Understanding Pipeline Integrity Legislation and Proposed Regulations
Friday, March 14, 2003
Marriott at Metro Center Hotel
Washington, DC

Introductions
Stacey Gerard, Associate Administrator, OPS
Ms. Gerard opened the meeting by discussing the following:

- Purpose of this meeting is to continue the dialog on integrity management for gas transmission pipelines
- OPS wants to assure that it has a complete understanding of the issues

Ms. Gerard introduced Sam Bonoso.

Sam Bonoso, Deputy Administrator, RSPA
Mr. Bonoso made the following comments:

- Noted that RSPA also has responsibility for hazardous material transportation, crisis response, technology development, and training
- Few issues are as complex as integrity management for gas transmission pipelines.
- There is a technical challenge and a benefit in performance-based approaches
- There is benefit in relying on consensus approaches; this rule relies heavily on a new consensus standard
- Past pipeline practices have not always been adequate; some failures have been significant
- The proposed rule is a response, and is on a fast-track
- The Pipeline Safety Improvement Act of 2002 provides impetus and all the authorization to go where needed; the law passed with the support of those whose lives have been touched by pipeline tragedies
- Safety is the purpose of the integrity management rule, and it is DOT's first priority

Ms. Gerard then went on to discuss the following:

- Announced that the comment period on the proposed rule is being extended 30 days, to April 30, 2003. The notice was sent to the Federal Register yesterday, and should be published shortly
- OPS will have another public meeting, if needed, to understand fully the issues/concerns regarding this rule
- The Technical Pipeline Safety Standards Committee (TPSSC) will meet to discuss this proposed rule during the last week of March
- The National Transportation Safety Board told Ellen Engleman (current RSPA Administrator and the President's designee to chair NTSB) during her briefing that the "Pipeline Enterprise" was the highest performing mode of transportation last year

Industry Presentation – Executive Summary of Industry Issues
Dan Martin, Senior Vice President, Operations, El Paso
Mr. Martin gave a presentation summarizing the industry issues, including the following points:

- Industry supports integrity management and is committed to improving pipeline safety
- Industry has made substantial investments in support of pigging, even without a rule requiring such testing, and is committed to continuing those investments
- The pipeline industry believes strongly in R&D. PRCI has been performing research for 50 years. The industry believes that technical solutions are the best way to improve safety
- Industry wants the public to understand and support improvement in pipeline safety

- Education and communication are two-way streets. It is important for industry to understand the concerns of public/regulators and also for the industry to educate OPS regarding the effects of its proposals
- Industry is committed to getting this rule right. It needs to understand the intent and interpretation; needs to know how to implement.
- There are practical restraints. Everything cannot be done in a single year.
- The rule is comprehensive, and has the potential to be very expensive. Nevertheless, the industry is committed to doing what's needed
- The rule is well structured, but some modifications/clarifications are needed. Today, there are six issues
    1. Focusing high consequence areas on those areas that are truly priority and simplify their determination.
    2. Preventing an overlap of baseline and reassessments, which would cause additional capacity constraints.
    3. Utilize current research regarding low-stress pipelines.
    4. Adopting the NACE recommended practice on external corrosion direct assessment and treating ECDA as an equivalent method of assessment. Also clearly define confirmatory direct assessment.
    5. Utilize established technical criteria for defect investigation and remediation and clarify the applicability of inspection technologies to detect excavation damage.
    6. Clarify the basis for hydrostatic testing of vintage materials and systems.

Mark Hareth, Hartford Steam Boiler
Mr. Hareth continued the introduction of industry issues, noting:

- With respect to HCAs, the August 2002 final rule is considered the "base" case
- The changes in the current NPRM add a large incremental environmental cost and a somewhat smaller increment in safety cost. Little benefit is seen in either area
- INGAA/AGA proposed a definition for HCAs in 2001 (based on technical work begun in 1999). It was developed using hard science and validated against actual events. Using it would mean reduced costs and increased benefits
- INGAA/AGA have revised their definition. The changes add safety benefit, result in slightly reduced environmental benefit, but decrease costs in both areas
- With respect to the question of overlapping baseline and reassessments, discussions with Congressional staff and examination of press releases leads industry to believe that Congress intended that baseline assessments be completed before reassessments were begun
- The overlap inherent in the proposed rule results in a significant increase in costs (environmental and safety), a decrease in environmental benefit, and essentially no change in safety benefit
- For direct assessment (DA), ANSI/ASME B31.8S and NACE 0502 are considered the "base" case
- The introduction of confirmatory DA (CDA) in the NPRM has reduced safety cost without impacting environmental or safety benefit. Pipeline operators commend OPS for this innovative approach
- INGAA/AGA seek simple clarifications to allow the CDA concept to be taken through the standard-setting process

Mr. Hareth then reviewed historical safety performance to set the stage for further discussions:

- Industry's goal is to achieve zero incidents

- Allegro-HSB has completed a review of safety performance over the period 1985 to 2001 to increase understanding of current safety performance and to help assure that efforts to improve performance build on existing practices
- An interim goal is needed on the way to zero incidents. Six sigma, reducing error rates to one in a million, is one such goal, used with success to manage "defects" in manufacturing
- Considering 310,000 miles of transmission pipeline and four "circles" per mile gives 1.24 million "units" of pipeline to be managed
- Recent experience has shown 3 internal corrosion incidents per year in line pipe
- It is only necessary to reduce this rate to 2 incidents per year to achieve one in a million over 1.24 million pipeline units

Q1, Stacey Gerard: Ms. Gerard asked if the study identified any "leading" indicators (e.g., defects found), since incidents is a lagging indicator.

