UNITED STATES DEPARTMENT OF TRANSPORTATION

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PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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GAS PIPELINE ADVISORY COMMITTEE

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TUESDAY
MARCH 27, 2018

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The Gas Pipeline Advisory Committee met in the Ballroom of the Hilton Arlington, 950 North Stafford Street, Arlington, Virginia, at 8:30 a.m., David Danner, Chair, presiding.

PRESENT

DAVID W. DANNER, Chair
W. JONATHAN AIREY, Member
STEPHEN E. ALLEN, Member
RONALD A. BRADLEY, Member
DIANE BURMAN, Member (via teleconference)
J. ANDREW DRAKE, Member
SARA ROLLET GOSMAN, Member
ROBERT W. HILL, Member
SARA W. LONGAN, Member
TERRY L. TURPIN, Member

RICHARD H. WORSINGER, Member

ALSO PRESENT

JOHN GALE, Director, Standards and Rulemaking

ROBERT JAGGER, Transportation Specialist

ALAN MAYBERRY, Associate Administrator for Pipeline Safety

CHRIS McLAREN, Program Manager

STEVE NANNEY, Program Manager

SAYLER PALABRICA, Transportation Specialist

DRUE PEARCE, Deputy Administrator

CHERYL WHETSEL, Advisory Committee Manager

P-R-O-C-E-E-D-I-N-G-S

8:37 a.m.

MR. DANNER: All right, good morning. I would like to call the second day of this Gas Pipeline Advisory Committee meeting to order. And today is March 27th, Tuesday, 2018.

Again, this meeting is being recorded and a transcript is being produced so I ask that everybody speak into the microphone so that it can be picked up. The transcript and presentations will be available on the PHMSA website, this is meeting 132, and on the eGov docket at www.regulations.gov. And again, the docket number for this meeting is PHMSA 2-0-1-6, 2016-0136.

So with that -- I don't know if we need to take roll today; I don't think so -- I'm going to hand it over to Alan and we can continue the discussion from last evening.

Alan.

MR. MAYBERRY: Thanks, Mr. Chairman. Just real quickly, two to go over.

Quick safety briefing, since I believe we might have some newcomers here. If we evacuate the building, to my right you see the exit signs on the doors there. Go into that service area there and turn right or left and go down the corridors and you'll get to the outside downstairs.

If you go to my left, you'll end up going down the stairs to the lobby area to get out -- downstairs, turn left to get outside that way.

Don't try to go through the double doors. There's some construction work going on there.

So with that and also just a reminder, silence your cell phones.

And with that, we will get moving on Day 2.

Yesterday, you'll recall that we were discussing the MAOP reconfirmation Section -- let's see -- 192.624(c)(1), which is Method 1, and 192.624(c)(2), which is Method 2.

As you may recall, when we left yesterday we were working on wording. It got a bit late. We though well, let's give PHMSA staff some time to tweak the wording and come back to you today with some proposed wording.

So we're back here today I know bright-eyed and bushy-tailed, hopefully coffeed up or whatever gets you going in the morning, ready to talk turkey here about this wording that's new and improved up on the screen here.

So with that, I will turn it over to our able staff here and get going.

Or I guess, for that matter, actually, as you recall, we were -- well, anyway, let me just cut right to the chase here. We've got the revised wording in red there. And you know you may recall that related to testing for material properties, as a part of this Method 1 pressure test, there's discussion around that testing. You wouldn't necessarily need that. The operator needs to determine what they need to determine to perform the pressure test. So that may recall

digging two headers and seeing what they have and determining, based on their good engineering judgment, to determine what that pressure test would be. As you know, a lot of things go into that.

Related to that, though, we also have built in, if you do not know the materials that you use in method or the procedures in 607, which are opportunistic in nature, to over time determine, you know gradually gather the records on that segment of pipe but you wouldn't necessarily need to have every material test document in advance of performing that pressure test.

So the wording up here is designed to accomplish that and I guess, with that, Mr. Chairman, I would turn it over to you and the committee to discuss it, see if that hits where we need to hit.

MR. DANNER: All right, you see the language up on the screen before you in red. Are there any comments from the committee about this

language and whether it satisfies you?

Yes, Steve.

MR. ALLEN: Steve Allen, IURC.

Is it necessary to basically define opportunistically?

MR. MAYBERRY: That points to really what's already in 607 which, by nature, is that. I would probably argue you don't really even need to say that because 607 is just that. So, that's just here to reinforce what's already in 607.

MR. DANNER: All right, any other thoughts or questions?

Okay, if there are no other thoughts and questions, then I'm going to take that as this language appears to be satisfactory.

We have a motion before us from yesterday. So I think we can -- Steve, you can either withdraw the motion from yesterday and we can start over -- oh, I'm sorry.

Sara has her tent card up. So, let's hear from her first. Sara?

MS. GOSMAN: Hi. Yes, thank you. I

just want to revisit the look-back period issue again. And one question I guess I have, which I raised at the end of yesterday, is why the notification provision at the end of that pressure reduction section doesn't address the issue of needing I suppose a different pressure reduction.

So, rather than opening up that look-back period further, why we couldn't do this on a case-by-case basis through the notification?

MR. DANNER: So I think that's -- does anybody from PHMSA want to respond?

MR. McLAREN: Chris McLaren with PHMSA.

Sara, by the word further, do you mean beyond five years or beyond 18 months?

MS. GOSMAN: Beyond 18 months, so keeping it where it was but just using the notification provision.

In part I think because -- Cheryl can talk more about here concern but what I heard was some concern about going back even further. So

it strikes me that that notification provision is the waiver version, the ability to accept that should handle these types of issues again, rather than opening it up for all.

MR. DANNER: Okay, Cheryl and then Rich.

MS. CAMPBELL: Thank you. Cheryl Campbell, Xcel Energy. So, thank you, sir, for bringing this back up.

And I think my comment yesterday was actually the other way, right, can we push it back to the beginning of TIMP because I know for a fact that many operators have reduced the pressure to meet the TIMP as part of their integrity management program. And I think the concern is from the operators is if you keep it at either an 18-month or a five-year look-back period, if I reduce that pressure seven years ago as a part of my integrity management program, then you know am I faced with having to reduce the pressure, again, to reconfirm MAOP? And I might not be able to do that and still hold my

load.

So you know we've done it. You know I know my company's done it and I think Sara -- sorry -- what Sara and I were talking about yesterday afternoon was hey, there's already a provision in there that you could provide that documentation to PHMSA.

So I think we're just looking for some clarity around how do we really want that part of it to work. And I don't believe it's your intention to say you have to reduce it again if you've already reduced it under integrity management.

Is that fair?

MR. DANNER: Steve, you want to respond to that?

MR. NANNEY: Yes. Am I on? Yes.

I'm not sure it's fair or not fair. So I just gave you a non-answer, I guess.

But the answer I would say first we started out with the 18 months and we heard the responders from the public and the committee the

last time and we went back and looked at it. And maybe five years, based upon the look-back period when the code came into play in 1970, and also the five-year look-back period when we had integrity management come into play in 2003-2004.

My question back would be is on these previous cutbacks, MAOP reductions, or pressure reductions, however you want to determine, have they been for integrity management for HCAs or have they been for these -- or have they been to not go repair anomalies? What have they been based upon? That would be one thing I think that would have to be taken into consideration.

Or have they been made because there wasn't adequate MAOP and it was done for this exact same issue that we're talking about, that there wasn't a verified MAOP and you took it at that time really doing what we're talking about here today? And I guess that's one thing that I'm not sure of.

And I think before we would consider going past the five years, we would need to look

at that. You know we can look at it and I think we probably already have in this notification that if you can't do something like that to us you can come back and give us a notification. You know we can look at something along that line but I'm not sure just saying that you made a reduction back then, we'd have to look at what it was about and everything.

MR. DANNER: Do you have follow-up, Cheryl?

MS. CAMPBELL: You bet. Cheryl Campbell, Xcel Energy.

So Steve, yes, I understand what you're saying and I think what you would find is that most companies -- I mean clearly I can speak for what we've done but I suspect other companies are in the same boat where we didn't necessarily have all of the MAOP records and you know when you look at the system, you might say all right I don't need that higher pressure and I don't have the records, so I'm going to drop the MAOP to validate it as a pressure reduction under

integrity management and call it a reconfirmation of my MAOP.

So otherwise, I mean it's kind of -- there's only a set number of reasons why you would do that. Otherwise, you are looking for that upward flexibility if you have growth and stuff like that.

So I think, for the most part, the reason we've done it is because we didn't have the records to support the MAOP and we decided we didn't need that higher MAOP. But I would imagine that there's a wide variety of reasons that like you were talking about. And again, I'm just trying to clarify what's the path forward on that that we can all agree to so that we don't end up spending a lot of time talking about it.

MR. DANNER: All right, Rich.

MR. WORSINGER: I was actually going to go back to the other slide. So if you want to let this discussion play out first.

MR. DANNER: Okay, that might be a good idea.

Alan, do you want to -- are you on this topic?

MR. MAYBERRY: Yes, I was just -- yes, it's on this topic, really Cheryl, what you were talking about.

You know certainly it sounds like in your situation that might be easier if it went beyond say 18 months or five years. I guess where we are now it would be easy to make that justification.

But you know as we develop a one-size-fits-all approach, there are a variety of reasons why people -- and we've seen them from our inspections and from incidents why operators are taking pressure reductions. You know maybe I've lost sight of the fact of you know perhaps there was growth in the defects, defects that may have been in the line that ultimately led to failure that you know maybe we needed to have that provision to make sure that operators are looking at -- you know not just blindly accepting what was done 18 years ago or 15 years ago but really

having a thoughtful consideration of well, okay, I did it back in 2005. Is it still valid? Is it still relevant or do I have other issues going on?

MR. DANNER: Okay, Cheryl.

MS. CAMPBELL: Yes, I just want to ask Alan -- so I mean are you suggesting, Alan -- and I don't disagree with what you're saying. Are you suggesting that -- well, say I dropped an operator. I have this friend who has this pipeline.

(Laughter.)

MS. CAMPBELL: Let's say an operator dropped the pressure in 2010, so I'm beyond the five-year look-back period, and that operator did it because they didn't have the records for MAOP. So their solution to reconfirm MAOP was to drop the operating pressure and they were able to do that.

Are you suggesting that the close the loop on that is the notification and the conversation with the State and with PHMSA to

verify that we're all on the same page or is there more that would need to be done there so that you're not in that trap? To me, it feels like a trap; I have to drop it again. And that's what I'm trying to avoid.

I'm not trying to avoid doing integrity management. I'm just trying to make sure that we're very transparent and we all agree on what the MAOP is.

MR. MAYBERRY: I was suggesting that it is already in that later section for notification that you would use that method that's there to notify PHMSA, the State, if it's beyond say five years, for instance. Okay?

MR. DANNER: Again, Rich has had his tent up but I think we're still on this topic.

So, Sara.

MS. GOSMAN: Just quickly, you know when I read the notification provision it looks to me like it's focused on the pressure reduction factors and a concern about those.

But if it's the question of the base

pressure and which one we are going to take, it seems to me like we could add that into that language, again, as a way of making this specific to particular concerns by operators rather than just opening it up.

But I'm curious whether you agree with that way of using that notification provision.

MR. DANNER: All right, Steve, you want to respond?

MR. NANNEY: Yes, that's what we had proposed in the Notice of Proposed Rulemaking is just what you're saying, Sara. If you look just justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipe segment, including material records, properties verified in accordance with 607, history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and any additional punitive measures that's been taken.

So what we would want is an overall general look at the pipeline and why you're doing

it, if you're trying to do something different than what the five years and what we've got laid out.

And so we've got a procedure in here to do what you're saying and what I think Cheryl was saying. And we were not adverse to that when we first came out with the rule.

MR. DANNER: All right, Andy.

MR. DRAKE: Andy Drake with Enbridge.

I agree with Steve. I think you have a procedure in here that's built in how to deal with it.

I think the question that seems relevant to me is what is the appropriate period to look back and why is it more than 18 months. I think that's really just a balancing act, quite frankly. It's like a little bell curve. You know what is the population of pipes that would be running at their MAOP within a short period of time? Not very many, probably. I mean the MAOP is the highest pressure we're allowed to operate under. So the tighter you make that time frame,

the less likely we are to be at that pressure, especially when you get into some of the market areas where a lot of other influences drive what is our operating pressure.

So you can go where a customer's dynamics occur, they have other takes that they're taking, and that operating pressure for that pipe could drop down 10, 15, 20 percent and stay there for two years. Well, you just deescalated your MAOP.

And you can kind of get into it. Well, now let's reset it. So it's now this lower MAOP and we'll redo it again. You can end up kind of ratcheting your MAOP down over time. So what operators would have to do is basically block in the pipe and pressure it up, periodically. Or you open the period up so they can look further back to deal with some of those natural dynamics.

The point is you don't want to open it up so long that something could happen in there and that's the balancing act we're looking at.

Eighteen months is pretty tight, actually. I think normal market conditions are going to see pipes running below their MAOP because they naturally have to but they could be running quite a bit below it. And if they can't look past -- back far enough to get some data, they're going to end up resetting their MAOP under this scenario, which you don't want to do that.

I think the other piece is how far is too long, when there could be accruing things in there that we would need to know about that could be growing into that margin and then you pressure up into a problem. And I think that's the balancing act.

We did this yesterday I think, actually, when we were talking about four or five years. It's the same discussion. How many waivers do you want to have? If you're down to 18 months, I think you'll have a lot of waivers because it's naturally, those cycles are going to be pretty predominate. People are going to have to file to get back kind of claw back to a

reasonable place. If you get it at five years, maybe that's a little long. I don't know. It's somewhere probably in that four range.

The same conversation we had yesterday I think is kind of where --

MR. DANNER: Do you have a proposal which we can then debate?

MR. DRAKE: This is -- I don't have a lot of these kind of pipes. I'd like some -- that's why I'm kind of listening, just sitting here listening to folks like Ron, and Cheryl, and other people that have more of the demand side of the pipeline. What is normal for them?

I would think four years is pretty reasonable. I think 18 months is probably too little.

MR. DANNER: Okay, thank you for that.

Steve Nanney.

MR. NANNEY: Again, just to state, PHMSA was agreeable on the five years. We do not have any problem with that and also, the notification that we have in the rule, as

written.

We were open to listening because some of the points Cheryl has made, Amy has made, and Sara, we hear you and we're not closed to looking past the five but we would need to see what was in it.

And that's what Sara was saying we needed to do and we think we've got that appropriately addressed in the rule.

MR. DANNER: All right, Sara. Oh, he's on a different topic. So we're -- he's hanging out.

MS. GOSMAN: Yes, so just to be clear I think I raised this both because I knew we would be talking about longer provisions but because I was interested, actually, in pulling back on the look-back period and trying to sort of tighten that back up again. But I hear the concern about the sort of operational characteristics.

So the five years comes from historic practice, in terms of how PHMSA has dealt with

this starting back in 1970 with it. Is that where you're coming from on that five year?

MR. NANNEY: Yes.

MR. DANNER: All right, Andy and then Cheryl.

MR. DRAKE: Very quickly, Andy Drake with Enbridge.

That's exactly where I was going is there is a precedence for five years and that is actually, I think, a good confidence builder for folks. That was a precedent set in the code.

MR. DANNER: Cheryl.

MS. CAMPBELL: Cheryl Campbell, Xcel Energy.

I can live with the five years. Sure, I'm fine with that and I appreciate the conversation about where we've been. I was just suggesting that there's been a lot of work on integrity management but I'm perfectly fine with the five years and then requesting the conversation with PHMSA, if you've got something beyond that.

MR. DANNER: Okay. So is there anything further on this topic? It looks like -- oh, all right, hi.

MR. BRADLEY: Thanks, Chair. Ron Bradley, PECO.

So Alan, in your opening comments, I think you covered this. But just in the sense the first sentence, second half of it, after March 2016 -- or March 26, 2018, if the pressure test segment does not have TVC records, your implication was TVC MAOP records, correct? That's my question because that's what we talked about yesterday.

And to follow the sentence does seem to lead there, use the best available information upon which an MAOP is currently based.

So it may be a good add to add in TVC just the acronym MAOP between TVC and records, just to enhance the statement.

MR. MAYBERRY: Okay, sure. I can do that.

MR. DANNER: Okay. Great, so we have

--

MR. WORSINGER: Thanks, Ron.

MR. DANNER: Was that it, Rich? You've been waiting for ten minutes.

(Laughter.)

MR. DANNER: You don't want to say anything? All right.

MR. WORSINGER: I thought I just did.

MR. DANNER: Okay, is there --

MR. WORSINGER: Great minds speak -- think alike.

MR. DANNER: All right. Is there anything more on the look-back period or do we think we're worked out on that one?

Okay and the language in bullet 3.

Steve.

MR. ALLEN: Thank you, Chairman. Steve Allen, IURC.

I think it might be more expedient for me to go ahead and withdraw my motion from yesterday and start over.

MR. DANNER: Thank you. So I think

we're at that point. So Steve has withdrawn his motion, which was not seconded yesterday, and I believe he is about to make a new motion.

MR. ALLEN: All right, that's fine. Steve Allen, IURC.

The proposed rule, as published in the Federal Register, and the draft regulatory evaluation with regard to the provisions for Method 1 and Method 2 of MAOP reconfirmation are technically feasible, reasonable, cost-effective, and practicable if the following changes are made.

For Method 1 pressure test, the paragraphs (ii) and (iii) to remove spike testing for lines with suspected crack defects; in Section 192.624(c)(1) refer to Subpart J instead of Section 192.505(c); as discussed in the committee meetings of December 2017 and March 26, 2018, if the pressure test segment does not have TVC MAOP records, use the best available information upon which the MAOP is currently based; create a requirement for an operator to

add the test segment to its plan for opportunistically verifying material properties in accordance with Section 192.607. Most pressure tests will present at least two opportunities at test manifolds for material verification.

For Method 2 pressure reduction, increase the look-back period from 18 months to five years; and strike the requirement in Section 192.624(c)(2)(ii) to perform fracture mechanics analysis on the segments that confirm MAOP via Method 2 Pressure Reduction.

MR. DANNER: All right, thank you for that. Is there a second?

MR. WORSINGER: I'll second, Rich Worsinger.

MR. DANNER: All right thank you, Rich.

All right, there is a motion before us. It has been seconded. If there is no further discussion on the motion I think, Cheryl, we're ready for a roll call.

MS. WHETSEL: All right, thank you. Before I get started, I just want to mention that somebody left a notebook here last night. So if you're missing it, here it is.

Okay and so now on with the vote. Okay, Steve Allen.

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner.

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman.

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan.

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin.

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell.

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake.

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley.

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger.

MR. WORSINGER: Aye.

MS. WHETSEL: Chad Zamarin. Oh, I'm sorry, he's not here.

John Airey.

MR. AIREY: Aye.

MS. WHETSEL: Mark Brownstein is not here.

Robert Hill.

MR. HILL: Aye

MS. WHETSEL: Sara Gosman.

MS. GOSMAN: Aye.

MS. WHETSEL: And Rick Pevarski is also not here.

And the motion passes.

MR. DANNER: All right, thank you very much. And now we're ready to move on to Method 3.

MR. McLAREN: Chris McLaren with PHMSA and I'm here to introduce the 192.624(c)(3) Method 3 MAOP reconfirmation method. We have about 30 slides and then we'll do another vote, as we break up these methods into voting

packages.

Firstly, the public comments on Method 3 for the engineering critical assessment from the December meeting were to remove requirements from ECA that relate to operations and maintenance or integrity management, which are not pertinent to the MAOP and put fracture mechanics in a different section.

Also, the public supported fracture mechanics but it requires a lot of data not always available. And the rules should clarify when fracture mechanics is required.

With regard to those public comments, PHMSA suggests striking requirements related to addressing pipe segments with crack incident history from 192.624 and addressing the new paragraph under IMP and in 192.917(e)(6).

PHMSA also suggests moving the fracture mechanics methodology out of 624 and putting it into a new standalone section, 192.712.

The new 192.712 would be limited to

the procedure for performing fracture mechanics but would not specify when or for which pipe segments fracture mechanics would be required.

So PHMSA would clarify when fracture mechanics is required in other code sections by referencing 712, since those references were taken -- will be taken out.

For MAOP reconfirmation, fracture mechanics would be required only when performing ECA, 192.624 Method 3 -- (c)(3), or for other technology notifications on pipe segments that have cracks and crack-like defects remaining in the pipe.

In Method 3, reference 192.712 is needed as fracture mechanics. PHMSA suggests revising 624(c)(3)(i)(B) to read as follows:

(B) The ECA must analyze any cracks or crack-like defects remaining in the pipe or that could remain in the pipe to determine the predict4ed failure pressure of each injurious defect in accordance with 192.712.

Also, PHMSA suggests that specific

technical requirements for fracture mechanics, including default Charpy values would be deleted from 192.624 and only addressed in the new 912.712.

Also we suggest adding a requirement to verify material properties in accordance with 192.607 if information needed for a successful engineering criticality assessment is not documented in the traceable, verifiable, and complete records as discussed in the December committee meeting.

With regards to the fracture mechanics requirements and in response to public Notice of Proposed Rulemaking comments, committee comments, and research that was completed after the NPRM was published, PHMSA suggests the following.

We suggest amending the fracture mechanics procedure, so much as to revise 192.624(d)(1) to strike language that specifies when or for which segments fracture mechanics analysis is required and replace with language that clarifies that 192.712 only addresses the

purpose and procedure for performing fracture mechanics analysis.

Also, strike 192.624(d)(1)(iii), the sensitivity analysis, and replace with requirements that operators account for model inaccuracies and tolerances.

PHMSA suggests amending the fracture mechanics procedure by striking references to 192.624, MAOP reconfirmation; strike references to 192.506, the spike pressure test; and add a paragraph to require records be retained, since the record requirement for MAOP reconfirmation at 192.624(f) would no longer apply; also, rewrite the remaining requirements to be more performance-based and restructured according to the outline: (a) applicability, (b) modeling, (c) fatigue analysis and remaining life, (d) subject matter expert review, and (e) records.

To continue with the public comments on fracture mechanics methodologies, industry reps on the committee agreed and industry commented that -- well, industry commented

discretely that default Charpy values proposed by PHMSA are too conservative and suggested using 13 foot-pounds in the body for the Charpy value for fracture toughness and seven foot-pounds in low-frequency ERW weld seam for the fracture toughness -- oh, four. What did I say? Sorry -- four foot-pounds.

PHMSA's response is that the established default values proposed of five foot-pounds in the body and one foot-pound in the seam, based on research documented in the Final Report, Task 4.5 titled Comprehensive Study to Understand Longitudinal ERW Weld Seam Failures, Phase One under a DOT Contract shown on the slide with the work completed October 23, 2013 provided us with those values that we proposed.

The study was based on 569 actual failures from the Keifner/DNV and Battelle databases and some important conclusions are summarized on the next slides, as we discuss this topic.

Conclusions from the ERW Seam Research

Failure conducted by PHMSA. Use of failure predictive models in the integrity management process can be effective if the gaps that lead to issues in predicting failures are bridged.

Toughness must be quantified for the seam type/manufacturer involved, and must be determined relative to the location of the defect; otherwise, significant predictive errors can be anticipated.

Likewise, the defect size must be reasonably quantified and care taken where adjacent features can interact axially along the pipe.

And feature shapes and sizes must be reasonably represented by idealizations that underlie the fracture toughness -- fracture analysis. Sorry.

Again addressing the comment by industry that PHMSA Charpy values are too conservative, PHMSA provides some of the conclusions from our ERW seam failure research.

One of the conclusions is that the use

of lower-bound estimates for the failure stress levels of cold weld defects and hook cracks with Charpy energy of four foot-pounds and selective seam weld corrosion with Charpy energy of 0.4 foot-pounds.

So based on this research and analysis, PHMSA proposed default values of five foot-pounds in the body and one foot-pound in the seam. And it's important to note that those default values would only be required when actual values are unknown.

To continue along this discussion, default values of five foot-pounds in the body and one foot-pound in the seam would only apply for pre-'70 pipe and post-'70 pipe with unknown or suspected low toughness properties or where vintage materials, technology, or other technical publications are not available for not applicable.

To continue, operators must use known values for or values obtained through pipe property testing whenever available or would only

use default values if actual values are unknown.

We have some example calculations illustrating the effect of raising the default Charpy values on predicted failure pressures in the next four slides.

The first two slides are examples of a 50 percent pipe body crack in a Class 1 location. It shows on the left in the body the red line of being five foot-pound value, a black line being seven foot-pound value, some number in-between the other research, and then the blue line being the 13 foot-pound.

This would show the effect of changing the Charpy V-notch values for fracture toughness on that predicted failure pressure of a crack in the pipe body that is 50 percent through wall. So it would show that that crack could actually be one-inch long on the red line and then prior to reaching one and a half inches long would be where it exceeded the predicted failure pressure.

Likewise, on the seven Charpy V-notch value, or black line, it would be around two

inches in length. And on the blue line, the 13 Charpy foot-pound value, about three and a half inches in length.

The next slide is going to show in the seam the Charpy values of 1, 2, and 4. Again, showing that that half-inch -- that on the red line, where it's a Charpy value of 1, that a half-inch crack in length that is half-through wall would not be predicted to carry the full MAOP.

The black line at two foot-pounds would fall below the PFP somewhere between a half inch and one inch. And the blue line would exceed the PFP ratio at about one inch in length.

So in addition to looking at Class 1, we looked at Class 3. So here we have, again, a half-inch pipe body crack. And this is in the body with Charpy V-notch values of 5, 7, and 13, illustrated by the red, black, and blue lines respectively and how long that defect could be in a Class 3 location, where we would have a higher safety margin.

The five foot-pound value half-wall thickness crack could go up to three and a half inches. The seven foot-pound crack could go up to -- the seven foot-pound value could have a crack length of five inches. And the blue line could have an anomaly somewhere larger than that for a half pipe body crack. And that is for the body.

Looking at the seam where those values are lower, looking at one foot-pound in the red, it would exceed the predicted failure pressure at somewhere between half inch and one inch.

The black line for two foot-pounds would exceed it somewhere between one and one and a half. And the blue line for four foot-pounds in the seam would allow an anomaly of two and a half inches that was half-through wall.

These numbers were run for us since the last meeting, based on the committee comments using the Battelle model that was developed in our research.

So INGAA also commissioned a

statistical study of Charpy values, which was submitted to the docket, performed by Structural Integrity Associates titled Statistical evaluation of Charpy Toughness Levels for Gas Transmission Pipelines. That report number is there and it was completed on July 7, 2016.

This study suggested using 13 foot-pounds for the body and four foot-pounds for the seam, based on a 90 percent confidence level that the values would be conservative.

The INGAA study pointed out that the values proposed by PHMSA represent a 99 percent confidence level that the values would be conservative.

To talk a little bit more about the INGAA report, that study notes that the conservative values may result in excavations that, in the final analysis, may be proved to have been unnecessary.

PHMSA acknowledges that using conservative values to assure safety in the absence of knowledge about the pipeline may

result in excavations for cracking anomalies, pipes, bodies, or seams.

PHMSA desires that industry make greater efforts to know the physical characteristics of the in-service pipe when records are not available.

Again to continue along that discussion, PHMSA encourages more excavation, testing of material properties both of pipe and body and seam, of pipe without records, at which times operators may verify the physical characteristics using the procedures established under 192.607.

Industry commented that default Charpy values proposed by PHMSA are too conservative and again suggested using the 13 foot-pounds in the body and 4 foot-pounds in the seam.

PHMSA commented that the Weibull probability distribution curves developed in the INGAA study show the effect of small differences in assumed Charpy toughnesses on statistical confidence in the predicted failure pressure, as

illustrated on the next slide from that report.

