Technical Pipeline Safety Standards Committee
May 28-30, 2003
Washington, DC
Executive Summary of Motions Approved

The Technical Pipeline Safety Committee met in Washington, DC from May 28 to 30, 2003. The following motions were approved during the course of this meeting:

With Respect to the Proposed Integrity Management Rule for Gas Transmission Pipelines

The proposed integrity management rule for gas transmission pipelines is technically reasonable, feasible, and practicable, subject to the recommended changes identified during committee discussion.

Those recommended changes were embodied in the following approved motions:

The TPSSC accepts the OPS current position to allow a bifurcated option for building count as part of the definition of HCAs.

The TPSSC accepts the OPS current position that 20 buildings intended for human occupancy occurring within a potential impact circle be used as a criterion for determining high consequence areas.

The TPSSC accepts the OPS current position that the C-FER radius (without additional safety margin) be used to define potential impact circle to define an HCA, and that the length of the pipeline segment that could potentially impact an HCA be extended (on either side) by one additional radius.

The TPSSC accepts the current OPS position that a 3 year period be allowed in which operators can use existing house count data out to 660 feet to infer the number of houses in impact circles exceeding 660 feet in radius.

The TPSSC accepts the current OPS position that a reliability analysis be conducted for plastic pipeline, as a baseline assessment, and that appropriate preventive and mitigative measures be required.

The TPSSC recommends the approach suggested by AGA as described in their letter to the docket of April 30, 2003, "Amendment to Low Stress Pipeline Requirements" pages 6 and 7.

The TPSSC recommends that the B31.8S position, as it pertains to defects of material and *construction and increased operating pressure, be incorporated conceptually in the rule.*

The TPSSC recommends that the OPS position allowing DA as a primary assessment method contingent only on applicability to the threats and providing for assessment intervals the same as those for other methods be adopted, subject to clarification regarding how CDA fits into the process and relates to the NACE Recommended Practice.

The TPSSC recommends modifying the proposed position requiring remediation of dents without stress risers in one year to allow treating bottom-side dents as monitored conditions if the operator runs the necessary tools to perform strain calculations, meets B31.8 strain criteria, and assures that the dent involves no corrosion or stress riser.

The TPSSC recommends that OPS revise the waiver language in the proposed rule to be consistent with the language in the statute.

The TPSSC recommends that OPS use the language proposed by INGAA, in its April 17, 2003, letter, as modified by Committee comments, as the basis for considering preventive and mitigative measures to be required for the third party damage threat.

The TPSSC recommends that the rule be revised to require that operators use the risk assessment process as described in ASME B31.8S as the basis for deciding when actions need to be taken for pipeline segments not in HCAs.

The TPSSC recommends that the rule be revised to require operators to submit performance measures electronically (vs. maintain the information) on a semi-annual frequency.

The TPSSC accepts the OPS position that rural buildings be addressed in the same manner as any HCA.

The TPSSC recommends that OPS substitute "public safety officials, emergency response officials, or local emergency planning committees" for "local officials" as used in the definition of HCAs.

The TPSSC recommends that an identified site be defined as any of the following occurring within a potential impact circle:

1. *A facility housing persons of limited mobility that is known to public safety officials, emergency response officials or local emergency planning committee and which meets one of the following three criteria: 1) is visibly marked, 2) is licensed or registered by a Federal, state, or local agency, or 3) is listed on a map maintained by or available from a Federal, state, or local agency, or*
2. *An outdoor area where people congregate that is known to public safety officials, emergency response officials or local emergency planning committee and which is occupied by 20 or more people on 50 days per year, or*
3. *A building occupied by 20 or more people 5 days per week, 10 weeks in any 12-month period (the days and weeks need not be consecutive).*

The TPSSC recommends that assessments conducted prior to the rule be allowed as baseline assessments without time limit as long as they substantially meet the requirements of the rule, and that reassessments for segments covered by such assessments not be required until December 12, 2009, to the extent allowed by law.

With Respect to Proposed Changes to Part 193

The TPSSC supports the proposed change to Part 193 to adopt the 2001 version of NFPA Standard 59A with respect to the design provisions of that standard.

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Minutes

The Technical Pipeline Safety Standards Committee met May 28-30, 2003, at the Loew's L'Enfant Plaza Hotel in Washington, DC. Linda Kelly served as chairman, and called the meeting to order at approximately 1:30 PM on May 28, 2003.

