US 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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MONDAY
MARCH 26, 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 1:00 p.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 telephone)
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:

HOWARD "SKIP" ELLIOTT, PHMSA Administrator

ALAN MAYBERRY, Associate Administrator for Pipeline Safety; Designated Federal Official

DRUE PEARCE, Deputy Administrator

CHERYL WHETSEL, Advisory Committee Manager

BRYAN CROWE

JOHN GALE, Director, Standards and Rulemaking

ROBERT JAGGER, Transportation Specialist

CHRIS McLAREN, Program Manager

STEVE NANNEY, Program Manager

SAYLER PALABRICA, Transportation Specialist

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

(1:01 p.m.)

MR. MAYBERRY: I think we're ready to get started, if I can have your attention.

Good afternoon, everyone, it's good to see you today. Thank you for your attendance at the Gas Pipeline Advisory Committee.

My name is Alan Mayberry. I'm the Associate Administrator for Pipeline Safety here at PHMSA. And under the Federal Advisory Committee Act I'll serve as the Designated Federal Official. As such, I'm the presiding official.

The chairman for today's meeting is the Honorable Dave Danner, Chair of the Washington Utilities and Transportation Commission. Before I turn it over to Dave, I had a couple of other housekeeping items to go through today.

First-off, I'd like to welcome two new members we have that complete filling the vacancies we have on our advisory committee.

First, I'd like to introduce Dr. Sara Longan, who is Executive Director of the North Slope Science Initiative for the Department of Interior, Bureau of Land Management, in Alaska. So welcome, Sara, and thank you for joining us.

I think on short notice flying all the way from Alaska to be here. So thank you for the warm, balmy weather which is actually cold here for us.

And then next, Mr. Jonathan Airey to my left. He is a retired partner with Vorys, Sater, Seymour, and Pease LLP. So, welcome, Mr. Airey. And thank you as well for joining us on such short notice.

And as you might have imagined, Sara represents the government side. However, Jonathan, or Jon, represents, he's a public member of the committee.

Also like to -- you'll hear from this person a little bit later -- but the Honorable Howard "Skip" Elliott, the PHMSA Administrator, to my right; and then as well Drue Pearce, our

Deputy Administrator, are in attendance today.

Very important items of note. The restrooms, first-off, are off to my left. Ladies rooms are straight across the corridor. Men's room to the left in back of that.

There are emergency exits. I need to point out a couple things related to that. First-off, you can go either to my left or to my right. Let's start with the ones to my right. You can go either direction, left or right, once you go through that corridor. And there will be exit signs at the end of the corridor that will direct you to go downstairs.

Let's talk about to the left here, because you'll have a little bit of construction going on out there, so one of the normal stairwells is blocked. But if you go out to the left and through the glass doors you probably came in, and take an immediate right and walk down to the lobby, that is the way to get out if you go to the left. So just keep that in mind. You keep going straight you'll be blocked by some

construction that's going on with the stairs area over there.

If you would silence your mobile devices just to minimize disruption, which I'm going to do right now just so mine doesn't go off.

And then related to audience participation and just general decorum, I know this is probably obvious but I need to say it anyway, is in order to complete the business of the advisory committees we ask that all parties hold their comments until we open the floor. Please keep your remarks brief, say, less than two minutes.

And, you know, I realize we may have in the, at least in the public have some service providers that, you know, really want you and need you to avoid any advertisements today if you will. You know, if I do hear advertisements, either the chair or I will cut you off. We may have to ask you anyway if you go on for too long to cut your comments short and, if necessary just

to keep the agenda moving.

And, please, if the comment's already been mentioned, you know, let's leave it at that unless there's a point that needs to be stressed, just again to keep the business moving and yet, you know, make sure we have enough time for everyone to comment with relevant points.

Also, there's an opportunity to present written comments. We have a docket number that we'll be -- that's actually we'll be sharing it to you in a bit, but it's PHMSA-2016-0136. That's the Advisory Committee docket where written comments may be submitted.

You know, this is a federal advisory committee meeting, as such committee members and members of the public are asked to preserve order and decorum during this meeting. No one shall either by conversation or otherwise delay or interrupt the proceedings or the peace of the committee nor disturb any member while speaking, or refuse to obey the instructions of the chair or the designated federal official. We are very

strict, and we will cut you off.

If someone chooses to be disruptive, we will ask you to leave.

I think that covers the housekeeping I had up front. You know, we have a good bit of business to cover over the next two-and-a-half days, so at this point I will turn it over to our chair for the day, the Honorable David Danner. David.

MR. DANNER: Thank you very much, Alan. And thank you, Administrator Elliott.

My name is Dave Danner. As Alan said, I'm the Chair of the Washington Utilities and Transportation Commission. And I am chairing the meeting today. So I will call this meeting of the Gas Pipeline Advisory Committee to order.

A reminder that this meeting is being recorded. A transcript will be produced for the record. And a transcript and presentations will be available on the PHMSA website, meeting Number 132, one thirty-two. And it's on the eGov docket at www.regulations.gov.

And as Alan said, the docket number for this meeting is PHMSA-2016-0136.

So, as we move forward today I want to remind members, presenters, and others to introduce yourself each time you speak so your comments can be acknowledged in the meeting transcripts. And for members, please set your tent card on end when you wish to make a comment and I will call on you in the order as your tent cards go up.

We'll now take roll call. Cheryl, can I ask you to, to do that?

MS. WHETSEL: Okay. Steve Allen.

MR. ALLEN: Here.

MS. WHETSEL: Dave Danner.

MR. DANNER: Here.

MS. WHETSEL: Diane Burman. Diane's going to be joining us by phone, so we'll check on her.

Sara Longan.

MS. LONGAN: Here.

MS. WHETSEL: Terry Turpin.

MR. TURPIN: Here.

MS. WHETSEL: Cheryl Campbell.

MS. CAMPBELL: Here.

MS. WHETSEL: Andy Drake.

MR. DRAKE: Here.

MS. WHETSEL: Ron Bradley.

MR. BRADLEY: Here.

MS. WHETSEL: Rich Worsinger.

MR. WORSINGER: Here.

MS. WHETSEL: Chad Zamarin.

(No response.)

MS. WHETSEL: He is not here.

Jon Airey.

MR. AIREY: Here.

MS. WHETSEL: Mark Brownstein is not here.

Robert Hill.

MR. HILL: Here.

MS. WHETSEL: Sara Gosman.

MS. GOSMAN: Here.

MS. WHETSEL: Rich Pevarski. Okay, Rich is not here today.

Okay, thank you.

MR. DANNER: All right. And Alan just informed me that Diane Burman is on the phone today. Welcome, Diane.

Okay. And now up on the screen before you you see the agenda for today's meeting. We are going to have a discussion of gas gathering and the strategy for addressing the issues relative to gas gathering pipelines in the proposed rule. And we will have briefings and, hopefully, a vote on outstanding issues. That includes MAOP reconfirmation and related issues, IM clarifications, definitions, and repair criteria.

And it is our hope that we will adjourn with some good results to show on Wednesday at 5:00 o'clock.

So, with that I will turn it back over to Alan and he will -- Oh, okay, in that case we are going to go to Skip Elliott, the PHMSA Administrator.

MR. ELLIOTT: So, good afternoon,

everyone. This is a little bit different than you're probably used to, but I learned a long time ago when I started to talk to groups that it was very rude for me to talk to group with my back to most of you. So I asked my team if for today's comments I could come up here so when I address not only the committee that I can address all of you that are here representing the public and interested parties as well.

First of all, good afternoon and thank you for all coming out for this meeting. I believe the strength in this committee lies in its diversity. You come from across the country and represent many facets of our pipeline safety stakeholders. And it's that breadth of experience that convinces me that our shared goal of zero incidents is not mere aspiration, in fact it can be achieved.

None of us here is perfect but perhaps all of us can be. I'm personally committed to the safety goal, and I know that you all here today share that same goal with me.

I enjoy these opportunities to speak with others who accept the challenges of chasing perfection. There's a problem for me here though. As a safety administrator, boring is the highest good because no news in my business is good news. On the other hand, as a public speaker boring is less desirable, and a fear, however, that you all may be about to discover that as a public speaker I'm an excellent safety administrator.

This is the fifth meeting on our gas transmission rule. And I applaud your dedication to pipeline safety.

I'd also like to also extend my welcome to the new members of the committee.

I'm happy to see all of you again today. And the last time I addressed this committee I was getting my feet wet as PHMSA administrator. Since then I've had the opportunity to meet with many of our stakeholders, as well as learn more from PHMSA's hard-working safety professionals. I can tell

you that everything I've seen has made me more impressed with our pipeline infrastructure's admirable safety record.

Our job as a regulator is to establish minimum safety standards. And this committee serves an important role in helping us simplify our rules and make sure that our limited resources are invested where they are needed most and have the greatest safety benefits.

Like many other issues before, PHMSA's regulatory agenda is part of ongoing regulatory review pursuant to the executive orders issued last year by the White House. We are reevaluating both current and planned regulations, working to make them less onerous without sacrificing safety.

As we move forward on our regulatory review, one way that we're working to prioritize our rulemaking efforts is by making sure that we are responsive to Congress in closing outstanding mandates. So far PHMSA has completed 34 of the 42 total mandates from the Pipeline Safety Act of

2011. And remaining mandates are a top priority.

PHMSA has made significant progress working towards the final rulemaking efforts that will close the rest of these mandates. And, as you know, we believe that this rule will close several more of those important mandates.

To complete these mandates as quickly as possible, we are splitting up this rule so we can move the mandated actions forward. And Alan will go into that detail in a bit.

As part of the efforts to complete this rule and close these mandates, PHMSA has reviewed and analyzed over 400 comments in response to the gas transmission and gathering pipeline rulemaking. And I hope with your help we can continue building on all the input and hard work that's come before us and complete this rule. I want PHMSA to move forward on clearing our mandates and looking ahead for other innovative ways to improve safety.

Now I want to take a moment to talk about innovation. You probably remember that

it's one of my favorite themes, as well as one of Secretary Chao's key goals. I'm proud of the R&D work we've accomplished so far at PHMSA, funding 270 projects, and bringing 27 new technologies to market. But I believe that we can do more.

I encourage research and development efforts that will improve, create, and apply cutting edge technology to safety solutions. And I believe this is an important element in our drive to improve safety. And I know it's been a major theme in my talks with many industry leaders.

So I want to pose the question to you: what can PHMSA do to support R&D efforts and innovative technology solutions? What red tape can we remove to help you push innovation into your safety systems? I want to hear those ideas.

With a long career in industry and as a former railroad executive, I am here to say that now is not the time for industry to celebrate the administration's efforts at regulatory reform. While we should all be proud

and congratulate ourselves on the amazing safety achievements we've achieved over the last 20 years, our focus now must be on future safety improvements.

We have a short time together to show that the best path to higher levels of safety is not an endless proliferation of burdensome regulations, but instead, that together industry regulators and the public can simultaneously achieve reform that increases both efficiency and safety. To this end I encourage all of you, both industry and our other valued stakeholders, to work towards supporting and advancing pipeline safety outside of the regulatory arena.

I strongly encourage you to take advantage of our time together to go beyond just offering input on creating regulations that meaningfully enhance safety. These efforts might focus on researching new technologies or investing in infrastructure improvements.

Pipeline safety is a responsibility that all of us -- the industry, the public, and

our state partners -- share. The work that you do here truly demonstrates that at the end of the day we're all in this together.

I know that a great deal of work still lies ahead, and I look forward to your continued input and recommendations. I appreciate your willingness to travel here to discuss how to best support and expand the United States' pipeline infrastructure, reduce regulatory burdens, and protect both the public and the environment.

I want you to know that one of my goals at PHMSA is to make our rulemaking process, typically three to five years, move more quickly and efficiently. I believe your input is vital, not just for the rules that you provide expertise on, but as participants in the process. Your experience working with us on our rules gives you important insight to our process and our communications. So, please, I want to hear from you.

How can we make it easier for you to submit key feedback? And how can we be more

transparent and responsive in our rulemaking process?

I look forward to hearing more of your input and working together to complete our mandates. And, more importantly, to continually move the bar higher for gas pipeline safety.

Thank you. And have a good, productive meeting.

MR. DANNER: All right. Thank you, Mr. Elliott. Now I'll turn it back to Alan Mayberry to give some opening remarks.

MR. MAYBERRY: Thank you, Mr. Chair.

As the administrator mentioned, this is the fifth meeting of the Advisory Committee. I must say, this has been quite a long road we've been down together. And I'm very pleased here today to be before you seeing light at the end of the tunnel.

You know, this is a process that started back in 2011 with our Advance Notice of Proposed Rulemaking. And then we later issued a proposed rule -- Notice of Proposed Rulemaking in

2016. We're here today. In 2016, you know, in March 2016, I see the light at the end of the tunnel as we, you know, head to the home stretch on this rule.

As you know, we've tinkered with the formula here a bit. And I think here lately we've really had some good success, with good traction in making progress at these meetings. And I think what's helped, as we've talked before and discussed with many of you, I think the preparations we've made, the briefings we've done has helped to that end.

As you know, it takes a lot to put these meetings on. So I'd like at this point before I give you kind of an introduction to where we're heading with splitting up the rule, let me introduce the staff who really is responsible for putting all this together. So why don't we go around the room starting to my left here. John.

MR. GALE: John Gale, Director of Standards and Rulemaking, Office of Pipeline

Safety.

MR. NANNEY: Steve Nanney, Engineering.

MR. SATTERTHWAITE: Cameron Satterthwaite, Standards and Rulemaking.

MR. JAGGER: Bobby Jagger, Standards and Rulemaking.

MR. PALABRICA: Sayler Palabrica, Standards and Rulemaking.

MR. MAYBERRY: And why don't we go to other -- let's see. Oh, we have Cheryl.

MS. WHETSEL: Cheryl Whetsel, also Standards and Rulemaking.

MR. McLAREN: Chris McLaren, State Programs.

MR. MAYBERRY: Okay, thank you very much. And now, as the Administrator mentioned, we're looking to, you know, as we move forward to split the rule up into essentially three components. And this is actually, if you go to the DOT docket, it's already up there. You'll see that we have three regulatory identification numbers related to three separate rulemakings,

which I will define how we're going to do that in a moment.

And, obviously, you know, each rule that we are talking about putting into these three different categories will be written as final rules. I think that pretty much goes without saying.

Now let's talk about the first rulemaking. And, John, we're going to have to find a sexier title for these. We have kind of a catchall of different topics here. But under the reg --

MR. GALE: We can make it longer if you like.

MR. MAYBERRY: Okay. Yeah, I know, we've gotten away from calling them miscellaneous rules. But the title infers what's in it. But under the RIN number that you see there we will address this, the first of three:

The 6-month grace period for the 7-year calendar -- seven calendar year reassessment;

Seismicity;

The MAOP exceedance reporting;

That third bullet really relates to integrity verification process, or IDP;

There's also non-HCA assessments in the MCA definition, or Moderate Consequence Area definition;

And then there are related record provisions for those areas as well.

Okay, the second rulemaking we'll deal with another category, another grouping of repair criteria; safety features of ILI launchers and receivers; inspections following extreme events; management of change; corrosion control; certain clarifications of integrity management; and then strengthened assessment requirements.

And then, lastly, we will break out -- gathering lines into a separate rulemaking. It will stand on its own, which will include the reporting requirements. You know, and then what are the appropriate safety regulations for gas gathering lines in Class 1 locations.

And then probably the big elephant in the room is definitions related to gas gathering will all be in that rule. So that will be a single rule on gas gathering.

Again, you know, this is being done really, as the administrator had implied, to really, you know, make progress. We had, really with good intentions, created one rule just because we didn't at the time get too many opportunities to issue rulemaking, so we have one big rule.

But I think we've learned through the process that in order to be a little bit more nimble, or a lot more nimble, to get this done and see the end definitely, especially as it relates to mandates. But then all, you know, all these proposals that are important that it would be best to break it up into three different, you know, rules so we can get to the end game.

And then with that, be glad to talk about that further I guess during our discussion.

Sara, you have a question?

MS. GOSMAN: I just have a quick question. How is the two for one rule going to apply to this, so when you break it up into three?

MR. MAYBERRY: Well, we do obviously have to comply with the executive order on two for one. And we will be doing that through the rulemakings that these three, but also others that are on our agenda.

As you know, if you look at our regulatory agenda it includes other rules like plastic pipe and class location and others that we see those as providing the balance of both dereg and regulatory action that will help us balance it out and we'll be where we need to be.

But definitely that comes into play and we will comply with that executive order through this process.

MR. GALE: Yes, just -- John Gale -- just real quick. Sara, we don't believe it's going to hold us back, you know, with our reg reforming issues that we've already identified.

In addition to two for one, we also have the budgetary that we have to address. And, obviously, that's no change because we're not changing the impact, we're just splitting it into three components.

MR. MAYBERRY: Questions? I guess we'll go ahead and move into gas gathering.