Response: Mr. Hareth responded that not much has been done in this area yet. A structure exists in B31.8S for collecting such data and OPS has embraced that structure in its rule.

Public Concerns
Rick Kuprewicz, President, Accufacts, Inc.
Mr. Kuprewicz stated that he provides negotiation assistance in Washington State over issues involving pipeline concerns. He made a presentation including the following points:

- Integrity management for gas pipelines has four objectives:
  1. Clear, easily understood, definitions for HCAs
  2. The rule sets minimum standards
  3. Re-instill confidence in an important transportation infrastructure
  4. Reaffirm industry's credibility with the public
- There is a problem. We need to get a handle on catastrophic failures
- There is general confusion regarding HCAs. There needs to be clarity. We are not putting resources in the right place if we are spending lots of time just understanding what HCAs are.
- The public has concerns about the inspection program doing well.
- The concept of "identified sites" plays an important role. It is a positive step in the NPRM
- The concept of moderate risk areas (MRA) is confusing. Confusion increases anxiety
- The HCA definition should be able to be displayed as a simple logic diagram – on one page. There may be disagreement on the details, but all should agree on what it covers
- If the HCA rule is not clear, the rest of the IM rule is expensive, but a distraction
- "Identified sites" covers areas in class 1 and 2, and is an important concept for gaining public confidence. It provides a clear focus on unsheltered individuals at risk. Including hard-to-evacuate individuals is a reasonable approach
- MRA is hard to understand. It appears to conflict with the concept of HCA. It's hard to explain why we are excluding part of class 3 and 4 areas, which are otherwise covered. It confuses the issue. The public will not support it.
- The potential impact circle should apply to all classes, and this needs to be clarified.

Mr. Kuprewicz then commented on other issues related to gas pipeline integrity management:

1. Pipeline modification and siting
   - C-FER is an empirical concept. He supports its use as a tool for IM

- C-FER, and the concept of potential impact radius, should not be used as a siting tool
- He has seen some evidence of this tool being used by companies as justification to site compressors, etc. in very sensitive areas
- More sensitive engineering analysis needs to be used for siting
- The Carlsbad victims were outside the threshold radius

2. The "myth of IM"
    - Integrity management is a good concept, but it's not everything
    - It is not a caveat for other things required of prudent operators
    - It is important to keep an eye on other factors important to good operation
    - IM is important, but it would be wrong to focus on it and allow abusive operation elsewhere
3. Performance measures and risk management
    - IM does not exclude risk management processes
4. "Other technology", as used in the rule, is a good concept. Innovation drives improvement. This allows innovation to proceed.

Mr. Kuprewicz closed by suggesting the following questions for discussion:

1. Does the HCA definition pass a simple logic diagram test?
2. What percentage of pipeline miles is going to be HCAs? What is the breakdown by class?
3. Is there an unintended detriment? Are we driving pipelines to smaller diameters and very high pressures? No one should be trying to force operators away from bigger, more efficient, pipelines
4. What performance measures are subject to review?
5. What is the timing for the final rule?

At this point, the meeting was opened to questions:

Q1 Ms.Gerard: Asked to further explain question 2, the percentage of miles that will be HCAs.

Response: Mr. Kuprewicz said this is a good reality check. The public will be interested in how much of the pipeline is being protected.

Follow-up, Ms. Gerard asked about percentage of the population covered? We are looking at consequences, not miles

Response: Mr. Kuprewicz stated the public wants information it can understand, and miles are easy to understand. How much is in each class gives perspective.

Q2 Ms. Gerard: Did you vet these views with local groups?

Response: Mr. Kuprewicz said these are mostly my own views. There is a struggle within public groups over the concept of performance-based regulation vs. prescription. I am comfortable with performance-based.

Q3 Ms. Gerard: Are you comfortable with the rule's criteria for using the performance-based approach?

Response: Mr. Kuprewicz said yes, but the devil is in the details. New security requirements (related to protecting information) could make it difficult for an observer to do a reality check.

Q4 Phillip Sher (State of CT): What are you suggesting is better than C-FER, for siting?

Response: Mr. Kuprewicz said C-FER only considers two variables. There are more sophisticated engineering analyses that consider more variables. They are not practical as screening tools for integrity management purposes, but they can be used for site-specific purposes.

OPS Discussion – Legislative Requirements
Barbara Betsock, Chief Counsel for RSPA
Ms. Betsock addressed the question of what is required by the recently enacted Pipeline Safety Improvement Act of 2002.

- The statute looks at risk. It requires addressing the highest risk and providing protection
- The 7- and 10-year periods provided in the legislation are minimum requirements
- The statute requires that the highest risk facilities be assessed in 5 years and reassessed "at a minimum" of once every seven years. It is hard to see how to read that any differently.
- There is some flexibility in the proposed rule regarding the nature of the 7-year reassessment.
- It is not apparent that the start of reassessments can be delayed beyond 7 years, given the language of the statute.
- RSPA invites comments on its reading of the statute.

