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>> JEFF WIESE: Good morning, everyone. My name is Jeff Wiese, associate administrator for pipeline safety at U.S. D.O.T.'s Pipeline Hazardous Materials Safety Administration. Welcome and thank you. Wasn't expecting a crowd of this size, but we are happy to have you.

There must be a little interest in the topic. That is good news. We are here today to talk about pipeline integrity verification and a proposal that we have made. I'd like to welcome you and thank you for taking the time to meet with us.

I have a couple of introductory remarks for you. My job is to play Vanna White and tell you where things are and safety and security and all that.

It is my pleasure, I want to introduce a couple people who will help us set the stage. I'll run through the agenda for you in a second.

I did bring greetings from my boss, Cynthia Quarterman, who would like to be here, but she has a family engagement that I encouraged her to keep.

We have a detailed agenda. We have a lot of people here. As someone said, every meeting requires someone to be very stern and disciplinary. And it is my job here today.

Forgive me if that tone comes off, but we have a lot to do in a short amount of time. We want to communicate a lot of information. We want to provide opportunities for people to express their views.

But I want to thank all the people who have come, the moderators, presenters and others, and I would say that the integrity verification process that we propose today is available to you in a number of formats.

There are large formats which I could even read, there are smaller ones out on the table. I encourage you to take that.

This morning, our hope is to identify and illuminate some of what we see as the drivers for our proposal. We want you to understand those. We want to make a case for that.

What it means for performance, we will talk a little about our process and then we will open the floor to Q and A.

At this time, I want to say that because of the number of people here and the interest in the topic, forgive me again if I'm stern. But at the Q and A time, I'd really prefer that you have something to say, you know. Don't just be rhetorical. Don't just ask nitty-gritty questions. There is plenty of opportunity for that, as you will see. We have a docket. I welcome that kind of feedback.

But today since we have limited time, be sure when you do Q and A, you identify yourself, and who you are associated with, and then try to be succinct. I'd like to generally provide three minutes to anyone who wants to talk. But given the number of you and if we have more time, we will let people go longer. But it is my expectation we are going to be tight on time.

Lunch is on your own. There is a registration list out there. For those of you who know Boston, there is plenty of stuff within a one or two-block walk.

We are going to get other people's perspective on the issue this afternoon, which should be interesting. We will get a little about operator experience and again we will have a pretty long Q and A. We will sum it up and then take off.

This is important for you to understand that we intend this to be an ongoing dialogue for a little bit. All of our presentations -- we are going to be transparent about this process. All of our presentation handouts, things that you want to submit will be made readily available to anyone.

Please feel free, that URL is difficult to remember. I'm sure you can get to it if you went to our website, the phmsa.dot.gov and did a search for IVP. There is an official docket. We invite you to submit comments to the docket.

There are comments already. Phil, I believe AGA already filed its comments, or preliminary, preliminary. You mean you have more? (chuckles).

Sorry. I couldn't pass that one up. More fun later. Three minutes. Remember the three minute rule.

We will try to have people on the floor roaming and have microphones. If you have something to say, we want to hear it. Raise your hand. Try to help us out by identifying yourself, again.

I don't use the index cards very much. I would have struck this one. But if you really are terribly intimidated about asking a question, we do have index cards in the back. If you print nicely and I can read it, I will try to entertain those time permitting.

But it is important to say that we are also webcasting this. That is really the future for a lot of our meetings. We can't afford I think to have people spend so much money to get somewhere to have a dialogue.

We are in sequester after all. Next year looks like it will be worse than this year. We will try to webcast any significant meetings we have, so anybody can participate, the public, operators, regulators, alike. We are fortunate we have a lot of state regulators in the crowd, but it is not always the case. They happen to be in town on another meeting. If you are on the webcast, you can E-mail your questions. There is an address on the webcast.

We welcome that. By the way, I'll say to the folks who are doing the webcasting for us, it has been phenomenal, the growth rate in the number of people who participate in these meetings by webcast.

At any rate, just trying to help you out so you don't always have to travel.

Housekeeping items, most of you probably came up the stairways, there are stairways there and back out the doors and to our right, rest rooms are there and then all the way around to the left.

Clearly, I'm getting to the end of my opening comments. But say the flow chart is proposal, it is not willy-nilly. We have spent a lot of time on this proposal. We bring it to you in the spirit of a proposal. We welcome your comments on how it can be technically improved.

Separate that from the cost of doing it. We are interested in doing the right thing and the technically correct thing. It is important that when you give comments and feedback to us, and I know that there is a tad of anxiety about it, be specific. What is wrong with it? What is technically incorrect with it?

As I said earlier, if you have an alternative proposal, that addresses the underlying drivers, we welcome that.

The docket will be there. I welcome that as well. We have a couple of quick comments that I think most of you are aware of, I recognize a large percentage of this crowd. There are quite a few Congressional mandates and recommendations from our friends at the NTSB.

Almost all of those stem from a series of really horrific accidents. There aren't many horrific accidents, but when they happen, they are horrific.

Any of you, and I think we will see a little more of that in vice-chairman Hart's presentation in a minute, but these things all interrelate. Some will say you should deal with these one at a time.

But I'll tell you that we see them as interrelating very much, and getting to the point where operators know their system. If I can underscore that one more time, know your system. It is the foundation of risk management. If you don't know your system, you cannot hope to manage the risks in there.

I think these things are all interrelated. And that is why we made a proposal that is perhaps larger than some would like. But we think they interrelate closely. Know your system.

We are trying to be reasonable. We know this is, as I believe Chairwoman Herzman said, it's a heavy lift. This is critical infrastructure in this country. It daily delivers a huge amount of the energy that the country consumes.

We have to be cognizant of those issues. So we will try to be very structured. We will try to be very transparent. We will also try to be risk focused. We will have to pass cost/benefit eventually. I hope you appreciate the fact that we did not do this in rulemaking. This is an open meeting. We haven't begun rulemaking on IVP.

We are free to talk. We are not under the constraints of that procedure. It is an opportunity for us to talk. I hope you will appreciate that.

The mandates, I'm not going to spend a ton of time on these. My guess is that others will dwell on them. But we do have gas transmission. Steel pipe is our focus today. We are talking about how to establish MAOP verification options.

You will see that there is a difference between the NSTB recommendations and the mandate from the Congress.

Congress focuses on class 3, class 4, HCAs. The NTSB recommendation I think was larger perhaps. But again, in the end, we want you to know your system, having the records to be sure of that. We have seen in a couple of these accidents when we and the NTSB have dug into things that the records needed to substantiate the operating pressures were insufficient.

I don't think anyone would question that. The pipe that was in the ground was clearly not good pipe.

The grandfather clause is probably one of the, that is the real $64 question here. A lot of these, let's be fair, the pipe that is in this country now was put in before the federal regulations were put in place.

We really are talking about retroactively applying current requirements, and how do you do that when you didn't tell people at the time they put it in they needed to maintain all this.

We are not unsympathetic to that point that we are retroactively applying things. We think our proposal moves us in that direction in a sound and reasonable way.

Steam stability as we have seen has been an issue. There are questions that we will be talking about today about pressure testing levels, what are the right levels, what are the adequacy of the current standards that are out there and certainly the adequacy of the underlying regulations.

This is no small matter, either. Making the entire system piggable, one of the recommendations. I think we and the operators would love to have that. There is a question of cost in that. I will add quickly for the folks who work for us in our research and development and many of the industry, research folks that we have together brought out some real innovative technology that makes a lot of the system that was previously unpiggable now piggable.

I would say a lot more is needed on that front, and our proposal, one of the principles that we had in the proposal was to allow for technology to develop, to accelerate, to achieve the same goal, but don't foreclose the opportunity for technological innovation here.

Costs, processes and time lines, need your input. I would ask you, please, try to separate your comments as to what is the right thing to do technically, from how much will it cost.

We do have a big nut to crack. We have been talking with state regulators and with the FERC about this as well. I think some compromises are in order here so that we can accelerate the process of ensuring that operators know their system.

I think I've covered most of those points. With that, I will just close by saying, remember the fundamental rules, because I hate to be the person who has to apply them. Anyone is entitled to speak here, anyone.

I'll give anyone three minutes to speak at the right time. What you are not allowed to do is be disrespectful of others or to interrupt people. If you do that, and you don't heed my admonition, I'll either take a break, and I'll have you shown to the door, and I have alerted security, or not, but just be respectful. We will give you an opportunity to say whatever you want to say. There will be plenty of opportunity for you to reach others on the webcast, but do it at the right time. Be respectful.

With that, I'd like to take the opportunity to introduce the honorable Chris Hart, Vice-Chair of the NTSB. Chris is I'm pleased to say a friend of long standing.

Chris and I and a number of other people, I'd say he is a thought leader in many areas but safety culture, how to collaborate for greater safety, safety management systems. Chris and I have been involved in interagency setting for quite a few years, talking with others from NASA, to the wild land fire people and everyone else about best practices.

I want you if you would join me in welcoming Chris.

(applause).

>> CHRISTOPHER HART: We will let somebody who knows what they are doing do this part. Good morning, everyone. I want to thank Jeff for inviting me to be here. This is a great opportunity for me. One of the reasons I'm personally interested in this is because I happen to be the NSTB member who went to the San Bruno explosion.

I saw that, saw the devastation up close and personal. I appreciate the opportunity to try to do what we can do to solve this problem. Am I on the display mode?

Jeff asked me to -- first of all, I'm a member of the NSTB, as Jeff mentioned. And with me is Robert Hall who heads our rail pipeline and hazardous materials. He is here to answer the hard questions when I can't. That is not a very high bar. And also because, unfortunately, I won't be able to stay for the day, he will be able to answer questions in my absence.

Jeff asked me to briefly indicate what it was from the NTSB, what recommendations were that led to this. I started by telling him I don't do anything briefly, because I'm an attorney. That means my number one credo is never use one word when two will suffice. Nevertheless I'll try to be as brief as possible in talking about why we are here today.

First I'm going to start, many of you already know what the NTSB is. We are like the dentist, somebody you don't necessarily want to have investigating you. But for those of you who may not know, we are an independent federal agency that was created with the purpose of investigating transportation mishaps in all modes of transportation. A lot of people didn't know we did pipelines. When I went to San Francisco to San Bruno, what are you doing here, because NTSB does pipelines. The reason we are there, we investigate what happened and make recommendations to keep it from happening again. Our primary product is safety recommendations.

When you read the media, they would have you think all we can do is recommend. We are not a regulator. We can't require anything. The media would have you think people toss our stuff into file 13. But the reality is more than 80 percent of the time, thanks to the quality of our staff like Robert Hall who do great investigations and the quality of their analysis of the investigation to lead to the recommendations, people do the recommendations more than 80 percent of the time, even though they don't have to.

That is why it's an honor and privilege for me to be there with such high quality staff. Our single focus is safety. Jeff talked about cost. We don't do any quantitative cost/benefit analysis. We have to have our finger to the pulse of economic reality. We do that, but we don't do quantitative cost benefit study. Our focus is safety. The idea is we give you what you would be doing if in the ideal safety world, safety were your only consideration. And we know it isn't. But that is what Congress created us to do, is give you the notion of what you would do in a ideal safety world if that were your only consideration.

It is important that we are independent and we are independent in two respects. One is politically independent, and the purpose of that is so we make our recommendations and findings based on the evidence that we see and not based on the politics, not based on who lobbies most effectively, but based on real evidence.

Secondly, the functional independence, we don't have a dog in the fight. Most regulated industries when something goes wrong, the regulator is the investigator. If that is the case, something, if the regulator did something or didn't do something that is part of the links in the chain to the mishap, there is a likelihood you will not see that in the report. That is not a slam on PHMSA because PHMSA is a regulator. The point is it's human nature; I'm okay, you guys messed up, we did fine. And of course, the reason I bring that up is because of the grandfather issue. That is one of the ones, that is a regulatory device. We commented on that regulatory device in our recommendations.

That is something that might have been less likely to happen if the regulator had written, had investigated this and written the report.

That is the importance that we are functionally independent and politically independent.

Let's talk about San Bruno. This was a rupture of a pipeline that is a major source of supply to San Francisco from the south, the last terminus before San Francisco was the Milpitas terminal, and the rupture occurred not far from the Martin station. This piece of the pipeline, there are various dates but this piece was moved for community development and that was in 1956. This piece that ruptured dates back to 1956.

It was more than 50 years in place before we had this problem.

The problem occurred, the straw on the camel's back was a maintenance event, replacing interruptible power sources. They made process mistakes in the maintenance process which caused the pressure spike which is what caused this pipe to go up beyond the pressure that it could withstand.

That was sheer luck that we went this many years without this kind of mistake, because this pipe was very close to its limit, the entire time. And this maintenance spike was the event that, the straw that broke the camel's back.

The problem was exacerbated by the fact that it took so long to shut the valve off because the event occurred around 6:11, but the upstream valve wasn't shut until more than an hour later, 7:20. And the downstream valve, which is also a source of supply because it was connected to another pipe, so it was providing a source of supply from the back stream, wasn't closed until 90 minutes later.

That was the, excuse the pun, fuel for the fire was gas kept going for more than an hour, because there was no way -- these were manual shut-off valves. There were no automatic or remote shut-off valves. So the shutoff took more than an hour. The result was fatalities, injuries and destructions, eight fatalities, 38 homes destroyed, 70 homes damaged and devastated the neighborhood. The pipeline, in the middle of nowhere in 1956 when it was built, is now in the middle of the neighborhood running down the middle of the street. We see there is a lot of that, unfortunately.

That is what we are concerned about. That is why we made the recommendations that go beyond just this event because this is an industry accident.

This is not a PG&E accident. This is an industry accident. That is why we are concerned. There were a lot of pipelines in the middle of nowhere 50 years ago when they were put in, but now they are not in the middle of nowhere. Records are iffy. There are lots of things like this one that are problem, latent problems at this point. That is our concern as we try to discover latencies.

This particular problem occurred, there is a segment of pipe that consists of six pups that are mitered pups. This was the place where the pipe went from down slope to up slope. These were slightly mitered pups to negotiate this. This is a 27-foot piece of the pipe that the explosion blew out of the ground and blew it a hundred feet away from where it was. When we got there, this is the pipe segment that we saw sitting in the middle of the neighborhood.

The original fracture was in pup number 1 as you can see in this diagram. The pup integrity issues, the ruptured portion was installed more than 50 years ago, and the manufacturing technique and the properties were, did not comport with the PG&E spec. It was lower yield strength than was spec'd, chemical makeup was not according to spec and the rolling direction was circumferential instead of longitudinal. Not only that, we couldn't find who made the steel, because we know who made the steel for the long sections of pipe, but these mitered pups we could not find who made the steel and who did the welding. Welding was most likely field welding. We could not find who did the field welds. If we could identify the manufacturer, we would go to anybody and say anybody who got pipe from this manufacturer look at it or anybody who had this welder look at it, and we could have action. But we weren't able to do that because we didn't know who the manufacturer was and the welding was probably a field weld. The records indicated it was seamless pipe and it wasn't. They had a longitudinal weld seam. The weld where the rupture began in pup one was deficient quality, because it was a single weld rather than double weld. The size of the workmanship was substandard. Only the top, outside of the pipe was welded. There was no inside the pipe weld. Half of the weld, where it says no weld on the diagram, there was absolutely no weld there.

This pipe was defective from the beginning and the outside weld is deficient. The outside weld was thinner than it should have been. Only half of the pipe section was welded.

The stresses in a double weld, that it should have had, would have been lower than the stresses that we actually had in this incomplete weld. It was these stresses that over the years, again I say the pipe was close to its limit the entire time, but it was these stresses that ultimately led to the failure of this weld when it experienced that spike from the maintenance process.

Our probable cause that we determined as a result of the investigation was the inadequate quality assurance and quality control while this pipe was being constructed and inadequate integrity management from the time it was constructed up until the day of the event.

Contributing to that was the grandfathering which meant this pipe was not tested, not hydrostatically tested when it was installed, and also inadequate regulatory oversight to make sure problems like this were adequately accounted for before there was a catastrophe. The severity was exacerbated by the lack of automatic shutoff or remote shut-off valves, in addition to the emergency response, which was inadequate because they had no clue there was a pipeline running through their neighborhood. They didn't know and weren't ready to address it. The original thought was it was a plane crash because it was close to San Francisco airport. They had no clue about this pipeline running through their neighborhood and weren't ready to respond to it.

That all contributed to the severity of the accident.

In fact, the first responders, who were amazing in what they did, described to me when they turned the corner into the fire, it was so hot it melted the windshield on the fire truck. This was quite a devastating event.

When I was there, I saw melted houses and melted cars. I saw the devastation up close and personal.

The two major areas that we addressed that you will be talking about today are grandfathering and also integrity management protocols to minimize the threat of pipeline ruptures.

That is where this came from, was the San Bruno, what was the genesis of these two categories of recommendations that we put out.

Look at it this way. Here is a pipe segment that wouldn't have passed hydrostatic test the day it was installed. We know that now because of the defective materials and defective weld.

That margin of safety was so slim that it only took a minor -- it didn't reach the MAOP, which was incorrectly calculated because it was calculated based on the incorrect information. MAOP was 400. This gave 386. It didn't reach the MAOP. Safety margin was so slim, typically operated at 375, that a minor pressure deviation, minor pressure increase was enough to make it explode. Minor pressure deviation came from the maintenance process error.

As a result of, before we issued the final report, when we see something that needs immediate attention, we don't wait for the final report to issue recommendation. We issued a interim urgent recommendation to ask PG&E to conduct hydrostatic testing throughout their system on older pipes that they didn't have verification on the MAOP. When they did that, some of the segments failed the hydrostatic test.

The good news is once that was done, we were satisfied that the stability of the existing pipeline was adequate and furthermore confirmed the integrity of the existing pipeline. But the moral of the story is they had other pipes that were similarly defective, not necessarily such a slim margin of safety, but still some that were sufficiently defective to fail hydrostatic tests.

In hindsight, everybody is glad that happened and they are glad they did it, because they don't need another catastrophe like that. But that is the reason we issued the urgent interim recommendation. We did not want to wait until the final report to come out before we issued that recommendation when we saw this error on the piece of pipe. Do you have grandfathered pipelines? Most of you do. How robust are your records for those pipelines? There are lots of reasons why they are not robust. We understand that. There were fewer recordkeeping requirements back then.

We understand when records are not robust, that is not necessarily a slam on the people who don't have robust records. That was the regulatory framework that this is driven by, what the regulations require. We know the recordkeeping requirements were more sparse back then, than they are now.

On those ones that you don't have adequate records, do you have an integrity assessment program that can address these issues and could your program if it's not adequate result in a failure like what we saw in San Bruno?

The bottom line question is really simple. Are you willing to risk another pipeline rupture like we saw in San Bruno? Or would you rather find out now that you may have an integrity problem and fix it now before you see a catastrophic failure?

That being as brief as I know how to be, Jeff is basically the origin of these recommendations from the NTSB viewpoint. If I have time, I don't know if you want me to take questions now while I'm still here, or if you want to go to the next speaker. Thank you very much for the opportunity to be here. I appreciate that.

(applause).

>> JEFF WIESE: Since you are being gracious enough to take questions, I'd certainly invite anyone -- we are a little ahead of schedule, since I'm always brief. Chris beat his time line. Happy to take any questions. Chris can't stay. First, we can always pick on Robert later, but if anyone has a question, I

don't know if we have the mics out and about. There is one over here, sir, if you would like to -- could we have a mic at the back there?

Thank you for coming over. Thanks, Chris.

