UNITED STATES OF AMERICA

DEPARTMENT OF TRANSPORTATION

UNDERSTANDING PIPELINE INTEGRITY LEGISLATION

AND PROPOSED LEGISLATION

MEETING

Marriott at Metro Center Hotel
775 12th Street NW
Washington, DC
Parlor A

Friday,
March 14, 2003

The above captioned matter convened, pursuant to notice at 8:30 a.m.

CHAIRPERSON:

Stacey L. Gerard
Associate Administrator for Pipeline Safety

ATTENDEES/PRESENTERS:

Sam Bonasso
Deputy Administrator, RSPA

Dan Martin
Industry

Mark Hereth
Hartford Steam Boiler

Barbara Betsock
Deputy Chief Counsel

Mike Israni
Program Manager, IMP

Jim Anderson
NAPSR National Chair

Rick Kuprewicz
Public Commentor

OTHER ATTENDEES FROM OPS/RSPA:

Bill Gute
Regional Director

Chris Weydell (ph)
Regional Director

Jeff Weiss
Program Development

Linda Daugherty
Enforcement Officer

Lane Miller
TSI

Zack Barrett
Implementation Chief for future enforcement of Gas IMP
Western Region

OTHER ATTENDEES FROM OPS/RSPA: (continued)

Paul Wood
CYCLA (ph)

Linda Lasley
Department General Counsel

Sherry Pappas
RSPA, Legal Counsel

Elaine Joost
RSPA, Chief Counsel

OTHER ATTENDEES:

Philip Sher
State of Connecticut

Paul Biancarty
Duke Energy Corporation

Daren Moore
Tennessee Pipeline

Andy Drake
Duke Energy

Jim Anderson
NAPSR National Chair
State of North Carolina

Laurie Trayeek
American Gas Association

George Mosinskis
American Gas Association

Alan Eastman
Pacific Gas and Electric Company

Terry Boss

Judy Schlegel
Oklahoma Natural Gas

Paul Gustillo
American Gas Association

OTHER ATTENDEES: (continued)

Dave Johnson
INRA (ph) Transportation Services Company

Pat Cary
El Paso

Andrew Theodos

AUDIENCE COMMENTORS:

Phil Byrd
RCB

I N D E X

P R O C E E D I N G S

8:30 a.m.

MS. GERARD: If you're not interested in gas integrity management, you probably are in the wrong room. Maybe there are some other people who are interested down the hall but you're supposed to be focusing on gas integrity management if you're here. I'm Stacey Gerard. I'm the Associate Administrator for Pipeline Safety, and nice turnout. I think the significance of the day is to continue the dialogue on issues that are being identified associated with our proposed rulemaking on gas integrity management.

We are intending to try to develop a better understanding of all the issues that are identified or still need to be identified. My role today will be to try to direct questions to people who come to speak and raise issues to try to ferret out the best description of the issues for OPS to be able to consider as we proceed with this rulemaking.

We're very fortunate to have with us this morning the relatively new, four month old, Deputy Administrator of RSPA, Mr. Sam Bonasso, and Sam is a veteran in the transportation world, having about 25 years of experience in transportation, including being the Secretary of Transportation of West Virginia. He has also 25 years experience working with the National Consensus Standards industry, so he is very comfortable with the priority that we place on working with consensus standards here. I'd like him to say a few words just so you can get to know him and know that he's listening and paying attention to this issue.

MR. BONASSO: Thanks, Stacey. I've done pretty well for a four month old. I walk and talk now and I even know a few people in the audience here by name. Thank you all very much for joining us today for this important meeting about our proposed regulations on gas pipeline integrity management.

I've been with DOT's Research and Special Programs Administration, RSPA, since the Fall, and I'm quickly gaining an appreciation for the complexities of the many and varied ways in which RSPA serves the public interest. In addition to pipelines, RSPA has responsibilities for the transportation of hazardous materials -- regulating hazardous material transportation, prices response for the DOT system, technology development and deployment, and training for transportation safety professionals. It's a diverse portfolio of activities and it's been a real challenge, and exciting opportunity to learn about.

Few issues, however, in this organization are as complex as gas pipeline integrity management rule that we will discuss today. But as an engineer, and a former Secretary of Transportation, I understand the technical challenge, the importance of a performance-based approach to regulation, and how to achieve change through consensus-building. And I was really excited to see that that was the process that was being applied to this particular regulating activity.

President Bush has challenged us to provide a government that is citizen-centered, market-based, and results-oriented. And I can think of no better way to do that in this context than with a consensus standard. To meet these standards, our Secretary of Transportation, Norman Y. Mineta is leading DOT to change the way we do business by fostering innovative and pioneering approaches to our work. In the past year, Secretary Mineta and the Department built the new Transportation Security Administration from scratch, an extraordinary accomplishment. You don't hear the words, it's impossible spoken around the DOT today.

Pipeline safety is our challenge. We need to improve pipeline safety. Our past practices have not been adequate. At times, tragically, inadequate. Our exceptional pipeline professionals, Stacey Gerard and our people in RSPA's Office of Pipeline Safety, have devoted considerable effort to crafting regulations that can truly raise the bar on pipeline safety in an innovative, performance-based approach. And they have done this on a fast track.

If my experience as a private sector business person is any indicator, performance-based standards are something that most business people are interested in working with.

Less than three months ago, December 17th, President Bush signed the Pipeline Safety Improvement Act 2002. This new law grants us the authority to move in the direction we need to travel. It strongly supports integrity management regulations. It strengthens RSPA's lead in a more substantial R&D program for pipeline integrity, safety, and reliability. It broadens our partnerships with states to improve oversight of interstate pipelines. The law reinforces the importance of sound, operator qualification programs. It supports expanded emphasis on one call programs, and it enhances efforts to help communities live safely with pipelines. This new law is a critical milestone for the pipeline industry, for federal and state regulators, and for the American public.

It's testimony to all of you that this law got passed in a lame duck session. I mean I was -- I had only been here about a month when the whole thing happened, and I was absolutely stunned that you were able to pull it off, and I realized I working with people that were really dedicated to making things happen. It passed with the support of grass roots efforts on behalf of those whose lives have been touched by pipeline tragedies. It passed with the support of those who worked to protect our environment. And it passed with the support of the pipeline industry who stood tall, united and committed to pipeline safety and reliability.

Our goal is a pipeline infrastructure that is worthy of the confidence of the American people. Americans expect that the pipelines that bring them a large measure of their quality of life, their mobility, and the vibrant economy, will be reliable and safe. Safety is the purpose of the gas pipeline integrity management rule, and we and you know that. Safety is something that Secretary Mineta constantly reminds us is our first priority. We can dive down into the details of the problem, but we can't take our eye off of safety.

From our view, we are very encouraged by the prospects of improving safety of the nation's pipelines. Our dedicated professionals have developed a comprehensive and flexible program to address all threats to pipelines. The President and Congress have given us a strong pipeline safety law. Across the pipeline enterprise, state and federal government, industry and public, all of you here today, we are resolved to find solutions that are effective and efficient. It's one thing to improve safety, but we must do more. We must do all we can to assure Americans that they can live safely with pipelines.

As we move forward, I know we'll have an important story to tell all of those people. Thank you for bringing your energy, perspectives, and participation here today and throughout the process. I look forward to working with you.

MS. GERARD: Thank you, Sam. Really appreciate your being here. So our purpose today is to delve more deeply into technical, administrative, and economic issues that stakeholders have identified with our proposal. What we've done is identified a representative from industry, from state government, and from the public to lead off the discussion with an overview from their particular perspective. I want to tell you that we are dedicated to having a full discussion of the issues in light of what we learned at the public meeting a couple weeks ago, and in light of petitions, both from the public, and from the industry. We have decided to extend the comment period 30 days, and that notice went to the Federal Register yesterday. So if we don't get it all done today, we'll have yet another public meeting.

We have our advisory committee meeting in a couple of weeks which technically is a public meeting, but if we still need to have more time for discussion in a public setting, I'm committed to having another public meeting in April. But we can decide that as we see how the discussion of the day goes on. I was real interested to hear Sam use the word, the pipeline enterprise. That's all of us. And I heard that word a couple weeks ago when we were at the NTSB reviewing our performance, and getting the NTSB's take on our approach to resolving a number of their recommendations, and I was really surprised and excited to hear them say that when they brief their intended nominee, the President's nominee to be the new Chairman, our existing Administrator, Ellen Engleman, they told her that according to their performance measures that the pipeline enterprise was the highest performing mode in transportation last year. So I think that's really a sign of the outcome of the dedication and the energy that the whole pipeline enterprise is bringing to discussing pipeline safety problems and looking for the range of solutions that are the most intelligent. And that's what we're here today to do is to become more intelligent about the issues associated with this proposal.

I'd like to see a show of hands just so we know who's here. How many in the audience represent pipeline operators? The clear majority. How many contractors to pipeline industry? State government? Good to see you. Representing the public? Well, Rick, you've got a big job. You've got a big job ahead of you. Okay. Anybody wants to change sides and do Rick? He could use some help on his team. Are there anybody representing the media here? Okay.

Now that we know who's here, I would like to call for our first perspective, Mr. Dan Martin to give some overview of industry comments.

MR. MARTIN: Thank you, Stacey. Good morning. I appreciate the opportunity to make a few comments here opening this morning, and kind of highlight for you some of the items that we plan to have addressed today in the technical discussions later on.

First off, I guess, as we're talking about the pipeline enterprise, I'm up here making comments representing the NGA, AGA, and APGA. We've been working very closely over the last many months, reviewing the proposed rulemaking and the impacts, and doing the evaluations on how we can make it better and overall improve pipeline safety.

But I want to back up and reiterate comments I made before, comments that Sam touched on as well. The pipeline industry is committed to improving pipeline safety. We feel very strongly about that in several areas, and we talk about investments. In my opinion, we have made a lot of investments in the past to improve pipeline integrity. We are committed to continue to make those investments. We're making those investments now, preparing systems, for ...ability if you will, even though there's not a rulemaking that's been approved yet. Various companies are modifying systems in anticipation of this, and we are also committed as we go forth to making many more investments to improve pipeline integrity.

So I think from that perspective, we are committed to continue to make investments, and as we'll see as we talk later, they are substantial investments to modify our systems to meet some of the requirements of the rulemaking.

As far as research goes, the pipeline industry is a very strong believer in research and development, and have been over the many, many years. One of our key groups, the PRCI, celebrated its 50th year this past year, and that's been one of the key institutions we use for our research. We've put a lot of money into that. That's voluntary funding. We also look at co-funding opportunities. We continue to make the investments in research. We feel very strongly technical based solutions are one way that we can continue to improve pipeline integrity and we're committed to continue to make investments in research.

We have been involved in the OPS BAA activities in reviewing, being on those various groups that are looking at the research. We're very excited about some of the opportunities we see coming out of the BAAs, and further again, supporting the technical basis for improving pipeline safety.

The third item on there was public policy that's been touched on. We want to make sure that the public understands we are committed to improving pipeline safety. The various groups did send letters to Secretary Mineta this past year supporting pipeline safety bill -- legislation, and we continue to support it at this point as well.

The last two items, one is education. That's kind of a two way street. That's education for us to understand the concerns of the public, of the legislators, of the regulators; and then also to educate those very groups on the impacts of what they're proposing on the industry, but also what we are already doing that may address some of those concerns. And the communication is the same way, that we want to make sure that we communicate adequately in forums like this as to what we are doing, what we propose to do, and the impact on any proposed regulations, what it would have on the industry and ultimately on the consumers as well.

So with that, we are continuing to be committed to the integrity rule, in getting it right. That's one of our efforts here today, is to make sure we touch on the points that the regulators can understand that we feel need to be considered, reconsidered, taking into account some of the points we plan to bring up to get it right. That we need to get it right the first time as we go forward, as opposed to coming in and modifying it at a later date.

The other thing on the development, I think is very important, is to understand exactly the intent, the interpretation of what is being proposed. We need to make sure that we understand that as we're trying to apply it to the impact on our facilities, and how we would actually implement it. Implementation is a big piece as well. It's one thing to say, to do something without understanding the impact on the systems. An example would be taking all the systems, you can't do everything in a given year. I mean there's only so much opportunity within a given year to do work on pipeline safety without impacting something. You know, potentially impacting capacity, or throughput, or deliverability to customers in the winter time I don't think is something that we want to do. And so I think as we go forward, and you'll see in some of the technical presentations, while we feel we need to understand the impact and the interpretation on these regulations and requirements.

Overall, the rule, we think, is very comprehensive. It has the potential to be expensive, but as I mentioned, the industry is committed to make modifications on the systems, to do what we need to do. But then, you know, to get it right and to implement it, I think, is a key thing. The key take away today is to listen to some of the technical presentations that I'm going to summarize here in a moment, but all in all I think the rule is very well structured. We think there's just some areas of modification that we would like to get our comments in today to make sure that you take those into account in consideration as we go forward in the coming weeks.

What we've done is boiled down the technical presentations. We'll basically have six today. The first one will be touching on refining the definition of an HCA, the focus on the priorities, and simplify the determination. Again, another key thing here is making sure we all understand how this would be defined. Definitions are key. And so that it can be implemented.

To back up and to talk about that just for a moment, I think it's key to understand the interpretations as we go forward and we develop our plans, and as the regulators come in to review our programs to make sure we're in compliance, we want to make sure we don't have different interpretations on what we need to be doing. We need to understand that up front.

The second technical presentation will be prevent the overlap of reinspection period on baseline period causing additional capacity constraints. I touched on that. We are committed to do the inline inspections, but we need to understand the true impact on the natural gas infrastructure out there, and ultimately on the consumer.

The third item is utilize available research and understanding for inspection requirements below stress pipelines.

The fourth topic will be talking about adopting the NASE external corrosion direct assessment standard and accept as an equivalent inspection method and clearly define confirmatory direct assessment methodology as well. Again, clearly understanding the intent, and we have some examples we'll show on that.

Item five, utilize established technical criteria for defect investigation and remediation, and clarify the applicability of inspection technologies to detect excavation damage.

And then lastly, we will be touching on clarifying the basis for pressure testing of the vintage materials and systems.

Those are the six key areas that we would like to discuss today in the public forum, obviously, as we submit comments. There may be some other ones, but we think these are the key take-aways today and messages we want to deliver here. And then with that, we've also had some work done by Mark Hereth from Hartford Steam Boiler, and he's going to come up and talk a little bit about the environmental and safety impacts as we see it today.

MR. HERETH: Good morning. The news of the 30 additional days is welcomed, especially in the context of being able to look very carefully at the environmental and the safety impacts, both from a benefit standpoint and a cost standpoint. And I'm going to walk through those briefly today, and give you more of a visual presentation of this as opposed to throwing numbers out.

And I'm going to cover three of the areas that Dan talked about initially. The first has to do with the HCA definition, and if we take the HCA definition that was promulgated in August of 2002 and look at that as the base case, and then work our way across and look at what are -- if we make changes to that -- we'll talk about that. What are the incremental environmental costs that come with that? What are the incremental environmental benefits that we can look at? What are safety costs and then what are safety benefits? The idea is that when we look at change, let's consider both the benefit and the cost of both to the environment and to safety.

So if you go down and you look at our second line there, that really shows the changes to the definition that were made in the NPRM that was issued recently. And the concern, I think, from an operational stand -- from an operator's standpoint, is that the changes in the rule, while they are comprehensive, and they are the kinds of things that operators understand need to be addressed, the concern is that they do increment the environmental costs, and it's not obvious from the analysis that we've done at this point that we can see the environmental benefit that comes with that. And in a similar way, in a smaller way, there is an increment in safety cost that's not clear -- and this is where there is going to be more discussion this afternoon about clarity in the definition to help understand, so we can demonstrate that there is clearly improvement in safety and environmental.

Now, one of the things that we're going to see this afternoon when Darren Moore talks more about the HCA definition, because he's going to step back to the year 2001 and really look at work that was initiated in 1999, and the key is that the industry developed a consequence-based approach, a technical-based approach, using good, hard science that was then validated using actual incident data. And when we looked and compared the consequence-based approach that was technical-based, and compared that to the base case, if you apply that kind of thinking and reasoning, you actually can reduce environmental cost, you can improve environmental benefit, and you have the same effect with safety. If you improve the safety benefit, while at the same time reducing the cost of the safety. So we're going to get into details this afternoon to show that. We want to show you visually that the concern is, on the part of the operators, it's to improve the benefit, both from a safety and environmental standpoint, and to bring clarity into the good work that's been done with the HCA definitions.

And then if you look at the more recent work that the industry has done following the issuance of the NPRM, there has been additional focus and additional work on the consequence-based approach. And the proposals that you will see this afternoon really offer the opportunity to pick up things that were not conceived in the industry's original work in the year 2001, and really going back to the beginning of the year 2000. And what the industry is proposing, or the operators are looking at doing today is to really add to and provide a greater level of safety.

Then the second issue Dan talked about was this potential for the overlap of a baseline and reassessment period. And again, if we start with that base case of being, in this case, Congress, and the interpretation that many of us have seen is that -- and Andy Drake will actually present this in some information this afternoon -- is that when we've listened to staff, we've listened to press releases from members of Congress, we see the message that the idea is to complete the baseline and then begin reassessment. However, the rule gives the impression that there's the intention of having an overlap of the baseline and assessment periods.

And so what we've done here is to contrast cost and benefit for the environment and from a safety standpoint. If you look at the way the NPRM is set up, it does -- it would have the effect, if you would overlap the baseline and the reassessment period, which means you're going to have dual testing, or retesting going on at the same time you're trying to do your baseline work. You will have an increase in environmental costs and with not a commensurate increase in benefit. You will have an increase in safety costs, because you will be doing activities on a more rapid basis, and from the technical work that we've done, and Andy Drake will talk about this this afternoon, and the work that Patel's (ph) done looking at the technology behind reassessment intervals, there really is no safety benefit. So the important thing is the operators want to convey that there is value in looking at streamline processes, working through issues, but there's got to be a good safety benefit from the standpoint of implementing those.

And the final area is to really look at confirmatory DA. And so the base case here is to look at what -- as we heard earlier on -- the work of national consensus standards and ASME B31.8S, really the integrity management standard laid out there, and then the work that NACE did with direct assessment with both external corrosion direct assessment, the work they've done with internal corrosion direct assessment and actually that they've undertaken with SCC, or stress corrosion cracking direct assessment.

If we then compare that to what's done in the NPRM, this is a case where the NPRM has really done something that's gone beyond, and done some, what we think are some really good things from a standpoint of providing another option for operators, is without really having an impact of any significance from an environmental standpoint, the NPRM proposes a methodology which actually reduces costs, but provides the same benefit. In the spirit of what Secretary

Mineta is committed to doing, which is to find better ways, more innovative ways to do things, I think operators are commending the agency for undertaking this, for coming up with an innovative approach.

The thing that you'll hear about this afternoon are simple clarifications to what's been done with CDA to help drive that through the national consensus standards or international consensus standards processes through NACE, and to reinforce what you've proposed in the NPRM.

The next thing I'd like to do is to talk just briefly about safety performance and how that fits into the context. The thing that we always have to recognize is where are we today on this journey that started back in the 70's when regulations were initially implemented? Where are we in trying to achieve? And the goal that's really been established by the industry, by the industry leadership, is the goal of zero. And so what we want to do is work through how you can get there.

What you'll see as a part of the comment process, is a report developed by ourselves and Allegro. Allegro -- a woman named Sheryl Trench does a common report that cuts across oil, natural gas and gas distribution, so the methodology is consistent across each of the forms of energy transportation. Yes, sir?

(question, off mike)

MR. HERETH: Zero incidence, which would mean zero injury and zero fatalities. Thank you. Good question. And that is a commitment that has been made by the executives.

If you take and look at drilling down into the industry experience -- and this is for natural gas transmission for a period of from '85 to 2001, and you then look at the causes of incidents, you break it down into third party damage, external corrosion, internal corrosion, and the industry has taken a very extensive effort to demonstrate and develop a common set of terminology here so that we can drill down and look at this historically over time. What I'm going to do is to take an example and walk through this, because the key is it's important to understand your performance today so you can drive the integrity work to improve, using the right tools, whether that's inline inspection, hydrotesting -- hydro -- pressure testing is what I really should call it, or direct assessment, for the combination of threats that are applicable to your pipeline, and then periodically go back and evaluate your performance and make sure you're making improvements. Because if you're seeing a degradation in performance, you need to go back and revisit your plan.

As the progress is made towards zero -- again, that goal -- there is a need to have measures along the way, and one of the things we wanted to do was to step back and say well, what do other industries do? What do other people do? And one such measure is 6-sigma (ph), and this is the technique that's used in the manufacturing industry in managed defects. The drive there is to reduce error, to reduce defects to one in a million.

So where are we in the context of what this transportation enterprise and this pipeline enterprise is endeavored into? Well, if we take the 310,000 miles of transmission pipes that are out there today in natural gas, and as we'll get into this afternoon, if we consider that there are four circles, or four corridors -- pipeline corridors within that mile, that yields 1.24 million units to be managed in a year. We take the 310,000 miles, there's four units within that -- that's the way the class location is defined, with a 660 foot corridor you double that to 1320, divide that into a mile, that gives you four units per mile. That says I've got a million and a quarter units that you're trying to manage in this pipeline enterprise.

(inaudible question)

MR. HERETH: But even if we go to the 660 foot corridor that exists in our class locations today, and if we take that and apply it to the system, that gives you a quarter of 1320 feet. If I take a mile, it's 5280 and I divide that by the 1320, incredibly, its four. No round off. It's actually four. So what that says is I've got four impact zones in each mile that I'm trying to manage. And you'll see this as we -- if you think about the impact circles or the class locations, that's what we're really trying to manage is to manage those areas along the system. So if we say that we start with that 310,000 miles, and we say we're going to manage those units, that says we've got a million and a quarter units that we're trying to manage day in and day out, 365 days a year. Yes, inter- and intra-transmission, thank you.

Now, let's take an example and work through this. Let's take internal corrosion. You saw on the list internal corrosion was one of the -- it's not the leading cause, but it's up there. It's a significant cause when you look at sheer numbers. And in fact, it turns out to be on average about three incidents per year per line pipe.

If I then go back and look at those one and a quarter million units that we're trying to manage day in and day out in this pipeline enterprise, that yields a rate -- if I look at an incident as a defect or an error, that's two incidents in a million. And if you think back to our 6-Sigma, that's looking and saying that's two in a million. Our interim measure to get to form zero is one in a million, and there's progress been made. We're close to that goal. Nobody's -- the operators are not saying they're giving up. You're not saying you're giving up. But we wanted to provide that because it's important to understand where we are today so that when we put these new requirements on, those are the requirements that are going to help us make that last increment from being close to 6-Sigma to getting towards to 6-Sigma, and then ultimately to zero. Yes.

MS. GERARD: Do you have any data, I mean incidents are a lagging indicator. Do you have any leading indicator numbers on defects found that might be corrected to avoid ruptures? In terms of historical experience?

MR. HERETH: The answer is we don't have a lot of data that we can look at in a systematic way, but in B31.8S there have been a framework defined to get those leading indicators, and in fact, you've taken some of those and embraced those and you've taken the four key ones and embraced those in the NPRM, and then you have also taken the more prescriptive measures, and we commend you for doing this, I commend you for doing this from an outsider perspective -- you're looking and saying let's look at the leading measures as well as the lagging measures. And we'll get that data over time as people begin to get this testing going. Does that help? Good. Thank you.

For the sake of time, I'm going to move on unless there's any other questions.

(Pause.)

MS. GERARD: Rick, would you be prepared if I changed the order of the agenda, to just have a little point, counterpoint? Okay. Could you come up next?

MR. KUPREWICZ: That puts me on the spot.

MS. GERARD: Okay, well let's -- we may need a little break. I'd like to put Rick up next. Why don't we have just a stand up, stretch your legs, don't leave the room, because Rick can probably get himself set up pretty quick.

(Whereupon, the hearing was off the record for a brief period.)

MS. GERARD: There's been some additional attendance, and I just want to have another show of hands. How many people here representing the public? How many people here from the media? Okay. How many people here representing pipeline operators? How many here representing state government? We lost a few there. We need you in the room. We need to balance the scales, state guys in the room. How many people here are working with the pipeline industry as contractors? Okay, thank you.

Okay, I should say that. Thank you. How many people here representing the Office of Pipeline Safety? Or RSPA? Could you stand up? I want to make sure everybody knows who you are. Okay. We've got a couple regional directors -- there's Bill Gute, Chris Weydell (ph). We've got our mapping team, some of the eastern region. Mike Israni is here who is the architect of Gas IMP. Jeff Weiss, Program Development, Linda Daughterty, enforcement officer; from TSI, Lane Miller; Zack Barrett who is the implementation chief for future enforcement efforts for Gas IMP, and Paul Wood from CYCLA (ph).

Are there any federal agencies here, other than OPS-RSPA? FERC and NTSB, thank you. Okay, did I forget anybody who wants to be introduced? And you are? Department of Justice. Thank you for joining us. Anybody else wants to be introduced? Trying to set an informal environment here so that later in the day when comments are made, I want other people to feel comfortable coming up and doing point-counterpoint so we can all get as informed as possible.

Okay, are we close? Okay. I'm really glad that Sam Bonasso has the opportunity to get fully entrenched in these issues. I see him feverishly taking some notes over there and I'm probably not going to be able any of his questions later because there's some really good new material in these slides.

MR. KUPREWICZ: This is a good example, a point here that I think we need to really underscore what's going on here because the issue of high consequence area and the rulemaking is going to rely on some very sophisticated developing technologies, things like direct assessment, inline inspection. The key here is what you have in front of you is some of the most sophisticated technology, computer skills, and it doesn't work. So it's good to apply that new technology, but the caveat here is, whether it be inline inspection, sophisticated direct assessment, or other technologies that are out there being fostered to us, the key here is, you have to have confidence that it's going to work. Don't over-stress to the public something that you haven't proven yet and then find out that it didn't work, because the backlash from that can be tremendous.

With that, we'll just go right ahead and play along. I can make these slides available later on in the public domain. Thank you again for the opportunity to talk about a very important rule that's being promulgated here. I just want to say here that the gas integrity rule objectives, from a perspective that I see here consistently, fall into four objectives.

Do we have clear High Consequence Area definitions that everybody can reasonably understand? Do we understand that the federal regulations set minimum standards, so as pipeline operators and owners, these are the minimum standards, even the performance standards, so there's nothing that says you can't exceed those in areas that you feel are prudent. So we see the regulatory process as setting a minimum, whether it be prescriptive or performance-based, setting minimum guidelines that the public can have confidence that the situations are under control.