MR. DANNER: Yes. Any other question with regard to splitting this up into three?

(No response.)

MR. DANNER: So at this point we will go into our discussion of gas gathering pipelines. Okay, so Alan.

MR. MAYBERRY: Let me go ahead and cue the topic up. You may recall at the last meeting the topic came up about keying up the discussion, the strategic discussion on gas gathering at this meeting. Really not with the, not with to debate the issue today or to deliberate on the issue but just have a discussion that will sort of whet our appetites for the next meeting.

So, consistent with that commitment,

we made a commitment at that meeting to hold a preliminary discussion here today that will kind of seed the discussion that we'll have at our June meeting. So today we're going to, you know, present a brief overview. And then I'll talk a bit.

I'm going to turn it over to John Gale here in a second. And then after John's finished doing an overview I will give you a philosophy of kind of where I see us headed on that. So with that, I'll turn it over to John first. Thank you.

MR. GALE: Thank you, Alan.

Real quick, I'd like to invite Dave Murk from API, and Bryan Crowe from MarkWest to join us at the table at this time. Thank you, gentlemen.

As Alan has mentioned, the main discussion of the gas gathering proposals will occur at the next GPAC meeting. And just to be clear, we're not looking for a vote at this meeting on gas gathering.

PHMSA is committed to having a strategic discussion of the handling of this topic at this meeting. At today's meeting we will provide an overview of the gas gathering proposals and discuss our philosophy on how to address the issue of gas gathering moving forward.

We have also asked the American Petroleum Institute to provide the GPAC an overview of the activities of what's referred to as the API RP 80 group relative to gas gathering. As many of you are aware, API RP 80 is the document that we currently use to define, or help define gas gathering in the pipeline safety regulations.

We are then going to provide the public an opportunity to comment on our philosophies and our plan going forward, and then have an open discussion among the GPAC members on how to address the issue of gas gathering moving forward. But again, to repeat, we're not looking for a vote or, again, for details of the

proposals but just as a pass forward to address the issue.

So, what's the safety issue we're trying to address? Well, recent developments in the field of gas exploration and production from non-conventional sources indicates the existing framework for regulating gas gathering lines may no longer be appropriate. Modern gathering lines often operate at higher pressures and larger diameters, comparable to transmission lines, and present potentially higher risks than typical legacy gathering pipelines if an incident occurs.

To address this issue and these concerns in the gas transmission NPRM we propose the following:

We propose to subject all gas gathering lines to the incident reporting and annual reporting requirements of the code;

We propose to replace the use of API RP 80 for determining gathering lines, adding new definitions for production facility or production operation, and revise the definition of gathering

line;

We also propose to extend the regulatory requirements in Class 1 locations and for some Class 2 for lines diameter -- for lines with a diameter greater than 8 inches. And, basically, we propose to subject these lines to effectively what's referred to as a Type B requirements.

In a variety of our different advisory committees and in other briefings we also made it very clear that certain aspects of the gas transmission rule were not applicable to gas gathering lines, such as the IVP provisions, and the like, and some of the safety-related condition reporting requirements.

Some of the more specific proposals related to gas gathering were as follows:

In Part 191 we propose to revise the scope of the part to apply it to all gas gathering lines and require that all gas gathering lines obtain an op ID using our national registry, report incidents, and submit

annual reports.

This is very consistent with the approach we took in the proposal we had on hazardous liquid gathering lines.

In 192.3 and 192.8 we propose to replace API RP 80 for determining gathering lines and added in revised definition 4, gathering line, gas processing plant, gas treatment facility, onshore production facility, or onshore production operations. As many of you are aware, as you go through defining what's a gas gathering line you also have to define the end points and the beginning points of both production and transmission lines.

In 192.8 we also defined a new category of regulated gas gathering lines. I would call it a Mycus Ronnie legacy term of a Type A area 2 meaning all of the following:

A Class 1 location that's got a diameter greater than 8 inches -- or equal to or greater than 8 inches;

And if it was metallic, with an MAOP

greater than or equal to 20 percent of SMYS; or for non-metallic lines with an MAOP greater than 125 psig.

So, as I mentioned before, what we proposed effectively was to require these Type A area 2 lines to be subject to effectively what we refer to as our Type B requirements. So what are those requirements? So this would be, and just to be clear, this is in addition to the reporting requirements:

The design, installation, and construction, and initial inspection and testing for new or replaced lines. As many of you are aware, our authority limits us from imposing construction type requirements on existing lines.

We propose to require that all these types of lines be subject to the corrosion control requirements of the Pipeline Safety Regulations.

Also, consistent with the most frequent accidents and incidents we see related to pipeline safety, in addition to corrosion

control we propose to require that all these lines be subject to our damage prevention provisions in 192.614; and, of course, our public education requirements in 192.616.

We propose to require that the operators also establish an MAOP and provide a methodology for that in 192.619.

We also propose to require our operators, also consistent with damage prevention, to require that they utilize our line marker requirements in 192.707, and to require leakage surveys and appropriate repairs in accordance with 192.706, and other sections as appropriate.

And with that, I would like to quickly turn it over to Alan to give kind of our thoughts and philosophies where we stand on these three areas of the proposal.

MR. MAYBERRY: Yeah, thanks, John. I'll be covering there are three more slides and really three different topics. The first one is data. The next one relates to the definition of

gathering. And then lastly just a bit about the high pressure, large diameter gathering pipelines.

But first-off, if you look at the approach that, you know, as far as our go-forward approach, I could see us potentially taking one relates to data. And I think we would all agree that data collection would be very important. I think certainly to understand the assets that are out there related to gathering, currently unregulated gathering, I think data collection should be collected on, say, all gathering lines.

If we go to the next slide, related definition, as I said that's really the elephant in the room. Where do you draw the line between gathering and, you know, regulated gathering and unregulated gathering?

I know I have encouraged the RP 80 Committee of API to continue to work on their revision to the RP 80 standard for gathering lines. We have a history of considering standards that we incorporate by reference that

are developed by standards, developing organizations such as the API RP 80 group.

And while we currently, you know, in this proposal it doesn't propose to adopt the latest version of API RP 80, perhaps at a future rulemaking it could be considered as an adopt -- to be adopted for helping clarify how we define what is covered by regulation, what is not covered by regulation.

That really is the elephant in the room.

And then lastly, you know, the committee should consider, you know, all input from a variety of stakeholders because I know while certainly on the next slide I cover it, I make no secret of the concern over high pressure, large diameter gathering, there's a lot of input related to all gathering, not just the modern gathering but also the conventional gathering or traditional gathering that may be lower pressure. But we need to consider the input of stakeholders and just how we decide where to draw that line as

we go forward.

And while I always encourage stakeholders to work collaboratively to develop a standard -- in this case the RP 80 Committee -- we have to move forward in this area. So we accept the input and we move forward but, you know, either in the future with an adopted standard or in reg text, really those are your two choices. You adopt a standard, incorporate by reference, or you develop reg text, or you do a combination of both. But we will need to move forward.

And I look forward to the discussion on this that helps inform this, you know, where we land this. Again, you know, this discussion today is really to whet your appetite. We're going to be getting into this in the June meeting, so thank goodness not today. We have enough other stuff to go through today. But this is really just an appetizer for the next meeting. Hopefully it's provocative enough to make you think that, hey, let's come there ready to, ready

to talk about it.

And then lastly, as I've mentioned before, you know, certainly PHMSA and all stakeholders have seen in the advent of non-conventional sources of gas, you know, I guess nowadays maybe it is convention because it's been around so much, maybe we should call it conventional now.

But, anyway, the advent of horizontal directional drilling as a technology to extract more hydrocarbons out of the ground and subsequent increase in production of natural gas, we're finding that there are large diameter, high pressure lines that really design the federal minimum standard out of the equation, that go multiple counties, that really look and smell like a transmission line but aren't because they're installed, designed and installed under the, you know, outside of the code.

So, you know, to that end I think we should consider a federal minimum standard for at least the high pressure lines. But again, you

know, considering all the input as we move forward on that.

So those are the three areas: data, the definition, and the particular concern over large diameter.

I mentioned for -- I made a mention of, you know, considering all stakeholder input. And there's a reason for that. Because certainly people are also concerned about conventional gathering. So I don't want to lose sight of and predispose the outcome of this. Let me assure you I'm not doing that. But we do need to consider, you know, all the options and just where do we draw that line. And, you know, I'm not so -- haven't really predisposed the outcome so much that I want to lose sight of the convention at all. I think we need to consider that. And I look forward to the committee, you know, discussion related to that.

Next we have, as far as to round out what we're planning for today, we will have a brief presentation of the API RP 80 Committee.

At that point we will open it up for public comments. And then before we turn it over to the committee for discussion before we wrap up.

And with that, are we on schedule for the agenda? I just want to make --

MR. DANNER: Yes, we're doing great.

MR. MAYBERRY: -- be mindful of time that we have time for the feature presentation.

Okay. With that I will turn it back over to John.

MR. GALE: The first speaker from the RP 80 group to us, Alan, is going to be Bryan Crowe from MarkWest. And after that Dave Murk from API is going to give us the presentation, I believe, on the development process that API uses.

And with that, I'll turn it over to Bryan.

MR. CROWE: Thanks, John and Alan for giving us the chance to speak to the GPAC.

My name is Bryan Crowe. I'm with MarkWest, General Manager Operations for our

northeast operating area. We operate the larger, higher diameter, higher pressure, higher flow unconventional gathering lines out of Marcellus and Utica.

So today we're going to talk about the API recommended practice for onshore gas gathering lines. I'm going to give you a high level overview of gathering if it's something that's new to you. We're going to talk about the current regulations, how it's set up. Then we're going to move into the RP and the background and what we see as the path forward.

And this is really setting the stage, like Alan had said, for the June GPAC meeting.

All right. So gathering lines are a specific set of pipelines that serve a different function than transmission and distribution lines. So what a gathering line does is it takes the gas from production facilities and production operations and it brings it to usually a central processing facility.

From there, that processing facility

removes natural gas liquids and any other impurities to create pipeline quality gas. That gas is then delivered to the transmission and distribution customer, and then they deliver it to the final customer for use as either high volume or any other type of energy.

So the safety of these pipelines is a top priority for the gathering line industry. These lines are currently regulated. And PHMSA data does show that regulated gathering lines have an excellent safety record, and we want to keep it that way.

There is a wide variability on the different formations, and life cycles, and production, and conventional versus unconventional. So gathering is very unique in the way that the rules are formed around it. And there is a lot of different stakeholders, like Alan has alluded to.

So this is a recap of what John and Alan were talking about earlier. So PHMSA has expressed concerns with the safety of rural

gathering lines, particularly the larger diameter, higher pressure lines.

So, as technology has advanced over the past few decades, development has moved into shale production. So when you do the unconventional long bores on the drill-outs there you end up with a lot higher pressure, a lot more volume coming off of one well tap. So, in turn, you end up with some larger diameter, higher pressure pipelines.

So, prior to this advancement in technology, conventional gathering there's a ton of 2 and 4 inch small diameter, low pressure, low risk pipelines, and they're strung out throughout rural areas. After the shale revolution kind of takeover you still have those same pipelines in the ground, and the vast majority is still small diameter, low pressure pipelines. But there are some large diameter, higher pressure lines. But, again, the vast majority are on the smaller diameter, lower pressure, low risk.

So industry is committed to addressing

these concerns. We would love to see reasonable, risk-based approach for continued safe operation of rural gas gathering lines.

So, current framework. PHMSA does regulate pipelines, gathering lines, as do state agencies. So these gathering lines are not unregulated. And what I mean by that, regulations apply to Type A, Type B gathering lines.

And I have a picture. I'm better with pictures than I am with all the words, so we'll go over a picture in a minute. But just to give you an idea, Type A gathering lines are higher stress pipelines in the Class 2 or 3 or 4 location. And the Type B is a low stress pipeline in a Class 2 or 3, 4 location.

Class 1 is the pipelines that we say are exempt. So that's what the NPRM that was focused on, these higher diameter, higher pressure pipelines in a Class 1 rural gathering area. And that's defined as buildings intended for human occupancy.

So this is your current framework for regulations for gathering. So I'm going to start for the highest risk. So if you move over to the right of the screen you'll see Class 4. Now, this is not to scale but it does assume a sliding mile. So your class location unit is the top line. So this purple line up here, down to here. This is your class location unit.

So as you do your class survey, you're looking for buildings and particular structures inside of that sliding mile. And what that does is it gives you a risk framework to determine what kind of requirements should that pipeline have. So a Class 4 pipeline -- that's over there on the right-hand side -- is a building where four or more stories are prevalent. So it's an area where buildings with four or more stories are prevalent. And so that's running through a downtown city or something like that.

Class 3 site, so there's a long definition for Class 3 site. It's a building that has 20 or more people for a certain amount

of weeks. And I'm not going to bore you with all that. But it's a building that if there was anything to happen within 300 foot you would have to consider that a Class 3 site. So Class 3 site you're looking at 300 feet in, not the full 660.

A Class 3, just based on the amount of dwellings, are 46 or more houses. So to give you an idea that's, in a sliding mile, you would have to have this much residential areas, buildings intended for human occupancy.

Class 2 is slightly less than that. You're looking at 11 up to 46. So this is your 11 threshold.

And then what we are focusing on, and what the NPRM is focused on, is this box right here to the left. So you can see we've already identified the higher risk areas. So these are either Type A or Type B based on the amount of pressure that you're operating, compared to what your pipeline is designed for. So that's your SMYS or what you can operate at.

So if you're going to design it a lot

higher and operate it lower it's not as risky as if you're going to design it and operate it closer to the top there.

So we're worried about this one house, okay. Because that one house matters as much as any of these other houses; right? And that's what we're saying in industry, and we've heard the public and we've heard all the comments. So we want to make sure that one house is covered. So how do we do that?

So what we've determined, the RP 80 group, initially we kicked around just changing definitions and moving forward like that. But what we determined is it makes sense to not only look at the definitions, but from industry how do you bring all that together? You know, there's a lot of good operators out there. We're already following a lot of industry practices for these lines. And how do you put all that on paper and move forward on that?

So we decided to open up an RP. And Dave's going to talk about how all the RP stuff

works later. But this RP is for Class 1 rural gathering. It's not only just to define it but also how do you determine risk? And then once you determine that risk, what do you actually do with it?

All right. So we had our first meeting January 16th through 18th this year. We had almost 100 participants show up. We've had 67 different entities. Industry was there, obviously. Regulators. We had representation, and we still have representation from NAPSR, PHMSA; trade groups, INGAA, Polypipe, API, GPA. And then we also had the non-industry groups: EDF, Pipeline Safety Trust. We had some unions show up. And RP is open to anybody that wants to be part of the process. So it's an ANSI standard. And, again, Dave can talk about that later.

So we realized we had a tight time limit, so we needed to address stuff in a hurry. So what we did is we broke up the entire group, instead of trying to draft something by committee

we broke it up into subgroups. So we have a risk categories group. They define risk and how that's determined.

We have a design construction testing group. So once you've determined risk how do you design construction and test it?

We have a corrosion control group.

And we have an O&M, or an operations and maintenance group.

So the last meeting was actually last week. We had a meeting on March 21st of last week.

All right. So, develop, our idea here is to develop a complementary framework for rural gas gathering lines. So, again, Part 192 already covers Type A and Type B in the Class 2, 3, and 4, which goes back to the pictures.

We've already defined the risks in those. We already have our requirements. So we're trying to figure out that one to the left, that one house.

So this proposed RP takes that one

house and that risk and it breaks it up into two different types. So there's already a Type A. It has more stringent requirements than the Type B. And then what we're saying is the Type B should have more stringent requirements than what we're proposing on the C, or something similar. And then Type D is even lower than that because Type D would be basically very, very low risk.

So a Type C is already a low risk pipeline because it's not in the 2, 3, or 4. But there is a potential of that one house, and that's what we're looking for.

So we're using existing proven concepts that are already in the code to evaluate potential public risk. So something that we've kind of come to a conclusion to is we can use the diameter of the pipeline and the operating pressure and you can determine what your impact radius would be if there was ever a failure on the pipeline.

And we've also used a class location analysis, combined with potential impact radius,

to help determine that risk. So instead of just throwing a diameter out there and saying, you know, this diameter and whatever pressure you're operating at it's going to be this risk, this is a little bit more surgical approach to actually doing it.

So we're going to create a practical approach that industry can implement. So we don't expect to, you know, be able to do everything at once. Right? So if you've got a 2 inch line operating at 20 pounds it's not the same risk as a, you know, 30 inch pipeline operating at 1400 pounds. So, with the resources that you want to make sure that we have a implementation and a journey, a path forward to kind of address all of that.

All right. So this is what we're calling the three, two, one method here. So it's three tiers, two methods, and you're looking for one dwelling. Again, you're looking for that one dwelling in the Class 1 location.

So there's three different tiers.