>> CHRISTOPHER HART: Thank you.

>> JEFF WIESE: While he is getting to the mic, I will say, by the way, help us. One of the greatest risks in pipeline safety is excavation damage. On most of your pins or a lot of the pins, you will see, we are trying to get out the message on call 811. We are coming up on August 11. It is a shameless pitch. I wear it everywhere I go.

I would urge you to try to get the pin and wear it and help us promote that campaign.

>> AUDIENCE MEMBER: Good morning. I'm John Dunn, with Consumers Energy in Jackson, Michigan.

Mr. Hart, thank you for your presentation. I would like to note that you mentioned, I believe, that there was a pressure spike that initiated the failure in San Bruno. I also realize NTSB, I believe that I've read that you are recommending that we hydro test pipelines and then put a pressure spike on those tests. Could you clarify that, please?

>> CHRISTOPHER HART: I'm going to ask Rob to give the details of that. You are beyond where I can give an intelligent answer. I'll ask Rob to come up. Thank you for the question.

>> We have recommended pipelines be pressure tested, pressure tested to a pressure above what the established MAOP is.

We have also recommended that the spike test methodology be used, because the spike test has been shown to be the test that best gives you the strength that you are looking for but minimizes any damage that might occur as a result of the hydrostatic test.

So that was the specific reason for the spike test.

It is important to note that the spike that occurred as the initiating event here was below the established MAOP of this particular pipeline.

Although it was a pressure increase that occurred due to some abnormal maintenance, the pipeline should have been able to withstand that, had it been designed properly and installed properly.

>> CHRISTOPHER HART: Thank you, Rob. Don't go away. (chuckles).

Any more questions from the audience? If you have any more questions in the course of the day, Rob will be here all day to answer them. Thanks again for your attention. Thanks also for your passion to address this very difficult problem, and we are all in this together. We don't want to, we want to do whatever we can to help, to help improve safety for all of us. Thank you very much.

(applause).

>> JEFF WIESE: Thank you very much, Chris.

Appreciate your taking time out to be with us today. We will accommodate your schedule as needed in there.

We are a little ahead of schedule. I've told Blaine he doesn't have to be quite as fast as we had urged him before. But Chris really helped us set up the problem that we are looking at. While we did just talk about one incident, I'll tell you that many of us in this room see every accident in the country every day.

This is not anomalous. There are others. I would hasten to add that the system provides reliable and safe service. It is not my point to you, it is just I want to be clear this was not just an isolated event.

We know what we have seen in other cases, where this has been true. It is almost always a surprise to the operator. The challenge, as Chris alluded to, is this is a pretty big nut to crack.

It could be potentially very costly. Anything that we do through the IVP process will eventually find its way to rulemaking. Those of you familiar enough with rulemaking know that we must pass a cost benefit.

I think the general public is not quite as aware of the restrictions of the regulatory process. But we are keenly aware of it. Things don't move as fast as they should. Sometimes one of the major impediments is the lack of underlying data to talk about the size of the problem and the potential costs and potential benefits.

I would say that while the Congressional mandate that relates to this issue was due on July 3 of this year, we knew inherently there was no way to move forward a proposal of this magnitude without better data.

I use that as a way of providing a segue to Blaine Keener who really heads up a lot of our data collection and quality and data systems and has been integrally involved in a lot of aspects of our work for years, to say we set about working with people to collect the data that was going to be needed to characterize both the size of the problem and then invite comments on the question or the cost, rather, and that is one of the things I mentioned earlier.

I will say and I'll hasten to comment on Robert's point about hydro testing, there are always competing points of view on any technology or any process.

So for the record, in the docket, we invite your comments on hydro testing. We would welcome that. That needs to be a matter of public debate. What are the pros and cons of hydro testing, so that we have a full and open disclosure.

With that, I introduce Blaine Keener who will talk to you about the data collection we did on this process.

>> BLAINE KEENER: Good morning, everybody. My name is Blaine Keener. I'm the national field coordinator. It is my formal title. My informal moniker

is the data weenie. It is a rather recent thing in my career.

The topics I'll cover, the collection of the data, how the public can access data, run through highlights of key data points, and then take a little bit of time to talk about each of the parts of which there are many, and then link some of those key data points to the Congressional mandate and the NTSB recommendations that you have already heard about.

The reports were due June 15 of this year, rather than the usual March 15, that did a couple things. We had time to modify the data collection system, and pipeline operators had more time for gathering the data to be able to submit it.

We had 903 operators that filed reports by July 1. There is more reports than operators, based on the fact that commodities are reported separately. We had some operators that do natural gas as well as propane or other gases.

That is 32 less operators than reported in 2011. So we are actively reaching out to those operators who submitted in 2011 but did not in 2012 to see if they will give us something.

We have had 115 reports that have been supplemented, to either update or correct the data after they were submitted. We are expecting that we are going to end up with more supplemental reports to continue updating and correcting the data that we have.

The slides will be available, those two links will take you to the on-line form and the on-line instructions for the annual report for gas transmission and gathering.

As I mentioned, we do a lot of different slices of the data. The nominal pipe size is what diameter is the pipe. Your part J is the decade in which it was installed. There is a couple of key terms that come later. I've forgotten the golden rule, don't read the slides to the audience. Maximum operating pressure and the records, that was a new section for 2012. One of the reasons we had the delay, the submittal date. And then the pressure test range and you are going to find internal inspection capabilities is more or less what is termed on the annual report.

You will hear things like ILI for in-line inspection and pigability. Those all basically mean the same thing.

We include the HCA miles in three different parts. They were in part L for several years. We also in part Q and R included specific data for inside and outside of HCAs.

We recognize that there was a lot of interest in having the data. So we put together a data set as of July 1. We put that out for the public to be able to access both in the docket and on the public meeting Web Page.

Unfortunately, some of those reports are missing some parts. Overall we think the data is pretty sound. But there are some stuff around the edges that we still need to clean up from a data perspective.

We added some of the key data points related to mandates and recommendations in mid-July. We sort of fumbled the part Q data. We were 10 percent too high in the data that we put out in mid-July. But the data today is, takes care of correcting that.

The OPS website link that is in the presentation will take you to a page where you can download the data set. I think it was not actually August 5 but August 6 that we added 7/31 data. If you want to get an updated version of that, it is available now on the website.

Unfortunately, some of the reports are still missing parts. There is ghosts in the machine that we are still chasing down. We will continue to update that data set on a monthly basis.

Since different attributes are reported in different parts of the form, you are going to find different mileage numbers. Our data collection target, when we redid the data collection was to be within a half a percent for total gas transmission miles and within .3 percent for the HCA models. In other words, you can't tell us that you have 10 percent more in part P than you told us in part H.

Those worked with varying degrees of consistency. We know we have some issues where we are not within our half a percent, and we will start contacting operators to try to get tighter correlation amongst different parts of the form.

Traditionally, we use the part J by decade installed value for the answer about how many miles there are. So as of July 1, and all this data is as of July 1, not the July 31 edition that is out there now, but 302, a little over 302,000 which is a little less than what we had in 2011.

Again there is still a couple operators that we need to remind. I'll be interested to see if we actually go over the 2011 value when 2012 reports are in. For HCA miles we use part L. We have just under 20,000 miles or six and a half percent of the total that is in HCAs.

On this slide, we used the data from part Q which gives us both class location and the HCA look. The upper right quadrant, class 1 and class 2, not in HCA, 88 percent of the mileage.

The vast majority of the mileage is class 1, class 2, not in HCAs.

As you might expect, the percent of mileage that is in HCAs is highest for class 4, and then class 3, class 2 and class 1 dwindle down, dwindle down to not very much pipe at all.

I'm going to take a couple slides to go through the parts. Here is your nominal pipe size, reflection of the diameter. These slides also have the intra and inter, broken down by color on the bar charts.

About 35 percent of the total mileage is intrastate and about 65 percent is interstate pipelines operate under FERC certificates.

As you can see here, we don't have much at all on the really high end. We get the clump in the middle between 10 and 36 for the nominal pipe size.

In a decade installed, here you can see we got the pre '70s and then the 1970s or after. We had a huge spike in the '50s and '60s. 59 percent of the total is precode pipe, back before the 1970s.

When we look at the specified minimum yield strength, you see there is a big chunk there, in 61 to 72 percent range.

That is class 1 and class 2 areas where you are allowed to go into those ranges. Unknown is troubling. It concerns us that almost 7,000 miles of pipe people don't know what the SMYS is created by the operating pressure.

You will see this slide again later in a slightly different format.

This is what I call the grandfather interlude. You heard the term already. 619A3 is not the grandfather class. Under 192619A there is four factors that you need to consider. You need to consider the design, you need to consider pressure test history, the operating pressure in the five years preceding 1970 and your pipeline history.

If you don't have all four of those things, you cannot establish your MAOP by A3.

In other words, if you don't have the complete design records, if you don't have pressure test records, you can't even consider A3 as the basis for your MAOP.

Essentially what that is telling us for the operators that did pick 619A3 as the method that they use to establish their MAOP, basically that means the design, the pressure test and pipeline history all supported a higher MAOP, but the operator chose to go with the lower value which was that operating pressure in the five years preceding 1970.   619C on the other hand is the grandfather class.   That is where you say, design, pressure test, they don't matter anymore.

I've got this record of an operating history between 1965 and 1970 and that establishes my MAOP.

Here is how it breaks out for all the miles.   A1 again is the design of the pipeline system.   A2 is the pressure test.   A3 is the operating pressure before 1970.   A4 is basically a local mileage thing, and the regulations specify especially corrosion, as long as you are confident that your corrosion is good, you may come up with a lower number for your MAOP if you have corrosion problems on a particular pipeline.

The next over is C, which is the grandfather clause. D is our alternative MAOP regulation.   In the instructions we also asked operators to include special permit pipe in there. For several years we issued special permits that were roughly equivalent to our alternative in the MAOP regulations. That is clumped together in D. Then the other, we haven't looked closely at the other. But it has to do with regulations that have evaporated over the years.

We are still not quite sure what to make of the little bit of miles that is in the other category.

If you look just at the HCA miles, the chart looks fairly similar. Almost all of the 619D is in HCAs. Then you have got a similar distribution to what you had on the total miles within the HCA miles also.

Then incomplete records, for MAOP, and again for 88 percent of the pipelines we did not collect this data. Anything in a class 1 and 2 location outside HCA is 88 percent of the total, we didn't ask for information about your records.

You can see the distribution again is similar. Luckily D is, that is all relatively new pipe. We don't have incomplete records just using D, but again it's similar dispersion to what we saw for the MAOP methods bar charts.

Then in the final part, that includes mileage data, is your part R, pressure test range, and the in-line inspection. This is basically a three-part graph. On the left is all the miles thrown in there. You can see that we have got the pressure test greater than 1.25 for the majority of the pipelines.

Then just a little bit of the pipelines have that midrange pressure test, and you got a significant amount where the pressure test is less than 1.1.

The three bars in the middle are all in-line inspection able, so you see there sort of mirror the all miles as far as what the pressure test range is.

Then all the way over on the right is the 40 percent that ILI is not able.   It is a fairly even distribution between the pressure test over 1.25 and pressure test less than 1.1 with a little bit in the midrange.

That is the overview by parts portion.   I'm going to roll into the mandates now.

As Jeff already mentioned, we are talking about records for class locations 3 and 4 and HCAs and reconfirming MAOP for pipeline with incomplete records.

We had just over 5,400 miles that had the incomplete records and a little less than half of that is in HCAs and a little more than half is outside of HCAs in class 3 and 4 locations.

The other aspects of that section 23 mandate was the strength test, all untested pipe in HCAs operating over 30 percent SMYS.   We have just over 3200 HCA miles that were less than 1.1 on the pressure test, and as you can see from the next slide, we assume about

77 percent of that is over 30 percent SMYS. We have chosen not to pursue the whole less than or greater than 30 percent SMYS issue, partially because this issue of strength testing pipe is also covered by NTSB recommendation P1115, and they didn't mention anything about treating between 20 and 30 percent SMYS differently. In our analysis you will find that we don't treat it any differently either. It is transmission or it's not.

So again, here, this is similar to the slide you saw earlier, except we pulled the 30 to 72 percent SMYS bars and combine them all together. You got about 77 percent of your total mileage that is over 30 percent SMYS.

The next recommendation is P1114 which is eliminate the grandfather clause and require the hydro test for pre '70 pipe. From part Q, we have got, we are guessing about 55,000 miles of grandfathered pipe. Again that includes the miles that were reported under 619C, the true grandfather clause, and the mileage that was reported under 619A3 which some people may have mistaken for the grandfather clause.

Another relevant data point here is that mileage without pressure test, or sorry, with pressure test less than 1.1. We got almost 94,000 miles that falls into that category.

The other bit of data we were concerned about is pipe that operates at over 72 percent SMYS, just over 20,000 of that.

And that dreaded unknown SMYS category. We recognize the special permits pipelines can go over 72 percent SMYS, except for that mileage, we are expecting that those elevated stress level pipes are going to be under the grandfather clause as far as MAOP method.

Again, we have the data in a lot of different parts. But it is not all interrelated. In other words, we don't know the MAOP method for the pipe over 72 percent SMYS. We know how much is over 72 and then we have the MAOP method in a different part of the form.

We are expecting that the grandfathered miles and the pressure test less than 1.1 are actually close to the same number. We contacted some operators to ask about that difference between miles grandfathered and miles with pressure test less than 1.1. Some of the feedback we got was, we are not sure about our pressure test data yet.

So we reported those miles that we weren't sure of in the less than 1.1MAOP category. There is a chance over time with supplemental reports and as operators finish their verification of records, that we might see that pressure test less than 1.1 go down, and so we are guessing that the true mileage that is going to be subject to this recommendation is going to be somewhere between 55 and 94,000 miles.

For the grandfathered miles, what we did in this one is stacked the 619A3 on top of the 619C. You see not very much at all in HCA. Again, the vast majority is in the class 1, not in HCA for grandfathered miles.

Here is a breakdown of your pressure test with percentages. We have about 31 percent that is the less than 1.1MAOP or no pressure test.

When the pressure test is less than 1.1 MAOP, small portion in HCAs, and again, no surprise there, vast majority in class 1 locations.

Here is a breakdown, interstate versus intrastate for over 72 percent SMYS values. You can see not much intrastate at all in the over 72 and over 80 categories.

But then on the unknown, we got a lot of unknown on the intrastate side of the shop. The recommendation P1115 deals with manufacturing and construction defects, which Chris demonstrated very clearly in the San Bruno incident.

We are talking about considering those stable only if your pipe has a pressure test over 1.25 MAOP.

Within HCAs, we got just over 3200 miles where the pressure test is below that level. It's a fairly even distribution of how many of those miles can be internally inspected and how many miles cannot.

With those miles where the pressure test is less than 1.25, so again the 3200 from the last slide is all the way on the right, not very much at all, but that is what is in the HCAs, and the vast majority of that less than 1.25 is in your class 1 areas outside HCAs.

P1117 is accommodating in-line inspection pigability, smart pig concept. Again we got 40 percent of the mileage, where internal inspection is not able. There is a lot of reasons for that. Sometimes there is things poking through the center of the pipe, metering and measurement type devices that would not allow pig to go through.

Sometimes it's that the pipe is too small. And there is not commercially available technology to put a pig into small pipes.

The punch line at the end is we don't really know how many miles are not able due to size or system configuration. But we threw together some data on the pipelines less than eight-inch and then the pipelines less than the six-inch to try to give an idea of how much may be limited just by pipe size.

Then this chart provides that breakdown of by location and by HCA what is piggable and what is not. In the right hand column, you have the 40 percent that is not piggable. Again you see the vast majority of 88.8000 is class 1 not in HCA. You have a smattering of mileages in the other category. Class 2 not HCA, second highest one, of course.

That is the breakdown of the in-line inspection able versus not.

And I believe it's time for questions.

>> JEFF WIESE: That is enough to put you to sleep, huh? We are going to need that data. I know that is a lot to digest first thing in the morning.

But I clearly know that some of you have questions on that. Blaine has spent a lot of time on this. My thanks to Blaine. He and his team have spent an amazing amount of time on this.

So we do have a lot of the data that we are going to need to do any rulemaking on the efforts that we have. But I would like to take the opportunity, we have a few minutes. I promise I'll let you out for a break. If you would rather, we can all stand and stretch or something. No? Okay.

We will go to questions. Thank you.

>> AUDIENCE MEMBER: Hi, Lauren, with Conn Edison in New York. I have a question about the numbers you quoted with the miles that may require pressure testing.

The part R of the annual report asks a question about pressure testing above 1.25. You mention NTSB recommendation that also focuses on that 1.25. But the IVP chart mentions, I think it is step 3, for class 3 and 4 pressure testing requirements is actually 1.4 or 1.5.

Did you consider the NTSB in terms of the IVP chart?

And do you think you are underreporting potentially the miles that might have to be pressure tested?

>> BLAINE KEENER: That is more of an IVP question, which is -- (chuckles).

Remember, data weenie, IVP proposal. Steve, would you be -- do you want to hold on that thought until you do your presentation? Can we do that? Okay. Thank you.

>> AUDIENCE MEMBER: Alex, project consultant services. Do you have a number of how many pipelines or miles are located offshore?

>> BLAINE KEENER: Yeah, offshore, I think, is about 5,000.

>> AUDIENCE MEMBER: That are included on these provisions and recommendations?

>> BLAINE KEENER: Yeah, the specified minimum yield strength slides, you will notice they have a label that says onshore only. When we collect the part K data, with the SMYS, you get different pressure ranges for the offshore, than you have for the onshore.

We wanted to be able to show all of the onshore ranges. So we limited that to onshore pipe. But all the other slides and all the other parts is all the data, the onshore and offshore.

>> AUDIENCE MEMBER: Thank you.

>> JEFF WIESE: It may be useful to note, Alex, that we did include all the pipe that you used to regulate at

Bessie. So that was strictly for the jurisdictional pipe for our side.

Other questions? Do you know if there are any questions coming in from the webcast? No? Okay.

Well, you have an opportunity, you will have more opportunities. Clearly that was a long presentation. I have a couple of quick remarks. Then we will take a break.

I would like to encourage, we have other presenters coming up. We don't have all your slides yet. Unlike others, we understand that most of us put together slides in an airplane. Right?

So if you are presenting, please make sure that during this break or during lunch, you see Steve Nanney or one of us, and we will get the slides and get them into order there.

I'd like to close this session by coming back to remarks that Chris made, because that is why we are here. We are here to stop things like that from happening.

I think I was remiss in not telling you that while we were supporting the NTSB investigation, had people actively helping the NTSB in that, PHMSA didn't wait, either. We were talking to NTSB. We put out advise re bulletins, our state partners didn't wait. A lot of them began doing as did we checks with operators about records.

Between advisory bulletins and inspections and outreach to presentation, I think it is natural. You have to get the message out to people before they start taking action.

I do want to tell you that I know a lot of operators and a lot of the companies, I know they have done a lot of work trying to firm up the underpinnings of their system, know your system. Having the adequate records to prove that. And then I will tell you that I know that that was a lot of work, but there is a lot of good to come of that.

Again, I come back to the foundations of risk management are know your system. Right? Then know what is around your system. All the work that we are doing here today and that the operators have done, have yet to do and that we will do together with the NTSB and others will benefit the public by giving us a safer system that is reliable.

But it is a big nut to crack, as Blaine showed you. We will be doing more on this, and we will put presentations in the docket. That is a lot of information to digest. But I want to tell you, we absolutely positively needed it to do the rulemaking. Without it, we couldn't have moved forward.