This was the Weibull distribution curve in the INGAA-sponsored report done by Structural Integrity Associates showing on the red line a 90 percent confidence value utilized in the report for its proposed Charpy V-notch values; the blue line showing a 95 percent confidence for seven foot-pounds, which was the other number we evaluated when looking at pipe body to understand what the differences in our numbers were; and then a 99 percent confidence level for the five foot-pounds value for pipe body that PHMSA proposed.

It shows the number of tests on the left in that Charpy V-notch value as we go down on the right -- on the bottom.

So just to sort of reiterate one more time as we present data for this topic, this is probably the tightest case of a Class 1 location, that having the lowest safety factor, with a seam anomaly having the lowest Charpy V-notch values proposed in both of these studies, showing what a

half-through wall crack would look like in terms of its length and its ability to withstand the predicted -- to carry the predicted failure pressure as its length grows.

This is one of the slides we looked at previously and provides discussion for why we proposed one foot-pound for unknown values in the seam.

To continue on with several more slides, PHMSA comments again on the same topic that to address cases where default Charpy values may be too conservative, PHMSA suggests allowing operators to use differing values upon submittal of a notification demonstrating conservative Charpy values would be used.

I seem to have lost control. There we go.

So this concludes the PHMSA response to the comments on Method 3 and fracture mechanics.

The following slides summarize a number of revisions that PHMSA suggests the

committee consider to address comments received in the NPRM and in our March teleconference committee meeting.

In light of the committee comments from the December 2017 meeting, PHMSA suggests the committee consider the following.

PHMSA suggests revising 192.624(c)(3), Engineering Critical Assessment, and 192.624(d), Fracture Mechanics as follows. Specify that if information required for the ECA is not available on TVC records, the operator must use conservative assumptions or verify missing information for 192.607. Remove ILI tool performance specifications and replace with requirements to verify tool performance using unity plots or equivalent technologies.

In light of the committee comments from the December meetings, PHMSA suggests the committee consider that, since crack defects would be addressed by IMP and not addressed as part of the MAOP reconfirmation in 192.624, to strike 192.624(d), Fracture Mechanics Analysis,

for failure stress and crack growth analysis and move Fracture Mechanics to a new standalone section, 192.712, making conforming edits to refer to 192.712.

The new 192.712 would not specify when or for which segments fracture mechanics analysis would be required. It would be limited to the procedure for performing fracture mechanics analysis, when required or allowed by other sections of Part 192.

In 192.624, it would not contain default Charpy values or other technical fracture mechanics requirements. Requirements to perform fracture mechanics as part of the ECA in 192.624(c)(3) would simply refer to the new 192.712.

And PHMSA suggests revising 192.624(c)(3)(i)(B) to read as follows: The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each injurious defect in accordance

with 192.712.

Also in light of those comments from the December meeting, PHMSA suggests amending the fracture mechanics procedure to address technical comments received from the NPRM and committee comments. PHMSA suggests utilizing the fracture mechanics requirements originally proposed for 192.624(d) in the new 192.712 with the following revisions.

Strike the language previously proposed in 192.624(d)(1) that specifies when or for which segments fracture mechanics analysis is required and replace with language which clarifies that 192.712 only addresses the purpose and procedure for performing fracture mechanics analysis.

Also in light of the comments from the December meeting, PHMSA suggests the committee consider striking the (d)(1)(iii) sensitivity analysis and replace with requirements that operators account for model inaccuracies and tolerances.

Strike reference to the 192.624 MAOP reconfirmation.

Strike references to the 192.506 spike pressure test.

And add a paragraph to require records be retained, since the record requirements for the MAOP reconfirmation at 192.624(f) would no longer apply.

Also, as previously discussed, we propose rewriting and restructuring according to the following out line for the new 192.712: (a) applicability; (b) modeling; (c) fatigue analysis and remaining life; (d) SME review; and (e) records.

Also in light of those December meeting comments, PHMSA suggests that the committee consider clarifying that default Charpy values of five foot-pounds in the body and one foot-pound in the seam only apply to pipe with suspected low-toughness properties or unknown toughness properties and clarify that use of differing default Charpy values may be requested

by notification to PHMSA.

Thank you.

MR. DANNER: All right, thank you. Anything else? Otherwise, we'll go into public comment.

All right, is there anyone from the public here today who wishes to comment on Method 3?

Go ahead, sir.

MR. TOMAR: Good morning. This is Munendra Tomar from Kinder Morgan.

I'd just like to present a couple of observations and things that I think we should be considering, specifically in relation to the default CVN values that have been proposed and some of the justification that has been provided in the slides previously provided by PHMSA for the use of those and to counter or not accept the recommended values from the Structural Integrity INGAA study.

I have some slide numbers noted here, which seems to have changed since the first

iteration of these slides came. So if I'm off by a couple slides in my references, pardon me.

So the slide 48 seems to address or refer to the Task 4.5 Report from the Phase 1 Battelle ERW Study, which was a summary report. And there's reference to the sample size of CVN values used as 569. And when I went through the reports, I noticed that the values that are referenced in these slides and forms the basis for the default values recommended comes from the detailed reports 2.3 and 2.4 sub-tasks, which were by DNV and Keifner, respectively.

In Task 2.4, which is where the values of .4 and 4 foot-pounds come from, those were based on 33 failures, no actual testing was done, and the CVN values were calculated by back-calculating from the failures.

Now this back-calculation is based on predictive models, which we all accept and want to be conservative but, by that logic, the CVN values calculated would also be conservative. So that's one point I would like to consider or I

would like to request for consideration is that we need to keep that in mind that the CVN values, as were found in Task 2.3 and 2.4 were conservative, inherently.

The other point is that on slide 54, there are some plots, and this is one of those plots, which seems to suggest that -- now this is for pipe body but when we look at the same plot for seam, there seems to be a suggestion that between one foot-pound and four foot-pound, there's not a big difference in terms of which crack would be acceptable.

In reality in the NPRM, a 50 percent anomaly is deemed as an immediate. So in order to truly understand the effect of these default values, we need to look at smaller defects, a 25 or 30 percent defect. In those cases, the effect of changing the CVN values would be actually larger.

The other point I'd like to make is on slide 64 there is mention that operators can use higher default values if they can notify PHMSA

and provide justification. However, the industry report from INGAA which Structural Integrity presented, which uses most of the same data that was used in the Battelle Study and just performs a more statistical evaluation, takes the entirety of the set into consideration and PHMSA doesn't deem that acceptable. Then that brings into question what kind of justification can we, as operators, provide that would be acceptable to PHMSA.

And the other question is if the comment is that 99 percent is the confidence level that is acceptable, then that goes beyond the norms of most other industries we know. Most of the drugs we use every day are not tested to that kind of rigor. Why do we want to impose that on pipeline CVN values?

Thank you.

MR. DANNER: All right, thank you very much.

Yes, sir?

MR. PASKETT: Good morning, Mr. Chair,

members of the committee. I want to thank you for the opportunity this morning to provide comments to the docket.

For the record, my name is Bruce Paskett. I'm Chief Regulatory Engineer for Structural Integrity Associates, who did the study for INGAA with respect to Charpy impact values.

For those of you who are not familiar with Structural Integrity, as the name suggests, the company, since the early 1980s, has done structural analysis for nuclear power plants using fracture mechanics. So fracture mechanics, although it's kind of a new area for oil and gas, for pipelines, it is certainly not new to Structural Integrity.

I will tell you that I am not a fracture mechanics expert but my colleague, Mr. Peter Riccardella, who performed the analysis for INGAA, is a recognized industry expert and I think it's also important for you to note that Mr. Riccardella provides guidance for the Nuclear

Regulatory Commission. So, he is well-respected.

When Mr. Riccardella conducted the study for INGAA he used and found reasonable default values in the absence of TVNC records. And those numbers, as contained in PHMSA slides today from slides 48 to 63, were based on 13 foot-pounds of body cracks and 4 foot-pounds for seam cracks.

Mr. Riccardella has reviewed PHMSA's slides today that you've all seen this morning, slides 48 to 63, and he points out if Structural Integrity were doing this analysis for a pipeline, fracture toughness is only one of the parameters that are considered in the analysis. So the other input parameters would also be applied -- loading, fracture toughness, crack growth rate, and defect size.

So Structural Integrity and Mr. Riccardella's analysis and study was based on a 90 percent confidence rate for the toughness. If you take a 90 percent confidence rate for those four parameters that I just mentioned, the event

frequency of a failure would be one in 10,000 years. In my opinion, that would be a very acceptable safety factor.

So to summarize, although certainly as PHMSA has proposed, a 99 percent confidence level or percentile in the toughness values would certainly be more conservative than 90 percent that's proposed in Structural Integrity's report performed for INGAA. When you combine that with other conservatisms that are included in typical fracture mechanics, we believe that that 90 percent and specifically the 13 foot-pounds and 4 foot-pound numbers that were included in the report for INGAA are more than adequate for pipeline safety. So we would like to encourage the GPAC Committee to reconsider and PHMSA to reconsider the numbers that are proposed in the rule.

Thank you.

MR. DANNER: All right, thank you very much.

MR. HERETH: Mr. Chairman and members

of committee, I'm Mark Hereth from the Blacksmith Group. I appreciate the opportunity to comment on this topic of use of the Charpy values, the default values.

In actual experience, we haven't seen failures that have actually occurred that are two and a half inches in length and 50 percent or more deep or, as in the case of Mr. McLaren's example with the seams, where it was one-inch in length and greater than 50 percent.

The failures that we've seen are more typically eight inches or greater with that kind of depth. This, we think, provides an indication that the values are very, very conservative, as supported by the report prepared by the previous speaker. And we can appreciate the conservatism but its seems like the conservatism goes far beyond the experience that we've had in the industry.

Thank you.

MR. DANNER: All right, thank you very much.

MR. OSMAN: C.J. Osman from INGAA and, believe it or not, I actually have a comment unrelated to fracture mechanics.

So INGAA appreciates PHMSA's revisions to separate out and clarify the fracture mechanics process from the ECA procedure but there were a variety of other topics related to the ECA procedure that were discussed at the last GPAC meeting, I guess the December GPAC meeting, and were also brought up during public comment that we do want to make sure PHMSA addresses at some point. These were related to separating out the aspects of the ECA that are related to integrity management and managing long-term integrity threats and focusing the ECA method on confirming material strength similar to a pressure test.

So there are a variety of other components to the ECA, other than the fracture mechanics process. The fracture mechanics part of it is important. We want to make sure those other issues and comments and discussions that

the GPAC had are reflected in PHMSA's final ECA process for MAOP reconfirmation.

Thank you.

MR. DANNER: All right, thank you.

MR. BELLEMARE: Good morning. This is Simon Bellemare with MMT. This is my third meeting I attend so I know better the rules and I'll be very brief here.

There is a written comment that was submitted by Professor Eagar of MIT speaking to the value of physical sampling. And I want to bring into perspective because we heard from the industry. There were four comments that were not really public comment or comments from the industry. And the intent from INGAA -- I'm sorry -- PHMSA is very clear here. It's written in the slides that it's an incentive to go and run tests because there is a lot of steel from the different lines that is available and it doesn't take too many data points -- that's what you'll see if you read the two-pager from Professor Eagar -- to be able to validate a statistical

distribution that you already have some information about.

So you take a bell curve or generate a bell curve and then you adjust it for the type of steel that you find from physical sampling.

And I believe that really is the intent of these minimums here to say go and collect some data. We're not talking about digging out the whole pipeline, not at all. Ten tests for a segment, if you read Dr. Eagar, tells you something about the statistical distribution that allows you to address the tail end of fracture toughness, which is what can cause the incident.

Thank you.

MR. DANNER: All right, thank you.

Okay, are there any other public comments this morning?

All right, seeing none, I'll turn to the committee. Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I think those were some very good

comments from the public and I appreciate that.

I think this is a good place for us to pause and really think about what's practical here. We can get into battling consultants. I don't think that's terribly constructive here. I think these are credible folks I think really trying to figure out what is an appropriate level to set here.

And I think the thing that helps me, you know I think it was on slide 61, the test for toughness was not really put into practice, the Charpy V-notch test was not really put into practice, I don't even know if it was invented, until the late '60s, somewhere around there.

So when you think about that, more than half this infrastructure was built before the test existed. So by default, the pipe will not have a test record for Charpy impact testing in its MTR. It wasn't done.

And that doesn't mean, as you can see on slide 61, that the pipe doesn't have toughness. It has toughness. It just doesn't

have a record of toughness because the test wasn't done.

So what is an appropriate assumption here when we're dealing with the vast majority of pipe that has toughness that just didn't have the test done? Should we default that because it was prior to 1970 and doesn't have the test that it would be now assumed to be as tough as a Coke bottle so that we can make sure that everything is inside the envelope here? I think that is ridiculously overly conservative, quite frankly. It's actually beyond that. It's punitive.

I mean I think what you want to try to do is look at that chart and say what's a reasonable assumption to make for some kind of anomaly assessment. I think the comment that Mark Hereth resonated with me, when we look back, slides 53 through 56 are an interesting technical exercise. I appreciate that. It reminds me of my fracture mechanics classes in college. That's interesting.

What's relevant is what is really

happening. Are we having failures out there that look like this? No. Well, that's good to know.

So how do those things fit together as we try to model what's the appropriate thing to do here? What's a practical solution?

When you look at engineering critical assessments, and this really comes into play when we look at anomaly, you know integrity management anomaly response, there's a lot of variables that play in here. This is one.

The tolerances associated with those other ones have a lot bigger influence on what's happening here. And what we're trying to do is make a reasonable, practical assumption about the tail end here.

I appreciate the last fellow's comment about we're gather more data over time but while we're in this interim place, what is an appropriate assumption to be making about this one variable and what is its impact in our defect assessment modeling?

And I think that when we scoop all

this together, I think the fact that there are 1500 data points that were used in this assessment, and we are trying not to bias the population one way or another but just look at this distribution, and we find that levels exist that are much higher than that, obviously, but even the tail end, as we make those assumptions, I think if we don't recognize the practicability of the vast majority of the pipe being well above that, we're going to end up having a lot of excavations to go look at cracks and look at anomalies that are not that significant. And I think that's actually just inappropriate.

So I think right here what we're trying to do -- and I appreciate the fellow's comment about one in 10,000 years. I think I'll have to rely on that statistical analysis but thumbs up. That's good.

But I think the point here is what is a practical level of conservatism. If one in 10,000 years seems reasonably conservative to me, given that distribution right there that we're

looking at and the fact that what we've seen from failures historically, and I just think you're really trying to make an assumption about what we can do that's practicable in the absence of so much of the pipe not having had the test done without being punitive.

MR. DANNER: All right, thank you.

Any other comments? No other comments. Okay.

Oh, all right, Cheryl.

MS. CAMPBELL: Cheryl Campbell, Xcel Energy.

So I'm not even going to pretend that I know very much about fracture mechanics. I depend on a lot of very sharp people. But the one in 10,000 years resonates with me. I'm very interested in hearing PHMSA's thoughts around this.

What I do understand is I have a lot of different things working together that's layered on top of each other to try and make sure that I've got -- I call it belts and suspenders

as opposed to an appropriate level of conservative stuff. But you know I do understand that my tool tolerance, you know I dig more holes than I have to because I know what my tool tolerances are.

So I'm very interested in PHMSA's thoughts around this idea of one in 10,000 years for failure mode.

And then Andy's comments about we're not seeing failures based on this when we have half of our infrastructure that's in this didn't do a test. So how do we drive to that thing that works but that keeps everybody safe, without assuming my pipeline is essentially the toughness of a coke bottle?

MR. DANNER: All right, thank you.

Anyone else? Steve, do you want to respond?

MR. NANNEY: Yes, this is Steve Nanney with PHMSA.

As Chris went over in the slides, PHMSA is quite willing of looking at other values

than what we had proposed. In fact, we had put other values even on the chart to have this discussion or on the figure like the one that's up there.

The key thing that we've been seeing, and here's our point, is we do have operators that are assuming numbers similar to this Weibull or higher, where they've had numerous failures and they've all been in the very low foot-pounds, whether it has been in the weld seam or the pipe body. And the point is is when you're seeing failures and multiple failures on your pipe and you're seeing things come out at one foot-pound, or a half a foot-pound, or three foot-pounds, or some number like that is what it's showing in that weld seam are maybe 10, or 12, or 6, or 7 in the pipe body, going and using something like this to take its place is not using a conservative value. In fact, it's using the opposite of that when you've got multiple data points that show the opposite.

And just like Chris went over in the

slides, you know we're willing to work with something but it needs to be reason and it needs to be based upon what the operator is seeing. And the operator needs to take an effort to find out what they've got, not just assume something. Whether the numbers we're proposing or these other numbers are right, wrong, or indifferent, the key is is to try to get some data to back up whichever one you're using is our point and especially if you've got failure data points that are not backing up the report.

MS. CAMPBELL: Can I respond to that, Mr. Chair?

MR. DANNER: Yes, go ahead, Cheryl.

MS. CAMPBELL: Steve, that sounds like PHMSA has data on failures of these lower Charpy values. Is that -- I mean that's what I heard you say.

MR. NANNEY: Yes.

MS. CAMPBELL: Can we see that data?

MR. NANNEY: I don't have it here today. The answer is no, not today.

MR. DANNER: All right, Sara.

MS. GOSMAN: So, like Cheryl, and maybe even more, I can't pretend to be versed in this technical area but I just want to pull back here for a moment.

So as I understand what we're doing, we're looking specifically at pipelines that don't have records on toughness or are grandfathered and are in particular areas, so areas where we're going to see more vulnerability by populations.

And there are a series of possible responses to that, including pressure tests, pressure reduction, pipe replacement. So this is -- plus other technologies that people can bring to PHMSA. So this is one set of responses and it's the one that is an assessment that you would do instead of doing things like pressure tests, which I understand. You know we had this conversation yesterday where we really want to get to. In a lot of these cases, as I understand it, there's a pressure test.

So it seems to me that I don't know what the right number is but I think to be conservative about the basis for this assessment, given the other things out there that are available, makes a lot of sense.

And I guess I would also say that you know in the kind of academic work that I've done say in the toxics arena, we make a lot of very conservative assumptions about toxics because we want to stay very far away from the point in time in which we say have enough exposure to result in cancer.

So I think that extra conservatism, while it's certainly a part of debate in risk circles, is not unique to this particular area and can be justified when really what you're trying to do is to say there are these other possibilities, including doing the testing itself. But if you're going to do this kind of assessment, then do it in a way that assures us that really you're acting as if this pipeline were the most risky possible.

So if that's in fact what we're doing with this data, then it seems to me like we see that in other regulatory context, too.

MR. DANNER: All right, thank you.

John.

MR. AIREY: John Airey, retired guy.

I'm curious about the data that you do have and the nature of it because it appeared there was very little practical field data. But I'm curious. You said there's a lot of failures that you've encountered and it seems like it would be -- the nature of that.

MR. NANNEY: Well, can I?

MR. DANNER: Yes.

MR. NANNEY: Okay. My point was in these older pipes normally what we see is if you have a seam failure, normally, and it's an older vintage pipe, it's going to be a single digit and a low single digit number. Whether that's one foot-pound, five foot-pounds, four, I'm not going to sit here and put a stamp on any of them but it's going to be normally a lower number.

If it's stress corrosion cracking or something in the body, it's going to be higher and everything.

My point that I was trying to make is normally we see the low numbers when see the failures.

The point that we were making and what Chris went over in the slides, and why we put it in front of the committee, we're willing to work on the language as far as not just basing it on some report that has nothing to do with your pipe. You know we don't mind basing it on if you've got something to show that it's in that realm but that doesn't mean that it's in that realm.

I've seen here in the past few weeks some pipe made two years ago that failed and it had one foot-pound strength and it was supposed to be high frequency ERW pipe.

So my point is is just because we've got this report is where you're seeing the cracking and things is normally it's going to

happen in the low-toughness pipe. The high-toughness pipe, you're probably not going to have the cracking is normally what happens.

So the point is is this going to happen in the low toughness. That's why we're talking about it. But again, in what we're wanting is, one, that if you have data showing that it's less, you can't go to a report like this and use higher data. That's the point I'm trying to make to the committee.

And two, if you use a number, you need to be actively trying to get data to back up what you're using, if you're using a report such as this. That's the two points Chris was going through in the slides. We didn't quite maybe state that exactly but that's the point where we were coming from.

And yes, like it says on our slides, we still have those numbers. And you know we were looking at the discussion today to see should we move up a little, should we leave it like it is, or whatever. So that's what we were

seeing the discussion today as being.

MR. AIREY: Can I follow-up on that for just a moment?

Are you suggesting that if you went to the midpoint here that is something that PHMSA would find acceptable?

MR. NANNEY: This is Steve Nanney with PHMSA.

That is exactly what I'm suggesting, that if we looked at some compromise and we looked at something along the line that the operator needs to take efforts if they don't have that information to get it, and if they have failures and other data like that that shows that it's less, they've go to use it. I think that is a very workable solution.

MR. DANNER: Andy.

MR. DRAKE: This is Andy Drake with Enbridge.

Steve, I absolutely agree with that. If an operator has the data, then they need to use the data. You know I mean that's just

prudence.

I think you used the word a few minutes ago interim. I see this as sort of an interim solution because you've got a real problem, a real issue with the fact that most of the population of the pipe wasn't tested. It doesn't have that information and yet we find ourselves in the position of having to do defect assessment and using this.

So as we're trying to gather this data opportunistically, what is a reasonable assumption to make about that population of pipe?

If you have data, you should be using it, obviously. But in the absence of that data I think both of these numbers are very low. I mean when you showed slide 61, I mean they are way down at the tail end and I think that's where we get into the conversation about what's enough conservatism. Is it one in 10,000 years or one in 100,000 years?

I think this is a temporary issue, as we gather more information and that's all I'm

saying is use something practical and don't damn this large population. I don't think we're creating an inordinate risk in one in 10,000 years of event while we work to gather the data.

But I do think if we don't do something more practical, the toughness levels you're talking about are going to create a lot of excavations and a lot of work for pipes that aren't having defects that are critical.

MR. DANNER: Cheryl.

MS. CAMPBELL: Cheryl Campbell, Xcel Energy.

So again, I'm just trying to understand, seek to understand. So what I think I'm hearing both Steve and Andy say is we're saying let's start with a number. And I, again, don't know if it's 4, or 13, or 7, or something else but I dig -- I make a dig based on that. I make that assumption. I make a dig based on that.

To your point, Steve, I don't have that data about that pipe. So I attempt to

collect that data under 607 while I have that excavation open.

If I learn it's one or two, when I thought it was something else or I made an assumption it was something else, then I think we would all assume or expect the operator to take appropriate action based on that new information.

Is that your point, Andy? And if it is, I agree with that.

MR. DRAKE: Absolutely. I think that's just prudence and diligence. You would never discard the actual data that you have, in lieu of trying to make some sort of assumption. You're just making a reasonable assumption until you get the data.

MS. CAMPBELL: So to your point and Steve's point, what we're talking about is what's that starting assumption for that pipe. And again, I'm sorry, I'm just trying to make sure I understand the -- okay.

MR. NANNEY: If I can say something, I'm agreeing with you. I'm agreeing with you.

MR. DANNER: You may say that, yes.

So I have a question for Andy. You keep using the word interim. Just how long is this interim?

MR. DRAKE: Well, I mean we've got a lot of consultants around here.

MR. DANNER: Yes, and they don't agree.

MR. DRAKE: Well I think it's back to the thought of opportunistic. I mean this is the whole design, as we're gathering this information, we're trying to make these assumptions. You know you're just filling in that data as you dig this pipe.

And how long does it take to get statistically significant? I think one of the consultants who was just talking a few minutes ago says it's not that much. I don't think it's a tremendous length of period of time. I think you're talking probably the period of the assessment interval, which is seven to ten years. I think you're going to have a lot of information

in that period.

So, I see Steve shaking his head yes. I mean I think that's a reasonable assumption.

MS. GOSMAN: All right, thank you.

I'm sorry I didn't see who put it up first. So, all right, Sara, you're first.

MS. GOSMAN: All right, thank you.

So there's a time question which, thank you. I also have just a question on scale.

So you, Andy, you had mentioned that at a certain point in time this test came into effect and before that, we don't have information on toughness. So does that mean that for all pipe previous to that date we don't have adequate records so, therefore, we have to do ECA, or pressure test, or a pressure reduce, or replace? Is that what you're saying? No, okay.

So then what's the scope of the set of pipelines that we're talking about here that are in the world in which we don't have records and we need to actually use ECA as one of the possible responses?

MR. DANNER: Okay, I think Steve, you want to take a stab at that?

MR. ALLEN: Yes, Steve Allen, IURC.

To go along with what Sara was saying, from a cost-effectiveness, what are we -- what's the delta between 90 percent confidence factor and a 99 percent confidence factor, based on the population of pipe that this method would be used for? I mean there are other methods available. Okay so there must be a certain number of pipes that this particular method would be used.

Okay, given that assumption, based on either 90 percent, or 99 percent, or somewhere in-between, I'm curious as to what the financial implications are because whatever rule we make, it needs to be cost-effective. And that seems to be absent in this conversation.

And one other thing. It also stuck with me the failures of one every 10,000 years. That's kind of interesting. I was just curious as to what that number might be at 99 percent confidence and at somewhere in-between, the 95

confidence. Are we talking about one in a ker-billion or I mean because at some point it becomes impractical and especially when you start looking at the financial implications.

So you know I need to know what the populations of pipes that would be subject to this, as Sara had mentioned, and then some sort of sense for what the financial impact is or the economic impact.

MR. DANNER: All right, Andy and then Alan.

MR. DRAKE: This is Andy Drake with Enbridge.

Sara, it's a great question. I think, to be very honest, what's happening here is this is not so much about ECA. It's much more about anomaly inspection criteria, which is a separate section but it's the same numbers. So we're having a conversation now about anomaly inspections in remediation just because it's the same criteria.

You know I don't know that we would

get too worried about doing the ECA so much volumetrically from a population standpoint as we would be about anomalies.

Steve, to your point, I'll give you an exact example. In our world today, the tool technology for crack assessments is at the edge of the technical envelope. We are not where liquid pipes are because the acoustic tools need the fluid liquid to transmit the acoustic signal into the pipes so they can get an accurate assessment of the crack and they're very, very advanced in that. I think the precision of those tools, the accuracy of those tools is very high. Unfortunately, in gas that sound, that ultrasonic signal, doesn't transmit very well in gas. So crack tools, ultrasonic tools, are on the edge of development right now and our ability to use them accurately is an experiment.

We ran a tool in Texas here a couple of years ago. This thing basically was a thing finder. It found millions of things, none of which were cracks. It was great. I mean if I

could just dig up the entire pipe and assess everything that it dug up -- that it identified, that would be awesome. Unfortunately, that's where we are in the state of technology.

So what we did, and now this is where technology is right now, and many operators are using this technology. It's evolving. It's getting a little bit better. It's getting better at identifying critical cracks, critical anomalies. So basically you put like a stage-gate filter on the tools' output. It's pretty accurate at finding big things. Below that, man, you are in the blender. That thing is finding everything. It is looking for surface irregularities, all kind of noise in the pipe.

So if I try to drop down and start looking for tiny little cracks because I've had to assume this thing is basically a Coke bottle, I don't know why I would even run the tool, to be quite honest with you. I don't know what I would be going after. I need something that's practicable, not just an engineering exercise in

crack sizing. That was interesting.

But when we play this, I've got to figure out how do I use this tool that's at the edge of its technical capability as a screening device with some criteria that makes some kind of sense. And that's all that's really happening here.

And I think we're just trying to get down to some -- how can you practice this, not just the obvious curves here, slide 61 about the majority of the population and where it is; it actually has more toughness; what's a reasonable assumption but also, where's the tools and what are we looking for, and how does this play?