These are very conservative. And I do have pictures. So we'll go over it here in a second.

Tier 1 would be a 2 to 12 inch.

Tier 2 would be a 14 to 24 inch.

And a Tier 3 would be a pipeline that's greater than 24 inch lines.

So there's two different ways to determine your risk. An operator can do a modified class analysis, which is very similar to the sliding mile. You're looking for a certain amount of residences inside that 660 feet. Or you can do a more surgical, more calculated approach and use your potential impact radius. And what you need to know there is your diameter and pressure.

So if you don't want to do your diameter and pressure you can just use your diameter. But, again, you're looking for that one dwelling.

All right. So this is a Tier 1 pipeline here. So the top line is the same, this is the same background as I used for the class

analysis. So this is you've already done a class analysis for 660 feet. So now you're going to run a supplemental based on a generic Tier 1 number. And these calculations were done doing the wet gas factor, which is .73. It's a more conservative factor when calculating PIR than the regular C-1 or just the methane. So it's a little bit, it's a lot more conservative.

And we also assumed 1440 psi. So this is your Tier 1. And it gives you a default number of 330 feet. So you would be looking for a resident inside this 330 feet.

All right. So a Tier 2 pipeline is a 14 to 24 inch. And if you look down here it's, again, we assumed .73 and 1440. So, how we determined both of these outsides, so if you don't know your pressure, we assumed an ANSI 600 1140 system. We calculated out the PIR for a 24 inch. And that gave us right around 660. So it's not a number that we made up, it's something that science has behind it, as is the 12 inch 330. That's the PIR calculation for a 12 inch is

right around 330. So it's really it's based on scientific method here.

All right. So how do I get back? There we go.

So this is what we're calling the Tier 3. And although there's not a lot of these pipelines out there, there are some gathering lines that are greater than 24 inch out there. So if you were to operate that pipeline right at your maximum design pressure you can exceed the 660 foot. So obviously, you know, when you're kind of looking at this those are the ones that are the highest risk. So you would want the more stringent requirements moving forward and then kind of coming down from there just from a risk management basis.

All right. So, from a function standpoint -- let me go back here. All right, so we're looking at the one on the right right now.

So from a function standpoint -- there it goes -- gathering is very unique to transmission and distribution, especially on the

suction side, which is the majority of your miles. And what I mean by that, when you drill a well you have a lot of flow and you have higher pressure. However, that well declines rapidly. So you may design your system for 1400 pounds or 1440, whatever that is, but after a year or two you're going to have to add compression. And when you do that you still have a pipeline that's designed for 1440 but your impact radius if you had a failure significantly drops.

So I'm going to give you an example. This is a 24 inch. All right. So if I add single stage compression and I lower my suction pressure to 600 pounds, my PIR drops that much. All right. So, for example, the 24 inch the calculated PIR is 665 feet. If I lower my pressure to 600 pounds my PIR goes down to 429 feet. And that's using the more conservative wet gas factor. It would be even lower if this was dry gas. But we want to make sure we're conservative there.

So this can operate like this for a

couple years. This is very typical of what we're experiencing up in Marcellus right now. These wells, they have an initial production of a couple years. You can free flow them directly to a sales line. And you can without compression. But after about two years tops you have to add compression. And then after about another year or two from that it drops below 600 pounds to where you have to add even more.

So you're going to go from 600 down to this. And this is the same line, the same pipeline that was originally built for 1440. It's the same line that, you know, we -- that it's moving the same product. Nothing's really changed other than that well pressure's gone down so much that if we don't add compression to it the well will no longer be able to flow. So your potential impact radius now for that same 24 inch line that was 429 feet, it just drops back down to 248 feet. All right.

And as these wells, as they get down to their, through their life cycle, they tend to

line out. And a lot of the conventional and a lot of these wells are operating at around 100 pounds. And you can see that it continues to drop.

So that it's different than a normal transmission line that's feeding a customer at a constant pressure. It's more you design it a lot higher and then over time your impact radius and all that gets a lot smaller.

All right. So what we would do on this, how this would work for your potential impact radius, as an operator for me determining my risk what I would do on the right-hand slide is I would do modified class analysis using my baseline numbers, which again we determined on a worst case scenario of 1440 psi.

So we're talking rural gathering. I've done an analysis on my system, not every system. But on our system I'm throwing out 97 percent of my pipelines are outside of these -- I don't have any residences or any kind of buildings inside of my windows. So I'm able to

knock out a lot of the Class 1.

Of the 3 percent or so that is still left, I can go and determine what my pressure is, my diameter, and use a more surgical base to kind of accurately portray what the risk is. And then I can make sure that I'm dedicating, you know, my limited resources and all that to the proper pipelines.

And one thing I do want to show is, like, a 2 inch conventional. We have a lot of conversation on that. Right here it's at 55 feet at 1440. But as it continues to drop you can barely even see it. You know, a 2 inch once you get -- a lot of the conventional, you know, impact radius is less than 15 feet. So, you know, your 2 inch conventional, the smaller diameter the risk isn't the same.

So once you determined if you had a residence in here, again that would be what your Type C versus your Type D requirements would be. And that's kind of the whole framework of this. It's a process that's moving forward. I don't

have all the specifics. We have directions. But it's something that the stakeholders have to vote on. It's an industry consensus with outside stakeholders.

So I'm going to talk real quick about the next steps of this process. I'm going to turn it over to Dave.

Next steps, we just had the meeting to give API some direction on how to draft it moving forward. So we're going to start drafting it. In May we're going to circulate the RP draft to the work groups. The work groups are going to do their review, final editing. And we're looking at June going out to ballot for this document.

July and August, you send it out for ballot. Then you have to do the comment resolution. September, a second ballot. And October and November a comment resolution. And, hopefully, December we can get to where we can publish the RP.

And, you know, Alan had mentioned participants. And I just kind of, we just wanted

to put this up there. There's a lot of different people, lot of different companies. There's a lot of different industries represented, trade groups, regulatory agencies. And we're all trying to work together to come up with a good risk-based reasonable solution to this issue.

All right, I'm going to turn it over to Dave.

MR. MURK: Good afternoon, everybody.

John, how much time? We're good on time?

MR. GALE: Forty-five seconds.

(Laughter.)

MR. MURK: As John mentioned, I'm Dave Murk. I'm the Pipeline Manager for the American Petroleum Institute. And prior to my time at API the last two years, I did 26 years as a federal regulator and had oversight of pipelines both on the marine terminal side with the Coast Guard as well as with PHMSA and the Office of Pipeline Safety. So I bring a perspective from the regulatory and the importance of standards and

incorporation of standards into regulations in my current job.

So Bryan's presentation was really the meat of what we wanted to talk about and present today from a gathering perspective. But thought it would be important really quick, high level, to give you a sense of the API standards process for a couple of reasons which I'll hit on.

And really the last slide I think that Bryan showed with the participation is one big part of the standards process that I think is invaluable as we develop standards and recommended practices.

So let me run through real quick and then we'll get to questions because I know there's probably some questions.

So API itself, we actually represent the entire oil and gas industry. So we cover all three segments: upstream, midstream, and downstream segments. And in that, as a standards setting body we've got over 100 years, or coming up on 100 years of standards development and

publication. We have 700 technical standards across the industry.

And in that, the volunteer aspect of that is incredible. You know, just in the 100 that you saw that Bryan put up for the gathering lines RP is an example of the commitment that is involved from folks or stakeholders that have a stake in seeing the RP or a standard move forward. And one-third of all of our standards are actually referenced in some type of regulation. And that holds true on the pipeline side as well.

And I'm going to show you what we call our pipeline safety placemat. And this is 30, I believe there's 34 standards up there, somewhere around there, that are strictly pipeline-related recommended practices or technical reports that we have in play right now that have been published or are close to publication.

And roughly same amount, about a third of those, are in some way incorporated by reference. And it just shows you the volume of

any importance that as an industry we place on standards and recommended practices. And I think this is a good visual just from the standpoint of, you know, this is just one segment, one aspect of our industry that has standards around it. And you can see the number associated with it.

So our standards process, as Bryan hit on some of these points, it's a consensus-based process. And I think that's an important point. And the participation that we get is based on a third, we call it the third-third-third make-up: a third of industry participation; a third of manufacturers and suppliers; and a third category is others, so that's your other stakeholders, the public, regulators, NGOs, et cetera, that would want to participate in the process.

So that's ultimately what we strive for in the process, in the development of an RP or recommended practice that we move forward with a standard.

The other important piece for us a

performance-based approach to it. Performance-based standards and recommended practices allow the flexibility for us as an industry, based on the unique nature of and size of operations across-the-board. Provides that ability to scale based on risk, as Bryan just talked about from the RP 80 group and gathering lines. It allows for that flexibility to really focus our resources, or to focus resources where the greatest risk is.

It's an accredited process through the American National Standards Institute, an ANSI process. And our program through API is actually audited every five years by ANSI. And we see it as a transparent process just based on the fact that it is consensus, does -- we do strive to get that mix and that balance of those who are participating on the group.

But we can also take another step within the ANSI process to get additional input, which we're looking at for another RP we're working on right now, 1162, where you actually

have additional public comment and additional discussion with underrepresented groups on that RP development group that can support the further development and get additional input, as needed, moving forward.

So, again, the process, you know, for us is important. It is audited. And we're not the only standard-setting body. There's obviously others like NACE, and ASTM, ASME, et cetera, that do similar types of standards. And so, you know, for us, again, this is an important aspect of moving forward.

The last thing I wanted to talk about was the difference for us between prescriptive and performance-based. I already hit on it in some way. Our focus, obviously there's at times a need for a prescriptive standard or a prescription within a standard. Our focus, based again on the ability, the flexibility, and the scalability of risk and performance, and really focusing the resources on the highest risk. We focus on the performance-based standard or

performance-based aspect when we're developing recommended practices and standards.

And the importance of that as an industry that's heavily dependent on technology, and I thought it was appropriate with Administrator Elliott was talking about the focus he has on innovation, the importance of innovation, and meaningful technology was something else mentioned earlier. You know, for us that's extremely important. Meaningful technology and technology that can be applied early as it's being developed to implement the latest and greatest and safer technology is important.

And that's where, from our standards standpoint, we think it's important that it be performance-based because it allows for that flexibility, as well as new technologies are developed. And it encourages, in our view, innovation. And it's not a hard and fast requirement, as some of the prescription is.

Again, there's going to be a need at

times to have a balance of both, but the, you know, the focus for us as an industry is more on performance-based, based on the uniqueness of the operations and the requirements to apply resources where the greatest risk is.

And so I think that is it for me. That was, again, a quick snapshot of our process. And I think it was good to dovetail off of the RP 80 group, which showed a lot of aspects of our process as it's being developed.

The one other thing I would note is the RP 80 group, typically an RP can take anywhere from 12 to 18 months or more. This is one area -- this is one recommended practice that really we place a great deal of importance on, recognizing the importance to the gas rule. And it's really been expedited. And really there's been a lot of great input into it across the board from a lot of different key stakeholders. So, I appreciate the effort in moving this recommended practice forward.

So, John, back to you.

MR. DANNER: So, thank you, Bryan and Dave. So, if you would stay in your seats I'm going to ask for any public comments or questions and -- from the folks sitting behind me. And then we will turn it over to the committee for the same.

So, is there anybody here in attendance who has comments on what you just heard from API?

Yeah, if you'd come to the mic in the aisle.

MR. EDWARDS: Hi. Kepler Edwards with the Plastics Pipe Institute, Wyman Associates. I just have some prepared comments that I wanted to read off.

The proposed Type A area two gathering lines applies to pipe 8 inch in diameter or greater, operating at 125 psig or higher. The proposed changes would make certain Class 1 applications regulated, thereby invoking current part 192 design rules intended for Class 3 and 4 gas distribution and limitations on plastic

piping that are in conflict.

This rule would effectively limit the use of PE over 8 inches in diameter to gas gathering applications with a maximum operating pressure of less than 125 psig, or require the use of larger diameter pipe to provide the same gas flow at the lower pressures.

Many -- 50 percent of the total HDPE gathering market, large dimension PE gas gathering systems in operation today operate successfully at pressures above 125 psig, designed using the design equation with a design factor of .63. Overall, more than 1,000 miles of 8 inch and larger PE pipe is installed for gas gathering applications annually.

PPI believes that the proposed rule to regulate onshore gas gathering lines, Type A non-metallic area two Class 1 locations, with a nominal diameter of 8 inches or greater, or with a maximum operate -- MAOP more than 125 psig will have a dramatic cost impact to gas gathering pipeline operators.

PPI estimates that the design pressure limitation annual compliance cost to industry to be approximately 140 million. We estimate that the newly regulated lines to be at least 30 percent of the total industry reporting energy pipe and sales, we estimate that at least 50 percent of the gathering lines are designed with an MAOP equal to the maximum design pressure designed on PE 4710, design factor, DF, of .63.

To achieve equivalent gas flow with a 125 psig design pressure limitation for regulated thermoplastic pipes, the NPRM will require PE pipes currently designed to SDR 13.5 or lower to be upsized or switched over to other more expensive materials. The total cost of eliminating rework is at least .3 -- or 30 cents per pound, which will be passed through the industry operators as the rework material will have to be sold in lower resin cost markets and to scrap recyclers.

I just wanted to introduce those comments. And thanks for your consideration.

MR. DANNER: All right, thank you.

Are there other comments?

(No response.)

MR. DANNER: Okay, hearing none, let's turn it to the committee. Are there any questions or comments for Mark or Dave?

Yes, go ahead.

MR. ALLEN: Yes. Steve Allen, Indiana Utility Regulatory Commission.

Dave, when you mentioned the distinction between prescriptive and performance-based approaches -- and I think you and I have talked about this once before, the Transportation Research Board of the National Academy of Science, the study that they had completed, and the report from, I think, last October talks about the four different classifications of a regulatory standard being a micro means, micro ends, macro means, macro ends. And everyone in the room probably knows I'm a big cheerleader for micro ends or macro ends being safety management systems.

Any consideration of a management systems approach incorporated into the recommended practice?

MR. CROWE: Yeah, I'm not that familiar with the macro ends, and -- can you hear me now?

So I'm not that familiar with the macro ends and what you're talking about. But as far as the SMS method in performance-based and all that, I know Stuart -- he's with API and heads up the group, he is wanting to waive in the SMS, you know, from the API side of it into this RP and make sure that we do weave in some of the safety management systems.

MR. MURK: Yeah, Steve, thanks for the question.

So, as we move forward with any of our recommended practices, safety management systems, continuous improvement, planned new check act element of that is being incorporated into our RPs moving forward. So there will be some element of safety management incorporated into it. To what degree, you know, will depend on the

RP itself. But, yes, we're -- that's part of our process moving forward is to include those types of elements in.

MR. ALLEN: Mr. Chairman, may I follow up?

MR. DANNER: Yes, Steve.

MR. ALLEN: Okay. Yes, Steve Allen, IURC.

Yeah, I just wanted to -- I misspoke. Really we're dealing with, okay, the performance-based or the prescriptive-based approach being the micro means, you know: how are you going to do it?

Where the macro ends approach is really more of a general duty statement. All right? The management system is really more of the macro means. You know, here is the what and, generally, here is the approach that needs to be taken but not specifically spelling it out.

So I just wanted to clarify my earlier comment.

MS. CAMPBELL: Thank you, Mr. Chair.

Cheryl Campbell, Xcel Energy.

I just have a question. I'm probably not going to do a great job of articulating, I'm just going, just going to admit that up front. So, first of all, API, I want to thank you guys for doing a lot of standards work. I mean, a lot of us use a lot of these standards. I appreciate the process and the way that they're built.

I'm curious when we talk about this -- and I'm not a big one for writing a whole bunch of new rules and creating a lot of more stuff, right. So please understand where I'm coming from, I look at this and I think, okay, I see a lot of new concepts and ideas. I'm not sure they get you to a new place, but I'm very interested in that. How does this compare -- I mean if you have a -- we have a whole bunch of pipelines in this country, transmission pipelines in Class 1 locations without any houses around them that follow a certain code. How does this compare to that code that's already out there?

And does it bring more pipelines --

does it change the way you build some of those pipelines?

And as kind of a follow-up to that, I mean it feels like -- and I used to work in the midstream sector, so the wells start here and they tend to go down over time. I get that. But is the way to deal with that -- what we've got here is a sliding scale of MAOP over time. And then can you use a lot of the words that are already in the code instead of creating a lot of new stuff?

MR. GALE: John Gale, PHMSA.

Cheryl, just real quick, you know under the current regulations, you know -- for gathering lines that is -- so we kind of -- we carve them up into what we call Type A lines and Type B lines. So we -- in our proposal -- I mean, we've got to remember we're talking about in terms of a path forward for this committee to look at this rule. What API is putting forward is both kind of a combination of something we can look at short-term, plus possibly more of a long-

term solution on this issue.