To those who wanted that rule to move faster, I understand. But that is what we are here about today. So with that, I want to thank Blaine for that. He put a lot of time and effort into it. What time should we break to? 10:40? How long is that?

We will take a 30-minute break. When you see the doors close, you will know that we are convening again. Thank you again for your attention. I'd make a race to Starbucks, okay?

(break).

>> JEFF WIESE: Welcome back, everyone. One of the few who didn't get to Starbucks I see, and none of my friends in the front row brought me a cup. I can buy my own. Welcome back. I hope you had a nice break. A lot of work happens during breaks, a lot of opportunity to exchange information. So enjoyed that very much.

I wanted to take a second of your time, if you would, to speak to people on the webcast. We are serious about trying to expand the use of webcasting. So we can reach people who couldn't otherwise travel here.

I do want you to know that there have been a number of questions that have been coming in. But the people we have in the back, we have senior folks back there, are able to answer these right away. Don't hesitate. If you are in the webcast, send your questions in.

We will try to generalize those. We are trying to do some fine-tuning too that you might not notice, but we have asked our friends at the webcast service to focus more on the slides, and less on the presenters. So we don't have to clean ourselves up a little bit here.

More on the slides, less on the presenters. People were starting to ask for the slides already. I wanted you to know that we are listening, and we have gotten all the slides together just now, the last slides from the people who are presenting. We are going to try to post those today, probably within the next few hours.

We are just juggling a few balls here. But people were asking for them. And that is fair. I think that we will get that out.

The last question that I have to comment on, someone asked about we have heard multiple times, when will rulemaking start on this?

It is a natural question. I would say you can do it on your own. You don't need us to do a rule. Get after it. But failing that, we will begin rulemaking after we have had an opportunity to hear from you. We have a comment period out there. Some people have already asked about extending the comment period.

But since some of my friends have already gotten their comments in, they are ahead of the curve, we don't have to worry about it. But as soon as the comment period is over, we will see whether we need to extend it or not. But as soon as it's over, we will probably enter rulemaking. That reduces our ability to talk openly about it.

So please engage when you have an opportunity. I know some disagree with that. But it's our policy and I have to follow our policy.

With that, I'm going to be turning to Steve Nanney. A lot of you know Steve already. Steve has led the team in PHMSA and also the NAPSA folks, state regulators who did a lot of the vetting of the model. It has taken a lot of iterations. I think it is stabilized now. Steve is the architect here but not the sole creator of this. You can't just blame Steve.

But at any rate, Steve is a great hand here and a lot of experience, and I'd like to turn it over to Mr. Steve Nanney.

>> STEVE NANNEY: Thank you all for coming today. I think I was on vacation in Florida and drew the short stick as far as being the presenter in going through this. Jeff didn't give you the entire history on it.

For the folks that are on the webcast, as we go through today, there will be an IVP chart that we will be talking about. If you look at the bottom of your IVP, of your webcast, you will see a link that you can click on it, and look at the chart that we will be talking about.

For the ones that are here in the meeting room, we had handouts. So you should have the IVP chart to look at. We also have some 3 by 5-foot charts on both sides of the room and I think right here in the front that you can look at, during the breaks and everything.

For some of you that can't see well like myself, I'm sorry we have such a small sheet. I've got a bigger one for me. But anyway, thank you.

First of all, what is integrity verification? Well, first of all -- (pause).

Hold on one minute. My slides are turning, but yours aren't. What is integrity verification? From a PHMSA standpoint, it is a multidisciplinary engineering approach to verify steel gas transmission pipeline integrity.

Also, we realize that a pipeline may contain some flaws, it may have gotten damaged through its history and life span. And also, it may have aged. The goal of this program is to establish a comprehensive program to address a number of the Congressional mandates and the NTSB recommendations.

I'm sure you are all much aware of that, based upon the previous presentations that we have had.

The basic principles of the IVP approach or IVP chart is basically based upon four principles. Number one, to apply it to higher risk locations, to apply it to high consequence areas, and also to a new term that we are introducing here, moderate consequence areas, which I will define a little later in the presentation.

Principle number 2 is to screen segments for categories of concern. In other words, locations such as grandfathered segments. The third principle, ensure we have adequate material and documentation, in other words, adequate records.

4, to perform assessments, to establish the MAOP of the segment. Principle number 1, of course, I think we all know what high consequence areas are, based upon integrity management.

But moderate consequent areas or MCAs as we have introduced here is nonHCA pipe in class 2, 3 and 4 locations. It's also nonHCA pipe in class 1 locations that are populated in a PIR.

In other words, what we are proposing is one house or one occupied site, within that PIR, would make it an MCA.

We think that will align us with the INGAA commitment. Also, PHMSA estimates that we have about 91,000 miles that will be either in a HCA or MCA, out of 300,000 miles of pipe.

Again, this just goes through the HCA mileage. Blaine went through this earlier in his presentation. If you look, as far as HCA mileage now, out of 301,000 miles, we have got about 20,000 miles of HCA pipe.

We estimate that the MCA mileage could be around 71,000 miles of pipe, for a total of approximately 91,000 miles.

Principle number 2, we plan to screen the categories of concern. In other words, we plan to apply the process to the pipe segments. Number one, with grandfathered pipe, number two, that lack records to validate the MAOP, that lack an adequate pressure test, that operate at pressures above 72 percent SMYS, and they have a history of failures due to manufacturing and construction defects.

Principle number 3, know and document pipe material. If you do have missing or inadequate validated traceable material documentation, then you will need to establish the material properties by an appropriate or approved process.

One way you can do it is cut out and test pipe samples. There is presently a code approved process in the code. I think if you go look at 192107 or 192109 there is an approved process there.

They are not saying as we go through this rulemaking, if there is any requirements to cut out pipe and sample, it doesn't mean we plan to go by that section of the code. But we would take a look and come up with a new method as far as validation, even if there is cut out and test pipe samples.

Another way that we would be considering and we would definitely like to have your comments is in situ and undestructive testing. We would want to go through a validation process and I probably have it in the notice of proposed rulemaking as a code approved type process.

I know if you go back and look at IMP, we had other technology where you could submit new technology and based upon it. That would be something that we will have to consider going through this rulemaking process.

But we do want to look at other technology in doing this. PHMSA's goal is not for operators to go and have to cut out a lot of pipe. But we would expect you, when you do cut out pipe, to test the pipe.

If you don't have adequate records, you know, if you go look at the integrity management principles, if you go look at a B318S, look at subpart O, it has in there, if you don't have adequate records to do integrity management, PHMSA would have expected operators to be testing their pipe through integrity management as they did cut outs in integrity management work.

The other is, I know a question that comes up is field verification of code stamp for components such as valves, flanges and fabrications.

But we do know that there will be items such as that that PHMSA would look, if you have got an ANSI 600, ANSI 400 stamp or something like that, that we would consider accepting.

In other verification methods, we hope after the workshop if you do have some other methods as we do go through the rulemaking process to consider, submit them in to us to look at. That is what we want to see.

Principle number 4, assessments to establish the

MAOP. Again, we want to allow the operator to select the best option to establish the MAOP. We want to give you more than one option. We want several options.

The candidate IVP options for establishing MAOP of course just like the NTSB and the Congressional mandates, that we would consider and want to be part of the toolbox, subpart J test with a spike test. I realize on the spike test, we haven't put out any definitions of what a spike test would be. We want to hear your comments.

We do have some research projects going on. We will see what it shows us as far as seam issues, as far as spike tests.

We do realize that probably a 90 percent spike test or 1.25 may not be enough, if you have pipe with cracking type issues.

Another method we consider is derate the pipeline pressure. In other words, if you have a operating pressure, is look at derating it.

Then another that I know we have heard a lot of comments on is an engineering critical assessment. PHMSA will have some guidelines, and we will definitely consider an ECA type approach.

Of course, you can always replace the pipeline and put a new pipeline in. If you do have pipe that you do have a lot of failure history and issues with, that may be the best approach.

Other options that PHMSA should consider, we do want your comments. You don't have to ask us a question today. You can always submit it in to us later. But we do want to see those comments.

We hope to get them.

The draft IVP process steps, if you look at the sheet, we have tried to break it down into sections. If you look, the first section is the grandfathered clause and MAOP review. On your chart that will be process steps 1 through 4.

Then we have an integrity review which will be process steps 5 through 8. >> STEVE NANNEY: If you do have pipe that you do have a lot of failure history and issues with, that may be the best approach. The other options that PHMSA should consider, we do want your comments, you don't have to ask us a question today, you can always submit it into us later, but we do want to see those comments. We hope to get them. The draft IVP process steps, if you look at the sheet, we've tried to break it down into sections. If you look, the first section is the grandfather clause and MAOP review. On your chart, that will be process steps 1 through 4. Then we have an integrity review which would be process steps 5-8. Then process step 9 is a risk review, whether you have an HCA or an MCA. We probably should have made that step step number one, because you can go there to see, one, where your pipeline falls. What we're trying to make sure of, if you have a pipeline in a Class 1 location and you're out in the desert or you're somewhere where there's homes and people not living around the pipeline, your pipeline doesn't apply to this process. That's the point we want to make is it would not be in an HCA, it would not be in an MCA. So the item you should probably look at first is process step 9, even before you go to 1, to get a feel for is your pipeline in an HCA or an MCA. Then steps 10-12 is a low stress review. The material documentation review is process steps 13-15, and then we have an assessment and analysis review, which is step 16-20. The last one, which all of them go to, 16-20, is an implementation phase, and that will go through there.

Then the last one is deadlines for implementation, and you'll see as we go through this, you'll see a to be determined on all the implementation deadlines. Again, we wanted to hear comments that we'll get on our website after the workshop today, what everyone thinks a reasonable time is. We'll also be talking to other agencies like the FERC, things like that, we'll be talking to the states, and we'll get everyone's input before we start putting dates for that. Again, the next sheet is the integrity verification chart, and again, as you can see, since I am -- I don't see too well, I've got a little bit bigger sheet than what we handed out to you all. But it does go through the process. If you look at it, we tried to get comments that we got from the states and we have inputted all the comments that we did get from the states.

Going to slide number 11, consideration of state-specific requirements, from the meetings that we had, we were asked that some of the states have requirements that exceed the federal. As you all know, the states have to at least meet the federal requirements, but many of the states go well past what the federal requirements are. Some of those would be like requiring a pressure test of 1.5 times the MAOP in all locations. Also, some states have everything classified as a Class 4, and then some of them have additional requirements if the MAOP is greater than 125 pounds. And the process that we will be laying out and that you'll have to consider is you've got to take into account the differences in the federal and in the state.

Process step 9 is the HCA/MCA screening box of this step. And if you look, we would recommend that being accomplished first and everything. Going to the first block on the screen is the draft process step 1, is what we call the grandfather screen, and it is 619(c). If you look, 192.619(c) is the grandfather clause, and the grandfather clause is where you don't have other records except for the five-year operating history going back from July 1, 1970. And that is the grandfather clause. If you look at 619(a)(1) to (a)(4), that is not the grandfather clause. You can say based on what Blaine Keener went through earlier today, we're expecting 22,000 miles in 619(c) as grandfather clause, we had 22,000 miles in 619 (a)(3) and we do know some operators reported 619(c) data in 619(a)(3). And definitely as Blaine said earlier, you can still go back and change that data in and resubmit it in into the database. We estimate that about 14,000 miles of MCA/HCA miles will be credited to 619(a)(3) and 619(c) through this process. Also the grandfather clause 619(c) will include pipelines that operate above 72% SMYS, unless it's a pipeline that's an alternate MAOP pipeline. I think there are pipelines, there are some in the U.S. that operate somewhere between above 72 up to about 85% SMYS. Draft process steps 2-5 is inadequate record screen. In other words, it's 619(a)(1) through 619(a)(4). If you look at (a)(1), that's the design pressure, and you will need material records to check your design pressure.

If you go into step 3, 619(a)(2) is your hydrotest, subpart J, hydrotest for your pipeline. If you have those records, you can see on the box, you go to yes, then you go over to box number 4 which is of 619(a)(3) is your historical operating pressure records. Then if you have a yes that you have those records, you would go over a yes there to box 5 and it would be 619(a)(4) is operator analysis of the segment history. Boxes 2-5 are in the code presently, and if you go look at 619, it says you have to take the lowest operating pressure of those four steps so what we would expect you to do based upon our chart is you would start at 1, 619(c), then if you went to 2, if it was a yes that you had the records, you would keep going through the screening process. If it was no, it would kick down into the process that you have to do something, unless it's not in an MCA or an HCA.

Process steps 2-5, the related mileage, based on what was submitted in, as Blaine again went through earlier, we had about 5,400 miles reported with incomplete records, in HCA's Class 3 and 4 locations only. We had approximately 7,700 miles estimated in Class 1 and 2 MCA miles with incomplete records. And from that, we're expecting about 13,000 miles of HCA and MCA miles with incomplete records. But we realize after we get more submittals after the workshop, these mileages will change.

Draft process steps 6-8 is the integrity review section of the screen. And again, as you go through that, you would start at 6, you would go through the screening to see if you have an operating failure. If it's been manufacturing construction failures that you've had, if the answer is yes, it will take you to a different part of the screen. If it's no, you would go on down to see if you have Legacy pipe, which I'll give the definition of it later, and that would be with a pressure test less than 1.25. If the answer there is yes, it pulls you to one screen. If it's no, you keep going through the process. Step 8 would be modern pipe with a pressure test of less than 1.1 MAOP. Looking at the mileage, again, very quickly, we had a total mileage with a pressure test of less than 1.25 times MAOP of 113,000 miles. And we estimate we'll have about 27,000 miles in an HCA or MCA. Pipe mill pressure test would not be allowed as a pressure test, if you only had a pipe mill pressure test as documentation. Again, in box 6, we would want you to consider the manufacturing and construction failures of the segment. One question, I know that I had gotten earlier, was what if we have a failure after we go through this process? What we envision the process to be right now would be what the historical looking back tells you on it. We're not trying to look forward right at the moment. One way if you have issues there that may be considered would be PHMSA working with you on an enforcement action or something if we do have an issue with it later, but that's something we'll have to consider as we go through any rule-making process is if you do run into a segment that has issues later, but we haven't thought through that, and we don't have anything written down for if.

Also, what we would be considering in any new rulemaking is if you look at the code presently, you can in a Class 1 only pressure test 1.1 times MAOP, if you do not have anybody living within 300 feet of the pipeline.   And that is something that we will definitely change through this rulemaking.   We will go for a minimum test of 1.25 times MAOP, if it is in a Class 1 location.

The definitions, going back, if you look at 7 and 8, we had Legacy pipe and modern pipe.   Now, I want to just go through what the definition of it is.   Legacy pipe would be low-frequency ERW pipe, in other words, an example of it would be Youngstown still where we have had all the ERWC issues.   Also single submerged arc welded pipe would be one that would fit in that.   Flash weld, if you have AO Smith flash weld pipe that's had hard spot issues, that would be in this definition.   And pipe with a joint factor less than 1.0 like lap welded pipe.   Modern pipe is an easy definition, it's any pipe not manufactured with the listed issues in Legacy pipe. We may expand those definitions as we go through the process but right now that's what we have as a definition, you're welcome to give us any comments or any suggestions if you think how we should expand it. As far as Legacy problematic construction techniques, again, what we put here are things that we realize through operating a pipeline can become issues as far as integrity issues with your pipeline. Wrinkle bends, if you have a high mitered pipe, Dresser couplings, nonstandard fittings, you can read the rest of the list, but we'll take your comments there and consider it. Transmission line, what's the definition of a transmission line? One thing you'll see as we go through this, number two, I highlighted in red, is it operates at a hoop stress of 20% or more of SMYS. You'll seal that we have a definition of low stress through the chart of being less than 20% SMYS to go ha long with what the present part 192 code has. Looking as you go through the chart and the process, the draft process steps 9-12 is the location and low stress screen. In other words, if your pipe gets through it and it is an HCA or an MCA and you do have Legacy type issues with it, whether it's construction or whether it's seam-type issues due to manufacturing, then it would make it to 9. Then from there, if it's a yes, you would go to 10, or if it's a no, you would go down to low-risk segments. But it it's less than 20% SMYS, you can go through that and see if you have Legacy pipe manufacturing issues or Legacy construction issues and from that, you may or may not have to do something. But it it's no that you do not have issues with any of those in 11 or 12, you would go on to 21 and not have to do any more to that. But if you do wind up, you have Legacy issues, there would be more work you would have to do.

Draft process steps 1-12, again, based upon the present 2012 annual report data that we've got, we're thinking that it will be approximately 33,000 miles of gas transmission pipe, about 11% of the total. That may change as we get more data in, but that's what we're thinking it will be presently. Also when you look at the chart, draft process steps 13 and 14 is the material documentation steps, and if you look at 13 as you go through it is do you have validated traceable material? Then going down from it to 14 is, is there missing or inadequate material documentation, then cut out test pipe to establish material properties. Our goal is to establish material properties, it's not going out and do unwanted testing and cutting. I personally hate, you know, hot taps and things like that and getting a lot more potential leak places in the pipeline. The thing in our notes, material documentation required for pipe valves, flanges, fittings and components, again, on most of that, if it's a valve or a flange, we're looking at confirming the NC rating things such as that that we would define out. Also, validated number 2, if you look at note number 2, validated material properties required for X42 and greater pipe, in other words, greater than 2 inch OD on the main line. Our point there is if you've got a valve that isolates the pipe from the main line and let's say it's 2 inch or below piping that's an operator type gas for an operator, things like that, or sample line, we're not trying to make any operators chase that. We're trying to get it to where if you do have a valve that you can isolate that piping from the main line that you do not have to chase that as far as finding the material properties. Also as I stated earlier, valves and components, ANSI rating, cutouts, if we do have to do cutouts for a vintage of pipe you've got, there would be a limit based upon how many joints or how many miles apart you would have to do them and if it's a short segment to see what you would need to do. If you've got 100 feet of pipe or maybe a couple hundred, we're not expecting to go and do cutouts on that. Use of in situ NDE, we would definitely want to consider and have a validated approach for doing that. Note number 7, we would look at each unique combination of pipe type, seam and vintage. Why are pipeline material records needed? I think we probably all know the answer to that. To establish the design and maximum operating pressure. If you go look at 192.105 or 192.619, it givers the criteria there. Also we need it for integrity management programs. If you go look at subpart O in the gas code, you go look at B318S, it says in there you have to know grade, wall thickness, seam type, diameter of the pipeline. You know, when you go and you're evaluating anomaly evaluations, you've got to look at the safe operating pressure of the pipeline and that safe operating pressure is based upon wall thickness, grade, seam type, Class location, things like that. Also your grade, if you're using R string or that type anomaly evaluation, you add 10,000 pounds to the grade of the pipe that you're not using yield strength, you're using something close to ultimate tensile strength. When you add 10,000 pounds you're getting closer to ultimate tensile than you are to yield strength.