Well, this actually comes into play in that. I'm trying to make an assessment from a tool run not out in the ditch. If I'm in the ditch, I'm going to get the toughness data. That's the part that we learn over time. That's why we're talking about gathering this. But for that first assessment, if I have to assume numbers like this with tools like we have and

tolerances that I'm trying to deal with with those tools, I don't even know how it's practicable, to be very frank with you.

MR. DANNER: All right, Alan.

MR. MAYBERRY: I'm kind of marveling at the discussion here. This is a more complicated version of the discussion we had related to hydro and just what do you do you know as you use the method, in this case, the ECA.

So and certainly we can appreciate that wherever we dial in the sweet spot you know more conservative is not necessarily -- you know it's just going to take more resources. Where do we find the ideal level that has you not digging on the thing finder type situation, where you are just digging on things. So what is the sweet spot?

I think we have a similar understanding on what we're after here. You know really what are the boundaries we're working within, as you work towards understanding what you have in the ground through 607, similar to

the discussion we had, in a way, on the hydro.

So we have some voting language here, I believe, that we could -- you know we're going to put it up there just so we can talk about the boundaries we're dealing with here.

MR. DANNER: So while we're doing that, John, why don't you go ahead?

MR. AIREY: I haven't heard a discussion about cost. If this addresses half of the pipelines out there, what kind of a cost implication is embedded in it?

MR. DANNER: Well, people have raised cost. We don't have any estimates of costs in front of us.

Steve.

MR. ALLEN: Yes, Steve Allen, IURC.

Then I'm not sure how we can vote on that if we don't have a sense of the cost-effectiveness. I mean isn't that what we're -- that's one of the criteria for passing a rule.

MR. MAYBERRY: We don't necessarily have the costs. I mean that's what we do when we

leave here but we don't necessarily have exhaustive cost-benefit for every scenario that you deal with here. That's why we have the public input, the input of the members, to kind of get a sense of what the impact could be or would be and then we'd go from here and deal with that.

MR. ALLEN: Mr. Chair, may I follow-up?

So with that, I would at least like to hear from our industry members as to what you believe the cost impact is of this. I mean is this a non-starter or what?

So and also I might add the conversation or the question I had about the -- and I don't know if this is accurate or not. It was just handed to me. The one in 10,000 years figure that was given at a 90 percent confidence, at 95 percent confidence level, that was an incident every one in 160,000 years. And they say at 99 percent it's one at 100,000,000 years.

Now, I don't know if that's accurate

or not but if that is accurate, that's kind of interesting to consider. What level of conservatism is appropriate? Yes, it's likely somewhere in-between but I just share it with the membership.

But I would like to hear from industry what you think the economic impact on a 90 versus a 99 percent or something in-between.

MR. DANNER: So I think yes, the conversation is really about diminishing returns, too. And it could be you don't really need to have precise cost information if you know that there are diminishing returns.

So Cheryl, do you want to --

MS. CAMPBELL: So I can share one of our experiences. We ran one of these crack tools. I mean we had a line that -- I can't even tell you why we -- you know we must have thought that there might be an issue there, right, or we wouldn't have put a crack tool in it. And it came back -- and Andy's terminology about thing finder is pretty interesting because that's

exactly what it felt like. It came back with it said I had several one-half inch openings in the pipe. And I am not talking about a longitudinal crack like a hook crack. It said I had a half-inch opening in the pipe. I clearly did not have a leak on that pipeline, certainly one of that size. It operated at 800 pounds. If I would have had a half-inch opening in the pipe, I would have known about that. I would have had a lot of other issues telling me that.

And the net result is we ended up digging I'd say probably 20 holes and found absolutely nothing when you went down. Now, do I feel better about the pipe? I know more about it than I did before but I dug a whole bunch of holes that didn't necessary help advance my integrity program on that pipeline.

And we basically have moved away from the crack tools and said the technology has got to get better, unless we really are concerned about cracks in specific pipes.

Now in fairness to my friends at

PHMSA, we have identified another pipeline where we do have some cracks and we've taken some steps to resolve that, which frankly just included renewing the pipeline because I can't deal with it.

But I think it's an interesting problem and I think Andy's point is you end up digging a whole bunch of holes and you don't really advance your integrity program and you haven't improved safety. I think that's what the concern is.

And I can't tell you how much those cost. I mean they could have been -- if they were in an open field, they were five grand but if they were under an interstate highway, it's a whole other conversation.

MR. DANNER: All right, Andy. Yes, just a brief comment. I think we're going to take a break and we will come back with some proposals.

MR. DRAKE: This is Andy Drake with Enbridge. I think that would be awesome.

(Laughter.)

MR. DRAKE: I just feel like maybe before break give you some fuel. I think it is hard to come up with a cost but I think it's almost more of a matter of practicability at this point.

The tools that we're dealing with and the assessments we're trying to use, we are not even plugging in toughness really into that. We're just trying to find cracks because the tolerance of detectability is pretty -- is the bigger issue actually at this point. If we try to plug this in there I think there's appropriateness here to plugging in a toughness value. I think we don't want people to be too optimistic, you know a conspiracy of optimism that this pipe can stop the hammer. It can't. It's got -- it's probably got low toughness, to Steve's point. It's how conservative or how much punitive do we want to be with that big population of pipe about that assumption, given the tool tolerances.

So when you scoop all that together, I think you're just trying to say all right, we want to feather in some toughness considerations in your model. We don't want you to be super optimistic. We want you to be conservative. We've got 1500 data points to come up with this answer. Put that into play while you're gathering more data opportunistically. And I think that's what we're trying to do -- I don't mean to say thematically -- but at a high level.

But I would say if you go back to those charts on 53 through 56, you get a sense the defect size is two or three times longer. Well, you add that to these tool tolerances and all of a sudden, you're digging up anything, I mean two or three times smaller. So you're digging up a lot and that's the problem, especially given the tool tolerances if you put them together.

And I think it's just a matter of practicability. That's really it. You're just sort of feathering this new requirement in while

you gather more data. What's a reasonable and practical assumption for this first tranche of work. Does that make sense?

MR. DANNER: All right, thank you. Alan.

MR. MAYBERRY: I think actually Andy covered the practicality part. I just want to know what's practical and I'm good. We can take a break.

MR. DANNER: Okay, it's 10:19. Everybody be back so we can start at 10:30.

(Whereupon, the above-entitled matter went off the record at 10:19 a.m. and resumed at 10:51 a.m.)

MR. DANNER: Okay, let's go back on the record here. All right. I'm going to turn it over to Alan who will --

MR. MAYBERRY: Okay. Thanks, Mr. Chairman.

MR. DANNER: Okay, Alan. Thanks.

MR. MAYBERRY: Yes, thanks. Right before the break we put this -- some language up

there and, you know, based on the discussion we just had prior to the break, we've edited the language and of course the discussion centered around the Charpy values. If you could put that last slide back up there. Okay, cool.

So, in red you see up there, you know, basically on -- you know the overall heading of a revised Fracture Mechanics requirements by -- then we added related to that first one in red there. Operators can use a conservative Charpy energy value based on a sampling similar to the requirements of 192.607. And the operators can use Charpy Values from somewhere or the same vintage pipe until properties are obtained through an opportunistic testing program.

And then in that next one we're looking to, you know, get input on defining what the -- you know, the body and the seam values for Charpies are and then adding a little more clarification that -- related to -- let's see. Unknown toughness properties in the history of leaks and failures. That would also impact that

and operator must work diligently to obtain this data if unknown. And then -- you know, different from these you can do a notification.

We -- that, you know, as I've discussed with many of you is a common feature of, you know, why these revisions that we're making is their notification provisions. If you're going to go outside of that to PHMSA. So we've got that aspect built into this as well. And that -- we offer that up for comment. I don't know. For starters, if anyone wants to fill in the excess, that would be appreciated.

MR. DANNER: All right, Steve.

MR. ALLEN: Thank you. Steve Allen, IURC. So, the second to last bullet point where it says, and a history of leaks and failures, is that to address the concern mentioned by Industry and the public that we're just not seeing problems with such small anomalies, or what?

MR. MAYBERRY: No, that's just if you have those characteristics and a history of leaks and failures. You know, that's where you would

use those.

MR. ALLEN: That's what I was saying. If there is not a history of leaks and failures then yes, it would apply.

MR. DANNER: Okay. All right, Sara?

MS. GOSMAN: I'm not sure --

Actually, I thought that was a great question. I'm not sure I understood the answer to it. So, if you don't have a history of leaks and failures are you not using ECA or how does this -- or you're using other Charpy values that are different?

MR. MAYBERRY: Steve.

MR. NANNEY: I've forgotten how to operate this. The -- what we're meaning there is that if you have a history of leaks and failures, we want you to work diligently to obtain the data from the leaks -- from the leaks and failures. In other words, not just to rely upon the X and Y -- whatever we decide there for that number to be. But if you've got other data that's less than that -- those numbers to definitely use

those and any other information that you have on that particular pipe.

MR. DANNER: All right, Andy.

MR. DRAKE: This is Andy Drake with Enbridge. Yes, I think that would probably work a little bit better if we put a period at the end of toughness properties and said, if the operator has a history of leaks and failures they must work diligently to gain the data. I think that's actually what you're trying to say.

MR. NANNEY: That's correct.

MR. DRAKE: Yes and I think that would work a little bit better. I think just a little bit of -- I think this is reflective of the conversations we've been having and I appreciate that. Just as a point of data, I would offer up the 13 and 4 in the X's there which is congruent with INGAA's proposal. And, I think, a bit of data here is if we try to strike a balance here, so to speak, or come from a balance; try to strike a compromise at 95 percent and you end up at 7 foot-pounds. I think the relevance of that,

it sounds -- I mean, when we've talked negotiating that -- oh yes, that's good; but we'll meet in the middle.

Well, the problem is that seven years is still in the brittle regime. And what that means is that you have to consider the pipe is fully brittle and there's no ductility in it and when you do the assessment, you cannot use the modified lock, seek and assessment criteria to assess the viability of that pipe which is a big deal. It really has a huge effect on the reassessment frequency. And I think that, again, it's sort of like a little cliff. You just fall off into this place that's very, very damning to 99.99 percent of the pipe. And I think -- that's all we're trying to avoid.

I think the relevant issue here is applying toughness is a huge step and we are in a huge transition between not doing it at all and now doing it. Where we also have a huge chasm of data missing. What is a reasonable assumption to make for this as we launch into this and gather

more information?

I think this is an interim position that we're talking about. The question is, is in this interim position is are we being conservative. And, I think, through all the data that we've seen both of these are conservative. I think one of them is kind of overly conservative almost to the point of being impracticable. And, I think what we're trying to do is do something that's a good positive step that's practicable in the interim while we're gathering more information.

And I think that's where the 13 and 4 really strikes the appropriate technical solution.

MR. DANNER: Okay, Sara.

MS. GOSMAN: Just have a few more questions here. When you say that the operators can use a conservative Charpy energy value based on sampling similar to the requirements of 607, what do we mean here by similar as opposed to just the requirements of 607? And then my second

question is given that operators can use Charpy values from similar or the same vintage pipe, I'm wondering why that doesn't address some of the concerns about the default values. That is, if you have similar, same vintage pipe which I assume you would in a lot of these circumstances, why wouldn't you just use the Charpy values from those and not go to the default?

So, I guess one for PHMSA and maybe one for Industry.

MR. DANNER: All right. So why don't we start with Andy. Do you want to respond to Sara and then, you got your tent up so maybe something else you want to talk about.

MR. DRAKE: I'm glad to work on the wording of the whatever number bullet that is; the second red one there. But that is the intent is that operators should be using the data that they have and applying it appropriately to similar materials. That's a reason -- that is diligence. So, if we want to modify the words a little bit but that's the intent, in my opinion.

I see Steve shaking his head. So, I think, we're trying to go that direction and I think that is reasonable and practicable also.

MR. DANNER: All right. Steve, did you want to comment on this? Oh, okay. You didn't -- I'm sorry.

MR. NANNEY: No. Andy basically said the same thing I was going to say.

MR. DANNER: Okay.

MR. NANNEY: So --

MR. DANNER: All right. Cheryl?

MS. GOSMAN: Can I --

MS. CAMPBELL: Yes.

MS. GOSMAN: Can I just follow-up? I'm sorry. I -- on the question of sampling similar to the requirements, I'm just curious about what that means. Why the word similar is in there. That strikes me as saying we're not really doing the same thing as 607 Board just doing something similar to it and I just don't understand what that means.

MR. DANNER: Yes, Steve. Please.

MR. NANNEY: We're going to change it to same. Can we do that, Bob?

The only reason we put similar is because I asked Sayler to do that. So, but similar and the same, to me, is basically the same.

MR. DANNER: So -- but if you're going to say the same --

MR. NANNEY: Yes.

MR. DANNER: -- why not just have it based on 607? Okay. So that's where it is now. All right. Cheryl?

MS. CAMPBELL: Okay. So, I -- I'm just trying to think through this, right? And there's just a couple of -- and I wouldn't even call them concerns, but I feel like we're very close and that we're all trying to say the same thing. So I'm just asking us, right?

Are we -- because I think the intention is let's start with this assumption. If you've got something else that you think is similar then go ahead and use that. If you

don't, then here's a place to start. And, oh by the way, if you've -- if you get down in there and discovered something else, right? You need to take some prudent action, right? I mean, that's where we're all at.

So, my question for all of us is have we made it clear enough in the guidance here. Because I know we're not writing code, Alan, right? Are we making it clear enough and are we providing enough clarity for our friends at the State who will be the one looking over my shoulder, right? And trying to make sure that -- you know, I'm trying to make sure that I'm following the rules, right? And we're not going to get crosswise with the way it's enforced at the State.

So, I just want to make sure we're providing enough guidance to PHMSA, right? That we get to a place that's going to work for all of us and we're not going to get crosswised when our friends at the States are enforcing it.

And I can live with that 13 and 4 as

a starting point as long as there's clarity, right? Around -- if you don't know and you find out something different then do something about it.

MR. DANNER: All right. Alan?

MR. MAYBERRY: Yes. I was just going to say in response to, you know, the State component. I mean, we're getting pretty prescriptive here by providing, you know, some lower numbers. So, I think that makes that easier.

MR. DANNER: Sara?

MS. GOSMAN: All right. I'm going to try a proposal. See what you think.

So, I'm wondering if we can split the bullet point second from the bottom here and focus on those pipes that have a history of leaks and failures and whether we can apply the more conservative default assumptions to those and apply the -- one of the 13 and 4 to follow assumptions to those pipes that don't have that history of leaks and failures. And here's why

I'm trying to cut it that way, right?

I understand that just getting to the middle on the numbers is -- I mean, we don't have the data for that, but maybe we want to be more conservative when it comes to pipes that have that kind of history. And, to me, that seems defensible that we could apply different default values to a pipe that is considered differentially risky.

MR. DANNER: So, just to clarify. So that would be if a pipe has a history of leaks or failures as opposed to an operator?

MS. GOSMAN: Yes, pipe.

MR. DANNER: Okay. Okay. Is there any comments on -- Sara?

DR. LONGAN: Thank you, Mr. Chair.

If it remains if a pipe has a history of leaks and failures, this goes back to us better understanding the type of data PHMSA does or does not have or the type of data that PHMSA expects to have or not have in the future. I'm just wondering how that addition is enforceable.

However, I appreciate your comments, Sara, and understand that there might be an importance of separating this. I just want to make sure that if it is separated it is clear for operators to understand what's expected and PHMSA has the opportunity and the availability of the information they need to comply here.

MR. DANNER: All right. Any other comments on -- okay. Yes, Andy.

MR. DRAKE: Andy Drake. I think the only -- I'm directionally good with this. I think the only caution I would say is, where a fatigue -- or where toughness plays in here it would be if it has a history of leaks or failures due to cracks, not -- I mean, if it has a corrosion issue, that's a separate problem. Yes. And if it had -- does that make sense? And, look, just --

MS. GOSMAN: I think that's fine. Yes. Yes, I understand the failure mode issue.

MR. DANNER: So, if a pipe segment has a history of leaks or failures due to cracks --

MR. DANNER: All right. Any other? That's five and one, isn't it?

PARTICIPANT: Yes, five and one.

MR. DANNER: Okay. Any comment on this one? All right. I'm hearing silence which, I think, it means it's time for a motion. Is there anybody whose eyes are good enough to read it from where they're sitting?

Cheryl, can you give it a shot? I can't read it from here.

MS. CAMPBELL: Yes, I'll do it.

MR. DANNER: So --

MS. CAMPBELL: I'll do it. I'll do it. It's a lot of talking. I'm just saying. Okay.

MR. DANNER: I know.

MS. CAMPBELL: The proposed rule is published in the Federal Registry in the Draft Regulatory Evaluation with regard to the provisions for Method 3 of MAOP Reconfirmation Fracture Mechanics are technically feasible, reasonable, cost-effective and practicable if the

following changes are made.

Strike Section 192.624(d), Fracture Mechanics Analysis for failure, stress and crack growth analysis and move Fracture Mechanics to a new stand-alone section, 192.712. The new Section 192.712 would not specify when or for which segments Fracture Mechanics analysis would be required. It would be limited to the procedure for performing Fracture Mechanics analysis from when required or allowed by other Sections of Part 192.

Section 192.624 would not contain default Charpy toughness values or other technical Fracture Mechanics requirements. Requirements to perform Fracture Mechanics as part of ECA in Section 192.624(c)(3) would simply refer to new Section 192.712. PHMSA suggests revising Section 192.624(c)(3)(i)(B) to read as follows: the ECA must analyze any crack or crack-like defects remaining in the pipe or that could remain in the pipe to determine the predicted failure pressure of each injurious

defect in accordance of Section 192.712.

Add requirement to verify material properties in accordance of Section 192.607 if information needed for a successful ECA is not documented in TVC records as discussed in the December 2017 Committee Meeting. Remove ILI tool preference specification -- or, tool performance specifications and replace with requirement to verify tool performance using unity plots or equivalent technology. Revise the Fracture Mechanic requirements by striking sensitivity analysis requirements and replacing with requirement that operators account for model and accuracies and tolerances.

Striking references to Section 192.624, MAOP Reconfirmation. Striking references to Section 192.506, Spike Pressure Test. Adding a paragraph to require our records be retained. Operators can use a conservative Charpy energy value based on the sampling requirements of Section 192.607. Operators can use Charpy values from similar or the same

vintage pipe until properties are obtained through an opportunistic testing program clarifying that default Charpy values of 13 foot-pound body and 4 foot-pound seam only apply to the pipe with suspected low toughness properties or unknown toughness properties.

If a pipe segment has a history of leaks and failures due to cracks, the operator must work diligently to obtain toughness data, if unknown. In the interim, those segments must use Charpy values of 5 foot-pounds body and 1 foot-pound seam. Clarifying that use of differing default Charpy values may be requested by a 90 day notification to PHMSA.

MR. HILL: Robert Hill, second.

MR. DANNER: Thank you. Is there a second?

MR. HILL: Robert Hill, second.

MR. DANNER: Okay. Thank you very much. All right. So, if there's any further discussion. If there's no further discussion, we are ready for a roll call vote.

MS. WHETSEL: Okay. Looks like we're ready.

Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner.

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman.

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan.

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin.

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell.

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake.

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley.

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger.

MR. WORSINGER: Aye.

MS. WHETSEL: Chad Zamarin is not here.

Jon Airey.

MR. AIREY: Aye.

MS. WHETSEL: Mark. Robert Hill.

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman.

MS. GOSMAN: Aye.

MR. DANNER: Motion passes. All right. Thank you everyone.

All right. So, let's go right into Methods 4, 5 and 6. So, who's going to make the presentation for staff?

MR. NANNEY: I will.

MR. DANNER: Okay. Mr. Nanney, go ahead.

MR. NANNEY: Okay. I don't want to skip something. Okay. Let me go -- okay. Am I right? Okay.

Starting on Slide 77. This is Steve Nanney with PHMSA. Committee comments on Method 4 in pipe replacement. There were no comments so we will not be going into it. I think pipe replacement's quite obvious.

Going to Slide 78. Seventy-eight is, again, public comments on Method 5 for low stress pressure reduction and that was from our December 2017 Meeting and it says here Method 5 applies to less-risky pipe. Commenters have asserted that it is more onerous than Method 2 with many additional requirements related to enhanced patrols, leakage surveys and suggested making 5 comparable to Method 2. In usage of a Method 5 should not limited based on pipe size or MAOP.

Going to Slide 79 a couple of things that PHMSA looked at is, again, some of the Committee comments on Method 5, Pressure Reduction for small potential impact radius and diameter from the December Meeting. Industry representatives supported public comments which questioned the need for some of the measures such as patrols and leakage surveys in addition to the 10 percent pressure reduction. So, PHMSA went back based upon the various comments that we've received and I think we indicated this at our December meeting.

If you look at Section 624(c)(5)(ii) on ECDA, we would strike that. For six -- Section 624(c)(5)(iii) crack assessments, we would strike that section. And again, we've got Section 712 if anyone needs to do a crack assessment that they could use. We're revising Section 624(c)(5)(iv) and we're changing the frequency of patrols to four per year.

Let's see. Section 624(c)(5)(v) the frequency of leakage surveys would be four per year. Strike 624(c)(5)(vi) on odorization and then Section 624(c)(5)(vi) remaining life calculations. We would strike it.

Going to Slide 80.

MR. DANNER: Steve, I'm sorry to interrupt. So, you have on the slide that you have two (c)(5)(vi)'s, odorization and remaining life. So, should one of those be seven?

MR. NANNEY: Oh, yes. One should be seven. I did not see that.

MR. DANNER: Sorry to interrupt.

MR. NANNEY: Going to Slide 80. Slide

80. Okay. Slide 80, again, some of the other comments that we received from the Committee, the Industry representatives supported public comments which promoted expansion of the applicability of Method 5. In other words, not limit the usage based on pipe size or MAOP.

And we went back and looked at that and we suggest changing the applicability in Method 5 by dropping the size and operating pressure limits and utilizing a PIR of less than 150 feet. And that is the PIR that we had originally had in the Notice of Proposed Rulemaking. Also, in addition, PHMSA would expand the look-back period to five years and in response to the comments we had from Method 2 that we've discussed already.

Slide 81. And I don't know if you can see that here in the room very well, but it is showing the various pressures and if we went to a PIR of 150 or less -- and just to give a few points for the record, for an eight inch pipeline, we show 149 feet as being the PIR. For

a 12 inch pipeline, it would be 144 feet. For a 16 inch pipeline, it would be 136 feet for the PIR. For 20 inch, it would be 138 feet for the PIR and on down if it was a -- some of the bigger sizes, we have that also.

But anyway, just to put on record what those would be. I believe originally we had proposed an eight inch -- or an eight inch with a PIR of 150 as being the maximum.

Going to Slide 82, the committee comments on -- going down to Method 6, other technology. And for Method 6, other technology, the committee members commented to adopt the same no-objection letter language as voted in 607 and PHMSA suggests inclusion of the same no-objection language as voted by the committee for Section 607 which would be applied to any notification of any of the methods is what we would do.

All right. Going to Slide 30 -- I mean, 83. What am I thinking? Slide 83. Again, this concludes our response to Methods 4, 5 and 6. And again, the following slides will

summarize a number of the revisions that PHMSA suggests. Slide 84. Again, this is what PHMSA suggests the Committee to consider.

We suggest revising proposed Section 624(c)(5), Method 5 which is pressure reductions for segments with small potential impact radius and diameter as follows: the leak, the size and pressure criteria. The applicability would be based solely on PIR of less than or greater than 150 feet. Also, we would strike in Section 624(c)(5)(ii), ECDA. We would also strike (c)(5)(iii), crack analysis program. We would also strike (c)(5)(vi), odorization and (c)(5)(vii), Fracture Mechanics Analysis.

And again, as I stated earlier, we would change the frequency of patrols and surveys for Class 1 and 2 to four times per year. Class 3 and 4 to six times per year.

Slide 85. Again, PHMSA suggests the Committee consider the following: revising proposed Section 624(c)(6), other technology as follows. Use same 90 day, no-objection letter

language the Committee approved for Sections 607 for any notification under Section 624.

With that, I turn it back over to the Chairman.

MR. DANNER: All right, thank you. And at this point we will take public comment on Methods 4, 5 and 6. Do we have anyone wishing to speak?

Go ahead.

MS. KURILLA: Hi. Erin Kurilla with the American Public Gas Association. One of the -- I'm going to refer to Slide Number 79. I just wanted to thank PHMSA a lot for taking another look at Method 5 for low PIRs -- small PIR pipelines. I think we definitely saw a fix for the applicability of this method by changing it to the 150 foot. I think that's cleaner and helps a lot of operators understand if their pipeline is in this bucket.

My concern is that while I appreciate that PHMSA kind of really narrowed the, what you're calling compensatory measures -- kind of

looks and talks and feels like P&N measures in some way for these low-stress pipelines. However, I find it interesting that you're still asking these operators for -- that are working on pipelines that are 150 feet or less in their PIR to both do a pressure reduction and do additional actions. It still feels like it needs to be an or. We're talking about the lowest of the low risk of these pipelines.

So, you know, again Method 2 is still just a pressure reduction but here we're doing a pressure reduction and we're doing additional actions. Granted, I know it's a less pressure reduction but it still feels like if I'm doing a pressure reduction, why am I doing additional activities?

Thanks.

MR. DANNER: All right. Thank you. Is there any other public comment? Okay. Seeing none, let's open it up to the committee. Any thoughts on 4, 5 and 6 or the proposal you just heard from APGA? Okay. Cheryl.

MS. CAMPBELL: I guess I'm interested in PHMSA's comment about the additional actions.

MR. DANNER: Does PHMSA have a comment about additional actions? Steve.

MR. NANNEY: I'm not sure I understand what you mean by additional actions. I guess I don't -- I'm not quite understanding the question.

PARTICIPANT: Like surveys and all the additional requirements.

MS. CAMPBELL: I think that -- can you go back to the --

MR. NANNEY: So --

MS. CAMPBELL: Yes.

MR. NANNEY: Well, first of all, if you go and look on that Slide 79, we're only requesting -- asking for 10 percent pressure reduction. If you go and look at Method 2, it would be based upon a 25 percent. Also if you look at the chart by taking the diameters. If you go to that chart, Sayler, that -- and make it a little bigger. If you look at some of the

smaller lines by -- without putting a limit on pressures. If you look at the green there, you can see 950. That's, I think, 4 inch and 6 inch.

So, the pressures can be very -- could be potentially very high. I'm not saying they are. I'm just saying that potentially. So, we did unleash a lot of things. We thought that if you did have a higher pressures on these smaller lines, you still would have a potential of harm and you needed to be checking it. We thought we had done a lot of roll-back and compromise and -- but we also thought that if you had the higher pressures and everything, you needed to still be doing the surveys if you didn't take the full pressure reduction.

MR. DANNER: Okay. Whose hand is that? Sara.

MS. GOSMAN: Quick question. Applicability. So this would still apply just to those lines who cannot do an in-line inspection. Is that right?

MR. NANNEY: I don't think we limited

it. I think we gave that as a -- you may be looking at some wording that I haven't looked at lately, but if it says that that's what we were doing but I did not remember that, Sara. I ---

MS. GOSMAN: So I'm looking at 5 -- at the bottom of that first paragraph that says, which cannot be assessed using in-line inspection or pressure tests. So that's retained in the applicability.

MR. NANNEY: Yes --

MS. GOSMAN: Okay.

MR. NANNEY: The answer is yes.

MR. DANNER: Okay. All right. Any other comments? All right. Seeing none, maybe we can go to the voting slide then.

Okay. We have a motion in front of us. Is there anyone who wishes to make this motion? Thank you, Rich.