The principal topic discussed at this meeting was the proposed rule on integrity management for gas transmission pipelines. Other topics included excess flow valves and the proposed rule making technical corrections to Part 193.

Integrity Management for Gas Transmission Pipelines

Chairman Kelly commended the OPS staff, and INGAA/AGA, for the preparatory material sent to the committee. She reported her belief that there is overall agreement on many issues, among them:

- the need for clarity over complexity
- the need for public understandability
- the need to focus the earliest and greatest energies on areas with the potential for greatest harm

Ms. Kelly also noted that all considerations begin from the premise that no serious injuries or death are acceptable.

Ms. Kelly requested a motion to accept the proposed rule. Discussion of each issue on the agenda related to the rule would then be intended to result in an amendment to that motion. Following additional guidance from Committee Counsel Barbara Betsock, the Committee approved the following motion:

The proposed integrity management rule for gas transmission pipelines is technically reasonable, feasible, and practicable, subject to the recommended changes identified during committee discussion.

Mike Israni then provided the following information as background to committee discussion:

- The proposed rule was published January 28, 2003, and was the subject of several public meetings
- The comment period closed April 30. OPS will consider late comments to the extent practicable.
- A total of 89 documents were received in response to the notice of proposed rulemaking

(NPRM). They ranged from 1 to approximately 100 pages. They included a total of 773 comments.

- A summary of submitted comments, and a description of issues related to the rule describing OPS's current considerations was provided to the committee before this meeting.
- OPS is seeking a vote on the proposed rule, as published in the NPRM, with recommendations as the committee finds appropriate.

Committee discussion of issues related to the rule then proceeded.

(For each issue, Mike Israni described OPS's goal, the related question(s) as posed for discussion during the public meeting, trends in public comments, and current position under consideration by OPS on the issue. These are described for each issue below, followed by a summary of Committee discussion and vote/recommendations).

1. HCA Definition – Bifurcation Option for building (SIHO[1]) count

Goal: Identify those segments of a pipeline that present the greatest potential hazard to people in order to focus integrity management efforts on those segments.

Question: Should a rule allow two options for building count (SIHO):

- following the definition of high consequence areas defined by final rule (192.761) on August 6, 2002 (67 FR 50824), or
- using potential impact circles along the entire length of the pipeline

Requirements for how an operator treats identified sites (i.e., places where people congregate and hard to evacuate buildings) that are defined in the high consequence area would not change under either option.

Comments: The industry uniformly supported this option. Public support was evident. States commented that class 3 and 4 areas should be included and potential impact circles should be used for other areas on the pipeline.

Current OPS position: to allow the option for building count

[1]SIHO = Structures Intended for Human Occupancy

Committee discussion:

Questions were asked regarding the criterion selected for building count and any planned changes to the C-FER model for calculating potential impact circles, which were deferred to later discussion.

Mr. Drake noted that it did not appear there is a practical option for large diameter pipelines, and that they appear obligated to use circles. Mr. Israni responded that this was correct.

(Mr. Matthews joined the committee by telephone after this issue was discussed. He suggested adding a third option, allowing an operator to apply integrity management to its entire pipeline, as a means of reducing the burden associated with identifying HCAs.)

A motion was made, seconded, and approved that:

The TPSSC accepts the OPS current position to allow a bifurcated option for building count as part of the definition of HCAs.

(Dr. Feigel abstained from this vote, indicating that he saw linkages between issues that made it difficult to make an informed decision at this point).

2. Population Threshold

Goal: Identify those segments of a pipeline that present the greatest potential hazard to people in order to focus integrity management efforts on those segments.

Question: Should the criterion for determining the population density component of a high consequence area be based on 10 or 20 buildings intended for human occupancy within the impact circle:

Comments: Industry and public (1 comment) supported 20. States supported 10. Related comments included a need to include critical infrastructure (made by States) and suggested use of 10 instead of 20 people as a criterion for outside gatherings (public).

Current position: Use 20 buildings intended for human occupancy occurring within a potential impact circle as a criterion for defining HCAs.

Committee discussion:

Mr. Lemoff asked why States felt that 10 was appropriate? Mr. Israni noted that there were 4 comments from States and that this suggestion was contained in one of them. It is equivalent to class 3 density (assuming uniform building distribution), and a criterion of 20 would not include many pipelines, particularly low-stress lines. The State concluded OPS should be more conservative.