We carve these regulations up under Class Type A and Type B. And as I went through before under Type B -- which is what we propose to address or put these new lines under -- it's about seven different things that we would impose: cathodic protection, public awareness, things like that.

And then when it comes to new construction we would apply our construction requirements that are in the code. By statute we can't apply our construction standards to lines that are already in existence if we newly regulate them. So we're kind of -- we're limited by that.

What we can apply -- and that's what we proposed to apply -- was our construction standards that are currently in the code to new and replaced lines.

MR. DANNER: All right, Ron Bradley.

MR. BRADLEY: Thanks, Mr. Chair.

Just a comment and not really a

question. But I wanted to just share a thought here, a few thoughts.

One, I definitely appreciate the design here to whet our appetites to get us thinking about this. So I really appreciate that. The downstream impacts of the gathering lines impact greatly us and our customers, and it's a great topic to introduce this way.

And then just to sort of echo on what Cheryl said. She did say -- and I want to repeat it -- API does some great work. We appreciate it. We've used your studies. I'd encourage you to continue. Just wanted to put that on the record.

MR. DANNER: All right, Jonathan.

MR. AIREY: I come at this from a slightly different perspective. Ohio had a lot of conventional low pressure gathering systems, that many of which still exist. When the Utica became dynamic and MarkWest and others came in to build the midstream, it was a totally different construction level that was encountered.

And what I'm curious about is isn't it a option here to just address the non-conventional and to leave the existing regulatory scheme in place for the low pressure until RP 80 is updated? If we're looking at a impact radius on a 2 inch gathering system at 1440 psi, 55 feet, it doesn't seem to me that requires any immediate regulatory activity.

And when it goes down to 100 psi and it's 15 feet, that doesn't strike me, again, as something that requires significant regulatory activity to address it. And it might be better to wait and see what RP 80 does for conventional gathering.

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

MR. MAYBERRY: Yeah, actually, Jon, that's actually what we'll be getting guidance from the committee on. It's where we do land the rule.

As you know, we have a proposal out there in a Notice of Proposed Rulemaking that's

fairly far-encompassing. You know, I've made a big point, and I know others at PHMSA are saying certainly of concern are the high pressure, large diameter, the more recent -- you know, the modern gathering that's been installed. But, you know, we'll be seeking the input of the committee on really where we land it. And that will be, you know, focus of our discussion in June.

MR. AIREY: You know, I really agree with that suggestion that the focus ought to be on the non-conventional, horizontal stuff because the pressures are dramatically different. And given the lack of conventional activity, the pressures in the existing system are declining significantly. So the risk is really not that significant for much of the conventional stuff.

MR. MAYBERRY: Right. And if you would indulge me, Mr. Chair.

Yes, I -- you know, certainly from a public safety perspective we recognize that. But also -- and as you know, we deal with all the stakeholders. And, you know, so we can't lose

sight of the fact that there are also concerns with conventional related methane emissions. So that comes into the equation there that we consider as we decide where to land it.

MR. DANNER: All right, thank you.

Are there any other questions or comments from the committee members?

(No response.)

MR. DANNER: All right. Then I think that that concludes our conversation for today on gas gathering. And we will pick up this conversation at our -- oh, I'm sorry. John, do you have -- oh, okay, so we will pick this up again at our next meeting.

And now we're going to move on to discussion of some of the other outstanding issues. So I'm going to turn it over to John Gale.

And thank you, Mark and Bryan, for your presentations.

MR. GALE: Yes. John Gale again, PHMSA.

So, as the great regulator in the sky once said, what a long strange trip it's been with this rulemaking. And I'm looking down here, I can't believe we've had five advisory committee meetings since January of 2017. We pulled off three of these since last December.

We put forward a plan and a schedule in place soon after the December meeting to possibly get us to the point that at this meeting we could be done and completed with all the transmission proposals by March 28th. And I think all involved should be commended for that.

I kind of remember a flashback to the very first meeting that we had back in January of 2017. And it was a simple proposal. And I believe it was Erin Kurilla from AGA at the time stood up and made a small motion or support for one of the very small proposals we have in the rule. And it was -- you know, it was small thing, but it set a tone for us to move forward with this rule.

As Alan said, we've dealt with over

400 comments on this rulemaking. It deals with a variety of topics, some very, very difficult. But we are now on the precipice of possibly completing this action in short order.

We've dealt with a variety of things. We've dealt with cancellations. We've dealt with weather cancellations, other cancellations, we've dealt with hurricanes and the like. But we've gotten through this process, and all should be commended.

So just, again, a recap of where we've been. Back in January of 2017 we were able to get passage from the committee on the issue of the six-month grace period for reassessment intervals.

We passed a proposal related to safety features on the ILI launchers and receivers.

We also passed the proposal related to seismicity, and inspections following extreme events, and management of change.

And then we kind of set in process the kind of the step-by-step kind of process we were

going through where we would discuss topics and then resolve the issues and get that vote and move forward at the following meeting. And those topics of that first meeting involved corrosion control, issues -- some issues related to records and IM clarifications.

Then in June of 2017 we were able to pass our proposals related to corrosion control, some of our record provisions, some of the IM clarifications, the MAOP exceedance proposals, and again we had another discussion but didn't pass or didn't have a vote on issues related to some additional records sections, some of the IM clarification procedures in 192.917(e)(3) and (e)(4), and one of the more significant proposals in the rulemaking regarding material documentation or material verification process in 192.607.

Then in December -- which to me I think was really a turning point for this rulemaking -- we were able to get passed and get a positive vote on material documentation, which

was very significant. And we even began -- and to our surprise, were able to get a vote and passage on issues related to strengthening IM assessments for ICDA, SCCDA, and adding guided wave ultrasonics to Appendix F, and passage on the strengthening of assessment requirements for 192.150.

Then we set in place and began a conversation on one of the more significant proposals in the rule as well on MAOP reconfirmation, and additional discussion on strengthening of assessment requirements for 192.493, 506, and 192.921.

We then had a meeting on March 2nd, 2018, while the government was closed -- not to point that out, Alan -- we passed requirements, and to the committees to be commended for it, you know, over the phone, which is a challenge, some of the requirements again on strengthening IM assessments related to spike tests and ILI standards and HCA assessment requirements.

But we also tackled some more meatier

issues like the assessment outside of HCAs, which is a very big step in terms of the pipeline safety regulations, and addressed the issue of the MCA definition.

We also came to resolution on most of the record provisions in 192.13(e), 192.67, 192.127, 205, and of course Appendix A.

We then had, and did not have a vote on, the discussion of the repair criteria, which we will hopefully be able to get to a vote at this -- today's, or the next three-day meeting.

So, some of the issues we're looking to discuss at this agenda for this meeting over the next three days:

We hope to resolve the issues regarding MAOP reconfirmation. So that involves the scope of the section, so what lines would come under or be subject to 192.624;

The schedule for completing those assessments;

The methods we would use, the six methods we've identified;

Fracture mechanics;

The notification requirements, and;

The record retention requirements.

We also hope to address and get a positive vote on issues related to MAOP in 192.619 and 192.503, and also the associated record requirements.

We hope to come to conclusion also on some of the IM clarification issues in 192.917(e)(3) and (e)(4) that we had put off.

We also have some additional definitional issues we have to resolve that we hope to address at this meeting. Also, I don't want to -- I also want to point out, going back to number two there, is the issue in 192.619(a)(3), which is the class location safety factors for determining MAOP, which we hope to address in this meeting.

So what's going to be left is, hopefully, just gathering lines. And as we've had a discussion today, we hope -- you know, hopefully we'll have a way forward to at least

begin that discussion in that June meeting. And, if need be, we will also address in that June meeting the topics that we do not conclude at this three-day meeting.

We're optimistic, however. And our goal is is to have votes on almost everything related to gas transmission in these three day meetings and just leave for us to complete those proposals related to gas gathering.

And with that being said, Chairman Danner, if it's okay I would like to turn it over to Mr. Nanney, who will begin our discussion on the MAOP reconfirmation process that was proposed in the gas rulemaking.

MR. DANNER: Okay. Before we do that, let me ask the committee though if you have any questions with regard to the schedule that John has laid out. Andy?

MR. DRAKE: This is Andy Drake.

It may be appropriate while the administrator and assistant administrator are here -- this is my prep material for this

meeting. You know, and I have a stack that's at least five times that sitting behind my desk from the other meetings.

I really just wanted to say thanks to the PHMSA staff. You guys have done an amazing job digesting the carpet bombing of information that you've taken over the last couple, well, year now, digesting this and turning it into -- turning it around pretty quickly and allowing us to come back to a meeting actually having a record of what we talked about at the previous meeting in the form of revisions to the proposal and slides. It's really helping these meetings move along.

And I just wanted to make that comment out loud here to the whole group. But I know many of my peers appreciate the same thing. This has just been an unbelievable undertaking. But to keep track of this and keep it kind of going in real time has really been appreciated. I just wanted to say thanks.

MR. DANNER: All right. Yes, thank

you. And, again, I do think we've made tremendous progress. We're on something of a roll. And I'm optimistic we can continue progress between now and 5:00 o'clock on Wednesday.

So, John, take it away.

MR. GALE: Yes, Chairman Danner, I'm actually going to turn it over to Mr. Nanney at this time.

MR. DANNER: All right. Steve.

MR. NANNEY: Steve Nanney. We'll be starting with the MAOP reconfirmation process. And since the committee has had a chance to review the slides, and I hear many of you don't want to stay two days, we can just take a vote now and make it a short meeting.

(Laughter.)

MR. NANNEY: Well, first of all, the MAOP reconfirmation will be our first topic. And you can see here we'll be talking about Section 624, the scope, completion date, MAOP methods, reconfirmation methods, fracture mechanics,

notifications, and records.

Going to the next slide -- and if you can't hear me let me know and I'll get closer to the mic -- is some public comments that we saw that we were planning to highlight similar to what we've done previous. The scope not included -- include pipe of past failures. Past failures are addressed based on response to the event and integrity management.

And based upon this comment, PHMSA suggests striking 624(a)(1) based upon the committee recommendation. Instead, PHMSA suggests including a new 917(e)(6), which is in the integrity management section to address failures due to cracks and crack-like defects in HCAs within the integrity management program. And, again, it's recommended by committee members.

Going to slide 12 -- again just to give an idea of what we're doing here is from 2010 to November 2017, again, we've looked at reportable onshore still gas transmission

incidents caused by cracks or material defects. And we saw about 112 total incidents.

And you can see that right now by manufacturing date there was about 71 manufactured before 1971; 21 that were manufactured 1971 or later; and then 20, year of manufacturing -- 20 did not have a year of manufacturing reported.

And a breakdown by cause was 19 by stress corrosion cracking; 65 were construction defects; 28 were latent manufacturing defects.

And of these incidents, 45 of them -- or about 39 percent -- occurred after a post-construction pressure test. And 14 incidents occurred on pipe with less than a 30 percent SMYS.

Going to slide 13, another public comment that we received was delete legacy definitions from Section 3 and put into 624 by using the joint factor less than one specifically applicable to the MAOP reconfirmation. And also clarify that the intent of dresser coupling is to

address mechanical non-restrained or sealed type -- sealed-only type.

And, again, if the committee votes to strike 625(a)(1), these definitions would not be needed, in which case PHMSA would suggest to withdraw the definitions for legacy construction techniques, legacy pipe, and modern pipe.

Going to slide 14, another comment we got was exempt low pressure pipelines based on low risk and questionable cost benefit, and to comply with statutory mandate. In other words, limit the scope of Section 624 segments with an MAOP greater than or equal to 30 percent of SMYS.

And PHMSA's comment there for slide 15 is -- and for this comment is for pipe without records, the statutory requirements in 601.39(a) through (c) would not allow PHMSA to exclude pipe segments on this basis. All applicable pipe without records and HCAs or Class 3 or 4 locations must reconfirm MAOP.

In the scope of the Notice of Proposed Rulemaking for Section 624(a)(2) is mandated by

statute. PHMSA estimates that the mileage is about 4,500 miles based upon reports from the 2016 annual reports. And a breakdown by HCA and class locations will be shown on the next slide.

And you can see here, based upon the 2016 operator annual reports, what we're looking at with most of the mileage being in Class 3 locations.

And you can see the breakdown from HCAs to non-HCAs and then the total of each one.

Going to slide 17, again a PHMSA comment on this was for previously untested pipe. The statutory requirement requires that such pipe be tested if operating at a pressure exceeding 30 percent of SMYS. And PHMSA suggests to limit the applicability of Section 624(a)(3) to lines with MAOP greater than or equal to 30 percent SMYS.

In a table comparing the estimate segment mileage, FAR 624(a)(3) is shown on the next slide.

And in doing this, you can see here the -- in this slide, this is for grandfathered

segments. And the criteria for grandfathered segments, as you can see in the first row there, is HCA with an MAOP greater than or equal to 30 percent SMYS, and a Class 3 and 4 non-HCA with an MAOP greater than or equal to 30 percent. And in doing that, about 979 miles would be HCA pipe in there; 1235 would be non-HCA, for a total of about 2200 miles of pipe.

If do HCA (all) in Class 3 and 4, all non-HCA, you can see in the middle row the total would be about 2600 miles of pipe.

The last row, HCA with an MAOP greater than or equal to 30 percent SMYS, in Class 3 and 4 non-HCA, with an MAOP greater than or equal to 30 percent, and a Moderate Consequence Area Class 1 and 2 with an MAOP greater than or equal to 30 percent. If you look at the numbers there, we still have the 979 miles for HCAs; about 5834 feet for non-HCAs for a total of 6813 miles.

Going to slide -- oops, I went too far -- slide 19, another public comment we got was clarify the past test that meets subpart J are

acceptable and valid. And, again, PHMSA's comment there is a pipe segment with a pressure test meeting subpart J in accordance with Section 619(a)(2), and with the TVC records that demonstrate compliance with Section 619(a)(2) would not require MAOP reconfirmation under new Section 624(a).

Now, going to slide 20, the committee comments on this applicability from our December 2017 meeting. Some of the members desired to remove past crack/seam incidents from the applicability criteria, in other words strike Section 624(a)(1).

The second bullet is some committee members desire to restrict the scope to segments greater than or equal to 30 percent SMYS per the original mandate for previously untested pipe. And also, based on leak before rupture concept for lower stress lines.

The last bullet is other committee members supported retaining the scope proposed in the Notice of Proposed Rulemaking to address the

NTSB recommendations.

Going to slide 21 will be the PHMSA comment to that, is our response there was we suggest that we strike 624(a)(1), the cracking criteria, and address it in Integrity Management as I stated a couple of slides earlier. This would create a Section 917(e)(6) to address segments with crack incident history in an Integrity Management. And also limiting Section 624(a)(3) for grandfathered pipe to segments with MAOP greater than or equal to 30 percent SMYS.

Slide 22, again also PHMSA suggests that Section 624(a)(2) for pipe without records, that we retain that as mandated by the statute. PHMSA also suggests changing 624(a)(2) to refer to MAOP records instead of subpart J pressure test records. And records to establish MAOP would be -- are defined in 619(a) for post-code pipe; in 619(c) for grandfathered segments.

Slide 23, in light of the committee comments from the December 2017 meeting, PHMSA suggests, as I stated earlier, that the committee

consider the following:

And there's three suggested amendments to the scope of Section 624.

Number 1, revise 624(a) to strike paragraph (a)(1) which was a proposed criterion related to lines with previous reportable incidents due to crack defects. And by doing that, the new definitions of modern pipe, legacy pipe, and legacy construction techniques would no longer be needed in the rule. And PHMSA suggests withdrawing them from the final rule

Going to slide 24, another recommendation or amendment is renumber Section 624(a)(1) for line segments without TVC records as paragraph (a)(1).

Revise to refer to TVC records required in Section 619(a) and (c) instead of pressure test records required by subpart J as shown below. Instead of there being pressure tests, show records necessary to establish maximum allowable operating pressure in accordance with 619(a) or (c) for the pipeline

segment.

And then, lastly, renumber Section 624(a)(3) for grandfathered lines as paragraph (a)(2), and revise to apply only to lines with an MAOP greater than or equal to 30 percent of SMYS.

Going to slide 25, on section 624(b), the completion date, there were no comments on that section.

Going to slide 26, again this is from our December 2017 meeting. And, again, this is in response to the NPRM comments. PHMSA suggested to the committee that we consider the following:

PHMSA suggests revising Section 624(b) as indicated in the PHMSA response to public comments. In other words, revise 624(b)(1) to address how the completion plan and completion rates required by 624(b) would apply to pipelines that are not currently applicable under 624(a) but may become applicable in the future. In other words, they're located in an HCA or they become a Class 3 or 4 location.

And, again, and lastly, would revise 624(b)(2) and (3) to refer to pipeline mileage instead of location.

