to get rid of defects or --

MR. THOMPSON: Well, since -- in the last 10 years I don't recall any.

MR. IRONSIDE: No.

MR. FOX: What year was that hydro test done on Line 3?

MR. THOMPSON: 2006 we had.

MR. FOX: 2006.

UNIDENTIFIED SPEAKER: And, Steve, I think that was the section between Hardisty and Matiscol (ph.)?

MR. IRVING: Yeah. Just downstream.

MR. PIERZINA: I guess, just out of curiosity, I want -- you know, because you do have a process and you have the inputs, is there a way to see what type of driver would get you to hydro test a portion of line thinking that, you know, it's got to be somehow related to, you know, a higher probability of failure or a higher consequence? Just -- you know, it sounds like everything is there, but I'm just wondering what it would take to get you to a decision to use, say, a non-ILI tool, you know, on a portion of the system? You know, play with -- you know, if we played with numbers, would there be a way to get there? Or is it just -- that's something that's there, but --

MR. THOMPSON: So, one of the realities of hydro testing is that it's a point in time where you achieve a certain objective, and that being that you've proved that you do not have a critical feature in the pipeline and you can demonstrate that you don't have a through-wall feature in place at that time. In that regards it's a fairly limited value for us. So we need to be able to -- so in order to get to that point, we need to have a great deal of uncertainty about the effectiveness of the ILI tools, because, you know, clearly the tools can see features and size them that, you know, in dimensions that are a lot less than critical size.

So in order to do that, there has to be enough of an uncertainty around the condition of the pipeline and our ability to identify features. If we can't do it now and identify critical-size flaws, then that can mean that we don't have that ability going into the future or we can't necessarily see that as well. And that hydro testing option now and into the future, because of its limitations, isn't all that attractive. So you can see with -- there's other ways of managing uncertainty. So when you talk about probability -- if you've got a pipeline section with a lot of features on potentially and you talk about probability, that's where we can look at enhancing our dig program. And we've looked at that on Line 6B. That can then lead into some of our other options. And I think Scott talked about that where -- you can see the third bullet point there about pipe replacement.

MR. PIERZINA: Right. Yeah, and it's -- we don't need to get hung up on that. I was just curious if there's a way to mess with the inputs, you know, to get -- you know, that would drive you to something other than an ILI inspection for a defect assessment?

MR. JOHNSON: From a -- you know, you guys can certainly speak to this better than I can. We did a dig program on our Spearhead line prior to doing a pressure test.

MR. CHATTRE: Would you identify yourself?

MR. JOHNSON: Pardon me?

MR. CHATTRE: Would you identify yourself?

MR. JOHNSON: Jay Johnson. You know, we did an integrity dig program on the Spearhead line, followed up by a pressure test, a hydro test. So that would be, you know, for a number of reasons. And I think that would be confirmation, Brian, to your question is, you know, based on the tool run that the prior owners had, we did a repair program, and then pressure tested. And the repair program, basically it validated itself, for lack of a better term.

MR. NICHOLSON: Well, we can get into it later, but I thought I saw something about probabilities up there and I think maybe the question was, do you get probabilities on detection from the tools? Is it -- are you told that it's got a 90 percent chance of detecting crack-like features and do you take that back, you know, well, the 10 percent we can't live with, the consequence would be too great; maybe a hydro test is a better solution? Or I guess what I'm hearing from you is the threshold of detection is great enough that it doesn't -- never warrants a hydro testing?

MR. IRONSIDE: That's right. And it has to do with the -- I mean, you'll see a published probability of detection for all in-line inspection tools. They're required to do that. But those probabilities of detection are related to the smallest feature that the tool is classified to be able to find, right?

MR. NICHOLSON: Right.

MR. IRONSIDE: And so that's not a critical feature. At a critical feature, of course, the probability of detection is a lot greater, a lot better than for just a small feature. So those are some of the things that aren't published that we work to understand with the in-line inspection vendor to assist in our decision making.

MR. NICHOLSON: Okay. So that is something you look at when you're --

MR. IRONSIDE: Yes.

MR. NICHOLSON: Okay.

MR. FOX: They provide that information in the curve that shows probability of detection corresponding with -- in relation to the size of the defect?

MR. IRONSIDE: That's right.

MR. THOMPSON: It's Matthew Thompson here. Clearly, regardless of what the vendor tells us, we have to monitor what we're actually seeing on the pipeline as well. So, you know, if they promise one thing and they're not delivering, well, then we have to act on what we're actually seeing on the pipeline.

MR. FOX: Is there a type of defect that you cannot find or, you know, that you've experienced on your line that you can't find periodically or with the types of tools available today?

MR. IRONSIDE: Well, I would say that the technologies are sound, that the capabilities of the tools are well understood, that there are the potential for unique scenarios to occur on a pipeline that make those technologies challenged to identify something. So is there a possibility of some kind of unique condition to exist that those tools can't identify something, I think the answer is yes. But at the same time, the abilities of the tools to identify things is continuing to improve.

One of the areas that is of a focus is secondary features in dents, for example. So when you have a dent or a deformation in the pipeline, the sensors on the tools become challenged because of liftoff or other reasons, so there's lots of work with PRCI and other research organizations to understand how better to identify secondary features in dents. So that would be an example.

MR. NICHOLSON: Was the Marshall failure one of those unique conditions? Is that what you're saying in that? Marshall wasn't detected because it was unique or were you speaking of other lines?

MR. THOMPSON: Well, I was speaking of other lines, yeah.

MR. NICHOLSON: Oh, okay.

MR. IRONSIDE: So it is close to 10:00.

MR. NICHOLSON: Okay.

MR. IRONSIDE: The rest of the slides and what Sean and

Ryan and Geoff were intending to talk about was getting into more detail about the individual processes of understanding the ILI data, making those decisions, that type of thing. I'm not sure if you want to think about, is that the best use of the time going forward or should we, you know, save that for specific interviews, or how would you like to handle --

MR. NICHOLSON: Yeah, let's go off the record at this point. Let's go off the record and talk about that. You're finished, right, Scott, with your part of it?

MR. IRONSIDE: Yes.

MR. NICHOLSON: Okay. Go off the record.

(Whereupon, the interview was concluded.)

CERTIFICATE

This is to certify that the attached proceeding before the

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IN THE MATTER OF:	ENBRIDGE - LINE 6B RUPTURE IN MARSHALL, MICHIGAN Scott Ironside Presentation
DOCKET NUMBER:	DCA10MP007
PLACE:	Edmonton, Alberta, Canada
DATE:	December 5, 2011

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

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Cheryl Farner Donovan
Transcriber