Why are pipeline material records needed? Again, just to touch base on the Pipeline Safety Act of 2011, paragraph 23, we have a congressional mandate asking us to do that where we have incomplete records. Again, as I had stated earlier, for the record, here are some of the code type areas for material determination and MAOP determination. Material documentation, records management. Materials should be manufactured based upon applicable standard, and also if it's a newer pipe since the code, it should be based upon a DOT referenced standard. Why do we want it? To be able to maintain the structural integrity of the pipeline. And again, as I stated earlier, we need it for pipe design, we need it for integrity management. Going through the IVP chart 15, as you go through that, select the method to establish the MAOP. Again, PHMSA proposes four approaches for that. A pressure test with a spike test, derate the pipeline based upon the present MAOP with a margin based upon the issues with the section. Replace the pipe. And again, as we've stated earlier, an ILI or an engineering critical assessment program, which would be equivalent to a pressure test. Draft process step 16 is the pressure test option, and again, we would be looking at a spike test there based upon the issues. I know I've been asked by a lot of people, well, what would be PHMSA's definition of a spike test? First of all, we haven't sat down and defined it yet, but I would expect it to be something greater than 90% SMYS, it would probably be somewhere between 95% SMYS and 105% SMYS. The hold time as I've got here, between minimum 30 minutes to an hour, maybe 15 minutes to an hour. Again, I put these up for discussion, not that PHMSA decided what we'll do. Again, the spike test is for cracks, whether it's seam cracks or cracks in the body is what we're looking for, or if it's a manufacturing and construction defect. Draft step number 17 is the derate option, and again, we would have that in there for an operator to look at what the issues are, look at the fatigue analysis for the life of the pipeline and you could do a derate option there. Again more on step 17, the replace option for the pipeline. We realize that would be the most costly. Sometimes it may be the ultimate solution and it may not be the most costly. I mean, if you have an incident trying to keep a pipeline that's gone past its life due to cracking issues or not knowing what the material is, it may be a lot cheaper to replace it than to keep it in.

Draft process steps 18 through 19 is the engineering critical assessment option. Again, the engineering critical assessment would be commensurate with segment-specific issues and documentation shortcomings. In other words, you could do an engineering critical assessment and look at things such as running close interval surveys, coding surveys, interference surveys, looking at the cracking issues you have in your pipeline, and from that, see what you need to do to the pipeline. And began engineering critical assessment may include an ILI program on your pipeline. And from that, that program, you would go to 19, and after you go through step 18, whether it's an ILI program or an engineering critical assessment program, still from 19 when you follow it on down, you still may need to do a hydrotest or you still may need to do other things. That would be based upon the results of running the ECA or the ILI program.

Draft process steps 18 through 19, again, is the engineering critical assessment would be in it. And PHMSA expects you to look at maximize technology in an ECA ILI program. We would expect to use the highest level or state of the art tools there. In other words, to give you an example, if you're running a comprehensive ILI program and you're using EMAT tools and you're using tools in the ditch to verify, we would expect the operator to have very strict precise procedures for the ILI company to carry out their ILI and evaluate the results. The same thing if you go in with an in the ditch, nondestructive examination methods, that there be well defined procedures that are not just only procedures that your vendor gives you, your service provider, but your actual staff goes through and you all agree upon it and everything as we go through this. The thing that we have found, we've got a low frequency ERW R & D program going on right now, and we're finding a case study that Dr. John Kiefner, I believe did with Kiefner & Associates going through 13 cases. In the past operators have not done a very good job of that as far as writing out with the vendor the specifics with the ILI company and with their own people of what they're going to do with the results, whether it's the ILI vendor or the in the ditch NDE company. So that, we will definitely have to get defined out better and do a better job in following it through. We all realize whether it's EMAT or other tools for crack detection, we're all learning, but we all are going to have to do a better job of documenting that. And I know there are some companies that are doing a real good job of doing it because I've been meeting with one or two of them in particular, and I know they have done a very good job, so I know we can do it.

When you look at steps 15-21, and I went through and put this up, let's just run through it, if you get down to 15, select a method to establish the MAOP, and again, from that method, you can go to 16, 17 and do a pressure test, you can derate the pipeline, you can replace the pipeline in box 17 if you look over to it. Or you can go to 18 and put ILI program in place or an engineering critical assessment program. But whether you do an ILI or an ECA, based upon the results when you go to box 19, you still may want to do a hydrotest. It may be that the findings that you are getting through an ILI, let's say if you had seam cracking and it was significant, depending upon how much you have, it may be very prudent to go hydrotest after you've run the ILI. And again, after you go through and you get to 16, 17 and 20, then you go to 21 to continue to operate and maintain in accordance with part 192. It doesn't mean that you do a one and done. If you've got issues that need to be periodically re-evaluated, then we would expect that to be evaluated. The approach, some of the things and the limitations, let's just take for example pressure testing, we realize that if you only pressure test, that it produces little information about the pipe condition other than how it is today. We also realize that any defects can grow after that hydrotest, and it could result in pressure reversals. And again, that's why we would be wanting to have spike tests to help mitigate those.

Technical R & D, ongoing R & D suggests that the above issues might be less valid than believed. We also think that we will have to have a hydrotest greater than 90%. How much greater, as I said earlier, we don't know. And again, operational. We realize a pressure test requires service disruptions in most cases, maybe all cases. And we know some operators will definitely want to go an ILI or ECA type route where they can. Limitations of ILI, technically. They provide much more detailed information about the defect, but the state of the art limits assure that all such defects will be detected and that detected defects will be accurately characterized for cracks and seams. In other words, we may get more issues than we can evaluate or accurately evaluate, which if we do get things such as that, we may have to do a pressure test. And operationally, ILI cannot be accomplished by some lines, as Blaine Keener in his presentation showed us earlier, that there will have to be some lines fitted for ILI that aren't now. But PHMSA realizes that we probably will not be able to get to 100% on the ILI. That's the goal, but we also are realizing that may not be accomplished in all cases. I mean, if you've got a pipeline, a lateral that's only a couple of miles, it would probably be very difficult to run ILI and get good results from it. Specific guidelines and criteria. Where do we go next? The IVP chart is a high level concept chart. We're not expecting it to have the details and the specifications in it to date. Those are under development. But we do plan to use the knowledge from this workshop and comments that we get here today and on the website to further develop the details. And again, as I've stated earlier, some of that would be how do we define a spike test? What would be a derate criteria to use? What should be an ILI program requirements and specifications? Not only ILI, but in the ditch NDE. And again, what should we do to verify material or documentation, whether it's pressure test records, whether it's material strength records? Give us any comments you've got there or any methods. Sometimes just comments, just throwing out a comment doesn't help, but if you do have some methodology that we could consider, that would be greatly appreciated. The target completion time frames. Again, as far as implementing IVP after the rulemaking, we realize it will be a multiyear effort, and we realize there will be graduated time frames with priority given to Legacy pipe segments, HCA's and high stress segments if those segments have issues with them.

The last slide here that I've got shows TBD, to be determined. Again, this is how we see we would break it down based upon stress. It would be looking at pipelines in the greater than 50% stress level, the 20 to 50 and then the less than 20% SMYS, and also breaking it up to whether it's in a Class 1, 2, 3 or 4 location or an HCA and whether it's Legacy pipe or modern. So whether we put -- you know, whether the number is seven years, ten years, 14 years, whatever, give us your comments on what you think a methodology there should be.

Again, in closing, our IVP chart is on our website. We have charts here in the room for you to look at. You're welcome if you've got items there you think we should consider adding or consider modifying in some way, you're welcome to submit those in to us. Again, thank you, and I think I'll turn it back over to Jeff.

(applause)

>> ALAN MAYBERRY: In case you're wondering, I'm not Jeff. I'm Alan Mayberry, I'm Deputy Associate Administrator for Field. We're doing a tag team. We fed you with a fire hose on the IVP. Over the past weeks we've had discussions with several of you. Many of you have seen a sneak peek, if you're an advocacy group, you've certainly heard this before. But we want to open it up to questions and hopefully we'll have some answers, if there are answers we don't have today we'll put them out in if the public documents. If you have a question, please be as succinct as you

can, if you have a comment, likewise, state your name, your affiliation, and we'll take questions first from the group here. We also have the ability for people on the webcast to send questions in, then we're also monitoring the Twitter feed, which I'm not really up -- I mean, I do the social networking thing, but I'm not -- this is kind of newspaper to us at PHMSA with doing the Twitter, monitoring the Twitter feed as we go. So we're going to see how it goes here and then if we have questions that come through that way, we'll go there as well.

Also, again, if you have -- and I know people have heard us probably say this to excess, we're all about solutions here. We've thrown out a proposal that we are going to largely address the mandates and NTSB recommendations. Certainly there are other solutions out there, we're interested in hearing them. Some of the parts of the IVP that Steve went through, there's some TBA kind of aspects to it, like the schedule, like the spike test and there are some other specifics that are yet to be addressed, so we're interested in your input on that too. The whole idea behind these public meetings is to have a dialogue with you, the stakeholder, on where we should go with this and how we can be successful in implementing this process and then also meeting our statutory mandates and of course trying to deal with our friends over at the NTSB who have recommended in this series as well. So with that, we'll open it up to questions. So we have a microphone here. That is the microphone in the room. First up to bat is --

>> Don Stursma, Utilities Board. I'm listening to comments and I heard a couple references to 192.107 and 109 and based on exhaustive research done within the last ten minutes sitting in the back of the room.

(laughter).

I would like to point out that as I read 192.109, it is intended for pipe before installation, the number of measurements, type of measurements specified, that's not something you do on an in-service in place pipeline. I think that rule is intended strictly for pipe of unknown wall thickness that's to be installed, and I don't know if it has really any practical application for an existing pipeline. Same thing with 107, it's reference to determining the yield strength, it refers back to appendix B part 2. Again, as I read appendix B part 2 in its entirety, it was intended for installation of pipe of unknown specification before installation, probably being able to use up what you had back in the early days of the regulation, not really practical for application to an existing in service pipeline, and specifically the number of tensile tests, you know, you would be turning an existing pipeline into a piece of Swiss cheese with that many tensile straps. As the industry says, you have to take the pipeline out to service it and cut those, plus have potential repair in place. I understood from the presentation that perhaps it's recognized that the number of tensile tests might be something different than what's in appendix B and what a realistic or practical number is, I guess I'm sorry, but I can't offer a solution, as you requested, but it seems to be that you're aware of that problem that some of the existing regulations, some of the existing provisions of appendix B really aren't applicable to existing in service pipeline and you're going to have to come up with something specific to this type of activity.

>> STEVE NANNEY: Just to answer your question, we agree with you, what you're saying, that going and trying to cut straps or cutting every ten joints or whatever it says in those, the point is, PHMSA realizes that through this rulemaking process, we will have to come up with guidelines on what we do. Lacking those, that's the only guidelines in the code, and if you go look at -- I don't want to get into a code debate right here in this, but just to tell you, if you go to the code 619, it does refer back to establishing an MAOP and that's in (a)(1) that is how you would establish it. But we do recognize it, we have worked with other operators with issues that have come through and we have put some practical solutions together of a combination of some cutouts and some in the ditch type methods that we're

doing now so we definitely understand your concern and question and we will be considering that as we go through this process. And thank you for the comment.

>> Hi, good morning. My name is Lindsay Sander and I'm a consultant with a number of operators. The question I have for you is that this morning there's been an emphasis on gas transmission. However, gathering lines are subject to the gas transmission regulations if you are type A line, and in light of the pending regulation changes to gathering as well, this could have significant impacts to the gathering industry. My question is, have you all considered that yet? Will this be completely separate to make sure that it doesn't overlap existing gathering regulations, or have you even gone down that path yet?

>> STEVE NANNEY: First of all, we haven't gone down that path yet, to make the simple answer. We'll have to -- right now we're concentrating on gas transmission. After we get through with it, probably just to go further is we will probably then be looking at hazardous liquid pipelines, and then I would say if we do, or whatever we do with gas gathering would be third in the pecking order as we go through this.

>> Thank you.

>> STEVE NANNEY: But we haven't sat down and discussed it, to my knowledge, as far as what we plan to do there.

>> We look forward to that discussion. Thank you.

>> ALAN MAYBERRY: We also had a question on a card similar related on distribution and that's also not addressed in the IVP, but that's down the road addressing as well.

>> Hi, I'm John Dunn from Consumers Energy. Steve, early in your presentation, you made a reference or some kind of comment that this process that's identified in the chart applies to pipelines that have not passed the records review that we've been asked to do already. Now, did I gather that correctly, or are you planning on applying this to each and every pipeline that we've already looked at?

>> ALAN MAYBERRY: If you've addressed the records issues and you've filled the gaps in records, then you've addressed the concern over records, so the IVP would take that into account and it would funnel you to the appropriate part of either continuing to operate it, because you know what you have, or through that process, you've found your gaps and it will give you a process or a method to deal with the records gap. Right.

>> Hi. Mark Lauver with Quinn (sounds like) Gas Company. I have a question that was similar to the one that was previously asked that maybe relates to stepping from I guess process step 13 to 14. If I have material records on a pipeline segment but it may

not maybe meet the complete, I guess, interpretation of what's recently been issued, is there any potential or could you comment on any potential to maybe use a pressure test to validate, to further validate or to validate, you know, what you have in place versus maybe having, you know, some of the, you know, very complete definition of what has been recently issued?

>> STEVE NANNEY: The answer is yes, we will take pressure testing and the level of the pressure test into account for that. To give you an example, if you've tested to 100% SMYS, that would be looked at one way, but one of the issues is, a lot of times when you tested to like 1.25 times you still may be at 70 or 80% of SMYS, you may not be at 95 or 100 or higher. But we would take that into account based upon the level of the pressure test and then from that is the issue you run into is when you evaluate defects, anomalies on the pipeline, is how do you apply that to R string or an evaluation type analysis of that. Well, we would have to have some criteria that spells out if you have done a pressure test of how that would be equated. Does that answer?

>> Yeah, I think so. Thank you.

>> Christina Simms, American Gas Association. The statistics that you were providing on the amount of pipe going from steps 1-12, I believe are going to be very low compared to what we're seeing within the

industry. Part of that is if you look at how operators submitted their reports on steps 2-5 on (a)(1), (a)(2), (a)(3), et cetera, that they were looking, when the regulations were established, operators needed to determine the lowest MAOP for a line, and then have the records for that particular -- to verify the lowest MAOP. It was not the and, it was the or. So when operators submitted their annual reports, at least for AGS members, the vast majority said do I have complete records based on one of these. When you look at your statistics, the statistics you have are more the or's, not the and's. On the solution for that, I know that DOT has recently implemented a data quality and analysis team made up of government, public and the industry, and I would suggest that that team take a closer look to get you some valid statistics on the amount of pipe that could potentially be affected.

>> STEVE NANNEY: Christina, we agree with you that we realize that some of the numbers of 619(c) and 619(a)(3) need to be combined. In fact, before the workshop a couple weeks ago, I got Blaine to give me a list of the operators and picked out the top ten and I e-mailed and talked with each one of those, so we do know the top ten that has (a)(3) have gotten an e-mail and a phone call from myself, so I think we have an idea of some of that and we will adjust any adjustments we need to make to the numbers as we get more

information. But we definitely need the numbers you're talking about to get better numbers and it would much be appreciated. And thank you for the question.

>> ALAN MAYBERRY: I guess we just add an agenda item for the first ADEQ meeting. There's an advisory bulletin put out we're aware of this, that may have helped some confusion and where that was put, either (a)(3) or (c). We'll address that as we go forward.

>> Tom Bubernak from DMV. I have a question about low stress pipes. I would think from a low risk, the lowest risk would have less of a consequence and to have manufacturing problems with low stress pipes would be almost nonexistent. Is there a rationale for including the low stress pipes in the flow chart?

>> ALAN MAYBERRY: What are you calling low stress?

>> Under 20%.

>> ALAN MAYBERRY: Okay. It doesn't mean we haven't forgotten about it, it's just this IVP chart is intended to address transmission or in particular pipelines operating at 20% or greater SMYS, and that was actually a question that came up as well. Yes, it's anything above 20% SMYS is transmission pipeline. It doesn't mean the other is not important, it's like distribution or gathering, we're tackling this right now and those will come later.

>> I don't think you understood the question perhaps. In the flow chart it shows that under 20% with Legacy pipe manufacturing or Legacy construction techniques still get kicked into the verification.

>> ALAN MAYBERRY: Well, that's because there's some transmission pipe. I'm sorry, there is some transmission that operates at below 20% SMYS. So yes, it would still be in there.

>> Thank you.

>> ALAN MAYBERRY: Thanks for clarifying that.

>> Sorry to sneak up on you in the last second. I wanted to hear various comments from the industry. This is a first start, I would really encourage, this is a dialogue, getting the process going. For those of you who followed the gas integrity management and the liquid integrity management rules, this was much of the discussion going on similar, not exactly as many people here. I expect that PHMSA is going to get, just by the number of people in this room, and by the way, how many are industry here? Wait a minute, how many are not industry here? Okay. You're going to get a lot of comments, okay? So you'll probably end up extending that. That's okay, that's the whole process here. I want to congratulate you guys, this is a lot of effort here. I think the message I'm taking back and sending back to members in Congress and that is something like over 30,000 miles of pipeline we just really don't have our

handles around, some of that is in high consequence areas, the whole issue of integrity management was data driven, accurate data driven, so there will be some questions coming up here.   This is an attempt to start the process it try to get a handle on that.   I'm going to have to hear some comments this afternoon before I reserve final judgment but obviously this is a positive step, took a lot of work and effort.   It's kind of an it rated process with data coming in as you're evolving it, so I would want to just say I appreciate your efforts here. It's going to be a while before you get there, but I think some members in Congress are going to be asking questions before you get done with it.   So thanks again.

>> ALAN MAYBERRY: Thanks, Rick, and thanks for your participation in the past at these workshops as well.   Apparently I misstated one of the questions. And I just wanted to clarify the answer.   The question was, and this is one that was written on a card, are the segments that are being discussed going to apply to pipelines that operate over 20% SMYS or have an MAOP of over 20% SMYS?   And the answer is the MAOP is the key, it would be a pipeline that happens the MAOP.   You may be operating it below, but if it's got an MAOP of over 20%, so that's the driver right there, so that's what we're after.

>> All right.   Then I had one question that came in

after my Q & A was done about recommendation P11 17, make all lines applicable. On that slide, the numbers that were provided were 40% gas transmission not piggable, like 23% was 8 inch or less, 15% was 6 inch or less and then it was we don't really know how many miles are not able to be pigged because of pipeline configuration, so the question, but that's what was on the slide, we're not sure how many miles pipeline configuration is an impediment to ILI.

>> ALAN MAYBERRY: A couple more questions from cards. Regarding step 17, will PHMSA prepare guidelines for operators to determine the proper derate based on Class location? The answer really is simply yes on that note there. Feel free to step up. We'll be informal here, and we have ten more minutes worth of questions, so I want to hear from you. Then the last card I have right here is regarding step 17 what does PHMSA expect operators to do to perform remaining life fatigue analysis? I think what we're after here in this setting or after today is input from you related to that, so we're looking for your input on that, really how do you apply that to gas pipeline, gas transmission pipelines. Certainly there's a lot out there related to liquid lines but we need to hear from you as well on gas pipelines.

>> My name is Andy Drake with Spectra Energy, I appreciate the work you've done here and I appreciate

the workshop just a chance to think through this together, it's obvious that you've put a lot of thought into this and I appreciate the fact that you walk through t -- walk through what you're trying to accomplish. It's very clear you have a lot of objectives in front of you that you're trying to solve and I think therein lies the basis of my comment or question, and that is, you are trying to do this so many things here that it becomes very difficult to discern what some of the criteria or even what some of the boxes apply to and it might help if we, as you walk through those, as this conversation evolves, you can help kind of elaborate a little more. I'll give a case example. You talk about 125% MAOP hydrostatic test is an acceptable hydrostatic test except if it wasn't at a high enough stress level. But I think there is a dichotomy of issues you're trying to address there. The 125% hydrostatic test I think we all agree is valid to determine the acceptability of a MAOP but the reason for the high stress is to determine material strength for use maybe in anomaly say for pressure calculations which is a totally different thing than MAOP, that's INP and I think when we're blending those together and trying to accomplish them at the same time, it gets very confusing what's the hurdle rate and what's the target and I think it would help as we go through this if we can be a little more deliberate about talking about which one is okay for what purpose because I think as we jam them together, it gets so convoluted the target is almost impossible to discern. That would be just maybe a helpful accomplish as we go forward, because you have a lot of things you're trying to do at one time up there.