Stacey Gerard noted that OPS originally considered using 10 houses, also because of the apparent equality with the existing criterion for class 3 housing density. OPS changed its position based on comments which convinced it that the uniform distribution inherent in equating 10 houses within an impact circle to the existing sliding mile criterion does not reflect the actual situation found along pipelines.

A motion was made, seconded, and approved that:

The TPSSC accepts the OPS current position that 20 buildings intended for human occupancy occurring within a potential impact circle be used as a criterion for determining high consequence areas.

3. Impact Radius

Goal: Assure that the identification of high consequence areas includes the population at risk from potential pipeline accidents.

Question: Should additional safety margin be applied to the potential impact circle radius calculated using the C-FER equation?

Comments: Industry proposed adding an additional length along the pipeline to address the elliptical shape of historical accident footprints. NTSB commented that horizontal jetting, which produces the elliptical shape, should be considered. One State suggested that additional margin was needed. The public suggested that margin should not be added if it would introduce confusion.

Current position: Use of C-FER radius (without additional safety margin) to define potential impact circle to define an HCA. Extend the length of the pipeline segment that could potentially impact an HCA (on either side) by one additional radius to meet concerns for an elliptical shape of explosion footprint in many accidents.

Committee discussion:

Ms. Kelly questioned how the current position compares to use of 4000 BTU/hour/square foot as a flux criterion. Mr. Israni replied that this would make the circles larger (approximately 12 percent), also resulting in some additional pipeline length being identified.

Mr. Drake noted that the elliptical nature of a limited number of accident footprints was recognized when the C-FER correlation was developed. The constants were selected to make the circles somewhat larger as a result. The circle remains conservative for identifying population at risk. The proposed change exaggerates that conservatism, addressing the axial nature of some accident patterns.

Mr. Lemoff noted his understanding that this did not affect how HCA's are picked, but rather increases the amount of pipe to assess thereafter. Ms. Gerard agreed, noting that she sees the affected pipe segment as separate from the definition of an HCA. The HCA is the government's conclusion of what areas have sufficient numbers of people to necessitate additional protection.

Daron Moore (El Paso) informed the committee that a preliminary analysis of pipeline that would be affected by the rule on the Tennessee Gas system determined that adding a radius would approximately triple the amount of mileage covered.

A motion was made, seconded, and approved that:

The TPSSC accepts the OPS current position that the C-FER radius (without additional safety margin) be used to define potential impact circle to define an HCA, and that the length of the pipeline segment that could potentially impact an HCA be extended (on either side) by one additional radius.

4. Population Extrapolation

Goal: Avoid imposition of unreasonable burdens while assuring consideration of the entire population at risk for potential pipeline accidents in HCA identification.

Questions:
1. Should a rule allow an operator to use data regarding the number of buildings within 660 feet of the pipeline (available now to operators because of the existing definition of class locations) to infer (extrapolate) the building density in potential impact circles larger than 660 feet?
2. Should this be limited to an interim period of five years to allow operators to collect additional data on buildings beyond 660 feet?

Comments. Industry suggested allowing extrapolation until December 17, 2002 (i.e., five years after signing of the Pipeline Safety Improvement Act of 2002) or until data is available, whichever occurs first. State and public comments did not address this issue.

Current position: Allow an interim period of up to 3 years (from the date of the rule) to gather data beyond 660 ft. for population density. Identified sites must be determined within one year of the effective date of the rule.

Committee discussion:

Dr. Feigel asked what the definition of identified sites includes. Mr. Israni responded that it includes places where people congregate and buildings housing people of limited mobility, as described in the final rule on HCAs. This led to a discussion of industry's petition for reconsideration of that rule and whether changes to the definition are being considered. Ms. Betsock advised that the petition itself was not before the committee for consideration, but that the committee could consider the substance of the petition for possible recommendations to OPS. Not all members were familiar with the petition, and further discussion of the definition of identified sites was thus deferred until copies could be provided. (That discussion is described later in these minutes).

Mr. Thomas noted that aerial photography would be the preferred means to gather this data, and that three years is shorter than the normal cycle used to photograph the right of way. Photos could be taken as often as every 2 to 3 years in high growth areas, but at intervals as long as 8 years in rural areas. He suggested that excess costs would be incurred to perform complete photography in 3 years and the 5 years would be closer to the average interval now used.