Slide 27, again this is from our December 2017 meeting and it's response to public Notice of Proposed Rulemaking comments. And PHMSA suggests the committee consider the following:

Revise proposed Section 624(b). Again, as indicated in a response to public comments, revise Section 624(b)(3) to address completion date for newly identified segments as follows:

And this would be (b)(3). The operator must complete all actions required by this section on 100 percent of the pipeline mileage that meet the conditions of Section 624(a) by, insert date that is 15 years after the effective date of the rule, or two years after the segment first meets the conditions of Section 624(a), whichever is later.

MR. DANNER: All right. Thank you,

Steve.

Now let's open it up to the floor if there are any folks behind me who wish to comment on A or B.

MS. DiBIASIO: Hello. My name is Adele DiBiasio and I work for National Grid.

National Grid supports a number of the proposed changes to 624. However, PHMSA's suggestion to revise 624(a)(2) to require TVC records in accordance with 619(a), which includes both paragraph 1, subparagraphs 1 and 3, or C, would in fact, as written, require segments with a valid pressure test to have their MAOP be verified if we're missing MOP records from 1965 to 1970.

These MOP records were not required to be maintained. And locating TVC pressure records or charts from this period is virtually impossible, as electronic records were not available at that time.

We request that PHMSA considers limiting the scope of 624(a)(2) to records

required by 619(a)(2) alone, just a pressure test or paragraph C. Additionally, we request that PHMSA allow for pre-code pipelines without MOP records from '65 to '70 that an operator be allowed to use the MOP of the five years prior to this rulemaking.

With regards to slide 26, we are encouraged that PHMSA has explicitly addressed pipelines that in the future may fall under Section 624. However, requiring the completion of all activities within two years is overly burdensome, given the extended time required for obtaining permits in the states where we operate. This time is added to the design and construction times.

National Grid requests that PHMSA consider allowing two years to develop a plan, and seven years for completing all actions.

Thank you.

MR. DANNER: All right, thank you.

Are there other comments?

MR. KURILLA: Hi. This is Erin Kurilla

with APGA.

I just want to make a comment pertaining to slide number 19 where PHMSA states that a pipeline segment with a past pressure test meeting subpart J would have to meet the MAOP reconfirmation requirements. Just like the committee or the Advisory Committee just to discuss a little bit about the importance of meeting a requirement at the time that the pipeline was constructed and not by current codes.

And we just reference subpart J here basically. We're asking pipelines that were constructed in the past to meet current requirements.

So I would like this to say a pipeline segment with a past pressure test meeting code requirements at the time of construction, instead of just referencing current subpart J.

Thanks.

MR. DANNER: All right, thank you. Are there any other comments?

(No response.)

MR. DANNER: Okay. Let's open it up to the committee then. Are there comments on A or B? Or questions? Mr. Drake.

MR. DRAKE: This is Andy Drake with Enbridge.

I thought there were some good comments there. I particularly want to confirm that an operator with a TVC record or a pressure test in accordance with 192.619(a)(2) would not be required to perform an MAOP reconfirmation regardless of SMYS. Is that right? I mean, I think there was a question there that was just brought up about to the code at which the pipe was installed to. I think that's actually a good add there for clarification.

Is that what you're talking about when you say subpart J test?

MR. DANNER: Steve, that question's for you.

MR. NANNEY: Steve Nanney with PHMSA. Would you just repeat that? I hear it but I'm

not hearing what you said. If you don't mind.

MR. DRAKE: Really just a confirmation that if you've got a TVC record test -- and I appreciate the other person commenting about TVC record -- I think really the point is the test is the gold standard. If you have a test, that's actually the litmus to validate the MAOP. Whether you have TVC records or not is subservient to that.

I think that the other question is really about is it a 619 -- or 619(a)(2) test at the time the code was written when that pipe was installed? Because codes moved around. And what is the standard? What's the target?

MR. NANNEY: Well, the target would be at the time it was constructed, unless you're doing a new test.

MR. DRAKE: Thank you. That's what I was looking for.

MR. DANNER: Okay, does that require, Steve, does that require a change in what you have here or is that -- do you feel that that's

captured in what you're written?

MR. NANNEY: I heard somebody say something as John was saying something to me. I'm sorry.

MR. DANNER: I think Andy was seeking clarification. And I was just asking if the clarification you gave, is that captured in what is written here or does that require new language?

MR. NANNEY: I think it's, I think it's captured in what we plan to do in the rulemaking, yes.

MR. DANNER: Okay. Andy?

MR. DRAKE: Just a follow-on comment about TVC records. I think I was trying to capture two thoughts. And I just wanted to make sure we isolate them.

One was the issue about at the time the pipe was tested. The other is this issue about TVC records. I think that's really going to come up in 192.624(c)(1), which is the next discussion. But I thought the commenter's

question about TVC records is really valid as sort of a place holder here.

If the test is the gold standard, I think we need to be conscious about adding the words TVC to the test. Because TVC comes with all kind of burdens about MAOP confirmation. The test may not meet the criteria for TVC.

And I think as long as you have a test, that is the gold standard. And I think that will help kind of ease some anxieties about what is the hurdle rate for the test of the record. Is it a TVC record or is it a hydrostatic test record?

So I just I don't meant to be getting into mincing nomenclature here, but you have to be careful because you start kind of a do loop we can't get out of because you may not have all the TVC records. That's why you're doing the hydrostatic test.

So I just wanted to kind of put that thought out there.

MR. DANNER: Do you want to respond to

that? Okay, Ron.

MR. BRADLEY: Thank you, Mr. Chair. Ron Bradley from PECO.

So I want to sort of underscore that. The document uses -- almost had a cramp. I hate when that happens.

(Laughter.)

MR. BRADLEY: The document uses the word TVC at this point. I would say exactly what Andrew says, a valid pressure test in hand, the way I read this, and there's a lot here so I just want to unravel what I've heard, Steve, a valid pressure test in hand, you're done. You've got what you need, you can move forward.

If you have to reconfirm and you've already got that valid pressure test, you're set. So when you reference 619(a), I sort of in my mind see the reference to 192.619(a)(2). And I think you said that's --

MR. DANNER: Okay, Steve. Your mic's off.

MR. NANNEY: Yes, it is on the pressure

test.

Now, as far as the portion that we talked about the last meeting -- I don't know if it was March the 2nd or the meeting in January -- as far as it's getting material documentation records for anomalies and things like that, when you go do a dig if you don't have those that would still be a part of it. If you had a valid pressure test and you had anomalies and things like that in the pipeline, when you go do the dig and you don't have those material records you would need to get that. That would be part of it.

MR. DANNER: Okay. Alan. Or, Ron, did you have a follow-up?

MR. BRADLEY: Yeah. Just to -- so just wanted to -- I follow you with the repair. And I think we'll talk about that later. I was just thinking about the -- every now and then I hear the concern about having traceable, verifiable, complete records as it relates to doing your pressure test. And we're doing a pressure test

with water or a different medium but nothing explosive.

And I think we're safe that the onus would then be on the operator that if we did something wrong, I mean we generally bring the pressure up slow, but when we've done an MAOP for reconfirming lines I know in my company we confirm back at the existing MAOP. So the practice works. If we have a valid pressure test we're in good shape.

If we have to MAOP and we don't have all of the traceable, verifiable, complete records that you could tie to the pipeline, we bring it up slowly and confirm MAOP with the hydrostatic pressure and then we're set.

So it seems like the process works.

MR. DANNER: Alan.

MR. MAYBERRY: I just wanted to make sure we're on the same page with what we mean by a valid pressure test.

And then also I heard the comment from Erin was that, you know, to tweak it to be what

was valid at the time. Well, we, when we say a valid pressure test or subpart J pressure test are you meaning -- and this is a question for, I don't know, Andy, Ron, or Cheryl perhaps -- that the level would be consistent with what's in subpart J or the level is consistent with what it was required to be at the time it was installed, which may vary a bit from subpart J?

MR. DANNER: Okay. So Ron's got his tent up. Do you want to respond?

MS. CAMPBELL: Define the word "level."

MR. MAYBERRY: Well, Cheryl, you know, whether it's one-and-a-half times or, you know, that, the ratio, MAOP to test pressure.

MR. DANNER: Sara.

MS. GOSMAN: Sara Gosman.

So I wanted to get back to this issue of threshold 30 percent SMYS. So if I'm understanding the data correctly on the data slide you showed us, the incidents from the last, what, seven years there have been 14 incidents on those types of pipelines, and 10 leaks, and 4

ruptures, if I'm correct.

So, you know, back to this question I guess of risk. So one that I have here is, you know, we look to this question of pressure as a means of understanding the risk of these lines. But when we also have to think about exposure on the other side.

And I'm wondering if one possibility here might be to include those grandfathered pipes that are in areas like HCAs where we're going to expect more exposure. Because to me, right, the -- if we expect more exposure we should go down in terms of, or be more conservative in terms of the safety set of requirements, especially if we're seeing some of these pipelines actually have incidents that are ruptures.

MR. DANNER: Any other comments? Ron.

MR. BRADLEY: Yeah, Ron Bradley, PECO.

Just to respond to Sara's thoughts, I mean I thought the same when I saw the numbers about the ruptures for pipelines lower than 30

percent SMYS. That word "ruptured" tends to evoke a, you know, a concern.

But do a little bit more research and find and, you know, ask them a few more questions about the specifics you find things about the issues that happen that are probably tied more to integrity management and less to -- and most of those pieces of pipe that failed had valid pressure tests. And then over time, whether it was a disruption of flow, or a vibration or something, over time there was a failure mode that came about.

But those were not, I don't believe they were related to a lack of having a valid pressure test up front.

MR. DANNER: All right, anyone else? Cheryl?

MS. CAMPBELL: So I do want to -- I'm sorry, Cheryl Campbell, Xcel Energy -- I wanted to go back, Alan, and make sure that we talked about your question about the level. Can you state it again so I make sure I understand it?

And then I'll make sure I'm answering the right question.

MR. MAYBERRY: Okay. There was a suggestion to clarify that what we're saying was that the -- I mean, currently we're talking about it has to have a valid subpart J pressure test. But the suggestion was to make sure that that means that it's a valid pressure test, I guess just really an alteration, a valid pressure test at the time of installation.

Which may have preceded, you know, prior to 1970 perhaps it would have been a pressure test but it wasn't -- you know, we didn't have subpart J at the time. It was a pressure test. But I imagine that, and I believe there are cases where, many perhaps, where it was a valid pressure test at the time but it may not be at the level that subpart J specifies, or a combination of subpart J and 619.

MS. CAMPBELL: So are you saying, say, a pressure test of 1.1 versus 1.25?

MR. MAYBERRY: I just want to make sure

I understand what I'm agreeing to.

MS. CAMPBELL: As do I. So what that -- and I'm, it's never good when I just speak, you know, stream of consciousness, but I'm going to give it a shot because I know there's people around the table who are going to correct me if I just mess this up.

So what might have worked in a pre-'70 world, say a 1.1 times, and I'm in whatever class location I'm in, and I should have tested to a 1.25 for that class location, is that what you're asking about is, hey, maybe the MAOP should be something different than the 1.1 if you're in a Class 3 or 4?

MR. MAYBERRY: Right. Could it be if it were to be done just like it was then today, would it still result in that MAOP. I'm gathering --

MS. CAMPBELL: The right safety factor.

MR. MAYBERRY: Right.

MS. CAMPBELL: We're talking about the right safety factor.

MR. MAYBERRY: Right. I'm gathering that perhaps it would be a little bit different. Not much, but it could be. I think there are, you know, cases out there like that.

MS. CAMPBELL: Okay. No, I need to think about that for a minute.

MR. DANNER: Andy.

MR. DRAKE: Hey, Alan, this is Andy Drake with Enbridge.

I mean, just to be very honest, you're proposing changing subpart J. The question is not before 1970, it's before today. Is the current subpart J 1.1 test valid, or are we going to now come up with a new subpart J criteria today, tomorrow, next month that is a new subpart J target? That's really what the question is.

And that's where the -- I'm just being as transparent as possible. I think folks are worried J is moving around, not before the code but current code is moving around. So, is the current, the current today subpart J standard the gold standard? If it is, I think everybody's

okay. If it's the tomorrow standard then we've got to stop because that's a target we haven't even been held accountable to date.

MR. DANNER: Steve.

MR. NANNEY: Yeah. Just to answer, as of today if you've got a valid 1.1 pressure test, and it's Class 1 and it met the requirements, the answer is yes. If after the rule goes into effect you have to re-pressure test it, it's 1.25. That's what the rule states in 619(a)(3) or (2) or what -- I think it's (a)(2).

If the class location changes and you need a pressure test, it needs to be what 619 says it should be. If you started out at Class 1 and it's now some other class that requires a pressure test higher, you'd have to meet whatever that class location states.

MS. CAMPBELL: Okay, I understand. And yes.

MR. DANNER: So are we all on the same page? Okay, I see Andy, Ron, and Cheryl all nodding. I haven't seen Sara nod yet. Okay.

Any other comments? Sara.

MS. GOSMAN: Sara Gosman.

I just wanted to thank Ron for his information. I wonder if there's any way that you can remind me the mileage that we're talking about here in terms of pipelines, grandfathered pipelines that would remain grandfathered under your proposal?

MR. GALE: So, Sara, are you specifically referring to the less than 30 percent slides?

MS. GOSMAN: I am, yes.

MR. NANNEY: You're asking how much mileage is less than 30?

MS. GOSMAN: Yes. And older than '70.

PARTICIPANT: Grandfathered; right?

MS. GOSMAN: Right.

MR. DANNER: Can you turn your mic on, Steve.

MR. NANNEY: I said we'll have to look and get back to you on that, Sara. We put it together in previous slides but --

MR. DANNER: Okay. So we are at that point in the afternoon where it might be good for us to stretch our legs for 10 minutes. So why don't we take a break and we will come back here at 3:18.

(Whereupon, the above-entitled matter went off the record at 3:08 p.m. and resumed at 3:41 p.m.)

MR. DANNER: Okay. We are back on the record here, folks. Alan, do you want to kick us off for this part of the discussion?

MR. MAYBERRY: Yes, so I'll get things started. Thank you, Chairman Danner. Before the break there was discussion, I know, and concern over the modification we made to what we have presented today that we had taken out Class III and IV non-HCA pipe less than 30 percent.

There was a concern that while that could potentially be high-risk pipe I know our focus on this, certainly we are addressing pipe of the stress level that probably instigated this area from the very beginning, the way San Bruno

and the incident involved pipe that was operating above 30 percent. It's kind of tricky, too, and you can see the fun of making policy on a national level.

We're also dealing with an issue that was not addressed back when the code was first implemented in 1970 because of the impact on commerce to having operators go back and test pre-code pipe, but nonetheless I think we have a possible solution here that's up on screen to the left, the last bullet to what we have modified the language, you can see as we discussed or addressed pipe above or equal to 30 percent SMYS that we would look at the cost and benefits of including Class III and IV non-HCA pipe that is less than 30 percent SMYS.

It looks like this is a good compromise that would have us look at that, and we can decide whether or not it gets included based on the results of that cost/benefit. So we'll just kick it off with that for the discussion.

MR. DANNER: Okay. Sara?

MS. GOSMAN: As an instigator here, I guess I will explain a little bit about what I am thinking, which is in terms of trying to get at this risk-based regulatory approach, it seems to me that the pipe that we could be most concerned about is the pipe that's outside of HCA's but where we still have exposure to, say, residences. Right? Class III, for example.

And so what I'd like to do is, but you know, the issue is we're talking about not that much mileage here, and there's a set of data that PHYSA could gather and go back to on this question of costs and benefits. I think that we should ask them to review that because again, this is a narrow set of pipe here where we'd see more of the risk.

But it's not a proposal to included it, right, it's a proposal for PHMSA to go back and look at the costs and benefits of including it.

MR. DANNER: Okay, the language,

though, does not say that if the costs and benefits, if it shows benefits it should be included. The language doesn't say that. It only says review it. Is that still acceptable, Sara?

MS. GOSMAN: I guess my thinking is if benefits are greater than costs, by definition we'd want to see an agency adopt that kind of rule, for social good. That would be my assumption but it's not put into the language, it's true.

MR. DANNER: Yeah.

MS. GOSMAN: We could.

MR. DANNER: So we should think about whether it needs to be in there. Anyone else have any comments on the language up there? Andy.

MR. DRAKE: This is Andy Drake with Enbridge. I think just to try to capture the conversation we had about sub-part (j), I think it will help if under the fourth bullet, the sub-piece where it says "Records necessary to establish MAOP in accordance with 196.19(a) or (c), it should say 192.619(a)(2). That is the

hydra test requirement.

That's what I think part of this is, when you reference 619(a), there's a whole fleet of criteria that you're exposed to. And I think that's what's sort of got people anxious about this. If you're talking about the hydro test, that's 619(a)(2). So you put that in there, I think that locks together.

And then you've got in there, "at the time of construction," which I think the code at the time of, I think you've addressed that but I just want to be, I'm not a regulatory constructionist but I do know that 619(a) has a lot of criteria so you really should just talk about the test. I think that's just a point of clarification.