Do the regulations -- and the whole objective here, based on several recent events in the last several years that have occurred, is we need to be insured, or we need to reinstill in the public confidence in very important infrastructure in this country. Make no bones about it. Right now, I consistently see anxiety and concerns that well exceed the issues regarding terrorism. They see this infrastructure in their back yards and they want to feel comfortable that it's under control.

MS. GERARD: Rick, I didn't really introduce you and where you're from.

MR. KUPREWICZ: Hi.

MS. GERARD: Say where you're from.

MR. KUPREWICZ: I'm from Washington state. I'm the president of Accufax Incorporated. What we basically are is a third party, independent organization that assists parties in trying to negotiate issues related to pipeline. Obviously, in Washington state we have the Bellingham liquid pipeline failure which initiated a lot of activity in that area, and I operate across the US and Canada. Thank you, Stacey, for helping me out.

The last objective, the fourth objective is we need to reaffirm the industry's credibility with the public in this country. I know many people here are very positive, forthworth folks, but there is a problem int his country regarding this critical infrastructure and we've got to get a handle on some of these catastrophic failures. Give me a second here.

Regarding the High Consequence Area definitions, we have some problems here. Regardless of which side, if I can characterize it that way, you're on, we see general confusion the High Consequence Area. There needs to be some clarity, whether you're an industry, the public, an inspection agency, or various other players, as we go through the latest High Consequence Area rulemaking, there appears to be a great deal of confusion. And I don't want to belittle attorneys for making a living, but that kind of confusion can really create problems for all sides, and it's not putting resources in the best place if we're trying to use legalese to understand a very simple concept. Now, we may not agree on the exact definition, the final outcome of how many miles it covers and whatever, but if we can't agree what the definition is, it's just fraught with all kinds of problems. And in the industry perspective, it just generates tremendous costs for these folks.

Because the last thing we want to see you is taking an inspection program that isn't going to really be productive for you. I think that's a bona fide public concern as well. So I was glad to hear this morning about the need to be -- you know, efficient and enterprise and all that. No one's trying to regulate you guys out of business. That's what I see consistently from the public side of it, so there is an understanding of that process.

A positive note, we think, in the High Consequence Area rulemaking, there was focus on identified sites. We think that plays a very important role in the definitions of High Consequence Areas, and we see that as a positive step in getting clarity to some of the past, shall we say less than strong, regulation.

The Moderate Risk Area, I'll get into in a minute here, is confusing to many of us on this side of the fence. It appears to be a last minute change, maybe a bona fide reason for it. We don't understand it. Potential impact circles is another issue I want to talk about real quick.

In the High Consequence Area definition, if I could step back to these four major points I made earlier, there are a couple issues here. As I mentioned earlier, it's not only confusing to many in the industry, but it's also confusing to the public. And I get back to that credibility issue. If the confusion runs rampant, the credibility gap just gets bigger and bigger, and the anxiety levels go up. And that serves no purpose for this country, or for the infrastructure. In my simple way of looking at things, the High Consequence Area definition should pass what I call the simple logic diagram test. It should fit on one little piece of paper, and if you want to call it a logic diagram, or a flow diagram, you should be able to just go down through it and say okay, I understand this concept. I may not agree with the full definition and what it covers, but I understand it covers this, and it covers this, and it covers this. Gentlemen can agree to disagree, but if they can't agree on what they're agreeing on, we're in real trouble. And that's what I hear, and there's many -- a vast group here from the industry that I think are all shaking their heads, yes. That in itself should be a flag. And I think the 30 day effort here, the extension, is a positive step, a very positive step.

If the High Consequence Area definition is not clear, the rest of the integrity management regulation is just an expensive distraction. It's going to take a lot of resources. It's not going to satisfy any of the public or the industry's standards, and we're going to spend a lot of effort maybe not going very productively forward. So we need to underscore the fact that the High Consequence Area definition needs to be clarified.

Jumping to the identified sites here. As I mentioned earlier, it's key to gaining the public's confidence. It's probably one of the most important areas in the High Consequence Area definition, from our perspective. We believe that it covers areas in the Class 1 and Class 2. We think that's an important concept. We didn't say it covers all areas, or even the majority of areas in Class 1 and Class 2. We think that the identified sites provide clear focus on what we call the unsheltered risk individuals, which has tended to be an area of less significance in past regulations and we think this is a very positive step and want to reinforce that effort.

MS. DAUGHERTY: What's an example of unsheltered public areas?

MR. KUPREWICZ: Carlsbad -- individuals were outside. When you're getting into the heat flux zones and you're not sheltered, you don't have a lot of time.

We commend also the identified sites in that it's addressing issues -- hard to evacuate buildings -- that's a regional approach. The issue that probably is being wrestled with with members of the industry is it also addresses where people congregate. You know, what's that mean? And I've seen many players to argue, well, it's -- we've got 20 people and 50 days, that's not enough. And I've seen others that say that should be bigger. But we can disagree about what the exact definition should be, but the concept's important. So we want to reinforce those efforts within the OPS. We think that's a positive step.

Back to the Moderate Risk Areas. We're having a hard time understanding this. Some in the industry are having a hard time understanding this. Our reaction is that the Moderate Risk Area conflicts with the High Consequence Area objectives. From a perception perspective, it's going to be hard to explain to people why Moderate Risk Areas are excluding certain areas of Class 3 and Class 4. We think the Moderate Risk Area overly complicates and confuses the High Consequence Area definitions. It's not going to be well received by the public, and at this time, we cannot support the Moderate Risk Area concept.

In the definitions related to High Consequence Area, the animal called "potential impact circle" -- we think this can be easily resolved, but we believe there's some clarification needed to insure, as we believe OPS intended, that this covers all Classes and in the wording of the potential impact circle, again, it's probably very clear to the people who authored it, but from a third party perspective, reading this and trying to avoid legalese and misinterpretation, circle of radius, or threshold radius seemed to be interchanged. And we think they mean something different. So we ask someone to look at those. It's one or the other. Which one is it? So we'd say in the potential impact circle, we think you mean threshold radius, and so that can be easily resolved and clarified.

I need to take a couple of minutes to talk about some other gas integrity management rule issues as a result -- that are coming out of the result of some of the efforts that everybody's been working on productively in the last couple years. Specifically, there'll be three areas -- what we call pipeline citing and modification issues, the myth of integrity management, and performance measures and risk management.

On pipeline citing modifications, I've run across in the last six months -- and this is kind of something that's evolved as a result of High Consequence Area definitions, so this is more of a heads up for all the folks in the room. The potential impact radius calculations, the C-FER studies and whatever, from our perspective, are empirical developments we think are very positive steps and we support this concept for development of a tool that should advise or assist management or pipeline managers on what areas of their pipeline they should be looking at with a higher degree of scrutiny.

We do not believe the potential impact radius should be used as a citing tool. I've run across a couple situations, not in Washington state, where very eager companies tried to add new infrastructure, either new pipeline or compressor stations or whatever, are citing the potential impact radius as a reason for citing the equipment in very sensitive infrastructure. I'll go even beyond the High Consequence Area and call it very sensitive. Again, we support the concept of the -- of using this correlation, empirical correlation for screening, but not for citing. We advise that if when you're getting -- if you're in a situation where you have to encroach into these very sensitive areas, you use more sophisticated engineering tools that are out there, that go beyond this empirical correlation.

A classic example -- I need to use this case and don't want to do it to ... folks, but it's just true. The Carlsbad situation where 12 people died, were outside the threshold radius zone. The public understands that.

On the myth of integrity management. We believe integrity management plays an important role and we support the development of this regulation. We've got to caution however, that as managers of corporations, you can get so much energy focused into integrity management tools and concepts -- we're going to hear a lot of discussion today about this -- but integrity management is not a caveat for other issues that are required in proper operation or prudent operation of a pipeline company. Keep your eye focused on the operation and the management processes that serve historically as checks and balances. Integrity management plays an important tool in insuring the safety of these pipeline -- this important pipeline infrastructure, but if you go and focus in the extreme just on that, believing that you now can abusively operate your pipeline, you're setting your executive team up and you don't really want to be doing that.

The other side of this coin is integrity management does not advocate or excuse poor risk management processes. We support the risk management concept, the performance-based concept that the industry is advocating. We think that's a proven process. Integrity management serves as an important tool to serve those processes, however, if you're not making the right risk management calls, this tool can still get you into trouble.

With that said and done, we've got some key issues and questions for discussion at this meeting today, so I appreciate your moving me up forward, even though the technology isn't worth a darn.

MS. GERARD: I'm really sorry --

MR. KUPREWICZ: That's my fault for not getting here earlier, but the following questions, I think, need to be addressed or concerned or answered today, or at least before the final regulation is promulgated. Does the High Consequence Area definition pass the simple logic diagram test? I think we can reach consensus in this room that we need to get this issue, we need to get this clear. It serves no purpose for lack of clarity. We may not agree on the final definition, what it covers, but if we can't agree on the clarity, we've promulgated bad regulations.

This is another issue that I'd like to understand in this process, is what percentage of pipeline miles are going to be High Consequence Area once we figure out what that definition is? And of those pipeline miles, what's the breakdown by Class? We're not looking for 50 percent, 30 percent, 20 percent, or 90 percent High Consequence Area definition. We're just using that as a gauge to understand how much effort is really going to be spent here by these companies in the next 20 or 30 years. It's a good reality check. It's a question that's going to come up so let's just answer it right up front.

Another question I'd ask the operators, are we trying to promulgate good regulations but we may have one of those unpredictable outcomes that nobody may want. Are we inadvertently driving pipeline infrastructure in High Consequence Areas or sensitive areas towards smaller diameter pipelines that are less efficient, and getting the smaller diameter, are we inadvertently driving to exotic higher pressures? And if we are, then I'd ask everybody to step back and say, we are creating the illusion of safety here because as pipeliners, I'm sure vigor is more efficient, and no one is trying to get you away from that process. I think that's a positive step.

So I want to be careful. A less experienced person could think, we need to put in smaller lines and go in the 2000-3000 pressure range with more exotic metals. Because now you're -- it's an illusion of safety.

What performance metrics are subject to

review? This is an issue that's going to get batted around, and we're not going to resolve it today, but I'll leave it as a question.

And again, the last question would be, on the final rule timing. We support the efforts that everybody's working hard the last couple years. 30 days we should be able to reach consensus on what the definition should be. We think the High Consequence Area definition is the most important issue in this. The other details can come along. And we commend OPS. They set up four parameters for testing -- pressure testing, inline inspection, direct assessment, and other -- and we like the concept of other because we see this as a positive step. Because in America, it's innovation that drives, and so we understand the important role that OPS plays in trying to drive additional innovations that results in efficiencies in cost and improved safety all the way around. And we don't want to close that opportunity. That's all I have for now.

MS. GERARD: Wait Rick, I have a couple of questions for you. On the issue of what percentage of the pipeline is HCA, was that your question?

MR. KUPREWICZ: Yes, what percentage of the gas transmission pipeline -- the 300,000, 310,000 miles. Are we talking -- well, when we've finished with the High Consequence rulemaking, are we at ten percent, five percent, 30 percent, 50 percent? And then roughly -- again, these aren't exact numbers, we're not looking for that -- and then what does that break down by Class area?

MS. GERARD: Would you think it is relevant what percentage of the population living near the pipeline is protected? I mean, you know, the -- looking at the consequence issue here, what we're focused on is really defining what is High Consequence, and I have concern about looking at it just in terms of mileage.

MR. KUPREWICZ: That's a detail. I have no problem with adding the detail, I'm just looking at this as a first series of questions, and if you want to go into greater detail, that's fine. But I think the average person, trying to wrestle with the credibility issue and are we moving forward in a progressive manner, their first question is going to be what am I addressing? Understanding that they're going to believe that Class means higher population densities. So you can explain that to an average guy in more detail. Most of them won't listen for the detail, they just won't understand. I mean that's the way most --

you know, sound bite era where everybody wants to hear the first question. So I just say that's the first question that I want to ask, and then you want to bring the clarifier in, the classification or the population data.

But it's a good reality check in the sense of -- you know, bad regulation here, bad interpretation, could cost this industry many tens of billions of dollars over the next several decades, and nobody wants to do that. Nobody's wanting to make this an less efficient process. So this is a reality check to understand -- are we -- you know, is this going to get really out of hand or is this right in the ball park?

MS. GERARD: I wanted to ask a question -- you come from a community where there is very active citizen groups who are looking at the pipeline issues, and did you have an opportunity before coming to this meeting to discuss the issues you were going to raise with a broader group of people, or are these just your personal views?

MR. KUPREWICZ: Most of these are my personal, but I did have a chance to discuss it with several of the more opinionated -- I'll be very candid. There's a tug-of-war going on between prescription and performance. My personal view is I have no problem with performance as long as there are other qualifiers. There is an internal struggle going on there. It is back to this credibility and trust issue, and I'd say you can't promulgate regulation where you're catching every situation.

MS. GERARD: Were you comfortable with the criteria we proposed in the rule for qualification, for the performance approach?

MR. KUPREWICZ: Yes. There are a couple unknowns there. One is -- you know the devil's in the details in terms of performance. B31.8S kind of gives you a road map. You don't have to necessarily follow it completely. The other thing, and I think this has come up in some other meetings, the issue of national security and what can you disclose is -- you know, where's the reality check. If you're going to performance based, again there's two schools in that camp. There's an extreme camp that wants to know everything about every anomaly in your pipeline, know everything about your business. That's one extreme. Then there's the other side that says, well, wait a minute, we just want to understand that they've got the right management processes, they're operating and following their design conditions and they're following reasonable performance measures. So I'd say those are the two extremes. And in all rule making, extremes don't tend to work out. They tend to work the compromise.

As you try -- and it may be very honest, meaningful national security issues in some situations, but it comes across as, we're trying to hide some of the important issues regarding do we have confidence in the management process. So there's the balancing act that needs to happen here. I caution and advise -- my personal opinion is very seldom do I need to know all the details about a company when I get in and look at a a company. I just need -- there are certain flags that you can see and as inspectors, you folks look for them as well. Very seldom do you need all the details, or all the anomalies, what kind are they? What kind of pigs are you running, whatever.

MS. GERARD: I appreciate your comments and I just want to make sure you understand that just because we called you up early in the day doesn't mean that that's the last we expect to hear from you today.

MR. KUPREWICZ: I am not normally shy. Thank you for the time. Any other questions?

MS. GERARD: Phil, identify yourself for the transcriber.

MR. SHER: (Off mike.)

MR. KUPREWICZ: Excuse me, what was your name again? Philip Sher, okay, thank you.

MS. GERARD: State of Connecticut.

MR. KUPREWICZ: State of Connecticut. We have a recorder up here.

MR. SHER: (question off mike)

MR. KUPREWICZ: Yes, more engineering analysis for very sensitive areas. The super analysis is an honest attempt to try to make a first pass cut of rational zones using measured parameters, and the parameters they use are the pipe -- nominal diameter, the maximum allowable operating pressure. When you look at more detailed -- I won't say blast clouds, but flame fronts and whatever, you also have to work on several other variables, so there are more detailed. For integrity management, it would be very difficult to apply these, but on a site-specific situation, you get into these.

It isn't a modeling, it's an engineering approach, and it usually captures things like time to ignition. Time to ignition sets then the thousands of pounds of fuel before ignition, so the problem with time of ignition is, as anybody can tell you, in rupture scenarios, it can vary considerably. But if you're in a very sensitive area, you need to look at the realistic factor. Thank you.

MS. GERARD: When you have questions, please pick up the mike and identify yourself for the public transcript. Any other questions for this presenter? Okay, Rick, thanks very much, and we will be able to get your slides up on the website.

MR. KUPREWICZ: Sure, no problem.

MS. GERARD: Back on our schedule, I wanted to have a brief explanation from Barbara Betsock about interpretation of the legislation as it relates to one of the issues in the industry presentation. This is the issue of -- Andy, Barb's going to speak to the issue of the second issue on your slide, the ability to control the schedule of the baseline and the retesting interval, and whether there's opportunity there to make any changes.

MS. BETSOCK: Good morning. When we look at the statute, the first thing that is apparent is we were really looking at risk. And we felt that very strongly as we were working through the regulation on it. When the statute passed, we didn't see that we needed to make huge changes to the approaches we were taking, but it is apparent that what Congress was aiming at was to make sure that we addressed the highest risks, and that we provided protection to the appropriate areas.

As a result, we didn't look at the Congressional language, where they put in ten years and seven year periods as being anything different from what the plain meaning is in the statute. We looked at the language, and if you look at it, it says it's minimum requirements. What the agency is to do is to establish requirements for integrity management and among the minimum requirements are that the baseline be done within ten years, not later than ten years is the precise language that's used. That's not establishing -- that's establishing an outer limit for that baseline, not an absolute time.

Therefore, our proposed regulation has some variables in it for when you are to do the baseline. In addition, the statute says that the highest risk facilities are to be subjected to a baseline assessment within five years. The statute goes on to say that minimum requirements include reassessment of these same facilities within seven years, and the language is, at a minimum of once every seven years. The language is precise: at a minimum.

It's very hard for us to see this language as anything but what it seems to us to be pretty plain, and that is that if you have a very high risk facility, you may have to do your baseline assessment in two years, and a reassessment in seven. There is some flexibility in our proposed rule on what the reassessment is, but we don't think we would meet the requirements of the statute if we read it any other way.

Now we do invite comments. If you see any -- we understand industry has some concerns about this and thinks that they read it differently, and we certainly invite any comments on the language of the statute and recognize that statutes can change if indeed we find that that is a major problem, and we're wrong on that, it is possible a statute could change. But right now, that is how we read it. As I say, we will take comments on the language of the statute where you may see some ambiguity that we're missing. It's not cast in concrete, our opinion, but we need -- it really needs to be pointed out, the ambiguities. Thank you.

MS. GERARD: Wait a minute, Barbara. Any questions? Identify yourself, sir.

MR. BIANCARTY: Paul Biancarty, Duke Energy Corporation. Barbara, I think I understand what you're saying about the plain language. I'm wondering if you've got some legislative history? I notice that there's not been a conference report published, to my knowledge, since the December 17th enactment. I'm wondering if you know of any -- maybe Stacey might know -- whether there's some other language somewhere that would throw light on this question of what was intended when the legislation was prepared?

MS. BETSOCK: Well, you only get, Paul, you only get to that language if you find an ambiguity in the statutory language. The law is pretty clear that the plain meaning of the law governs. What Congress voted into law counts. Committee reports, colloquies by members, those things you only reach if there's ambiguity. So we need to find the ambiguity first. I'm not aware of any legislative history that really is contrary to this except some colloquy by one member, and that isn't even on the floor.

MR. BIANCARTY: Is there any report that is likely to be published subsequent to the previous reports? I mean this legislation has been going on for quite some time. I know there is an old conference report, but do you know if there's going to be anything published that would reflect more directly on the December action?

MS. BETSOCK: We have not heard of anything else being published, but that doesn't mean it won't happen.

MR. BIANCARTY: Thanks.

MS. GERARD: Any other questions for Barbara Betsock? Thanks, Barbara. Our next presenter will be Mike Israni who's with the Office of Pipeline Safety, and he is the architect of this proposal. Mike's going to give a brief overview. This portion is just on High Consequence Areas.

MR. ISRANI: I want to take just five minutes to set up the computer.

MS. GERARD: Why don't we take a five minute break.

(Whereupon, the hearing was off the record for a 15 minute period.)

MS. GERARD: We're changing the format a little bit to get the dialogue going in a little bit more fluid way, so we've called up a cross section of representatives here. If there's a state guy who wants to come forward and get near the mike, I want to make sure that we have everybody commenting on everybody's point of view here. I think that will help eliminate the situation. Where is Jim Anderson? Come up here.

MR. ISRANI: Okay, I'm Mike Israni. I'm the Program Manager for Pipeline Integrity Management. Sitting next to me is Daren Moore from Tennessee Pipeline. And we have Andy Drake from Duke Energy, and we have Mr. Anderson representing the state of North Carolina, and we have Zack Barrett from our Western Region, but he'll be our integrity management implementation leader for the gas integrity management group; and we have Linda Daughterty who's our enforcement officer in the Office of Pipeline Safety, and finally we have Rick Kuprewicz -- I shouldn't forget his name -- from the public, from Washington state.

I offer this integrity management rule and the team with ... chief counsel's office and developed input from all sources. I'm not at all surprised what I'm hearing about the High Consequence Area confusion. This is what happens when you try to bring a balance of industry, public, and regulators into a rulemaking where everybody has their strong views. I'm here to communicate what is in the rule, the proposed rule, and why it is there. I'm here to clarify, not interpret, rules for you. And I'm going to listen to your issues, and we are taking notes and we'll try to work on those.

In the morning session, I'm going to present High Consequence Area. In the afternoon session, I'm going to talk about integrity management requirements in those High Consequence Areas.

So I'm going to start with our main goals.

Our main goals are to improve public safety and provide increased assurance to the public. And we'd also like to accelerate the integrity assessment of the pipelines in the High Consequence Areas. Some of our operators have already been doing assessment of the pipeline. This will accelerate the process. And for those who have been not doing it, this will require them to do it on a periodic basis as we have called out in the rule.

We also like to improve integrity management systems within the companies. Some companies already have a mature integrity management program, and by this rule we would like to bring uniformity so that all the companies, all of the integrity management programs are in accordance with our elements. They will develop their integrity management programs and they will follow. And finally, we would like to improve government's role in validating integrity management.

This is where we have the High Consequence Area in the rule -- final rule that we issued on August 6th, last year. Four components of the High Consequence Areas. First of all, I'd like to say that the High Consequence Areas for the gas and the liquid rule are different, because gas and the liquid are different entities, with different physical properties. Their impact is going to be different. Gas being lighter, it will rise up. Gas, indeed, when the pipeline ruptures and gas leaks and gets ignited, it will flame up farther. Impact of the flame of fire is limited as compared to liquid. Liquid can flow to the streams and have an impact in a large area.

The four components that we are including in the High Consequence Area. The first one is Class 3 and 4 locations. Why the Class 3 and 4 locations? Currently in our regulations, Part 192, Class 3 and 4 locations are defined as populated areas. This information has been in the books for 30 years, has been in the ASME B31.8 standard for 30 years, and we chose Class 3 and 4 locations because we believe that industry already has the data on this information, so this will minimize the work for them having to go out and relocate all the people in the residential areas falling in the 660 foot zone that Class 3 has the corridor limits -- 660 feet on either side of the pipeline.

I'll go to the third component here, the building or facility having persons whoa re difficult to evacuate. When we decided to write the integrity management rule, we wanted to go beyond what currently Class 3 and 4 locations will control. We wanted to include these facilities like hospitals, schools, nursing homes, prisons, which are not covered previously. If they were falling within the Class locations it was fine, but if these facilities were in Class 1 and 2 locations, we wanted to include them.

Our goal was to improve safety or existing regulations, and we also wanted to add places where people congregate, such as playgrounds, camping grounds, recreational facilities. Currently we have this requirement in the regulations, but it is limited to only 300 foot corridor, and by this rulemaking, we expanded that to go beyond 300 feet, to go up to 660 or even 1000 feet.

For each and every element, I'm going to show you some diagrams and sketches to clarify things for you before I answer any questions.

In this slide, the very first component on the top that you see is the fifth High Consequence Area that we added in the proposed rule that got published on January 28th. This component represents residential areas which are beyond 660 feet, which were not picked up in the original High Consequence Area final rule that we issued on August 6th last year. So we wanted to pick up those areas because impact can be felt that far, and we have had evidence, in places like New Jersey -- Edison, New Jersey, where the impact was felt beyond 660 feet, and there are other incidents where impact has gone beyond that limit. So we wanted to add this component of residential areas which are located -- this would include the areas which are outside of Class 3 and 4 locations, meaning in Class 1 and 2 in areas where the housing is located beyond 660 feet.

We use this 20 building or more factor within 1000 feet, purely mathematical derivation from -- using the same density that we currently use in the Class 3 location. 46 buildings in a mile by quarter mile rectangle will be the equivalent to 20 buildings in a circle of 1000 diameter.

We also introduce Potential Impact Circles and Radius and Threshold Radius -- and I'm going to clarify what those are and why we are introducing those. The first one is Potential Impact Radius. Here we used the C-FER equation, which is .69 square root of pressure times diameter squared, and that's in the ASME B31.8 standard. We're using the same C-FER equation as our base equation.

And we want to add a safety margin to that equation, and that's why we chose to use Threshold Radius. Why we did that? Because C-FER equation has a good record -- they have actually seen the explosion distances and measured, using their mathematical calculations, and found that they have pretty much laid the footprint of the explosion, but there are still some assumptions within the C-FER equation, and we wanted to take care of those by adding safety margin. There are other reasons too. The time is very slanted, and if your pipeline is running like this, and if the pipeline ruptures, your explosion footprint will be longer than what C-FER calculates. That's because of the flame, which is higher, will obviously go above ground. So the safety margin will take care of some of these small things.

Potential Impact Circles that we use in this for the impact zones, was based on the Threshold Radius, meaning C-FER equation many use, you calculated what radius is, we added a safety margin to come to Threshold Radius, and that radius to be used to determine the circles, Potential Impact Circles. So we define Potential Impact Circle as one which has 20 or more buildings within a circle of threshold radius of 1000 feet. Or the Potential Impact Circle is one which has hard to evacuate places in all these three corridors, or places where people gather.

Potential Impact Zone is sliding the Potential Impact Circle along the pipeline.

And now the good part. I'm going to show you diagrams so you can understand each and every component very clearly. The very first component was class location. Class 3 and 4 are High Consequence Areas by definition. Class 3 location is defined as one continuous line of a pipeline with 46 buildings in a 660 feet on either side of the pipeline corridor. So you have a rectangle with 46 buildings, that becomes a Class 3 location. Class 4 location is where four story or higher buildings per the line. So I shown you some in the diagram here, all these Class 3 and 4 locations -- they're down there. This is very simple, simple combinations. There are so many different scenarios for class locations, but this is just gives you sort of a rough picture of what Class 3 or Class 4 locations are.

This one slide gives you all the components that we have in the High Consequence Areas. We'll start from the left hand side, Class 3 locations. As you see, this one covers all those 46 buildings in the one continuous mile. This is one component, and we have Class 4 locations as well as a High Consequence Area. This is a new component that we added in the proposed rule. Residential areas which are beyond 660 feet which happen to fall in Class 1 and 2 location, which were not picked up originally in the High

Consequence Area, the final rule that we put out. So this proposed rule adds that to the original High Consequence Area component. And how do you -- we do not see this residential area to be in one continuous mile as the Class location is. So therefore, we use this by using the Threshold Radius and the Impact Circle to determine, and we think if 20 buildings falling in a circle of 1000 feet, then that becomes a High Consequence Area.