A motion was made, seconded, and approved that:

The TPSSC accepts the current OPS position that a 3 year period be allowed in which operators can use existing house count data out to 660 feet to infer the number of houses in impact circles exceeding 660 feet in radius.

5. Plastic Transmission Lines

Goal: Provide enhanced protection to high consequence areas when standard assessment techniques will not work.

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Questions:
1. What assessment requirements should be applicable to plastic transmission pipelines?
2. What operational and failure experience data exists for operational plastic transmission pipelines (e.g., number of failures, causes, conditions contributing to failure)?

Comments: Industry commented that there is a very limited amount of mileage of plastic transmission pipeline, operating at low pressure, and that the threat of concern is third party damage. Industry suggested that OPS should rely on enhanced protective measures for this pipeline. State comments supported the industry position. Public comments did not address this issue.

Current position: Require reliability analysis, based on the plastic pipe database, as the “assessment” method. Require preventive and mitigative measures consistent with all low pressure pipelines.

Committee discussion:

There was some discussion about whether plastic pipe need be included. Ms. Gerard reported OPS’s understanding that the law requires inclusion of all transmission pipeline. Phil Bennett (AGA) noted his belief that OPS has some flexibility since Congress was likely not aware that plastic transmission pipeline existed. Mr. Bennett agreed that the proposal treats plastic pipe in a reasonable manner. He further noted that some of the preventive and mitigative measures under discussion, that being those related to preventing/detecting corrosion, are not appropriate for plastic pipe.

Jim Wunderlin distributed a handout describing changes recommended by Southwest Gas, which operates approximately 600 miles of plastic pipeline that meets the functional definition of transmission pipeline (approximately 300 of these miles are in class 3 or 4 areas). Mr. Wunderlin’s handout is included as Attachment A to these minutes. It generally agrees with the OPS position that assessment methods applicable to other pipelines not be applied to plastic pipelines.

Michael Comstock asked if there is any consideration on the time in which the reliability analysis would be required. Ms. Gerard responded that it would need to be done within 10 years, unless the pipe fell into the “riskiest” first half, consistent with the requirements for completing baseline assessments.

Ms. Kelly commented that she would be uncomfortable with anything being exempt from assessments, and that this approach would establish another method for plastic pipelines.

A motion was made, seconded, and approved that:

The TPSSC accepts the current OPS position that a reliability analysis be conducted for plastic pipeline, as a baseline assessment, and that appropriate preventive and mitigative measures be required.

6. Low Stress Pipelines

Goal: Reduce assessment burden for pipe not expected to fail by rupture, but still provide enhanced protection for high consequence areas.

Questions:
1. Should assessment requirements for low-stress pipelines operating at or above 20% SMYS but less than 30% SMYS allow use of only confirmatory direct assessment (CDA) for reassessments? (baseline assessment: Pressure test, ILI, or DA)
2. Should assessment requirements for low stress pipelines operating below 20% SMYS allow use of CDA for both baseline and reassessments?
3. Should Preventive and Mitigative requirements in Class 3 & 4 locations outside of impact circles be enhanced to provide added assurance?

Comments: Industry recommends using B31.8S intervals for assessments and requiring preventive and mitigative measures. State comments were mixed, with one recommending longer intervals and one shorter. Public comments indicated a desire for a full baseline assessment, but expressed no preference on reassessment intervals.

Current position:
(a) <30% but $20% SMYS
Baseline assessments: DA, ILI or PT
Reassessment: 20 years + CDA required at 7 and 14 years
(b) <20% SMYS
Baseline: CDA (10 years)
Reassessment: CDA (every 7 years)
(c) In class 3 or 5: additional preventive and mitigative measures

Mr. Israni described the enhanced protective and mitigative measures OPS is considering as:
- increased frequency of leak surveys
- required one-call participation
- qualified staff to mark/locate and supervise excavations

- monitor all excavations OR more frequent patrols with follow-up

Mr. Wunderlin referred to Paul Gustillo (AGA) to describe the industry position on this issue.

Mr. Gustillo handed out a flow chart (Attachment B to these minutes). He reported that industry is proposing a full assessment for baseline, regardless of pressure. This is more than the position under consideration by OPS would require for pipeline <20% SMYS. The AGA proposal is for CDA every 7 years **or** preventive and mitigative measures. Ms. Gerard responded that she did not think the law would allow this. Mr. Gustillo responded that electrical or leak surveys constitute "assessment" and would thus meet the requirements of the Act.