Q1 Paul Biancardi with Duke Energy, asked whether any legislative history was available. He noted that no conference report has been published and asked if there was any other language upon which we could rely to determine Congressional intent.

Response: Ms. Betsock responded that Congressional intent is only considered when the plain meaning of the law is unclear. Here, there is no ambiguity. She is not aware of any documented legislative history.

Follow-up: Mr. Biancardi followed up by asking if a conference report is expected.

Response: Ms. Betsock replied that RSPA has not heard of any such plans.

OPS Presentation – Overview of High Consequence Areas
Mike Israni, Program Manager, OPS
Mr. Israni provided an overview of the concepts underlying the definition of high consequence areas, making the following points:

- OPS's principal goal is to improve public safety
- OPS also seeks to accelerate assessment of pipelines in HCAs, improve integrity management systems in companies, and improve the government's role in validating IM
- HCAs are defined differently for hazardous liquids and gas, because of different characteristics of those products that result in different effects from leaks and ruptures
- For gas, the basic definition of an HCA was established by the final rule issued in August 2002. This includes:
    - Class 3 and 4 areas. The requirements to identify and protect these areas have been in existence for 30 years. They were adopted as part of the HCA definition, because OPS believed that operators already have data on these areas and additional effort required would be limited

  - Areas where people congregate. These have been included in the class 3 definition, but only to a distance of 100 yards from the pipeline. The HCA definition expanded this to include other locations within the area potentially affected by pipeline ruptures.
  - Facilities having persons who are difficult to evacuate. These facilities pose issues similar to those for areas where people congregate, and they are treated similarly.
  - Impact circles. This is a new concept that adds areas beyond 660 feet, for large-diameter, high-pressure pipelines, since experience has shown that accidents on such pipelines can have an affect outside the historic 660 feet corridor.
- The proposed integrity management rule includes several features that modify the definition of HCA:
  - A new component encompassing areas where the area of an impact circle of threshold radius 1000 ft or larger includes 20 or more buildings
  - The radius is calculated using the C-FER equation and the result is increased to a defined threshold to provide additional safety margin
  - Moderate risk areas, within HCAs, would have a longer interval for testing. The preamble to the proposed rule poses a question for public comment as to whether the additional actions required in such areas should be limited to additional preventive and mitigative actions only.
- Mr. Israni then provided several pictorial example depictions of HCAs

Comments and questions were then solicited from members of a discussion panel:

Comment, Andy Drake, Duke Energy

- Noted that this is an intricate rule
- A lot of effort has been expended to incorporate the best technology, but then additional safety margins are added. This dilutes the effect of these efforts
- It is not possible now to estimate, with any degree of certainty, how much of his pipeline system is covered by the rule
- We need to understand what the overarching targets and goals are.

Response: Mike Israni responded saying the concern appears to be directed at why a threshold radius was used. This was chosen for simplicity, safety margin, and consistency with long-standing definitions in 192.5.

Ms. Gerard added with respect to OPS's goals:

- Expand protection, including additional geography
- Stay science-based, considering the likelihood of an effect if there is a failure
- Focus oversight
- Answer the question of where additional protection is being provided

Mr. Drake continued:

- At Duke, it is possible to run scenarios on a GIS system.
  - Class 3 and 4 comprises about 12 percent of total system mileage
  - Approximately 50 percent of valve sections would have at least one HCA
  - 80 percent of compressor discharge stations would be covered
- Pigging is the answer for big transmission companies, if assessment needs to be done repeatedly. 80 percent of the system will be investigated using this method.
- Other scenarios are now showing that up to 75 percent of class 2 and 50 percent of class 1 mileage are being included, along with 100 percent of discharges. That

results in doing everything, and losing the intended focus on areas of highest consequence.

Mr. Drake concluded by questioning the need for a definition of HCAs. If we are going to need to assess everything, why do we need it. We should just do it all. Costs will ramp up significantly, however.

Q1,Ms. Gerard asked if it was practical to assess only part of a pig run.

Response: Mr. Drake responded that it is physically possible, but not practical. It would not be defensible to ignore data actually in hand.

Q2, Linda Daugherty, Enforcement Officer, OPS, asked whether it would be possible to prioritize response to an assessment to address HCAs first.

Response: Mr. Drake responded that this is not really practical. When you find an actionable indication – anywhere – you need to act on it, in accordance with national consensus codes.

Q3, Zach Barrett, IM Implementation Program Manager, OPS, asked if the industry would prefer to calculate impact zones, with margin, rather than using fixed corridors.

Response: Mr. Drake responded that the gas transmission business is different from hazardous liquids. It moves a single product with a specific, predictable signature. The industry has a great deal of data on the zone within 660 feet of its pipelines, and wants to take advantage of that. The goal should be to maximize use of that data and calculate consequences. This is just a place to start – to focus. For liquids, there are a limited number of what would be, in the gas context, middle-sized companies. In gas, there is a much wider range. Some companies are very large. Many are small. There are an order of magnitude more companies in total. We don't want to make this too complicated for small operators.