Not all operators will have to worry about this component if their pipeline damage and pressures would never have an impact that would go that far. Only those operators which have larger diameter pipelines, mostly rule upon this if you have greater than 30 inch diameter pipelines and more than 1000 pound pressure, you will have to consider this factor. There will be some cases where pipeline is 30 inches or even less and really, really high pressure, you could reach that impact zone, but very unlikely.

Then we have shown on this slide, by example here, the prison which is hard to evacuate, churches or playgrounds which is falling under the places where people gather, and are hard to evacuate. I've shown the distances that these can fall in any of those corridors, depending on the pipe diameter and pressure, and it may or may not apply to all pipeline operators depending on the pipeline diameter and pressure.

This is one example of how an operator will determine how much of the pipeline segment is going to be affecting the High Consequence Area. For example, if you have a prison located 400 feet from a pipeline; your pipeline diameter is this, pressure is this. If you calculate, using C-FER equation, your potential impact radius is 468 feet. We are adding the safety margin and bringing it to 660 feet corridor. And this 660 feet, as I say, originally be in the proposed rule we have -- in the High Consequence Area rule as well as in the proposed rule, we have put these three corridors: 300 feet, 660 feet, and 1000 point more for uniformity, more for simplicity, and also to take care of some safety margin.

So if you are falling anywhere above 300 feet, but less than 660 feet, you use 660 foot corridor, and that's how we have proposed in the rule. So the 660 foot threshold radius, if you draw a circle, you will see the area ... the pipeline, and that pipeline becomes your High Consequence Area segment of the pipeline. This is one way of determining the pipeline segment that will affect the High Consequence Area.

Second method for doing that, by sliding an impact circle. You will get the same results, but this is another way to do it. If you draw the impact circle using your Potential Impact Radius C-FER, which in this example I've shown 655, and then your threshold radius, 660, you adopt 660 for circle and you keep drawing the circle unless you've got the point that is closest to the pipeline, and then the other end -- so this becomes your zone, what we call Potential Impact Zone. Similarly, if you have something on this side, your zone is going to be a rectangle.

Also I have shown on the diagram that we have included residential areas which are beyond 660 feet, and here is a good diagram to indicate how we have picked up -- what we mean. So if your residential area, if you have 20 or more buildings located such as they are mostly falling beyond 660 feet, for this particular illustration, you see there are only about three or five building which fall within the 660 feet, so it would not fall in the Class 3 location, even if you had a quite concentrated residential area. But if your pipeline diameter is large enough, the Potential Impact is going to be much higher, and if you get 20 buildings in a circle, that becomes an HCA.

This was -- I picked up this gauge from the

C-FER model report. And here I've shown how you can determine the threshold radius. For example, if there is a 12 inch pipeline diameter, and your pipeline pressure is 800, your Potential Impact Area is close to 150. So we are using -- instead of the 150, we are using 300 for threshold because we are using only three corridors, 300 feet, 660 feet, 1000 feet as I said earlier. So in this case, you see for a 12 inch pipeline up to 1400 pressure, you will never get beyond 300 feet. We are using the same threshold, 300 feet in this case. If you're a 24 inch pipeline, and your 1000 pound pressure, your Potential Impact Area is going to 450 or 480, so you're using 660 foot threshold. That's how we are showing the simplest case, how to determine threshold radius.

Once you know threshold radius, then you draw the impact circle using that threshold radius, and you determine your segment.

Caution here about what is Moderate Risk Areas -- and this was introduced in the last minute, what's causing the confusion. Here's just one illustration, one example, of how Moderate Risk Areas can be used. If you go the sliding mile circle -- the sliding mile definition of Class 3 location as we currently have in Part 192, and while we are considering as a part of High Consequence Area, and if you get building scenario like this, you have this entire area as a Class 3 location because you -- if you slide this anywhere, you get 46 buildings. So the situation was happening that you have only a couple of buildings -- one or two buildings on this side, the majority of the buildings are clustered here. So then this part becomes Moderate Risk Area. What we mean by it is if an area, falling within the High Consequence Area in the broad definition, but has a less impact as compared to this cluster of homes which we call High Consequence Area. So under the proposed rule, we are saying in the Moderate Risk Area you have more flexibility, you have longer intervals for testing. Whereas High Consequence Areas we are giving you ten years for baseline; for Moderate Risk Area, we're giving you 13 years for baseline.

Unfortunately, I can't show you this clearly, but I was trying to show, for example, a church located in Class 1 location -- these are examples of some rural buildings and example I picked was a rural church, where there's a High Consequence Area or it's a Moderate Risk Area, we have put as a question in our preamble, and we are inviting public comment on this. Currently this church would fall as a High Consequence

Area, and the question for the public is, whether we've done this as a Moderate Risk Area because those buildings are occupied infrequently and they'll meet the definition if there are 20 or more people gathered there 50 days in a year. One this is determined that this is a Moderate Risk Area, then again, you have flexibility on the testing intervals as for the proposed rule.

We have also asked for comments with the Moderate Risk Areas we can go a bit further flexibility and require only confirmatory direct assessment or preventive and mitigative measures. Confirmatory direct assessment or preventive and mitigative measures only. These are questions we ask from public and when we receive their comments, we see their strong viewpoints and we'll make a determination accordingly.

Now for most operators who are using smart pigs or who are doing pressure testing, Moderate Risk Area may not mean much, because smart pigs you'd be running for ... compared to station, you know, could be 50 miles, 100 miles, so these few miles that you saved is not going to do much for you. But when you do direct assessment, it matters a lot, because definitely less excavations you'll be required to do.

Or when the same operators who are using smart technology, when their time comes for confirmatory direct assessment, and they decide to go with confirmatory direct assessment in lieu of again ... after seven years, then they will be appreciating to have Moderate Risk Areas.

This is an example of why Moderate Risk Areas can be useful and why we introduced them. For example, in a Class 3 location, if your cluster of buildings which are located such that they are beyond the 300 foot threshold that we have, for small diameter pipelines whose impact radius never goes -- or impact circle never goes beyond the 300 foot threshold, may have an entire area, entire Class 3 as a Moderate Risk Area, and may not have to do as stringent testing as we have for the rest of the pipeline which falls in High Consequence Area within the location. For example, if you're five buildings in Class 4 location are so far away that they're barely touching the 660 foot limit, and your impact zone reaches only here, so you, in that case also, we're considering this as a Moderate Risk Area.

Okay, so that's for the next session, so I will take questions.

MR. DRAKE: Everybody's so quiet. I have a comment and a question, I think. Stacey put me up here to make it lively, and I'll try to live up to that expectation, but -- I think -- my name's Andy Drake. I'm with Duke Energy gas transmission out of Houston, Texas. An observation, I think, which picks up earlier public comment -- we very much share that sentiment. You see going through this, this is a very intricate rule, and I think we recognize that there's a lot of effort to incorporate technology and precision and a lot of different drivers here. But what the fall out is that it becomes inordinately inconsistent, I mean inordinately intricate and inconsistent in trying to be so precise it starts moving around. In some places, you know, we even see where we're trying to be really precise, where we're using these models, and then we're throwing it out to a big -- adding big safety margins onto it, or throwing it out into a big threshold radius, it seems kind of like you're measuring with a laser and you're cutting with a chain saw. What are we doing? Why are they doing this fancy equation? We're just going to go way out there anyway, why don't we just go way out there, make it simple?

I think the fundamental engineering principle is, you know, keep it simple. Just principle. If we get -- I'm a big believer in you can get a lot of bang for your buck with a very focused level of the effort.

Define that effort and focus on it, and you will get the magnitude of what you're trying to accomplish. If you get to the 99 percentile, the effort becomes disproportionately complex. And I think that's kind of where we're headed here.

I guess what I'd like to see is -- here comes the question part -- is what are your over-arching goals and targets? When my management looks me in the eye, they say, Andy, how much is this rule -- how much of our system's in this rule? I literally do not know. I literally do not know. And my management will be extremely anxious about that. We're at the fourth quarter here, two minutes to go, and we are talking about something that we can't land. This is very concerning to us. When we look at this rule, we are trying to gauge how to ramp up on this. We are just spinning our clutch wildly. I literally don't know where to start, because we're seeing huge swings in the volumes of pipes and the type of pipes and the type of sites we're chasing. And I think we need to -- I think we're buried so deep up against the tree that we're doing some sort of microscopic analysis of bark fiber. We need to back away and look at the damn forest and work our way through the trees. We have gotten way wrapped up in the details here and we need to back up and gut-check ourselves on what are our goals here and land this thing with some sort of reasonably straight forward, reasonably technical-based effort that protects everybody. We're not -- the point here is -- and I think we recognized that earlier -- this is a starting place. We don't want to burn up all our energies defining where to start. We want to start. But when we spend all this energy trying to keep all these balls in the air with who lives where and where did all these people move to and who gathers where, and what intersections are gathering enough traffic to be considered a gathering -- holy cow. Don't we just want to inspect the pipe? Yes. Daren. He's next.

I just want to -- really do have a question, and that is, what are your over-arching targets and goals? And if we can see that, I think we have a chance to land this. But right now, it's becoming incredibly complex to see what the target is. You, Mike, anybody out here who can handle that?

MR. ISRANI: Let me start here. What I understand from Andy's concern here is about counting all these residential areas, the large corridor like 1000 feet long, even if they may have an impact zone going only about 680 or 690, and what he wants to see, why are we going that far? As I said earlier, that we chose these special radius for simplicity. We also chose to take care of some safety margin, and we also chose because current rule has 300 foot and 660 foot corridors already there, and we wanted to have one fixed corridor for longer periods.

What I see the point is mentioning that there would be some operators who would just miss the target and so what I understand is I think your objection for that would continue if the potential impact zone was determined as a circle with some safety margin as compared to having some fixed special radius?

MR. DRAKE: My question is bigger than that.

MS. GERARD: His question was what are our goals? ... expand the level of protection over what they are in the existing rules? We are trying to pick up more geography than we have in the Class 3 and 4. That's clearly one of our goals. We are trying to stay science-based as we pick up that. We want it to be based on the likelihood that if there is a failure, you could affect these larger areas. And one of our goals is to be able to be more effective in our oversight -- that was Mike's fourth. We also want to know and be able to communicate to everybody else where we're adding the protection, so we do want to be able to answer the question, where we are providing the protection. I think those are our goals.

MR. DRAKE: I'm glad to sit here, I mean we want to talk about this, we want to work this out. I can tell you what the scenarios we run through just trying to keep up with the turbulence of this rule. At Duke Energy, the company that we hold, we have a GIS system, we're able to try to run these different scenarios down there by using the computer-based data system that we have on the corridor. When we look at Class 3 and 4, it comprises somewhere around 12 percent of our total mileage -- outright, just miles on the pipe. But -- and here's the question that you want, I think, too, there's collateral information that bears on it. That represents about 60 percent of our valve sections, 50 percent of our valve sections, and 80 percent of our compressor station discharges.

Now, what's the relevance of all that? Sounds like some sort of incredibly -- go back to the microfiber thing. But the point is how you work the pipe depends not how much of the system is going to be inspected. That's just Class 3 and 4. It doesn't take into account the gathering places, which I think are valid also. Those are outside Class 3. Those are extra places. That's just Class 3. But given that, for the big transmission companies for sure, pigging is the answer that you're going to try to get to, because financially it's the -- when you have to do this over and over again, it becomes the better answer. That means you're going to be pigging, for us, 80 percent of the system is now going to be investigated because of that mileage. What's the target?

Now some of these other scenarios that just came out, switched us up where we're running now 75 percent of our Class 2, 43 percent of our Class 1. We're up, in the compressor station discharges, we're at 100 percent. That's 100 percent. That's not a focus. That's everything. If we're trying to find somewhere to start, I think you've got to keep all those numbers kind of in front of you.

And that's what I'm asking you. What is our target? Class 3, on our system, represents 75 to 80 percent of the people. That's just Class 3. And then you add the gathering places on top of that. I just want to know what our target is. What are we trying to hit? You know, in some of these scenarios, if we're going to 100 percent of the pipe, we don't need HCAs. We can quit the effort. Forget it. Why are we tracking all this stuff? Just do it. But that's not -- I think you're going to find that the cost is ramped up very quickly on a lot of the operating sector, very,

very quickly on a lot of the operating sector. So I think those are the questions I think we're trying to get some clarity to. Yes, over-arching, we want to add value and we want to look at more geography. But we need some more specificity.

MS. GERARD: Clarifying question. You just said you're going to have to run the pig on all that amount of pipe. When you say you have to run the pig, does that mean you have the full cost of assessment on the whole line when you run the pig? Just because the instrument is traveling through the system, can you choose to interpret the data on part? It's a question. We need to know the answer.

MR. DRAKE: Woe to those who gerrymander the inspection effort. Woe to those.

PARTICIPANT: I'll second that.

MS. GERARD: Okay, so the answer is you have to interpret --

MR. DRAKE: It's physically possible to do that. You can't pass the red face test when you start screaming. You are way out there now.

MS. GERARD: Okay, so the answer is yes, you have to look at the entire inspection result. So what you say we're asking you to do is leading to assessment of the bulk of the system, and the cost of assessment as well, and that is not our goal. Our goal was to prioritize.

MR. DRAKE: The goal is to prioritize.

MS. GERARD: Okay. I just -- I had to ask the question.

MR. KUPREWICZ: Let me add too, though, when I was asking the question about the percentages. I don't have an answer, nor do I care. I'm just using that as a reality check on whether or not the HCA -- so there isn't a preordained objective here to get everybody to 90 percent or 100 percent. The question is going to come up from the public, and it can be answered, and it can be answered honestly.

MS. DAUGHERTY: Andy, I have a question. Let's say, for example, and take your example just a little bit farther. If you run your inspection tools through, let's say 80 percent of your system, and let's say the rule has gone through and identified your HCAs. You will have results for a huge part of your pipeline. That's good information. I think we all would agree to that. You will be able to risk prioritize those areas in HCAs first, so you will stack that up, and that's where your assessment intervals will be based on.

The other information outside the HCA, that's good information to be acting on, but your priority will still be for your HCAs. There's a question in there somewhere.

MR. DRAKE: The management of the data, I'm looking at ... as executives of the pipeline industry. When you become aware, knowledgeable of that, it does not matter if it's in an HCA or not, you are bound by engineering and -- to action on that. I mean, so yes, and no. No, when you find an actionable anomaly and you don't action against it, I think you're exposed. And our lawyers are over there shaking their head yes. I think you're going to find that when the information is discovered and it becomes precommitted on schedule based on national consensus standards that drive what diligence is.

MR. BARRETT: I think -- if I can get back to -- my question to you is whether or not you would prefer to be able to calculate that impact zone with a given safety margin on that, as opposed to going to these straight corridors?

MR. DRAKE: I think that you have to -- I think this is probably where the slippery parts are. The gas industry is very different from the liquid industry, fundamentally. First of all, we move one product, natural gas. We do not move butane, propane, crude oil, jet fuel. We move one product. That product has a very specific signature -- lighter than air, burns at this rate and it creates a very significant pattern, constant pattern. It's all very predictable. And I think also that helps the gas industry, is that the gas industry has a great deal of data on people that live and actions that take place inside this 660 or quarter mile wide corridor. And you want to try to take advantage of that.

The liquid rule, as Mike pointed out, fundamentally -- the consequence patterns are much more elusive, and so the areas are much different shapes and you have to be very conservative when you look at that, and I think work. And I think the fact that they don't have class locations also bodes the fact that they don't have the resolution of data where the individuals are inside these areas, so you switch to the census data. Those are all logical things, you know.

You switch to the gas side, you want to -- I think the goal should be you want to try to maximize the use of that data and you want to maximize and take advantage of the fact that you can profile the consequences, and you want to couple those together. I don't think the goal, really, is perfection. It's just to try to identify places to focus. I think over-arching our goal, as Dan martin said, is we don't want any failures, anywhere, any time, period. What we're starting with here is trying to divine a starting place, not a level of acceptability on danger. That's not the point at all. We're just trying to define how much is a big enough first bite. That's it.

And I think you've got some operators -- you've got a very diverse operating environment, different from the liquid. Liquid, the companies are typically the same size. They're middle size -- compared to gas companies -- they're middle size companies and there's a limited number of them. And you look at the gas infrastructure, there's almost an order of magnitude more operators. Some of them are huge, much larger than the largest of the liquid companies. Some of them, most of them, most of them are very, very, small. They're the service operators that provide gas to your house. And they're very small. They don't have some of these data systems and management tools, and you want to try to respect that dichotomy.

So you may need, in order to deal with the reality of this environment, an either-or. Either you use a real simple tool, or you can use something that's really precise. But you don't want to go to the little, little operators and say you have to do this really complex modeling. They're going to go -- it's my wife and I and we don't have time to do that, you know, man.

MR. ANDERSON: You're doing my presentation.

MR. DRAKE: That's good news. We're all kind of coming together maybe here a little bit.

MR. ANDERSON: I was invited here to make everybody else feel good. And I'm probably the least qualified person to be sitting up here.

MS. GERARD: Who are you?

MR. ANDERSON: My name is Jim Anderson, and I am the chair of the National Association of Pipeline Safety Representatives, which is a state regulator for pipeline safety. I did not get this position due to the fact that I'm real smart or brilliant. I missed the national meeting two years ago, and they voted me in. That's the way it works. That's the way it works.

I've got a few people here that I do -- now I know Mark, and I was on the LBC risk management group along with Alan and some operators here. One of the things that I am going to speak about is the difference between inter- and intra-state facilities. Looking at Mike's slides a while ago, he started out with a 12-inch diameter pipe to come up with his PIRs and moving on up to a PIZ and all these acronyms. I'm about a 3/8ths inch processor and four PIM whirl right now, looking at something. That's just the way it works.

So I'm looking at some of this stuff and I'm looking out really just for North Carolina. I started out in 1979 as an inspector in Kansas. I went to Oklahoma as a program manager. I actually used to be a gas operator around a gas utility company for about four years and then the state of North Carolina hired me to be the program manager for pipeline safety. And I was talking a while ago about I'm about as lost as a goose in trying to read this and trying to understand this. One of my concerns is, if I look at some of this stuff and I question my operators, do they understand it enough to know that I'm right or wrong? You can get into some of this.

When I do my presentation, I'm going to show there are some differences between inter- and intra-state operations, and a lot has to do with size of pipe and when it was constructed or how it was constructed. But they're actually two different animals that I'm going to talk about. Thank you.

MR. ISRANI: Anybody else on the panel?

MR. KUPREWICZ: I've got a question that focuses on what I said earlier this morning on the

Moderate Risk Areas. It seems to me -- first of all, I'll make a question statement first, and then a question. My understanding is what's driving the Moderate Risk Area definition is trying to avoid accelerating timing of certain areas that may not fall into some zone. And it's added for complexity that everybody's going to have to calculate, whether they're a big system or a little system. Is that what's driving the Moderate Risk Area?

MR. ISRANI: Yes.

MR. KUPREWICZ: Okay, so the answer is yes. And I'll play again, many of these folks are going to go to direct assessment, whatever that means -- we're in the codes and processes of trying to develop that right now. So I describe that as evolutionary or in its infancy. Yet to be determined whether that will work. Hopefully it will. But the regulation says if you use direct assessment, you've got accelerated timing anyway. So if we're adding this complexity that's probably scaring a lot of people, and changing -- I can see me sitting in front of a management group and I have to say, I don't know what the numbers are. That's a position nobody ever wants to be in. If this is adding some of that complexity and it's driven by a timing issue, then one thing to think about would be eliminate the Moderate Risk Area and change the timing that has been set for the Moderate Risk Area back to the same parameter time.

Is the Moderate Risk Area acceleration really worth anything? Is it worth all this complexity? If the answer is no, eliminate that concept as a regulation concept and normalize the incentives to be exactly what they are for the other technology. That's a lot of words, but that's kind of what I see going on here.

So I see micromanaging. I agree with Andy here. I see some micromanaging going on, trying to catch that last one or two percent. The reality is, we don't know what direct assessment is. We think we do. We hope we do, but we may be overstating its advantages.

MR. ISRANI: I'll let Stacey talk and then I'll give some answers.

MS. GERARD: Well, my questions was -- one of the questions that was within the body of the preamble was, should we consider eliminating the testing requirement for those areas which, while they may have been, while they may be existing Class 3 and 4, we now know they're outside of the impact zone of the explosion. The question -- we define these areas, but we really were asking questions, is it worth bringing testing? That's the question. So if you aren't testing in them, does that change the balance of nature here in terms of whether it's worth identifying them, and then doing other types of activities in those areas now that we know they're outside the impact area?

MR. KUPREWICZ: My perspective on the Moderate Risk Area? The answer is no. It's adding a lot of complexity. I don't see the gain. That's my personal opinion.

MS. GERARD: (comment off mike)

MR. DRAKE: I think we've kind of got a hybrid going on here, and that's part of the problem. I think we fused the either/or together and came up with some sort of hybrid crossbreed that doesn't serve anybody. You're talking to one group, the small operators, Class 3 and 4. Just do that. It's pretty straight forward. Now, when you look across the room and you start talking to other operators and say Class 3 and 4 is a very crude tool. It's 30 years old, it uses sliding miles, incidents don't happen on miles basis. People -- it's a very crude and rudimentary tool. But it's very doable. It's a known.

Now, when you start switching gears and here's where we ran into the problem. When you switch gears and you start saying, but that's not really where the people are. There's this model, these circles, these impact zones. We can move them around and find where the people are. Shouldn't we do that? Well, yes. When you start doing that you start seeing that the old tool is real rudimentary. It's a big blob. Now you're seeing places inside the class that's where the people are and you're also finding where the people aren't.

And I think the past ... test, when you start doing that, you've got to separate the two. Either do it this way, Class 3 and 4, or you do this circle. But when you do the circle, to pass the ... station, you shouldn't be doing the circle just to decide the Class, you should be looking around to where the Class schema might have worked the other way also, where it missed people that were grouped together, but there weren't enough people to get across the mile hurdle. If you're going to use the complex tool, you've got to step up a little bit more.

But we kind of merged those ideas and came up with this hybrid MRA thing and it's like, well, what do we do with that thing? That's some sort of a mating of a beaver and a cat. I don't know what the hell happened there with that thing. I mean, you know, we like beavers and we like cats, but we don't really like that middle thing. And I think that's what you've got here is you've got -- when you look out here at the MRA, you've got that hybrid thing. You've got two people out there. You've got two people out there in this MRA. Well, two people? What are we talking about? You've got this hybrid thing and we need to distill that. We need to separate the two options from one another.

MS. GERARD: Did I hear you say, now that we have a more sophisticated tool, the impact zone, go either or. Either use the Class location or use the tool over the entire pipeline?

MR. DRAKE: (answer off mike)

MS. GERARD: Okay, well, let's just -- that was Andy Drake from Duke. Oh, you couldn't hear him.

MR. DRAKE: Andy Drake. I think that there's two presentations here that you just maybe ought to let them present, because if they're going to answer -- we're sort of hedging on the answer to your questions. We're dancing all around. Great segway.

MR. ISRANI: I just briefly want to say something. One of the questions asked by Risk, how much of the HCA, percentage-wise, we are expecting by this rule? We did a cost benefit analysis and we find

42,000 miles, from our estimate, will be affected by this rulemaking. 42,000, roughly, miles out of 300,000 miles of transmission pipeline. That's roughly 12 percent of the pipeline.

MR. DRAKE: Run through that again, please?

MR. ISRANI: Our calculations -- our estimates show that about 42,000 miles of pipeline that fall in the High Consequence Area, from the transmission pipeline, out of 300,000.

MR. ANDERSON: Interstate or inter- and intrastate?

MR. ISRANI: Together. All together, yes.

MS. DAUGHERTY: Mike, you said that the 42,000 is just the estimate for the segment of pipes inside the HCA. That doesn't include the extra pipe between valve sections or anything like that?

MR. ISRANI: No, it does not. And we could ask some other questions, also, but because we are running short of time, we're going to have Daren Moore give his presentation and when we have some time in between, I'll answer some questions. So, Daren Moore, please.

MR. MOORE: If someone cannot hear me, please raise your hand and I'll try to speak louder. 30 to 40 minutes, we have a lot of material to cover. It's an incredibly complex rule. High Consequence Areas is an incredibly complex as it's currently written, area to discuss. So I'll move through it as quickly as I can.

Rick, I appreciate your candor this morning. You made some excellent points. The question I've just now heard raised some other good points. I think most of them are going to be addressed in the next 30 to 40 minutes. There's a lot of issues here that I'm going to try to get on the table, and hope I'll make it simple enough that we can all understand it. That's my goal as we move through this.

We heard the pipelines are the highest performing transportation mode. Good news. That was last year. Outstanding news. It's tough to improve on that, but as Dan Martin said, it's our goal to do it. And we're going to do our very best to do that. This presentation is a step towards improving pipeline safety, but by itself, when I do it, it's going to take a comprehensive rule to accomplish those goals. And this presentation is part of that comprehensive rule.

Since it is a long presentation, I have an outline. I'm going to describe the industry work in defining HCA. We started that work in 1999, recognizing the issue and going forward. It's not something that just happened in the last year. It started in 1999. I will then discuss the January 28, 2002 NPRM as it applies to HCAs in some detail. I'll quickly discuss the intent of what the HCA definitions are, and then rubber meets the road. You've asked for specific proposals -- Stacey asked for specific proposal back. I'll make that in the discussed proposed industry definition. And finally, I'll compare and contrast the OPS and industry approaches in concluding.

The question becomes -- we do have some over-arching goals here that we've talked about. Industry believes that number one, absolutely we have to have credible science as a goal in this rulemaking -- and Rick mentioned that as well from the public's perspective. We want to address most of the people along the pipeline. In the Q and A a moment ago, Andy mentioned that we address approximately 70 percent of the people who live along the pipelines in the proposal we're about to hear. And three, we want to address a significant part of the pipe, but we want it to be focused enough that we're not wasting resources. Address as much pipe as we can, make it focused. Those are our over-arching goals.

So the question is, how do we define HCAs? And the work in 1999, it led to a pure technical approach. We'll call it the C-FER circle -- we're going to see it a few times later. Out of that became an empirical model, validated with real data. They had questions about the assumptions that go into the C-FER modeling, how it may not fit in. We have real data which validated the C-FER circle approach. That led to the INGAA-AGA proposed definition in 2000, referenced in the docket comments. And we were very pleased to see OPS incorporate some of the best ideas in the NPRM. They incorporated the C-FER methodology, the C-FER circle in the NPRM, but not in a holistically enough way. We have a proposal that will help address that.