Ms. Gerard noted that the industry proposal was more stringent than that of OPS. Mr. Gustillo responded that they are proposing a more stringent baseline in order to get relaxation on reassessment. Ms. Gerard noted that this is a key point.

Mr. Drake noted that a research project was conducted on the leak vs. rupture threshold, which showed that these pipes leak. That project could be considered part of an assessment to meet the law. With its conclusions, appropriate treatment is to prevent damage, not do assessments. ASME implemented that position as full assessments at long intervals. AGA seems to be using assessments – leak surveys – at 7-year intervals to look for problems considering the manner in which this pipe fails. Interim leak surveys would comply with the law and be constructive in terms of how problems would actually arise on the line.

Ms. Gerard indicated she saw value in the AGA proposal. Mr. Israni noted that the more stringent approach would be acceptable.

Ms. Gerard noted that there was some concern over bare pipe. Mr. Israni added that the NACE recommended practice lists only one tool for bare pipe, making DA impossible unless an operator can identify a second appropriate tool. Stanley Kastanas (OPS) noted that the agency has discussed the option of an operator proposing a replacement schedule.

A motion was made, seconded, and approved that:

The TPSSC recommends the approach suggested by AGA as described in their letter to the docket of April 30, 2003, "Amendment to Low Stress Pipeline Requirements" pages 6 and 7.

7. Pressure Testing for Material and Construction Defects

Goal: Assure protection against material and construction defects that could result in delayed failures.

Question: Should the requirement to pressure test pipeline to verify integrity against material and construction defects be limited to pipeline segments for which information suggests a potential vulnerability to such defects? If so, what information should be relied upon?

Comments: Industry commented that historical safe operation demonstrates stability, and that separate assessments should not be required. One state commented that an arbitrary test should not be required. Comments from the public did not address this issue.

OPS position: Pressure test for material and construction defects only required where actual operating pressure increases above highest level experienced in previous 5 years.

Committee discussion:

Mr. Thomas asked for clarification that these requirements would only apply to pipeline segments in HCAs. Mr. Israni agreed.

Dr. Feigel suggested caution in approaching this issue in this manner. All pressure testing introduces some risk. He would recommend that some fracture toughness or crack growth evaluations be conducted before subjecting pipe to a pressure test.

Mr. Drake noted that ASME attempted to characterize pipe of concern and that characterization is reflected in the position under consideration by OPS. There were other provisions in ASME that addressed Dr. Feigel's concern.

Further discussion elicited that this requirement would only apply to pipe that was not pressure tested after installation.

Ben Andrews noted that the proposed language appears to invalidate MAOP after 5 years. He stated an operator should have a right to operate at MAOP. Removing that right goes far beyond the subject of today's meeting.

Mr. Drake disagreed. He noted that this is similar to language in the ASME standard. The standard recognized that MAOP could have been established by high pressure experienced in 1968 (i.e., before the effective date of Part 192). If the pipe hasn't seen that pressure in many years, there could be a problem if pressure is increased significantly. Problems have been experienced under such circumstances.

Mr. Drake suggested that the 5 year window should not be a "rolling" 5 years, but rather should be locked to the effective date of the rule. Phil Bennett (AGA) suggested considering fixing it to a date 6 months after the effective date of the rule.

Dr. Willke noted that the written position provided to the committee indicated that this applied to low-frequency ERW and lap-welded pipe. He asked if this represented a condition in addition to a segment never having been tested and being located in an HCA. Mr. Drake agreed and indicated that these are criteria joined by "and" in the ASME standard.

Mr. Andrews noted that pressure testing is not always possible, e.g., single feeds, and suggested that a mirror of the uprate process be allowed.

A motion was made, seconded, and approved that:

The TPSSC recommends that the B31.8S position, as it pertains to defects of material and construction and increased operating pressure, be incorporated conceptually in the rule.

8. Direct Assessment Equivalency

Goal: Assure that direct assessment provides an understanding of pipeline integrity comparable to that provided by other assessment methods.