Comment, Jim Anderson, State of NC, indicated agreement and that the proposed definition is too complicated. He said he was here as the chairman of NAPSR and will speak later to the differences between intra- and interstate pipelines.

Q4, Rick Kuprewicz asked whether the goal of MRAs was to avoid accelerating assessment timing if not in some zone.

Response: Mike Israni confirmed this is correct.

Comment: Mr. Kuprewicz then went on to note that the regulation indicates a need to accelerate timing for direct assessment, since that technology is evolutionary. He suggested eliminating the MRA and revising the overall timing to achieve the same end by normalizing DA schedules to other technologies.

Comment: Ms. Gerard noted that a question has been posed in the preamble as to whether the requirement for assessments should be eliminated in MRAs. She asked if that wouldn't increase the value in identifying these areas.

Response: Mr. Kuprewicz responded in the negative and said he sees the MRA concept as adding additional complexity with no gain.

Comment: Mr. Drake noted that we have a hybrid that doesn't serve anyone. Small operators will just use the existing class 3 and 4 designations. Larger operators can apply the new tool (impact circles) and see that the old method is very coarse. We shouldn't need to do both. If we use the circle, we should use it everywhere, not just in class 3 and 4.

Q5: Ms. Gerard questioned whether this implied using the impact circle tool over the entire pipeline system.

Response: Mr. Drake deferred to the prepared presentation of Daron Moore.

Industry Presentation – High Consequence Areas
Daron Moore, El Paso
Mr. Moore then made a prepared presentation reflecting industry's recommendations for addressing the question of HCA definition. Mr. Moore made the following points:

- Industry's goals are to base actions on credible science, to address most of the people along the pipeline, and to address a significant enough percentage of the pipeline while remaining focused enough not to waste resources
- INGAA began work to define a valid technical basis in 1999. OPS adopted the results (the C-FER equation) but not in a holistic way
- C-FER was validated against actual data. It worked well to predict the limit of consequences

Mr. Moore proposed a "pure technical approach" to defining HCAs that would use impact circles and encompass any circle including 20 or more structures intended for human occupancy or an identified site (meeting several criteria). Stacey Gerard asked if this proposal envisioned using impact circles on the entire pipeline, and Mr. Moore responded in the affirmative.

Mr. Moore described several objections to the definition of HCAs, as it would be modified by the proposed rule:

- It is not technically based
- It is excessively complex
- It is subject to conflicting and inconsistent conclusions
- It is extremely burdensome on small pipeline operators
- It does not recognize the small impact of small-diameter, low-pressure piping
- It requires use of data not readily available (i.e., outside the 660 ft corridor)
- It is inconsistent with other portions of Part 192 and with the 1000 persons per square mile criterion used for liquid HCAs
- The addition of 15 percent margin to the C-FER calculation is not based on science
- Use of a threshold radius is arbitrary
- The use of 20 or more buildings as a criteria only for very large potential impact circles (i.e., greater than 1000 ft) is not based on science
- It will be difficult to impossible for operators to comply, and this is not a desirable outcome for anyone

Mr. Moore proposed using a definition that is based on a constant consequence of 20 "houses". He indicated that this would include approximately 70 percent of the population along the pipeline, and result in pigging about 80 percent of the total pipeline (for operators using pigging as their assessment method). He noted that decreasing the criterion to 10 houses would bring in massive amounts of class 2 piping and large amounts of class 1 and would cause the rule to lose its focus. Under the industry proposal, the number of houses considered should remain constant (i.e., a constant consequence) and not vary with the size of the circle.

Mr. Moore then used several flow charts and graphical examples to demonstrate the complexity of the proposed definition for HCAs. He identified several "issues" associated with using this definition, in addition to its complexity:

- Industry has collected house data within 660 ft and "outside area" data within 300 feet since 1970
- Collecting house data beyond 660 ft within one year is not practical
- Collecting additional data would pose undue burden on operators
- The definition for identified sites abandons the historical 10-week use period in favor of 50 days (not necessarily consecutive) per year. This would be unreasonably burdensome
- Derivation of a population density based on an assumed uniform density at the current criteria for class 3 is unrealistic in that it does not recognize the real non-uniformity of populations along the pipeline

Mr. Moore offered an alternative definition on behalf of INGAA and AGA:

- It would allow operators a choice, to use a definition based on class methodology or based on impact circles
- Operators choosing class methodology would still use impact circles to include piping on the basis of identified sites (or for pipelines where the impact circle is greater than 1000 ft)
- Operators choosing impact circles would use them to identify circles containing identified sites or 20 or more structures intended for human occupancy
- Determination of the existence of 20 or more structures for impact circles greater than 660 ft in radius would be accomplished by pro-rating that number to allow the determination to be based on the data in-hand for the 660 ft corridor

Mr. Moore presented several pictorial representations of how the proposed definition would work, and identified the following factors that support use of the proposal:

- It uses science, proven by field experience, to the greatest extent practical
- It treats all areas the same. A consequence to 20 houses is important regardless of the class of the pipeline
- Existing processes are maximized, by use of a criterion of 5 days/week vs. 50 days/year for "identified places"
- It supports a focus on inspection of pipeline rather than gathering new population data
- It is not confusing, so that the public, regulators, and operators can all understand its use
- It allows operators to use the August 2002 HCA definition if they so desire
- It permits a focus on true HCAs while avoiding inconsistent applications

At this point, the meeting was opened for questions

Q1: Ms. Gerard asked if operators could apply different sides of the bi-furcated approach (i.e., class methodology or circles) to different parts of their system?