MR. WORSINGER: Rich Worsinger, Rocky Mount Public Utilities. Cheryl, I'll give you a break.

Voting language for MAOP

Reconfirmation Method 4: Pipe Replacement, Method 5: Pressure Reduction for Small PIR and Diameter, Section 192.624(c)(5) and Method 6: Other Technology, Section 192.624(c)(6).

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation with regard to the provision for Method 4, Method 5 and Method 6 of MAOP Reconfirmation are technically feasible, reasonable, cost-effective and practicable if the following changes are made.

For Method 5, pressure reduction for segments with small potential impact radius and diameter, delete the size and pressure criteria. The applicability would be based solely on a PIR of less than 150 feet. Strike ECDA Crack Analysis Program, Odorization and Fracture Mechanics Analysis requirements. Change frequency of patrols and surveys. In Class 1 and 2 locations to four times per year. In Class 3 and 4 locations to six times per year.

For Method 6, Other Technology, use

the same 90 day no-objection language -- no-objection letter language that committee approved for 192.607.

The proposed rule as published in the Federal Register --

MR. DANNER: That's the same line. Is that the same on both sides?

PARTICIPANT: Yes, it's the same on both sides.

MR. DANNER: Yes. So --

MR. WORSINGER: Good.

MR. DANNER: You're done. Is there a second?

MR. BRADLEY: I second the motion. Second.

MR. DANNER: All right. It has been moved and seconded. Is there any discussion before we go to a vote on Methods 4, 5 and 6?

All right. Seeing none. Cheryl, time for a roll call vote.

MS. WHETSEL: Steve Allen.

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner.

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman. Is she there? Sara Longan.

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin.

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell.

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake.

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley.

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger.

MR. WORSINGER: Aye.

MS. WHETSEL: Jon Airey.

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill.

MR. HILL: Aye.

MS. WHETSEL: And Sara Gosman.

MS. GOSMAN: Aye.

MS. WHETSEL: Okay. Motion passes.

MR. DANNER: All right. Thank you very much. Let's go right into 624(e) and (f). Presentation by PHMSA Staff.

MR. NANNEY: All right. Slide 89.

Again, the committee comments on the notification procedure. There were none. The committee comments on the records requirement were none. PHMSA suggests retaining the notification procedure as published in the Notice of Proposed Rulemaking. Use the 90 no-objection letter language the committee approved for Section 607 for any notification under Sections 624. And again, PHMSA suggests deleting the word reliable from the records requirement as voted on during the June 2017 meeting.

And as discussed in our March -- the second teleconference meeting, PHMSA will provide guidance regarding TVC records in the preamble of the final rule.

Mr. Speaker.

MR. DANNER: All right. Thank you very much. So, is there any public comment on

these proposals? All right. Seeing none. Is there any committee discussion? Andy.

MR. DRAKE: I got a couple of comments and they may just may be questions. You know, I think we still want to make sure that we're clarifying in 192.619(a) that segments that a complete at 192.624 test have a valid MAOP. I think we've been through that. It just, I think it's a good continuity check here.

I think -- the other thing that -- and I'm trying to make sure I understand what you're trying to accomplish here. I think we need an exit ramp to 192.624 and I think (e) creates kind of a counterproductive do-loop that may create a compliance problem and I just wanted to try to get your thoughts on that. It looks sort of like you get stuck in there with (e) and I don't know how you get out to 624.

Sorry, I was reading ahead.

MR. DANNER: Okay. So, in other words you have no comments on 624(e) or (f)?

PARTICIPANT: No, just (f).

MR. DANNER: Okay. So do you -- would you clarify? Did you -- you had no comments on 624(e) or (f)?

MR. DRAKE: I don't. This is just (f).

MR. DANNER: Oh, I don't have a slide for (e). All right. Okay. So, we have a motion in front of us. Oh, okay. Yes.

MR. HILL: I'll be more than happy to make the motion if you're ready.

MR. DANNER: I am ready.

MR. HILL: Mr. Chairman, the voting language for MAOP Reconfirmation Notification Procedure and Records under Section 192.624(e) and 192.624(f). The proposed rule as published in the Federal Register and Draft Regulatory Evaluation with regard to the provisions for MAOP Reconfirmation Notification Procedure and Records are technically feasible, reasonable, cost-effective and practicable if the following changes are made.

PHMSA will provide guidance regarding

TVC records in the preamble of the final rule as discussed in the March 2 meeting and retain the notification procedure as published in the NPRM. Use the same 90 day no-objection letter language the committee approved for 192.607 for any notification under Section 192.624.

My name's Robert Hill.

MR. DANNER: Thank you, Robert. Is there a second?

MR. WORSINGER: Rich Worsinger. Second.

MR. DANNER: Thank you very much. Is there any discussion on the language before you? All right. Hearing none. Cheryl, ready for roll call vote.

MS. WHETSEL: Okay. Steve Allen.

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner.

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman.

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan.

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin.

MR. TURPIN: Aye.

MS. WHETSEL: Sorry. Cheryl Campbell.

MR. DANNER: She's not here.

MS. WHETSEL: Andy Drake.

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley.

MR. BRADLEY: Aye.

MS. WHETSEL: Sorry. Rich Worsinger.

MR. WORSINGER: Aye.

MS. WHETSEL: Jon Airey.

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill.

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman.

MS. GOSMAN: Aye.

MS. WHETSEL: Thank you.

MR. DANNER: Okay. Motion passes.

So -- okay. We are going to keep going with a hard stop at 11:55. So, let's get right to it. Chris.

MR. MCLAREN: Well, very good. I'm Chris McLaren with PHMSA. I understand I'm what's standing between us and lunch. Okay. In this set on mine, it says 3 but we'll use is the A, B, C, D, E and F letter designation on the left as we talk about these following topics in this slide session.

A for 192.619(e), the proposal is to require 192.624 for MAOP of Applicable Segments. B, 192.503 make conforming edits to reference 192.624. And C in 192.619(a)(4) refer to 192.607 for that material documentation and D look at 192.619(a)(2) to update the Class 1 pressure test factor. Topic E is 192.619(f) to -- revisions for the MAOP records. And in 192.605(b)(5), the operations and maintenance requirements.

Okay. On this topic session discuss these A and B topics grouped together on 619(e) and 192.503. So, from the December 2017 Committee Meeting and in response to the NPRM comments, PHMSA suggested that the committee consider the following. Shorten and clarify

192.619(e) to remove text that duplicates the scope of 192.624(a) and in that modification to read within (e), notwithstanding the requirements of paragraphs (a) through (d) of this section onshore steel transmission pipelines that meet the criteria specified in 192.624(a) must establish a document the maximum allowable operating pressure in accordance with 192.624.

Withdrawal of the proposed revision to 192.503 is not needed since 192.503 already invokes 192.619 which would adequately reference the new requirements of 192.624.

Topic C, MAOP in 192.619(a)(4). The NPRM we propose referring to material verification. The issue is that it is part of responding to the material documentation mandate, establishment of MAOP under 192.619 should rely on TVC records. PHMSA proposed to require that operators use 192.607 to document missing information as needed under 192.619(a)(4) from Section 23 of the Pipeline Safety Act of 2011.

NPRM comments received a reference to

192.607 is not appropriate in 619(a)(4). Proposal is vague and does not provide sufficient information about what to do if material verification has not been completed and records for some components are not available or how to determine the limiting condition.

PHMSA's response is that the modifications proposed and approved by the GPAC at the December meeting addressed this comment. The amended 192.607 would allow operators to verify material properties in specific cases such as might be needed to establish MAOP without the need for a long-term sampling program.

Also referring to the same topic area, PHMSA believes that operators should evaluate material properties under 192.619. Included reference to 192.607, so that operators may verify material properties if TVC records are not available. PHMSA suggests clarifying that 192.607 does not necessarily apply to all segments when determining MAOP by adding if applicable after the references to 192.607 in

192.619(a)(4).

Still on Topic C, one of the NPRM comments was to clarify if the proposed reference to 192.607 in 192.619(a)(4) is addressing only transmission pipelines or both transmission and distribution pipelines. PHMSA's response is that the scope of 192.607 applies only to transmission pipelines. PHMSA suggests clarifying that 192.607 does not apply to distribution pipelines when determining MAOP by adding if applicable after the reference to 607 in 192.619(a)(4).

Topic D, 192.619(a)(2). The updating of Class 1 pressure test factor for MAOP. The issue is that one conclusion of the NTSB investigation of the PG&E accident in San Bruno, California was the premise that in Title 49, Code of Federal Regulations, Part 192 of the Federal Pipelines Safety Regulations that manufacturing and construction-related defects can be considered stable even when a gas pipeline has not been subjected to a pressure test of at least 1.25 times the maximum allowable operating

pressure is not supported by scientific studies.

PHMSA proposed to require that the MAOP pressure limitations specified in 192.619(a)(2) for new Class 1 pipe segments be based on subpart J pressure test divided by 1.25 instead of 1.1. The basis was NTSB recommendation P-11-15 Gas Research Institute Report 04/0178 evaluating the stability of manufacturing and construction defects in natural gas pipelines, report number 05-12R in 2007.

It says recommendation. So on this topic of increasing the class location factor for pressure testing of steel pipe located in Class 1 areas installed after the publication of the final rule, PHMSA received the comment that to clarify the MAOP is to be based on the highest pressure to which the segment was tested after construction. PHMSA's response is that for pipe segments installed on or after the effective date of the rule, the MAOP limitations of 192.619(a)(2) is based on the test pressure of a successful subpart J pressure test divided by the

applicable class location factor.

Another comment to the NPRM was clarified at 619(a)(3). In cases where past operating pressure records are not available but pressure tests records are available. PHMSA's comment is that per existing code requirements in 619(a)(3), the pressure restriction in 192.619(a)(3) based on past operating pressure does not apply if the segment was tested in accordance with requirements in paragraph 192.619(a)(2).

Another comment was that the effective dates proposed for the revised factors being applied the date of new rule or the date of new rule minus one day, it seemed to cause uncertainty and the commenter recommends that the effective date for new Class 1 factors be -- the new Class 1 test factor be 180 days after the effective date of the rule.

PHMSA's response is the new pipelines cannot be operated unless pressure tested existing 192.505 prohibits the operation of a

pipeline greater than 30 percent SMYS if there is a building intended for human occupancy within 300 feet of a pipeline unless that segment has been hydrostatically tested of at least 125 percent of MAOP. The proposed rule would extend this requirement which is already in effect of day -- in effect today to all Class 1 pipe regardless of the nearness of the buildings.

Topic F -- or Topic E, 192.619(f), MAOP records. The issue is that in response to the PG&E accident in San Bruno, California, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 mandated that operators report pipe segments for which records could not be verified that accurately reflect the physical and operational characteristics of the pipeline and confirm the MAOP of them. PHMSA proposed to add a new paragraph, 192.619(f) to more clearly specify that operators must have records to substantiate MAOP. And the basis is Section 23(a) of the Pipeline Safety Improvement Act of 2011 and 49 USC 60139(a) and (b).

Some of the comments to the NPRM -- one was the proposed rule, as written, would apply to distribution gathering onshore and plastic pipelines. PHMSA suggests clarifying that the MAOP Records requirements proposed in 192.619(f) would apply only to onshore steel gas transmission pipelines. Another commenter was that the 192.619(f) should clarify that it applies only to records needed to establish and document MAOP. PHMSA suggests revising 192.619(f) to clarify that it only applies to records needed to demonstrate compliance with 192.619(a) through (e).

Still on Topic E. Another comment to the NPRM advocated that new MAOP record requirements only be applied prospectively beginning one year after the date of the rule. PHMSA's response is that similar to the proposal that the committee voted on at the March 2nd, 2018 meeting, PHMSA suggests revising 192.619(f) to clarify that MAOP record requirements are not retroactive. Existing records on pre-existing

pipelines must be retained for the life of the pipeline. New pipelines must make and retain records for the life of the pipeline.

Other sections such as 192.624 and 917 would require when and for which pipeline segments missing MAOP records must be verified in accordance with either -- with 192.624 and/or 192.607. Also, MAOP records would be required for any pipeline placed in service after the effective date of the rule.

The next topic, Topic F dealing with 192.605(b)(5) within the Operations and Maintenance Section. PHMSA proposed to add clarification to the requirement for over pressure protection applied to segments with MAOP's established using MAOP Reconfirmation per 192.624 methods. NPRM comments were revised. Subsection is redundant and unnecessary. PHMSA should retract this proposed revision as duplicative of the current requirements such as in 192.605(b)(1).

Another commenter said to delete the

reference to 192.731. Another comment was clarify if the requirement is addressing only transmission or both transmission and distribution. Another comment was PHMSA has not provided justification for imposing this requirement on distribution pipelines. And lastly, code has never required operators to include procedures specific for each individual controller device in their manual.

PHMSA's response is the proposed changes to 192.605(b)(5) was intended to be a confirming change to clarify that applies segments with MAOP determined under 192.624. The proposed change was not intended to introduce any new or substantially different requirement and was intended only to provide clarification. Based on the public comments received and the unintended confusion it might create, PHMSA suggests that the proposed revision of 192.605(b)(5) be withdrawn.

Thank you, sir.

MR. DANNER: All right. Thank you.

Yes, I think what we will do now is we're going to break for lunch. It is currently eight minutes to noon. So, I will come back at one o'clock. One o'clock?

Yes, I think we can get started at one o'clock. And we will take public comment on the MAOP Proposals and we'll go from there.

So, thank you.

(Whereupon, the above-entitled matter went off the record at 11:52 a.m. and resumed at 1:06 p.m.)

MR. DANNER: All right. At this point, we are going to take public comment on the MAOP proposals. Is there public comment on these items?

MS. KURILLA: Yes, but I can't find my page. I'll go off memory.

MR. DANNER: We'll give you a moment.

MS. KURILLA: Erin Kurilla, APGA. I think it was slide number 79 maybe, although it seems like that was a long time ago. Maybe not slide 79. No. That was my last time I talked.

Anyway, not slide 79. I apologize but it is -- this is really, I guess, just a call to the GPAC to kind of slow down and really think about the changes that we're making to 619. Very appreciative of PHMSA making it clear in a couple of their slides that the changes, especially to 619(f) are prospective for transmission pipelines only. I think it's really important, especially since 619 applies to both distribution pipelines and transmission, and I'll make a little joke here. I always tell people I really don't want in 20 years to be explaining to people when 619(f) went into code, so adding in a, you know, effective date on a prospective basis for those MAOP records is really important.

I'm going to tee Andy up. I know he kind of gave this comment before we were on the last topic, but I actually find 619(e) unnecessary, although I understand why PHMSA is including it. It's really to ensure that everyone understands you have essentially three ways to establish your MAOP now. You have 619(a)

which is the lowest of the four; you have 619(c), the grandfather clause for still those pipelines that are allowed to use that; and now you have 624. So I'd really encourage PHMSA to look at the language in 619(a) and just add 624 there. And I don't think you need 619(e). All 619(e) does not is point operators to 624; 624 in and of itself is self-activating. We don't need to be told to go do 624. What we need is to make sure there's not a loop between 619(e) and 624. And by adding 624, again, as an option in 619(a), it's a really clean way to do that, so thanks.

MR. DANNER: All right. Thank you. Go ahead.

MR. OSMAN: CJ Osman with INGAA. Similar to Erin, I'll admit these are probably some wordsmith-type comments but with the importance of 192.619 and 192.624 and how they play together as well as places where the specific words and being clear really do matter. So we appreciate that PHMSA has clarified the requirement in 192.619(f) will be to keep records

needed to establish document compliance with 192.619(a) through (e).

What wasn't clear from the slide deck is whether that means PHMSA is proposing to eliminate the list of examples that was in the original proposed 192.619(f). We don't think that those examples are helpful and we think they actually create confusion. Just to remind folks, the list there is records related to design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. And I think the discussions yesterday and today confirm that not all of those records will always be needed in all cases to establish MAOP. So just removing that and leaving the requirement to establish and document records and compliance with 192.619 is probably sufficient.

Let's see. Also, we're a little concerned with the proposed requirement on the slide deck for operators to retain existing records on pre-existing pipelines for the life of

the pipeline. While certainly we understand the sentiment, if you have a record related to your MAOP, you shouldn't be throwing it out. But we're concerned about how that could be enforced and what type of obligation there would be on the operator to prove that they have retained all of their records on existing pipeline going forward that they had in the past. So again, don't disagree with the point there but just a little concerned about how that could be enforced and how that could be interpreted both by PHMSA inspectors out in the field and also by the state partners. So just something for the GPAC to consider. Thank you.

MR. DANNER: All right. Thank you.

MR. MILLER: Hi. Shawn Miller with Dominion Energy. Comment is related to the previous two in that we're trying to eliminate two clarifications, the looping effect that this could have. We appreciate the clarifications PHMSA has provided to 192.619. PHMSA should also clarify in 192.619(a) that compliance with any of

the six methods to reconfirm MAOP in 624 satisfies the 192.619 requirement for pressure test records. One of the triggers to reconfirm MAOP under 192.624 is not having TVC records of a pressure test for the pipelines installed after 1970 as outlined in 517(a).

If an operator reconfirms MAOP using a method other than pressure tests, it may never have a pressure test record. PHMSA will remove ambiguity by referencing 624 in 619(a). Thanks for your consideration.

MR. DANNER: All right. Thank you. Are there any other public comments on these items?

(No response.)

MR. DANNER: Hearing none, I'm turning to the Committee. Andy?

MR. DRAKE: This is Andy Drake with Enbridge, sort of a do over from my comments last time, but I agree with the comments that were made by the public. I think those are some good comments, not to reiterate them but I do think we

need to clarify in 619(a) that a segment that completes a 624 test has a valid MAOP. I think we just need to kind of explicitly lock those two together. They do interplay with one another. I think that 619(e) does or can create a counterproductive kind of do loop that creates a compliance liability that we need to address, and I don't think we lose too much by taking 619(e) out.

The other comment that I would make is about (f) and I think it's really more of an enforcement clarification here. I just want to be clear that (f) is interpreted -- when you have this long list of things here, you start getting into operations, maintenance, inspection testing, you know, all these things. I don't know that that helps us. I think it actually may confuse some things. The confusion that I've seen in enforcement issues even to date is that (f) can be interpreted that any new operating or maintenance data could require an MAOP to be reevaluated. That's not appropriate and that's

not the intent of this.

If we have -- we run a pig and we find an anomaly that has a depth, we may have to restrict the MAOP until we can fix it, but we don't revise the MAOP. And I think that seems maybe like a subtle distinction. It's not. You do the MAOP once. Then you safely operate your pipe over a period of time. That's why we pull the MAOP over here and technically management over here. MAOP is a one-time thing. Operating safely is an ongoing continuous event, so I just want to make sure that that's -- I'm reading (f) correctly, that it's not intended revise the MAOP every time we get some sort of maintenance data back in or inspection data back in. Thanks.

MR. DANNER: All right. Is there any other comment on this? Ron.

MR. BRADLEY: Thanks, Mr. Chair. Ron Bradley, PECO. So just a general comment. I appreciate the work that the Committee and that PHMSA's done in separating and making sure that the language is very clear, that 619(f) and all

that we've worked on is relating to transmission pipe. It's important; 619(f) isn't very clear if someone were to take it out of context and just apply it to any segment of pipe anywhere with natural gas in it. I have seen this happen. I wouldn't state it if I didn't. So I think we really -- I really appreciate you guys making the statement that these standards, 619(f) specifically applies and you have it in there on shore steel gas and transmission pipelines. Thank you.

MR. DANNER: Okay. Oh, sorry, Andy, that's you.

MR. DRAKE: I'm going to ask Steve directly, did my interpretation resonate with your expectations?

MR. NANNEY: I think so. This is Steve Nanney, PHMSA. Yes. I was reading something when you said -- so I think I caught it but I'm not positive.

MR. DRAKE: Okay. I'll just -- I don't want to put you in a tough spot. I mean

I'm doing the same thing over here so I can totally appreciate that. The (f) -- section (f), I think the -- my concern there is that the long list of things that we have there, all those examples can create some confusion. I think it can be -- create an impression similar to Ron. I have seen this in enforcement issues where people come out and go "well, you've got an in-line inspection line that shows an issue, you need to revise the MAOP," and that is not how we look at this. We look at MAOP as being validated one time and then maintenance and operating data time going is treated as an integrity management thing that we may have to revise or temporarily restrict the operating pressure until we fix something. But we don't revise the MAOP. Is that correct?

MR. NANNEY: Steve Nanney with PHMSA. Yes.

MR. DRAKE: Thank you.

MR. DANNER: So is it your proposal, Andy, to take the examples out?

MR. DRAKE: That would be my recommendation. I think it just cleans this up a little bit.

MR. DANNER: Okay. Sara?

MS. GOSMAN: I wonder if we could solve this problem by putting in "may." So records that establish the pipeline MAOP "may" include but are not limited to?

MR. DANNER: Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I think the record we just created may solve the problem. It's just we need some guidance material to help clarify what the intent of all this is. I don't know that it -- I don't know that an exhaustive list helps or not helps. I mean basically, you're saying everything should be -- could possibly weigh in here, which is accurate but I think the confusion it creates is "do I have to consider all of this" or, you know, "when have I done diligence to set this up," which is all the other sections that we've been talking about to date. So I don't know how much

value it adds is really my point.

MR. DANNER: Sara.

MS. GOSMAN: Yes, I understand that. I mean when I read it, in terms of interpreting it, I think it's nice to sometimes have examples, but I certainly understand the point that you don't want to be limited by those examples. So my thinking here is if it's -- if the word "may" or something similar is in there, it gives us a sense of the universe of the kinds of documents that might be the ones being referenced here but wouldn't imply that any given one of those or perhaps all of them, right, are necessary.

MR. DANNER: Cheryl.

MS. CAMPBELL: Cheryl Campbell, Xcel Energy. Another potential solution might be to offer up some of those examples in guidance rather than in the regs where they're a little easier, shall I say, to adjust over time or, you know, kind of change and evolve over time. So maybe the solution is to pull it out of the regulatory text but include it in guidance with

your word "may," right. It "may" include these types of records and then it gives us a script to have it change or evolve over time. They could adjust that.

MR. DANNER: All right. Any thoughts on Cheryl's proposal?

MR. DRAKE: This is Andy Drake with Enbridge. I like that proposal. I think -- because that's the issue you're trying to get to is give people guidance to give them clarity and I don't know that we're adding a lot of clarity here by adding this long list. I think if you take it into the guide material, you have a chance to actually explain what it is you're trying to accomplish.

MR. DANNER: Okay. Any other responses? All right. Yes, Steve, you have --

MR. NANNEY: From my perspective, from PHMSA, we agree and we'll do like -- Sara and Cheryl, Andy, we'll try to get language in there, "may" and either in the preamble or something like that, what Cheryl's talking about. I think

it's very doable.

MR. DANNER: Okay. Any other comments?

(No response.)

MR. DANNER: All right. We have voting language in front of us. Do you want to look at it and make any further suggestions before we entertain a motion? Andy.

MR. DRAKE: This is Andy Drake with Enbridge. And Steve, I'd just like your thoughts on section (e). I mean do you see it adding a lot of value? I mean to me, it doesn't lose -- it doesn't hurt anything to get rid of it. It just creates a compliance do loop. And if we could clean that up, I think this is a good chance to do that.

MR. DANNER: Yes, thoughts, Steve?

MR. NANNEY: Steve Nanney, PHMSA. I would like for us to look at it. I'm not opposed to it but I just want to make sure it makes good sense before we do it.

MR. DANNER: So, Steve, we have a

motion in front of us so if you're going to look at it, you should do that now. So -- yes, Steve.

MR. NANNEY: We'll look at putting it in (a), and it may be a -- it'll be a subsection just like the others.

MR. DANNER: So I'm sorry, I didn't hear that.

MR. NANNEY: Drop -- we would move it from (e) into (a) and it would be a subsection in (a) is what I'm saying.

MR. DANNER: Okay. Andy.

MR. DRAKE: Last comment while we're editorializing here. I think we do need to add some kind of reference to 624 and 619(a). And if -- is it getting typed up there? I was -- I don't see it.

MR. DANNER: I don't see 624.

MR. DRAKE: On the left. Okay. Then I think another comment that we would say is I think just to help lock 624 and 619(a) together that we should reference 624 in 619(a). And I think that just locks them together. That's all

you're trying to do. I'm not trying to do anything squirrely. I think it just clarifies the interlock.

MR. DANNER: Steve?

MR. NANNEY: PHMSA agrees. We will -- that's what the purpose of 619(e) was.

MR. DANNER: Sara.

MS. GOSMAN: I'm just trying to follow this conversation. Sara Gosman. So where in (a) would we be putting this reference?

(No audible response.)

MS. GOSMAN: Is this your proposal?

MR. DRAKE: This is Andy Drake with Enbridge. All I am proposing is that we would add a comment in 619(a) that references 624, maybe just trying to recognize that that hydro test that you do in --

MR. DANNER: Right, but there's also a proposal to put (e) into (a). I think her question is where does (e) go in (a).

MS. GOSMAN: Yes.

MR. DRAKE: That was Steve's proposal.

MS. GOSMAN: Oh, all right.

MR. DANNER: I was just talking about --

MS. GOSMAN: I'll look to Steve.

MR. DANNER: -- 624 but -- all right, I think they're conferring on that as we speak. So Sara's question was where in (a) should subsection (e) go.

MR. NANNEY: I'm not sure yet. I just had Erin to come by and show us -- I'd like for us to be able to look at that. We've agreed that we would put it in (a) and everything as requested. To get down to a subsection of a subsection, I would expect the Committee to let us at least have a chance to look at it and make sure we're not having any other unintended consequences.

MR. DANNER: You're very demanding, Steve.

(Laughter.)

MR. DANNER: So why don't we -- we could just leave this language and then when you

figure out how best it should go in, just -- we can have a conversation at that time, whether that's later this afternoon or tomorrow. Is that -- I think we're okay with it going in. We're just -- it's a matter of where so -- which I don't think is going to be particularly contentious.

MR. DRAKE: I'm supportive -- this is Andy Drake. I'm supportive of that. I think we've got sort of direction here and I don't mean to get in there and start wordsmithing about how to do it. I just --

MR. DANNER: Right.

MR. DRAKE: I think directionally, this is --

MR. DANNER: Okay. Alan.

MR. MAYBERRY: I was just going to say why don't we just you guys decide where you want it, advise us on it, and we'll take it from there.

MR. DANNER: Andy.

MR. DRAKE: This is Andy Drake with

Enbridge. I endeavor to prepare to make a motion here.

MR. DANNER: So that's excellent because, again, I can't read it. So -- I'm not wearing those glasses so yes, go ahead.

MR. DANNER: Okay. Voting language for other proposed issues related to MAOP, paragraphs 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), and 192.619(f), the proposed rule as published in the Federal Register in Draft Regulatory Evaluation with regard to MAOP-related provisions in sections 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), and 192.619(f) are technically feasible, reasonable, cost-effective, and practicable if the following changes are made.

With regard to proposed revision to paragraph 192.503, with regard to proposed revision to paragraph 192.605(b)(5), PHMSA will consider moving 192.619(e) to be a subsection of 192.619(a) and will consider referencing sections

192.624 in 192.619(a); clarify that paragraph 192.607 does not apply to distribution pipelines when determining MAOP by adding "if applicable" after the reference to paragraph 192.607 in 192.619(a)(4); clarify that the MAOP records requirements proposed in 192.619(f) would apply only to onshore steel gas transmission pipelines; clarify the MAOP records requirements at 192.619(f) only apply to records needed to demonstrate compliance with 192.619(a) through (e); move the example of MAOP documents to the preamble and guidance material, and clarify that the MAOP records requirements proposed under Section 192.619 are not retroactive, similar to the proposal that the Committee voted on at the March 2, 2018 meeting; existing records on preexisting pipeline must be retained for pipeline's life; new pipelines must make and retain records for life of pipeline; other sections such as 192.624 and 192.917 would require when and for which pipeline segments missing MAOP records must be verified in

accordance with paragraphs 192.624 and/or 192.607; MAOP records would be required for any pipeline placed in service after the effective date of the rule. Wow. Is there a second?