MR. DANNER: All right, thank you. Are folks okay with that clarification? Okay, I see nods. All right, any other discussion on the language that we have up there?

MR. MCLAREN: Should (c) still be included in that clause?

MR. DANNER: All right, so the way it reads now is (a)(2) or (c) at the time of construction. Hearing no objections. All right, if there's no further comments on this language, are we ready, is there, I think we're ready to entertain a motion. Does anybody have a motion with regard to this language?

MR. NORMAN: And just to be clear, Chairman Danner, we have two separate motions here. One for paragraph -- is that right, two?

MR. DANNER: All right. If we're going to do it as a single motion then let's ask if there's any discussion on the right side there. Give folks a moment to read it. Sara?

MS. GOSMAN: I can make the motion if you'd like.

MR. DANNER: Okay. I'm not seeing any discussion, so let's entertain a motion.

MS. GOSMAN: Okay. The proposed rule is published in the Federal Register and the Draft Regulatory Evaluation with regard to the provisions of the scope and completion date of

MAOP confirmation are technically feasible, reasonable, cost effective and practicable if the following changes are made:

Four MAOP reconfirmation scope. Revise Section 192.624(a) to strike paragraph (a)(1) which was the proposed criterion related to lines with previous reportable incidents due to crack defects;

Create Section 192.917(e)(6) to address segments with crack incident history in IM;

Withdraw the new definitions of modern pipe, legacy pipe and legacy construction techniques;

Renumber Section 192.624(a)(2) for line segments without records as Paragraph (a)(1);

Revise to refer to records required by Section 192.619(a) and (c) instead of pressure test records required by sub-part (j), as discussed by the committee, as shown below. Records necessary to establish maximum allowable

operating pressure in accordance with Section 192.619(a)(2) or (c) at the time of construction for the pipeline segment;

Renumber Section 192.624(a)(3) for grand fathered lines as Paragraph (a)(2);

Revise to apply only to lines only with MAOP greater than or equal to 30 percent SMYS.

PHMSA should review the cost and benefits of including Class III and IV non-HCA pipe with less than 30 percent SMYS.

MR. NORMAN: Do you need to read the second part, the right side?

MS. GOSMAN: For MAOP reconfirmation completion dates:

Revise Section 192.624(b) to address how the completion plan and completion dates required by Section 192.624(b) would apply to pipelines that are not currently applicable under Section 192.624(a) but may become applicable in the future, e.g. located in a future HCA or Class III or IV location as follows:

Section III. The operator must complete all access required by the Section on 100 percent of the pipeline mileage that meet the conditions of Section 192.624(a) by -- insert date that is 15 years after the effective date of rule or two years after the segment first meets the conditions of Section 192.624A, whichever is later.

MR. HILL: Robert Hill would second that motion.

MR. DANNER: All right. We have a motion and it has been seconded. So is there any further discussion on the motion before us? Cheryl.

MS. CAMPBELL: I just have one question or comment on the right side there, right, and I'm not trying to create another problem, maybe I'm going to be the instigator this time, Sara, but "the operator must complete all actions required by this section," "that is 15 years after the effective date or two years after the segment first meets the conditions."

I think that two years is sometimes okay, I think that for some pipelines that this applies to, I think that two years might be a bit of a challenge. So is there, do we want to think about a different number there? I'm just throwing that out to the committee that I think that two years might be kind of a challenge.

MR. DANNER: Any thoughts? So it's basically 15 years after the effective date of the rule or two years after the segment first meets the conditions of 192.624A, whichever is later.

MS. CAMPBELL: Yes, so, Chair, I'm thinking about we're 15 years down the road, right, and you discover a pipeline that meets the criteria and now you got two years, right, and for certain parts of the country or certain systems that might be a real challenge to get through that. That's all I'm suggesting.

MR. DANNER: So if I may, what kind of time period would you be suggesting?

MS. CAMPBELL: How about five?

MR. DANNER: Yes, Sara.

DR. LONGAN: Sara Longan, DOI. I'm wondering if there have been any public comments on this specific part, and I also believe that in various places, including rural and perhaps Arctic in Alaska, the two years and other regulatory efforts is usually a challenge to meet just because of the shorter operation and seasonal challenges that we face. So I would support the committee having a discussion of lengthening two years to five.

MR. DANNER: All right, so, we did not receive public comments on that issue. But let's have some conversation. Ron?

MR. BRADLEY: Yes, Ron Bradley, PECO. I do recall, I think it was someone from National Grid, going off of memory, that had a suggestion of how it was maybe two years for planning but didn't sort of have an outside window. I think Cheryl's recommendation around five is a good one, because there is some planning required in some of these trickier areas. That may just work.

But I do think someone put a thought on the record earlier, and I'm glad that Cheryl brought this up for discussion.

MR. DANNER: Okay. Other thoughts? Yeah, John?

MR. AIREY: I'll move to amend the motion to insert five years where we have discussed.

MR. DANNER: Okay. We have a proposal to amend the motion. Andy? Oh, you are? Okay. So while the issue is always in some instances two years is doable and in some instances two years is not doable and you want them to do it in two years when it's doable, and yet you understand if the ground is frozen for 11 months of the year that two years can be a struggle. So that's what we have to deal with here. Sara?

MS. GOSMAN: So I'm not sure what the appropriate thing to do is with an amended motion on the table, but I'll just say one other possibility is to do the kind of notice provision that we've been doing where we want an exception

to a rule, so we keep it at two years but somebody can go to PHMSA and then argue for a longer time period if the ground is frozen or if there are other particular issues that affect that operator.

MR. DANNER: Okay, so, John, I'm going to take your proposal as part of the discussion as opposed to a formal proposal at this time so that we can have a discussion without getting swallowed by Robert's Rules of Order.

So we have a proposal to move it to five years and a counter-proposal to say why don't we leave it at two with a waiver process for extending it to five. Any discussion on those proposals? Sara?

DR. LONGAN: Thank you. Sara Longan, DOI. I think that that's a good counter-offer. I would just add that in some places then, the operator or applicant would have to go to PHMSA all the time. In the Arctic, 11 months the ground is frozen regardless. So I think the five-year option allows for more flexibility both for the

operator and for PHMSA.

MR. DANNER: Would it be required that you get a waiver every time, or could there be some kind of a blanket waiver that would apply to for example, a geographic area with challenging weather? So that in other words it would be a one-shot saying, I'm north of the Arctic Circle, please --

DR. LONGAN: Mr. Chair, follow up?

MR. DANNER: Sure.

DR. LONGAN: I think that's also a good suggestion, but I think that we've all been in this type of situation before where there are acquisitions and maybe the ownership of the field or the pipeline might change. I think that just going in, flexibility is smart to think of on various levels, both on the regulator and the regulated.

MR. DANNER: Okay. Thank you for that. Steve, and then Andy?

MR. ALLEN: Yes, Steve Allen, IURC. Perhaps language, I'm not a wordsmith but, five

years but as soon as practical. So basically you're saying get it done as quickly as you can, not to exceed five years.

MR. DANNER: Okay. Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I appreciate the conversation that's going on. I was just sitting here trying to imagine, we have five lines in Boston and New York City and trying to get something inside our budget cycle and permitted within two years is actually not really practicable.

I think that's not to your point, that's just going to become matter of course, and I hate to do waivers for matter of course kind of stuff. I'm kind of with Steve. I know you should be moving as quickly as possible, but there needs to be some target that's a practicable target. It's not just a small tail end of the pipeline that you're talking about, actually.

So I think there's some guidance here that we would be shooting more for a four-year number or something like that, you know, moving

as quickly as possible. I think Steve's point is well taken. We should be moving quickly but I think you're going to need more than two. That's my best thought right at this moment, so I'm just kind of throwing it out there for conversation around the table.

MR. DANNER: Okay. Alan?

MR. MAYBERRY: Just from a standpoint of having to implement this, I would prefer something probably definitive, such as five or two or just a number. I know we have flexibility in other areas but in this one, I could see a lot of these coming in if it were a concern in, say, some areas where it's difficult to permit or where there are construction fees and issues like in Alaska.

So I think we can live with five and maybe even add the language, even though it's not enforceable, as soon as practicable. We don't enforce that but it probably would end up being five years.

MR. DANNER: All right. Ron?

MR. BRADLEY: Ron Bradley, PECO. I agree. I was just going to sort of reinforce that. I like the language of five years or as soon as practical. Especially, you don't want an operator to be penalized to move quicker and have challenges if it's recoverable in some states, where some states may challenge you on doing more than the minimum. I like that language.

MR. DANNER: All right. I would just counter that by saying I don't want anyone to be dilatory when they actually have the resources and time to do it, and they say well, we need another, we have another three years so we're not going to do it this year. That's what I think we're trying to balance here. Okay. Steve Nanney?

MR. NANNEY: Yes. Just one thing. Whether we keep it at two or five, you realize the operator should be identifying these facilities in the first couple of years of the 15 years, not waiting till the last two or three years to get more time.

When I hear that we're not having

enough permitting time, I'm thinking that permitting should have been done in the first five years, not the last two years. So that's just a comment to make. That the intent of this is to identify this early on and then you have 15 years to implement everything. Just a comment.

MR. DANNER: All right. Thank you. Sara?

MS. GOSMAN: My concern about "or as soon as practicable" is that it could actually lengthen out the time period and because it's not particularly enforceable, I think it would be hard to engage in a discussion about what was practicable. And if we're talking about, you know, seven or longer years, I think I'd prefer to either have a hard line if we're not going to do a waiver process or to make clear that the "or as soon as practicable" makes it earlier.

MR. DANNER: Well, but it would say "so as soon as practicable but not to exceed five." So five would be the ceiling. And "as soon as practicable" would be --

MS. GOSMAN: I would want that.

MR. DANNER: Okay. So, right now -- Oh, Cameron?

MR. SATTERTHWAITE: Yes, Diane has a question. She wants to weigh in on this. Diane, are you there?

MS. BURMAN: Yes, thank you. I just wanted to say I like this language "as soon as practicable but not to exceed five years," but I think it's right to find the appropriate balance and I do understand Sara's concern but I think it is covered by the "not to exceed five years," so I think it really tries to take into consideration the reasonableness.

I'm comfortable with the language, understanding that "as soon as practicable" really does try to focus on the need to do it with due diligence, as quickly as possible, but understanding limitations. So I think it sets the right tone and is reasonable.

MR. DANNER: All right, thank you, Commissioner. When Cheryl said five, I don't know

how much thought went behind the five, so now let me just pause it. Would anybody have an objection if it were to say, "as soon as practicable, but not to exceed four." Cheryl?

MS. CAMPBELL: So, I'll -- I would state, Mr. Chair, that the five is based on my experience with dealing with large urban and suburban communities and the amount of time it takes to do permitting and things of that nature. The bigger and older the city is, the more complicated it can be at times. So I hear what you're saying, I think as soon as practicable, I mean the reality is if you say not to exceed five, and I find one of these lines, and Steve, just to, you know, it could change, right?

I mean, I agree with you. We should be identifying this stuff early on but that doesn't mean that growth and stuff isn't going to push a pipeline into this category. So that's why I was thinking about it, but the reality is in my operating areas in everything except for the more smaller communities, not to exceed five, I better

be working on it today or I might exceed five.

MR. DANNER: So -- Thank you for that, just let me ask. We're starting out here with 15 years and then to now five, how big a category is this of needing that full five years?

MS. CAMPBELL: My belief, that I would welcome input from other operators around the table, but again I agree with Steve that I have a population that's in this 15 year bucket that I should be working on and I should be working diligently on starting the day after the rule goes into effect. The group of pipelines we are talking about here are I think relatively small because something's changed on the system. There's been growth or something else has changed on the system and I went from a Class I location that was not an ACA into an ACA. So I would think that it's a relatively small group of pipelines, but I welcome other thoughts.

MR. DANNER: Okay. And so, Andy, I'll call on you, just again my concern is by making it five everything becomes four and a half

whether it's needed or not. Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I agree with Cheryl. I think this is a very small population, I think is what you're, when you really look at it, because the 15 years is designed to take care of the stuff that we've currently identified. And we will chew through that pretty quickly.

It becomes about the Delta, the new stuff, the changes, and how quickly you can adopt them. I mean, if I had to look at this on the fly -- I do have to look at this on the fly, I think even for growth areas even if you're only talking a couple of days a year, just the basic permitting issues are more than two years to get them into our budget cycle to get them permitted and ready to go. I would say somewhere in that three or four range.

I think five is going to deal with the vast majority of these. If we came out with four, I can work with that. I think if you go over four you're probably going to end up with a waiver

which we can create some waiver category for that. I'm fine with that.

I don't mean to sound like we just keep kicking the can down the road, but two is going to, two is going to be a problem. I can tell you that right now. And the other part of that is we do have, a lot of these pipes are probably going to end up affecting customers which is not trivial either.

So there's a lot of coordination has to go on here. I don't think two is practicable. I think five is your high 95, 90-some percent confidence that you're going to get everybody in. If we wanted to go with something like four, I can deal with four but I think then you'd need to have some sort of waiver criteria for special considerations. Whatever the committee wants, I mean I'm good either way.

MR. DANNER: Okay. I, speaking for myself only, I would be comfortable with that and I would be more comfortable with that than five because I do feel that there's a lot of time and

the more time you give folks the more they wait until they take the action. So if it were four plus a waiver, I think I personally would be okay with that. Any other thoughts?

MR. DRAKE: I would second that.

MR. DANNER: John, you had the original five. Okay. So I'm hearing a begrudging consensus around four plus a waiver. Excuse me?

MR. GALE: Just real quick, Chairman, do we want to plan, there is a waiver for one year already built into the RFP, though, so that will get us back to the five years if we need them.

(Simultaneous speaking.)

MR. GALE: So does that mean we have to go three plus a waiver?

MR. HILL: Mr. Chairman, as long as PHMSA's got the capability with the waiver, let's just do the four and vote. That would be my recommendation. Robert Hill from Brookings County.

MR. DANNER: Thank you, Mr. Hill. I

think I am hearing no further comments, so it looks like it's, well, I'm seeing now four years with opportunity for a waiver application, which is going away. Steve, go ahead.

MR. NANNEY: All right. Could we put either a waiver or no objection from PHMSA so we can take a look, if you want to recommend, so we can look at which one we put in any wording? A no objection letter is a lot easier than a waiver.

MR. DANNER: So, yes, I don't have -- any thoughts on what Steve is proposing? Stephen?

MR. ALLEN: I didn't hear him. I honestly didn't hear him.

MR. DANNER: Yeah, okay. Steve, can you restate, can you restate that? Some folks didn't hear you.

MR. NANNEY: All I ask is that I recommend that you put either a waiver or a no objection from PHMSA. A no objection, and then we can look at it and see which one we put in the rule-making. A no objection is a lot easier than a waiver. A waiver becomes a special permit and

it's a process all in its own.

MR. DANNER: Okay, Sara and then Sara.

MS. GOSMAN: Sara Gosman. So, Steve, I'm just wondering, the language that's currently in the proposed rule, the notification language of one year, is that, sorry, the language that's currently in the rule, is that --

MR. NANNEY: That is not a waiver.

MS. GOSMAN: Acceptable? Right. That is not a waiver.

MR. NANNEY: That is a notification for a no objection letter from PHMSA.

MS. GOSMAN: How I read the current proposed language is that we are not referencing a waiver at all but we are relying on the proposed year extension based on a notification. So that's okay?

MR. NANNEY: Yes.

MR. DANNER: All right. Sara?

DR. LONGAN: Sara Longan. I just always question when there is a waiver or no objection, and Steve, I take that as very devise from the

agency who would have to be participating in the action. I don't know though, is there a term on a no objection from the agency or would the operator need to wait an indefinite amount of time to understand if it was allowed or the objection would be off.

MR. NANNEY: Well, throughout this is on the notifications. It's been a 90-day reply back from PHMSA ,

MR. DANNER: So if -- Diane Burman.

MR. SATTERTHWAITE: Okay, go ahead, Commissioner.

MS. BURMAN: I was just confused also about a waiver versus the no objection and if it was understood after this four years. I am just trying to make sure that I understood exactly what we were doing. If it's four years -- but if it takes longer than that I just don't want to somehow be penalizing folks if they're in good faith trying to fix it.

I'm just concerned. We went from five years to four years and we're trying to establish

what the right amount of time is, so, to me it's more important that the language "or as soon as practicable" and I think that's what we had hoped to achieve but also allow that flexibility that's necessary without penalizing folks. So I'm just looking for making sure that we're all careful about what we're doing without causing ambiguous, ambiguity, in the regulations.

MR. DANNER: All right. Thank you. Steve?

MR. ALLEN: Yes, thank you. Steve Allen, IURC. Just to point out, in previous meetings we have some language already in place regarding no objection within 90 days or something like that. It just feels like we could reuse that language in this situation.

MR. DANNER: Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I know we have a lot of record here about the years and I'm actually good with the last proposal, I think, we had on the table there

but I want to come back to the 30 percent SMYS discussion.