The C-FER model is based on, as Andy mentioned a moment ago, based on the fact that natural gas behaves very predictably upon release. It's lighter than air. It goes up. When it releases, you can model the energy inside the pipeline. The model is based on the pressure, MAOP, and the diameter, and it comes out with the equation we'll see later.

After we determined that these were the overriding factors, and then started looking at the detailed factors, we asked C-FER to do the math behind it. They came up with the equation that we'll talk about in a moment, and then the rubber met the road, and we said how does it look in the real world? Does it work or does it not? Are we right or are we wrong?

The model validation, we looked at three Canadian incidents on the top, TSB are Canadian incidents, and we looked at a variety of NTSB incidents. Initially we kept it to this population area, this group of incidents, because that's where the best data was. The NTSB and TSB went out and literally chained off how far away things were. You look at the black lines on each one. Those are the proposed HCA radiuses, and you look at the maximum offset to burn extent in the blue. You notice that in all but one case, it's less than what the predicted -- than what the model predicted. Look at the green equivalent radius of burn area, then go down to offset the injury and fatality in yellow and red, and note that the model performed remarkably well when calibrated against actual data determined in the field. Because the model works is the underlying thing.

And we heard a while ago, Rick say the model had to work, the science has to work. It does in this case.

We went ahead and put together a slide here showing what a rule would look like if we -- for High Consequence Areas -- only if we used the C-FER circle. I know you can't read it very well, but it incorporates the circle going across the entire pipeline system. It incorporates 20 or more structures inside a circle, triggering the HCA, and it also includes any identified site. The identified site definition is very similar to what was in the final HCA rule published on August 6, 2002 -- and you can see that up there. It incorporates the PIZ and the PIR, and that's where the equation comes into play. So the bottom half of that slide is just the boiler plate stuff pulled straight out of the final rule of August 6th. The identified site definition is extremely close to August 6th. It's applying it to a scientific, validated circle as opposed to class locations and things such as that.

I've prepared a flow chart for what the pure circle would look like. You can see it's pretty simple. Start at the top, you determine what your radius circle is. You apply the radius to the entire pipeline system, and then inside those circles if you have 20 or more structures intended for human occupancy, or an identified site, if you do you have an HCA. If you don't, it's not an HCA. Stacey.

MS. GERARD: (question off mike)

MR. MOORE: Every foot of pipe -- I'll answer the question by stating the question. The intent here, when it says go down the entire pipeline in the second rectangle, you would go down the entire pipeline including all classifications -- Class 1, 2, 3, and 4 -- and all the pipe that you had. It would not be limited by anything, because you're looking scientifically at all of the pipe.

We also took a look at the hazard area, and you'll note the third one down had an orange -- that is a 30 inch pipe, and if you look at the 1000 pound vertical line, it crosses the 660 almost exactly. It's interesting that that would happen because the 660 corridor was determined back in the sixties and by empirical data, guys who went out -- pipeline safety folk went out looked at incidents, and they said, you know, 660 makes sense. When you do the model, and after you finish with the model that was determined scientifically and try to validate it, it works almost precisely at 30 and 1000. Why 30 and 1000? Because that was practically the biggest pipeline that the United States had in the mid-1960's. It's amazing how closely this stuff works.

That brings us to a big issue. For me to shift gears and take a look at where the NPRM is right now. There are a lot of positives that we mention in the NPRM and there are only three or four major issues.

The biggest is probably the HCA definition. We spent almost the entire morning talking about that. The problem with the NPRM that we see -- and I'll call them issues are:

The NPRM in many cases is not technically based. That flies in the face of one of industry's over-arching goals. It also flies in the face of what Rick said this morning is the public's perspective. That's important. It's extremely complex with many variables, and I'll show you some slides displaying each of these in a moment.

There are many conflicting and inconsistent solutions. Mike had some slides a moment ago, I'll show you some more that will show you some areas where Mike's ideas certainly make some sense on the surface, it's an amalgam of good ideas. There's some gaping holes and inconsistencies we need to make sure aren't there when we get done.

Extremely burdensome for low pressure systems. The small impact of low pressure and small diameter systems is not recognized inside the existing NPRM. Data on houses is not readily available outside the existing 660 foot corridor, so we have a massive data issue if we go down that path, which will cause a lot of resources to go to collecting data instead of inspecting pipe. And that's not what we want. It's not what industry wants. It's not what the public wants. It's not what OPS wants.

The language is inconsistent with other language in the existing natural gas pipeline safety regulations. I'll display that. The proposed HCA definition is inconsistent with the liquid rule. Empirical ... is difficult to look for, there are also some intrusive issues involved in trying to figure out who is inside the structure.

And finally, operator compliance is going to be extremely difficult in some parts of the NPRM and in some instances, it's going to be impossible to apply. And that is not what the public wants; it's not what OPS wants; it's not what industry wants. We want something we can comply with, something that improves pipeline safety. Those are our over-arching goals.

Let's get into some of the details. In the not technically based section, we saw one of the slides that when your PIR extends past 1000 feet you need to add a 15 percent addition to the C-FER equation. That 15 percent is arbitrary and it is not based on science. We showed in a couple slides a while ago, the validation of the model. The model works as it is. We do not need a 15 percent addition to make it work better.

The threshold radius is arbitrary and not based on science. That's the TR you may have seen. I'll show you some examples in a moment. If you have a PIR of 320 feet, you're going to be looking out to 660 feet because the 320 is over 300. That threshold radius is not based on science. We're going to show some real life examples of we're going to have to look at over 95 percent more ground than outside the circle of impact, and that's not the way we want to be going forward in this rule.

The use of class locations is not the best scientific solution available today. It's a good solution, and for the smaller operators who don't have the time, the mom and pop outfits, whatever you want to call them, that don't have the time to do all the science, we're going to propose a solution that allows them to use the class locations very similarly to the August 6th final HCA rule, but we're going to have a bifurcated approach, where they can use the circle and the science as well if they so choose and really dive into that data and make it right.

And finally, the use of 20 or more buildings -- we see that in the existing NPRM -- that's a good idea, folks. Makes a lot of sense. There's a lot of different ways you can come to 20 structures being the right answer. There's some talk about ten. There's some talk about 46. Twenty, we think, makes a difference -- I'll talk about that in a moment. Unfortunately, it's only applied to PICs greater than 1000 feet. It should be applied everywhere. So that's not based on science, and we'll show how that works.

Talking some more about the 20 or more buildings. We discussed a moment ago it should be applied to the entire pipeline, regardless of circle size -- 20 or more buildings I'm discussing. The NPRM says that the PIR greater than 1000 feet, the operators should examine the PIC for 20 houses. That's a good thing, again, it's not inclusive enough. It's not holistic enough. The existing hazardous liquid HCA definition utilizes 20 houses if you base it on that 1000 people per square mile. Drive your way through the math and use the 660 circle and the existing corridor, and the existing natural gas pipeline safety regulations, it comes to, assuming 2.5 people per house which is what OPS intuitively agrees to, it comes to 20 houses. It's interesting OPS would derive the 20 here, INGAA in heavy deliberations three years ago, arrived at 25. We're very close. Those numbers make sense.

Further, I want to talk about ten houses and

I want to go down -- ten houses inside the circle and 46 houses inside the circle. That's essentially the boundaries we have around this discussion. If you go with 20 houses, you're going to be looking at about 70 percent of the population along the pipeline. That's a good thing, and Rick said that earlier. You're going to be looking, in the pigging side, at about 80 percent of the pipe if the operator chooses to pig in a big way, and many operators are as a result of this rule.

If you went to ten houses inside the circle, what would happen? You'd bring in massive amounts of Class 2 pipe and greatly expand the scope of this. You bring in large amounts of Class 1 pipe, and again, greatly expand the scope. This would result in unfocused inspections and loss of impact of the rule. We would not be focusing our resources where we want to to improve pipeline safety.

To show how 20 should be held constant, and not range depending on circle size, this slide here, the left hand circle has a PIR of 1009 feet, and it has 20 houses inside it. We would be offering additional protection to the 20 houses inside that circle, regardless of the circle size. It's an absolute number of people we want to offer additional protection to. The second circle, the R is let's say, 660 feet.

Again, 20 houses inside that circle you want to protect -- additionally protect above and beyond the existing successful pipeline safety regulation, those houses. And if the circle were 300 feet in radius, if it had 20 houses in there, we ought to be protecting -- additionally protecting those sites as well. So it's a constant number of protection. It's not a rating or a sliding scale.

The complexity side. A group of us sat down a few weeks ago and tried to figure out what the existing NPRM said. 192.761 in (A) talks about Class 3. (A) talks about Class 3, (B) talks about Class 4, (C) is identified sites for four inch or lower pipe, (D) is 30 inches or larger -- or vary 30 inch pipe, (E) is everything in between, and (G) is when you have 20 or more buildings for the really big pipes over 1000 feet. It's kind of complicated. I'll go through this quickly here.

This is what an operator winds up looking at. Gee, how do I figure out where my High Consequence Areas are? I've got all these different shapes and colors and personally, I'm getting phone calls from our field based guys asking me what in the world are they looking for? And I ... a presentation for them, very clearly for a couple hours, walking through this. This is complex, and I don't think any operators fully understand what this stuff has.

I created then a flow chart for what the existing NPRM definition looks like.

PARTICIPANT: You've been talking to Rick --

MR. MOORE: No, I've never met Rick before today, honest truth. I'm sorry you can't read it.

PARTICIPANT: It doesn't matter.

MR. MOORE: It doesn't matter. It's complex, yes, it's complex. Okay, let's get into a few examples of how this thing can work. These are tying off some of the stuff that Mike said before.

In this case you have a 30 inch pipe at 1050 psig -- I'm not making this stuff up. There's an operator in the room, he's sitting two people over from me -- he has about 13,000 miles of pipe in one of his systems. About 8000 miles of that pipe is a 30 inch pipe with an MAOP of 1050. This is a real life example, guys, so bear with me for a moment. PIR of this pipe, 671 feet. In the existing NPRM, if you had an office building 350 feet away from the pipeline housing 50 people -- 50 people in that office building, you would not be an HCA. Under the existing rule, even though the PIR is only 671 feet, if you had a licensed day care with say, three people in it, at about 590 feet or whatever from the pipeline, it is an HCA, even though the PIR is 50 percent less than that.

Another example. Again, we have a 30 inch pipeline at 1050, and then -- on the left side, and then 1000 on the right side. On the left side, 20 houses within 1000 feet would be an HCA, even though the PIR is only 651 feet. On the right side, you have 35 houses within 660 feet, yet it's not an HCA. Inconsistencies and we're not providing equivalent protection along the pipeline. We should be.

Another example. Again, going back to the Duke Exsel (ph) pipeline, left side, 20 houses in 1000 feet is an HCA. If you have a building of 50 people inside it's not an HCA.

And one last example. I'll be quick on this point. Left side, Class 3 with 46 houses is an HCA. Right side, it's Class 2 and only 45 houses, one less, it's not an HCA. Now you have to draw the line somewhere, and I recognize that, but that's the way the actual NPRM works.

Give you a table. I got tired of pictures, decided to put a table in this time. You can see you have a 30 inch pipe at 1000 pounds -- in the yellow I'm talking about -- with a 655 PIR, so your PIZ in the existing NPRM is 660 feet. Very reasonable. If you have a 30 inch pipe with 1020 -- let's say 1050 in the real world MAOP, the PIR then is above 660 so your threshold radius, the PIZ jumps out to 1000 feet. Guess what the rule then says you have to do? You have to go out and gather enormous amounts of data from 660 to 1000 feet, even though your PIR, which is proven and validated, by science and by field experience, would be only say over 660 feet. That's inconsistent. It's not where you want to go down with this rule.

Another example here, if you look at the 16 inch pipe on the left, and the 20 inch pipe. One has a 292 PIR, the other has a 338. Look what happens to the PIZ though with a 300 foot cutoff. The 16 inch 700 pound pipe with the 292 PIR only goes to 300 PIZ. Pretty consistent. Makes some sense. The 20 inch pipe at 600 and 338, jumps out to 660 feet. You're talking about 95 percent more stuff for no safety benefit. Inconsistent. Yes, Jim.

MR. ANDERSON: For my presentation, remember this, because I'm going to come back intra-state transmission, and a lot of intra-state transmission pipelines -- they don't have 10 inch diameter. A lot of them are ten, eight, six, four, three or two. So they're going to be encompassing even more. So look at those numbers and see where it's going to impact the intra-state operators more directly.

MR. MOORE: Thank you, Jim.

MR. ANDERSON: I've got a couple ... I've got to get in. During our technical difficulties time --

MR. MOORE: Jim and I don't know each other either, for the record.

MR. ANDERSON: I'm just going to make him look good.

MR. MOORE: I appreciate all the help I can get, Jim. On the data issues. We need to move through this stuff. Industry has collected house data since 1970, out to 660 feet from pipeline. We've also collected small, well-defined outside area data out to 300 feet on pipelines since 1970. Those two are required by the regulation and we've done it for years and we're actually good at it. Over that time, we have very precise data for those numbers. Collecting house data, however, out to one year -- or within one year out to beyond 660 feet, say the example of 30 inch and 1050 pipe, we have to go out to 1000 feet, is completely unrealistic. It took us 30 years to do this. This is not the right way to go.

And finally, collecting data essentially beyond where the existing national gas pipeline safety regulations say will create an undue burden on operators, will make the rule shift resources to data collection from inspections, and that's not what we want.

Language consistency. Talk about identified sites. I think identified sites are a good thing. Industry does as well. I think Rick does also. He addressed them a couple different times in his presentation. The identified site definition includes buildings, the existing pipeline safety regulations intentionally does not, because it's a vast scope right there, you have to go out and find this data. It also talks about 50 days a year, instead of five days a week as the regulation currently has it. Sounds innocuous on the surface, it didn't sound that bad, but the way it works in the operator world when they're trying to comply, is that 50 days a year means I have to look maybe 316 days and determine nobody was there, instead of looking for ten weeks. All of a sudden, the compliance costs go way up and are we really adding value? Five days a week is 50 days. I'm not sure we're adding value by doing that.

Twenty persons is not consistent with hazardous liquid HCA definition -- that one calls for 50 persons as I described a while ago. And going back to how many structures -- you can arrive at ten structures inside a circle if you take an evenly spaced Class 3 at the minimum threshold to drive a Class 3 of 46 houses, but that doesn't address the reality of population distribution. The reality is is that it doesn't work in an evenly spaced way. And so that ten becomes a very conservative threshold that usually expands the scope but doesn't add value. So we need to be very careful about using that argument on a go forward basis.

Okay, we talked about the existing NPRM. Now let's talk about what the goal is and then we'll talk about our proposal. The law says we need to conduct an analysis of the risk, the facility locator identified and show a document, implement or written integrity management program for each facility to reduce the risk. That's what the law that was passed on December 17, 2002 says.

The NPRM preamble that just came out says establish a rule to require operators to develop integrity management programs for gas transmissions pipelines that, in the event of failure, could impact High Consequence Areas. And we talked about the industry's goal as being broad requirements. They are and they have been consistently, for years, that any -- going back to 1999 and 2000 when we first started really discussing this -- any determination of an HCA or any inspection requirement should be technically based. Your requirements should, to the extent practicable, follow existing practices. They've been proven successful. Let's build on them, not throw them away -- processes used by the industry.

And finally, we want to make maximum use of existing house data. The circles -- pure circle approach or modified circle approaches do that. We still believe that this is the right answer going forward.

So that brings us to the alternate INGAA-AGA proposed definitions. We talked about pure approach at the very start of this presentation, the pure circles. We recognize the pure approach is not practical at this time. Yet rules that are proposed -- we have a final rule out there already -- so the proposal we're about to make is going to bridge the gap of regulatory practicality with the science of identifying High Consequence Areas within the confines of the law. Also within the existing regulations, and a historical application of those regulations.

This is the flow chart for the industry proposal. It has quite a bit of stuff up there. Very carefully, it's a bifurcated approach. You see the start button in the circle makes the word definition. Pretty much almost everything to the left of the start circle is one way of identifying HCA. Pretty much everything to the right -- underneath it and to the right is another way to identify HCAs.

To the left is based on Class 3 and 4, the first diamond says, Class 3 or 4, question mark. The answer is yes, bang. It's HCA. If the answer is no, you do your circle, and you start working your way through it. And it looks very closely to the final rule issued on August 6, 2002. The left side of this looks very similar. It includes identified sites. It has Class 3 and 4. It's very close to what the final rule had and that INGAA commented very positively on when it came out.

On the right side, you talk about the pure circle approach, giving the operator the option of going one way or the other. You define the circle, and then you start looking inside that circle, and there's a variety of things in there to make sure that you're catching everything as best as possible. I won't go into gross details here, but it's a bifurcated approach. It allows the use of the existing data. It allows the use of the scientifically based and validated circles. It also allows smaller operators or those to choose to use existing Class 3 or 4 stuff if they choose to go down that path. It offers something to everybody. It's based on C-FER. It's either what OPS said in the final rule, and offers even better protection on all the pipe, based on science. Take the right side, you're looking at every foot of the pipe. Stacey.

MS. GERARD: You need to go over it again Daren, because we can't see what's up there, and be clear -- you said if you went to the left, Class 3 or 4, the answer is no, it sounded like you then went to the right. But I heard you say there's a choice for the operator. Is there a choice?

MR. MOORE: I'm going to -- if you want me to spend the time and walk through it, I'll be glad to do it. Very good. I intentionally stayed away from that, if we need it, I'll do it.

You start here -- I don't like these things, they make you look like you're really nervous. I'm just standing here guys, just talking. I'm a talking head. Start here, and you go down and the first question you ask is are you going to use class methodology or are you going to use the C-FER circle methodology? If you go circle, and right there it says, PIC circle and right there it says Class. Can't see it, I know, but that's what it says.

If you go down the PIC side -- if you choose to go down the class methodology, you go this way. Once you go down this line, you never come back over here. Okay? It's a true bifurcation. You go down this way, is it in Class 3 or 4? If the answer is yes, it is an HCA. If the answer is no, you define your circle. Is the circle greater than 300 feet or less than 660 feet? Now why would we ask that? The answer is we recognize that our existing data for identified sites, largely identified sites, and identified sites it actually expands on the class location definition currently in the regulation.

You only go out to 300 feet. I mentioned that a while ago. We have looked past 300 feet. This is a bonus plus, if you want to compare and contrast and see the delta, this is a big delta. You're getting more identified sites, bigger definition inside 300 feet, and you're collecting on whatever your circle size is outside. It's a big deal. Is it bigger than 300? Less than 660? I can't read it either guys. If the answer is no, then you ask if it's less than 1000. If the answer is no, then it's no HCA. If the answer is yes, you have to go to the language which we're after that has a D in it, and that shows you no HCA or

HCA depending on whether or not that's in there.

Coming back over here, at this point, if the answer is no, -- the answer is yes, I'm sorry. If the answer is yes, you've got identified sites inside the circle, the answer is yes, it's an HCA. And that identified site, again, goes beyond 300 feet if the PIC is bigger than 300 feet. If the answer is no, it's no HCA.

Now, come back over to the circles. You define your PIC size. Is the PIC less than 660 feet? If the answer is yes, are there 20 or more buildings inside the PIC? And if the answer is yes, you have an HCA. If the answer is no, you then ask the question, is there an -- just one -- identified site inside the circle. If the answer is no, there's no HCA. If the answer is yes, it is an HCA.

Okay, come back to the circle being less than 660 feet. If the answer is no, is the identified site inside the circle? This is where the circle is bigger than 660 feet. If the answer is yes, it's an HCA. If the answer is no, then we have a prorating idea here for SIHO to be related back to the area of the PIC to the radius of 660. What this does, and this is SIHO is a building -- Structure Intended for Human Occupancy -- it's a building. I'm mimicking the existing pipeline safety regulation and say SIHO. This is -- prorating is key.

Let me describe it for a moment. The idea is you have a circle of 660 foot radius, and we know what's inside that circle. We've been counting houses and looking for houses for years. If the PIC is greater than 660 in lieu of spending enormous resources and going out to whatever distance it may be beyond 660, 675 or 1200 feet, it would make some sense to prorate what you're looking for inside the 660 circle. In other words, if your area of your PIC is 1000 compared to 660, let's say that's a 3:2 ratio, you apply the 3:2 ratio to the 20 structures we've discussed, so if you had, let's say, 14 structures inside the existing 660 circle, then that would trigger the HCA. It's a way for operators to stay away from having to gather enormous data and misdirect resources.

MS. DAUGHERTY: I was going to ask, Daren, if that assumes that the houses are evenly distributed between that radius -- around that radius. The proration makes an assumption that they aren't all at the edge or --

MR. MOORE: There's a built in assumption there, Linda, and there comes a time in this analysis where we have to use the built in assumptions. We tried to make it simpler in the existing NPRM by going out to 300 or 660 or 1000 feet to the threshold radius and that's a massive assumption. This is a smaller assumption, but it is one.

Okay, I'll try to say this again. I probably didn't say it well because I wasn't planning on talking about it in detail so I didn't prepare myself real well for this. If you have a circle of 660 feet, you know the radius is 660. You know what your data is inside that circle because you've been gathering it for years. For that particular pipeline it has a PIC of let's say, 1000 feet. In lieu of the pipeline operator going out and spending a lot of effort gathering data from 660 to 1000, what the operator could do instead is to say okay, the ratio of the area -- let's say the area of the 1000 foot circle compared to the area of the 660 foot circle, let's just say 3:2. We agree that 20 structures is the number to use for the triggering of an HCA, right? So we'd apply 3 over 2 to 20 over something and that something would be, let's say, 14 houses. So if you had 14 houses inside the 660 circle, that would trigger the HCA, instead of the 20 houses triggering the HCA. I could go over there and scratch it on the board if you want me to.

MS. DAUGHERTY: I understand what you're

saying.

MR. MOORE: Okay, any other questions on that? That's how the flow chart would work for the INGAA-AGA proposal. Paul?

MR. WOOD: Paul Wood with CYCLA (ph). If I understand, though, the left hand branch, correct me, I'm accepting that this is a proposal, so if I understand, the left hand branch correctly, you're not dealing with anything less than 300 feet or between 660 and 1000, the way your diagram is put together?

MR. MOORE: The way the logic diagram is put together -- I put this together a few weeks ago, it winds up having, Paul, is that you look for identified sites, and the definition of identified site is bigger than just the regulation definition, we're going to be looking for more sites than what we already had inside 300 feet as well. That is a flaw in the flow chart because I did it a few weeks ago and we discussed at INGAA-AGA. There's a debate of whether you should look for identified sites all the way to your PIC radius regardless of prorating -- for identified sites, yes. There's an argument for that. Good point.

Moving on. Here's some examples of how the alternative proposal would work as opposed to what we just showed you on the NPRM. I have a yellow line right there, and that is the PIR for this particular pipe. This is going back to Duke Pipe, 30 inch, 1050 psig. In this case, you have an office building with 50 persons, it would be an HCA, and that is different from what the NPRM has. You have the licensed day care, 950 feet from the pipeline, it would not be an HCA now, and that is different from what the NPRM currently proposes.

Again, using the example we just saw, you can see that the lines drawn across where the PIRs were actually were used, on the left side, the 20 houses in 1000 feet would not be an HCA now because many of the houses are outside the PIC, and they would not be affected by a pipeline failure. On the right hand side, you have an inside the 660 thresholds and it wouldn't go out to 1000 feet under the NPRM and that would be an HCA, and that is different from the NPRM. Again, what we're trying to do is show consistency in application. All houses are equal. We're going to treat them that way. That's different from the way the NPRM treats houses. They have been treated separately depending on where the circle is and the threshold radius.

Third example, you see the line for the PIR, 20 houses in 1000 feet, is now not an HCA, and that is revised from the NPRM, that on this left hand side would be an HCA under the NPRM. Again, the right hand building of 50 persons, now would be an HCA under the industry proposal, and that would be revised from the NPRM which would not have that as an HCA. And the final example, on the left side you have Class 3 with say, 55 houses, and that is an HCA under both proposals if they're both within the PIC, and as it's drawn it is. On the right hand side, you have Class 2 with 35 houses and that would be an HCA. It would be a revision from the NPRM, so you're consistently applying the rule for the entire pipeline as opposed to mixing and matching and guessing and hoping you have your diamonds right and all that.

Okay, so let's close by contrasting the benefits for the industry's proposal. One, it examines every foot of pipeline for HCAs, every single foot, Class 1, 2, 3, and 4 gets examined under the industry proposal.

Two, it extensively uses data developed over 30 years to precisely examine land use for true HCAs. And it would do it in a manner that looks for both structures and identified sites.

Finally, it enables operators to evaluate the entire system for HCA on much higher resolution, regardless of plat. You're looking at a very high resolution way. This is much different from the hazardous liquid rule, and that's because the predictability of gas upon release is extremely, for lack of a better term, modelable. We have a model that pictures it very well and it's very predictable. We need to use that advantage if it makes sense, based on science. We use science, proven by field experience, to the greatest extent possible in the industry proposal. That's one of our over-arching goals in the industry, use science that's credible, and by showing that the model works in the real world, it's credible.

Second bullet, it treats all areas the same. In other words, 20 houses equals 20 houses, regardless of the class location. We need to offer additional protections to the places that need it. Places that have the density, and not mix and match and offer it -- well, these 20 houses yes, and sorry, those 20 houses, no. That's wrong. That's wrong. We need consistency.

Existing processes are maximized without the loss of pipeline safety. Go back to our five days a week instead of 50 days. It worked in the past, that process that all of our fuel guys are doing and gathering every single day and continuing into the future.

The focus, under the industry proposal is on inspections of pipelines. That's where the safety benefit comes from. It's not in identifying HCAs. It's on the inspections themselves. So the focus is on the inspections, hopefully would be. Hopefully wouldn't be on gathering large amounts of data to define the central HCAs -- grow on that and not throw out what we have.

Finally, the -- no, not finally -- the proposal is not confusing in application, pretty simple. We think the public can understand it. We think the regulatory community can understand it, federal and state, and we think operators can understand it. Big advantage. It addresses structures ... buildings through usage levels, not incident and frequently what will turn out to be intrusive data collection.

And it includes reasonable, and technically based portions of the existing NPRM and that's important. We need to recognize that the NPRM has a lot of good stuff in it. It just so happens -- and we're going to talk about several areas today where we agree on the NPRM. When we're talking about something this complex, we're talking about it in a day, there's a lot of good stuff there. Definitions of identified sites as modified by industry, and take away some of the very big ambiguities in it, makes a lot of sense. Class 3 and 4 for smaller operators makes a lot of sense. And 20 houses as applied in the system, makes a lot of sense as science has backed it up.