MS. CAMPBELL: Second.

MR. DANNER: All right. It has been seconded. Steve?

MR. ALLEN: Steve Allen, IURC. I just wanted to point out that in the -- on the right-hand side, the second bullet point where it talks about "only apply to records needed to demonstrate compliance with 192.619(a) through (e)," if (e) is going to be moved to (a), then it should be (a) through (d).

MR. DANNER: Good catch. So I take it then you will revise the motion and the --

(Laughter.)

MR. DANNER: I think we're good. All right.

MR. DRAKE: I'm good with that --

MR. DANNER: The motion and the second are good. So any further discussion? Sara.

MS. GOSMAN: More just a request of PHMSA, in putting in "if applicable" to what is it, (a)(4), because that section, 607, as I understand it now is not self-activating but we're referencing it in various places, I just would want to be clear that the applicability references the type of pipeline, right, rather than say anything about whether 607 applies in this context or not, if that distinction makes sense to you.

MR. DANNER: All right. Is that something that we need to amend the motion to do or is -- Okay, right. So we -- any further discussion? Steve, your hand is up? Okay. All right. No further discussion. Cheryl, roll call?

MS. WHETSEL: Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Thank you. Sara Longan?
DR. LONGAN: Aye.
MS. WHETSEL: Terry Turpin?
MR. TURPIN: Aye.
MS. WHETSEL: Cheryl Campbell?
MS. CAMPBELL: Aye.
MS. WHETSEL: Andy Drake?
MR. DRAKE: Aye.
MS. WHETSEL: Ron Bradley?
MR. BRADLEY: Aye.
MS. WHETSEL: Rich Worsinger.
MR. WORSINGER: Aye.
MS. WHETSEL: John Airey?
MR. AIREY: Aye.
MS. WHETSEL: Robert Hill.
MR. HILL: Aye.
MS. WHETSEL: Sara Gosman?
MS. GOSMAN: Aye.
MS. WHETSEL: And the motion carries.
MR. DANNER: All right. Thank you very much. And that takes us to integrity management. So who's going to tee this one up?

Yes, we're ready.

MR. McLAREN: Well, the next session, Section 3, is going to be covering integrity management in the 192.917(e)(3) and (e)(4) in the threat identification section.

In light of the Committee's comments from the June 2017 meeting, which were -- actions were deferred to now until we had cleaned up some of these other topics, PHMSA proposes that in conjunction with striking the previously proposed 192.624(a)(1) to revise the proposed 192.917(e)(3) as follows. In paragraph (e)(3), delete the phrase "and must reconfirm or re-establish MAOP in accordance with 192.624(c)." In paragraph 192.917(e)(3)(I), delete the reference to 624(a)(1) and replace with, "the segment has experienced a reportable in-service incident as defined in 191(3) since its most recent successful subpart (j), pressure test due to an original manufacturing-related defect or a construction, installation, or fabrication-related defect."

And also from comments from the June meeting, PHMSA suggests the Committee consider that in conjunction with moving the previously proposed 624(d) regarding fracture mechanics analysis to a new section, 192.712, suggests revising the proposed 192.917(e)(4) as follows. In paragraph (e)(4), delete the reference to 192.624(c) and (d) and replace with a reference to 192.712.

Also in light of those June comments, PHMSA suggests the Committee consider that in conjunction with striking the previously proposed 192.624(a)(1), add a new 192.917(e)(6) to address cracking within the integrity management program as proposed by the Committee. This would be similar to the corrosion beyond clause in 192.917(e)(5) and proposed to read as follows. New (e)(6), cracks; if an operator identifies any crack or crack-like defect, including but not limited to, stress corrosion cracking or other environmentally-assisted cracking, unstable seam defects, selective seam weld corrosion, girth

weld cracks, hook cracks, and fatigue cracks on a covered pipeline segment that could adversely affect the integrity of the line, the operator must evaluate and remediate as necessary all pipeline segments, both covered and non-covered, with similar material properties and environmental characteristics associated with the crack or crack-like defect, and operator must establish a schedule for evaluating and remediating, as necessary, the similar segment that is consistent with their operator's established operating and maintenance procedures under Part 192 for testing and repair. Thank you.

MR. DANNER: All right. Thank you. So we will now take public comment on these integrity management proposals. Do we have any public comment? Go ahead, sir.

MR. TU: How's everyone doing. My name is Wen. I represent AGA. Just a comment on 192.917(e). There is a reference to, in subpart -- or in paragraph 3, there is a reference to

hydrostatic pressure tests. We are recommending that that word, "hydrostatic," be removed because any strength test -- we're talking about strength tests here and any strength test that's approved by subpart (j) should be -- should qualify.

And additionally, in that same section, I would suggest adding a language so that a pressure reduction or in the assessment done with ILI, for example, engineering critical analysis, be allowed to confirm manufacturing construction defects as well. Thank you.

MR. DANNER: All right. Thank you. CJ, go ahead.

MR. OSMAN: CJ Osman with INGAA. Just a couple small points. First is in (e)(4), which addresses ERW pipe, there's a reference to pipe body cracking. ERW is a seam type. This section is about seams so the reference to pipe body cracking here probably doesn't belong. It probably makes more sense in the next section on cracks, which is new. That was a holdover from some previous versions so probably something that

PHMSA could consider moving over.

Also, we'd certainly agree with PHMSA's proposal to evaluate pipes with cracks using fracture mechanics modeling and cyclic fatigue analysis, but including the reference to 712 here might be duplicative with the anomaly response and repair requirements that you all are going to consider later. Those sections specify what an operator has to do as far as analysis is concerned if they identify cracks. This section is not about anomaly response and repair. It's simply about establishing assessment requirements, which is a little bit different.

Lastly, for the new section on cracks, we're suggesting that PHMSA and the PAC consider whether to add operating and maintenance history in the list of variables to consider when determining whether and where crack evaluation and remediation is important. Certainly, operation and maintenance history factors into consideration when determining where the crack threat may be active.

Lastly, getting back to a list of examples here. There's a list of crack types, one of which is unstable seam defects and not all unstable seam defects are crack or crack-like, so we're not sure that that specific example is appropriate here. Thank you.

MR. DANNER: All right. Thank you. Are there any further public comments?

(No response.)

MR. DANNER: Okay. Seeing none, now turn to the Committee. Any comments on these proposals or the public comments that you've heard? Sara?

MS. GOSMAN: On slide 111, I'm looking at the proposed language and I just wanted to understand the use of the term "as necessary." So, for example, it says, "The operator must evaluate and remediate 'as necessary' all pipeline segments, both covered and non-covered, with similar material, properties, and environmental characteristics associated with a crack or crack-like defect." So to me, this

reads in a confusing way because we're requiring operators to evaluate and remediate but then we're -- all pipeline segments with similar material, properties, and environmental characteristics, but then we're saying "as necessary." And I'm wondering which part of that is supposed to be "as necessary."

MR. DANNER: Or are they all necessary and we don't need to say it? Steve?

MR. NANNEY: I think we can probably delete it. We would consider doing that.

MR. DANNER: Okay. Ron?

MR. BRADLEY: Thanks, Mr. Chair. Ron Bradley, PECO. So to tag onto one of the comments that was made by one of our public -- don't recall who it was -- but PHMSA should ensure that the pressure test method allowed by Part 192 can be used to confirm stability of manufacturing and construction defects. That word "hydrostatic," I think we can delete the word. My sense is -- that would be my recommendation.

MR. DANNER: All right. Steve, do you have a response to that?

(Off microphone comment.)

MR. DANNER: Microphone.

MR. NANNEY: Sorry. I thought I'd punched it. We'll consider doing that as long as it meets subpart (j), yes.

MR. DANNER: Okay. And we also had a comment about the list of examples. Addition to that?

(No response.)

MR. DANNER: All right. Any other comments on this section?

(No response.)

MR. DANNER: All right. Hearing nothing -- sorry, do you have a --

MR. GALE: Yes. John Gale, PHMSA. Just real quick for the members. What we did is -- so to kind of save your voice a little bit -- we've added just a reference to that to the definition of cracks there on (e)(6). So we have the definition or the section there on the right-

hand side, so you'd have to read it off completely. We just have a reference to it if that's suitable to the Committee.

MR. DANNER: Okay. And that -- so the words "as necessary," I understand are coming out on the right side. All right. So I guess if that's the case, we're ready to -- anybody want to volunteer to read on the left side?

MR. GALE: Just the left side, that's correct.

MR. DANNER: Ron, thank you.

MR. BRADLEY: Okay. This is Ron Bradley, PECO. Voting language for integrity management clarifications paragraph 192.917(e)(3), (e)(4), and (e)(6), the proposed rule as published in the Federal Register and the Draft Regulatory Evaluation with regard to the provisions for IM clarifications are technically feasible, reasonable, and cost-effective and practicable if the following changes are made.

Revise proposed paragraph 192.917(e)(3) as follows. In paragraph (e)(3),

delete the phrase, "and must reconfirm or re-establish MAOP in accordance with paragraph 192.624(c)." In paragraph 192.917(e)(3)(I), delete the reference to 192.624(a)(1) and replace with, "The segment has experienced a reportable or in-service incident as defined in 191.3 since its most recent successful subpart (j) pressure test due to an original manufacturing-related defect or a construction, installation, or fabrication-related defect."

In conjunction with striking the previously-proposed 192.624(a)(1), add a new 192.917(e)(6) to address cracking within IMP as suggested by PHMSA staff during the meeting, presented in the slides and revised by the Committee.

MR. HILL: Robert Hill, seconds.

MR. DANNER: Thank you. It has been moved and seconded. We have language in front of us? Any further discussion on the language before us? Andy.

MR. DRAKE: This is Andy Drake. I

know we're trying to move along here and I don't mean to slow us down, but I thought there was a good comment made about removing the references to "body" -- pipe body cracking. Is there any concern with adding that, or having that removal restriction?

MR. DANNER: I believe that would be a question for PHMSA staff. Okay.

MR. McLAREN: Maybe CJ could refresh me on where exactly that is.

MR. DRAKE: Mr. Chairman, while they're deliberating?

MR. DANNER: Sure.

MR. DRAKE: This is Andy Drake with Enbridge. I thought that there was in -- in (e)(6), when we're looking at this new language that's being proposed, slide 111, about halfway down where it says, "All pipeline segments, both covered and non-covered with similar material, properties..." yadda, yadda, yadda, I think "all" opens it up to everything which is okay but I do think it would help if we added a couple words of

-- you know, to help qualify it, with similar operating history and maintenance history, material, properties. If you're trying to help people fingerprint what the subset of "all" is, it's not just everything that has similar materials. It's similar operating history, similar operating environment. You know, I think given that "all" is in front of that, I keep a couple more qualifiers doesn't hurt.

MR. DANNER: And so what are the qualifiers that you're looking to add?

MR. DRAKE: I would just when it says, "with similar," -- who's got the pen, so to speak, over there, the typewriter, you know, keyboard -- I would add with similar operating history and maintenance history and then it says, "material, properties, environmentally." That's all I would add in there. That's the things that cause the cracks. That's what you're trying to tell people to look for.

MR. DANNER: Okay. So do the scribes want to put that in? All right. Cheryl?

MS. CAMPBELL: Okay. So I -- again, so I apologize. I hate to do this but I want to go back to these words, "as necessary" that Sara brought up. And as I think about this, right; as I kind of think through this, right, so an operator must evaluate, right. So you identify these features, these anomalies, whatever, and you evaluate them, I don't need to remediate "all" of them. So I -- is it possible that the phrase "as necessary" was -- I'm not an attorney so I apologize, Sara -- I'm going to use some words that may or may not be grammatically correct -- does "as necessary" qualify it, right, to say those that you should be remediating?

MR. DANNER: So what I think you're proposing is that we would put a comma after "evaluate" and remove the comma after remediate so that it would read, must evaluate, comma, and remediate as necessary, comma --

MS. CAMPBELL: Correct, because -- so simple example, right, I mean we -- one of our pipelines, the first time put a tool in it, I got

like 20,000 hits back, anomalies back, right. But the vast majority of them were coding faults or little scrapes and scratches, right, because it's in an area where there was a -- there had been a lot of construction and excavation. And, you know, we went through it and picked out the ones that were serious and needed to be remediated and the rest of them, we are monitoring, right, on subsequent runs. So I mean that's -- so I don't know what the right words are to qualify it like that, but that's really, I think, what we're trying to say.

MR. DANNER: Well, I think this -- if we change the commas, that does it, because it says you evaluate everything and you remediate what needs to be remediated.

MS. CAMPBELL: There you go. That's what we want to do.

MR. DANNER: So that would mean you would do it there and you would also do it at the second "as necessary," so there would be a comma after "evaluate," the third line up from the

bottom.

MS. CAMPBELL: Yes.

MR. DANNER: So it be evaluating, comma and remediating as necessary, comma.

MS. CAMPBELL: Yes. I mean that's what our intention is.

MR. DANNER: I think that is what our intention is.

MS. CAMPBELL: Okay. Ron.

MR. BRADLEY: I read it I have no business doing this. The agreement to remove hydrostatic in lieu of a subpart (j) test medium, we should include that up there, that we would pull that -- we got agreement on that that we would pull the word "hydrostatic" as the medium and, you know, we said as long as we would use the subpart (j), I don't know, the test would be okay.

MR. DANNER: Okay. Actually, I was waiting to see what PHMSA staff was -- said about that.

MR. NANNEY: Yes. We did the thumbs

up on that.

MR. DANNER: Oh, we did give thumbs up that? So "hydrostatic" is not the only test that -- okay. And then there was a question about whether the operating and maintenance histories would be something we want in the list of examples. Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I think Ron's got a good point. I think you want to keep the tools open because you may actually use a pressure reduction, a pressure restriction to meet this. It may not be a hydro test. It may be a pressure restriction to satisfy this which is one of the other sections, which I think is where you're going, Ron.

MR. DANNER: Yes. So did -- we got the okay from PHMSA staff that they didn't have a problem with it. That's what I think we wanted to hear.

MR. NANNEY: We will consider it, PHMSA will.

MR. DANNER: Okay. So we don't have

a "yes" or "no" yet. I think we're waiting to hear back from them. So are there any other issues? Sara?

MS. GOSMAN: Okay. So I think that the "as necessary" with the relevant commas is fine with me and that makes sense. I think I was trying to figure out where that "as necessary" came in and that makes sense to me. I'm just -- we're wordsmithing a lot here but I'm trying to figure out -- the point of this -- so the point of it is to look at similar segments, evaluate them, and remediate them as necessary. The more that we add in what constitutes a similar segment, the more that we potentially constrain the ability to evaluate and then remediate. And so I don't know operating and maintenance history. That strikes me as the kind of thing that could be very specific to any given pipeline and thus might make similar, right, mean a very narrow set of possible other pipelines. So -- but perhaps I'm reading that incorrectly. So I guess, Andy, since you proposed this language,

I'm wondering how broad or narrow that term is meant to be or whether we just want to say "similar pipelines" or "pipelines with similar characteristics," right, and leave it to a broader determination what those things would be in any given context?

MR. DRAKE: This is Andy Drake with Enbridge. My intention there was trying to help people fingerprint what drives crack growth. You know, an operating environment, if it's in a fatigue environment, that is very relevant and you would want to know that, and you would want people thinking about that, and that will not flare if you're just picking materials.

So you're trying to find --- you're trying to fingerprint the bad guy here. You know, operating environment, if we're in stress corrosion crack, if you're trying to look at stress corrosion cracking threats, the operating environment is hugely germane to trying to fingerprint the bad guy. By this discussion, we are creating a record of intent here. But I

think you'd need those to help people focus in the areas that are driving the problem.

If you're just going to look at all of the materials, well, theoretically, all materials are susceptible to stress corrosion cracking. That's not going to help terribly. You've got to compliment these two to start fingerprinting. It's not intended to inordinately narrow it. It's intending to try to characterize it, if that makes sense.

MR. DANNER: But doesn't it have the legal effect that when you -- the more things you put in that can be dissimilar, the more you're saying that we don't have to evaluate because it's not -- this pipeline is not similar because it's operating history is different?

MR. DRAKE: I assume that question was asked to me so. This is Andy Drake with Enbridge. I think it -- that's certainly not the intent. The intent is genuinely to try to characterize what's causing cracks and give the attributes that drive that. If we're only going

to do one of the attributes so that we can keep it open, we're really not helping people characterize what causes cracks. You're just -- if the material is susceptible to cracking, then you should go look for cracks. It's like all materials are susceptible to cracking so that didn't help narrow the universe down very much. You need to start of putting some sort of shape around what causes cracks to form and drive and if you add a couple things, I think you start getting people thinking about the environments where this is a problem. It's not intended to be inordinately exclusive. It truly, I think, is helpful to people to start trying to characterize what is the problem.

MR. DANNER: Well, so one thing that we could do is simply say "all pipeline segments, both covered and non-covered, with similar characteristics, 'comma,' which may include..." and --

(Off microphone comment.)

MR. DANNER: Okay. Did the scribes

get that? Yes, Steve.

MR. NANNEY: Steve Nanney with PHMSA. This is all part of a section, 192.917, and part of it is a section (b) that you have to go look at data gathering and integration. And that data gathering and integration has all of this that you're talking about as part of it and some more. So the point is, it is just like what Andy said and the questions from Sara, is you're going to have to do it whether it's in there or not so from a PHMSA standpoint, we'll consider it either way because it's implied in (b) in your data integration you got to look at all of that, under 917(b) which is part of this. So I guess we'll consider it however this Committee recommends and everything.

MR. DANNER: Okay. That's helpful. Thank you. Ron.

MR. BRADLEY: Yes. Ron Bradley, PECO. I would ask similar to what we did earlier today with a PHMSA consideration that there be a bullet in here similar to what we did where PHMSA didn't

make the agreement but at least considered removing, and in this case, the term "hydrostatic." I would like to have it on the slide for voting purposes.

MR. DANNER: Okay. So that -- you would add that on the left side to say that PHMSA will consider removing the term "hydrostatic."

MR. BRADLEY: In paragraph, was it, 917(e)(3)? Thank you.

MR. DANNER: So, yes, Cheryl?

MS. CAMPBELL: Thank you, Mr. Chairman. Cheryl Campbell, Xcel Energy. I agree with that and I think we talked about this earlier but I just want to make sure. I mean the intent here is not to limit the tools that the operator has in (e)(3), I think. Is there a way to make it clear -- I mean I like removing the term "hydrostatic," but is there a way to make it clear that -- I mean I think your intent, Steve, is that the operator confirm that the manufacturing and construction-related defects are stable. So one way to do that is a pressure

test but there might be other ways to do that such as, you know, pressure reduction could take you out of that range or if there's a tool, right, that could confirm that the manufacturing/construction defect is stable. All I'm suggesting is that we make sure that the tools, right, people have tools in their toolbox to use because the goal is verifying the stability of that unless we're trying to say this is the only way to verify that it's stable, and I don't think that's the intention. I'm asking, I guess.

MR. DANNER: Okay, Steve?

MR. NANNEY: We'll consider it. I mean we would consider other tools, yes.

MR. DANNER: So do we want to change that sentence, amend it further and PHMSA will consider removing the term "hydrostatic" from (e)(3) in order to allow other appropriate testing procedures?

PARTICIPANT: Sure.

MR. DANNER: Okay. So I'm just trying

to get a sense of the Committee. So if we further amended that to say we'll consider removing the term "hydrostatic" 'and' allowing other appropriate testing procedures or effective testing procedures?

PARTICIPANT: That would be my recommendation.

MR. DANNER: All right, folks, it's only 2:00 o'clock so -- all right, so are there any further comments on this voting language?

(No response.)

MR. DANNER: All right. So hearing none, we have an amendment -- or we have a motion in front of us which has now been amended. So I think we --

PARTICIPANT: We're going to have to withdraw the last motion.

MR. DANNER: So, yes, I hate to say it. We're going to have to withdraw the last motion and re-read this page. So who made the motion?

MR. BRADLEY: I did.

MR. DANNER: Ron, will you withdraw the motion and make a new motion and then read it?

MR. BRADLEY: All right, Mr. Chair. This is Ron Bradley, PECO. I withdraw the motion that I just made and would like to make a new motion. For voting language for integrity management clarifications, paragraphs 192.917(e)(3), (e)(4), and (e)(6), the proposed rule as published in the Federal Register and the Draft Regulatory Evaluation with regard to the provisions for the integrity management clarifications are technically feasible, reasonable, cost-effective, and practicable if the following changes are made.

Revise proposed paragraph 192.917(e)(3) as follows. In paragraph (e)(3), delete the phrase "and must reconfirm or re-establish MAOP in accordance with paragraph 192.624(c)."

In paragraph 192.917(e)(3)(I), delete the reference to 192.624(a)(1) and replace with,

the segment has experienced a reportable in-service incident as defined in paragraph 192(3) since its most recent successful subpart (j) pressure test due to an original manufacturing-related defect or a construction, installation, or fabrication-related defect.

In conjunction with striking the previously proposed 192.624(a)(1), add a new 192.917(e)(6) to address cracking within IMP and suggested -- as suggested by PHMSA staff during the meeting, presented in the slides, and revised by the Committee.

In 192.917(e)(4), delete the phrase related to pipe body cracking.

PHMSA will consider removing the term hydrostatic from (e)(3) and allowing other authorized testing procedures.

MR. DANNER: Thank you. Is there a second?

MR. HILL: Robert Hill, second.

MR. DANNER: All right. Thank you. Any further discussion?

(No response.)

MR. DANNER: All right. Cheryl, we're ready for a roll call.

MS. WHETSEL: Okay. Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake?

MR. DRAKE: Aye.

MS. WHETSEL: Ron Bradley?

MR. BRADLEY: Aye.

MS. WHETSEL: Rich Worsinger?

MR. WORSINGER: Aye.

MS. WHETSEL: Chad Zamarin?

(No response.)

MS. WHETSEL: Not here. John Airey?

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill.

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MS. WHETSEL: Motion carries. Thank you.

MR. DANNER: Okay. So -- all right, so we're ready for presentation on definitions?

MR. McLAREN: Chris McLaren with PHMSA. Seeing about 17 pages of definitions in this section 4. The status of Committee comments and votes related to new or revised definitions proposed for 192.3; definitions previously voted upon in the March 2nd meeting included the moderate consequence area and occupied site. So the status of Committee comments and votes related to new or revised definitions proposed for 192.3 include definitions scheduled for discussion at this meeting, Agenda Item 2, MAOP

confirmations.

So PHMSA suggests deleting three of the proposed definitions from the NPRM in conjunction with changes to the scope of 192.624, MAOP reconfirmation. Those three definitions no longer utilized or needed include legacy construction techniques, legacy pipe, and modern pipe.

The following definitions relate to topics previously discussed and voted upon but the vote did not explicitly include a vote on related definitions. So we'd like to take up the following definitions at this time; electrical survey, close interval survey, dry gas or dry natural gas, transmission line, distribution center, in-line inspection or ILI, in-line inspection tool or instrumented internal inspection device, a pipe segment that accommodate inspection by means of an instrumented in-line inspection tools, and that was new based on a comment received to the NPRM; and definition of traceable, verifiable, and

complete records, and that is a new definition per an NPRM comment.

Electrical survey; the existing definition means a series of closely-spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify a location where a corrosive current is leaving the pipeline. The NPRM proposed a revision such that electrical survey means a series of closely-spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on an ineffectively-coated or bare pipe line.

PHMSA suggests the Committee consider withdrawing the proposed NPRM changes to this definition. The proposed changes were minor technical clarifications proposed in conjunction with the changes proposed to Appendix D. And during the June 2017 meeting, the Committee voted to withdraw the proposed changes to Appendix D and as a result, the revised definition is not needed.

Close interval survey; the NPRM proposed a revision such that close interval survey means a series of closely-spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purposes of quantifying voltage or IR drops other than those across the structure electrolyte boundary.

PHMSA suggests the Committee accept the definition as modified per the comments received in response, the comments modified below per the comments received in response to the NPRM. Continued, and the proposed definition was based on the use of this term and the proposed changes to 192.465, external corrosion.

During the June 2017 meeting, the Committee voted on 192.465. However, the new definition was not explicitly included in the vote. So the definition for consideration would be that close interval survey means a series of

closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of the cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage IR drops other than those across the structure electrolyte boundary such as when performed as a current interrupted, depolarized or native survey. Those items in red for the revised ones.

Dry gas or dry natural gas; the NPRM definition was dry gas or dry natural gas means gas with less than seven pounds of water per million cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream. PHMSA suggests the Committee accept the definition as modified below per comments received in response to the newest proposed rulemaking. The proposed new definition was based on use of this term in the proposed changes to 192.927, internal corrosion direct assessment.

During the June 2017 meeting, the

Committee voted on 192.927. However, the new definition was not explicitly included in the voting language. Proposed revisions would read as follows. Dry gas or dry natural gas means gas above its dew point and without condensed liquids being formed via pressure reductions.

Transmission line; the existing definition of transmission line means a pipeline other than a gathering line that one, transports gas from a gathering line or storage facility to a distribution center, storage facility or large volume customer that is not downstream from a distribution center; two, operates at hoop stress of 20 percent or more of SMYS; or three, transports gas within a storage field. Note, a large volume customer may receive similar volumes of gas as a distribution center and includes factories, power plants, and institutional users of gas.

The proposed revision is that a transmission line means a pipeline other than a gathering line that transports gas from a

gathering line or storage facility to a distribution center storage facility or large volume customer that is not downstream from a distribution center; has an MAOP of 20 percent or more of SMYS; or transports gas within a storage field. Note, a large volume customer such as factories, power plants, and institutional users of gas may receive a similar volume of gas as a distribution center. That was in the proposed NPRM.

PHMSA suggests to the Committee that accept the definition as modified below per comments received in response to the NPRM. Transmission line means a pipeline or connected series of pipelines other than a gathering line that one, transports gas from a gathering line or storage facility to a distribution center, storage facility or large volume customer that is not downstream from a distribution center; two, has an MAOP of 20 percent or more of SMYS; three, transports gas within a storage field; or four, is voluntarily designated by the operator as a

transmission line. Note, a large volume customer may receive similar volumes of gas as a distribution center and include factories, power plants and institutional users of gas.

Distribution center; there is not an existing definition in the NPRM proposed that a distribution center means a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line. PHMSA's response is since this section of the NPRM is applicable through transmission lines only and since this definition may significantly impact distribution lines, PHMSA suggests the Committee review withdrawal of this definition from the rule.

In-line inspection; in the NPRM, it was proposed that an in-line inspection means the inspections of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called intelligent or smart pigging. PHMSA suggests that the Committee accept the definition as modified below per API RP 1163

based on the comments received in response to the NPRM. And that would be that an in-line inspection means an inspection of a pipeline from the interior of the pipeline using an inspection tool, also called intelligent or smart pigging. Note, this definition includes tethered and self-propelled inspection tools.

On the in-line inspection tool, the notice of proposed rulemaking proposed a revision that in-line inspection tool or instrumented internal inspection device means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside, which is also called an intelligent or smart pig. PHMSA suggests the Committee accept the definition as modified below per API RP 1163 and comments received to the NPRM. And that would read that in-line inspection tool or instrumented internal inspection device means an instrumented device or vehicle that use a non-destructive testing technique to inspect the pipeline from the inside in order to identify and

characterize flaws, analyze pipeline integrity, also known as an intelligent or smart pig.