I think certainly this is significant change, and I appreciate the comments and concern around it. What I would ask is that if we're going to vote on this, I want to know what it is the outcome was, also. I would like to see PHMSA bring this back to the committee, what was the resolve of your assessment before the final rule. I think we all, this is significant change and I think we've talked about this eclectically over the last year, but the four ruptures that were cited I don't think have anything to do with material flaws.

And I think that's really germane here. It's not relevant, the size of the population, because I don't know that we have exactly defined the population. I'm not sure that that slide that we showed at the break, that's what we were in the hall huddling, what's our confidence in that number? Is that the right number? And the general consensus was, that's not

the right number.

So that's what pauses me here. I don't think we have a good sense of what exactly is the cost of doing this. We're not sure that there's -- well. We're pretty confident there's not a significant threat here, but we see an uncertain cost, and yours is getaway. I'm not sure what the concern is.

So I'd like to see us revisit this, at least, before the final rule. That's, I can vote on this but I think we vote in good faith, both sides, that we would see it again before the final rule.

MR. DANNER: All right. Steve, and then Cheryl. Okay, Cheryl?

MS. CAMPBELL: I don't disagree. I think what will be challenging is I don't think this is like straight linear miles, right, so if the miles, what did we say it was? Maybe 400, maybe 400 miles, I don't think that's a straight-up million dollars a mile for a hydro test. I think that's very disparate pieces here and there

and could be a lot more challenging to do.

So I think some careful thought about the cost side of it to go with that benefit side, I think is required for this one. But otherwise I would agree with Andy. I am fine with voting on this but would like to see the result of that analysis before the final rule.

MR. DANNER: Okay. Is that an analysis that could be done before our June meeting?

MR. MAYBERRY: Ideally I'd rather just have the direction of the committee and then we go off and do our thing, and ideally not have to report back. I'm not sure it can be done by June. My preference is to get the will of the committee and we'll take that under advisement for the administration and we'll go from there.

Honestly, I'd rather avoid having to come back to committee. Just trying to get to the finish line I'd rather avoid that.

MR. DANNER: Okay. Thank you. Sara, and then Steve?

MS. GOSMAN: I don't want to slow down

the process at all here. I think the intent of this is, well, I need to step back for a moment. The NTSB, of course, recommended that we remove all grand fathered pipe, so that's sort of where we're starting and then we have a statute that includes the threshold of 30 percent SMYS.

What I'm looking for is some middle ground here that acknowledges the potential risk that isn't being addressed through the IM program. That seems to me this class III and IV non-HCA.

As I understand it, there is a concern about the benefit versus the cost side. If PHMSA reviews the cost/benefit analysis and finds that the benefits of requiring reconfirmation are greater than the cost as a regulatory person I think that tells us that we should be regulating them.

So that would be my instinct, to not necessarily need to review that, because that would be the, well, if you're concerned about the input, I guess, it sounds like maybe the question

of costs or what the real incident data that needs to be looked at on the benefit side is, and you're nodding, then I think maybe that could be given to PHMSA as part of their review and consideration.

MR. DANNER: Andy?

MR. MAYBERRY: I think you had a direct response to Sara, is that correct?

MR. DRAKE: Yes. I appreciate that. This is Andy Drake with Enbridge. I'm actually good with that. That's exactly what the core of my concern is. I just want to make sure we're making decisions on facts and data. And that would, we're making a big decision so let's make sure we have the right data and right facts.

And I think that was the drift of what was the energy at the break, was we don't have this data or we're not in agreement with the data, so we need to get a line on the data and then I'm good. If the cost/benefit comes out and we were all stacked hands that the data's the data, I totally agree with Sara. That's exactly

the right decision. I'm just not sure we're all synchronized on what the inputs are at this point.

MR. DANNER: Okay. Steve?

MR. ALLEN: Steve Allen, IURC. I think I agree with both Andy and Sara on this, but the statute calls for what, exactly? The reverification on everything greater than 30 percent? Then I think that's really our orders.

If at a later date you do the assessment, the analysis, and it looks like "Class III and Class IV pipe less than 30 percent" needs to be added back in, perhaps it could be.

The discussions we've been having this week and previous regarding the different between a leak and a rupture, that was a little blurred for me this morning when we saw the four out of 14 ruptures on pipeline less than 30 percent, but from what I'm hearing from our industry members that perhaps that is a little bit misleading.

So I guess I go back to what the task

was from the statute, being greater than 30 percent, and I would almost suggest we leave that in the red text like that or take it out.

MR. DANNER: All right. Alan?

MR. MAYBERRY: Just thinking out loud here, I mean one other option would be okay. We go do this analysis, we come back but then get a consensus of the group at a later date, whether it's June or whenever, to on a pass forward to actually address it at a future date.

Initially we'd go with, I guess, what's more in line with the mandate and move that forward but then just come back at a later date when we do have the report or the information that we're talking about there related to the cost/benefit of III and IV non-HCA less than 30 percent, that we come back and report back to this committee and then make a decision then to attach it to another policy that we might be moving through the process. That's just another thought there.

MR. DANNER: All right. Sara.

MS. GOSMAN: So I'm concerned if we move it later that it will be number four in line of possible rules. And I think it's directly in front of us and you've done the cost/benefit analysis for the rule already through the IRA, it's just -- So to me what I'm trying to get at there is there was a proposal to include all pipelines here, right, in the proposal. NTSB says we should do that. Statute says threshold mandatory is 30 percent SMYS.

So what I'm trying to do is look at that risk, identify a particular area of risk and ask for more data analysis but I think PHMSA already has because they had to do it through the IRA.

And maybe it does mean coming back in June to reconsider it, but again, my feeling on it is if the concern here is that the costs outweigh the benefits, if that's the ultimate concern about why we're not doing regulation of less than 30 percent SMYS. I don't feel like I have enough information in front of me to be

confident that that's the case.

MR. DANNER: Yes. And I think that's where I come at this as well. I think that basically if we find out that the costs exceed the benefits, then they don't go forward. It's not included. If the benefits outweigh the costs, then it is included. That's how I see this.

So again, speaking for myself, I'm comfortable with that language. Andy?

MR. DRAKE: This is Andy Drake with Enbridge. I appreciate your position, Sara, and I think I like that, where's the mandate, those are always good words. What is it that we went into the woods looking for when we started the?

But I do think we can get the information and so this is a challenge to the trade associations and anybody else who has the information, to file that to PHMSA and try to make sure we have the facts to discuss this.

I don't know if there's any way for us to get a line of sight to this before making, I appreciate where Alan does want to move forward

with this, but I'm kind of stuck here because I think if we give you clear direction we won't see it again which means we won't get a chance to even see the facts as they were digested by PHYSA.

I do know that the four ruptures, I've got them sitting right here, and one was selective seam well corrosion, that's not a manufacturing flaw. One was a hydro test that was tested to significantly above a hundred and, well, significantly tested well above 30 percent SMYS. It wasn't a material failure.

The third was mechanical vibration, and the fourth was an off-shore overload, so that's not a material flaw. So those are some facts that go into this. I think getting some more facts from other parts of the industry that have how is the miles and that sort of thing, and what's the cost/benefit.

I would be fine actually making a proposal to get the facts into PHMSA and have that discussion off-line and then let this go

where it may go on cost/benefit. I'm good with that.

MR. DANNER: Just so I understand, so you're saying go ahead and use this language today, approve it, but let's ask for them to report back as soon as they know something and then if we need to revisit it we can do so.

MR. DRAKE: I think it would be nice if in June you could give us an update but you're not actually asking our vote at that point. I would ask for PHMSA to have an outreach between now and June and get the facts, because this has sort of changed on the fly. So let's make a really well-informed decision.

I mean, we're already straightening out some of the facts around the table right now. That's good to know. So let's just be explicit about getting facts. I'm kind of looking back here at the trade associations, because they're going to be all over me if I don't.

I just want to be clear about that. I think that's where a good source of data for some

of the facts on scale are, and if there are other facts that people have, let's try to get those. So if you can define a time frame that you want to take facts in to make this decision, I think that would be very helpful.

MR. DANNER: Alan.

MR. MAYBERRY: I can commit that we're going to take it back and review it if, you know, whether that would be June or a later date, it's, it could be later. But we could report back, yeah.

MR. DANNER: Okay. I think that leave us, we've got the motion in front of us, amended with the language in front of us, so not to exceed four years, we don't need to put in language in regard to -- Oh.

MR. GALE: Mr. Chairman, we're about to pull up some language to correctly modify the motion.

MR. DANNER: Okay. So if someone could make a quick motion for us. Sara? And if possible, Sara, since it's the issue is slide

two, if that could be, can you move that to the first screen, this way on the left? If that's possible. I need two on one side and the motion on the other so they can see the context.

MR. GALE: Yes, Chair, if we could have a motion, read this language and have them vote on that, we could amend the motion after we vote on the full motion.

MR. HILL: Mr. Chairman?

MR. DANNER: Yes.

MR. HILL: I'd like to make a motion as, I move to amend the motion by deleting the phrase "two years" and replacing that phrase with "or as soon as practicable, but not to exceed four years," and adding directions for PHYSA to consider a waiver or no objection procedure for extending the time line past four years.\/d All right.

Do we need a second for the motion, to amend the motion? Okay. So the rule's been seconded. So we now have a motion to amend the motion. Do we need any discussion or shall we

just go to a vote? Alan, your card is up? Okay. We have a motion, we're ready for a vote. Do we need to take a role call or can we just have an aye or nay? All right, roll call.

MS. WHETSEL: Because we had so much fun doing it.

MR. DANNER: Yes.

MS. WHETSEL: Okay. 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: Chad Zamarin?

MR. ZAMARIN: Aye.

MS. WHETSEL: John Airey?

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill?

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MR. DANNER: All right, the motion passes. We now have before us an amended motion. I think that means we don't need any more discussion, I think we're ready to take a vote on the amended motion.

MS. WHETSEL: Okay, so on the amended motion, Steve Allen?

MR. ALLEN: Steve 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?

MR. ZAMARIN: Aye.

MS. WHETSEL: John Airey?

MR. AIREY: Aye.

MS. WHETSEL: Robert Hill?

MR. HILL: Aye.

MS. WHETSEL: Sara Gosman?

MS. GOSMAN: Aye.

MR. DANNER: All right, thank you. The

amendment passes. It's 4:30. Should we keep chugging away? All right, so I will turn it Alan or staff.

MR. MAYBERRY: I will turn it over to Steve. Or Chris, Chris McLaren with PHMSA is going to lead us through the next session which is Methods 1 and 2 of 624(c).

MR. MCLAREN: The first one is 624.192 624(c)(1) Method 1. So we'll start out, we have about a dozen slides and these will cover both Methods 1 and 2 before our next discussion break.

At the December 2017 meeting in response to public NPRM comments, PHMSA suggested the committee consider the following:

Suggest revising 192.624 as indicated in the PHMSA response to PHMSA comments by revising 624(c)(1) to refer to sub-part (j) rather than 192.505(c) for the pressure test.

Public comments on Method 1 pressure text included did not require spike testing for any segments for purpose of MAOP reconfirmation. A statement that the spike test is for crack

mitigation. One comment emphasized the importance of spike tests and noted that there were too many failures following an in-line inspection and remediation program.

PHMSA's response is that if the committee recommends the deletion of 192.624(a)(1) then the spike test requirement in Method 1 is not needed. PHMSA suggests that the 624(c)(1)(ii) legacy pipe and (iii) pipes susceptible to cracks be deleted also.

Committee comments on Method 1 pressure testing in the December meeting, the industry representatives expressed opinion that spike test is for crack integrity assessment and is not appropriate for MAOP setting of reconfirmation. PHMSA suggests that if the committee votes to support deletion of 624(a)(1) lines with crack line defects, from the scope of 192.624 then the spike test requirement in 192.624(c)(1)(ii) and (iii) would not be needed would not be needed and could be deleted. Spike test requirement in 192.506 would still be

utilized where appropriate in other rule sections.

Committee also commented, suggesting adding language to address material documentation in 192.607 with respect to information needed for a pressure test. PHMSA suggests that the committee consider explicitly requiring that information needed to perform a successful pressure test in accordance with sub-part (j) not documented in TVC records must be verified in accordance with 192.607.

On Method 2, there were no committee comments in the December 2017 meeting. In response to the public comments to the NPRM, PHMSA suggests that the committee consider the following:

Revising 192.624 as indicated in the PHMSA response to public comments by changing the look-back period for Method 2, pressure reduction, and Method 5, pressure reduction based on PIR, from 18 months to five years before the effective date of the final rule.

So that concluded the PHMSA responses to the comments on Methods 1 and 2, and the following slides summarize a number of revisions that PHMSA suggests that the committee consider to address comments received from the NPRM as well as in the March 2 committee meeting.

PHMSA suggests revising proposed 192.624(c)(1) pressure test as follows:

Delete paragraphs (ii) and (iii) to remove spike testing for lines with suspected crack defects. These requirements are not needed if the committee votes to eliminate 192.624(a)(1), lines with previous failures due to cracking or manufacturing defects from the scope of 192.624.

Number two, refer to sub-part (j) instead of 192.505(c) for the pressure test requirements.

Number three, add requirement to verify material properties in accordance with 192.607, material verification. If information required for a pressure test is not documented in

TVC records, as discussed in the December 2017 committee meeting.

PHMSA also suggests revising 192.624(c)(2), pressure reduction methodology, as follows:

Increase the look-back period from 18 months to five years from the effective date of the final rule. To strike the requirement from 192.624(c)(2)(ii) to perform fracture mechanics analysis on segments that confirm MAOP, via Method 2.

And with respect to TVC records, the NPRM already included a requirement for verifying missing material properties per 192.607 if needed to support a notification for an alternate pressure reduction approach using Method 2.

Thank you.

MR. DANNER: All right.

MR. ALLEN: Mr. Chairman?

MR. DANNER: Yes, Stephen.

MR. ALLEN: If I may, Steve Allen, IURC. Could you go back to slide 38 for me? Thank

you very much. All right.

MR. DANNER: So at this time we're going to take public comments on 192.624(c). Is there any public comment? Go ahead, sir.

MR. KERN: Good afternoon. Mike Kern, National Grid. My comment is on Method 2. So National Grid requests that PHMSA consider allowing a look-back period to be extended to the beginning of the TIMP program. There can be many reasons for pressure reduction.

For example, class location changes and other operational issues. The intended purpose of the rule that's meant by these reductions, pressure reductions, and with the provision that they can be documented. In most cases further reductions in pressure cannot be made with consideration to the existing customer loads.

So the real pragmatic approach to this is, what are we trying to do? We're trying to do a strength test, right, or verify that the pipeline had a strength test. So any operating

history that the operator has, as well as the pressure reduction below a certain point, really is a kind of a de facto strength test, right?

A strength test is a strength test, whether you intentionally do it with a hydro or you do it by lowering the operating pressure, it performs the same function. So we ask that consideration be given to that time period.

Right now it's a five-year look-back, we're saying that is, we think the operator needs a little more flexibility and operators have done pressure reductions, but come up with a practical time period beyond the five years.

MR. DANNER: All right. Thank you. Other comments? Okay, hearing no other comments, are there any comments by committee members with regard to Methods 1 or 2. Andy.

MR. DRAKE: I just have one comment here. It really goes back to a comment we made in the previous section about TVC records. I think that TVC is a very high hurdle and it comes with some luggage that we just need to make sure we

understand what you're talking about here.

When you say a TVC record must be verified when we're doing the hydro test, I don't, I think, is the record you're talking about the hydro test record itself has to be TVC or are you talking about the materials needed to make the determination about the hydrostatic test?

The reason I ask is if we're not careful, you can kind of create a vicious circle you can't get out of. The reason you're doing the hydro test may be because you don't have TVC records. Some of you want to do the TVC test, that's the gold standard to validate fitness for service of MAOP, you may not have TVC records because the whole reason you're doing that test, you know, is we don't have a TVC hydro test.

That's a different thing. I'm just trying to figure out when you say TVC records are needed to do the hydro test, that seems kind of contradictory.

MR. DANNER: Steve, you want to respond

to that?

MR. NANNEY: Steve Nanny with PHMSA. Let me answer it this way. If you were going to do a hydro test, would you hydro test the pipeline not knowing the wall thickness and the yield strength and the class location of the pipeline?

And by that I mean, if you go out to do a pressure test for MAOP, you got to know some attributes to know what the pressure test is going to be. You also have to know some attributes to know if you meet the standards for the class location you're located in.

So the point here is if you go do a pressure test, we would expect you to have records to know what you're pressure testing whether that's diameter, wall thickness, yield strengths or all those type things. But if you do not have adequate ones, what we've said is when you go do digs for 607 we would expect you to document those material properties.

MR. DANNER: Andy, do you have a

follow-up?

MR. DRAKE: Yeah, that makes sense, Steve. It's just the tripwire of the word TVC because what you're saying is I need to know something about the pipe.