>> ALAN MAYBERRY: Thanks, Andy, we appreciate the comment.

>> John Dunn, Consumers Energy. Just before lunch, if you don't mind, I would like to carry something back with me to lunch to discuss with people. Could you say one more time why it is that PHMSA decided to not follow the law the way it was written? In other words, PHMSA decided to present requirements for pipelines that had not been previously tested, that were operating at less than 30%. The law says greater than 30% previously untested. So if you don't mind, could you it rate that? Thank you.

>> ALAN MAYBERRY: Hopefully I can keep that fairly simple. I think it is fairly simple. Thank you for the question. The law, the statute is one aspect of what we're trying to solve here but also the NTSB recommendation relates to the same matter and it doesn't differentiate, you know, between 30% SMYS and above, so that's the main reason right there.

It's a quiet group here. I tell you what, let's go ahead and -- no, you're not allowed.

>> Don't let me ask a question.

>> ALAN MAYBERRY: We have an insider here. You still work for us, right?

(laughter).

>> Still until this morning.

>> ALAN MAYBERRY: Right.

(laughter).

>> Yeah.

>> ALAN MAYBERRY: You're not going to get off that easy. I would like to first make a comment. Linda Daugherty -- actually, Linda and I are switching roles at PHMSA. She was the DAA for --

>> After this meeting.

>> ALAN MAYBERRY: I don't know, I may change my mind today. But she's decided she wanted to go back to the operations side so Linda has gone back to the central region in Kansas City and is now a region director in the central region, still filling in in my old role, field operations, so we're kind of doing a tag team for the next couple months at least until October. But anyway, with that intro, I would like to introduce Linda Daugherty our acting or deputy for field operations.

>> Just Linda. Hi, guys.

>> ALAN MAYBERRY: She's an insider, so take it away, Linda.

>> Hey, I have a question. I thought Andy's question was very good and on target. We have a lot we're trying to accomplish with this process and in

some ways by putting so much together, we may be creating confusion. That was not our intent. Our intent was to try to figure out a process that we could walk through that would hit all the but phones so that when we got to the very end, we could say, got them all, we've accomplished everything, rather than having separate processes that would need to cover all these different items. So I guess my question back to Andy or whomever else here has courage to stand up here at the mic, do you think that separate processes for these items, for these requirements, is preferable? Is that better for the industry?

>> (off microphone).

>> Yes? Come up and talk and put it on the record so we can hear what you have to say. This is really important for you to get your comments and your thoughts on the record, whether you put it on the docket or you tell us today, so we can have that dialogue. Otherwise, we aren't hearing what you need to have, so come on, Andy.

>> ALAN MAYBERRY: Or at least if there's a proposal that would define that, you know, you could submit it to the docket.

>> Wow. Since I asked such a great question, I guess I'll get to elaborate what I was thinking about. I think the concern I think that you can see is there are many good things that are trying to be done here and

they need to be done and they can be done but as we put them together what ends up having is I think you fail so many boxes across the top that you end up coming with a very large number of population in the pipe down by this case by case discussion, and the criteria can't be clarified too easily as to what the hurdle rate any of that criteria has because it's all interactive, it's integrated, you could be good enough here but maybe a little too low here, but the in ex-case, a little more over here, so you have a lot of pipe coming into that box where you'll have a case by case discussion with very unclear acceptance criteria. That's frustrating to us, it's frustrating to you, I think it's frustrating to the public because it looks arbitrary and capricious to some degree but the more you can isolate that you get some of the enter dependency to split off and the hurdle rates become very clear and I think the discussions can move on much quicker and I think that gives much more certainty to the public and to all the stakeholders for that matter did we hit the box, yes, it can be very clear. And I think that was the nature of my concern is I think just for example the MAOP issue, 125% versus high strength, once you differentiate between trying to define safe pressure calculations for anomalies and you need to know the strength, otherwise you can't make that calculation, there's a lot of ways to figure that out. That may not happen in those top boxes with records, but you need to know and I think the public really needs to know. When the dust settles, 125% test on the facility is the ultimate litmus test for its MAOP. Good. The next question is how long is it valid? That's a separate question with a separate series of processes that you go through, fatigue analysis, corrosion analysis, fitness for service studies, but I think when you mash them together you get too many things moving at one time that are interdependent and it's almost literally a case by case discussion to figure out is it okay. That was rally the nature of my comment.

>> ALAN MAYBERRY: Thanks, Andy. And you have a solution to help us meet our mandate, in two years, I think. We're after it.

(laughter).

Okay. Then we had a question on Twitter, need to clarify the difference between 619(c) and the grandfather clause. Actually what we're saying is 619(c) is the grandfather clause, so that was an easy one there. Thanks.

>> Robert Hall. Yeah, I would like to make a comment regarding the NTSB recommendations, and I encourage PHMSA, I see that they've put a lot of work into this, but let's not lose sight of the accident that resulted in those recommendations. Although I've only had a little bit of time to study this thing, looking at it in the totality of the issues that PG & E had that

ultimately resulted in the recommendations and the failure, I see holes where issues that PG & E had would not be caught by this process, and that's just based upon a preliminary analysis. So I encourage PHMSA as they go through this to look at the major failures, not just San Bruno but Marshall, Michigan, and some of our other catastrophic accidents and use notices as cases to test your process and look at the issues that were there and I think we'll get a stronger process if we do that.

>> ALAN MAYBERRY: All right. Thanks, Rob, I look forward to further dialogue on your perspective there as well.

Okay. We're right on noon, the hour. We're going to break for lunch. We're taking an hour and a half. We'll be back here at 1:30 sharp Eastern time. So with that, thank you, and have a pleasant lunch.

(lunch break) >> JEFF WIESE: Before we get going with the program for this afternoon I want to show you something that might be more fascinating to me, to understand what we were trying to show you earlier and perhaps were not doing such a good job of it. We were trying to invite people to submit questions via Twitter and you see -- I am sure many of you have seen a Twitter fall, but if you haven't I have been in meetings before where we took questions via Twitter and it worked very well.

>> Is anybody familiar? It is frozen.

>> JEFF WIESE: You think it is in our control? Houston we have a problem.

>> Let me take a look at it.

>> JEFF WIESE: Okay. Maybe I will just review the agenda real quick while Cameron tries to figure out how to do this. I don't know how many of you have participated in a Webcast, if sequester and keeps going and cuts deeper next year, we might have to do a lot more meetings that way. So this afternoon we have a couple of people. I am going to -- we will take a break unless Cameron thinks we can do it right now, we will get going. I will show you later. Sorry.

We have got a couple of people we wanted to round out some perspectives on the IPV process and we brought in James Hotinger and Carl Weimer and then we are going to come back and have a couple of operators, Nick Stavropoulos and Bruce Paskett and that will be moderated by Randall Knepper. They are doing -- thankfully they are doing some damage prevention legislation in Pennsylvania. With that I guess I will turn it over to Jim and hope that we have the presentation fixed by now. Virginia's experience, even I can do this one. It is not. So Cameron, how are we doing back there? Okay. He is good but he is not that good. You want to open up?

>> JAMES HOTINGER: I can.

>> JEFF WIESE: Maybe we will start talking a little bit since we have some time we need to chew here. I think there is a switch in the back.

>> JAMES HOTINGER: It will work. My name is James Hotinger and I am the assistant director of the division of utility and railroad safety with the Virginia State Corporation Commission. I have been for awhile. And as Jeff said NAPSR was invited to send a person to do this presentation and so they selected me. And while my presentation is primarily on the experience that we have had with our operators in Virginia, I did discuss and go over with the NAPSR board and they agreed with the presentation as it were if we can ever get it up. While I was preparing the presentation I spent a lot of time looking at the verification process, integrity management and how it compares as well as the history of how we got to where we are today. And -- we have a blink. Is it still up yet? There we are and now we know who I am and where I am from. Any questions? I started looking at the issue and found out these issues are not that new. Integrity verification has been discussed for at least the last 46 years. I have a copy of the transcripts from the Senate and house hearings on the natural gas act in 1967. One of the reasons that we are here is that older pipe that's in the ground.

And Senator Magnuson who was the chairman of that committee -- this was 1967. So then I went on to read the transcript to see what industry was saying at the time and this is from Mr. Burlingame and he said that I think you will find from the record many companies are already dealing with changing population density by the retesting, relaying or doing whatever is necessary to see if the line is safe. He went on to say that equally impressive is the practice of retesting and reevaluating pipelines where populations occur. Many companies have adopted this practice and this practice consists of making periodic surveys to determine areas in which encroachment is occurring and area affected by encroachment, design, operating history and conditions of the pipeline are reviewed. And if the operating history of this line is good the line must be either tested to 90% of SMYS to improve safety or the operating line must be reduced. If it is questionable it must be replaced. These practices account for the fact that are not and will not be allowed to become a threat to public safety. That's 46 years ago. If we were still doing that -- I don't know when that happened but still doing that we might not have been here today.

All that being said I will get to the Virginia experience now. We have got a total of 3,000 miles of gas and about 1100 miles of hazardous liquid transmission. Intrastate gas transmission we only have about 482 miles and what it does range from 4 to the 24 inches of well and our operating pressures range from 500 up to 1300 psi. So when did we start with this? Well, when the advisory bulletin came out January 24, 2011 we took it upon ourselves to generate a letter to all our operators in February that said we wanted to come out and look over your documentation. When can you have it ready for us? So they all responded back and then March and April of 2011 we went out and reviewed all the documentation that the operators had for transmission lines and I use the term had, they did not necessarily have everything that was necessary to demonstrate the MAOP. We also look for those pipelines where they had the MAOPs between 15 and 20% of SMYS and the reason we did that is we have some operators that will design pipelines to operate like 19.9599% of SMYS. So it is not a transmission. During the course of this investigation we found that several of those lines because of the fittings they had used and other things they were operating about 20% SMYS and were transmission lines. They had come back and revisited the approaches. 11 segments of pipeline that had issues and because each one of these pipelines may have had one or more issues that we identified. Again it was -- they didn't have the pressure test data or wall thickness or pipe strength or information on fittings used. So what I am going to talk about is give three examples of pipelines in Virginia that had issues and what was done to resolve the concerns and so forth.

Biggest concern to us was the age of the pipelines. As you can see we had pipelines as old as 1958 that were missing information but we also had pipelines as late as 2010 that were missing information. And that was what was most disappointing. In light of integrity management that has been in place for ten years requiring knowledge of your system companies were failing to record all of the data necessary to demonstrate the adequacy of the system as late as three years ago. So here is example 1. Six miles of 12 inch X42 put in place in 1994. 375 wall pressure tested was operated 19.95% of SMYS. This is one of those that I told you about. Record view found that 27 grade B fittings in that pipeline. So that meant we had a problem. It was operating above that 19.95% of the SMYS. We asked the company to verify that information. Information indicated that that would be grade B fittings. There was not certainty that they were used in the pipeline. So we -- they went out and did some exploratory digs and they dug up six of them and they found one that was grade B and five of them were not. The sixth one was. So as a result of that how did they resolve this issue? It was now considered transmission because of that grade B fitting.

So it was operating almost 24% of SMYS. That company did not want to continue to operate it as a transmission. They reviewed the load and the needs of the customer served and they lowered the pressure in the pipeline and derated and it is now 20% less of the SMYS. They didn't think it was a transmission to start with. So I would encourage you that if you have any lines that are operating near the 20% SMYS level to go back and look at those records as well because you may find some that are operating about 20% SMYS because fittings were used incorrectly or information is incorrect.

The second example is a little bit easier, that 17 miles of 18-inch steel pressure 1250 psi. In the sea limits it is serving a power plant. And in looking at the MAOP documentation when they constructed the pipeline they were going to pressure test it in 12 segments, and the last three segments for whatever reason the documentation of the segments tested was incorrect. For example, on the 10th segment the station numbers went backwards rather than continuing on for like 7,000 to 8,000. It went 7,000 to 5,000 and then the 11th one was related to that one and the 12th one related to the 11th or the 10th in order to resolve that concern they are drawing up a hydro side testing plant by no later than April 2014 because that's when they have to complete their assessment for integrity management and that's one of the things that we are concerned about is that in light of integrity management why operators aren't researching more of this information because lack of knowledge of the system is a threat and becomes a risk and should be taking opportunities to get that information and to comply with integrity management requirements. And my third example is the one that -- it is one of those unknowns that was on Blaine's chart. 23 miles of 6-inch steel installed in 1958. It is serving a town. It is one of the main feeds to the town so they can't turn it off. And they know it is 6-inch pipe. That's it. They didn't know the wall thickness. They didn't know the pipe strength. They couldn't find pressure test. How do you go about resolving those issues? First off helped develop a sampling plant to measure wall thickness and we looked at statistically valid samples. Whenever we ask our operators to do something we want to be sure that it is verifiable and demonstratible that it can be repeated and there is validity to it. It is not that we will take ten samples and be done with it. We made them run the sampling. They used 95% confidence with 5% margin of error. And they assumed that they would have up to 50% error in their samples. So that gave them the maximum number of samples to take. They also had some sections of pipe where they had rerouted the pipe and replaced it. And they excavated those areas to take examples of strength tests and also lowered the operating pressure from 500 to 400 while they were doing it.

So the sampling plan showed it is 1 in 8 wall and the pipe section moved came back and demonstrated the grade B strength of 35,000. Now I want to tell you that researching documentation is also a challenge for us regulators because this pipe is installed in 1958 we had to be sure that it met the API 5L of 1956 which was the most recent one at the time. And with the help of PHMSA we were able to get a copy from the Library of Congress. It took us awhile to find that copy so we can verify their testing was valid and did meet the chemical compositions and so forth of the steel manufactured at that time. Now they also in addition to these things they also did a DCVG survey over the entire pipeline. They also did a CIS and installed additional test points wherever it was low. So they could have better accuracy as to the condition of the line that's coding and so forth. And while they were doing this, they are also planning to derate the pipeline by installing basically building additional pipeline out from the town because if they moved the capacity further out they can lower the pressure coming in. So all the while they are doing all these activities their ultimate plan is to derate that pipeline. Meanwhile they did find a remaining problem. While they were doing all AVDAs they did thickness measurements. 561 1 in 8 wall. Three weeks ago they did one at 156. So excavated that and found one joint, upstream and downstream was 188 but this one joint of pipe was 156. So that's the monkey wrench in the works as it was.

That's one of the things that I want to leave you with integrity verification or integrity assessment are living, breathing processes. They are dynamic. They were moving forward. They have done these things and now they have to go backwards a little bit and restart at a certain point. They don't have to go back to the beginning. But they are going back to revisit this. And so they are currently evaluating the statistical analysis to determine the function of the pipe. What happens if we have several joints and again because at the end of the day they want and we want as well a valid documented approach to ensuring to demonstrate they know the integrity of this pipeline, because if an issue ever occurred with this pipeline the first thing anybody looks at is records and documentation. If it is not there then the excuse -- where is the excuse. So that's why in every step we take we ask for the reasoning behind it. There has to be an engineering reason behind it. Valid assessment and we review all of that stuff. We reviewed all the HCAs for all of our pipelines and all the non-HCAs areas of our pipeline to make sure they have been assessed properly. And it is a process. It is not -- it is not something you do once. And so our operators are still continuing to get that data.

We have seen, for example, in areas where they don't know the pipe strength they take out sections but I want to also offer the suggestion that on a large amount of pipe tapping coupon may be used for samples because GTI has done a study and you can find it where they use mini samples to demonstrate this strength and they have validated that process. So even something as simple as a tapping coupon may be used to confirm the strength of the pipe. All the data that you take every time you are out there in the field needs to be kept and applied to integrity verification and assessment. If you don't know the wall thickness, every time you weld you have to check for lamination. Remember those readings and save them. Every time you expose the pipe look at it and examine tapping coupon. Take the strength of those wall thicknesses. You can gain the information you lack through your operational maintenance if you keep the information and give it to the right people.

One of the things that we found over the year companies have a lot more data than they think but it is over in the department and they didn't talk to that department and when they start looking they find that they do have that information. Do a thorough research. Think of all the things you do in the pipeline, what departments. Corrosion department may show up in your integrity management but may not have showed up in records relative to pipe thickness. Again I can't reinforce the importance of using all of that data that's available. I think that many of you probably have more than you think you do if you just looked at what you had.

And all of it has to be verified with demonstrative. At the end of the day as a regulator to ensure compliance with 192 and you as an operator to ensure that you are providing the public safety and you can demonstrate to the public that you are doing that it has to comply with 192 to establish an MAOP. Any questions? I mean I can go in more detail and more examples of different types but those kind of cover the gamut. And I can go in to as much detail as you would like.

>> JEFF WIESE: Is it the Webcast? Is that it? Are you still sleepy from lunch? You were sleepy this morning and we cut you a lot of slack. Now come on. Very good.

>> JAMES HOTINGER: Yes, sir.

>> I am Mike O'Shea. Thanks for sharing those examples. I think those were applicable and helped me understand. You mentioned the industry references were going back to try to fill in data gaps and using like API 5L. I am curious of PHMSA's position

on doing the same, not just for pipe but for the other components and fittings and flanges and whatnot. Is that a recognized acceptable practice? Go back to different standards?

>> JAMES HOTINGER: Can I rephrase your question? What you are saying is if you have the fittings and so forth and you know you examine the characteristics or able to demonstrate they have met a standard?

>> Yes. If you have fittings and you don't have all of the original records for those fittings to qualify their material properties, is it valid, does it meet the traceable verifiable complete standard or some version of that using assumptions, conservative.

>> JAMES HOTINGER: They used pipe and tested. It wasn't -- they actually had value. What you are saying is you don't have the value but you know that this was a whatever valve.

>> Yes, and your example when you said they opted to use the lower SMYS. Does that apply to or could that apply to the fittings as well?

>> JAMES HOTINGER: So what would you be missing? You know that you have, I don't know, what's a type of valve we are talking about here?

>> It could be just a fitting, elbow. It could be a T.

>> JAMES HOTINGER: It is a 375 wall elbow.

>> Right. You would have some properties on

that but you wouldn't have --

>> JAMES HOTINGER: You wouldn't know who the manufacturer was?

>> May not know the manufacturer or the SMYS. Is it acceptable to look to an industry reference given this era?

>> JAMES HOTINGER: The only example I had where they had a pipeline where they had seven fittings they didn't know anything about and no markings on those fittings and they replaced all seven fittings.

>> Or if that -- so that's the first question. First second would be if pressure test is done you validate the integrity of the line, does that go in to suffice to meet the requirements that --

>> JAMES HOTINGER: The challenge I see with that how would you demonstrate what percent of SMYS you are operating on. If you didn't know the strength of the fitting you could be operating at 100 of SMYS and not know it if you don't know the characteristics of that fitting itself.

>> JEFF WIESE: Fell free to submit to the docket and we will be answering questions on the docket. Sorry that's probably not --

>> Thank you.

>> JEFF WIESE: Others?

>> JAMES HOTINGER: Maybe.

>> JEFF WIESE: Okay. Thank you.

(Applause.)