Here's the definition of the pipe segment; the pipe segment can accommodate an inspection by means of an instrumented in-line or inspection tool. It was not a proposed NPRM revision but PHMSA plans to include a discussion in the preamble since comments were received in response to the NPRM trying to support delineation of a pipe segment such that a pipe segment would -- it can accommodate an inspection by means of an instrumented in-line inspection tool means a pipe segment that can undergo an in-line inspection using an in-line inspection tool without any permanent physical modification of the pipeline.

Traceable, verifiable, and complete records; the Committee commented previously that a definition for TVC records is needed. Clarity is needed that the TVC standard the operators have been applying since 2012 based on the Advisory Bulletin 2012-06 are being retained as

those that industry has been used to and incorporating. PHMSA will explain TVC in the preamble. Traceable, verifiable, and complete records means a record or records that one, can be clearly linked to the original information about a pipeline segment or facility; two, document information confirmed by other complementary or separate documentation; and three, is finalized as evidenced by signature, date or other appropriate marking.

So in the next bit here, the status of the Committee comments and votes related to new or revised definitions proposed for 192.3; these following definitions will be addressed in conjunction with the repair criteria; significant seam cracking; significant stress corrosion cracking; significant selective seam weld corrosion, new per an NPRM comment; wrinkle bend; and hard spot.

Discussion of the following definitions related to the gas gathering topic will be deferred to the next meeting, such as the

revised definition of a gathering line and new definitions of a gas processing plant, gas treatment facility, and onshore production facility operation. Thank you.

MR. DANNER: All right. Thank you. So we will now take public comment on these proposed definitions. So we will now take public comment on these proposed definitions. Erin.

MS. KURILLA: Erin Kurilla, APGA. I suggest that we break this up into buckets just so that both the public comments can stay focused on a couple of the definitions that are related to each other and then the GPAC can vote and then we'll kind of progress through that if that's the will of the GPAC to do it in that manner.

MR. DANNER: Let me ask the GPAC what their will is. So do we want to go through these definitions one-by-one and take comments on the individual definitions or do we want the commenters to basically go through the list? Andy.

MR. DRAKE: I think given some of the

motions we've had and then the revisions to motions and things, I think it would probably be in the best interest to take these one or two at a time. I just think there are so many here that we're going to be all over the board with trying to dial these in. It would probably make sense maybe to group them into two or three at a time maybe for some of the bigger ones anyway, like transmission line and pigging. I just hazard to try to do this all at one time. I think you're going to get comments all over the place.

MR. DANNER: Yes. So the thing is there's going to be some that probably have little discussion and so we're going to go through -- well, why don't we just do it that way then. Okay.

The first --- well, the first thing I'm going to do -- we have before us the suggestion deleting the proposed definitions of legacy construction, legacy pipe, modern pipe. Is there any public comment on the proposal to delete those definitions?

(No response.)

MR. DANNER: All right. No one is commenting on those. So we now have -- how about why don't we do electrical survey and close interval survey? Is there anybody who wishes to comment on the definition of electrical survey or close interval survey; anybody want to comment on dry gas or dry natural gas?

MS. BYRNES: Yes.

MR. DANNER: Come forward.

MS. BYRNES: Good afternoon. I'm Corrine Byrnes from National Grid. I just have a really quick comment on the proposed definition of dry gas or dry natural gas. The less than seven pounds of water is deleted and replaced with above its dew point and without condensed liquids being formed by a pressure reduction. That definition is -- it would not be correct. There's always the possibility of liquids forming if you have any water in your pipeline system at all. And most tariffs say seven pounds per million, you know, as the criteria. So there's

no way for us, as operators, to enforce that and it's in contradiction with NACE guidelines. Thank you.

MR. DANNER: All right. Thank you. Any other comment with regard to definition of dry gas or dry natural gas?

MR. DANNER: Okay. So we're going to skip to in-line inspection and in-line inspection tool or instrumented internal inspection device. Any comment on in-line inspection.

MS. KURILLA: Yes.

MR. DANNER: Okay.

MS. KURILLA: Okay. I've got to remember my chain of thought. Actually, no, I don't have a comment on this.

MR. DANNER: Okay.

(Laughter.)

MR. DANNER: Does anybody else have a comment or not have a comment on ILI?

(No response.)

MR. DANNER: Want to do pipe segments? All right. We're going to -- how about pipe

segment can accommodate inspection by means of instrumented in-line inspection tools.

And then, finally, the discussion of TVC traceable, verifiable, and complete records.

MS. KURILLA: Erin Kurilla, APGA. Just one. Love that we're trying to get this into the preamble language. I think it's really important with the amount of times that we see TVC mentioned throughout the proposed rule, that there's a lot of clarity and consistency around what that standard means. Just encourage PHMSA to maybe even expand their discussion of this in the preamble to reference the, I guess, response to a request from AGA back when this first was introduced into kind of our jargon, that a single record, if it's a quality record, can meet the standard of TVC. I think we all know that now but I'd love to see that included in the preamble language. I think CJ has --

MR. DANNER: All right. Thank you.

MR. OSMAN: CJ Osman with INGAA. An additional topic we'd like PHMSA and the PAC to

consider with the description of TVC is whether it would be appropriate to focus the discussion of TVC on MAOP records. Both the NTSB and PHMSA have previously applied the TVC requirement specifically to addressing MAOP records. It may not be the appropriate standard to be applying when talking about other records that are used in anomaly response calculations and other things in the code, so would like PHMSA and the PAC to consider whether specifically calling out MAOP records in this definition in the preamble. Thank you.

MR. DANNER: All right. Thank you. All right. Other comments? So I think that covers all of the definitions with the exception of transmission line and distribution center. Is that right? Oh, it is. I'm just not speaking to it. All right. We -- again, we have -- I think we have covered all of the definitions with the exception of transmission line and distribution center and so Alan, is it your recommendation then that we would go ahead with the discussion

of the voting language and just omit those two definitions at this time?

MR. MAYBERRY: Yes. Let's go to a discussion on what we've covered so far and then we'll decide on voting.

MR. DANNER: Okay.

MR. MAYBERRY: As we do that.

MR. DANNER: All right.

MR. MAYBERRY: Either one big vote or we're dividing it up. We'll see how the discussion goes.

MR. DANNER: Okay. All right. So any discussion from the Committee members on the definitions that we have heard public comment on so far? Cheryl.

MS. CAMPBELL: I'll kick it off, Chair. Cheryl Campbell, Xcel Energy. So I'm wondering if on a couple of these, probably close interval survey and dry gas, is it appropriate to reference the NACE definitions rather than building a definition within Part 192? I mean we've referenced outside standards groups prior,

you know, for certain things, or incorporated it into the code, so I'm wondering if it's appropriate to do that for those two in particular, because those are -- I mean those are common terms that we're all using and that NACE has also said this is what this means.

MR. DANNER: So -- Andy.

MR. DRAKE: I would echo those comments. I think trying to stay with definitions that are common in the industry and understood and how they connect to other things we're trying to do are important. If we create a separate definition for what NACE defines dry gas, I'd just like to understand what are we trying to accomplish? Is there something that's not functional with the NACE definition, because that is more of an industry standard term and understood by a lot of folks.

MR. DANNER: Okay. Thank you. Steve.

MR. ALLEN: Steve Allen, IURC. Would it be possible to hear the definition, the NACE definition?

MR. DANNER: So does anybody have access to the NACE definition. Cheryl.

MS. CAMPBELL: I think I have it.

MR. DANNER: Okay.

MS. CAMPBELL: NACE defines close interval survey as a method of measuring the potential between the pipe and earth at regular intervals along the pipeline. And that is ANSI NACE SP0502-2010, pipeline external corrosion direct assessment methodology.

MR. DANNER: Okay. And is there a definition of dry gas as well?

MS. CAMPBELL: NACE defines dry gas as a gas above its dew point and without condensed liquids and that references NACE SP0206-2006, internal corrosion direct assessment for pipelines carrying normally dry natural gas.

MR. DANNER: Okay. So that definition is similar to the one that's proposed here. So it does not address the concern we just heard from National Grid about that not having enough specificity about the seven pounds of water per

million and so forth. If we wanted to go with the NACE, do we incorporate by reference or do we simply lift it and put it into the rule? So Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount Public Utilities. Just wanted to reference something, Steve, we talked about during the teleconference.

MR. DANNER: Yes. He's focused on some other things right now.

MR. WORSINGER: Steve, I just wanted to reference something we talked about during the teleconference about. We talked about that -- the qualifier with the MCAs, that this would only apply to the free-swimming ILI tools that we could use without modifying the pipeline. And I didn't' see that here today. I just wanted to confirm that that's what the understanding was.

PARTICIPANT: I know. Now I'm going to have to go back.

MR. NANNEY: All right. You said without modification to the pipeline. Say that

one more time?

MR. WORSINGER: We want to make sure this applies to pipelines that can be fully assessed by a traditional free-swimming ILI tool without modifying the pipeline. We talked about that during the teleconference two weeks ago.

MR. DANNER: March 2nd, yes.

MR. WORSINGER: March 2nd, thank you.

MR. NANNEY: I'm trying to make sure which one is -- this in-line tool definition or which definition are you talking about?

MR. WORSINGER: Yes, definition of an in-line tool or pertaining to an in-line inspection.

MR. NANNEY: It's not the one pipe segment can accommodate inspection --

MR. DRAKE: I think it actually is the accommodate.

MR. WORSINGER: Yes.

MR. NANNEY: Okay. That's what I was trying to make sure I understood. Well, if you look, we've got on there without any permanent

physical modification of the pipeline.

MR. WORSINGER: It doesn't talk about a traditional free-swimming tool, ILI tool.

MR. NANNEY: Well, there's some pipelines that may be running some of these other tools, whether it's tethered or self-propelled, through them that they may make a modification but not be permanent where you have to put permanent launchers and receivers.

MR. DANNER: Okay. So, Alan, do you have some --

MR. MAYBERRY: First off, are we -- let's make sure we close the loop on that. I was going to address another issue.

MR. WORSINGER: Rich Worsinger, Rocky Mount. I don't think the concern is the launchers. It's that the pipeline itself can accommodate it and --

MR. NANNEY: You're talking about putting in -- like where you've got reduced port valves or something like that? Just trying to make sure I'm understanding what you're saying.

MR. WORSINGER: Yes.

MR. NANNEY: Okay. That's what we thought the any permanent physical modification to the pipeline meant, that we put in there.

MR. DANNER: Okay. So just want to make sure we're just --

MR. DANNER: -- talking about pipe segment. Okay. Andy?

MR. DRAKE: Yes. I think this may actually be more important than I was first thinking. The ability to accommodate inspection, we voted on this many times now, you know. I think we voted on it with the understanding that we were talking about segments of pipe that would support a free-swimming tool. Robotic tools can go through all kind of stuff so if that is now the definition of a section that accommodate pigging, I think we need to stop, because that is very radically different than the assumptions that we made, at least I made, and I think that would be consistent with most people's understanding of the conversations and votes

we've had to date.

So I just want to be real careful here. I appreciate that we don't want to say operators shouldn't use robots or shouldn't use tethered tools but here you're trying to say for the scope of when we consider a segment supporting piggability, it should be free-swimming, because that is a huge difference in how we would approach even our cost benefit study. What does that mean? Well, anything can accommodate a robot. I mean even piping in a station can deal with robots. So that -- but that wasn't what we were talking about today, at least not what I was thinking about. Is that right?

MR. NANNEY: Well, let me just ask what wording are you looking for is what I'm trying to find out.

MR. DANNER: I think Rich had that language, didn't you?

MR. NANNEY: That's why I'm asking it.

MR. WORSINGER: Rich Worsinger, Rocky

Mount Public Utilities. Regardless of whether a pipeline is able to accommodate robotic, the definition of able to accommodate is considered only for free-swimming tools. I believe your -- the analysis is based on the premise that you can cheaply I -- use an ILI tool and I don't believe a robotic tool --

MR. NANNEY: Okay.

MR. WORSINGER: -- would be a cheap tool.

MR. DRAKE: This is Andy Drake.

MR. DANNER: Andy.

MR. DRAKE: Just to complement that, I don't -- I think we're just trying to define what does a -- when we say piggable segment, what is it we're talking about. We're talking about segments that's for free-swimming tools. It doesn't mean that when we define an in-line inspection tool, it may -- there may be all kinds of in-line inspection tools. But I think that definition of accommodating inspection tool is important because it really sets the expectation

of the operator. And I think it's the basis of our cost benefits and our comments to date is how readily can this thing be made piggable. If it's free-swimming --

MR. NANNEY: Okay.

MR. DRAKE: -- that's one thing but if it's the ability to do any kind of tool, that's not what we've been talking about.

MR. NANNEY: Can I say something? Do not strike -- what I think we're all agreeing upon is in 130, pipe segment means of -- instrumented inspection tool means a pipe segment undergo the inspection -- an in-line inspection using a free-swimming is what -- yes, we'll add that. We'll consider it as we -- you know, a free-swimming in-line inspection tool, that's what -- we'll add that.

MR. DRAKE: All right. Alan?

MR. MAYBERRY: Before we got off on that, I was going to go back to the NACE; you know, this proposal for the NACE wording on dry gas. And, you know, where we are right now is

really based on the comments we've received. If there's a suggestion for us to consider that, I would encourage the Committee to, you know, word it as such that to consider the NACE definition in revising or providing a definition of dry gas or dry natural gas.

MR. DANNER: So anyone want to respond to that? Sara.

MS. GOSMAN: I think -- so Sara Gosman. I'm in agreement that it's helpful to make sure that we're consistent with terms used in the field. I wouldn't want to see us directly incorporate by reference a NACE definition, because I think essential to public regulation is the Agency setting the regulation -- by regulation the definitions that it's going to be using to regulate. And when I look through the definitions already in the code, there aren't any others that directly reference a standard so --

MR. DANNER: So --

MS. GOSMAN: -- but I think, you know, if we want to take language from NACE because

that's language that we use in the field to understand that particular term, that makes complete sense to me.

MR. DANNER: So yeah, I think from my point of view, the goal would be to make it as consistent as possible and lift it verbatim unless we have an objection to what they have or we think that we can come up with a better definition.

MR. MAYBERRY: I think that would be consistent with intellectual property laws so --

MR. DANNER: Okay. Any other comments? Steve.

MR. NANNEY: Yes. Can I ask the Committee one thing? Originally, PHMSA recommended that we have with less than seven pounds of water and not subject to excessive upsets for electrolytes or water liquids into the gas stream. And hearing the public comment from the individual from National Grid, it sounds like what I think we were hearing is that we might, should reconsider that. I think PHMSA would

consider either or, you know, based upon the comments. We're not -- either or of them would be fine with us so whatever you would like to recommend to us, we'll consider.

MR. DANNER: So this is Dave. What I heard is that without the language that references the seven pounds, that it's actually not an accurate definition and that concerns me. So I would be comfortable going back to the original definition in the NPRM. Andy?

MR. DRAKE: I would avoid using the seven. I think that created -- I think the direction that comment was going, I think, was it isn't constructive consistently across the industry. I think the NACE definition is more consistently applicable and I'd just stay with the --

MR. DANNER: Oh, so I think I misunderstood the comment then. Maybe -- I wonder if the person from National grid could clarify for me.

MS. BYRNES: I think the concern is

around the pressure reductions because when you regulate gas from a high pressure to a low pressure, you can then introduce liquids that were previously in vapor state.

MR. DANNER: Okay. So let me ask did you have a problem with the original NPRM definition that's at the top of the page on the screen on the right?

MS. BYRNES: Well, going back to some of the other comments, I think it is -- I think there's an assumption whether or not every operator has the same tariff, you know. I mean, you know, seven pounds is kind of an arbitrary number.

MR. DANNER: Okay. Thank you very much.

MS. BYRNES: Thank you.

MR. DANNER: Cheryl.

MS. CAMPBELL: So I think this is kind of an interesting conversation and I hear you. I think seven pounds is an arbitrary number that a lot of interstate pipelines have sort of used

over the years. I will tell you, you know, we have a lot of gen behind our own system and connected to other interstates, and we have considered -- I'll say it this way -- starting a national conversation about changing that seven pounds, right, because it does create problems at times at those generation plants where -- when it kind of moves around.

So I mean from our point of view, we would consider tightening that so to -- I would struggle leaving the seven pounds in there, I think, is what everybody's saying, right, because it's something that I think is -- gets talked about between pipelines and customers.

So can you solve it? I mean I think the problem here is the water, right. So I mean can you solve it by saying that the liquids -- it's not necessarily hydrocarbons, it's the water that's the problem. Is that -- Corrine, is that where you're going?

MS. BYRNES: Yes. The water causes the internal corrosion.

MS. CAMPBELL: Yes, because it's water that's creating the internal corrosion risk, not the hydrocarbons, right?

MS. BYRNES: Yes.

MS. CAMPBELL: So can we just say it by clarifying that the dew point is related to free water and not to hydrocarbons? Or does that just create more confusion?

MR. DANNER: Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I agree with the seven pounds. That's really more of a tariff condition and it -- what it means to the pipe as far as dry varies from pipe to pipe and the situations that you're in. I do think the key that is coming up over -- and you may reiterate this or hopefully, this -- the last five words in PHMSA's proposal, I think, is where the hitch in the get along is being formed via pressure reductions. If we took that out, you are the NACE definition, and I think that's where there's some angst building, you know, because I can create all kinds of things to

happen with a pressure reduction and that's not terribly helpful in the definition of dry. So that's where I think going back to the NACE definition helps provide some continuity of how that is effectuated on the pie. That's really all I think the issue is.

MR. DANNER: All right. Steve.

MR. ALLEN: Steve Allen, IURC. Cheryl, could I ask you to read that definition, that NACE definition again, please?

MS. CAMPBELL: Happy to, Steve. NACE defines dry gas as a gas above its dew point and without condensed liquids. So there's probably people smarter than me in the room about this but, I mean, to me that says -- and I'm dry -- a long time ago, right, when I was -- used to be an engineer, without condensed liquids, so without liquids entrapped in the gas stream? I meant they're vaporized at this point, right? Am I interpreting that correctly?

MR. DANNER: Steve.

MR. ALLEN: Steve Allen, IURC. So the

intent here is to define dry gas to be gas without electrolytes in it?

MS. CAMPBELL: Without what?

MR. ALLEN: Without electrolytes, without water?

MS. CAMPBELL: Without water.

MR. ALLEN: And that, I don't know, condensed liquids? I mean I'm really kind of okay with the NACE definition but I that causes angst for others, I'm all ears but I think the key is, is you want to define dry gas as gas that doesn't have any electrolytes in it or doesn't have any water in it. I'm -- you know, I'm trying to make it simple.

MR. DANNER: So could I hear the NACE definition one more time? Cheryl, do you have that?

MS. CAMPBELL: I'm sorry, Mr. Chair?

MR. NANNEY: Could I hear the definition -- the NACE definition one more time?

MS. CAMPBELL: For dry gas?

MR. NANNEY: Dry gas, yes.

MS. CAMPBELL: You bet. Dry gas is a gas above its dew point and without condensed liquids. So a pretty simple definition.

MR. DANNER: Okay. Alan.

MR. MAYBERRY: I was just going to say we can -- we'll work with the suggestion here and, you know, the concern of a condensed liquid, I mean I know I've seen issues even below seven pounds; if you don't add heat, for instance, you're going to have issues as you take a pressure drop. So we'll work within the -- you know, considering the NACE definition and have really more of a performance standard as opposed to prescriptive standard and probably also add a little clarity in the preamble I would say, too, to what we need.

MR. DANNER: Okay. So I think we need to have that reflected in the voting language.

PARTICIPANT: Yeah. It's being tweaked.

MR. DANNER: Yes.

MS. BYRNES: I just want to say thank

you.

(Laughter.)

MR. DANNER: Thank you. All right. Sara.

DR. LONGAN: Thank you. Sara Longan, DOI. It would be helpful to me to hear either PHMSA or the Committee's dialogue, in part, to respond to the comments that CJ made regarding TVC applicability to MAOP. Is this only or is it elsewhere? And I ask in order to inform the Committee on how it might impact the TVC definition before us.

MR. DANNER: Okay. Anyone want to respond to that question?

(No response.)

MR. DANNER: I guess -- I think PHMSA is still trying to dot the i's and cross the t's on the last issue, so -- or -- Steve?

MR. NANNEY: Well, the -- this is with 15 seconds of thought, so TVC would mean an MAOP, of course, but it would also be in support of items that maintain that integrity. In other

words, if you make a repair, you would want to have that documentation to maintain it. If you have to have pressure test records, you would have to have those type records, but any records that you need to maintain your MAOP would be part of it. In the section such as pressure tests, but it would be subpart (j) already requires those records to begin with and 619 reference back to them. And if you go look in the section around -- I'm going to probably say the section wrong but it's like 701, 703, the sections for doing repair. If it's in a non-HCA -- Chris is telling me 713 -- and also in the subpart (o), the 900 series where you're doing anomaly repairs, there's also a section on repairs in the corrosion section. But any of those that you're doing to maintain the MAOP, you would need to keep those under TVC to maintain that pressure.

MR. DANNER: All right. Any further discussion on that, questions about that? Andy.

MR. DRAKE: This is Andy Drake with Enbridge with a similar 15-second response to

digest that -- or opportunity to digest that. I'm trying to just think through out loud. I mean TVC, we've been sort of trained over the last year TVC and MAOP, TVC and MAOP, and it has a -- is a very definitive mean -- you know, luggage that comes with that.

When we start talking about opportunistically gathering data for anomaly criteria, is -- I'm trying to -- I'm literally thinking on the fly, which is probably dangerous but we're going to vote on something here in a minute so I need to do this, but when we're gathering data opportunistically, is that going to meet all of the hurdle criteria of TVC? Or are we really saying you need to have records to support those decisions, because TVC is a very specific hurdle rate standard of care, and we reserve that for this once in a lifetime decision. I'm trying to -- I'm literally not sure how that plays with data that we collect kind of as we go. I don't know if it's going to meet all of the TVC hurdle rates. It's just

we're gathering information as we go to keep populating those decision trees. You know what I mean?

And I just want to be out loud because if we keep forcing everything back to TVC, I don't even know what might happen for records that aren't related to MAOP, they're just decisions we're trying to make on IM. Are we really burden -- loading up the system with all of the requirements of TVC; is that really necessary? I'm asking. I'm really just thinking out loud.

MR. DANNER: All right, Sara.

DR. LONGAN: Sara Longan, DOI. I'm going to ask a question and if it needs to be rhetorical, I accept that and then provide maybe a comment by example. What I'm curious about is if there are data collected and records produced to comply and satisfy pressure testing or anomaly repairs that may not meet the standard of TVC, which I've learned over the course of a day-and-a-half or a day is quite high, is that something

PHMSA would accept? And I see this as another possible do loop, maybe, unless PHMSA has flexibility and acceptance of data that might not reach the TVC standards. And I ask these questions because I don't want to go down a rabbit trail, but in other regulatory frameworks where the bar has been excessively or exceedingly high and increasingly high, the agency doesn't win and maybe the private sector doesn't win either, because they're producing good data that could inform PHMSA potentially, but it may or may not meet that very high TVC standard. Thanks for hearing me out.

MR. DANNER: All right. Anyone else on that issue? Cheryl.

MS. CAMPBELL: So I'm -- as I think through this, I'm looking at item three there under traceable, verifiable, and complete, and I'm thinking about the questions posed, right? So I'm -- I've got a hole open. I'm evaluating an anomaly. I'm doing non-destructive testing. I'm doing whatever. How do I -- I don't know how

to do number three in that scenario. And I'm not trying to -- I'm just trying to understand, right; I mean I'm trying to figure out how do you have a -- how do you generate, make, right, a record that either helps me evaluate that anomaly or does something with that repair. Or am I over-thinking this?

MR. DANNER: Alan?

MR. MAYBERRY: You know, we've gone down this road for a while. I can vividly remember that first Advisory bulleting. Actually, the NTSB recommendation that, you know, first, you know, put those three words on it. And we've been down this road together dealing with that phrase, and it's all been within the realm of establishing MAOP. So I don't know if we put -- maybe make a tweak to that wording there that it's -- related -- yes, record or records related to MAOP that -- Yes. Okay. Here I am wordsmithing but establishing -- related to establishing MAOP.

MR. DANNER: All right, Steve.

MR. ALLEN: Steve Allen, IURC. Yes. I think that makes an awful lot of sense to go ahead and add something in here that says that, you know, these records are related to records that were created or associated with, you know, the pressure. I mean that's where it first came up in 192.624(2) on pressure test records, and it was specifically talking about establishing -- necessary to establish maximum allowable operating pressure. It doesn't bleed over into other things. It's specifically talking about that. So I think that makes a lot of sense to add something there to say that.

MR. DANNER: All right, Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I agree with Steve. I think adding something there just helps. That's been the context of the conversation to date. I don't -- I'm not trying to undermine anything about the other records. I just think when we say TVC, that's what it's about. We're going to need other records always. It's just the

applicability of this to the other things, I think, starts to get kind of convoluted.

The other thing that I would bring up here is, you know, I think PHMSA has acknowledged that a TVC record can be a single quality record. And I just want to make sure we're still in that place. Everybody's shaking their head yes. Good. Okay.

MR. MAYBERRY: I think we -- but the wording should say record or records. It should be very -- I mean --

MR. DANNER: So Sara Longan, did this answer your questions? Do you feel like you got what you were looking for?

DR. LONGAN: Quite well, thank you.

MR. DANNER: Okay, great. All right. Any other --- any other questions about the definitions? Now we have two definitions to go. Do we want to do those and add them to this amendment? Don't we -- we have two more definitions.

Oh, Sara, go ahead.

MS. GOSMAN: Just quickly then to follow up on this conversation, which is really helpful. Are there references to TVC in other parts of the proposed rule that do not relate to MAOP? And if so, what is going to happen with those now that we've had this conversation?

MR. DANNER: So who is that directed toward?

MS. GOSMAN: PHMSA

MR. DANNER: Okay. So I believe Steve is preparing an answer for you right now.

MR. McLAREN: Chris McLaren with PHMSA. Yes, in 713, as I was reading through it, I found it in three places talking about those repairs.

MS. GOSMAN: That are not -- and repairs not specific to MAOP?

MR. McLAREN: The repairs would be made to the repair criteria based on the predicted failure pressure, which does come into play with MAOP but you have to know the data for both, so it can be redundant.

MR. DANNER: Did that help, Sara?

MS. GOSMAN: I guess I would maybe need to go back to the language and take a look at it myself, too, but let me -- maybe let me express my concern, which is if the conversation that we just had is about limiting TVC to this particular context, I'm just wanting to make sure that wherever we've addressed this term previously, that we know what that term means in those other places, which might mean that we might need to revisit those, sorry to say it, but revisit those parts of the proposed rule if we are going to now limit TVC to the context of MAOP.

MR. DANNER: So another way to do that could be to take the definition that we have here and just say for purposes of and then cite the parts of the code that we want it to apply to so that if the term appears somewhere else, it doesn't mean that this definition necessarily applies to that. Even though it may be undefined, it would nonetheless have some meaning

just from the plain language.

MS. GOSMAN: Yes. I think that's one way of approaching it. I just worry because it's such a specific term that it seems to me either we have a definition for that term that's consistent throughout, or we perhaps use different terminology.

MR. DANNER: Okay. Andy?

MR. DRAKE: I think -- a little bird just told me that we haven't voted on anything where TVC has been used other than records so far. So the allusion to it being covered in repair criteria is a discussion we haven't had yet. So there's -- I don't think we're going to have to worry about going backwards. The conversation is still in front of us about how that fits. So if that helps kind of lower anxieties a little bit, I don't think we've done anything that's not related to records so far on TVC.

MR. DANNER: All right. Sara?