MR. NANNEY: Yeah.

MR. DRAKE: TVC is a different standard. And I think this goes to the heart of the PG&E failure in San Bruno. You'd like us to fill it with water and have the problem happen with it full of water. You know. If I don't know everything about it, I would like to err on the side of over testing it and having it fail with water than assuming it was okay based on paperwork.

And I think that's the really important message here. We can go in, gather the best information you have but don't exhaustively study this trying to get the TVC standards. Put it on test. And that's the validation you're trying to look for. I think that's what I hear you say, is do the best you can with the

information, make a good choice about the test and get on test.

MR. DANNER: Steve, you have --

MR. NANNEY: I would say yes, but again, if you do not have adequate material with records we would expect you to do the validation when you do the digs. And if you find that what you assumed is incorrect for the class location, etc., you would have to make changes based upon those findings.

I mean in other words, you may assume that you've got one wall thickness grade pipe, and if you find that that's incorrect and it doesn't meet the class location, you might have to change the pipe out.

MR. DRAKE: Before you do the hydro test. I mean, I think we've had this conversation a couple times. We're trying to differentiate between establishing MAOP and doing integrity management. I think we're trying to make sure of a practicable standard to start doing the testing.

If we have to start sampling all over the place to figure out how to put a pipe on hydro test, I think you're going to delay the hydro testing a lot. I don't know that's really what you're saying. It's try to make a good choice here and go forward.

MR. NANNEY: Well, and making a good choice, what we would expect and we've stated this before, is when you go do a pressure test and you're putting your manifolds in, we would expect you to do samples there to check to see what the wall thickness, the grade, that information is, and if you find that's different than what you think it is you would not be permitted pressure testing.

So we expect, what we've stated before, we expect you to do practical things to justify what you've assumed. And then as you forward with additional digouts, our 607 states to do those other confirmations as you do those digouts.

MR. DANNER: Okay. Cheryl?

MS. CAMPBELL: Thank you. Cheryl Campbell, Xcel Energy. I'm struggling with this part of it, to be honest. I mean I do not believe I'm operating any pipelines that I don't understand the MAOP on. However, as a practical matter, and I have examples, real life examples, where we thought we understood the MAOP, we looked at the records and were concerned and when through a hydro.

We based that hydro on what we thought the MAOP was. The pipe was something very different, to put it bluntly, and we ended up in sort of an emergency renewal mode.

My concern with your statement, Steve, and I don't disagree fundamentally what you're saying, I should know what I'm dealing with before I start doing something like a hydro. The concern that I have is there's a lot of pipe there. The only way for me to do all the sampling and get to where I think I can do what you want, is to dig up the whole pipe.

I'm going to go back to what Andy said

and what I've said before, the hydro is what tells me whether or not I've got the pipe that meets my needs. So I'm struggling with doing all that material verification before I do the hydro because the reality is I'm never going to be sure that I understand that piece of pipe unless I dig it all up. And that's not practicable to me at all.

MR. DANNER: Okay, Steve?

MR. NANNEY: Well, first of all 192.607 does not say that you got to dig up all the pipe. It was set up to where when you go do excavations, again to repeat, on a mile basis if you do not know what the material is, is you go and do an excavation to check the pipe properties. That's what we would expect you to do.

If you go and you're testing a mile of it and you dig your bell holes for your manifolds, we would expect you to check that and to have some hopefully records like alignment sheets, things like that, that verify it.

So if you go and you do a pressure test and you don't have any of that, then yes you may have a problem with meeting 607 but I would not expect you to go do a pressure test not knowing anything about the segment.

MR. DANNER: All right. Any other comments? Ron.

MR. BRADLEY: Yes, Ron Bradley, PECO, and I'm struggling to try to find the right words too, so I'm challenged with the notion that there's an operator that does not know enough about the pipe to evacuate the gas from it and to hydrostatically start the pressure test.

Sometimes the traceable, verifiable, complete records are just lost in moves or office reallocations, I think there are lots of reasons for it. But our maps would have enough information to say what the pipe is rated for, we have personally in my company hydrostatically pressure tested a few lines that did not have traceable, verifiable complete records.

We did have nondestructive test

samples of 2 ECDA, things like that. We knew wall thickness, we knew material, we just did not have traceable, verifiable complete. We hydro-statically pressure tested up to where we thought the MAOP was and we stopped. And that was enough to figure out how to operate that line. We didn't take it to a place where we had a failure on it, we just took it to where we needed to verify it had traceable, verifiable, complete records after that. And that did get us to reestablish our MAOP. We feel pretty good about that.

So I struggle with the nuance between knowing exactly what material you have, and I hear you, Steve, and on the other hand that's that integrity management piece to make sure we nail, but then on the other hand to use water to bring the pressure up gradually to a place where I thought it was 800 pounds, oh, yeah, it's 800 pounds. And it's holding, and everything's good and now let's get that water out, let's dry it out and let's get it back to service. Just a story for consideration.

MR. DANNER: Andy?

MR. DRAKE: Thanks. This is Andy Drake with Enbridge. I think, I'm hoping there's not this huge chasm between us here. It's not all or none, I'm hoping is kind of where we're at.

An operator, obviously, would use the information that they have in setting a hydrostatic test. If you dig down and install the manifolds, you're going to measure and if it's not what you thought it was you're going to stop and rethink.

The concern, I think, that's flagging here, I think it says here that PHMSA suggests that the committee consider requiring the information needed to perform a successful pressure test in accordance with sub-part (j), not documented TVC records must be verified to 192.607.

That is, I think, where the hangup is, because the sampling frequency in 192.607 is like one a mile. So you have to do one a mile to figure out how to do a hydro test? That seems

like all it's going to do is delay the hydro test, a lot. Which is not the point.

The point is let's make a good choice, use the data that we have, get the thing on hydro test, make sure it's safe, collect the data we need to make a tailored management over time. That seems to congrue with the conversation we've been having for a year, and I think that's, maybe it's just how we're talking about what we need to do.

Obviously we would use the information we have to pattern and design the test, but we may not have enough information in accordance with 192.607 then to proceed with the test, which I think is counter-productive. I can't believe that's where we would want to get to. I think that's the only issue that's at stake here.

MR. DANNER: Sara?

MS. GOSMAN: Sara Gosman. Just so I understand the proposal by PHMSA, I'm going to read this. It says "information needed to perform a successful pressure test." That strikes me as

cabining the amount of information needed here under Section 192.607, because it's related to that, is the information needed for this successful pressure test.

MR. DANNER: All right. Steve.

MR. NANNEY: Again, it's what we would expect is if that the operator did not have the records again as you do excavations on the pipeline, we would expect you to verify that.

If you did the pressure test and you dug the ends out, we would expect you to verify it there. If you thought you needed to do more, that would be up to you.

But in the future as you do digs, we would expect you to check it. That's what we would expect.

MR. DRAKE: That's congruent with the conversation we've had for the last year.

MR. NANNEY: I think that's all, we're just trying to interpret how you want us to apply 192.607 to do the test. What you just said, that makes sense. We would use the information we have

to make the decision about the test. It may not be all of 192.607 for every mile of that hydro test, but we would gather that data over time.

MR. DANNER: Right. Alan?

MR. MAYBERRY: I think you pretty much summarized what it's going to say. I think it's not all or none. You have time. The 607, the opportunistic is, I think Steve pointed out, it's not, okay, you have to do it before you do the hydro, you're going to be digging up manifolds at each end and you're going to have an idea of what you have and use judgement to determine what Will be pressure tested. But then over time through 607 you would gather the information.

MR. DANNER: Steve.

MR. ALLEN: Steve Allen, IURC. So Steve, what you are saying is that when you go out to do a hydro test, you actually, if there's information that you don't have, peg into that. As you expose that line, you try to identify or determine that information at that point in time to help you interpret the results of the hydro

test.

MR. NANNEY: That's correct.

MR. ALLEN: So I guess, I don't understand, so I guess what industry is saying if you already have a valid pressure test or hydro test without the information, why do you have to go back and do it again? Or, I'm missing the disconnect here.

MR. DRAKE: Just for clarity, can you restate that double negative again?

(Laughter.)

MR. ALLEN: I'm not sure that I can. If what Steve was saying, if you go out to do a hydro test. You gather the information that you don't know about, as much information as you don't know about the pipeline at that point in time, that helps you to interpret the results of the hydro test at that point. Correct?

MR. NANNEY: Correct.

MR. ALLEN: So, but then is industry saying okay, if we have a valid pressure test, if we have results from a pressure test but we don't

have records to go along with that. Are you saying that all bets are off? Or I think what I heard Steve say that then you need to develop a plan that over time you opportunistically try to gather that information as you go out on integrity digs or whatever else.

It's not saying that hey, you don't have the records, you absolutely have to go out and do a hydro test right this day. You need to go out and develop a plan to help support what you've got. Is that not right?

MR. NANNEY: That's correct. This is Steve Nanny, just one other thing. If the only place that this, when I hear what Andy has said, if it was a two-mile pipeline test segment that they were doing and they dug, or say a mile and a half, and they dug both ends of it out and they did not have, they weren't sure about the wall thickness and the grade, they didn't have those records, they could make those tests when they dug it out and check the wall thickness, diameter, grade, seam type.

If it's three miles, they might, or what he's asking is do I have to go make the third one. And what I said was if you've got alignment sheets, other things, you're technically sure it's the same, you can do the rest under 607 later. That's what I hear the question being and that's how I've answered it.

And that's how 607 said is, if you tested three miles of pipe and you did it on the two ends and you had a mile in between that you didn't have that information, the next time you dug that you would need to get that information.

MR. DANNER: Okay. Andy?

MR. DRAKE: Thanks, Steve. This is Andy Drake with Enbridge. That's exactly the scenarios I think that we're trying to clarify. The words that we're looking for, in 607 was opportunistic. As you're out there, you gather this information. It could be a lot of information. We want to try to get onto hydro testing as quickly as possible. Obviously we're going to use the information we have. If you're digging up the pipe to put

barrels on it or put manifolds on it, you're going to know that information.

But I just would not want us to send a signal where now it's, I got to go get all this information before I can put on hydro tests. I think that's going to throw everybody into a different pattern than we've been talking about which as Alan said, opportunistic.

And it's a little curiosity of why 607 is referenced here, other than you should use the information you have to make the best choice you can about the hydro test, and gather the information opportunistically about the material properties over time. But I think this record shorted it out. I just wanted to make sure we were clear how it plays.

MR. DANNER: So there's voting language in front of us, so it might be if you need clarification you might want to see how you would wordsmith that gently. Any further comments? Alan?

MR. ALLEN: That last bullet on the

screen on the left, like we just discussed at length, 607 is opportunistic so the procedure's listed in there.

MR. DANNER: Okay. Steve.

MR. ALLEN: Steve Allen, IURC. Should the word opportunistic find its way into this? Oh. Never mind.

MR. DANNER: So, there it is. It's in red. Okay. It is 5:03 and I think if we press ahead we can vote on this. So the word opportunistically is there, so, Steve, do you want to opportunistically make a motion?

MR. ALLEN: Sure. I move, this is Steve Allen, IURC. I move 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. Bullet point 1. The lead paragraphs (ii) and (iii) to

remove "spike testing for lines with suspected crack defects."

Second bullet point. In Section 192.624(c)(1) refer to sub-part (j) instead of Section 192.505(c).

Third bullet point, add "requirement to opportunistically verify material properties in accordance with Section 192.607 if information required for a pressure test is not documented in TVC records as discussed in the December, 2017, committee meeting."

For Method 2, Pressure Reduction. Bullet point 1. Increase the look-back period from 18 months to five years.

Bullet Point 2. Strike the requirement in Section 192.624(c)(2)(I) to perform fracture mechanics analysis on segments that perform MAOP via Method 2, pressure reduction.

MR. DANNER: All right, thank you. And I think you meant to say, "strike the requirements of 192.624(c)(2)(ii)." You had a

single i. So, okay, there is a motion. Is there a second. Oh, okay, I thought we took the comment, second first and then comments, but we'll take comments. What did you say? Yes, I'm looking for a second. Are you seconding?

MS. CAMPBELL: No, I'd like to make a comment.

MR. DANNER: All right, well, regardless. Why don't you go ahead and make your comment.

MS. CAMPBELL: I'm sorry, Chair. Robert's Rules of Order are not my specialty. Two concerns that I want to put out on the table for the committee.

I'm not sure that the third bullet really captures the conversation that we were just having around using the best information that you have at the time to do the pressure test, right? I mean, I think it talks about opportunistically going and getting it if you don't have it, but it feels like we need to add something there about consistent with the

conversation at this meeting about the pressure test. Because I think you still have in there that you have to have all those TVC records before you design the pressure test. So that's one comment.

The second comment relates to Method 2 and the pressure reduction. I'm not remembering why we increased the look-back period from 18 months to five years but here's my concern around this.

I agree that pressure reduction is a valid way to do MAOP reconfirmation. My concern here I think is consistent with what the gentleman from National Grid brought up in that we've been doing integrity management now for however long we've been doing it, and I think a number of companies have used pressure reduction as a method to do MAOP reconfirmation and I'm pretty sure that I have reduced the pressure in that time period beyond five years and this kind of feels like I'd have to go back and do it again.

I do not believe that that is your intention, but I'm asking that question. That's not clear to me, and that's why I'm asking the question.

MR. DANNER: Okay. Ron, you had your tent up. Are you --

MR. BRADLEY: Yes, thanks, Mr. Chair. I'm Ron Bradley, PECO. I put it down primarily because I think Cheryl went at the second one, which is, I'm reacting to the public, just so happy when the public comes in and shares their information, I think we want to recognize it.

Mike from National Grid, I didn't catch his last name, but he talked about this five-year period and it drew my attention back to the factor segments or Alan, the question you had about I'm at 1.1, if I'm in a Class I level and now we go to a 1.25, well, the only way I can work there is if I reduce my pressure.

Now I can sort of work okay, but if this is in fact implying that the five years is okay, but I did this maybe seven or eight years

ago and I'll have to reduce again, and if I do that I may lose customers. I think that's an area we want to pay attention to. I think that's what I heard from the gentleman from National Grid.

MS. DAVISON-LEWIS: Thank you. Sara?

MS. GOSMAN: I just have a question about the look-back period as well, but maybe from a different perspective. I'm wondering, if the concern is about flexibility here, there's also a provision at the end of that section about using a less conservative pressure reduction factor, and I'm wondering if there's any relationship between that, which seems like a kind of exception, waiver, process and the concern about the look-back period.

MR. DANNER: Does anybody want to respond to that? Yeah, Rich.

MR. WORSINGER: Yeah, Rich Worsinger, Rocky Mount, North Carolina. Mr. Chair, I have a problem with that third bullet. It just seems like it's a what comes first, the chicken or the egg? If we don't have all the records we need to

verify the pressure test or how we establish MAOP we want to do another pressure test. But we can't do that if we don't have all the records we need. And it just -- I just kind of feel like we don't know where to start here.

Industry, as I'm listening to this, wants to go pressure test those pipes where our records are not what they need to be. But if we don't have those records, it just seems this is preventing industry from going and pressure testing the pipes, and it's going to delay it.

I'm really struggling with that third bullet, and I don't know if it would be best to sleep on this, let PHMSA chew on it overnight, or are we going to continue just to grind through this?

MR. DANNER: All right, well, hold tight. We'll consult with our friends at PHYSA. In the meantime, Andy?

MR. DRAKE: Andy Drake with Enbridge. I agree with Rich. I think the third bullet, I think we just need to revise it to reflect the

conversation that we had, which is we don't need TVC and we don't need 192.607. We need to use the information that we have available to us to make the best decision we can about the hydro test. Period. And that's what we want people to do. And then, the other things kick in over time as we need that information but to tie this here, I think it's -- I don't just think so, I know so, because I'm getting texts like crazy saying that this creates more confusion than it solves. And what I would like to do is just reflect the conversation we had, which is use all the information you have to make the best decision you can about the hydrostatic test parameters. Period. 607 cues up on its own, TVC cues up on its own, it's not germane to this section. It's not that we're trying to get rid of TVC or 607, it's just that they don't belong here.

MR. DANNER: So I think that PHMSA is trying to get there. The reference to the March 26 committee meeting obviously shows they're going in that direction. It sounds like we're not

going to be able to come to closure on this tonight, Alan. I'm wondering if we should break now and pick this up in the morning and you might have some new language by then.

MR. MAYBERRY: I'm good with that. We can take a look at it. I think we know where we're trying to head on this one, on the third bullet, it's just at this late hour --

MR. DANNER: Yes, wordsmithing under pressure is hard. So let's do that, let's adjourn for the day and we'll come back and they will present us with language, new and shiny, that will work.

So thanks, everybody, have a good evening, I'll see you at 8:30 in the morning.

(Whereupon, the above-entitled matter went off the record at 5:13 p.m.)

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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: 03-26-18

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