Response: Mr. Moore responded both are technically adequate and have basis. It would be difficult for an operator to explain why they use different options.

Q2: Mr. Barrett asked why not stay with the class 3 density as the size of the circles changes?

Response: Mr. Moore said a fixed 300-ft circle penalizes small operators. The objective here is to protect the same number of people.

Q3: Ms. Gerard asked for a point of clarification and noted that 1000 people/square mile is one of 2 criteria identifying high consequence areas for liquid pipelines. The other is “other populated areas”, not quantified but considerably conservative compared to 1000. She then asked why the proposal includes bifurcation?

Response: Mr. Moore said there are many different operators of different sizes. APGA represents about 900 members, mostly small. INGAA represents about 28 large companies. AGA represents about 200 members, small to medium sized. This allows all of them to credibly establish HCAs without requiring small operators to expend enormous effort to go down an impact circle path. At the same time, it allows larger operators, who can do that, to use the best science.

Comment: Lori Traweek, Vice President, AGA, commented that this is very important to AGA. They believe that including all pipe in class 3 and 4 areas is very conservative (compared to application of the C-FER equation) and will only be done by operators without a lot of transmission mileage. She also suggested that it may make sense to make different choices at different points on an operator’s system

Q4: Mr. Barrett asked wouldn’t the analysis be easier to do if there are fewer miles to consider?

Response: Ms. Traweek said it is a resource issue. Where do you want to apply available resources? Operators may get better results if they focus on inspections.

Q5: Bill Gute, Eastern Regional Director, OPS, asked if you have a 36-inch pipeline at 1200 psi, and the PIC goes beyond 660, is that not considered?

Response: Mr. Moore said it is considered. We would pro-rate the number of houses to those that should be found within 660 feet and use the identified data to compare to that smaller number.

Follow-up: Mr. Gute asked if a hospital at 680 ft would be included if there were no houses in 660 feet?

Response: Mr. Moore said that is an issue we need to discuss.

Q6: Mr.Gute said Mr. Drake indicated he would have to pig 80 percent of his discharges under the proposed rule. What change is there under the PIC concept?

Response: Mr. Drake said it is close to the same amount of discharges. There is some trade-off in valve sections. If the criterion goes from 20 to 10, I would pick up 100 percent of my discharges.

Q7: George Mosinskis, AGA, noted that he represents 187 operators with 5 to 5000 miles of transmission pipeline, and asked for confirmation of his understanding that IM is an added layer of protection.

Response: Mr. Israni confirmed that understanding.

Comment: Mr. Mosinskis then noted that there are already about 12 annual inspections, etc. to assure safety.

Q8: Ms. Gerard asked if we consider the impact circle side of the bifurcated approach and have a smaller pipeline with a 100-ft circle, would you consider extrapolating downward? You realistically can't get 20 houses in such small circles.

Response: Mr. Moore said that is a good question, but better answered by States or small operators

Comment: Mr. Kuprewicz added that we shouldn't forget the point that unsheltered people or people close to the pipeline implies less time is available. He recommended not getting tied up in house count.

Response: Mr. Moore responded that identified sites would still be considered in smaller circles.

Comment: Alan Eastman, Pacific Gas & Electric, commented that his company has about 6000 miles of transmission pipeline. He complemented Mike Israni on his explanations. Regardless of what is decided on HCAs, PG&E wants to add safety. The rule will require inspections and that will clearly add safety, regardless of whether it adds geography. He supports use of a scientific basis, and noted that use of the impact circle concept has already produced benefits in discussions with local officials about why permits are needed for pipeline repairs.

State Presentation – Public Meeting on Integrity management in HCAs
Jim Anderson, State of NC, made a presentation representing the perspective of a state pipeline safety regulator. Mr. Anderson's points included:

- There is a difference in makeup and operation of intrastate transmission systems and interstate systems
- In North Carolina, there are 2789 miles of intrastate transmission pipeline
- The costs to assess that pipeline vary depending on the method used. They could range from $3.48 to $8.12 million per year (note that Mr. Anderson assumed all affected NC pipeline mileage would be assessed using each of the available 3 methods to arrive at these figures)
- LDCs have practicality issues with performing pigging or hydrotesting
- Much of the pipe in NC is small diameter, including some at 2- and 3-inch diameter. The proposed rule would impose a 300-ft threshold on that pipe, even though the calculated impact circle is very much smaller
- Increased use of gas for electric generation is resulting in a dual-peak system, in which there is much less low-demand time in which pipe can be taken out of service
- States want to assure that they are getting value for the costs associated with the rule
- States have compliance concerns, including: training for inspectors and operators, guidelines, and clarification of the regulation

OPS Presentation - Overview of Proposed Regulation
Mr. Israni made another presentation providing an overview of the proposed integrity management rule. Mr. Israni stated the scope of rule is for gas transmission, no gathering or distribution lines.