With the bifurcation approach in the industry proposal, the HCA definition permits an operator to largely use the final rule that came out in August, or, as an alternative, the left side of the flow chart you saw, on the right side, the operator could choose to intensively examine every circle of every foot, using the very best science we have at our fingertips today.

And finally, it permits focus to be on true HCAs while eliminating inconsistent applications. I think this provides us with what Rick mentioned as being -- being at clarity, we can understand it. I think it meets the goal of the public as we understand them today. It meets the goal of industry, and I think it meets the goals of the regulatory community. That concludes my presentation.

MS. DAUGHERTY: Could I ask some questions. Would the split approach -- would you envision an operator applying one branch of that equation to certain systems or certain lines, and the other approach to different areas of their system? In other words, one operator using both approaches?

MR. MOORE: I don't know on the same system, but just in different areas of the system?

MS. DAUGHERTY: Yes.

MR. MOORE: I think both methods on split path make technical sense, so an operator could use which one he chose. It would be difficult, I think, for the operator to explain why he chose one here and one there, and that's an inconsistency I think an operator needs to really address in his own thought process. But the technical basis is there.

MR. BARRETT: In choosing the 20 houses, why do you look at just taking the density that's already in the Class 3 location and moving that house per area density path in the smaller areas, because obviously it would take fewer houses to impact at that level. And 20 -- every 20 houses ...

MR. MOORE: To talk about the last part, you just mentioned, Zack, about you have a small radius circle due to a small diameter, small pressure, and go back to the slide I had at the start where the existing rule doesn't -- it penalizes small operators, operators of small pipes like that, because it goes out to 300 feet regardless, even though the circle may only be 50 feet or 100 feet, and they have to -- they're invariably being penalized. The circle itself, when you talk about we're wanting to offer additional protections applies across the board, because you're offering it to X people -- system of X people per area you're trying to protect. Stacey.

MS. GERARD: First a comment, just for clarification. Appreciate the consideration of consistent policy in the density question from liquid to gas. Point of clarification is that the 1000 people per square mile criteria for liquid is one of two criteria. The other criteria is the population in the census tract for other populated areas, which is about -- we don't know exactly how much more conservative, because it's not quantified per -- published per square mile, but it is considerably more conservative than 1000 people per square mile, which affected some of our considerations on the number 20. So it isn't really based on 1000 people per square mile. I just wanted to make that comment.

My question is there's a tremendous amount of work that's gone into this concept that you've proposed and really appreciate how much effort has gone into it on your part and everybody you work with, to come up with this proposal on behalf of so many pipeline operators. I wanted to be clear as to why you propose the bifurcation. I have a feeling there's several reasons behind the bifurcation, and I just wanted to be clear as to why. Because the issue of bifurcation, I think potentially could make it complex for us in terms of the administrative steps we would have to go through to favorably consider that proposal. So I want to be sure what the benefits are behind the bifurcation.

MR. MOORE: Number one reason, and Andy, jump in with number two if you want, whatever, that's fine. Number one, it allows different types of operators -- Dan talked earlier about ... INGAA companies -- about 28 INGAA companies. APGA has 600. AGA -- I'm sorry? 900. And AGA has about 200. These are all different size companies with all different pieces or amounts of technical data and computer systems and ability to evaluate different ways on their systems, especially APGA guys, my God. I've been educated a lot on that lately and how different they are from big transmission operators like myself. It's incredible. This approach allows them to credibly establish what their HCAs are without hauling in enormous amounts of effort going down circle path and they may not have the technology for it.

On the other side, it allows large operators who have the data in a database that they can get to, or if they want to use cellophane and slide it down an aerial view of their pipeline, they can do that too. It lets that operator use the very best science that they ... without bankrupting small guys. And that's our goal. Laurie, come up here.

MS. TRAYEEK: I'm Laurie Trayeek, I'm with the American Gas Association, and the reason that this is a particularly important point to us and actually also builds a little bit on Linda's question. Is that you need to understand that it is our belief that the choice of saying that all of your pipe is Class 3 and 4 is HCA is a very conservative choice, and it is only going to be made by an operator that does not have a lot of mileage that is transmission -- that does not have the kind of ability that Daren and Andy have suggested in terms of doing all of this analysis, or trying to determine exactly -- or wanting to do this calculation. So because of that, they are choosing to pay that amount of type and apply what the industry would consider would be a most conservative approach in deciding. Well, it's conservative -- that's really what Daren just established is that if you want to focus on consequence, then you want to look at the C-FER equation and you want to determine what the impact or consequence of what we establish as the criteria would be on that criteria, and that is where you should be focusing all your HCA enhancements. And if you're outside of that area, and you're not an identified site as we've talked about in a Class 1 or 2, though this applies to all, Class 1, 2, 3, and 4, then it's not necessary to add these enhancements.

So again, if an operator is going to choose to say that because of the limited mileage I have, because of the limited ability I have to do all of these calculations and all of this, I'm going to choose the most conservative, then they can make that choice, but again, we -- that's -- and that's why it's important, and it's important to have that flexibility, because an operator can have a system that operates in downtown Manhattan, but also operates is more less complicated areas outside of downtown Manhattan, and so it may make sense for downtown Manhattan for them to take that approach, but may not make sense to do it on segments outside of Manhattan. But the risk approaches all.

MR. MOORE: From the fact that they have less knowledge, shouldn't some of this analysis be useful for them to do? Since they have less knowledge, shouldn't some of this analysis be easier for them to do?

MS. TRAYEEK: It's just a matter of a resource issue and how they want to apply their resources, and if they want to choose to have a less -- take this more conservative approach to just say I will take this all as HCA, you're getting the same result from an inspection standpoint, you're getting a little bit more than maybe would be necessary if you applied -- so it's just a matter of how do you apply your resources and what's your best approach, and as long as the end game is still met, that flexibility helps the operator. Yes, it's the most cost effective way of getting to that same end game.

MR. MOORE: Bill?

MR. GUTE: I'm Bill Gute, Office of Pipeline Safety, and I guess I have a question. I might have missed something on the conservative and the C-FER approach. And I think when I was looking at the presentation there was a 30 inch pipeline at 1000 pounds, something like that, which is a 660 impact circle.

MR. MOORE: Yes, it was.

MR. GUTE: So the question I have, if you have a 36 inch pipeline at 1200 pounds, or something like that, and the impact circle goes beyond the 660, am I correct in saying that that's out of the picture now?

MR. MOORE: No, no.

MR. DRAKE: No.

MR. MOORE: Bill, the way it would work is let's say the 36 and 1200 has a radius of 1100 feet, just say that. That's your PIC. You would look on a prorated bases inside the 660 for however many houses -- that's going to be based on 10 or 12 houses. If you had 10 or 12 inside the 660, HCA. If you had identified sites inside the 660, HCA. And as Paul pointed out that maybe you want to look for identified sites on further out because that's not a proratable object.

MR. GUTE: I guess -- I think, my question, I can narrow it down. And maybe that's the one that Paul was asking it. Let's say you have no houses in the 660 and you have a hospital at 680, is that hospital covered?

MR. MOORE: Under Paul's question, the answer would be yes, because you look for identified sites now past 660.

MR. GUTE: So the proposal is it would look for those sites outside of the 660.

MR. MOORE: Bill, industry hasn't finished fine tuning that part of our proposal. We recognize that's something to debate in our community. Paul brought it out very well in his question, and it's something we've considered.

MR. GUTE: Okay, well, I think that is an issue that's absolutely --

MR. MOORE: We've identified it, Paul identified it, now you've identified it. We're all getting there. We're asking the right questions.

MR. GUTE: And I have one more question, I know it's getting near lunch here, but I've got to put Andy on the spot now. And I was just curious, I think this is a very interesting proposal, but you made a statement in your talk, whatever it was, --

MR. DRAKE: Whatever.

MR. GUTE: Whatever that was, I don't know. That under the proposed rule that we had that you would have to pig 80 percent of your compressor stations downstream compressor stations. I was curious if you had looked at, with the new circle approach across the entire system, do you have any idea --- would that be a reduction or would that be about the same? What would that turn out to be?

MR. DRAKE: When we look across the system, we pick up somewhere close to the same amount of the discharge sections. What you see -- and Daren hit on it, the population density distributions don't follow these 46 per mile evenly spaced out. Most of the people are in the certain parts of the country, and I think that's the value added is that if you want to cover those areas more intensively --

MR. GUTE: Yes, I agree with that, but if you say though, that --

MR. DRAKE: We trade some valve sections.

MR. GUTE: But it would still turn out to be about 80 percent?

MR. DRAKE: Well, I'm kind of hesitant here to kind of say a number because if I can't see the target --

MR. GUTE: We don't know what the definition is yet. We don't know --

MR. DRAKE: If I qualify it real heavily, if we use a number like 20 and if we use these -- some of these definitions to talk about sites, and yes, it's about the same. It moves it a little bit more, and I think you're a little bit more publicly credible, you're trying to find the people and address them, and that's the issue. But when the numbers move around, like if the number goes from 20 to ten, it goes to 100 percent of my discharges and now we're not focusing.

MR. GUTE: Okay, I just wanted that --

MR. DRAKE: So it's very volatile -- that number -- and that's why I'm kind of ... is that number is a very volatile issue. If you move that number around, it changes the hurdle a lot.

MR. GUTE: Well, it just struck me, though, that a circle would still cover a lot of valve sections because you're going to hit -- and basically you're agreeing with what I'm saying.

MR. DRAKE: Yes.

MR. GUTE: Yes, thank you.

MR. MOORE: Any other questions before -- I guess we're going to break for lunch at this point? Is that the idea?

MR. MOSINSKIS: I have a -- just an observation. I'm George Mosinskis with the American Gas Association, and as Daren said, we represent about -- exactly about 187 operators with mileage ranges -- with mileage in the transmission sector ranging from five miles to 5000 miles. Basically, what we're talking here is an added layer of protection over what already exists, correct?

MR. MOORE: That's correct.

MR. MOSINSKIS: There is in place at least --

MR. ISRANI: George --

MR. MOORE: Mike, you agree with that

statement?

MR. ISRANI: (off mike)

MR. MOORE: George, restate the question so OPS can answer the question.

MR. MOSINSKIS: Well, what I'm saying is that basically that what we're talking about here in t... is integrity management which is an added layer of protection from what already exists in terms of pipeline safety -- inspection, assessment, and integrity management.

MR. ISRANI: That part is true.

MR. MOSINSKIS: Okay, I just wanted to make sure that that is the case, and that we can identify at least 12 different special inspection procedures that take place, most of them, annually or even more frequently to maintain the health of the transmission pipelines, correct?

MR. ISRANI: That part is correct too.

MR. MOSINSKIS: Okay.

MR. ISRANI: Let me tell you one part I didn't think was correct. If we go either approach, what you heard from Daren right now, for the pipeline which have a very small impact circle, you will not find any pipeline that will fall under HCA definition. You cannot find 20 buildings even if you mount on top of each other -- four story and higher buildings, you cannot put buildings in a 100 foot circle, meaning you do not have any pipeline which is in on a HCA. So that was the point -- I can go through this entire and give 100 theoretical flaws there, but you know we are not here about battles, we are here to find some balanced approach.

MR. MOSINSKIS: I agree with you fully, Mike. That's all I wanted to ask.

MS. GERARD: Since Mike raised the question, I'd like to pose it as a question. If we were to consider the proposal on the right side of your chart, run the circle, and you've got a smaller pipeline that would have 100 foot, and you seem to have support for the policy of a consistent basis for number of houses, but realistically in that smaller zone, you obviously can't fit 20 houses. Would you -- since you're willing to take an approach to extrapolating from 660 out, would you consider an approach appropriate for extrapolating the lower side, downward, so that you would look for the same rate within 100 foot radius?

MR. MOORE: Stacey, I think that's a very good question, and Mike said 100 flaws, and perhaps that's one. I think the answer is best given by the states or perhaps by operators who are more affected by this, like our AGA members.

MR. KUPREWICZ: I just want to be sure you don't lose perspective here. I know it's easy to chase after these numbers and whether it's 20 or 15 or 25. Sounds like you guys got a workable solution. But from the perspective of the public interest, and I think I represent some of these corporations here, there's a point where the real issue is that if you're unsheltered or you're outside, you don't have much time, and if you're close up, you don't have much time. So as you get these smaller lines, building structures are less of an importance. We don't want to lose focus of that issue. I'm not saying if you're near one of these and your house burns down, that's one issue. But what you don't want to lose sight of is you've got playground that's right up against your right of way, and you lose a small diameter line, it still has tremendous ability to cause severe, serious casualties to those unsheltered individuals. So, to me, your defined sites is going to capture that trigger to bring in that additional scrutiny level and I wouldn't recommend -- or I would recommend not getting so overly focused on that building structure concept, because it becomes less of a -- the identified site is your real safety catcher for the areas of risk that I'd be looking at.

MR. MOORE: And Stacey, identified sites would still be looked for in those small circles as well. That's not off the table at all. And Rick, you're asking the right questions. Been doing it all day, and that's great stuff. We actually talk about different numbers of people, and if it's an outside area, because they're unprotected and may not be able to whatever, that the threshold is different than for those people who are more greatly protected inside a structure. That's in the proposal. I didn't talk about it, but it's in the proposal. And that will be filed in the docket comments.

MR. EASTMAN: Just a quick statement. First, I want to -- my name is Alan Eastman. I'm with Pacific Gas and Electric Company out on the west coast. We have about 6000 miles of transmission lines, Class 1 through Class 4. First I want to real quickly recognize Mike. I think he probably feels a little beat up at this point because of some of the statements that industry laid on that, and I think Mike did an admiral job of trying to define what is High Consequence and what is not.

First point I'd like to make, regardless of what is decided on the High Consequence Area definition, your comments, basically you want to add more geographical areas. Clearly you're going to add more safety just in terms of requiring inspections for those classes, in other words, Class 3, 4, the circle rule -- you know, geographic additions are one that are clearly going to require inspections. That's part of the whole process in improving public safety.

The second thing is I really support the scientific based impact circle rule, and maybe from a little different angle. Maybe kind of go on to what you were talking about. When you sit across the table from a permitting agency and you tell them that you need to tear up the new roadway that they just laid -- and I just got through having this conversation with the county of Santa Clara last week. I need something real defensible that I can show them that, hey, you've got folks -- first off, they did not accept that there's a federal law. There are some people really smart out there. I was pretty amazed that they brought up the C-FER rule to me. Great. Love it. We can talk about that. But I need something very defensible that I can say, okay, there is going to be an impact in this particular area soon, potential impact if an incident occurs because of this calculation. I think that's a scientific based approach that is defensible that will carry weight with public permitting agencies.

Then I think there's other permitting agencies that aren't as smart, and there are smaller operators that can just cut to the chase and go ahead and do their 50 miles Class 3, 4 and accomplish that added safety margin which you'd like to have.

So I guess I just wanted to make a statement that I really support the scientific basis, and I really believe down the road, if you look out into the future, one of your goals is to get more operators to get more risk management programs, and more risk assessment knowledge -- it's going to happen because more and more permitting agencies are going to say, wait a minute. Time out. Why do you need to tear up that roadway? Why do you need to drill every ten feet? Why do you need to replace those valves? I'm not convinced that's going to improve the safety of that line.

So, just in support of what Daren talked about, and also in support of what Mike talked about, I think it's doable, I think we can come together and if we get people focused in the right areas.

MR. MOORE: Thank you.

MS. GERARD: When we were making introductions earlier, we did not have in the room

Linda Lasley (ph) I wanted to introduce. She is with the Department's General Counsel, and Linda's here anticipating that this rule is actually going to be packaged as a final rule and come for clearance, and so we appreciate her being here in the Department to get the background to make it easier for her to consider this. It's an awful lot of technical information and if you don't live and breathe -- and even if you live and breathe pipelines, it's very technical. Imagine if you don't and you have to review this. So we appreciate her being here.

MR. MOORE: Any questions before I sit down and let Stacey have the floor back?

MR. ISRANI: I would say that since we have -- we had one comment from Rick, and then we should take lunch break and we have other items on the agenda.

MS. DAUGHERTY: I just wanted to make a comment before we go to lunch, we may lose some people, please keep in mind, any of you that are shy and don't want to stand up and ask questions, that you can always send in comments to the docket and we will consider those. We encourage you to do that.

Bon appetit.

MR. ISRANI: Right now it's ten after 12, so we can get back here by ten after one?

(Whereupon, at 12:10 p.m., the hearing was recessed, to reconvene at 1:10 p.m., this same day, Friday, March 14, 2003.)

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

1:20 p.m.

MS. GERARD: ... lingering out there in the hallway. Yes, before starting up the afternoon session, there's somebody in the room who was not introduced this morning properly, who should have been, and that's Sherry Pappas is sitting towards the back of the room, and she is Mike's co-author or partner. Sherry, could you raise your hand? Sherry is with RSPA Legal Counsel, and also who has joined us is the RSPA Chief Counsel, Elaine Joost who came just at the end of the morning session, but I'm sure we're going to make it worth your while for the afternoon session, Elaine.

So most people, I think, are back in their seats and we'll start up and I think we're going to make a slight adjustment in the agenda to call up Jim Anderson because I think his presentation flows nicely from -- just following the morning presentations.

MR. ANDERSON: Okay, let's see if we can stumble through this. I was in the office Friday and Anne Marie Joseph, the Office of Pipeline Safety, is my -- old days it would be pen pals. I guess telephone pals, me being the NAPSR Chair, I'm talking to her about three or four times a week. She knew I was in the office and she sends me an e-mail and says you're going to the public meeting aren't you? And I said yes. She said would you like to be a speaker? I wrote back in enlargement, "NO". She sends me back an e-mail stating, it would be nice if you spoke. Your time is late that afternoon. So we got it about 3:15, I figured I'd have about 12 people in the audience to talk to on Friday afternoon in Washington.

So we're going to be talking about state regulators. I am the Director of the Pipeline Safety Section at the North Carolina Utility Commission, and I'm just a plain and simple guy. My presentation's going to be plain and simple.

In addition to this integrity management that we are looking at, the 800 pound gorilla here, we also are operating and we still regulate our operators for Part 192. And I told Stacey yesterday, I feel like I'm going to a buffet with a saucer and everything else is just getting overloaded, overloaded and overloaded. But after I make this PowerPoint presentation and I'm probably going to do it again at a SEGA -- it'll be the second time I've ever done one. So if you all will just kind of bear with me on this.

The thoughts on this are mine. I got some people to help me put it together so it would make me look good, and help me get through here.

Now looking at a High Consequence Area, what came first? the pipeline or the houses? You know, if you're an intra-state operator, chances are this pipeline was built possibly 30-something years ago when there was no such thing as a HCA. All of a sudden, just like in real estate -- location, location, location drives everything. So all of a sudden, I don't know if they did a great horizontal directional drill through the back of these houses to get that pipeline through there, or was the pipeline there and the developer thought he could get some land and just put the houses there, which he probably did.

This is a Piedmont Natural Gas, one of the operators in North Carolina. I said hey, I need a picture of something or other, and this is what they helped me with. I think that kind of drives what we're really talking about right now. We were talking earlier, and I make the point that listening to the other speakers up here, they were talking 30 inch, 36 inch, 42 inch pipe -- very rarely did they get down to the 18, 12, 10 -- you know, that's what the intra-state operators have. And chances are, most of the intra-state operators, their pipelines are one way feeds. They're from really the main transmission line to where the load is, and anything comes beside it, they'll just put a T in there and go on.

So when you get down here to our in line inspections or going in here and pressure testing or direct assessment, which we don't know what it is yet, we're going to have a lot of concerns in everything. So when I got up here and I was talking to Mr. Director who's not here and I said, what's that going to cost you all when you all do all this stuff? He said, a lot. I said, you're going to pass it on to the investor utilities to pass on to rate payers aren't you? He said, probably.

So it's all going to filter down to where I'm working with the state people in North Carolina, and the utility commission, not only do we look at safety, we look at operation and rates, and Mr. Mike Wilkins is one of the Commissioners was at the ... meeting in February. He got wind of the pipeline safety reauthorization act session, went in there. He came back and talked to me. He said, get our operators in here. I'm concerned on what this is going to do to us.

So have meetings sitting in April, I'm bringing in my intra-state transmission people and I will say I've had the opportunity to work in Kansas, Oklahoma, and now North Carolina in pipeline safety regulation, and I know I've got some of my Oklahoma people here that I worked with before, but I'm really proud of my North Carolina people. I've been working with them for ten or 11 years, and we try to work together. It's not a butting heads. When this thing came out I called them and said, how are we going to approach this? I try to use it as a partnership method instead of me just telling, telling, and telling.

Because when I try to put this thing together and looking at it -- I'm going to put a PowerPoint here like I said, so I had meetings and trying to get all this. They helped me out and I'm going to go through this.

The intra-state lines -- this is North Carolina. This is Transco -- we've got some of those Williams people back here. That corridor there has got four interstate pipelines in it. I believe there's a 30 -- two 30's, a 36 and a 42 inch. And this is wide as it can, it's going right up there and it crosses 577, 95 and so forth, going on up into Virginia. Now those people there, they're set up for pigs to run it through there, to test and look and everything else.

For example, this line of North Carolina Natural Gas Line 1 is a 16-inch line that's got a compressor station out here at junction A. It kind of takes off and goes up there and feeds like Fayetteville on over here to Greenville, Washington, and so forth. Those are like ten or 12 inch lines. So they operate different. Their SMYS is different, and anytime that you have a dig-in and you had to go in there and do something to it and put a newer fitting in there, if you did have a place to pig, you might have made it mess up because it won't -- a smart pig will not be allowed to go through where a fitting was. So we going to change our complexity there.

Transco, our four lines here -- we have a Cardinal pipeline which is part of the Williams and Transco operation, and they feed the Raleigh area, but this is North Carolina Natural Gas. Down here you've got two lines going parallel. We do have one line that's 30 inches, and it goes from over here to the Transco takeoff to Hamlet. That's a 30 inch line but it also fuels five generating plants.

Now when you're getting into gas and electricity -- and the gas company's trying to buy electric companies now so they can bring gas where they want to for the generation and so forth, we've got down there -- used to, in the summertime when you was a gas operator, you might take a line down for a while to do repairs and so forth. But nowadays you can't do that any more. Now you're having a peak season in the winter for heating, now you've got a peak coming down here to generate electricity so you're caught short on some of this stuff. So what do you do?

You know, we're going to look at direct assessment, which right now the only thing I've seen is NACE and there's more acronyms than a show dog can jump over in this little deal anyway, that we're going to be looking at. And I'm going to bring that up too. Like I say, I'm afraid I'm going to embarrass myself up here and I won't -- everybody's going to laugh at me, but if I do good Stacey might ask me to do it again. So I'm kind of in trouble right now.

I used to run the gas system here in Pitt County, the Greenville Utility Commission. It's just a municipal -- it's pretty large. It's got about 17,000 customers, but we're talking about transmission lines. These two lines from Greenville over here to Little Washington, one of them's a four and one of them's a three. You're out here in what could be a Class 1 or 2 location, but nowadays in the intra-state operation, you're going to have more little rural churches going out here and putting their lots here close to your pipeline, it's going to change you from a possible Class 2 to a Class 3, but luckily our guys are pretty smart. They kind of design everything Class 3 just in case it comes up that way. Or it would not have been an HCA until now you've got more than 20 people or 50 people coming in there so many times a year that you're going to have to go in there and do some more testing.

I get the annual reports from our operators and right now we have 2789 miles of transmission lines. Now that's anywhere from a two inch line up to a 30 inch line, and if you get right down to it, and after talking with OPS yesterday, being Chair of NAPSR, I talked with Stacey on some NAPSR issues and kind went into a little bit of this. I wish I could have done a little bit more detail and come up with a percentage of what might be two or less than four inch, less than six inch, or less than eight inch. They might have a SMYS range anywhere from a 20 percent SMYS up to a 40 percent SMYS. These are intra-state lines. These are the ones that -- that come to Jim. We've got a 192 Jim there in Raleigh. I deal with all those people on the pipelines.

Now looking at the Code -- alright, after we go in and do our assessment, we're going to go in there and we're going to take our project over here on his risk assessment project that I think is very nice -- we're going to come in there and look and everything, then we're going to come in here -- we're going to direct assess this, which we're trying to work on a definition for right now.

Or we're going to do an inline inspection, which is smart pigs. Now we really can't do that on a lot of our pipeline. We've got a lot of 90 degree deals. We've got a lot of one way feeds. We've got a lot of pipeline put in before '94 when the codes said that you had to make everything piggable. So we can maybe scratch out that one on some of this stuff.

If you're going to hydrostatically test it, like you maybe get under new construction you're going to might have to take it out of service. No can do. We're kind of caught short there too.

So a lot of us are going back to what if -- to a direct assessment, and we don't know what that is right now. The only thing I've heard is, what?, it's external corrosion direct assessment. Well, we also use the terminology, a close interval survey, or do we need ... rectifiers up so we can get it from a negative .9 to a negative 1.3 or something or other? But to make sure that we get some off the bottom?

Alright, now looking at -- oh, there's really a two over there. We've got 2,789 miles of transmission lines -- slide me over?

PARTICIPANT: I don't think it's going to work.

MR. ANDERSON: Oh, man. But we've got 2,789 miles of transmission. Now looking at the way the intra-state operators operate, a lot of those are in Class 3 and Class 4 locations. So talking with my operators, you know, I said we might have 75 percent Class in our HCAs by the time -- But if I have 75 percent because of this, if you look at it, if you even want to try to pig it, if you find your HCA, when you did construct that line you've got a place to have a pig launcher or a receiver, you may be 20 miles down the road and although you've already done a risk assessment, you're pigging 20 miles to come up with your 1000 feet in here, and the cost gets astronomical. And that's going to be passed to my rate payers.

So then we're going to have 2092 miles in the integrity management program. You take our percentage of that, you're going to come up with 348 miles a year at an estimate cost of $10-15,000 a mile, that comes up to be about three and a half million to a little over five million dollars a year that our operators in North Carolina are going to endure to be passed on to our rate payers. Just for DA.

Now, if you opened up the USA Today yesterday, no actually day before yesterday, first thing you saw in the money issue was this guy here -- he's actually ... oil, but the thing he says, "It was a winter from hell" -- Long Island New York -- "says retired executive McFardle (ph)." His gas bill was $425 -- you know, 107 percent above what it was last year. So if you're going to add the cost of gas when you're out here purchasing, the overhead cost in February was double digits. Last year it wasn't double digits, now the price of gas is astronomical. And if we're going to add all this on to it, and with the recession in the economy -- we're rural in North Carolina, you know. We lost all of our furniture plants, we lost all of our textiles overseas, and everything, so -- and my state's broke.