MS. GOSMAN: So can I suggest that we

hold this conversation then until we talk about the rest of the places where we see TVC and then go back to the definition at that point?

MR. DANNER: Where else are we going to see TVC?

MR. WORSINGER: Repair --

MR. DANNER: Repair criteria, okay. Any response to Sara's proposal? Rich?

MR. WORSINGER: Rich Worsinger Rocky Mount Public Utilities. Sara, I think you're asking some good questions, but could we not define this for related to MAOP here? And then if we discover other areas, we address those so that we're just not kind of leaving something undone here? I guess doing the same thing, just putting this to bed here and then when we see the other areas that it might be needed, addressing it at that time?

MR. DANNER: Sara?

MS. GOSMAN: Perhaps I think about this like a lawyer but I -- so there is a definition in front of us of a term that's going

to be used throughout the regulations. So to me, it seems like we've got to decide what that terms means and where it's being used in the regulations and then decide whether we agree to that or not. So I prefer to have that conversation at one point in time in which all of those are in front of us and we can work through what it means.

MR. DANNER: Okay. So we do have a couple of definitions that we are going to take up separately, transmission lines and distribution center. It could be that we hold this one with those and we could vote on those when we have a better idea of where else we might see the TVC term applied. So what is the will of the GPAC. Andy?

MR. DRAKE: I would agree to make a motion that we just excise the issue about TVC until we get there. We've done that with other things and I think that gives the Committee, you know, a deliberate discussion where we've all got it all in context, which is, frankly, one of the

hardest things we're doing here, is we're talking about single issues and then we never really back up and look at how they fit together. So if there's any concern about how it fits together, I'd just say excise it and --

MR. DANNER: So the proposal would be basically, let's take that definition, we'll park it, we'll bring it back at a later date when we've had a discussion about the other sections? So I think that I'm hearing that and Alan and then Steve.

MR. MAYBERRY: Yeah. I was just going to say that's one option. We could also deal with it here but then also pick it back up as we go to anomaly repair, too.

MR. DANNER: So --

MR. MAYBERRY: Either way.

MR. DANNER: Okay. Yes. I mean I think it's okay for this to sit in the parking lot overnight. I mean I think we've agreed on the language as regards to MAOP, so the question is then if there need to be adjustments as we

deal with the other stuff. Steve?

MR. ALLEN: Steve Allen, IURC. Yes. I think that makes sense to go ahead and pick it up later, but while we're on it, Mr. McLaren, you said that TVC was referenced in other areas. And I think you specifically said 192.713. Is that the only place that it's referenced?

MR. McLAREN: Without my computer open to do a word search, I believe it is those three times. It's -- yes, in a couple of different instances or usages that it's applied towards.

MR. ALLEN: Thank you.

MR. DANNER: Okay. So -- all right, so we're going to park that and again, we still have definitions for transmission line and distribution center which we're also setting aside. And then we will basically figure out how we want to proceed with this voting language in front of us on the other definitions. Alan?

MR. MAYBERRY: I was just going to add or remind the Committee that related to TVC, we are going to put that in the preamble as opposed

to reg text. That's where we were addressing that. Just make sure that we're not --

MR. DANNER: Okay. Right, but I think the question was whether -- we just wanted to make sure after we've talked about the other parts, that the definition that we've arrived at for TVC is the correct one. So that's going to -- that's in the parking lot right now.

So I cannot remember if we have a motion before us on this?

PARTICIPANT: No.

MR. DANNER: We do not, okay. So I would look for a volunteer to read the large type. All right, Rich.

MR. WORSINGER: Rich Worsinger, Rocky Mount Public Utilities. Voting language for definitions in 192.3; the proposed rule as published in the Federal Register and the Draft Regulatory Evaluation with regard to the proposed definitions are technically feasible, reasonable, cost-effect, and practicable if the following changes are made. Strike the definition of

electrical survey; revise the definition for close interval survey, in-line inspection, and in-line inspection tool to read as recommended by PHMSA staff during this meeting and as presented in the slides; revise the definition for dry gas or dry natural gas as revised by the Committee during the meeting and reflected in the slides; consider adding free-swimming to the definition for pipe segment can accommodate inspection by means of an instrumented in-line inspection tool per Committee comments at the meeting.

MR. DANNER: Okay. Thank you. Is there a second?

MR. ALLEN: Steve Allen, IURC. No, Mr. Chairman. I just want to point something out with that language.

MR. DANNER: All right.

MR. ALLEN: I think the language as it exists, it would suggest that the language on traceable, verifiable, and complete records, transmission lines and distribution centers is okay, because it says that the proposed language

is fine, it's technically feasible, so on and so forth if the following changes are made. It doesn't say except for distribution center, transmission lines or TVC.

MR. DANNER: Okay. So we'll add that language in there. Thank you.

MR. ALLEN: Yeah. It needed a qualifier.

MR. DANNER: Thank you.

(Off-microphone comments.)

MR. DANNER: Okay. So what's that?

MR. WORSINGER: Can I modify --

MR. DANNER: Yes. You are hereby modified so now I'm asking is there a second? Do you have something else?

MR. WORSINGER: Do I need to say that or --

MR. DANNER: I think we're good. So -- well, I guess yes, why don't you orally modify your motion.

MR. WORSINGER: Motion to modify my motion to say everything but accepting the

definitions of transmission line, distribution center, and traceable, verifiable, and complete records.

MR. DANNER: All right. Thank you for that. Is there a second on this motion?

DR. LONGAN: Sara Longan, I second.

MR. DANNER: All right. Thank you very much. Is there any more discussion?

(No response.)

MR. DANNER: All right. Then I think we're ready for a roll call vote, Cheryl.

MS. WHETSEL: Are there any objections? All right. Steve Allen?

MR. ALLEN: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

DR. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?
MS. CAMPBELL: Aye.
MS. WHETSEL: Andy Drake?
MR. DRAKE: Aye.
MS. WHETSEL: Ron Bradley?
MR. BRADLEY: Aye.
MS. WHETSEL: Rich Worsinger.
MR. WORSINGER: Aye.
MS. WHETSEL: Jim Airey?
MR. AIREY: Yes, aye.
MS. WHETSEL: I mean, sorry, John. It's the end of the day is it?
MS. WHETSEL: Robert Hill.
MR. HILL: Aye.
MS. WHETSEL: And Sara Gosman?
MS. GOSMAN: Aye.
MS. WHETSEL: Okay, motion carries. Thank you.
MS. BURMAN: And I'm sorry. I was on mute. Diane Burman.
MS. WHETSEL: Did you say aye, Diane?
MR. DANNER: Yes.

MS. WHETSEL: Okay. Thank you.

MR. DANNER: Ms. Burman says aye. Okay. Thank you, Commissioner. It is now 3:13. We are going to take a break and we'll try and start again by 3:25, probably 3:30, but come back soon as you can.

(Whereupon, the above-entitled matter went off the record at 3:13 p.m. and resumed at 3:37 p.m.)

MR. DANNER: Okay. At this point, we are going to take under consideration the definitions for transmission line and distribution center. So I'm going to turn it over to PHMSA staff. And they will present on this, on these proposals.

(Off-microphone comments.)

MR. DANNER: Oh, we've already -- oh, I'm sorry. We've already had the proposals on these definitions. So we're going to take public comment on transmission line and distribution center. So is there anyone who wishes to comment on these proposed definitions?

MS. BARTHOLOMEW: Certainly. Good afternoon. My name is Mary Bartholomew. I'm with Southwest Gas Corporation. And I will be commenting on the transmission line changes specifically related to the change from operating pressure to MAOP.

At Southwest Gas, we utilize operating pressure in our hoop stress calculation for determining whether a line is considered transmission. New and replacement pipelines are designed to one of a few set pressures typically aligned with ANSI ratings associated with the components, example being an ANSI 300 valve that may be in the line. So we would set that design pressure and our multiple here 720.

Further, the test pressure is typically set to one and a half times the design pressure, creating a pipeline with an MAOP of 720 psig. While the MAOP is established at 720, the maximum operating pressure will typically be much less. A common operating pressure at our company is 300 psig.

It is important to note that by conducting the pressure test at a higher pressure it allows us to ensure that any construction defects or manufacturing defects have been more than adequately addressed.

In the future, if operating conditions were such that we would need to increase the operating pressure, our operating standards dictate a very specific and stringent set of requirements up to and including uprating in order to increase that operating pressure.

At this time, as we understand the requirements of the establishment of MAOP, once a design pressure and test pressure have been set for a new installation, the MAOP has been set and cannot be arbitrarily reduced.

As proposed in the rule, utilizing MAOP rather than operating pressure in the definition of transmission would require many of the pipelines operating at our company at very low SMYS values within, to be reclassified as transmission.

With the prescriptive nature of transmission integrity management, these pipelines typically operating at less than ten percent of SMYS will have the same assessment requirements and timeframes as pipes operating at 50 percent of SMYS, reducing our focus on the lines that are creating the most risk.

We would ask PHMSA, excuse me, to reconsider the proposed change from operating pressure to MAOP in the definition of transmission. Appreciate your time. Thank you.

MR. DANNER: All right. Thank you.

MR. BODELL: Yes, hi, my name is Clayton Bodell with Williams.

Similar to the comment just previously made, I think there's a slight distinction that needs to be made in item number 2 as it relates to, you know, MAOP versus operating pressure. The way it's written the calculation of MAOP versus SMYS is a different calculation that results as, from the hoop stress generated at that MAOP as a percentage of SMYS.

So the way that the rule is written right now you end up with, you know, with a number that makes sense. But what it should read in 2 is maybe something similar to -- and this is not withstanding the comment just made -- has or is operating at an MAOP resulting in a hoop stress of 20 percent or more of SMYS. Thank you.

MR. DANNER: All right. Thank you.

MR. MOIDEL: Good afternoon. Brian Moidel with Dominion Energy Ohio.

With regard to this slide right here where PHMSA suggests the committee review withdrawal from the rule, I would recommend that the committee considers the definition to provide, of distribution center to provide clarity and consistency with regard to the transmission line definition. Thank you.

MR. DANNER: All right. Thank you.

MS. KURILLA: Erin Kurilla, American Public Gas Association.

Just like Brian just mentioned, APGA strongly recommends that the definition of

distribution center be included in this rulemaking.

It's been an undefined term in our industry for a very long time. And there's been a lot of ambiguity around the definition of distribution center. I know PHMSA has answered countless interpretation requests on this term.

So we very much support looking at that definition. In fact, APGA supported the proposed definition in the NPRM. Since then, we've seen a slightly revised version come from AGA. And we would support AGA's revised definition for distribution center as well.

Just two other comments for the record, just encouragements to provide a little bit of clarity during this conversation with the GPAC around their justification for two changes. One has already been mentioned.

In the preamble of the NPRM, there really was no discussion about PHMSA's move from operating pressure to MAOP for determining the percent SMYS. So I'd encourage PHMSA to talk

about that and explain why they made that change.

And then the second change, which we've heard no comments on, is in red on that slide 126, is this addition of or connected series of pipelines that was not in the proposed rule nor have we heard any commentary on why that change was added and why PHMSA felt that was necessary.

So, encourage the GPAC to talk about both of those items as well. Thank you.

MR. DANNER: All right. Thank you. Are there any other comments on these two definitions? All right. Turn it over to the committee. Are there any comments? Steve?

MR. ALLEN: Yes, the PHMSA's recommendation to exclude the definition of distribution center I think is the wrong path. I think we do need to have that definition in there for clarity and consistency.

And I have seen the industries proposal for the definition. And I honestly would support that. I think it's a step in the

right direction.

MR. DANNER: Others, Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount Public Utilities.

John Gale, did you happen to bring that slide I sent to you?

MR. WORSINGER: I have an example for the committee that I think will help explain why we really want to have this put to bed.

This is a system in Lorimor, Iowa. And this is simply the line that connects Lorimor with their gas supply. It's a two-inch steel line MAOP of 150 pounds. It operates at less than one percent SMYS. And the Iowa Utility Commission considers these are transmission lines since distribution center has not been defined.

So this 4.7-mile line is considered as a transmission line, and therefore has to have DIMP and all the other various inspections and surveys. And there are numerous systems in Iowa that are subject to the same thing.

And if you need somebody from Iowa to

further testify, there's a guy who was born in Iowa in the back of the room. And I told him -- he's shaking his head no. Thank you.

MR. DANNER: So how do you know about Lorimor, Iowa?

MR. WORSINGER: Rich Worsinger, Rocky Mount.

This was shared with me by John Erickson at APGA. There was a pipeline class location methodology workshop back in April 16, 2014 where David Hraha, program director for IAMU, presented this and explained in more detail -- that's where we put this slide together -- situations such as this were there.

MR. DANNER: All right. All right. Thank you. So the definition that is up here, is that a definition, if we were to include a definition, is that a satisfactory definition? Steve?

MR. ALLEN: Steve Allen, IURC. While it is certainly better than what we had before, which was nothing, I don't know if I can read the

recommended language for distribution center.

MR. DANNER: Recommended by whom?

MR. ALLEN: Industry.

MR. DANNER: All right.

MR. ALLEN: Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example, one, at a metering location, two, pressure reduction location, or three, where there is reduction in the volume of gas such as a lateral off a transmission line.

MR. DANNER: Okay. So, Steve, it is your -- you would prefer that definition to the one that's on the screen.

MR. ALLEN: I think that definition provides even more guidance and more definition and more clarity.

MR. DANNER: All right. Is there any other conversation on this point, on distribution center?

All right. Hearing none, I guess I don't know how to sense the will of the committee. A few members have said they would like to have the industry definition substituted for the NPRM proposed revision and that it be included in the final rules. Cheryl?

MS. CAMPBELL: I guess I'm going to add my voice to I think we -- I would like to see us define what a distribution center is to add some clarity. I do think that it goes with the conversation about a transmission line since we're terminating it, right, and a distribution center.

And I will say, and I can see Christina cringing over there, but having spent the first 20 years of my career at an interstate and then working at a utility and the, frankly, the amount of energy and conversation around the difference between a distribution line and a transmission line is pretty incredible over the time period that I've worked here.

And people just spend a lot of time

debating, right, what, is that really a transmission line or is that really a distribution line.

So I would like to see some clarity around it, right, so that it's easier for all of us to deal with. And if this is the appropriate place to do that, then I would support that, Mr. Chairman.

MR. DANNER: All right. And again, you heard the definition proposed by Steve. And there's a definition on the screen. Do you have a preference?

MS. CAMPBELL: I guess I don't. I mean, I agree with Steve that the one proposed by industry has more specificity. But then do you say -- I mean, I hate to throw this out there. But, I mean, once you've defined that, do you then say whatever doesn't fit in this category, right, or a gathering line becomes a transmission line?

It can only go into one of those three categories. Is that correct, Alan? I mean, it's

got to be one of the three, right, a gathering line, a transmission line, or a distribution center. And to me, what's important is that we're clear about which of those buckets a pipeline goes in.

MR. DANNER: Okay. Steve, do you want to respond?

MR. ALLEN: Are you pointing at -- Steve Allen, IURC. John, I just wanted to get your attention. I've emailed that definition to you.

MR. DANNER: All right. Alan?

MR. MAYBERRY: You know, we'll consider it. If you want to bring something up for consideration, you know, after we leave here, we can do that.

MR. DANNER: Okay. May I ask? Is it the will of the committee, though, that we have, that we include a definition of distribution center in the rule? It looks like it's, the committee is pretty unanimous on that point.

So then the question is which

definition is preferred, especially keeping Cheryl's comments in mind. Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount. I know we don't like to wordsmith. But if we could get John to put that definition on up there and let us look at it, we might be able to put this thing to bed today.

MR. DANNER: All right. All right. And then, Cheryl, is your tent up? Okay.

MS. CAMPBELL: I'm sorry.

MR. DANNER: That's all right. Sara?

MS. GOSMAN: Rich, I'd just like to go back to the example that you gave to the committee to help me understand why in that context a definition would be helpful.

Could you explain that again to me, and perhaps, if you wouldn't mind, whether the two definitions that are on the table right now, whether they would affect the issue that you're bringing up here?

MR. WORSINGER: Sure. Rich Worsinger, Rocky Mount. Would the staff put that -- no, the

picture up there.

So, in this example here, in every other state, that would be classified as a distribution line. But in Iowa, the IAMU I think it is, they interpret this, because a distribution center is not defined, they interpret this as a transmission line.

So that means this operator, which serves a total of 198 customers, has got to operate and maintain that line at the higher standard of a transmission line. And so that's, brings along with it higher costs. And then those costs are borne by those 198 customers. And it's just, it's overkill.

MS. GOSMAN: Thank you so much for helping me to understand this. So the, it's the gate station that's here that's not being considered the distribution center?

MR. WORSINGER: Rich Worsinger, Rocky Mount. I believe it's the, that line that's depicted there. The yellow line is being characterized as transmission pressure that feeds

the gate station.

And the root of the problem is that there is no definition of distribution center.

MR. DANNER: Cheryl?

MS. CAMPBELL: So would the definition, right, that's proposed, would that solve this, because I hear what you're saying, right. The PIR on this is 17 feet, right? And it looks to me like it's a very rural, farming area, if I can read the -- right? So I'm seeing very little risk, right?

So will the definition, as proposed, of distribution center fix this problem, because if it does not, then we've not, right, we've not helped anything?

I mean, I get the point here. We've got a very small system, very small PIR. The risk is incredibly small. We don't need the higher, right, the higher standard.

But if we're not going to fix this problem with the definition we're proposing, then that doesn't necessarily help.

MR. DANNER: But the definition that we've heard from Steve, where it basically, it's based on retail customers as opposed to wholesale customers, probably would clarify for that particular utility. Rich?

MR. WORSINGER: A little more clarification on there. So, at the gate station, it's reduced down to 150 pounds. And then it doesn't get to Lorimor. And so that's where it's being interpreted as that's the distribution center.

So, yes, you're right, Cheryl. That line is, it's out in the country. So it's nobody around there. But it's being classified as a transmission line because they don't consider it a distribution center till it gets down there to Lorimor.

MS. CAMPBELL: So, under the proposed definition, pressure reduction location moves to that gate station where it gets dropped to 150 pounds. And the line now becomes a distribution line and is handled under DIMP. That's your

point?

MR. WORSINGER: That's correct.

MS. CAMPBELL: Okay. Thanks, Rich.

MR. DANNER: Okay. Ron?

MR. BRADLEY: Ron Bradley, PECO. Yes, that was a great conversation. And I appreciate it. So, for me, that underscores the need for a distribution center definition or a distribution definition, distribution line definition, because without that, you're left with the transmission line definition that we have.

And you don't, in that example, you don't, you basically check off number 2, definitely operating not at a hoop stress of 20 percent SMYS. And you check off number 3, unless Lorimor is a storage field, which it's not. It's a community of 199 people.

And it sounds like the regulator there said basically, well, prove that it's not a distribution center. You got no way of telling me it's otherwise. Therefore, you know, enter into this set of new standards for these people.

So I get that. I definitely believe we need to have a definition for distribution center.

The only other thing I would comment on relative to the, sort of backing up to the transmission center, the added language that connected in the transmission proposal. I apologize for jumping a bit. But the added language -- oh, it's up there -- or connected series of pipelines, I haven't settled in my head. But it feels like it could take you down a path that's not intended in this case.

I don't have many situations where I have transmission pipeline that goes in and out of distribution kind of systems. My network is a little bit different.

But I can imagine there being an area where you could maybe call something that was intended to be distribution transmission or not. I'm not sure.

Steve, maybe you can clear it up for me. Maybe I'm reading it wrong. The adder of

the or connected series of pipelines, I'm not 100 percent following it.

MR. McLAREN: This discussion came about because of some enforcement actions in Alaska and where the enforcement case ruling was that this one line was not a transmission line because it connected to another transmission line, and where clearly in our case, in our viewpoint was that these were all transmission lines. And the ruling went against us.

We have looked at other cases like that and through the history of the definition of transmission line over the years. And this is, what we came up with is seeming acceptable over that history and to solve that point, that a transmission line can, indeed, connect to another transmission line. That is the intent. Thank you.

MR. DANNER: Robert?

MR. HILL: Yes, Robert Hill, Brookings County, South Dakota. I agree. I mean, we've got a 42-inch pipe, and then we got a 10-inch,

another pipeline coming out to a big gas power energy plant. And both of those are considered transmission lines. So this language makes sense to me at least.

MR. DANNER: Okay. Cheryl?

MS. CAMPBELL: So I'm probably going to get everybody to cringe. But I'm going to go back to this idea that everything's got to be in one of three buckets, right?

So, I mean, if we can agree on what a distribution is and we can -- well, maybe we can't agree on what a gathering is. I mean, can we just say --

(Laughter.)

MS. CAMPBELL: Instead of wordsmithing connected lines, I mean, honestly, they have to be one of those three buckets. Is there anything else in the industry other than those three buckets? I mean, you got to be a gathering line, a transmission line, or a distribution line.

And if we can agree on sort of two out of the three, then does not the third become

everything else, just to make it simple?

MR. DANNER: John's going to answer that. John?

MR. AIREY: Let's make it four. Production line.

MR. DANNER: Okay. We have more buckets now. All right. Any other comments on this language? Steve?

MR. ALLEN: Thank you. Steve Allen, IURC. Some of the concerns expressed by the public, taking the definition of transmission line from operating at a hoop stress of 20 percent or more of SMYS to has an MAOP of 20 percent or more of SMYS. Humor me, and help me to understand the difference, please, actually why it was changed to MAOP.

MR. DANNER: Steve?

MR. NANNEY: Well, first of all, it's like I think the public comment we got. You can put pipe in. You can do a pressure test to establish an MAOP. But you can operate it at a pressure less than that. You can operate it at

80 percent of that. You can operate it at 50 percent of that. And that can be your operating pressure.

The problem with it is is you can raise that from time to time. You can go 20 years and be at that lower operating pressure and then one day decide we're going to raise it 20 percent. And it could have been 20 years that you haven't raised that.

So the thing of establishing MAOP versus operating pressure, well, is it operating pressure today? Is it operating pressure ten years ago? Is it operating pressure ten years from now? So that was the point in putting something that we know what it sets up.

You can always say my MAOP is a number less than that established. If you establish it at 700 pounds, you can always establish it at a number less than that.

Also, one reason that we also did it was at the time we were writing the rulemaking we have had the issue of the MAOP at San Bruno. And

so we were trying to make sure that we established and we had a set MAOP, and we didn't have where folks were raising or lowering it, that the MAOP would be established.

So, with the issue that we had seen at San Bruno on the seams, on the pressures there, we had decided that we would be more specific in making it MAOP versus operating pressure that was not defined.

MR. DANNER: All right. Alan?

MR. MAYBERRY: Just a couple of thoughts here. Well, first off, you know, I had mentioned this. I think, you know, you could guide us and tell us to consider, you know, the language you have up here related to distribution centers.

I'm not so sure. You know, having dealt with this issue and, you know, interpretations related, you know, from the state of New Mexico to eastern part of the U.S., I'm not even sure this language here would really address it the way you'd like for to put it to

bed.

I think there are a lot of nuances here. And therefore, I'd say, well, just, you know, have us consider this. We'll take it under advisement and go from there.

But, and I think that's why we were suggesting perhaps to just, let's park this and deal with it at a later time outside of this rule since the rule is mainly focused on transmission.

But I'm not so sure what you have there will put, you know, will definitively take every question out of, you know, what's a distribution center and what's not.

MR. DANNER: All right. Cheryl, and then Sara.

MS. CAMPBELL: So I understand where you're coming from, Alan. I want to, I do want to just vocalize support for number 4 up there under transmission line, because I recognize that it might make some people question why it has been proposed. So I'd just like to vocalize it so that people understand.

And I think that some operators have lines that operate in a more urban or suburban environment. And they meet -- nobody would say that they're a transmission line, right? I mean, they're clearly downstream of a distribution center.

Yet, the number of people around them would suggest that the risk profile is high, right? So operators may choose to maintain those lines as if, at a higher standard, right, the higher transmission standard.

I think that voluntary designation provides an operator with a way to say I recognize the risk profile of this pipeline. And I want to take care of it at this higher standard and make sure that their state regulatory body sees that, right, and they can have a good conversation about that, and frankly, you know, have a good financial conversation about that as well.

So, again, I just wanted to vocalize some support for that and explain why it's there.

It's not requiring anybody. It's just saying, if you have a pipeline that you are very concerned about and choose to designate it at a higher level because of its risk profile, let's allow an operator the ability to do that.

MR. DANNER: All right. Sara, and then John.

MS. GOSMAN: So I want to support this idea that we're going to make this definition more stable by using MAOP, that I think the way we want to treat definitions is to make sure they don't change based on, you know, characteristics today operationally versus tomorrow. And that seems to me like a good approach.

In terms of defining distribution center, I would feel more comfortable recommending that PHMSA consider the definition without giving them that specific industry language here. And part of it is I'm a little worried about the used primarily to deliver gas to customers who purchase it for consumption as opposed to those who purchase it for resale.

I just think there should be some wordsmithing carefully about how this definition might be constructed. And I think that's -- I would prefer to defer to PHMSA on how they're going to put together that language.

MR. DANNER: So, John, before I get to you, just my comment on that is I think that that's what this does. It does say include a definition of distribution center and consider revising the definition along the lines of what's down at the bottom.

It might be a little prescriptive in that it says, you know, revising it with that definition. Maybe we just want to say taking into account that definition.

All right. So, John?

MR. AIREY: I just wanted to ask Cheryl a question, if she was focused on examples such as the DJ Basin.

MS. CAMPBELL: No, I wasn't. It wasn't the DJ Basin I was thinking specifically of.

I was actually thinking about a pipeline that we own in downtown St. Paul, Minnesota that operates at a 300 pound MAOP and about a 15 percent SMYS. So technically it's a distribution line.

But I guarantee you that 2 or 300 pounds of blowing gas in an urban environment is a really bad day. So we would prefer to ILI that line.

MR. AIREY: I think the same issue has arisen around Denver --

MR. DANNER: Yes, speak into the microphone.

MR. AIREY: -- in an urban environment. So I thought that's what you were suggesting.

MS. CAMPBELL: I have several in Denver that are just like that.

MR. AIREY: Yes. Okay.

MR. DANNER: All right. Thank you. Rich?

MR. WORSINGER: Rich Worsinger, Rocky

Mount. Alan, you bring up a good point. I think we see different comments around the room that we all want to get this done. We see the value in defining a distribution center. But we also realize we need to get it right. And I think we're close.

Do you think this would be enough time from this meeting to the June meeting that we can, PHMSA can come back to the committee with a recommendation, recommended language that they're comfortable with?

MR. AIREY: Well, here again, I'm not too thrilled about coming back to the committee to -- you know, I'd rather get the direction or get the guidance, you know, say to consider and that we would come back.

We could brief the committee at a later date. But honestly, I really want to get your guidance and keep moving on it. I prefer to do that, you know.

MR. WORSINGER: You mean get our guidance today?

MR. AIREY: Yes.

MR. WORSINGER: Got you.

MR. AIREY: Yes.

MR. DANNER: So, I mean, without having another vote on it, though, would you be willing to come and brief us on the language that you've drafted?

Yes, go ahead, Steve. So, Alan?

MR. MAYBERRY: I mean, we're really looking for guidance from the committee. And, you know, we take that under advisement as we develop the final rulemaking. But even if we were to brief you, I mean, it could change even beyond that point. It's just --

MR. DANNER: Of course.

MR. MAYBERRY: Yes, it's always subject to change.

MR. DANNER: Well, yes, and I think we're all cognizant of the fact that we are an advisory committee. And then it's up to you to accept, reject, or modify our advice.

So, but I think we are all interested

if there would be an opportunity where we could provide additional feedback if the final language might be improved.

So, all right. Steve?