Mr. Israni identified the overall elements including:

- HCA segment identification, 12 months,
- Develop IMP framework, 12 months,
- Develop a plan, 12 months,

- Evaluate threats, continual evaluation and assessment, preventive and mitigative measures, etc.

The presentation reiterated the need to select appropriate assessment technology, ILI, pressure testing, Direct Assessment (DA) or other equivalent technology.

Regarding DA:

- Used for specific threats, and
- As a primary method will be conditional.

Explanations about ECDA included:

- Regions not necessarily contiguous,
- Similar characteristics and history,
- Similar expectations, and
- Regions can be redefined as appropriate.

Two charts were provided showing ECDA region indications and comparisons between CIS and DCVG vs. ILI log.

Briefly explained Confirmatory DA as:

- Streamlined integrity assessment,
- When used, CDA Plan is required, and
- Reiterated excavation requirements and investigation timeframes.

Reviewed the baseline assessment interval requirements:

- Start date of 12/17/02,
- Utilizing ILI or pressure testing, baseline complete within 10 years and 50% with most risk during first 5 years, and
- Utilizing DA, baseline complete within 7 years and 50% with most risk during first 4 years.

The presentation highlighted how and when prior assessments could be utilized.

Actions required addressing integrity issues include:

- Immediate repair conditions,
- 180 day remediation, and
- Longer monitoring requirements.

Preventive and mitigative measures discussed included:

- Actions specific to operator systems to enhance public safety,
- Considerations for remote control valves, computerized leak detections systems, inspection, etc., and
- Reference to ASME B31.8S.

Reassessment interval for segments begins after baseline assessment is complete and begins again upon completion of any subsequent assessment. When the reassessment interval is longer than 7 years, CDA is required within 7 years.

Performance measure monitoring was reviewed and specific performance measures must include:

- Miles assessed vs. program requirements,
- Number of immediate repairs completed,
- Number of scheduled repairs completed, and

- Number of leaks, failures, incidents by cause.

Finally Mr. Israni reminded the audience that the DOT had invited comment on several issues including:

- Should rural buildings (churches) be MRAs requiring less frequent assessment?
- Should rules allow 20 year reassessment for pipes operating below 30% SMYS?
- Should it be acceptable to use only CDA for pipe operating below 20% SMYS?
- Should a 10 year reassessment interval using DA be allowed for pipe operating below 30%?
- Should the rule accept NACE standard for DA without extensive requirements?

The final slide reiterated the milestones and they included:

- Final Rule – HCA definition – 8/6/02,
- NPRM – Gas IMP – 1/28/03,
- NPRM – Mapping – Spring 2003,
- Final Rule – Gas IMP – 12/17/03

Comment: Mr. Anderson suggested that OPS consider a separate subpart of Part 192 for IM. That would avoid the complicated sub-paragraph designations in the proposed rule.

Q1: Judy Schegel, Oklahoma Natural Gas, asked under what conditions will DA be applicable?

Response: Mr. Israni said when the pipeline is a sole source, when there is an economic impact on the community causing a disruption of supply, and when the pipeline operates at less than 30% SMYS.

Industry Presentation – Baseline and Reassessment Interval
Andy Drake, Duke Energy
Mr. Drake gave this presentation and stressed the Industry's position that the overlap of the baseline and reassessment periods had significant consequences including:

- Throughput and legal issues resulting in significant impact on systems. Taking larger blocks out of service (as would be required for overlap) would affect supply
- The issue is the definition of "facility" and the intent of Congress, and
- Referenced both a Battelle Report and the ASME B31.8S as a technical foundation for reassessment.

With regard to the overlap, the presentation indicated:

- OPS notes from February meeting reference Graham Hill who believes reassessment begins after completion of baseline, and
- Cited a press release from Chairman Tauzin regarding reinspection every 7 years after the 10 year interval.
- If the law isn't clear enough, then OPS should go back to Congress and get clarification

Additional throughput concerns were highlighted in an EEA Report which:

- Discussed the significant costs associated with the baseline inspections and
- The resulting supply interruption and price volatility as being exponential.

Comment: Terry Boss, INGAA, interjected that the EEA report simplified and accumulated all outages.

Q1: Ms. Gerard asked if the EEA report considered modification, testing, and repair, and did it quantify costs for all?

Response: Mr. Boss said the EEA report gathered them all together to simplify the analysis.

Q2: Ms. Gerard asked if modifications to the report are being made to clarify the report?

Response: Mr. Boss said not at this time.

Comment: Mr. Drake said we may prepare a paper for the docket and a point of clarification was made that 20 to 24% per year did not mean disruption for the entire year. It was also noted that price volatility reacts exponentially as system outages expand. The difference in cost in years 8, 9, and 10 goes from $300 million to about $1 billion.

Q3: Ms. Gerard asked is that cost of operations, or cost to the consumer?

Response: Mr. Drake said both. Costs go up and are passed on the customers.

Slides were them shown illustrating the OPS Reassessment Time Line and what industry believes to be the Congressional Reassessment Time Line.

Implications associated with previous inspection data include:

- Baseline implies 1st inspection ever,
- But operators have inspection data prior to 2003, and
- Operators who have been proactively inspecting should not be penalized.