Alright, so we're going to do an inline inspection. We've still got our 2789 miles and we've still got our 75 percent. Alright, so looking at this, to meet our ten year criteria, it's going to be something like 232 miles a year at a cost of $25-30,000 a mile, it's going to be a little over $5.8 million to almost $7 million a year that will be passed on to the rate payers.

Same principle here if we're going to use a pressure test -- we're going to hydrostatically test the pipeline. Looks like it's going to add up to be approximately $7 to a little over $8 million dollars a year that's going to be passed on.

Now, I'm all for safety, don't get me wrong. I've been in the business since 1979. As I said, I started out as an inspector, two program managers, as I said, I raised the IQ of two states then I come on in here.

Now these are some of the issues that we've got in here on the piggability. You know, someone said, we're going to pig. But you don't have a SnapOn tool that you can go ahead and snap on a pig launcher and a receiver. You know, you've got this stuff here that you're going to come in here and do this. Alright. Some of the bivalves that you put in and you operate in, they're not full open. You can't run a pig through things like that. Our L's and T's in there -- all this stuff hurts intra-state operators, especially when we're down in the four, six, eight, and maybe ten inch pipelines, and then if you ever had a damage and you had to go in there and stop it off, you left your ... fitting on there, you can't run anything in there anyway, although it was piggable when you did it, if somebody happen to give a D-9 locator out there and hit your pipeline, you came in there to redo it, you then stopped your ability to pig it.

Then if you come in here and you're going to do your hydrostatic testing, or you've got your environmental people out here won't let you dump water anywhere any more. You know you're out here looking for places for this. Then you've got your hydrocarbons in here and then you're blowing down and into purging of everything.

Cost versus risk benefit. Now this is something a poor boy from Arkansas, you know, we'd like to make sure he spends his money wisely. Now, looking at the costs I had a while ago, and like I said, my operators in North Carolina, they're good operators. If we're going to be spending eight million a year, or five million a year and over a ten year period, you're up to here to about $50-80 million dollars, that's a lot of money. I want to make sure that we get our bang for our buck. You know, if we come up here and do a risk analysis up here, and you might have a correlation -- you have a point zero up here to about ten, you do your risk analysis and you maybe somewhere in the three or two, according to whatever engineering specifications you're going to come up with.

Well, if I'm up there at a two, knowing I can't get to zero -- I know the gentleman said he can go to zero -- that might be our target, but there is some risk here. If I'm at two, then I need to come down to one or one and a half, I might not need to spend $8 million over ten years to get down there. But if I do a risk assessment and I'm way out here at eight or nine, I do need to spend that money to come back down here to make sure I'm right.

And that's what I want to make sure we do. I want to tell Stacey, you know on your risk reduction and your cost, I told them if I was Secretary Mineta and I'm going to tell my wife I'm going to go out and buy myself one of these HUM-V IIs to make sure they can get from where they are downtown Washington -- that might get you there. But if you then take that motor out and put a six cylinder in there and make sure you don't go too fast. And then you take it down to Jeff Gordon at NASCAR and put that head and neck restraint in there, and add that on in case you do get hit your head won't get shoved around. So it's going to cost you $75,000 to get to work, when you used to get on the metro for four, or whatever. So we're looking at a lot of money here, and are we getting our bang for our buck?

MR. EASTMAN: I think Andy has met his match.

(Laughter, applause.)

MR. ANDERSON: But I think I'm telling you the truth here for what I'm talking about. Everybody's shaking their heads.

Alright, now this has already been beaten to death today. You know, everybody talked about you're coming up here with your potential impact ways, the zones. You know, with your small diameter, you might get your 20 percent SMYS and whatever going up there, become a transmission line.

Looking at a six inch, and I just picked this out here -- you know, you've got a six inch with MAOP of 600 pounds -- they're all over the country for intra-state operators. You're Potential Impact Radius would be like 102 feet. Well, we've got to move it up to 300 so we can encompass some more people in there. There's our radiuses we're working with. You've got to round it up to the next highest.

Alright, we've got -- we're going to talk about this as being complex. Like I said, I'm just kind of plain and simple, and I'm struggling through this along with my other duties. I know we've got a year to come up with this, and hopefully -- I know there's lots more people in this room than me that can come up and figure this out and help us understand it and meet our objectives.

But we've got HCAs. We've got MRAs, CBAs, PIZs, PIRs -- like I said, we've got a lot of acronyms here that we've got to learn to deal with. You've got your formula. You've got your intervals here, what you're going to use, what timeframe you're going to use it in. And then you've got to go in there and retest it. What if you just built the line three years ago? Do you have to go in there and retest it again? Those are just questions that people come up with.

Concerns. Now I'm the program manager and I have four really good guys that work for me, but we're not PE's. These guys that I have working for me all worked in the gas business before. One of them worked for me in Greenville, one worked for a contractor, and two worked for an LDC in the state, and I hired them away.

Now I'm going to be leaning on OPS really hard to get this thing down to we can understand it, so we can go out and talk to my operators. And then we're going to have to make sure our operators are trained. Then I'm going to make sure that if I go out there and tell them they're right or wrong, they will understand if I told them they were right or wrong if I knew they were right or wrong. So that's why we're looking at that.

Then we've got some -- let's get some

guidelines down here that are realistic. We had some flow charts up here a while ago that were pretty complex, you know. I was pretty close to them, and I still couldn't understand them. We've got to get them down to the intra-state inspector's level that we can understand it, that we can go out there and talk to these people. And then, we've all talked about regulative clarification. Let's get this thing down to where we can understand it, basic terms, and meet our goals.

Now in our talk yesterday, when I was at OPS, -- and this is just common sense. You know, you've got a four inch pipeline operating at 20, 22 percent SMYS, it comes under this category. Now operators may end up saying, hey, if we just drop our MAOP 50 pounds or whatever, operating pressure, we're going to be at 19.9, and I think that's going to be the goal that you might want to achieve that you don't come underneath this. Well, will they still be able to meet the load demands on the other end if they reduce the operating pressure and so forth? And then all of a sudden, you can drop in five or ten pounds and it'll save you $30,000 a year for this five mile line that meets this criteria, chances are you're going to try to do it. Are we looking at something like that?

Maybe we can look at the definition of a transmission line. You know, my company a while ago, they entertained maybe 30 percent SMYS or whatever, let's get a correlation here. Maybe a small diameter, a higher SMYS, and maybe a four inch up to a 40 percent SMYS, a six inch up to 35, and eight inch up to 30 -- just have a little scale here.

If you're writing prescriptive rules, I guess you can get as prescriptive as you want. We've gone anywhere from prescriptive regulations, we've gone to performance regulations, and when you get into OP-2, which is taking up the other part of my memory bank on the other side right now, you're looking at process regulations. I'm regulated to death right now and just because I'm Chair of NAPSR, like I said, that don't mean I know everything.

So, that's my presentation -- tell me what this means so we can get up here and operate it. So, like I said, I'm Jim Anderson and I will entertain some questions. I can't guarantee I'll answer what you need, but I think we might have some intra-state operators in the room that we can enlist their help on. I just hope I made sense here.

(inaudible participant comment)

MR. ANDERSON: You're going to invite me back now. Thank you very much.

(Applause.)

MR. ISRANI: Okay, we are running one hour and 20 minutes behind time, so I'll try to cut down on my slides and stress only the key issues that I want to clarify in our proposed rule.

Since in the morning session we resolved issues on High Consequence Areas, so now we can go on in all those High Consequence Areas, what kind of integrity management requirements we are proposing. On January 28th we issued the proposed rule which asked the operators to develop their integrity management program and follow that in the High Consequence Areas. That proposed rule applies only to gas transmission pipelines which fall under the definition of Part 192 as currently states. No gathering lines, no distribution lines are covered in this proposed rule, and we are not looking at them at this stage.

These are the elements of an integrity management program that form the framework of your entire program that all operators will have to develop and follow. All those elements, one by one, are explained in the proposed rule. But I want to point the key things here.

That identification of High Consequence Area, developing IMP framework, and developing a plan is due 12 months after the final rule. And the last elements, from the management of change, communication plan, environmental and safety risk during assessment have been produced as a result of Pipeline Safety Improvement Act 2002 which specifies these things.

In the integrity management proposed rule, we are explaining all these elements. We are also giving cross reference to ASME B31.8S -- S stands for supplement. We tried to use as much as possible from the ASME standard B31.8. We have given reference to various sections and we have put some exceptions where we have. NACE standard wasn't developed -- NACE standard is for the direct assessment for external corrosion. This standard was in development and it got published after our proposed rule was already in OMB, the Office of Management and Budget. And we are considering using NACE standard as much as possible because we have used the language from the NACE standard for the direct assessment in our proposed rule.

Select Assessment Technology. After operators identify their High Consequence Areas, they identify the segments which affect the High Consequence Areas. They will determine the threats of each segment, all kind of threats, and based on the threats, they'll determine what technology to use -- whether to use smart pig, pressure testing, direct assessment or other technology which is -- could be under development or currently being demonstrated or proposed. But we are ready to look at any of this new technology.

Direct assessment as currently we understand is good for external corrosion, and the standard, the NACE standard, as I said, got published recently. We are still working on the internal corrosion standard, and stress corrosion cracking. I'm not sure if -- no, it's still under development or being planned here. So we have given some specific requirements for all of these. We have given reference to ASME's standard and also plagiarized some of the language from the draft -- from the details.

What is direct assessment? It's an integrity assessment method which utilizes the process to evaluate certain threats. Certain threats meaning we can look at external corrosion. We can use this process to check for internal corrosion and stress corrosion cracking. And we are not allowing direct assessment across the board. We are putting some conditions on it because it is a fairly new technology for us. And also it has not been used as much as assessment methods, so we are allowing direct assessment when other assessment methods cannot be applied. This is an example like Jim mentioned, when there are -- the last segments of the pipeline when they are sole source suppliers and there are not loops and cross connections available to the pipeline -- that situation. Or when there's a substantial impact on the consumers. If it so happens that operators find that it will really affect their communities and have drastic impact financially, those are the conditions. And also when operators have the pipeline which operates at less than 30 percent SMYS, we are allowing them to use direct assessment. And when the operators are going to excavate the entire segment. And here we are concentrating on small pipeline segments like cross connections or small length of pipelines where they excavate and examine the pipeline.

ECDA Region. When we day direct assessment and then for example it is being used for the external corrosion threat, the very first thing operators will be doing is for the entire pipeline, they'll be looking at this -- how to group it, how to have segments which can be grouped together to minimize going through the process again. They will look for ones of similar individual characteristics, similar operating and corrosion history, and other risk factors so that they can group those segments and then use a table that we have proposed in the rule or now in the -- we use the tables -- where they come from the NACE draft standard. Those tables will tell them for those kinds of segments what kind of direct assessment tools are suitable. So they'll determine what kind of direct assessment tools they can use, complementary tools they can use. So that will expedite the process for them and minimize -- they don't have to go through the whole process over and over again.

After the operators have grouped their ECDA regions -- external corrosion direct assessment regions -- for each and every region, we have defined -- this is just an illustration, an example, how operator will determine which region will need more excavation than others. And they will go on each and every region and use this external corrosion direct assessment device, look at the indications when they run over the pipeline. If there are -- this is just for illustration purposes only.

If the person who's doing the external corrosion direct assessment finds a pipeline segment that they have maximum indication, you know, the needle swings quite wide and they see a lot more of those in one region, that's a bad sign. That's a critical zone. These are called severe conditions -- severe indications, and that requires immediate action. And we have indicated in the direct assessment proposed rule that they will excavate all those indications. And this is for each ECDA region.

If you have some moderate indications -- and these things can be determined. These veritable positions of what are moderate, what are high indications or minor indications -- only experts who are running the tool can tell you, can decide, because they consider their tolerance limits and what indication is severe. So based on their best judgement and experience, they'll be able to tell you which is a severe indication. Excavate all of those indications here; and we require two high risk indications excavations in this portion of a segment; and here minor indications, we require only one excavation. This is just an illustration of how operator would go about their region, and how they determine excavation criteria.

This graph -- this chart I threw in there because just to give you the same example, what we are looking at. This dark one indicates the close interval survey -- you can read close interval survey and the next one here, this is from the DCVG -- direct current voltage gradient. This is the most commonly used direct assessment tool that operators use when they go below the surface and they look for their indications, for the coating ... coating damage or ... in the coating. And these are indications of what they find under the coating. You can notice in the close interval survey also they notice there was some drop here in the reading, .85 voltage here.

And the bottom chart shows the smart pig data. So you can see even the smart pig gives you an indication of these very high indications. This is just a relatively -- showing you the -- it's comparing the direct assessment with the smart pig data results, and we have a verification program going on where we want them to chart like this so that we can verify direct assessment is a valid process. That is still going on.

So if you notice, the indications on direct assessment, you are getting in the area where you are also finding on smart pig, indications of corrosion. And in the areas where you have some minor indications from your reader, the smart pig did not determine anything to be there.

Ed Arntag (ph) who was involved in the

process of validation, he had picked up this chart from one of the validation process that we are going through, and he picked up from some industry, so he's the one who provided me with it. This was from the -- yes, yes, the Gas Technology Institute and OPS. We had funded the program to validate the data and we have about 20 operators who are participating in this program, and we wanted them to chart the data of the smart pig results with the direct assessment so we can have more confidence in the direct assessment tools are working.

This was just showing this chart, I'm going to explain you in general what direct assessment they're talking about.

Another that Jim -- what is CDA. We are using this as a confirmatory direct assessment. Confirmatory direct assessment is a valued technique which we want to use to confirm the condition of the pipeline in an interim period. What I'm saying is that if you are using smart pig or you're using your direct assessment or pressure testing, whichever methods. Now you have finished your baseline with that. Your reassessment period, as we have scheduled this on the corrosion ... and as ASME standard required, was ten years period for a pipeline which was over 50 percent

SMYS, and we had 15 years time period for pipeline which are below 50 percent SMYS.

But then came the Act -- the Pipeline Safety Act of 2002, which required us, all operators, to have reassessment done every seven years. That will be things of confirmatory direct assessment would meet the legislation, and also we think would meet our goals. So with confirmatory direct assessment, you are measuring -- it's a streamlined version of the direct assessment. It's still a valid technique to do this, but the requirements for confirmatory direct assessment are not as stringent as we have for the direct assessment.

Some of the examples are like this. We are allowing you in the confirmatory direct assessment to use one tool. Direct assessment requires you to use two different complementary tools and compare results, whereas here we require you use one tool. We require excavation in immediate areas. We require only one indication in that scheduled area. No excavation in the monitored indications. Now here, in the ... seems like a small matter, but if you run longer in the pipeline it matters a lot, because you're doing one half of much less excavations and it's a direct savings there.

The law requires that the starting date for assessment begins from December 17, 2002. Our final rule is not out yet. And operators which are using smart pig and the pressure testing have to complete their baseline within ten years, as the proposal called for. And 50 percent of the pipeline needs to be finished in the first five years. Moderate Risk Area are given the extended timeframe, because we feel the Moderate Risk Area have less impact than the High Consequence Area.

But operators using direct assessment need a shorter timeframe. As I told you earlier, we are still in the process of validating this method. We want to have full confidence before we allow direct assessment to be equivalent to smart pigging and other for determining the condition of the pipeline using extended period. So we are allowing them a baseline period of seven years that they must complete the baseline, and 50 percent must be completed in the four years.

PARTICIPANT: Is that seven years from --

MR. ISRANI: All the date starts --

PARTICIPANT: Six year after you come up with the rule.

MR. ISRANI: Yes, that's true. We have

really lost a year. Because your clock starts from the time the President signs the bill, so that was December 17, 2002. The longer we take to assure the rule, the less time you'll have to finish the test.

I wanted to mention the prior assessments. We are allowing prior assessments going back five years, and that's required by the law. We are going back to the date, then, December 17, 1997. From then on we consider if you're done baseline, if you want to group that in the baseline.

Actions to address -- after you have run the baseline assessment, you have to mitigate all anomalies that you find and the conditions which are immediate have to be done right away. You have 180 day remediations and you have longer than 180 day remediations. Here we reference ASME B31.8S standard which has given you good tables and everything how to follow.

Preventive and mitigative measures. Just -- only assessment is not enough for measuring the integrity of the pipeline or try to figure out the integrity of the pipeline. You have to take the mitigative measures as well. And we have given some examples of our preventive and mitigative measures like emergency shutoff valves, or remote control valves, your computerized monitoring detection system, extensive inspection and maintenance as well. But ASME B31.8S has a lot more details on the preventive and mitigative measures that we have given reference to.

Reassessment period, as I said, the law requires you to have every seven years reassessment after the baseline. So after the baseline I said. I did not say segment, facility, other things -- that's a different issue.

Our current rule proposal says that if you are done pressure testing and ILI your maximum interval is ten years for reassessment and 15 years for those pipelines which operate at less than 50 percent SMYS. But the -- since the law requires seven years, regarding the confirmatory direct assessment, which I was telling you that in between you can do that to meet the law. And for the direct assessment, they want only dig samples of the defects, that you are to do every five years, or where they dig all their samples that they indicated, they have ten years to do that?

And no integrity is complete unless we can measure the performance. So we have in this rule, giving reference to ASME B31.8 for all the performance measures, there are four overall performance measures that we want operators to have arrangement that we can have access to that, and also the state. So we can monitor those real time.

And those four performance measures are here: The miles assessed versus program requirements; number of immediate repairs; and number of scheduled repairs; and number of leaks, failures and incidents.

And why we are doing this is because we want to prioritize our inspections. We want to see companies if they're falling behind schedule, we want to see how immediate repairs are being done, and we can see what we are influencing by this rulemaking is working. If the leaks are increasing or remaining the same or decreasing, it'll give us a good measure of performance.

I put this slide in to point out that in the preamble of the rule we do have some pointers there that we want public comments, and these are the major issues that are affected by ... law. The question is whether rural buildings, like rural churches et cetera, be designated as Moderate Risk Area instead of currently as we have them as HCA. And if they are Moderate Risk Area then we just require preventive mitigative measures. We ask the question. So we are encouraging industry people, public, anybody to give comments on this issue so we can come up with the right answer.

And we also have a comment -- we ask the public to comment on should the 20 year reassessment period be allowed for pipeline which is below 30 percent SMYS? Right now, pipeline operating below 30 percent SMYS has ... has impact zones not that high. Currently ASME standard also allows 20 year. We'd like to go to 20 year period if we see good justification from the comments.

And the same thing for the reassessment. We ask the question. NACE standard for DA -- we ask the question whether we adopt NACE standard directly or we have some minor requirements there in addition to NACE standard, so whether we should keep those exceptions. OPS wants public to give their comments on so we can determine, because we think that there's effect in this required law.

And finally, our milestones. We are scheduled to complete the rule by December 17, 2003, and mapping ... is being worked on and we should have it on time sometime this summer -- and other rules we already published. And with that, I close my presentation. Should we have industry give talk and then we ask for comments together? Okay.

(comment off mike)

MR. ISRANI: Okay, we are ready for questions on integrity management requirements final rule.

MR. BOSS: I want to make a couple clarifications. There is a -- the law is silent on giving credit for inspections before 12/17. So it's silent on that point, and the baseline for DA processes -- hydro and also the ILIs, ten years is in the law versus seven years.

MS. TRAYEEK: And I had a question for Jim, before you leave, just a clarification. Because on the slide that you presented, where you made the assumption that most of the miles there will probably have to use direct assessment, and you showed what kind of costs that you were looking at, that was based on a ten year baseline and a seven year reinspection?

MR. ANDERSON: Yes. Also, what I would like to do, if I'm invited back, is get a correlation of the diameter of pipe and the MAOP ...

MS. TRAYEEK: And just to clarify that Mike, what you presented, is the DA under the proposed rule would have to be done on a four year, for the first -- would have to be done on a seven year baseline, right, not a ten year baseline? Because that would certainly affect the cost impact --

MR. ANDERSON: Right.

MS. TRAYEEK: -- that you presented.

MR. ANDERSON: Also one other item ... since this is such a big -- you know, a lot of interest in here, might want to make another subpart. You know, you've got a subpart for OP, you might want to have a subpart just to fit it by itself for integrity management that would be set up there. It may be a separate subpart, just integrity management, instead of just tying it in to your maintenance section of subpart 1.

MS. SCHLEGEL: I have a question. Judy Schlegel from Oklahoma Natural Gas. It says baseline can be used only for other tools are applicable. By what standards do you say they are applicable? Does that mean because you don't have pig launchers, or would you say, well for 50,000, put a pig launcher in? What's the basis for not applicable?

MR. ISRANI: I mentioned four conditions under which direct assessment is acceptable. One was that if you had segments of pipeline -- if you have pipeline which is sole source, which doesn't have any of these loop lines or cross connections to other pipelines where product can be delivered while you're doing your assessment, that's one condition. Other one was like if you have a big economic impact on the communities because of using the smart pig or pressure testing and you are disruption of the supply, that's another reason. Small portion of the pipeline, you could use. And the third one is the pipeline ... less than 30 percent SMYS, you can use.

I also heard Terry Boss mention that the currently law allows direct assessment as one of the methods to be used in this.

MR. DRAKE: We need to take a break? Why don't we take a five minute break and let everybody kind of stretch their legs out, because we're probably going to be up on this panel for an hour and a half. Five minutes?

(Whereupon, a ten minute recess off the record was taken.)

MR. DRAKE: I have the dubious honor of being the chairman of the INGAA Pipeline Safety Committee and the Gas Industry Integrity Initiative. I think -- yet before you here, kind of a dubious distinction of probably having the most dense collection of metallurgists in our industry right in front of you. So that's kind of -- well, it's back to that HCA thing, you know. This is a pretty dense -- yeah, if you get three or four metallurgists at one table, that's really scary, you know. So watch out. They'll start talking about jakers (ph) and fracture mechanics and it gets really weird here by afternoon.

I'm going to talk about the overlap of the baseline and the reassessment period and the issues that we have around that. And we have several other presentations, and I'll try to get through in pretty short order with a brief comment period behind each one, and then we'll try to wrap up and take questions and answers actually in between each one, and again at the end. So we'll try to keep this open as much as we can.

As far as the overlap of the baseline and reassessment period goes, sure may appreciate Barbara Betsock's position this morning, and where the DOT sits. As far as where we are, we spend a great deal of time on the Hill, working with the House and Senate members about how to shape this law. I think where we're stuck right now is more of a throughput and legal issue than it is a technical issue.

On a system impact standpoint, when you overlap the baseline inspections with the reinspections, you start taking out large blocks of the system simultaneously. That's very, very significant when you consider how that affects capacity, especially in light of the summer load issue that Jim Anderson brought up, and when you consider price volatility of gas.

The issue around definitions, we think we're slipping mostly around the definition of facility, that the DOT is taking a definition of a work facility as meaning a specific site. Whereas, when we talked in the House and Congress -- the House -- their interpretation of facility was the system. That is significantly different. Fundamentally, that's where I think we're slipping on each other right now.

The Patel report and the ASME B31.8 document provide a technical foundation that show very clearly that once you're done with the baseline inspections and you mediate the findings, per these technical guidelines, the interval is way beyond these numbers. It's not a technical issue. We have to comply with the law. But I just want to make sure that the group is clear. The problem is not a physical problem. The problem is the issue about the law, and the issue about impact on throughput. And those need to be the drivers in sorting this out.

The overlie of the baseline and the reassessment period -- Congress deliberated on this explicitly at great length during the -- when they drafted the legislation. A couple weeks ago, February in Houston, second workshop on integrity management, Graham Hill stood up and walked through this at great length, and it's noted in the OPS notes. Matter of fact, somewhere here -- this is an RSPA document number. It records the transactions at that workshop. And when you read a quote summarizing what he said, "Graham Hill does not think the reassessment period begins until after the baseline period." Period. That was a direct question asked of the man. That's what he said. So I think when you talk about what the law says, and what its intentions are, we may need to go back to the legislative process and ask them for clarification. Because fundamentally, they took that into consideration in the development of the law.

You look at some of Tozan's (ph) office staff made a press release following one of the bills' releases and they said "All pipelines would be reinspected every seven years following the ten year interval." That was the thinking of the legislature when they were developing this law. If there's not a clarity in the law to reflect that, we need to go back and revisit it.

But the primary driver here -- I think when you look at the overlap, you look at the EEA report that was put together by INGAA and AGA to try to reflect what is the impact on throughput and price of gas to the customers on different intervals. You start to see that in the baseline period, what you find is you have the most extensive outages for facility modifications. It seems to make sense. You have the most extensive load on the service industry as they gear up. That seems to make some sense. You have the most extensive outages for remediation. Duke Energy and a couple of other operators have a great deal of inline inspection history behind them. Typcially what we're finding is that historical inspection data indicates that you find an order of magnitude more actionable anomalies in the baseline inspection, the first inspection, than you do on reinspection intervals. I see most of the operators shaking thier heads yes. That is a very important, fundamental concept to understand.

The way the baseline period will roll out, very likely, is you will have people that can pig -- they'll pig right away. No facility modifications. You'll get some system interruptions and you'll have some remediation issues. The people that can't pig will have system outages to make the systems modified to accommodate pigs and do the isnpections. They will then come down again very shortly to do -- when the log runs come back to them -- to make immediate repairs, and then they will schedule the following year or years the scheduled inspections. So those systems would be coming down two or three times to accommodate the baseline inspection efforts. And that is very fundamentally important, in how much the facilities are going to be coming down during the baseline period.

The baseline represents a huge block of capacity interruption, because you're changing from where you are now to a different place, and as you change, you're going to have significant outages just to make those deltas happen. Yes, of course.

MS. GERARD: I believe the EEA report is part of the docket?

MR. DRAKE: Yes.

MS. GERARD: Do you have one on?

MR. DRAKE: I have one on here and I will file it to whomever you want me to hand it to.

MS. GERARD: I just want to ask one question. Did the EEA report in the estimates, consider modification, testing, and repair -- all three of them -- quantified the effect in calculating the estimates?

MR. DRAKE: Terry can talk about that.

MR. BOSS: The EEA report simplified the process by lining up all those times together, say example, for pigging, a pipeline will be out a total of 30 days. What Andy is emphasizing is that it may be out 15 days the first time, another ten days the next time, another five days. They don't neceessarily occur all the way. The other thing the EEA report did assume was that it was perfect information, and perfect cooperation between all the companies when they're doing this, wherever they need to coordinate it. And we are excluded from doing that from a competitive purpose because of the marketing rules that we're operating under. So it assumes best case scenario that everybody knew what the other guy was doing and was doing it at the right time.