>> JEFF WIESE: Okay. Next up we have our esteemed colleague Carl Weimer. Carl has been a reluctant partner in this technical debate but we have drug him in kicking and screaming. Carl is well-known in the audience. And he is also a member of our advisory committee. We think it is important for him to be there and understanding that and giving us his two cents.

>> CARL WEIMER: And two cents is about what it is going to be worth, too. Well, I appreciate being here today, even if they did drag me in kicking and screaming. I have a fairly easy job because I am not an engineer. I don't own any pipe. I don't have to maintain any pipe. I don't have to regulate any pipe. So can stand up here and talk from a public point of view that's not very knowledgeable because we are not engineers what the public thinks about the safety without having to worry about how we are going to deal with that in the field or pay for it if we come up with something. So it is relatively easy.

We did reach out to a number of people and once I got drug in to this to look at the chart and give us some opinions. So I am trying to incorporate a lot of that stuff. It was pretty amazing because when we first sent the chart out to people it created a new flow chart with just about every member of the public that looked at this chart because I think only an engineer likes flow charts.

But as we worked through it and PHMSA walked us through the chart just they have a lot of the other stakeholders groups, we came to understand it and saw how much work went in to it and could follow from step to step and see there was a lot of good logic in here and we appreciated it once we got over the initial reaction. The data that was sent out and that was talked about a little bit this morning also shows that while there might be a majority of the pipe that falls in this there is certainly enough pipe, enough pipe miles that show there is a risk that needs to be dealt with. We took that even a step farther because you have heard me talk about before how we don't believe that the HTA classifications for class 1 and 2 pipes are protected enough. There is thousands of people that live within impacted radiuses. The data what is considered HTA now we think the mileage is much bigger for that one house that is within those PIRs and also kind of surprised this is even a needed discussion because the public had assumed that this had been taken care of when we adopted integrity management because the basic assumption of integrity management you know what's in the ground. So you know what the risks are and now we come to find out companies don't know what they have got in the ground. So we are going back to this integrity verification system. I am somewhat surprised this was not part of the integrity management and I think it drives home to us to get the need to get to integrity management. Not everything has been addressed and if we are making risk decisions based on things that we don't know what is in the ground it shows that there are things that need to happen. And it is also too bad that it took a tragedy the size of San Bruno to bring this flaw forward.

Also question the delay. This was supposed to be done in July. Congress passed this in January 2011 and gave PHMSA 18 months to come forward with rules. I think PHMSA had decided to wait for the data to help drive the rules which makes some logic but could have started moving forward and developing the integrity flow chart without waiting for the data because it was clear even in January 2011 that there was problems.

A lot of the rest of what I am going to say is kind of working through the actual chart. We agree with PHMSA on these sections across the top of the chart. It was clear to us as we worked through this if you read 192.619 A1 through 4 that it says you need to have all of those things. You can't just pick or choose one of them. You need all of them and if you don't have all of them, then you don't know what the lowest one of them that -- one of those is. So we believe that the way they had that part of the chart constructed makes a lot of good sense.

We also certainly supported the idea of moderate consequence areas. This is a whole new thing and it goes with something that we have been testifying to Congress on years now and it goes to the heart of Inga has joined us in the call of expanding high consequence areas. It starts to address that as we start dealing with those areas outside of what is currently a high consequence area and we certainly support PHMSA's proposal that the way to define this it was kind of left open and the proposal is to define it as one house or one site within a PIR.

We have a little bit of a concern of kind of giving some of the low stress pipelines a pass in this and this is an undefined concern that we want to look at more and we will probably put some comments in to it, but there are some studies out on a number of pipelines that have ruptured that would be considered low stress. Now my sense is that if you look at the loops on the chart that capture legacy pipe and legacy construction processes those loops are probably going to capture most of those low stress pipes that have ruptured but that's something we want to look at farther to know whether we really should be giving these low stress pipes a pass. One of the other things we heard from the public when we sent this out is there is a growing concern about climate change gas and if thousands of these miles are in low stress pipes or out in the middle of nowhere Nevada, it doesn't make sense if they are leaking or rupturing in those places because of the affects of methane going in to the air. So that should be considered too.

A lot of the stuff we see in the chart, you know, there is stuff to be determined yet and one of the material sampling protocols of it is unclear to us thinking about San Bruno where you had a short section of pipe this needs to be defined to us. If you have 20 miles of pipe that you don't have records on what kind of sampling are you going to have to do to make sure you are catching a piece of pipe that might be different than the other 19 and a half miles or 19.75 miles. So we like to see more clarity on that sampling protocol.

One of the biggest areas when we looked at this we are unconvinced that the ECA option will work. We have seen over and over inspections not catching these problems and pipelines going to failure after inline inspections. There is a lot of wiggle room in the whole engineering critical assessment since it is not defined yet. So we are not sure it meets Congressional mandate. The details of that means maybe comes forward we will feel more comfortable with it but at this point we are unconvinced. And if you follow through the ECA approach when you come out the other end it is based operator will take those results and take appropriate action. We think that's too much wiggle room for the operators. We would like to see something much more prescribed. If you come out the other end with certain information we know what the operator is going to do. We are getting back in to this loop of a lack of clarity. And one the last couple of slides is there is a whole lot of developed specific guidelines and TBDs in the chart and those just raise all kinds of red flags, too because the devil is really in the details on all this stuff. And there isn't any details in here now to assess and what we have heard over and over again this morning as the industry comments we will fill in the blanks on these. Well, we would rather see PHMSA fill in those blanks early to set the stage with a starting point for those operations versus letting the industry by their comments drive that issue.

We finally came up with our own chart which makes my head swim a little bit, but people said they wanted some examples of what people had for solutions. So we basically started with the same chart. Mainly focused on the grandfathering clause. So if you start up at the top if you were grandfathered, you would then go down and you would look at whether it is in an HCA or MCA. If you weren't grandfathered you would go off to the right and follow the PHMSA steps 2 through 8 and come out at the other end of that. We didn't pay much attention to that. If you were grandfathered you would go down is it in an HCA or an MCA, if it is you derate the pipe until you can do one of the following. Then you go about part 192. If it is not an HCA or an MCA then we would set up a -- there would be a schedule set up to be determined for one of the following and it would be the same route. We think in many ways this mirrors what NTSB had asked for. That's all. If you want to ask a nontechnical question and see if I can wrap my tongue around my neck and choke myself, great. Appreciate it.

>> JEFF WIESE: Surely you are not going to let that opportunity go.

(Applause.)

>> JEFF WIESE: Oh, sure if it is me or somebody you are willing to do it. If it is Carl you are going to cut him slack. Carl, thank you very much. I think it is important for people to understand that there are competing points of view out here and as a regulator it is -- the path isn't always crystal clear. We will often have people diametrically opposed to each other and both feel equally strongly as points of view and as a regulator at state and federal and it is our job to balance and find a path forward. God forbid it comes the day that we can never agree on a path forward so nothing gets done. We are going to have to move ahead and my guess is we disappoint a lot of

people and then we are probably in the right place. With that said I am going to invite up Randall Knepper. Randy is here moderating. He has taken over from Paul Metro. Paul is in up Pennsylvania in a hearing and Randy is going to be moderating and we have invited a couple of operators to give their points of view. If you allow me two seconds, first of all, I appreciate everyone coming. Everyone has a day job here including Carl who is a county commissioner. And I'd like to point out that Carl has become much easier to work with once he became a county commissioner. He now knows what it is like to balance those points of view and Carl has some pretty major projects going on in Wacom County, whether it is coal, export facility, unit trains of oil coming in. There is a lot going on. We know he has a lot to wrestle with and he has come in for advisory committee and Bruce has come in. He was the NAPSR favorite. They were voting for Bruce to come in and talk and I personally invited Mr. Nick Stavropoulos. Nick has been on a wild sleigh ride. And he is in a position to have learned an incredible amount. Thank you to all of you. With that I will turn it over to Randy.

>> RANDALL KNEPPER: I don't have a large role in it. Not a lot of heavy lifting. Jeff's description earlier probably sounded like a lot about diabolically opposed sides and that sounds like Congress down the

street. We heard a little bit from the regulatory side and we heard some from the county side. And nice to hear from the pipeline operators who represent the intrastate perspective. We are lucky to bring -- I guess the West Coast has gone to the East Coast here to give a perspective. And, you know, I'd like to introduce the executive vice-president of gas operations for Pacific Gas & Electric located in California, Nick Stavropoulos. I will hand it over to you.

>> NICK STAVROPOULOS: Thanks very much. Good afternoon, everyone. Great to be here. Unlike Carl I brought with me a technical expert that can answer those questions. So I don't have to get my tongue caught around my throat. My colleague at PG&E is here to take the ultra technical questions. Jeff, thank you for inviting me here today and thanks for starting a dialogue around how we are going to work together to get to 0. That's really what this is all about. Right?

How are we going to get there and I can tell you in speaking to my colleagues in the industry that's where we are at. We share the public's desire, expectation, and requirement, really our license to operate. Their expectation is that we will operate our system safely and that we can get to 0. And I think that's been demonstrated by other industries who have really taken the bull by the horns and taken their impressive safety records like we have and get even better. And that's really what we are trying to do as an industry. I think Jeff, that's what you are really creating here with the IVP to give us a process by which we can improve our game. Figure out how we can use technical analysis, engineering data to figure out how we can make the best use of the money that we invest every day in to our system.

So that's what we are trying to do at PG&E. I came to PG&E nine months after the San Bruno explosion. And I was really moved by the board of directors and Chris Johns, our president in understanding that there was an enormous amount that PG&E needed to do to ensure the public that we could get to 0. So we have embarked on a massive safety program.

We operate 80,000 miles of pipe. For those of you who know the math, that's around the world three times. Plus a little more underground. And that's an incredible responsibility. Now fortunately most of that is lower pressure distribution pipe but we do operate 2% of the gas transmission network in the country. But PG&E also operates 10% of the high consequence gas transmission pipe in the United States. One out of every 10 HCA miles we operate and we operate it in the most seismically active part of the country and we operate it in one of the densest, most difficult places of the country within which to operate. And we saw that the San Bruno neighborhood when that pipe was reinstalled in 1956 all of those homes were not there. For those of you who have been to central and Northern California a lot of construction has happened over the years. A lot of encroachment on our facilities. So when I first came to PG&E the first thing that we focused on was how could we build a safety first culture. How could we get all 6,000 of my gas workers focused on understanding that their goal was 0 injuries, 0 injuries to the public and 0 injuries to the PG&E employees and 0 injuries to our contractors. We decided to embark on developing a safety management system that we have been working to drive towards and we selected past 55 as our asset management framework model which is soon to become ISO 55,000 and that gave us the framework within which to operate. And as like Jeff likes to always say it starts with know your system, know your assets and as Carl mentioned the expectation of the public is that we already knew that. But it is -- as we know there is a lot more that we can learn over and above what we already know. So we really start with know our system. Completely understand all the assets that we are responsible for. And certainly the next step is to understand the regulations under which we need to operate those assets, but the third step is to understand the condition of those assets, the threats that those assets face. The mitigation strategies that we can deploy against those threats and select the right ones so that we can get the best value for money so that we can get the most risk reduction per dollar of investment and then identify that work and execute that work effectively at quality.

So one of the things that California Public Utility Commission did was to eliminate the grandfather clause in 2011. So we have been operating without the benefit of the grandfather clause for three years. And so we were given two and a half months to put together a comprehensive ten-year pipeline safety enhancement plan in two and a half months and we brought experts from all over the country, gas engineers, regulatory experts to come in to help us put together our decision tree, our flow chart as to what we should propose to do over a multi-year period of time. As you might imagine that flow chart is spit out at the bottom. Hydro testing, pipe replacement, inline and valve automation and that's the process we embarked on back at that point in time. Within six months of the first year we completed 152 miles of hydro testing, 97 separate hydro tests. I think we were doing about three, four miles a year up until that point in time. We did 152 hydro tests at a cost of $1.4 million a mile that first year.

We didn't stop there. We didn't just say let's go ahead. But what interim safety measures could we put in place and we started by know your system and we gathered up records from 70 different locations across PG&E and we went back to the original manufacturer specification as-built drawings, original engineering drawings and we scanned 3.5 million individual documents and linked those in to a GIS database. And we validated the MAOP of 100% of our pipeline network, of our gas transmission network. Not only the pipe but every feature and component of that pipeline system including a thousand miles of pipe that operates under 20% SMYS. So we didn't do HCAs. We just didn't move 30% SMYS but we included 100% of our entire population of gas transmission assets. We spent a quarter of a billion dollars doing that. A quarter of a billion dollars but we feel that we have a really good basis upon which we have been able to establish our MAOP. We reduced the MAOP of 6% of our network, about 160 plus different segments that we derated because of that work. There were a whole other array of sections that we cut out components of that pipeline because they were underrated for the pressures that we needed to operate and we replayed those components and brought the pressure down and derated those systems and brought the pressures back up after our view by the public utility commission. In some cases certainly we didn't have the complete records that we wished that we did and in those cases we use ultraconservative assumption. We field verified those conservative assumptions and we found that 96% of the time our assumptions were at or even more conservative with what we found in the ground. We have got all kinds of data we are going to share during the process of the quality of the result that you get from using certain types of data. For example, as-builts and manufacturer specifications versus early intent records like, you know, design, initial design drawings.

So the results from that is that we determine if 72% of our system is now validated with a strength test, traceable verifiable complete strength test a lot of that is post subpart J, but in California from the early 1960s until subpart J was adopted California had a requirement to do hydro testing at 1.25% of SMYS. So it didn't have all of the record requirements that subpart J has but it did have a pretty robust mechanism. So one of the suggestions that we will make is how do you account for that. How do you account for the various state rules that were in place before subpart J where hydro tests did occur. It was very complicated. You know, we are happy to share all the lessons. We have had many operators come in to visit with us to learn what we did and how we gathered records and how we parsed those records and how we organized those records. We developed and patented the MAOP calculator that allows you to take all of this linked information to automatically create an MAOP of your pipeline network and we are sharing that with industry, but it was a major massive and comprehensive undertaking but something we needed to do in the interim given the situation that we are in.

So while we did that, we also embarked on the actual physical work of testing and replacing our pipeline. So we identified 780 miles of HCA pipe that was not previously subject to a hydro test. And we risk ranked that work and we began to do that. We are in to our third year of operation. We are down to about $900,000 per mile. That includes all the costs of keeping customers connected while we do this work. So we have developed a very extensive portable L&G, portable C&G operation. We have almost 100 pieces of equipment. For example, last year we held 22,000 customers in Napa with portable L&G while we hydro tested for a several week period of time while we took that line out of service. We do everything we possibly can to make sure we can meet our commitments to customers and to be able to satisfy them either with C&G or L&G. So that's included in that cost. In addition when we do a hydro test we look for any anomaly that we observe. And we also use that time while that pipe is out of service to make piggable. So any component upon that pipeline or any feature of that pipeline that will prevent that line from being pigged we take that time and we make that piggable and that's also included in the $900,000. We have the most comprehensive environmental regulations in the country. So a very big part of our hydro testing is dealing with things that we didn't expect. There is Mercury in our lines that happened from old processes from the 1930s and '40s. We have to get the water level down to low levels and we have to do very short segments. So we are doing one mile segments, half mile segments. Hopefully most of you when you go to do your hydro testing you are table to do five, six and seven or longer mile segments where the cost per mile is substantially reduced. The setup time is a big part of the overall cost. We are going to replace 185 miles of pipe to give you an idea. We are doing about 60 miles a year right now. PG&E was doing three or four miles a year before San Bruno. We are going to make over 200 miles piggable and pig those lines. And another controversial item we are installing 225 automatic or remotely controlled valves to deal with the shutdown issue of how long it took us to get to those locations to manually shut off those valves and what was a very difficult situation. Again reminder that we are operating these pipelines in the most seismically active area of the country. We locate these valves in strategic locations associated with our seismic risk as well.

So far we have completed 404 miles of strength testing with 226 separate tests. So that gives you an idea of the volume of work. We had what I call three successful tests. Three ruptures. Two as a result of mechanical damage, the one that Vice-chairman Hart referred to that was actually mechanical damage that we found on a segment of line 132 and one seam failure on an incomplete seam wall.

So we are finding things in our network and we do call those successful hydro tests and make us feel good when we are done. Lessons learned on hydro testing, we wish we had a little more time to engineer and plan the execution of that work because we are like the 82nd airborne. We started in March and in June we were doing hydro testing and we had to do 97 separate hydro tests in less than a six month period of time. If we had more time to think about that, to plan it, to engineer it, to design it, we think we could have got a lot more work done for the money that we invested. So it definitely told us that we need to do a better job at that. We are already engineering and designing our 2014 and 2015 work and figuring out how we are going to execute that. Having the capability of portable L&G and C&G is incredibly valuable from a customer satisfaction standpoint to be able to keep providing service to customers while we are doing this important safety work. So that's some of the things that we are doing at PG&E on our transmission network.

Some of the work that we have achieved over the past two years or so and the work continues at a feverish pace and we are not slowing down and it has been remarkable to see the turnaround and the spirit of all of our workers at the company. How we are trying to restore the pride of the people who are in the trenches every day because they are the last hands that touch that pipe. And I need to be sure that those last hands perform that weld, do that inspection, wrap that coating in a way that meets the Martin quality standards that we expect so that the work that we are doing today can last for a long time and we can take comfort that all of this work is going to get us to 0. So thank you very much.

(Applause.)

>> RANDALL KNEPPER: Do we have any questions for Nick out there? Anybody want to come to the mic? Want to catch him in the hallway during one of the breaks? Oh, Linda is going to come.

>> I am becoming your most frequent questioner here. So you have an incredible story to relate. Taking a company out of a great tragedy and doing some great things to improve it so that people will be

safe going forward.   If you could go back and tell the regulator, I know California proposed some requirements, but you see we are looking at some similar challenges.   If there was something that you would communicate to the regulatory community of what would be most effective, what really worked, what is something that you would suggest that we move forward on?   I know I am putting you on the spot about that.   And then also the greatest lesson learned over this exercise that you have gone through.   Thank you.

>> NICK STAVROPOULOS: Thank you, Linda. Well, a couple of things.   One is one of the biggest things that we have tried to do introduce in to our culture is nonpunitive self-report and we are really trying to make sure that our people feel comfortable identifying issues, problems, and concerns and we had a difficult situation in that as part of that process we identified part of our distribution system that missed its leak survey on the appropriate time and that was identified by a low level worker in our mapping department who felt comfortable enough to raise the issue because we created a nonpunitive environment. Somebody missed something.   But a coworker was able to stand up and they knew that I wasn't going to penalize them and that's a message that we send and we reported that to the public utility commission.   And we were fined $17 million for that and that was difficult.

But I sent a note out to all of our coworkers that whether you fine us 17 million or 170 million it is not going to change our goal of driving to 0. And the only way we are going to get to 0 is if we keep identifying the issues, creating a regulatory framework where companies can identify problems and develop compliance plans and work out solutions without being ultra penalized. Companies should be penalized for consistent bad performance, doing the same thing over again. But I think that was a big lesson. And what we are finding now is we have got a culture where people identify issues and they are able to bring things forward. And our expression in our company is I can't fix it if I don't know about it. So we are trying to create that environment. So I would say that's sort of a big issue.