Consequently Industry requests consideration such that:

- Reassessment be defined technically by either the Battelle Report or ASME B31.8S and it should be based on testing/ repair criteria, effectiveness and modifications and operating stress levels, and
- The use of CDA is appropriate and potentially beneficial.

Mr. Drake summarized the Industry's position as:

- Need to eliminate the overlap of Baseline and Reassessment to minimize throughput impacts, and
- Encourages the use of previous inspection data including data from multiple prior inspections, irrespective of when it was conducted.

Q4: Ms. Gerard asked if the Industry is proposing an alternative, clear criteria, on the docket, for entry to the performance-based approach?

Response: Mr. Drake said we will probably propose something. Language like "state of the art", in the proposed rule, doesn't' help any of us.

Comment: Mr. Israni reminded the audience of the language of the law and reiterated why OPS took the approach it did, which was because risk hasn't gone away and Industry needs to repeat assessments.

Response: Mr. Drake referenced the Battelle report, B31.8S, etc. which all say that the time periods we are talking about are extremely conservative.

Q5: Mr. Sher asked would you wait 10 years to reassess systems you've already inspected?

Response: Mr. Drake said you need to be able to pass the red-face test. Anything older than 2003 will need to be reassessed during the baseline period. The question is when.

Q6: Mr. Sher then asked if he was saying if you found problems and repaired them then that location would then become a problem area?

Response: Mr. Israni said the conditions that resulted in the problem do not go away. If there are soil corrosivity issues, for example, they remain. The problem is repaired, but the need to continue to reassess the pipe remains.

Comment: Mr. Drake reiterated his belief concerning what Graham Hill said and that was the DOT has the ability to readjust intervals as necessary. The industry will file the reports referenced in my presentation along with comments to the NPRM.

Industry Presentation – Direct Assessment
Alan Eastman, PG&E
Mr. Eastman gave a presentation overview regarding Direct Assessment (DA):

- including general comments,
- needed enhancements,
- concerns regarding understanding Confirmatory Direct Assessment, and
- A comparison of language in the various standards.

In general,

- The DA process is pivotal for certain pipelines. The DA process costs PG&E approximately $28,000 per mile while ILI costs up to $250,000 per mile,
- Believes the baseline time and reassessment interval for DA should align with the two other forms of inspection, ILI and pressure testing,
- Remediation provisions need to be consistent with general remediation methods,
- The terminology needs to be consistent with terminology used in B318.S and NACE standards,
- DA research continues and hopes to address any gaps discovered,
- Associated standards development is underway.

With regard to ECDA,

- The rule should reference NACE standard,
- ECDA wording should be removed,
- The baseline and reassessment intervals should be the same as the other inspection intervals, and
- ASME B31.8S is being modified to reference the NACE standard.

With regard to ICDA,

- The supporting research is underway, and
- ASME B31.8S will be modified accordingly.

For Stress Corrosion Cracking,

- A NACE team is addressing this threat, and
- ASME B31.8S will be modified when appropriate.

Related to CDA,

- The pipeline industry supports the CDA concept because of its potential value, and
- When practical, this too will be added to ASME B31.8S

In conclusion,

- The DA process is essential,

- The NPRM language can be improved, and
- The new CDA process is critical in moving forward.

The industry has developed an NPRM cross reference table showing the NPRM language and tying that language to the appropriate consensus standard along with suggested recommendations.

Comment: Mr. Israni noted that there needed to be modifications to the NACE standard to make it enforceable since it is only a recommended practice. Accordingly pressure reductions and specific numbers of excavations had been added to the NPRM, along with requiring one excavation in the most suspect area. He then reminded the audience that a question had been asked in the preamble regarding DA.

Response: Mr. Eastman responded that the changes made still didn't make it auditable. It still leaves open what is immediate, how to integrate DCVG, etc. and does not agree with the proposed requirement that pressure be reduced before all indications have been excavated. DA is intentionally conservative. It is very likely that an operator won't find deleterious corrosion, even on immediate repair conditions. Pressure should not need to be reduced until the calls are validated. He said the industry will submit comments regarding pressure reductions and when they should be applied.

Industry Presentation—Low-Stress Pipelines
Paul Gustilo, with AGA
Mr. Gustilo gave this presentation and made the following Key points:

- Low stress pipelines are typically below 30% SMYS,
- Integrity management processes are the same for all transmission pipelines,
- OPS recognizes that at low stress levels generally leaks occur vs. ruptures,
- The option to utilize PIZ calculation in determining HCAs is appropriate,
- LDCs need the flexibility to utilize other effective technologies besides ILI, PT, and DA.

An Action Plan was suggested which included:

- Refining the HCA definition,
- Evaluating the CDA process from a low stress pipeline perspective,
- Develop specific mitigation measures by threat applicable to low stress pipelines.

Q1: Ms. Stacey Gerard asked if the LDCs would like to utilize the PIZ calculation?

Response: Mr. Gustilo said yes provided it was the one proposed by INGAA

Industry Presentation—Dents and Third-Party Damage
Dave Johnson, VP, Enron
Mr. Johnson gave this presentation and began by saying today's approach includes:

- A review of the rule,
- An outline of the challenges associated with the rule,
- An outline of recommendations

A graph was shown indicating a summary of incident causes.

He discussed the requirements associated with dents including immediate repair and 180 day remediation requirements.