MR. DRAKE: It also did not consider the magnitude of repairs necessary. We discounted that as basically a fundamental obligation on behalf of the system, but it does impact outage.

MS. GERARD: Are you making corrections to those estimates to consider that it was only based on perfect scenario? Are you doing any modifications to that estimate?

MR. DRAKE: I don't think they're going to redo the report. I think all that we had intended to do is perhaps provide a paper qualifying that, we can put on the docket as an attachment to it. But the report took a year to develop. I don't think we're going to try to gerrymander the report at this point.

MR. BOSS: It is very difficult to make some of these broad, and the HCA definition has probably changed about six times since we ran the original report, so we keep trying to hit a moving target on what we're talking about.

MR. DRAKE: Well, that's a fundamental concept that needs to be preserved here, is we took a best guess shot, based on 31.8, of what we thought the scope of this thing was, and we based the report on those fundamental precepts or assumptions. Some of the assumptions, we're seeing here, and some you're going to hear about are radically outside the assumptions that were inside that model, and they will change very significantly the amount of pipe that's out, the amount of length the pipes are out, and the cost impact of the rule. And those are all -- but like Terry said, we're trying to hit a moving target, even still today.

I think the take away here is that the resulting supply interruptions and the price volatility for the customer are exponential. Many of us that understand commodities trading, understand that those that watch California understand that. When you're dealing with taking a certain block of the infrastructure out, let's say ten percent is just kind of a guide number, a very idealistic number. It discounts the whole sequencing of outages from one year to the next -- let's say ten percent of something. It's just a number. You have a ten percent system capacity outage, what you see in the overlap is that you start looking at overlapping -- if you look at the reassessment intervals, are one every seven years, that's basically 14 percent a year. When you're looking at the baseline, you're looking at a ten year period, so you have one-tenth, ten percent.

But when you start the reinspection interval while the baseline is still occurring, you're in essence starting to interfere capacity on up to 20-24 percent of the system a year, for three years in a row. That is very dangerous. Very dangerous. It is not -- that was not the intent of Congress. We talked about this at length with them.

The concern here is that these numbers don't mean that ten percent of the system is going to be out for the year, it means that ten percent of those facilities will be out for some period during the year. But price volatility reacts exponentially as the system capacity diminishes. And as that number doubles, the price volatility, and the cost go exponential. This is just basic economics and price demand curves.

The point being, when you go from ten to twenty, it's not twice as much impact, it's four times as much impact. So our cost per year goes from an estimated $300 million dollars total estimated, to somewhere around $900 to a billion dollars, when you do that, during those three years. This is very significant. This is very significant. I can't believe the FERC representatives aren't somewhere up on the ceilign right now.

MS. GERARD: Point of clarification. When you say your cost goes up, are you talking about cost of operations or cost of gas to the consumer?

MR. DRAKE: Both. Both. We discount the cost of making the repairs, period. It is not included in our model, or any discussions that we're having here. Mostly we're talking about the price of gas to the customer, because of the availability on the stock market. We all remember things like -- well, look at the current market today. Jim Anderson -- New York -- the stock price of gas is 10. We're not even dealing with the HCA issue or the integrity rule right now, and the stock price of gas is $10 or more dollars in some places. California -- okay -- when you squeeze the capacity just a little bit, price volatility doesn't react linearly, and that's an important concept to keep in mind here.

This is what we think Congress intended to do -- this ten percent per year through the baseline, and then start the reassessment once the baseline of the system is done. Again, it's fundamental to the word facility.

We'd like to talk about what the baseline implies. There is a great deal of previous information that's out there. We don't want to see that information discounted. I don't think you do either. The current rule is very vague about that, and even kind of shuts out some of the data. The baseline implies that this is the first inspection ever. That's not the case in many places. Operators, a lot of operators, hvae inspection data prior to 2003, and the operators shoudl not be -- those that have been proactively inspecting, should not be penalized, because there's a lot of inspection data out there before 2003 and before 1997, or whatever the other date is. You want to try to encourage the bringing of that data into the system.

This is an example of perhaps how you could view a penalty. If someone had, down at the bottom, an inspection that was prior to 1997, let's say, under the rule that inspection is discounted. They're not allowed to consider it. They're obligated to inspect during the baseline period. And if they actually count the baseline -- if they actually count that baseline inspection, they could be obligated to inspect that section, even though it's been inspected and remediated very early in the baseline period, which doesn't make any sense at all. In actuality, the operator is almost better off completely discounting the old inspection data, completely not acknowledging that it ever existed, and just ranking the system as a low priority system and scheduling it way out to the end of the baseline period. That way they don't have to do three inspections -- two or three inspections prior to getting to that inspection.

We know that's not the intent, it's just some of the mechanics that are at work here. We need to try to straighten out some of those mechanics.

Consideration of previous inspection data -- the reinspections are technically defined by the Patel (ph) report. They are also defined by the ASME guidelines, the national consensus standards, and it's a function of the testing vehicle, the types of accuracy, the repair criteria, the system corrections, the effectiveness of modifications of system controls, and the operating stress level. All those things need to be, as they are in the Patel report and ASME, rolled into some sort of integral -- integrally combined together to make an educated and scientifically-based decision on when to schedule a reinspection.

The use of confirmatory direct assessment during the baseline period, which is 2003-2012, as a reassessment tool and a process control verification are technically founded. They're done by operators and have been done by operators for quite a while. And they're essential for lines that have already -- have a baseline section that wasn't done in accordance with B31.8S and we want to try to encourage the use of that old data. And we fully support CDA and we think it's a viable tool to minimize the load during the baseline period, which is all important in the net out to the customer.

Back to Jim Anderson's point. We want to do what makes sense here. If you've already inspected and you've already fixed it, certainly that information is useful and you want to encourage the incorporation of that data into the decision.

This slide just illustrates the point of going back and using the old data, using the Patel, using ASME to integrate that old data regardless of when it was done. You want to use that and bring it forward to make an educated decision about how to and when to reinspect the pipeline.

In summary, we think it's critical that you eliminate the overlap of the baseline and the reassessments to minimize the impact on throughput between 2003 and 2012 due to the magnitude of the baseline effort. We think that the legislature -- that was explicitly discussed with the legislature, and we think that they explicitly took that into consideration, and it needs to be clarified, even if we have to go back to the legislature and ask them for a special discussion and even a paper on their intent.

We want to encourage the use of previous inspection data, including data from multiple prior inspections, irrespective of when it was conducted. There's a whole host of information out there, older than 2003, and older than 1997, that you want to encourage the incorporation and use of. It should be used in conjunction with the Patel report, the B31.8 report, and CDA done during the baseline period to minimize the impact during the baseline period.

We think that the performance venue also offers a viable avenue here to lower the impact during the baseline period, and it should be accessible immediately for those with sufficient data. It shoudl not be pursued recklessly. It shoudl be done on some sort of clear, technically-based criteria. And it needs that clear, technical-based criteria to be shored up in order to execute against it for ourselves, for the regulating community, and for the confidence of the public.

That closes my presentation. And with that, we will turn it over -- you want to take questions now? We can handle a few questions now and then -- yes.

MS. GERARD: On your last comment, were you actually proposing or putting on the docket alternative proposed, clear criteria for access to the performance approach?

MR. DRAKE: I think we want to include that in our proposal, yes. That thing works like state of the art, don't serve any of us, and some of the things that were referred to in the preamble as state of the art, aren't really that important to the decision of the integrity of the pipe. GIS systems are not germane to how healthy the pipe is. That's just how healthy you are -- how fast you can make decisions about information. And I think those things need to be ferreted out.

MR. ISRANI: I'd like to start, for the panel, the question about reassessment. Language of the law, I would like our Chief Counsel's office to clarify for you when the reassessment process begins. That's not my area. But the reason for safety was the concern also why reassessment be here, on those segments which are done earlier, begins when those segments are completed at the baseline. The law requires, and the current proposal regulation requires that 50 percent of the highest risk pipelines to be done in the first five years. And those are the segments which Andy's talking about will see an overlap. And the reason they were picked up in the first five years is because those are risky ... that is based on all the data that you have collected. And just because you don't want assessment and fix those anomalies, doesn't mean that risk is -- the risk never stops. This is a continuous process.

If you had threats there, problems before, you might have problems again. And that's the reason why the reassessment period is decided on. I thought evading the law, what the law requires, and what ... is, but this is the concept that people with the safety look at. This was just a comment to explain why we took the approach also.

MR. DRAKE: I would offer counterpoint that the ASME and B31.8S documents, as well as the Patel report clearly show that once you remediate the baseline findings, the interval numbers we're talking about at seven are extraordinarily conservative. Extraordinarily conservative. And I think we all know that in our minds, and when you just think that these pipes have existed for years, all of a sudden, there's an urgency to not only get out and inspect it, which we believe for the baseline period, but now there's an inordinate need to come back again and very quickly -- we agree that we need to come back, but I don't know what the urgency is. I think there needs to be a counterbalancing of the issue about throughput and technology weighing in here.

MR. SHER: Andy, I have a question. If hypothetically you had already smart pigged an entire system, are you suggesting then that when the baseline period starts, that's when you would start your seven year reevaluation on that system? Or would you wait ten years from now to start the reassessment of that system that you had already smart pigged?

MR. DRAKE: I think that you've got a pass through that phase test here -- that's why I keep saying you've got to integrate the B31.8S document and its repair criteria and how long those intervals can actually technically be. The criteria in the Patel report and the date that was inspected -- I mean if it was inspected 1986, that's a long time ago. It adds value, but certainly the value is diminishing, and I think we need to start -- you may have to schedule that reinspection very promptly inside the baseline. But I think for the most part we're saying that anything past -- older than 2003 needs to be reinspected, reassessed during the baseline period. You're trying to figure out when is really all you're trying to do.

MR. SHER: I guess for the record, I'm Phil Sher of Connecticut. And then a question for Mike. Mike, you just added on something that I wasn't sure I understood, and I'll ask you to clarify. Are you saying if you already smart pigged and you found problems and you fixed them, that's an area that's of very concern because you might have new problems in that area? that becomes one of the more sensitive areas to put in the first half?

MR. ISRANI: I'm saying that your risk of threats is not one. There are so many threats on the pipeline, and if one segment of the pipeline, or a certain area or section of the pipeline you have considered yourself to be this schemed up to do in the first five years, then those are the areas we think need more concentration, even though you may have initially done the tests, found some anomalies, fixed things. If there was corrosion from some external sources, you're not changing the soil around it. You're not changing the conditions ... or anything in the ground. You still have those. So the same things can again attack the pipeline.

MR. DRAKE: Doesn't it depend on what you find or what the reason for the anomaly is? I mean if the anomaly was the original construction, that's not going to happen again in the future --

MR. ISRANI: And that we have one time requirement test.

MR. DRAKE: So you would have to evaluate why you have the anomalies. You can't just automatically assume they're going to repeat. They may or may not.

MR. ISRANI: But that's the meaning of anomaly. There are some anomalies which are time-dependent, some which are time independent.

MR. DRAKE: I think Graham Hill addressed this issue very clearly at least in the meaning on the workshop there, and I really encourage you to go back and review his presentation points, because he was very clear in saying that it's important that the DOT not be micromanaged here, that they try to follow the intent, but that they also use their head. If during the baseline inspection significant issues are found, the DOT may require, and they have those tools currently available to them, to specify the reinspection interval. They can mandate it. And the operators have the obligation to do it.

But instead, what we're doing is we're just assuming that everything is a massive problem, and we're just closing it down. And in doing that, you're going to create significant capacity issues in years 8, 9, and 10. Just for no added value on safety.

If there aren't any other questions, I'm going to turn the podium over to Alan Eastman and he'll talk about direct assessment. One last point, I will be filing on the docket, a copy of ASME B31.8S for the record. I will be filing a copy of the EEA report for the record. And there was one more -- the Patel report, the DTI report on interval ... for the record.

MR. EASTMAN: Good afternoon. Moving on. My name is Alan Eastman. I'm with Pacific Gas and Electric Company. I didn't put my title up there, Andy, because that and two cents doesn't buy you a cup of coffee. I'm the manager of the system integrity group located out in Walnut Creek, California. And as

I said earlier, we have roughly 6000 miles of transmission pipeline.

I'm here to talk about direct assessment. And I might just start this out with saying that in general, industry concurs with OPS on the use of direct assessment and confirmatory direct assessment basically in the same principle and context that they wrote in to the NPRM. What we're going to offer today is some points of clarification and some suggestions to possibly improve the wording so we can have consistent application out there in the industry.

We're going to talk about four basic things. We're going to provide some general comments on direct assessment, and some specific comments on each of the direct assessment techniques that are in various stages of development. We're going to suggest some necessary enhancements to the wording of the rule. We're going to talk a little bit about confirmatory direct assessment, but we aren't planning on getting into any real technical discussions. Maybe if there's questions during the Q&A period, we can try to field those. And then we're going to talk about a product that we intend to provide with our formal, written comments to the rule, and it's a product that's going to have a comparison between the DA language in the NPRM versus what's currently in industry consensus standards, the NACE 0502 and the B31.8S.

In general, we do believe that direct assessment is very pivotal in our operators' integrity assessment program, especially for those pipelines, as Jim mentioned, -- he picked on me, so I'll pick on him -- that present huge challenges for other techniques, challenges that might range from economic impacts to impacting customers and significantly impacting the environment.

Jim threw some numbers up there and I don't want to talk out of place, a lot of the cost estimates, the benefits and the costs that were derived a year or so ago from AGA and INGAA were well done. Where we stand currently with our company, is direct assessment is running us about $28,000 per mile. We have a pretty structured formal process. In comparison, some of those lines that we're using direct assessment on -- we're looking at $250,000 per mile to retrofit those lines for pigging, and that's not considering the cost of impacting the environment or impacting the customer. That's just the retrofit costs.

One last comment that I wanted to make on the pigging of a lot of those lines that Jim mentioned, just getting the pressure differentials to move that device three to five miles an hour along those systems is basically not doable as our systems are currently designed. We definitely are supportive of direct assessment. We are supportive of their being a formal structured, auditable process.

We also feel that the baseline time period and the reassessment intervals in the NPRM containing the direct assessment need to be the same as the other assessment methods offer, such as ILI and hydrotesting.

There's some remediation language in the NPRM that seems to be somewhat -- a little inconsistent with even the general remediation methods mentioned in the same rule. And we have a few suggestions for that.

Terminology, as we've all talked today, terminology needs to be consistent, we especially think in the direct assessment area. Needs to be consistent with industry consensus standards that are already issued like B31.8S, and the NACE standard.

There is some research that's continuing on some of the DA processes, like ICDA and SCCDA, and we want to continue encouraging to work together with the regulators for all of us to understand what those are doing for us.

Specific comments regarding external corrosion direct assessment. Mike had mentioned this.

The rule should, to the degree practicable, reference the NACE consensus standard O502 that's already been issued. It does a good job of laying the framework for how an operator is supposed to conduct his assessment. All ECDA wording that is not adding value in the NPRM, or might add confusion in terms of duplication of wording, should be removed, and we recommend that it either be referenced directly to NACE standard or as you see in this last bullet, B31.8S is basically revised to reference the NACE standard, so however we choose to do it, we recommend that the language be cleaned up and aligned well. And again, the baseline assessment period and the reassessment intervals need to be consistent with the other assessment methodologies.

Internal corrosion direct assessment research is underway in a standards group called TG 293. The scope is very similar to what's already been published with ECDA. It's going to be a structured, formalized process to insure consistency and quality, and one last thing, auditability.

Part, by the way, for those that don't -- maybe don't -- aren't fully understanding of what DA is, one of the key first steps of the DA process is to collect all the necessary data to answer the question, is it feasible or not to use that tool, that methodology to address the threat that's been determined to be on the pipeline. So again, that's a very important part of the DA process.

And then the plan is to go ahead and modify B31.8S to incorporate that by reference.

Stress corrosion cracking direct assessment. There's a group, 273, that's presently developing a standard that will address the process to be used for direct assessment of stress corrosion cracking. Similar types of wording, the thing is going to produce a structured process, it's rigid, it's formal and auditable. It'll provide guidance to operators -- are conditions worth stress corrosion cracking threats exist and how to find that threat. And then the B31.8S document will be modified in some form. I think right now the understanding is that it may be modified either by reference or as an appendix.

Confirmatory direct assessment. The pipeline industry does support confirmatory direct assessment for -- as a process for the reassessment period. We definitely feel it's going to add value in pipeline integrity and pipeline safety. And actually some value for us in reliability of those pipelines. Basically, life extension of those pipelines. We don't want to pig and pig and pig and just keep letting the corrosion process occur. You want to do something to address the threat in a preventative manner, and confirmatory direct assessment will definitely add value there. It is anticipated that the CDA methodology will be embedded into the B31.8S standard.

So in summary, again, this is envisioned to be a short comment type of presentation, we definitely feel that direct assessment processes are essential, especially under certain conditions. The NPRM language that's currently there is not bad. I think you guys did a pretty good job. We do have some suggestions that we think could bring clarification, and we agree that the confirmatory direct assessment process is critical in moving forward.

The one thing that we -- we weren't prepared to go through this word by word, line by line. We intend to give a draft copy, I believe, before leaving today. We're putting together a product, cross reference table, that's going to compare specific sections in the NPRM relative to the wording around DA, and what complementary standards in the industry -- how they address it, and then we're just going to be real specific about what we recommend. Whether or not we recommend the NPRM wording to be left as is, as you see on the bottom two lines of this comparison, or whether we have some wording that we want to suggest and recommend that would add additional clarity. This is just one page out of that product.

So maybe I made up some time for Andy. Are there any questions? Yes, Stacey.

MS. GERARD: Mike, you need to correct me here, but as I recall there were three specific questions we asked in the preamble where we, on purpose, departed from what we thought the NACE standard was going to be by way of enhancements, and we asked the specific question about whether the enhancements we suggested were worth the cost for the benefit that we thought. And maybe, Mike, you could drill down on those.

MR. ISRANI: I mentioned during my presentation that we have used the language from the NACE draft standard as much as possible. NACE -- we call it a standard, but it's a recommended practice. It has the language, sometimes, which cannot be enforced. So we had to modify some wording there to make it enforceable.

But the key differences that we found, that we had, are the one where the immediate indication are. What we added was to reduce the pressure 20 percent until all excavations are completed, which was not in the current standard, but it was being discussed there.

The second one was scheduled indication. We say that -- NACE standard also say that continue excavation until you find -- you continue excavation until you find that there are no more anomalies there. There we put a factor that until you find the corrosion depth is less than 20 percent SMYS. In fact we just put some numbers there to determine which is okay or not, from an enforcement point of view.

And third was the excavation one in a most suspect area. We use the term most suspect area, based on your risk data, instead of what NACE says, randomly, one. Because one area where you want to excavate.

So these are some minor differences, not too much, and as I say, some of the language that we have modified because NACE is a recommended practice where they use language which is not, sometimes, enforceable.

And we did put in the preamble, a question asking public to comment whether we should just adopt NACE standard as is, or retain our additional exceptions there. So we encourage the public to comment on that.

MR. EASTMAN: I'd like to make a comment, Mike, on your three issues and then invite the audience to -- or somebody else who would like to comment. The NACE standard, you're correct, as written, is not prescriptive enough for any auditor or any operator to take to the table and say we're meeting this. They can take it to the table and say we're meeting, in principle, the requirements in the NACE standard. The additional language that you added in the NPRM, while I believe a lot of it is good, still doesn't do that. It still doesn't tell an operator what an immediate indication is. It doesn't tell an operator what a severe close interval survey indication is. And how do you integrate that in with ECDG indications?

I'm a firm believer that every operator needs to have that as a procedure, that can be audited. I can go on record that on behalf of PG&E -- I don't know about all the operators, I think they would agree -- we're going to address the specific issues in that table that we provide you about things like pressure reduction. While I know the thought is well meaning, I do not agree that pressure reduction should occur until all immediate indications are excavated.

The process of DA requires for you to be very conservative in the initial integration of your data. One of the reasons that you do a direct examination, which is a third step of the process, is to validate your criterion for that particular pipeline, that particular coating, and that particular environment. It's very likely that an operator would say, hey, I've got five immediate indications, and I'm going to start excavating them. It's very likely they will not find any deleterious corrosion such as that would require a pressure reduction ...

So until such time that you validate your criterion, as an example, those kinds of language -- that kind of language in the rule, I think, is misleading and I think it will lead to inappropriate pressure reductions. There will be times where we do find things that we need to reduce pressure until we can continue excavating all the immediates. I agree with that. But the process is set up, properly applied, to deal with those case by case issues.

So we will provide comments in that table on how we suggest we address that, and it will be consistent with the other remediation requirements. I just ask that you consider them in how that process works. Okay, thanks.

MR. GUSTILLO: Good afternoon. My name is Paul Gustillo with American Gas Association. I just want to be on record first that I am not a metallurgist, so please don't weigh on me as a dense person. You'll have to figure out who the other two Andy was talking about.

I'm going to talk about low stress pipelines. You've heard a lot referred to low stress pipelines today. I'll be very brief. I have only about five slides. I just have got to go over some key points. Two slides on key points.

Low stress is generally operating at or below 30 percent SMYS. This is recognized in the docket. Mike referenced that in one of the questions OPS is asking. For low stress pipelines, and again, backing up a second, most of the LBC operators, LBC transmission operators you're hearing about, have such pipelines. Almost 50 percent of the LBC transmission lines operate below 30 percent SMYS.

The second bullet I have here, the process is the same, no matter what stress level pipe you are. For a transmission line, you follow the same integrity management process even if it was a 72 percent SMYS pipeline. The difference is in the assessment techniques and method that's schedules, like Jim Anderson referred to. These pipelines -- they need flexibility. You need to put your resources where you need them.

Third point, OPS does recognize that the failure modes are different for low stress pipelines. They leak versus rupture, and it justifies different assessment methods. This is all in the NPRM, in the preamble, and we support that. The option to utilize the PIZ tabulations is appropriate for low stress pipelines. I think Jim referenced some pipelines in his state, but overall, 50 percent of the LDC transmission lines are below ten inches. This is based on the 2000 and 2001 transmission annual reports. So that's a lot of miles.

And then, just to make sure people understand. Even though there are low stress pipelines, there are going to be some that are going to be inline inspected. There are going to be some that are pressure tested, and a whole lot that are going to be assessed with direct assessment. But these operators of these low stress pipelines do need the flexibility to choose other methods so that they can put the resources where they're due.

And also I mentioned service continuity. We saw the picture that Jim Anderson put up of the operator in North Carolina.

That's all I have, and this is really -- this is kind of where we are with low stress pipelines. I guess we have 30 days to do all this. The first and foremost is to refine the HCA definition. You heard a lot about the PIZ calculation. That definitely has a big impact for low stress pipelines. Your circles are smaller. I think -- I don't know if Jim referenced, but looking at -- a lot of the pipes are below ten inches. Six inch pipe at 150 pounds, you've got a PIR of 50 feet. Typical transmission line in a distribution system. Eight inch line, 200 pounds, you've got a PIR of 78 feet. Ten inch line, 300 pounds, you've got a PIR of 120 feet. This is either assuming like X42 pipe. So they're pretty small radiuses. So we want to refine the HCA definition first. And I guess these are parallel paths.

We want to evaluate the CDA process, from the low stress pipelines perspective. Maybe there's appropriate language we could put in the CDA -- into what CDA means in the ASME B31.8S in the proposed rule and so forth, that might be appropriate for low stress lines.

And then we want to develop some specific preventative and mitigative measures by threat. There are some out there. You know, ASME B31.8S and the whole table on preventive and mitigative measures. They are general, so we are going to try to see if we can come up with more specific measures, by threat. If corrosion is your threat, will enhanced CP monitoring get you there? If you have a remote monitoring system where you can just call up a CP test station anytime of the day and get your readings, would that count?

So we're going to develop these three areas, and then as we develop these, we will respond to the -- I believe in the NPRM there are four specific questions relating to low stress pipelines regarding the assessment intervals, how CDA is applied, what direct assessment is applied and so forth. So this is kind of our action plan. Very general. We will provide more specifics on this to the docket. Any questions? Yes.

MS. GERARD: Is that the option that was presented earlier by the joint industry proposal?

MR. GUSTILLO: Yes, that's the two options that Daren presented was one, we go down the strict Class 3 and 4 definition, which a lot of LDC operators may end up choosing. And the other option is yes, the strict pure circle option.

MS. GERARD: So what you're saying in that bullet is that you want to be able to reduce the size of the zone for the calculation proportionate to the --

MR. GUSTILLO: Stress level of the pipe, yes. Do you have any questions? Thank you.

MR. JOHNSON: Good afternoon. I'm Dave

Johnson with INRA (ph) Transportation Services Company. I'm vice president of pipeline safety there. And Jim talked, when he first spoke this morning, talked about how he got elected to the chairmanship. I got this speaker's spot in much the same way. I left a meeting for a little bit, came back and had my name next to this presentation. So I understand how that goes.

We're going to address, talk for a few minutes here, and I do have a few more slides than some of my colleagues up here, with a couple topics, but I know everybody's getting tired and wants to go, so we'll probably get through this pretty quickly.

There are a few issues about dents and third party damage that we do want to address, and the approach that we want to take on these are to first review the proposed requirements, talk about the risk factors and detection issues and outline the challenges inherent in meeting these requirements, and then talk about some recommendations that we will flush out further in more formal comments.

As we go through this, we do want to note, and want you to keep in mind that the fact that a condition exists is not exactly synonymous with a threat. There are some nuances of differences there, so please keep that in mind as we go through this.

We saw this slide earlier this morning, but it's some very good information. It points out a number of things. One is that not all threats to pipelines are equal or equivalent or are having the same impact on the safety and integrity of pipelines. This kind of information can help us determine where the greatest opportunities for improvement are and once we choose to address one of them, then we can try to select the appropriate actions and techniques for it.

And you will see that third party damage is right up there at the top, and if you look at the red part of the bar is on the pipe portion of the system. That's kind of what we're going to focus on. And as you go down towards the -- farther down, the previously damaged pipe, we believe, is a pretty fair representation of the delayed third party failures, where third party damage has occurred some time in the past and failed subsequently, as opposed to failing at the time the damage is incurred. And then dents, we believe, are a subset but by no mean the entire category of the construction and installation defects. We really don't have the granularity of data to sort everything out exactly, but that's kind of where these fit.