The second one would be if we had more time to put together our long-term safety enhancement plan and have more input from Pipeline Safety Trust, division of advocate, instead of two and a half months coming together, maybe we could have done some interim things and then developed a long-term plan. So I think clearly interim measures were necessary. That first year we hydro tested all 152 miles of San Bruno like pipe and maybe we could have taken longer time. The final macro thing and we see this in other industries is really driving that safety management system framework. Really having a framework within which your company operates. The ethos of your company around understanding the importance of knowing what you own, the condition of what you known and the threats those assets face and what you need to do to take care of those and be able to risk rank that and execute that work is very, very important. And I think also what we hear from other industries that have great safety records is that it is essential that the senior management of those companies and the board of directors are properly informed around the major risks that their companies face and the gaps that exist because every company has gaps. And I think that would be another lesson learned.

>> RANDALL KNEPPER: That's good with a regulator looking right over your shoulder.

>> NICK STAVROPOULOS: You did that well when I was back East.

>> RANDALL KNEPPER: Any other questions for Nick? Is that it? Okay. Why don't we move on to our next speaker who is also representing the intrastate transmission pipelines and Bruce Paskett who is the principal compliance engineer with Northwest Gas. We do have a question. Poor Bruce, we are going to hold off on you for one second. Nick, from the audience on the web, are you incorporating a spike test as part of your process and what percent of SMYS would that spike test occur at?

>> NICK STAVROPOULOS: Yes, we are. Jesus help me, 1.25 in the spike test, 10% above test pressure for 30 minutes.

>> RANDALL KNEPPER: Okay. But Jesus, do you know what percent SMYS that is?

>> Targeting 90%.

>> RANDALL KNEPPER: So you are targeting 90. Whoever asked that I think that's what they were looking for for an answer. Any other questions on the web? Going once, twice? Let's get on to Northwest Gas and Bruce. Thank you. Looking forward to your comments.

>> BRUCE PASKETT: Thank you. Good to go. Good afternoon. My name is Bruce Paskett. I am principal compliance engineer for Northwest Natural Gas in Portland. I want to begin my comments for thanking NAPSR and PHMSA for conducting this workshop and give us a better opportunity to understand the BP process. This is a great opportunity to open the dialogue on that. I also want to thank PHMSA and NAPSR for the opportunity to share the operating company's commitments to further improving pipeline safety and as Jeff challenged us this morning to doing the right thing.

By way of background and my legal disclaimer here today, it is important to recognize that LDCs have different diverse operations and that the action taken for integrated verification MAOP is specific to the individual operator. And the things that I am going to talk about today on behalf of Northwest Natural may or may not be applicable to other operators.

By way of background Northwest Natural, this is the agenda I will talk about. We are going to talk about the company background and enhanced safety programs and transmission PL MAOP and process and key learnings out of that. Some of our observations and issues and concerns with the draft IVP process. Industry's commitments for the path forward on how to proceed with the IVP process. And talk a little bit about AGA study on testing of inservice transmission lines.

Northwest Natural Gas Company background we have been in business since 1859. That's before Oregon was a state. We operate in Oregon and Southwest Washington, serving about 681,000 residential commercial and industrial customers. We design, construct and own and operate 634 miles of transmission main which is the primary topic of today's workshop. And also 13,000 miles of distribution main and 670,000 services. So that would probably qualify as a medium size LDC. This map quickly shows our service territory which is Northwest Oregon and Southwest Washington. About 10% of our facilities and customers are located in Washington.

For the record Northwest Natural is committed to the safe, reliable and cost effective delivery of natural gas in a manner that recognizes the impacts to the utility rate payer. It is very important to note that since the 1980s the company has worked very closely and effectively with the Oregon commission to implement enhanced pipeline safety programs that have significantly improved the safety of gas. This is a quick summary of those enhanced pipeline safety programs that we have implemented in conjunction and in partnership with the Oregon commission. I am not in the interest of time going to go through all of those. I will point out for you the first two or three which is the distribution integrity management program. That's not a typo. 1983. Some 26 years before the DIMP rule was finalized in 2009. And the first element of that we use DIMP lime principle even though DIMP was not in discussion at that time, the first element of was a cast iron development. Following on the heels of that we initiated in concert with the OPC a bare steel replacement program that we started in 2001 and we expect to complete that in 2015, some six years ahead of the stipulation.

So one of the high level benefits of our enhanced pipeline safety program I am proud to say essentially 100% and in two years, 2015 we can say 100% of Northwest Natural's underground infrastructure is constructed of modern state of the art materials and facilities. That's coded protected steel main and state of the art polyethylene plastic. We have got 634 miles ranging in sizes from 4 to 24 inches installed from 1956 to 2013. All of it is arc welded construction. As I mentioned coded cathodically protected main and in red 100% of our transmission lines have been subjected to a post construction pressure test. Quick note we have had a lot of the discussion on pressure testing today. You are all aware of the fact that subpart J in 1926 19 required post construction pressure testing ranging from 1.1 to 1.5 times MAOP in order to establish the MAOP. ASME 31.8S also recognized that pressure testing has been a long accepted industry test. No surprise there. We talked a lot about the Congressional mandates contained in the 2000 pipeline, 2011 pipeline safety authorization for PHMSA. DOT. Testing of -- and HCAs that operate at greater than 30% SMYS and the methodologies are pressure testing.

In response to NTSB recommendations PHMSA advisories and the Congressional reauthorization Northwest Natural initiated a very aggressive and diligent MAOP record search for not just those lines in HCAs but for all of our transmission lines. We focused on pressure testing because we felt that that was the most reliable method to give us the highest confidence in the pipeline safety on our system. What we found as a result of all this effort was all of our transmission lines even back to 1956, Nick talked about '61. We had an order from the Oregon commission in 1956 to use ASME B31.8, B31.8 and part 192. Third bullet, 100% of our transmission lines have had post construction pressure test with effectively 100% records but it goes beyond that. Because if you look at our annual report we just submitted nearly all of those lines were pressure tested at greater than 1.25 times MAOP. It is very typical for us even back 30 years when I joined the company to test at 1.5 times MAOP or higher. As a result of that effort we have a very high level of confidence in the MAOP and in the integrity of our system. I want to commend PHMSA for a great deal of effort and it is obvious that a lot of time and effort has got in to the proposed IVP process and we believe that there is a lot of good material in that. However an examination of that does raise some issues that we want to raise for the discussion and provide for the docket and perhaps some suggestions on how to solve those.

First issue is that it potentially creates a scenario where 100% valid MAOPs based on existing PHMSA regulations and B 31.8 are invalidated to that. Incomplete records to any steps of 5 this is and, and, and statements as opposed to or, or, or it moves pipe in to process that requiring coupons to be cut from pipe and no mechanism right now to cut coupons out of the fittings safely. So you are talking about cutting out perhaps cylinders or a complete cutout of the fittings themselves and talking about elbows 45s. You could have valid pressure test cut holes in your pipe and then go back and do a pressure test again which reconfirms the pressure test you had initially. We talked a lot today about the fact that it introduces the new concept which is an MCA consequence area. The obvious implications to that is it broadly expands transmission and integrity management. And we think it needs to be done in a thoughtful manner and high stress lines under this scenario are defined greater than or equal to 20% SMYS. For example, if you look in 192, 941, excuse me, on low stress assessments that uses the definition low stress assessments as less than 30% SMYS. Last bullet is it mixes separate issues and this gets to Linda's point that she made this morning. So thank you, Linda, for your question that you asked this morning. And by the way the slide was already in place before you asked the question.

(Laughter).

>> BRUCE PASKETT: But that was a great segway. It mixes separate issues in our opinion and it appears to fix the issues of MAOP validation with transmission integrity management or subpart O and

we believe it is very complex and it has created a lot of perhaps confusion in the industry. The other part about that is we are certainly committed to improving pipeline safety, but the idea of cutting holes in existing good pipe does cause concerns. And we are concerned that that might potentially divert resources away from what I would call high value work such as cast iron replacement, bare steel replacement or if you happen to have vintage pipe that is problematic for you. In response to that I want to go on record to say industry is committed and operators are proactively implementing and pursuing plans to pressure test and replace lines that haven't been pressure tested. That is a given. We believe that priority should be given to those pipelines in class 3 and 4 locations and HCA greater than 30% SMYS because Jeff, it is the right thing to do per your challenge this morning. I think I said 30%. I don't believe I stuttered.

(Laughter).

>> BRUCE PASKETT: I apologize if I wasn't clear. 30%. We believe that it would be productive and you heard some discussions this morning productive to separate the processes of MAOP and expansion of the integrity management to reduce the complexity of the process. And for the record AGA and member companies are committed to working with stakeholders to move forward in those processes.

For those of you who are not aware in response to the Congressional mandate for testing of untested lines the AGA commissioned a study to determine essentially what the cost of pressure test lines. So the findings of that and I will show you the tables momentarily, AGA member companies are committed to spend over $10 million incremental to implement the Congressional mandate for testing of untested transmission lines in HCAs. If you look at all intrastate transmission pipe that accounts to $25 billion. This chart shows real quickly this is AGA reporting companies in blue. Other intrastate companies in the kind of yellow and interstate companies in the red. The take-away from this chart is that intrastate and AGA member companies have a much higher percentage of their transmission lines located in class 3 and class 4 locations, which translates to much more complexity and a higher cost with respect to either replacement or inservice testing.

This chart shows out of the study again what the cost would be for AGA companies only and this is based on 56 reporting companies that accounted for 52,000 miles of intrastate transmission line and out of that approximately 3,000 miles were miles that did not have post construction pressure test in class 3, class 4 HCAs. These are either untested lines or transmission lines with a pressure test less than 1.1 times MAOP and this presumes a 42% replacement rate and in a lot of cases replacement is more cost effective than inservice testing because of all the complexities and certainly with single one-way feeds and you still have to maintain reliable safe service to your customers. So this is broken down by region. You will see replacements in red and rehydro testing existing inservice lines in blue. Again by region here is the cost. The bottom take-away out of this slide is that's $11.2 billion that the industry is committed to expanding to satisfy this.

To summarize Northwest Natural and the industry are committed to pipeline safety and are voluntarily implementing a number of initiatives to further improve pipeline safety beyond regulation because it is the right thing to do. We are committed to the testing of untesting transmission lines in class 3 and class 4 locations and class 1 and 2 HCAs that operate at greater than 30% SMYS using pressure testing or ILI. We believe that we need to separate the MAOP verification from expansion of TIMP but recognize that the industry is committed to both and we are going to suggest that there is a joint stakeholder kind of a group to work through the details. If you look at the IVP chart -- I am sorry. Where is Steve? Steve, I had the little chart by the way. You got the big one. There is a great deal to be determined, you know, specific -- develop specific guidelines. So we believe it would be helpful and useful to move the process forward, Jeff, if you use some kind of whether it is the CIRC 1 or 2 or 3 process or the DIMP process. Both NAPSR, PHMSA and public and industry at the table. And finally we believe that any of the processes involving intrastate transmission pipelines have to involve state commissions which is the same NAPSR folks on the commissioners. So that concludes my remarks. I appreciate the time today and the opportunity to provide some comments back on the IVP process. And I would be happy to entertain any questions.

(Applause.)

>> RANDALL KNEPPER: I don't see anybody rushing up to the mic right now. And maybe I will wait a couple seconds to see if anything is coming in from the web. But those were all interesting perspectives. I think what's next we have a break, is that right, Jeff? And -- okay. We will leave it at that. I think my perspective is PHMSA took a very good -- we do have a question here. So go ahead.

>> Rege George with Kendall Morgan. I had a question about one of the questions. A comment about MAOP verification was focused on pressure tests. Could you elaborate on that?

>> BRUCE PASKETT: If you are talking about the early-on slides on Northwest Natural's experience

in our path forward?

>> Yes. I think it was like the fourth or fifth.

>> BRUCE PASKETT: Thanks for that question. Our point was we followed very much the NTSB recommendations out of San Bruno which basically focused on record search for those transmission lines that had not experienced a pressure test. So that was the path. It was in direct correlation and agreement with what NTSB recommended. And if you recall the early recommendations that PHMSA needed to disseminate that information to operators. We started with do we have traceable and verifiable records for our pressure lines and we did. That's why we went down that path, because to kind of repeat my slide we believe that that information provided the highest degree of confidence in the MAOP of that line. If you got a pressure test -- it is my personal conviction, if you have a pressure test at 1.5 I believe that prompts -- trumps the other methodologies. I am very, very comfortable with that. Thank you.

>> RANDALL KNEPPER: Going once, going twice? Okay. That's it. Thank you for your insights and I will hand it over to Jeff.

(Applause.)

>> JEFF WIESE: Okay. I am just doing my quick Vanna White moment to tell you that we will reconvene at 3:20. That's largely for the people on the

Webcast. I did want to part with one thing as I invited Nick to come on purpose because I have heard Nick speak before. He is a member with some of the NAPSR people and myself at the safety management thing and the one thing that always strikes me and I have told him this, too, there is lots of good people out there doing lots of good work. Theirs was accelerated 100 times because of the cost of that failure. The difficulty is to convince people who haven't had that failure they need to move faster. They don't want to move that fast. Like Nick said it wasn't time enough to really do the right thing. We got to find a way to develop a sense of urgency in people in getting it done. We are highly cognizant of the need to work with the state regulatory commissions and we at NAPSR actually worked the model out before we went anywhere in publishing.

The next time we talk with the commissions it will be with the rate setting side and with FERC and that's really the question, that's why you see all the TBD in the bottom of the chart. The statute calls for us to work with on how long it is going to take. We understand that they play a role. So I just say to anyone that FERC and members play a strong role in ensuring the success of this project. We need to work with them on that. Thanks and we will be back at 3:20. >> The last session of the day's meeting, we'll let the interstate operators say something. Also the Hazardous Liquid Pipeline. After that, we'll have a Q&A session and summary session.

With that, the first presenter we've got today is, as I realized, y'all probably know he's retired. That's why we have a lot of noise, to wake him up when you're retired. He normally snoozes in the afternoon a little bit, I appreciate the noise, we definitely want him wide awake. I'd like to introduce Dwayne Burton. As you probably know, he's Retired Vice President of Kinder Morgan.

>> Dwayne Burton: Good afternoon, so glad we have such a big turnout to discuss going forward. I am retired from Kinder Morgan, but in the meantime, as important as our pipeline safety is, they've asked me to stay on to help maintain focus in some of the, some of the transition that we have with some of the personnel and organizations we have within Kinder Morgan.

So, I'm honored, but a little scared. When I say a little scared, I've been around the industry for a long time, so I shouldn't be scared, but this is truly an important topic that we have to move forward with pipeline safety.

And with, with that, I'll move forward in, in my, in my agenda, in my slides here. One of the things I'd like to talk about is whoops -- that, I'm technically incompetent.

[laughter]

>> Dwayne Burton: Okay, you're sure it'll work from here, right? I won't have to do that again. One of the things I'd like to talk about here, we haven't been, the INGAA companies and other companies within the various, uh, industries, in the pipeline industries, really haven't been sitting around waiting for things to happen. Or necessarily waiting for the IBP process to be thrust out there for our comments and, and recommendations.

The INGAA has spent a considerable amount of effort putting together a continuous improvement program. I wanted to spend a few minutes to talk about not only what the goals are, but what our progress is.

So, again, significant amount of effort has been put into that and it wasn't done in a vacuum. We used industry subject matter experts, operators, and not just operators from, uh, not just operators from the, the interstate natural gas, but the intrastates and other stakeholders. We used other industry groups. We had many discussions along the way with, with PHMSA, the NTSB, NAPSR, and PST.

In fact, uh, just discussed with Carl that, uh, he probably will be seeing more of me as I'll be moving into the chairman role of INGAA on the pipeline safety committee. So...I look forward to having those, those future discussions with Carl and the other stakeholders.

Coming out of, out of those efforts, INGAA provided the industry with a set of processes that addresses the stakeholders concerns. That being the processes are meant to insure pipeline safety and support the goal of zero incidence. And, you know, Nick, earlier, talked about, that not only the industries, but the companies themselves have to internalize that concept that they can get to zero, otherwise, they're just kidding themselves. Okay?

So, INGAA took it a step further, to their membership in trying to spread it across the industry, that it is truly something we can get to. It's not only a goal, but as we see through some of the data accumulations that we are actually moving toward that goal of zero.

Whoops. I told you I was technically incompetent. Okay, some of the results coming out of the Continuous Improvement Program is that the INGAA members have voluntarily made commitments to expanding integrity management. By that, we were implying the integrity management principles across the entire, our entire systems. And it's based, it's a phased approach that's based on population and prioritizing where the greatest population is. Coverage will include 100% of the population by 2030 and then, the other thing that I'd like to mention is that many of the operators are moving forward with that. And so, you ask, what do you mean they're moving forward with that? Well, through the, not only the continuous improvement process, but also through, through the fact that everybody's implementing their INM programs. The interstate pipe lines have actually covered 65% of their total mileage, which includes about 88% of the total population that resides along their pipe lines. That's pretty significant. Because...some of the, some of the, some of the marks, the water marks along the way, we were looking at 90% by 2020 and then 100% by 2030 of the population.

So, as you can see, we've made some pretty good progress, albeit, a lot of it had to do with you know, a significant amount of it is the fact that when we're testing the HEAs, we actually pick up part of the non-HTAs along the way. When you're doing non-inline inspection, okay?

The other thing that the Integrity Management Continuous Improvement Program has a focus on fitness for service program to dress the MAOP issues. It uses established risk based approach for hazardous liquid pipeline. We had a basis to start from. We didn't have to start from scratch. It addresses the testing of previously untests pipe lines. It applies to preregulation pipe lines where pressure test records don't exist and it prioritizes the timing of actions based on risk.

Now, some of the fundamentals of the programs or the fundamental thoughts that went into this program, we look at it that it's a one-time separate and distinct MAOP test versus the ongoing INM process.

It, it focuses on the lack of records on hydrostatic tests and, and wheel hydrostatic tests to 1.25 times an MAOP. And last but not least, it has well-established, uh, excuse me, well-established fitness for service using IOI or technically valid and justified methods.

Talking about comments on IVP. You know, the IVP was, was first sent out to the stakeholders on June 28th of this year. And since then, there's been a lot of scrutiny by the various stakeholders and what we, so far, the comments that have been gathered throughout the INGAA companies is that first of all, the draft IVPs generated many discussions between PHMSA and stakeholders and the stakeholders and the stakeholders.

Now, this is the official meeting, but I can assure you, there's been many, many telephone calls, conference calls, associated with how this is going to impact the industry overall. You know, of course, this workshop is definitely intended to solicit the stakeholders inputs, also the draft IVP demonstrates continued efforts to develop alternatives for moving to a higher level of pipeline integrity and safety.

INGAA shares and supports this ever-important goal.

Okay? We talked about that earlier. We feel that we've got a good plan of action already in place. The draft IVP incorporates certain aspects of INGAA's fit for service and INM, uh, expansion plan and commitments.

Some of the challenges associated with IVP is that the IVP draft appears to incorporate too many issues into one process. We talked about that this morning. And like Bruce had, had commented this morning, we certainly appreciate Linda, you asking that question, early this morning, and I think we heard a resounding yes to your question, that we should possibly separate those.

But, but, you know, those issues, you know, include the MAOP issues, the IM expansion as well as some of the material validation points. The MAOP determination methods, the draft IVP incorporates four record verification steps in order to progress to the continued operations. We call that within the INGAA, the "and approach" and many determination records were established used the 1970s vintage 192.607. We call that the "or direction." It was a little, a little curious to us, that, uh, during the, um, the annual report that we utilized the or approach, but the IVP process is incorporating the and approach.

The draft IVP includes multiple yes/no decisions that directs most of the preregulation pipe lines into the additional material testing and documentation regardless of the hydrostatic test history and the pressure-test methods.