He compared those with the requirements of B31.8S.

The Dent risk factors were then outlined as:

- Plain body dents which are not at risk under most operating conditions, except somewhat for top half dents when they are accompanied by mechanical damage.
- Dents on welds may be more susceptible to fatigue,
- Dents with cracks or gouges are subject to unpredictable failure and should prompt investigation and remediation.

A discussion of dent detection included:

- Geometry pigs which can't see seam welds and can't see mechanical damage,
- MFL pigs which can't see seam welds, can't see dents, can't size dents, and have a loss of resolution due to liftoff around the dents.

Dent challenges include:

- Timing 180 days vs. 1 year, 1 year allows scheduling within operation cycle,
- System demand changes have been noticeable since 1995,
- 1 year allows collection of data and reasonable repair schedule,
- For conditions that are hard to characterize, additional work is being conducted on dents and fatigue,
- Corrosion rate data is available.

Dent recommendations include:

- Utilize current studies to determine appropriate criteria,
- Focus on potential threats as opposed to unlikely threats,
- Use data where applicable from ILI tools,
- Require data integration.

With regard to Third Party Damage (TPD):

- Must address preventative measures and assessment tools

According to B31.8S:

- High resolution geometry tools can provide some defect information, but
- There has been no success in reliably identifying TPD with MFL tools, and
- MFL tools are not useful in sizing deformations.

TPD risk factors include:

- Around 32% of pipe incidents are related to TPD,
- Approximately 88% of failures happen at the time of the damage,
- Therefore, delayed TPD failures account for approximately 4% of incidents.

TPD Detection:

- Geo tools are not good at effectively finding TPD,
- With regard to MFL tools, DOT and PRCI are focusing on R&D but currently don't have any accuracy

TPD Challenges include:

- Mandating ILI inspections with marginally effective tools is a waste of resources

TPD Recommendations include:

- Focus on prevention with CGA,

- Help support One-Call systems with no exemptions, public education, use of markers, use of patrols and new technology development
- Don't mandate inspections targeting TPD, but the industry will look for,
- Investigate and remediate as necessary,
- Identify R&D needs and goals.

Q1: Ms. Gerard asked if we need another public meeting to discuss this further and is there enough information available on oversight and prevention activities within the industry to provide the DOT with sufficient data to determine the adequacy of the operators?

Response: Mr. Johnson said that Industry and Company comments will address these issues.

Comment: Pat Carey, El Paso, said with regard to the Common Ground Alliance, a key to success will be cleaning up the exemptions to the One-Call program where a lot of hits occur from exemptions given to certain individuals.

Industry Presentation – Pressure Testing
Andrew Theodos, with NICOR (Columbia),
Mr. Theodos gave this presentation and began by reviewing the regulations in the current rulemaking vs. what is in the ASME B31.8S standard.

The main pressure testing issues include:

- The addition of water into a system raises significant safety and reliability issues,
- Need to define "significant cyclic stress",
- Quantify basis for operating condition changes,
- Rule takes a 'coarse' approach to the issues and is not founded on data,
- There is not technical justification for pressure testing low stress pipelines,
- Significant gas outage issues will result,
- Both LDCs and some grid-like interstate systems will have numerous annual customer outages raising customer safety issues.

New research includes:

- Battelle report on vintage pipe,
- P-PIC report,
- Kiefner Report on cyclic pressure effects on pipe

In summary:

- Complete research reports for use in rulemaking,
- Industry and OPS need to work together,
- Final Rule needs to incorporate ongoing research to align with ASME B31.8S,
- Focus efforts on real risk as opposed to blindly testing everything.

Mr. Drake recapped the issues and they included:

- The existing NPRM was a good attempt,
- Executives are on record in support of this effort,
- Costs associated with IM will be enormous,
- The overlap of the baseline and reassessment periods is a major issue and we need to get with the legislature to resolve,
- Both DA and CDA are essential tools,
- Need to incorporate new data where possible,
- Low stress pipelines should be dealt with differently than high stress pipelines because of the typical failure mechanism,

- Look for the areas of greatest risk and go after them, don't look for anything everywhere,
- We can't solve the TPD issue with the current set of ILI pigs,
- We all need to work together.

Comment: Bill Byrd with RCP made the following comments:

1. Don't be afraid to follow the math in both directions – larger impact zones or smaller impact zones.
2. Rural Churches should be MRAs
3. NAPSR has said this should be an additional subpart and I agree,
4. When interpreting the rule, don't throw away the incentive for operators to put all of their systems in HCAs so that everything in the program won't require complete analyses,
5. Don't forget the upstream end where gas is put into the system, when you reduce pressure you also cause some not to be able to get into the system at all,

Ms. Gerard provided a meeting recap and closed the meeting saying:

- We are extending the Comment Period by one month and hopefully this will allow everyone to fully flesh out ideas and issues for the record.
- We must operate from material on the record so submit your comments to the docket.
- The Technical Pipeline Safety Standards Committee's public technical meeting will be the week after next and we will ask them to vote on the cost-benefit analysis.
- We can't conclude the rule without a vote from the Technical committee. We must comment on why we accept or do not accept amendments to the Rule proposed at the Technical Committee meeting.
- Thanks for participating.