So we're going to talk about the dents

portion first. The proposed rule has these requirements: immediate repair for dents with metal loss, cracking or stress risers and other remediation for six percent dents on pipe body and two percent on welds. There's some other requirements, more detail in there, but that's basically it. You compare that to B31.8S requirements and they look kind of similar, but there are some differences down at the bottom. Again, immediate on dents with gouges and scheduled at something under a year for the six percent and two percent, and 31.8S also had dents with cracks and mechanical damage in that. We'll come back to that.

The risk factors -- and this bears a little bit of examination. We think that plain pipe body dents and I think our experience shows us this, are not much of a risk under most operating conditions. If we look at the bottom half dents, bottom half of the pipe, they're generally constrained and stable. That's some of the construction type things: there's a rock in the back fill in the bottom of the ditch, you have the weight of the pipe plus the overburden backfill holding it there. It's not moving, it's not flexing, it's not doing anything. Chances are, it's been hydrotested. It's not going to go anywhere.

Top half dents are maybe a little different story. Those are certainly less constrained or could be considered unrestrained, or unconstrained. They probably do have fairly long fatigue lines. They're certainly more of an integrity issue if they're accompanied by mechanical damage, and with operating conditions changing, we do have a complete study underway that we think will bear on this, to help provide some guidance into the seriousness of these things.

Dents on welds, which are also covered in here may be more susceptible to fatigue, depending on the microstructure and material properties -- I gave myself away. I'm one of the metallurgists. Yes, thanks, Andy. And dents with cracks or gouges are subject to unpredictable failure. We don't have the means to characterize the nature of that damage and the material properties well enough to be able to say this thing will last X number of days, weeks, years, cycles. So we know the severity, of course, depends on the depth of the crack or the gouge. These things we believe, need prompt investigation or mediation, regardless of where we find them on the pipe.

Now, how do we find them? With some difficulty. Geometry pigs -- well, in line inspection -- there's essentially two kinds of pigs that we use --

geometry pigs and MFL pigs. The geometry pigs are unlikely to see the seam welds, neither the double submerged arc welds or the ERW welds. May sometimes see the GSAW (ph) welds, because of the weld bead. There's generally no feature on the ERW welds that the geometry pig will pick up. They also can't see mechanical damage per se. They can see some deformation, but they are incapable of determining the cause of that deformation, whether it's a rock, a back hoe, dent, a dent with a gouge -- they don't know. MFL pigs also are unlikely to see the seam welds. They can't see all the dents. They can't size the dents and there is some loss of resolution due to lift off of the sensors as they pass over the dents. So the detectability and ability to actually characterize metal loss in dents is less than it is in the body of the pipe.

I think this -- thinking about this and some of Rick's comments this morning -- kind of don't sell what we can't deliver. So we don't want to sell the public, the regulators, ourselves on saying these techniques will tell us everything we need to know about these features or these threats, because they don't.

So the challenges that we have. One is the timing of the remediation. The 180 days in the NPRM versus a year in 31.8S. A year does provide access to a complete operating cycle in order to accomplish any remediation. It allows time for the collection and integration of the data, and then the scheduling with some of the factors listed. Jim noted in his -- in one of his talks that system demands have changed. Is that the red line? Yes, the dark. I don't do well with colors -- they shouldn't give me colored presentations. The lower line represents probably how our systems operate traditionally, some time in the past, with usually one seasonal or one annual peak. And in the north, typically that annual peak was in the winter, in the south with power plant loads, that annual peak was probably in the summer. But with more homogenization, more types of uses of natural gas, demands on the system now are starting to look more like the upper curve, and that means that when you're trying to do remediation work, you have smaller, shallower windows in which to accomplish this, and what it can lead to is by the time you run a pig, get the results, analyze the results, your time is about -- your 180 days is about out and you go out and try to do something and you're in a peak. If you suspect you have damage on your pipe, I don't know about most of you all, but we mandate a pressure reduction when we excavate to investigate pipe when we suspect any damage. And that pressure reduction, that capacity reduction can then occur during peak times and then you're impacting the markets.

We don't think that on these types of defects that the difference between 180 days and 360 days is a significant risk factor. We think that the fatigue study will help define that for us.

So our challenges are remediation requirements, conditions that can be difficult to accurately characterize. We are working on the fatigue work. We have the corrosion work that I think has been previously filed in the docket, and the corrosion rate data suggests that it doesn't -- the corrosion rates are not real high, so the 180 days/360 days shouldn't be an issue there.

Recommendations for how to handle these are to use the results of our current studies to develop the appropriate criteria. Identify possible R&D needs -- that was mentioned earlier today as well. And focus on the potential threats, what we think are the real potential threats here, which are unconstrained dents, upper half dents in pipe, dents in pipe that are subject to fatigue mechanisms. Some of the reports on vintage pipes that were being done will help us characterize what kinds of pipe that might be, and any dents with likely mechanical damage, regardless of where they occur around the circumference of the pipe.

To do this we will use data that we get from ILI, although it's not perfect, and then data integration which we hear a lot about these days for other factors that may come into play that lead us to think that there may have been some outside damage to the pipe in that location.

Part 2. Third party damage. This'll be -- TPD will be the acronym for this, for the rest of this. In the NPRM it says we have to address this through preventive measures and assessment tools, deformation or geometry tools, and direct assessment under certain conditions -- and again, there's a lot more detail in the NPRM on this.

31.8S takes a little bit different approach and says this about these, that you can get some deformation information from the high res geometry tools, and as we said a couple minutes ago, they don't identify -- or the MFL tools don't identify third party damage too well, and they have limited utility in sizing deformation of damage in the dents.

The risk factors are there for this. We saw from the chart at the beginning, this is third party damage is a significant factor in about a third of pipe incidents, so this is something that needs some attention and is an area where improvements can potentially be significant. You can make a lot of headway here. That same data indicates that about 88 percent of the failures are at the time of the damage, and then the other 12 percent of these are under delay, so that the delayed third party damage failures are only about four percent of the incidents. Now, that doesn't mean that you should ignore them by any means, but that's a small subset. So keep that in mind.

Detection. It's kind of the same, same set of conditions and limitations that we talked about a couple minutes ago, and what we don't want to do -- and we talked about this earlier today also -- is expend a lot of resources on something, whether it's defining HCAs or chasing a defect that we can't see very well -- spend a lot of resources doing something that doesn't give us much return. That's not how to improve safety.

The challenges that we have on this, are we do have or it appears that a reading of the proposed regulation mandates inspections. The tools that we think are marginally effective -- they're certainly not as good as we can say, measure corrosion with some of these, and we don't think it's an appropriate allocation of resources to -- really what you're addressing is four percent of the incidents, just the delayed third party damages.

Prevention can impact all of them -- 32 percent, about a third of the total can be impacted by prevention. Also periodic inspection is not really the way to manage a defect that is not under the pipeline's control, the timing of it. We don't know when it's going to occur. It's somebody with a backhoe out there that may not have called OneCall that does this, so it could occur the day after we do an inspection, the day before we do the next inspection, any time in between. It's a time-independent occurrence and the time between when it occurs and the time to when, if ever, it fails, is indetermined by us also. So running pigs is not the optimum way to manage this.

Recommendations. Focus on prevention. Common Ground Alliance which OPS was instrumental in kicking off, we think is an excellent vehicle and organization to try to focus some effort on this. We think it's been a good organization. It's a good idea. We support it.

Effective measures are available and have been noted -- and a lot of these are listed in the proposed regulations. We agree with those. We think that they're good and should be employed. Further we support strengthening the national OneCall law -- OneCall system. We support thier use, their enforcement. We think there should be no exemptions to them. If you're going to dig, you need to call. Everyone. And we think OneCall systems, working with the CDA would be an excellent place to enhance excavator education programs, to provide some uniformity and standardization. Identify those folks and get a good message out to them.

So, to finish up, we think we should not mandate inspections specifically targeting third party damage, but we will look for it, and to the extent that we see indications of third party damage in our inline inspections, and we need to be looking for those indications as we have the logs read and graded, we integrate that data as part of our risk assessment -- that's the RA up there -- with data such as crossings that we know occur on our pipelines, OneCall tickets and any other excavation, utility activity we have out there, anything that indicates, that would correlate with possible third party damage.

Investigate and remediate as necessary, and again, continue to identify R&D to pursue goals for detection, monitoring and characterization of these defects.

MS. GERARD: Understand your point. Appreciate it. As it relates to improving, prevention and the third party work, could you go back to your last slide, or you're gone. Okay. As it relates to oversight, what would be prevention work? Do you believe that there's enough detail in what we have to be able to oversee the adequacy of the operators' evaluation of susceptibility to third party damage? I mean, remember the purpose here, where you're making recommendations about adjustments, take away the requirement here, rely on prevention more here. You're asking us to consider making these changes, and I'm asking if there's enough detail currently available to provide the operator with the criteria necessary for us to evaluate the adequacy of efforts in that prevention area? Or does more work need to be done in that area? You're suggesting to put more eggs in that basket, it's a better payoff.

MR. JOHNSON: That's not the prevention bullet. This is the prevention bullet. The public ed markers, patrols, surveillance and detection, technology. I think this area needs to be flushed out. Some of the things that are going on, and I don't know if Pat wants to talk about some of the things that are going on in CGA in damage prevention, but some of the other things that we know are going on are the development of what we think are improved standards for public ed programs that sets some goals and suggests some ways to assess the effectiveness of those programs, which just -- throwing a bunch of stuff out to people is not going to get it. Pat, why don't you talk about Colorado.

MS. GERARD: I just want to say we're extending the comment period another 30 days. We've got two weeks in this month and another 30 days and part of my question goes to, should we have additional public discussion, say next month, on issues like prevention and mitigation, which I don't -- which are not as fully fleshed out in the proposal as some other aspects relating to HCA, and I'm just suggesting that if you want us to consider putting more eggs in that basket, we might need some more structure in that basket.

MR. JOHNSON: Yes, and Pat's going to say a few words, but there is a section in the NPRM that talks about these kinds of factors, and I think they're properly placed and they need to be in there, so we support that, and I think our comments will reflect our support of those.

MR. CARY: Pat Cary, with El Paso. Just mentioned my name and half the room cleared out. There's a lot of good things that are happening within the Common Ground efforts. A lot of those are heavily supported by the OPS through some of the grants that were provided. One of the comments that you've made up here with the no exceptions is key to its success of the OneCall program.

From El Paso's perspective, we've had a lot hits this year that have been based on contractors working for entities that have exemptions from state OneCall laws. So that's one area that we could use some help that Common Ground really isn't addressing. They're not a lobbying effort, and they're strictly staying away from those things.

Some of the things that they are doing are collection of data -- it's going to be a voluntary program, but there will be a good tool to use on a nation-wide basis, web-based application that would collect data and when you're able to analyze that, similar to what they're doing in Colorado now, it gives you a real good tool to focus in on areas within -- geographic areas within your pipeline systems that you may have more susceptibility to third party damage.

I think those are probably two of the key points that are currently going on, what Common Ground is doing now.

MR. THEODOS: I don't think you have to worry that half the room left because you got up to speak. I mean it's like, oh, my gosh, it's another industry person, fifth one in a row. So if the other half of you don't leave, my presentation is also very short. And as Paul Gustillo said, I'm also in the same category of not being a metallurgist, or a dense metallurgist. Oh, what I'm talking on. I'm talking on pressure testing of the pipeline.

I'd like to go over what's in the current regulations. The goal is to address potential for material manufacturing defects. Hydrotesting or pressure testing in general is one of the primary inspection techniques for both baseline and reassessment periods. In fact, it's even mentioned in the Act that Congress passed.

The next couple of bullet items are details from the proposed regulations, and Mike's gone over regulations in a lot of detail, so we can save some time and move on to the fifth one.

The operators have to provide written justification as for why it isn't possible or economically feasible to pressure test a segment. This is in the preamble where it's talking about when you can use DA. It also mentions that operators must perform a pressure test at least once in the life of the segment unless the operator can demonstrate that pressure testing is not necessary to address this threat.

And finally, it mentions in both preamble and in the regulations themselves, that you conduct the pressure testing in accordance with subpart J of 192.

Or, as what's in B31.8S standard, there are a few items in there in section six. It's appropriate for addressing time-dependent and manufacturing and construction defect threats. Also, when used -- when raising the MAOP of a pipeline, or raising operating pressure above the historical operating pressure. And you test it to 1.25 times the MAOP.

B31.8S also contains a couple pages or so of details on the minimal data sets, risk assessment, response mitigation methods, assessment intervals and performance measures.

As far as some issues that we've identified and come up with -- first one is it raises significant -- criticism would be -- pressure testing all pipelines at some point in their life raises safety and reliability issues due to the difficulties in dewatering the pipeline, involving winter freeze-offs, introducing internal corrosion causing bacteria, and generally causing problems with reliability of service to customers. This would be particularly true on the LDC system and on interstate pipeline systems that feed directly to the LDCs, essentially the group systems or laterally market lines.

But natural gas production and underground storage operations has spent enormous investments on dehydration, slug catchers, filter separators, drips, tanks, et cetera in production and storage facilities to strip out water before it enters the transmission and distribution systems. And the reason's obvious, because even a little amount of water in these systems can cause horrific problems for the consumers due to freeze-offs. This rule would have us put probably thousands of barrels of water into the pipeline system, including the systems that are right up against the end user, the consumer.

The second item relating to this is for cities or communities which are single source feeds off the pipeline -- calling up on Jim Anderson's comments earlier. It would take anywhere from -- oh, we've averaged about 18 days for conducting pressure tests, but those consumers would be out of gas service for that time period. So there's also significant issues on customer outages for single source feed cities.

Definition of -- we also need some clarity on the definition of significant cyclic stress that would require pressure testing throughout the life of the pipeline. We're unclear as to what that means on page 4287. Also if there is, there is, as was mentioned earlier, there's some differences on the cyclic nature of gas pipelines and liquid pipelines on the cyclic issue.

Third bullet item, likewise, what is the basis for the operating condition changes? Is this per B31.8S or is this per something else? Need some clarification on that.

Proposed rule takes what I would view as a course approach to the issue that's not really founded on data and science. It's almost like the intent is to pressure test all lines so that you could check off an item on a list, versus pressure testing lines that have an identified issue that needs to be investigated and addressed in a timely manner. Think of all the threats that are out there -- 22 threats. A lot of what's in the rule, a lot of what's in the discussions across the table today is prioritizing, addressing High

Consequence Areas, and Moderate Risk Areas, timing of issues, with the recognition that not all threats, not all segments of the pipeline et cetera, are created equal.

Yet in this case, it's you've got to pressure test everything. Well, why? Some things may have an issue and some don't. Why are we addressing the ones that don't. We need to be concentrating time and resources on the other threats that do pose higher issues, higher threats.

Next point is that there is limited, or possibly even no justification to have to pressure test low stress pipe due to material, manufacturing defects, particularly for those other than having historical operating problems. It's also a higher environmental impact, other than the obvious impact of additional digging, we'll have large water disposal problems. In our system at least, we use bactericide in the water. We can't just dump that into a creek. In most places you can't. In some parts of the country, probably out west, I'm thinking from the desert environment -- we don't operate there, but I would imagine there's also an issue of acquiring the water, acquiring large volumes of water to do this.

And finally, significant gas transportation capacity outages beyond what was in the EEA analysis. The volume of pressure testing in the original EEA impact study was lower because it was assumed that only pipe with a realistic risk due to manufacturing construction defects, would have to be pressure tested. It was never anticipated that all the pipe would have to be pressure tested regardless of actual risk. Testing of all pipe in HCAs would have a bigger impact on the transportation capacity outages and resulting impact on the gas prices in the market place.

Industry has some ongoing research activities to help provide more scientific basis for identifying where we need to prioritize our efforts and what to address quickly. Patel's (ph) been working on a report on vintage pipe. The PPIC is HSD's name. I believe there is a corporate title name going -- change going on there, but they'll be working on a report. It'll essentially provide a summary of the Patel (ph) material and a practical users guide, if you will, on how to extract the data that's in the Patel report. There's also another ongoing Keifer -- Keifner (ph) report, studying the cyclic pressure effect on pipe.

The goals of the research is to add technical basis so we can make informed decisions to maximize our ability to address where there are real threats.

Summary of a few points here. We, the industry, need to complete the reports, these research reports, for use in the rule making. Both parties, or really all parties, there's more than just us and OPS, need to work together, and I believe we are as evidenced in today's discussion, to close this issue based on science and be sure that the threat is effectively and efficiently addressed in a timely manner. Third, the final rule needs to incorporate the findings, recommendations, and practices of the ongoing research so as to better align the B31.8S. And the fourth, we need to focus our efforts where there is a real risk, as opposed to blindly testing everything.

I believe it is quite likely that the vast majority of the pipe that would be subjected to this pressure testing obligation has survived decades of successful operations, which is a very good test, if you will, of a line for manufacturing construction defects. A key concept of the proposed rule is the integration of data to prioritize where work needs to be done to effectively the safety concerns. The requirement to pressure test all lines, regardless of the actual risk, if any, goes contrary, I think, to the whole premise of what we've been trying to accomplish in the rule and here in today's discussions.

And that concludes my remarks. Questions.

MR. DRAKE: Just to beg your endurance a few more minutes. What I want to try to do is just close industry with a recap on some points that Dan Martin brought up this morning, some of the key issues here, so we stay focused.

I think, in summary, for the most part, this is a very good technical effort in the rulemaking, to the degree that it's based on science and technology, it is a very good effort. And although Mike probably feels like he's been on some sort of carpet bombing effort here, where people are just beating the crud out of him all day long, it is really a well-founded rule.

There are some key issues that we are concerned about because of the cost issues that we're exposed to here. This is something we supported before the rulemaking came out. We felt, when we watched the liquid rule, that our credibility was at stake -- both the regulators and industry -- and we tried to step up, as Mark indicated earlier, with a very intense, technical effort to evaluate the protections afforded by the current code, the gaps, and the need to close those gaps. We offer technical reports to shore up our basis for action and define how to move forward physically. And we still support that. Our executives are on record of that. And even though it's a very expensive rulemaking, we're still supporting it.

But I think it's something that we need to be very careful and a few issues, to be careful about the scope growth and explosion to where they're not based on technology. Because the loss of control of the scope here can create costs that are extraordinary. This is the biggest rulemaking ever passed against this industry, period, from the pipeline safety standpoint. And you've got to understand that. The costs we're talking about that we are even agreeing with, and not arguing about, are very, very significant.

The fact that you're looking systemically at the pipe is a positive, but when you start losing some of the filters and some of the technology, and you start looking blindly at big scope or big issues, the scope growth becomes inordinate. And we end up with tremendous cost growth in this rule with no value. And those should be earmarks, where your ears should come up and look for those and trim those back because they waste our efforts, they waste our resources, and sooner or later they're going to interfere with our customers and the reliability of service of this product to the end user.

The issue of overlap is one of those issues.

I think we need to spend some energy on that. We understand where you are legally. We need to come together, get with the legislative folks, and define their intent. If that's where it comes out, that's where it comes out. But I think we need to get with our customers, if that's a fact, and get them ready for the fact in years 8, 9 and 10, they will see huge interruptions in service and brace themselves to that.

I think that the use of DA and CDA are essential tools to help manage the load during the baseline, and that we need to try to incorporate as much of the previous data and the previous efforts that have been done as we possibly can, and use our head, not for a hat stand, but analytically to help us navigate through this thing.

The low stress pipes are a different animal. They fail in different modes -- that's where the 30 percent came from, it kind of approximates the leak/ rupture threshold of pipe -- physical mechanics, again, the metallurgists at the table. It fails differently, it's a different animal. We need to look at it a little differently. They need some flexibility down there because of the volume of pipe down there, the proximity of the customers and a whole host of other things. I think that's well founded, technically.

The issue on dents. I think this, in conjunction with third party damage and materials, there's one common theme here, and that is fingerprint the bad guys, hunt them down, and execute against them. Don't chase everybody. In chasing everybody and blindly looking out there at these gigantic populations, you ignore technology and you waste resources exponentially. That there's good things here that we can use to try to trim that down and we need to incorporate that into our thinking.

I think on third party damage, we don't want to create a false sense of security. I think, when you look out at the public and say to them, we can stop all incidents, you are not credible any more. You are not credible any more. Someone needs to stand up and have the guts to say, I can't stop somebody who doesn't call OneCall, ignores all the ramifications and goes out and digs and hits my pipe with a hoe. 88 percent of the time, it fails time independent. Boom. I don't know what I can do to stop that. We're going to have to get better on prevention. We're going to get better on communications. We're going to have to get better on education. We're going to have to get better on monitoring. We don't want to chase third party damage with pig -- that's insane, a false sense of security to the public that we can actually manage that problem with a pig. That's ludicrous and we need to start telling people that. It's the wrong answer. And I agree with Dave. It doesn't mean that when you're pigging you don't look for it, but you don't chase it with a pig.

That's a very fundamental, important element here about controlling resources. Yes, we can do some things to characterize where, when, all those kinds of things, and we need to. When an operator sees fresh excavation in their area of patrol, shouldn't they do something. Hey, yes. We can help characterize that, shore that up as action items, but chasing it with in line inspection tools is the wrong answer. You're already way behind the curve here.

Diminished pipe materials -- I think we can do a lot of things. The current research efforts are in place. Yes, I know that some of the data that's out there about the focusing of this area as a problem area may be anecdotal, but opening up to all those old materials, irrespective of the anecdotal data is reckless. And we need to guard against that.

With that, that would close industry's position. I know we've taken a lot of time here, but I think it was very important and very constructive to have this dialogue, and I want to thank Stacey for giving us the opportunity to come here and try to prevent -- I mean try to present our technical basis and our thinking. Because I think our goals are very similar, now we need to try to come together and communicate as best we can, to help land this rulemaking practicably and effectively, where we shore up our credibility with the public, and we are able to execute against this in some sort of effective and reasonable means for both parties.

With that, I'm going to close the panel up here unless there are any other questions or comments from the floor. I'll turn the mike back to Stacey and Mike. Thank you.

MS. GERARD: These were prepared presentations. Are there any comments that are forthcoming from the audience that may be spontaneous or just were not scheduled? Anybody in the room is welcome to come to the mike.

MR. BYRD: A few random thoughts --

MS. GERARD: State who you are.

MR. BYRD: Phil Byrd with RCB. And some of these things have been said, maybe a little differently or not quite as specifically during the panel, so I just wanted to summarize five things.

Number one. Comment to OPS, don't be afraid to follow the math in both directions when it comes to Potential Impact Zones.

MS. GERARD: We're not.

MR. BYRD: You know, readily admit, it ought to get bigger. Let's accept the fact that it ought to be smaller than 300 feet, and even if you can't fit a house in a circle, well that just means it's not an HCA.

The second. There was a comment on one slide about if you've got a rural church that's in your circle and that's all, maybe that ought to be an MRA. I would like to expand that concept to if you have an identified site and that's the only thing that would cause you to be an HCA, maybe that part should only be considered as MRA. Just throw that out for additional consideration.

Third, the NAPSR chairman mentioned you ought to make this a subpart. I couldn't agree more. I read the Federal Register every day and it gets very confusing when you're trying to figure out, is this I that follows H, is this the I before I get to the double-i, and when you have that happen several time on the same page, you think, well, maybe we could just draft this a little differently, it would be easier to follow.

The fourth thing, and this is for farther down the road, but I'll go ahead and plant the thought. When you get around to interpreting this rule, don't throw away the incentive that people might have to put their entire system into their program. And the reason I'm saying that is, you know, when we deal with liquid operators, we're currently dealing with a rule, and they say, well, I'll just consider all of my pipes to be HCAs.

(inaudible question)

MR. BYRD: Well, yes, but you know, no good deed goes unpunished, and you might do that, but you're still going to have to do all the work that you'd have to do to figure out what would have been an HCA so that you can pass the audit. And I think it would be a good thing for public safety if the agency gave people some latitude. Say, if you throw all your pipe into this program, then we won't require some of the analysis that we would have required to say it's in or out. Did I make myself clear?

MS. GERARD: Perfectly.

MR. BYRD: Okay. And then the other thing to consider, when you talk about your 20 percent pressure reduction under certain situations, don't forget the front end of the transmission systems, where people are trying to get into the transmission system, not thinking about the distribution downstream. You know, there, you reduce pressure 20 percent, you reduce capacity, but you can still operate. If you're on the upstream side of the transmission system and you say you've got a pipe that operates 1100 psi, you're trying to get into 1000 psi system. Well, if I've got to reduce my pressure by 20 percent, I don't reduce by volume, I shut my pipe in because I can't get into the 1000 psi system any more. So be aware of that situation when you talk about any kind of random percentage pressure drop because of some indication that you found. You might have a bigger impact than you think.

MS. GERARD: Thanks, Phil. Anybody else with the energy or courage?

Well, this has been a really informative day. I don't think there's anybody who's been in the room today who hasn't learned something. Among the things that we've learned that's been a big surprise is there could be a very extensive alignment of industry, state and public views, which I think was surprise for a lot of people.

I know it's Friday afternoon and everybody's worked very hard to prepare very cogent presentations. We've just extended the comment period. That's to give people more time to fully flesh out concepts they prepared today, or issues that we've identified that we need more information for the record. In finalizing this rule we need to operate off the record, and the more explicit the record is, the better it is for us.

We'd remind you that we have a public technical advisory committee meeting in two weeks, on Thursday. At that meeting, we're hoping to have a vote on the cost benefit of this rule. There's a lot of information that's been presented here that I would like to see provided to the members of the advisory committee immediately so that they can read it. The purpose of the gas IMP discussion on Thursday the 27th is a briefing to try to get those members who will have to vote on the NPRM up to speed.

But remember, when they vote, which we expect to be in May, hopefully, they can vote with amendments, and they can prepare those amendments in advance. When we went through this process with the liquid rule, I think the committee had prepared in advance, different members had prepared as many as nine amendments which were voted on with the proposed rule, and that kind of preparation takes time, effort, coordination, detail.

We can have conference calls with the committee, and so you all put a lot of work into defining your positions, and I suggest that's a good investment, but that you need to prepare for some additional investment over the next few weeks to really fully maximize the investment you've made.

So that applies to everybody, whether they prepared and presented today, or they have material they still want to put in front of the advisory committee. We cannot conclude the rulemaking without that vote, and that vote is very important, and remember that when we go to final rule, we will account for each issue that the advisory committee took up individually. If we accept it, we say why. If we don't accept it, we say why. So I think it's very important to continue the effort that has gone into preparing for today.

I thank everybody for their professionalism. I think that the tenor of the meeting was extremely highly professional and at the same time I think it was informal enough that people really felt comfortable communicating. And so I think this is really a good day for pipeline safety, and we have more ahead. Thank you very much.

(Whereupon, at 4:20 p.m., the hearing in the above captioned matter was adjourned.)