MR. ALLEN: Steve Allen, IURC. So, if we reverted back to the original definition of distribution center that PHMSA came up with in the initial Notice of Proposed Rulemaking, does that make it any easier or -- I mean, I think that the industry definition certainly has more detail to it.

But at the same time, when you ask me which one I like better, well, you know, the initial language was a lot better than what we had, which was nothing. And I think, as a state regulator, I could probably do with either one.

So, if going back to the initial language that you had out there and then suggested to withdraw from the rule, if we reverted back to that language, does that help the committee get over this hurdle?

MR. DANNER: So I think what we've

done, though, is that there are now two definitions with which they can draw from. And I think that that's -- our guidance is basically, okay, here are a couple definitions, do your best. And then we asked would you be able to share what you come up with. And I think the answer to that is, no, we're going to, we'll surprise you.

(Laughter.)

MR. DANNER: And trust us, right? So, John is -- I don't know. We can, you know, we can gang up on him in June if -- but are we willing to move on today? Steve, and then Rich.

MR. ALLEN: Steve Allen, IURC. I really would like to move forward on something to provide them some guidance. And let's move on.

MR. DANNER: Okay. I think we have provided them guidance. Do you agree? Okay. Rich?

MR. WORSINGER: Rich Worsinger, Rocky Mount. I guess my question, then, is how do we put this in the form of a motion. Do we say

either do it, we like this one or they could use that one or --

MR. DANNER: Well, the motion in front of us simply says include a definition and consider the following definition, which was provided by industry.

So they have the benefit of that definition now. They have the benefit of the original NPRM. They have the additional benefit of whatever else they want to come up. But I think that that's the instruction we've given them.

So, if -- I don't know that, unless we want to come up with more precise language for them, if we actually want to give them a proposed definition and say this is it, I think we've given them all the guidance that they're going to get.

MR. WORSINGER: Alan, does that work for you?

MR. MAYBERRY: I think so. I was just going to suggest, I mean, outside of this one

issue, there's so much that there is consensus on in this group.

And that's, and this one, like I had mentioned, I'm not so sure what I see before, you know, me here, the words there would really, we'd still end up with -- you know, it wouldn't be as definitive as a distribution operator might want it to be.

Therefore, it might, you know, be best to table it. But if you want us to consider it, we would consider, you know, your advice.

MR. DANNER: Rich?

MR. WORSINGER: Rich Worsinger. Just to add the comments, I know this is a very important definition to industry, to AGA. And I can tell you, it is probably the most important item that we're talking about during these three days to APGA.

MR. DANNER: So do you want us then to come up with a definition and ask them to include that definition, or are you okay -- I mean, it looks like what we're going to get is going to be

some kind of a hybrid of these two definitions.

MR. WORSINGER: I think we've given PHMSA our guidance. You know, Steve certainly mentioned a lot. And I know AGA's reps have mentioned. I've given it our thoughts. I see Alan wants to get this done also. I think if we have the recommendation up here and that's what we pass on to PHMSA, I'm comfortable with that.

MR. DANNER: Okay. So is that the will of the committee? We've got a proposal in front of us on the left side up there. Is -- Ron?

MR. BRADLEY: Yes, I just wanted to -- thank you. Ron Bradley, PECO. I wanted to make the same statement that -- so there is a recommendation from industry on the board for review. I'm fine with taking that forward for a discussion. I mean, I'm fine with that being the voting and the recommendation.

MR. DANNER: Okay. Any other discussion on this before we take volunteers with good eyesight to make a motion? All right. It

looks like we're ready for a motion. Who feels comfortable reading it? Rich, thank you.

MR. WORSINGER: Voting language for -- Rich Worsinger, Rocky Mount.

Voting language for definitions 192.3. The proposed rule, as published in the Federal Register and the Draft Regulatory Evaluation with regard to the proposed definitions for transmission line and distribution center are technically feasible, reasonable, cost effective, and practicable if the following changes are made. Revise the definition for transmission line to read as follows.

Transmission line means a pipeline or connected series of pipelines other than a gathering line that, one, transports gas from a gathering line or storage facility to a distribution center, storage facility, or a large volume customer that is not downstream from a distribution center, two, has an MAOP of 20 percent or more of SMYS, three, transports gas within a storage field, or four, is voluntarily

designated by the operator as a transmission line.

Note, a large volume customer may receive similar volumes of gas as a distribution center. And it includes factories, power plants, and institutional users of gas.

Include a definition for distribution center and consider revising the definition per the definition provided by the industry and read aloud by Member Allen during the meeting on March 27, 2018 as follows.

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example, one, at a metering location, two, a pressure reduction location, or three, where there is a reduction in the volume of gas such as a lateral off a transmission line.

MR. DANNER: All right. Is there a second?

MR. ALLEN: Steve Allen, IURC. I

second.

MR. DANNER: Okay. Any further discussion on this before we go to a roll call? All right, Cheryl, let's go to roll call.

(Off-microphone comment.)

PARTICIPANT: Aye.

MS. WHETSEL: Dave Danner?

MR. DANNER: Aye.

MS. WHETSEL: Diane Burman?

MS. BURMAN: Aye.

MS. WHETSEL: Sara Longan?

MS. LONGAN: Aye.

MS. WHETSEL: Terry Turpin?

MR. TURPIN: Aye.

MS. WHETSEL: Cheryl Campbell?

MS. CAMPBELL: Aye.

MS. WHETSEL: Andy Drake?

MR. DRAKE: Aye.

(Off-microphone comment.)

PARTICIPANT: Aye.

(Off-microphone comment.)

PARTICIPANT: Aye.

(Off-microphone comment.)

PARTICIPANT: Aye.

MS. WHETSEL: Motion passes.

MR. DANNER: All right. Motion passes. It is 4:22. We're going to move ahead into repair criteria. So I will --

(Off-microphone comment.)

MR. DANNER: All right. I don't think we're going to finish repair criteria today. But we'll get started.

MR. NANNEY: We're at slide, we should be at slide 137. And we're going to go through slide 164. And then we will turn it back over to the Chairman. So --

Again, some of this, when we had our last meeting, we reviewed this. But we are going to highlight it again this afternoon. Then we'll get into more criteria when we start back on Wednesday morning.

The repair criteria revisions are in Section 711, 713, and under the IM section 933. And again, what PHMSA was, the issue we were

trying to do was greater assurance is needed, that injurious anomalies are repaired before they can grow to the sizes leading to leaks or ruptures.

PHMSA proposed to modify the repair criteria to include additional anomalies under both the immediate and one year conditions for HCAs to include criteria for cracks in response to NTSB recommendation on hazardous liquid lines, apply the HCA criteria to non-HCAs with a tiered response time for non-immediate conditions. Defects requiring a one year response in HCAs would require a two year response in non-HCAs.

We were looking at adding definitions for significant stress corrosion cracking in the pipe body, seam cracking in the weld seam, wrinkle bend, and hard spot.

And the basis, again, was inspection experience identified weaknesses and repair decisions in response to ILI data. Some injurious anomalies and defects are not identified and remediated in a timely manner.

Again, going to slide 139, what was the proposed repair criteria. If you look at this slide, everything on the left-hand side in the dark blue was existing anomaly criteria. And you can see here it was for HCAs only.

And that was a predicted failure pressure, a PFP, less than or equal to 1.1 times MAOP was an immediate. A dent with metal loss, cracking, or a stress riser was immediate. And any other anomaly requiring immediate action was an immediate.

And then there was a section that we had no requirements that you'll see now we were proposing in the notice requirements.

The anomaly type over to the right-hand side in the orange color was the PFP less than, equal to 1.1 times the MAOP. It would be the same for HCAs, new for a non-HCA. It would be immediate. A dent with a metal loss, cracking, or a stress riser would be an immediate. Any other anomaly requiring immediate action would be immediate.

A metal loss greater than 80 percent of the wall thickness, a metal loss affecting weld seams, as you can see the type, would be immediate, and then stress corrosion, cracking, and selective seam weld corrosion.

Going to slide 140, some other proposed criteria we had. Again, what was existing is on the left-hand side. A smooth dent greater than six percent, in other words, a top side dent was one year. A dent with greater than two percent at the weld was one year.

What we were proposing for HCAs and non-HCAs, which are on the right-hand side, would be a smooth dent greater than six percent. A top side dent would be the same as now, one year for HCA, two years new for a non-HCA. A dent greater than two percent at the weld would be the same, one year for an HCA, which is what it is now, two years, which would be new, for a non-HCA.

The predicted failure pressure less than or equal to 1.1 times a Class 1, 1.39 Class 2, 1.67 Class 3, and 2 Class 4, again, would be

one year, which is new, for an HCA, two year new for a non-HCA.

General corrosion would be greater than 50 percent wall loss, one year for, which is new, for an HCA and two years for a non-HCA. Metal loss greater than 50 percent at a crossing where there's a circumferential girth weld, et cetera, one year for HCA, two years for non-HCAs. A gouge or groove greater than 12-1/2 percent, one year for HCA, two years for a non-HCA.

MR. McLAREN: You said 1.1 for Class 1 --

MR. NANNEY: Okay.

MR. McLAREN: -- instead of 1.25.

MR. NANNEY: Okay. Any indication of crack or crack-like defect that is not an immediate condition, one year new for HCA, two years new for a non-HCA.

And going back, Chris said that on the PFP for Class 1 I said 1.1. It should be less than or equal to 1.25.

Going to slide 141, again, on what was

existing versus proposed, you can see here everything on the denting, a bottom side dent greater than six percent was monitored for HCAs only.

A top side dent greater than six percent with an analysis of critical strain levels not exceeded was a monitored condition. And dent greater than two percent out of weld where analysis demonstrates critical strain levels not exceeded was a monitored.

And you can see over on the right-hand side the new criteria would be the same as it's been for HCAs, new requirements for non-HCAs at the two year type limit.

And then down below on two percent at the dent, same for HCAs, but not applicable for non-HCAs.

Going to slide 142, the public committee comments on the repair criteria, some of it that we heard during our March 2nd conference meeting was revise the rule to provide separate requirements for ILI anomaly response

and repair, in other words, remediation.

And PHMSA's reply there was the long-standing integrity management rule allows operators up to 180 days for completion of the ILI assessment to perform any analysis needed to declare discovery of defects based upon ILI anomalies identified.

The IM rule also requires prompt repair of discovered defects on a defined schedule based on the severity of the discovered defect. And last, PHMSA believes 180 days is adequate timeframe for the initial response to ILI results.

Slide 143, some other public committee comments that we heard on March 2nd on the repair criteria is revise the rule to provide separate requirements for ILI anomaly response and repair or remediation.

And again, PHMSA's comment there is, in the proposed rule, PHMSA had proposed to revise the IM rule to allow operators to submit a notification to PHMSA when more 180 days is

needed for initial response. The same standard would apply in non-HCAs, except for a notification would not be required.

And the last comment is once the as-called defect has been declared to be an immediate or one year or two year discovery, the defect must be presumed to require repair based on the best available information and analysis of the ILI data.

Slide 144, again, this is public committee comments on the repair criteria from our March 2, 2018 meeting. Revise the rule to provide separate requirements for ILI anomaly response and repair or remediation.

And PHMSA, again, continued is at the time of discovery the operator must schedule the anomaly for excavation and repair. Also a pressure reduction is put in place for immediate conditions by the operator.

The rule allows operators to recharacterize the defect as one that does not require repair based on in-the-ditch direct

measures or measurements.

And lastly, revising the rule language to address response and repair in different paragraphs would not alter the timeline for discovery, excavation, and repair. And this approach has been in place since inception of the IM rule in 2003.

Slide 145, again, public committee comments on repair criteria from our March 2, 2018 meeting is, the comment was allow sound engineering judgment or conservative assumptions.

Requiring Section 607 to verify information without TVC records for all repairs and pressure reductions is impractical. TVC records are appropriate for MAOP reconfirmation, but not for repair response decision making.

PHMSA's response, determination of predicted failure pressure, PFP, in response to detection of pipeline defects is closely related to MAOP. If pipe could fail at pressures below or near MAOP, the operational MAOP safety limit to protect the pipeline is compromised.

The Act Section 23 requirement is to verify records was broader. The purpose of the verification shall be to ensure the records accurately reflect the physical and operational characteristics of the pipelines.

Going to slide 146 and just repeating PHMSA's response is calculation of PFP should be based on known physical characteristics that are substantiated and documented on TVC records.

However, the intent of the proposed rule is to allow operators to conservatively use material strength for Class A pipe, which is a 30,000 psi SMYS if SMYS is unknown.

PHMSA also recognizes that in cases where TVC records are not available operators must have a basis for grading the ILI logs. PHMSA suggests allowing operators to use the information upon which the current MAOP is based upon properties can be verified using the material documentation process specified in Section 607.

Slide 147, again, this is a public

committee comment on repair criteria on our March 2, 2018 meeting. Use of class location safety factors for calculation of a short-term pressure reduction as a safety precaution in response to an immediate condition is too conservative.

PHMSA's response, PHMSA suggests modifying Section 713(d)(2) to strike the phrase the lower of. The effect would be that operators would not always be required to use the class location factors when --

(Technical interference.)

MR. NANNEY: Hello? Now it came back on. Okay.

Our operators may choose to use either the calculated safe operating pressure based on class location, 80 percent of the operating pressure at the time of the discovery, or 1.1 times the predicted failure pressure based upon situational safety impacts to the public and operator personnel.

Going to slide 148, and this is comments on specific repair criteria for dents.

Slide 149, and again, this is public committee comments on repair criteria on dents from March 2, 2018. PHMSA should allow operators to use ECA, engineering critical analysis or assessment, to evaluate dents.

PHMSA's response, the original repair criteria for dents were developed in the early 2000 timeframe for both hazardous liquid and gas integrity management rules. Both in-line inspection technology and analytical techniques to assess dents have advanced significantly since that time.

PHMSA has gained confidence in applying ECA techniques to analyze dent defects through recent application of dent ECA and special permits.

Consistent with applying proven analytical techniques to evaluate corrosion metal loss and cracking defects, PHMSA suggests including a dent ECA procedure in the final rule as shown on the next slide.

Slide 150, and again, this is PHMSA's

response on ECA for denting.

PHMSA, the summary of the suggested ECA for denting. First of all is evaluate the potential threats for the pipe segment in the vicinity of the dent, including movement, loading, and cathodic protection, two, review the high resolution MFL and high resolution deformation in-line inspection data for damage in the dent area in any associated weld region, three, perform pipeline curvature-based strain analysis using recent high resolution deformation inspection data and compare dent profile between the recent and past high resolution deformation inspections to identify significant changes in dent depth and shape.

Slide 151, and this is continuing, is identify and quantify loads acting on the dent for a basis of the ECA, evaluate strain level associated with dent in any welds using finite element analysis, and calculate the plastic strain limit damage factors to infer the possibility of a crack, and last, estimate the

fatigue life of the dent using FEA with the operational pressure data in different fatigue life prediction models, which must have a reassessment safety factor of at least 2.

And the last slide on this -- I think I said lastly on the slide before. But it is PHMSA suggests that operators be allowed, but not required, to use ECA analysis for the following dent-related repair criteria.

First would be a dent with indication of metal loss, cracking, or a stress riser, smooth top side dent greater than 6 percent diameter, or a 1/2-inch deep for a diameter of less than 12 inch, a dent greater than 2 --

(Technical interference.)

MR. NANNEY: Now it's back on. Okay. A dent greater than 2 percent in diameter, or a 1/4-inch deep for diameters less than 12 inch that affects pipe curvature at a girth weld or a seam weld.

And again, dents analyzed by ECA but shown not to exceed critical strain levels would

be included in the repair criteria as monitored conditions.

Slide 153, again, this is public committee comments on the repair criteria from our March 2, 2018 meeting. And again, the comment was repair criteria for dents with metal loss should distinguish between top side and bottom side dents similar to the repair criteria for smooth dents.

PHMSA, the dent with metal loss criterion was part of the original integrity management rule in 2003.

PHMSA recognizes that top side dents represent the need for more urgent response than bottom dents. Some existing HCA dent repair criteria already make this distinction. PHMSA suggests applying this concept to dents with metal loss in non-HCA areas similar to smooth dents.

Going over to slide 154, and again, it's continuing from the slide before comments. Also, to reduce unnecessary excavation, PHMSA

suggests revising the immediate condition as follows, number one, allowing engineering critical assessment, in other words, ECA, to analyze the dent anomalies with indications of metal loss, cracking, or a stress riser and prioritize repair criteria as follows.

An immediate would be top side defects that exceed the critical strain levels. Two year would be bottom side that exceed critical strain levels. And monitored would be defects that do not exceed critical strain levels.

Slide 155, again, this is from our public committee comments on repair criteria from the March 2, 2018 meeting. The comment was industry commented that the proposed criterion of a gouge or groove greater than 12-1/2 percent of nominal wall thickness is duplicative and addressed by dent with metal loss and cracking criteria.

And PHMSA, PHMSA acknowledges that the proposed criteria using engineering critical assessment to analyze dents and cracks would

adequately address gouges and grooves and suggests deleting this repair criterion on that basis.

Slide 156, I think that was -- I was going to 164, wasn't I? Okay.

Now we'll go and talk about repair criteria for cracks. And this is slide 157. And again, this is from public committee comments on repair criteria from our March 2, 2018 meeting.

And the comment was delete the definitions of significant crack defects and use the alternative cracking criterion exclusively that was proposed by PHMSA at the March 2, 2018 meeting, which is much more practical.

PHMSA's comment, PHMSA agrees that having the originally proposed definition and an alternative repair criteria could be confusing.

To address crack defects, PHMSA suggests, number one, delete the two definitions, significant stress corrosion cracking and significant seam cracks, and drop the suggestion to define significant selective seam weld

corrosion, second, consolidate all cracking related repair criterion to a single repair criterion that applies to any crack-like defect.

Slide 158, again, this is committee comments on repair criterion from our March 2, 2018 meeting on cracking. And the last item there was utilize the alternative criterion PHMSA introduced at the March 2, 2018 meeting, which would allow ECA analysis of crack defects.

Slide 159 --

(Technical interference.)

MR. NANNEY: Is it working now? Yes. Okay.

The comment was industry commented that PHMSA proposed criteria for immediate repair of crack defects was too conservative and suggested 70 percent crack depth or predicted failure pressure of less than 1.1 times MAOP.

PHMSA, based on the proposed immediate repair criteria for cracks, successful application of comparable criteria and special permits, PHMSA believes 70 percent and 1.1 times

MAOP does not provide an adequate safety margin.

Our ILI tools for detection of cracks do not have the precision needed to allow through-wall cracks slightly, in other words, less than 70 percent or a calculated PFP slightly greater than 1.1 times MAOP, to be treated as a one year HCA or as a two year non-HCA condition.

Cracks can grow very rapidly. And last, material properties can have a dramatic effect on safe pressures as illustrated on the next slide, slide 160.

And the thing there, this is based upon, just showing if you had a 70 percent pipe seam crack, and again, you are operating in a Class 3 area, what it would look like based upon the criteria we were talking about earlier, the one-foot pound or four-foot pounds or, as PHMSA had in black, an alternative of two-foot pounds.

And you can see from the blue line to the black line to the red line what that shows you as far as pressures underneath your MAOP of 676, which is shown by the red line. And this is

a 70 percent crack.

And again, the next is showing the same criteria if it wasn't in the pipe seam or pipe seam weld. It was in the pipe body.

Going to the next slide, which is slide 162, again, this is public committee comments on repair criteria from our March 2, 2018 meeting. Industry commented that PHMSA's proposed criteria for immediate repair of crack-like defects was too conservative and suggested 70 percent crack depth or predicted failure pressure of less than 1.1 times MAOP.

PHMSA, based on successful application of comparable cracking criteria, PHMSA suggests the following crack criterion for an immediate condition, a crack depth plus metal loss greater than 50 percent of the pipe wall thickness, or crack depth plus corrosion is greater than the inspection tool's maximum measurable depth, or the crack anomaly is determined to have or will have prior to the next assessment a predicted failure pressure determined in accordance with

the ECA fracture mechanics procedure that is less than 125 percent of the MAOP.

Slide 163, again, this is public committee comments on repair criterion from the March 2, 2018 meeting. Industry commented that PHMSA's proposed criteria for a one year or two year repair for crack-like defects was too conservative and suggested 50 percent crack depth or predicted failure pressure of less than 1.25 times MAOP.

PHMSA, based on successful application of comparable cracking type criteria, PHMSA suggests the following crack criterion for one year, two year conditions, one, a crack depth plus metal loss greater than 50 percent of the pipe wall thickness, or the crack anomaly is determined to have or will have prior to the next assessment a predicted failure pressure determined in accordance with the ECA fracture mechanics procedure that is less than 1.39 MAOP for Class 1 locations or 1.5 times MAOP for Class 2, 3, and 4 locations as appropriate.

Slide 164, Chairman.

MR. DANNER: So Alan has stepped out. I don't know if he wanted to keep going through corrosive metal loss. But it is 10 minutes to 5:00. This might be --

PARTICIPANT: There's about 15 more slides. So --

MR. DANNER: There's about 15 more slides? Then why don't we proceed.

MR. McLAREN: These are the comments on the specific -- I'm Chris McLaren with PHMSA -- specific repair criteria for corrosion metal loss.

Committee comments from the March 2nd teleconference meeting we had was with the new repair criteria in 192.713 for corrosion defects, the corrosion repair requirements in 192.485(c) are duplicative, have the potential to create confusion, and should be deleted.

PHMSA's response is that the long-standing corrosion repair requirements are needed to address the repair corrosion defects on all

transmission lines.

The new repair requirements proposed in the NPRM have limited applicability. For instance, 192.711 and 713 only apply to transmission lines greater than 40 percent SMYS. And 192.933 only applies to high consequence areas.

PHMSA suggests retaining the corrosion repair requirements in 485 as proposed in the NPRM. However, PHMSA would also suggest including reference to 192.712 for evaluating corrosion in proximity to cracks or crack-like defects and for operators to make and retain records.

An additional committee comment was that the proposed criteria of corrosion greater than 50 percent of wall thickness is redundant to other repair criteria for evaluating corrosion metal loss defects using acceptable analysis techniques, for instance, B31G and RSTRENG.

PHMSA acknowledges that corrosion metal loss is addressed in other criteria within

the one year HCA and two year non-HCA repair criteria proposed and suggests deleting this criterion based on retention of the one year and two year repair criterion for corrosion metal loss, which will be addressed later.

Industry commented that the proposed criterion below is too conservative and duplicative of other corrosion repair criteria.

That example is the predicted metal loss greater than 50 percent of nominal wall that is located at a crossing of another pipeline or is in an area with widespread circumferential corrosion or is in an area that could affect the girth weld.

PHMSA believes that this criteria is appropriate for a one year HCA and two year non-HCA condition because the circumstances described represent higher risk.

Crossings with other pipelines are locations at which corrosion can grow faster than expected. Deep corrosion in an area of widespread corrosion is indicative of an active,

significant corrosion growth mechanism. And corrosion affecting a girth weld weakens the weld.

Industry made the comments related to the proposed criteria of corrosion metal loss affecting a detected longitudinal seam. If that seam was formed by a direct current or low frequency or high frequency electric resistance welding or by electric flash welding, the criteria should not apply to high frequency ERW.

The next or B, the criterion should clarify that the corrosion preferentially affects the long seam. And PHMSA should allow engineering critical assessment to analyze such defects to avoid unnecessary excavations.

PHMSA's response is on the next slide. And we suggest allowing, but not requiring, ECA analysis for the evaluation of corrosion metal loss affecting the long seam in 192.712. If the predicted failure pressure is less than 1.25 times the MAOP, the anomaly would be an immediate condition.

Scheduled conditions would be based upon being less than the reciprocal of class location design factor.

And PHMSA suggests inserting the word preferentially to assure that this criterion would not be applied to small corrosion bits near long seam. It would only apply to corrosion along the seam that could lead to slotting-type crack-like defects.

Additional public comments in the teleconference public meeting on March 2nd, a comment was to the use of class location safety factors for a one year HCA and two year non-HCA repair criteria is inconsistent with B31.8S, Figure 4.

PHMSA's response is that the goal is to reduce the rate of immediate repair condition. PHMSA suggests replacing reliance on Figure 4 with class location based safety factors for one year conditions and two years conditions.

B31.8S, Section 7, Figure 4 allows operators to not repair selected anomalies until

the defect has grown to a level of an immediate indication. Indications in the scheduled group are suitable for continued operation without immediate response provided they do not grow to the critical dimensions prior to the scheduled response is a quote out of, referring to Figure 4.

By not repairing anomalies until they grow to critical dimensions for an immediate condition, many anomalies could grow until they use up much of the safety margin and become immediate condition.

PHMSA believes that this is a contributing factor in explaining why the immediate repair rate has not dropped after completion of the baseline assessments and its scheduled assessments are allowed to grow until they become immediate conditions. This is illustrated on the slides that follow.

This is B31.8S, Figure 4, showing timing for scheduled responses for time-dependent threats, for operators implementing a

prescriptive integrity management plan.

You can see that that seven-year reassessment interval shows that, for that predicted failure pressure ratio how anomalies can grow to 1.1 for varying, for Class 1, and then Class 3 and 4 in the above 50 percent line.

Do we need any additional explanation at this time? All right.

PHMSA, in the Notice of Proposed Rulemaking, proposed criterias that would require an operator upon running an ILI tool or other assessment technology to assure that anomalies are repaired before they grow to an immediate condition prior to the next assessment.

This is, for instance, if the metal loss severity or predicted failure pressure for a Class 1 would be 1.25 times MAOP, and that would be a one year in an HCA or two years in a non-HCA. And that would -- likewise, as you go down, a 1.39 for a Class 2, 1.67 for a Class 3, and 2.0 for a Class 4.

By having these as scheduled

conditions, they should be able to be addressed in a more suitable manner without getting so close to the ultimate safety margin.

The table on the right provides the response time from Figure 4 showing that these varied response times often occur before the next assessment such that the anomalies at those predicted failure pressures are not assessed until the next assessment.

This is a graph showing our gas transmission incident history from 2004 to 2017. While leaks have increased and is, of course, the larger number in the green line above, it is really the failures per 10,000 miles of HCAs in the blue line and the significant incidents per 10,000 miles of HCA miles which would be the most telling, showing that that incident rate is not coming down and that those failures per miles of HCA continue to have rates that increase and/or stay at a higher rate, whereas that rate should be coming down if we were repairing those anomalies more rapidly in our opinion.

This graph shows the, is sort of a broken graph because that's the nature of data is data comes into us. And so it's important to look at the immediate repairs. And the dash line provides more of a two-year running average. And those immediate repairs performed total by, on transmission lines has sort of started to drop. And that's the data. It can be good or bad.

PHMSA has also noted that the trend in immediate repairs, red, has not decreased commensurate with the conclusion of the baseline assessment, blue, at the end of 2012.

It would have been more predictable to have seen those baseline assessments result in more immediate repairs and that we would subsequently during reassessment hope not to find as many immediate repairs, as is this case we were finding many times on the baseline assessments indicating that more remediation would be preferable.

Stop here? Thank you.

MR. DANNER: All right. We've had a

good presentation on repair criteria for dents and cracks and corrosion.

We will pick it up in the morning. And we'll go through the proposed repair criteria. And then we'll take public comment and have discussion and see if we can get through to the end of the agenda.

So we are in recess till tomorrow morning at 8:30.

(Whereupon, the above-entitled matter went off the record at 5:00 p.m.)

N

Q

C E R T I F I C A T E

This is to certify that the foregoing transcript

In the matter of: Gas Pipeline Advisory Committee

Before: US DOT

Date: 03-27-18

Place: Arlington, VA

was duly recorded and accurately transcribed under my direction; further, that said transcript is a true and accurate record of the proceedings.

Neal R. Gross

Court Reporter