Additional challenges is that the draft IVP appears to expand integrity management response processes, and what I'm referring to is the, the ECA box, where it lists out several of the, uh, particularly items that we may go through. That seems to be an expansion off of the, off of the existing IM.

Although the comments are due 32 days from now, there's several definitions and specific guidelines to be developed. That's the message you've heard several times and probably will hear with the next speaker, I hate to put words in your mouth, but there are a lot of definitions and specific guidelines that have to be developed along the way here.

The other thing that we considered to be a challenge is meeting the congressional mandate that requires taking into account consequences to safety and the environment and to minimize cost and service disruptions. Because, once this IVP process takes you over into that material validation section, it's, it's going to be a tremendous amount of work and at the risk of, of you know, of just, well, I'd put it this way, the risk of alienating you guys, I wonder, sometimes, if that's not confusing activity with progress. It's going to be a lot of work that's going to be added to the existing IM in testing work that we're really not sure what value that adds.

So...the basic tenets for INGAA is MAOP. The MAOP of pipe lines should be revalidated if there's a concern about the material strength and construction practices. At 1.25 times MAOP pressure test or alternative technology process that emulates the test during a pipeline's life adequately established material strength and construction practices of the pipeline. The next tenet, testing to confirm properties is not necessary where a pressure test has already established material strength and construction practices.

And then the improvement in technologies is anticipated to allow MAOP reconfirmation and validation. Basic tenets continued. This is under the category of integrity management. We feel that material properties are important for the IM program. No doubt, and also, uh, for establishing your MAOP test pressures. But we feel as though, in the IVP chart, that construction techniques should be addressed in the IM rather than in the, rather than in the MAOP revalidation. And that pipe manufacturing is also addressed in IM.

In addition to that, one of the interactive threats or interactive processes is fatigue of the material strength to natural gas pipe lines, addressed in the IM. As far as the IM expansion, the IM should be expanded and prioritized by populations.

INGAA's plans provides a basis to subplant the class along with the implementation plan. Prioritize using population. Our suggestions concerning the IVP chart is to reorganize the IVP goals and sub process and to separate out the con Kurt -- I'm sorry, separate and concurrently address MAOP validation separately. IM expansion separately. Uh, the adequacy of IM records and the risk priorities to help us get to the timeline.

We agree on common targets. I'm sorry, on common tenets. Or we should get to agreement on common tenets. That being hydrostatic testing is an improving process for confirming MAOP. Adequate material properties is important for IM. That technology can augment or sub plant vintage practices and solutions need to be operationally, technically and economically feasible.

The next suggestion that we have is to make comment period allowances, if needed, for the development of balanced solutions that are feasible and practical. INGAA is making the commitment to approach this effort with intent to find a positive solution to these.

The next three slides that I have are just additional information, I figured when we post this out there, it would keep people from having to go to the INGAA site to look this up. They're associated with the fitness for service.

With that, uh, I'd like to open it up for any questions that you might have. See, I knew this was the right place to be in the agenda for that.

>> Well, let me say, I'm going to ask Dwayne to stay on the stage. After Dave gives his presentation, we'll have both of them up here. Let's give Dwayne a hand for his presentation.

[applause]

>> Next on the agenda, we didn't want to get away without letting someone from the Hazardous Liquid Pipeline say a few words. I know they're wondering what PHMSA's looking at on the liquid side with us talking about the gas transmission pipeline side. So, with that, we invited Dave Ysebaert, President of Explorer Pipeline to speak to us. With that, I'll turn it over to Dave.

>> Dave Ysebaert: Okay, thank you. Nothing worse than going dead last as a presenter. So, bear with me. Anyway...I appreciate the opportunity here to give some feedback and comments to the proposed Gas Integrity Verification and Flow Chart. We know this is intended for gas pipe lines, but we appreciate this opportunity. We have experience with integrity of pipe lines and maintenance of pipe lines. We like the opportunity to come and to prepare for today, what we did, we polled, member API companies and AOPL

companies and got comments back. The comments we got back fall into four categories.

The first is, there's a lot of positive attributes of the flow chart. We wanted to highlight those. Next, we had some questions about scope and process of the flow chart. There's some missing key details that makes it hard to comment. And then we had some technical concerns.

So, each of these I'll go ahead and address. On the positive side, okay, the process allows for some flexibility. There's three methods for validating MAOP. There's no complete 100% method for assessing either integrity or MAOP on a pipeline. It's nice to have flexibility and the use of an engineering approach.

Also, the process focused on X42 pipe and pipe that's greater than two inch. So we think this flexibility is very good. We want to ensure that we're working on the right things that will move the needle on pipeline safety.

So, concerning the process of the flow chart. Okay, first, we're assuming this flow chart only replies to main line pipe and not into facility piping and other piping that might be under jurisdiction. It's scraper trap to scraper trap. But what is the intent of this flow chart? Is integrity verification a validation of the systems MAOP that's been grandfathered or lacks records? Is this a one-time assessment? Going through this process?

Or is this meant for regular reassessments?

So, if this is intended to address MAOP, then a one-time assessment should be sufficient. If, is the intent of the flow chart to be precipitative? So, maybe into rule? And if so, what will be the rule-making procedure on this?

The, if, if the intent is looking at expanding integrity management, and making this broader than just looking at assessing MAOP of a system, then that should be addressed separately and that gets into comments made earlier, this morning, you know, integrity management, and validating an MAOP of a system are two different things.

In the interest of time and getting something through, it might be worth separating these things, address MAOP of grandfathered systems independently and I think we could get something through quickly and address the integrity management piece of this. In the fall, they're looking at addressing IMP2.0. Is this something that would be addressed during that time?

Now, talking to Jeff, earlier this morning, it looks like that a similar-type process will be you know, pushed down into the liquid side. Here, I think it's kind of important to kind of delineate what are the differences between liquids and gas regulations.

On the liquid side, you know, we currently have rules defining how to determine MAOP. We don't have any grandfathered systems. They've been removed from the regulations. So, there's an appendix B of 195 that has a risk-based alternative to pressure testing older hazardous liquid lines. Where it goes ahead and it explains different methods besides hydro testing, how to assess an MAOP.

If the intent is validation of MAOP, it'd seem like the liquid industry is already in compliance with this. Appendix B, already includes, compliance deadlines and all liquid pipeline systems should now be in compliance. Additionally, the current integrity management rules address time-dependent features and require all anomalies to be remediated to support the established MAOP.

As far as details are concerned, usually the devil's in the details. We have key details that are missing and makes it hard to comment. When we're talking about things like documentation verification requirements, you know, what is the requirements for documentation? We've seen the material documentation plan for Longhorn and that's been held out there as an example. Is this what is meant by that? What are some of the requirements for the spike test, what percentage, what deration of the test? Same with deration to what percentage. And what is the details and requirements of an engineering assessment.

In the flow chart, it attempts to define some new terms for us. Legacy pipe, modern pipe, legacy problematic construction techniques and then, start, uses the term such as legacy problematic pipe manufacturing that hasn't been defined.

Additionally, why the emphasis on low-stress piping. Basically with model, all the low stress, legacy problematic pipe or low-stress legacy problematic construction techniques will require assessment. In other words, only modern pipe that is low-stress, that is not in an ACA or MCA is exempt. Manufacturing threats, and construction defects are stress-dependent. So, are we spending our energy on the right thing here? Is it better-served than something that would have more safety effect than low-stress piping?

Taking a look at the block 13 and 14 which addresses the records. So...the first step is to do an assessment of your records. The first question comes up is what is the definition of the validated traceable materials and if we do look at what was in the Longhorn environmental assessment, it says that it is traceable, verifiable and complete documentation of records and by records, they're referring to mill test reports, purchase orders, as billed drawings, the seem type, coding type, wall thickness and diameter. It doesn't leave any room for any kind of in the ditch method of testing this. I know it was talked about this morning, Steve, I think, brought it up, it's good that it's being considered.

There are in the ditch methods for testing yield strength. You can get data from your ILI tool runs that give you wall thickness and diameter. You can analyze your CP data and it can give you an indication about your effectiveness of your coding. There are other ways besides cutout and testing to get this data.

Lastly, if you followed the flow chart, it requires that you fill this loop and get all of your documents in place before picking an assessment method. And, in our mind, if you're picking a hydro test or a deration, we don't see the value of completing all those documentation if you're going to do a hydro test afterwards. You question the value, is your time better spent doing hydro testing or chasing every little document that might be missing?

There are ways to do a hydro test that you can use as validation of some of your missing records. A properly conducted hydro test, when you're pressuring up your system, you can plot your pump strokes versus your pressure rise and you can validate that you're not yielding your pipe. It is a way to validate your yield strength, the minimum yield strength in the system.

Documentation of records should be considered whenever doing an engineering critical assessment. Lastly, if we go ahead and look at the three different methods for assessing MAOP. The first requirement is hydro testing and it's a subpar J requirement. That's very limiting. And may not have all the records. It requires that you know the materials in your system. There are other approved hydro testing methods.

If you hydro test to 125% or whatever the regulation might be, and monitor the pipe for signs of yielding during your pressuring, that should be an adequate test to verify and validate the MAOP of a system.

Additionally, the hydro test is requiring a spike test. And a spike test may not be beneficial for all pipe lines. For example, there's a lot of seamless pipe out there that doesn't have history of cracks. Is there value in doing a spike test in addition to a hydro? It'd be our recommendation to just require a spike test when it's based on an engineering review considering such things as the data on the type of pipe it is, its manufacturing type and failure history.

And this really goes back to the earlier comment, is this, is the purpose of the flow chart for, uh, enhancing integrity management or for simply evaluating an MAOP. For spike test, it has value when looking at integrity management, but I'd question it for establishing an MAOP.

There's no mention about time to go through an assessment. I know there's a lot of to be determineds on the dates.

What's really of concern, some of these projects can take an awful long time to plan. If you look at a hydro test, we know how long it takes to go ahead and get permits for water and disposal and everything else associated with that, plus to plan for service disruptions.

During this interim period, if you design to hydro test and you're evaluating the hydro test. Is there an interim requirement until you get your hydration completed. Is there an interim status in this? Well, I thank you for this opportunity to comment, I really want to stress the value of working together collaboratively to ensure that we're really working on the higher value and higher safety value initiatives. Thank you. [applause]

>> Okay, thank you, Dave, very much. We're at that part of the program where we're going start with Q&A for the afternoon panelists. What we'll do here, the people in the prior panel, I know Bruce and, um, Jim, you're welcome to come up here and be close if there are questions you need to address. I think Nick and Jesus may have moved on. Anyway...thank you, Dwayne and Dave and now we'll just see, uh, hopefully we'll have a few more questions than we had this morning, but we'll go ahead and start with the floor here. If there are any questions we have, please step up to the mic here in the middle. We have a couple roving mics, state your name and affiliation.

>> Hasn't been through the sensors yet, just kidding. Okay, he's breaking out the chart for this one. Are there any others coming in from the web. Don't be shy also on the floor here. Yes?

>> Doug Snyder: San Diego Gas and Electric, I'd like to add onto the last presentation, you go through the entire process before you decide what you're going to do and there may be some pipeline segments that were constructed long ago that are not pigable, that have other legacy-type issues with them. That it may make sense right up front that you should replace them. And you know there, maybe there should be off ramps as we go through here, if replacement seems to be the best option, that'd the option you do rather than going through the materials validation.

>> It's anticipated, yes, that some pipe -- I think it was mentioned earlier, we anticipate some pipe. It may just be, if you go through the chart, it might be better to replace it. Also consideration of your leak history, your maintenance history of that segment. It may just be better to replace it. I guess that's by design, this pushes you in that direction, based on what you know about the segment. So....

>> Good afternoon.

>> Brian, go ahead.

>> Brian Moydell: With Dominion East Ohio Gas. We've committed to pressure-testing our untested pipe

lines over the past couple years, since reauthorization and we're committed to getting that done for pipeline. We feel that's the right thing to do. This IVP process, it seems, will negate all the work that we've done to this point and make us go back and cut up our pipe lines and, um, and retest them again.

Is, is that a correct assumption?

>> Not necessarily. I'm not sure what you did, Brian, on your pipe lines, but it depends on, um, you know, the record search, what you, how you dealt with any gaps, how you confirmed the material and the documentation you used in the pressure test.

>> That's the thing, we used the "or statement" and whenever we had an untested pipeline, we go in and pressure test it to 1.5 times MAOP to establish the MAOP and we just feel like you know, that's a lot of work that's, uh, that, that could be, uh, negated by this whole process.

>> Okay. We'll go ahead and turn back to Steve for the question that came in.

>> To read the question, it has to do with the IVP chart. And here's the question: How do you apply blocks one, four and five to post regulation pipe segments? There is currently no prepost regulation criteria for the first five blocks. In other words, blocks 1, 2, 3, 4 and 5. Which would be 619 C, the grandfather clause. The second one is design

pressure, material records, 619A1, 619A2, 619A3 and 5 would be the 619A4. For post regulation pipe segments, which would be after 1970, PHMSA would expect you to have the records to verify your design and MAOP. Per 192, 105 and, and 619 A1, so...we'd expect you to be able to do that.

One other question that I got and I'll just, since we had this, please explain, again, confirm the confusion between the definition of 619A3 and 619 C.

619 C is the grandfather clause. It's based upon, you do not have the records for hydro test, for your materials, for your historical O&M-type records. You go to 619 C, and that's based upon the highest pressure in the five-yore period from 1965 to July 1st, 1970. That's what PHMSA has defined as the grandfather clause. 619 C.

619 A3 is also the five-year records from July 1st 1970 going back five years, but in that particular case, in 619 A1, A2, A3, A4, you take the lowest of the 4. In other words, you'd calculate your design pressure based on class location, seem type, wall thickness and grade and come up with operating pressure there then you'd see what your test pressure was, you'd also look at the analysis in A4 of leaks and issues there with corrosion and then, then, uh, A3 is, uh, what that highest operating pressure is there. So you use the lowest of those four and that is not 619 A1 through A41

not the grandfather clause.

Thanks, Steve, yes?

>> Sara Smith: I'm a reporter with S&L Energy. This is probably for Steve, but to any of your colleagues at PHMSA as well, to what extent did you anticipate the desire from the industry and other people who have spoken today to separate out different components of the IVP chart into different processes, rather than combining them?

>> You know, I can take that one on, we, we were looking for input, that's why we're here today on the IVP process, you know, we're taking that, and you know, if there's a proposal for an alternative approach, we're interested in hearing that. If that involves separating components. You know, we'll have to hear more about that. Just needs to be presented as a proposal. We'll take it under consideration. But you know, again, that's why we're here. To get that kind of input. So, we came in with eyes open, saying we're open to other ideas, other solutions, so that's what we're after.

>> Thank you.

>> Go ahead.

>> It appears to be my role in life to be the bad guy. Allow me for a second to add so you have a fully developed thought on this, we do have congressional mandates that are already expired. We took time to get the data so we could do rule-making the correct

way, one thing you may not be aware of, but rule-making is an extremely tedious, time-consuming process. There are only so many bites at the apple that one gets. I'm not saying we won't listen to the feedback, I just want you to consider the fact that we might not be able to get three things through, you know? So there's that counter billing school of thought that says, we might be better off, as Alan said, we're open to alternatives, right? But the question is whether it should be woven together into one regulatory initiative. Because I, frankly, you know, things are not moving. It's easier to move one thing than three things. It may seem trivial, but it's not.

>> Just to add, one of the bullet points I had on the positives. This is generated already, early in the game. A lot of discussions between the stakeholders and PHMSA and the other public stakeholders as well.

>> I agree.

>> So, I'm sure it's not the first time you heard, let's see what happens if we separate these out.

>> Yep.

>> Thanks.

>> Mike Loshay: The question for Dwayne. Want to confirm what I think I heard you say in your presentation. The and/or, is it INGAA's interpretation or feedback on the IVP process that it'd be an "or" approach, instead of "and" approach?

>> Dwayne: It's INGAA's position that it should be an "or" going through that portion of the IVP, versus an "and." I think you heard other presenters saying it should be the "and." I think it's the different positions that we have. We think the "or" was somewhat established in 192.607 between 1970 and 1973 when decisions had to be made as to whether your pipeline met one of these or it was grandfathered, okay? And, and it doesn't mean that when those decisions were made, you didn't have all three or four of those. The decision was made at that point, what's the lowest we have. We think the "or" is sufficient for determining the validation of the MAOP.

>> Great, one quick follow-up to that, is, if that, your answering approach, is a pressure test sufficient to validate MAOP?

>> Yes, that is one of the tenets that I had up here, from INGAA's position, that a pressure test is sufficient to validate an MAOP.

>> Thank you.

>> Dwayne: You're welcome.

>> Go ahead.

>> Terry Voss: With INGAA. I think a recommendation was that perhaps we could separate these issues, but we thought we could work on the issues concurrently. It doesn't mean you can't put the issues together in one package, just work on them

separately.

>> All right, thank you. Anymore questions? Going once? Anything from the web? Any cards? Okay, I guess we'll get wrapped up a little bit sooner today. Again, I'd just like to express appreciation to all the participants, you that came today, you that traveled here to be here for this important event.

You know, we gathered some input, I must say, we didn't hear a silver bullet as far as an alternative approach. We heard some big comments that we'll take back. I'm sure the dialogue will continue, to the point that's been brought up, you know, we're all very well aware at PHMSA, any of, time constraints we're under. I'm sure many of you are as well.

So we do need to move forward, we need to move forward deliberately, and we also need to be sure that we address the issue thoroughly and come out with something realistic. Our goal is to have, obviously, for safety sake, resources to be put where they're most effective. That's our goal to get out of this. Not just to go through a paperwork exercise, it's not just to go put a bunch of wholes in the pipe just because it makes us feel better. This is to ensure the safety of the public. We have to remember, we're here today because of a couple events that happened that really pointed to some shortfalls in how we manage, um, and how we confirm MAOP and how we've done it, um, you know, over the -- since we introduced the grandfather clause, for instance, back in 1970.

So, we can't lose sight of that. I must say, also, as you leave here today, please take with you some homework to continue the dialogue. We ask that if you have comments or request that you have comments, please post them. We have a docket set up for that. If you have questions, there are a number of contacts at PHMSA, we're, we're -- please send your questions in as well.

I would ask too, I know that many, you know, we see a lot of the same faces we enjoy seeing from the stakeholder community, but that only represents a small fraction of the regulated communities. So...with you, and your position at your company, please talk this issue up, it is, it does represent a paradigm shift to how we manage pipe lines. It does have impact on how we oversee the industry and how in turn, you'll manage your pipe lines and confirm the MAOP of your pipe lines.

Please make sure your leadership is aware of this and is something to anticipate coming down the pike. And just stay engaged. If you have or if you have a proposal to offer, we're, as far as solutions, especially some of the blanks we had up there, the TBAs, we're interested in that. Conspicuously proposals for TBA items were left out of the discussion today. Can't say

I'm totally surprised about that.
And, uh, I think that's about it, Jeff, did you have anything for the good of the order in wrapping up?
>> Not much, thank you, Alan, for doing that. I don't know how people are here, I'm guessing a couple hundred, maybe? Who knows, I can't count. I thought you'd find it interesting to realize that there's 250 to 350 people on at any given point in the webcast. It's an effective way to get people involved and informed. We're able to take good questions that come off the web, you know and we may have to study them, but I wanted to point out to you, it's a successful way of reaching out further. We'll try to make use of that and save everyone some of their travel budgets, particularly ourselves. So thank you.
>> Okay, and with that, we will stand adjourned. Thank you again.
[applause]

[Meeting concluded at 4:13 p.m. ET].