Questions:
1. Should DA be allowed as a primary assessment method contingent only on its applicability to the threats?
2. Should the assessment intervals required for direct assessment be revised to be the same as those applicable to in-line inspection or pressure testing?
3. Are there opportunities to quickly schedule and assess research demonstrations to provide additional data on which to base judgements about validity?
4. Would a longer baseline assessment interval produce data that would lead to early improvements in the DA process, thereby increasing the effectiveness (or assurance) of the process in later application?

Comments: Industry expressed strong support for allowing reassessment intervals for DA that are the same as for ILI and PT. State comments were mixed: one recommended a 10-year baseline, while another commented that reassessments should be required in 5 years even if all anomalies are excavated. The public expressed concern that DA is an unproven method.

OPS position:
- Allow DA as a primary assessment method contingent only on its applicability to the threats
- Revise required intervals (baseline and reassessment) for DA to be the same as those required for ILI and pressure testing.

Committee discussion:

Ms. Gerard noted that additional research was discussed at the April 25, 2003, public meeting (at which these questions were presented for discussion). OPS stated at that time that this additional work is improving the confidence the agency has in DA.

Dr. Willke asked if there was any way in which DA was not being treated like ILI or pressure testing. Mr. Israni responded no. The only condition is that it be applicable to the threats expected. The same applies to ILI. Pressure testing is essentially applicable for all threat types. Ms. Gerard noted that the inspection protocols (yet to be developed) will provide for drilling down to evaluate an operator's decisions on assessment options. Dr. Willke noted that all methods have their strengths.

Mr. Wunderlin suggested that the rule should incorporate the NACE recommended practice on DA. Mr. Israni responded that OPS is considering such incorporation, and is reviewing the standard to assure that it would be enforceable. Dr. Feigel suggested that the rule language not make use of the NACE standard mandatory, but rather that there be a presumption of conformity with allowance left for operators to define other acceptable bases.

Mr. Drake asked whether confirmatory direct assessment (CDA) would be defined more thoroughly in the rule. He believes that discussion over the last several weeks has provided additional clarification on this method, particularly that it is intended to confirm an operator's assessment process and that it <u>is</u> considered an assessment.

(Mr. Matthews joined the committee by telephone after this issue was discussed. He expressed his disagreement with the current OPS position. He believes that a 20-year reassessment interval is much too long. He suggested that reassessments be required no less frequently than once every 5 years until more experience is gained with this assessment method.)

A motion was made, seconded, modified after discussion, and approved that:

The TPSSC recommends that the OPS position allowing DA as a primary assessment method contingent only on applicability to the threats and providing for assessment intervals the same as those for other methods be adopted, subject to clarification regarding how CDA fits into the process and relates to the NACE Recommended Practice.

Ms. Kelly referred to Dr. Feigel's comment regarding allowing flexibility for operators to define another acceptable basis for DA and ascertained that it is the consensus of the committee that OPS consider this suggestion.

9. Dents and Gouges

Goal: Assure protection from delayed failures associated with dents and gouges while avoiding unnecessary excavation and repair.

Questions:
1. Should a repair criteria for dents located on the bottom of the pipeline be different from that allowed for dents located on the top? Should the presence of stress risers or metal loss affect this decision?
2. Should the requirement to remediate in 180 days be changed to one year?

Comments: Industry supported use of ASME B31.8 repair criteria, changing the required remediation period to one year, and treating bottom-side dents as "monitored conditions".

Current position:
- Any dent with a stress riser or gouges should be repaired immediately.
- Revise remediation criteria to allow one year for repair of dents specified in paragraph 192.763(i)(4)(ii).

Committee discussion:

Dr. Willke questioned how an operator knows if there is a stress riser. He sees a potential for a presumption of the existence of a riser leading to inappropriate treatment of many dents as immediate conditions. Mr. Drake agreed, stating that we need to avoid digging up a lot of benign dents and creating non-benign situations. Mr. Israni noted that the OPS position required immediate remediation only when it is known that a stress riser exists.

Mr. Drake noted that Kiefner and Associates had been assigned to incorporate consideration of dents with stress risers into ASME B31.8. They added strain considerations that are comprehensive. He suggested that OPS could allow that operators who are willing to run a strain calculation, for constrained dents, and who assure from inspection logs that there is no corrosion or stress riser, be allowed to treat those dents as monitored conditions.

Ms. Gerard asked how one would know that a dent is constrained. Mr. Drake responded that bottom-side dents would be presumed to be constrained, and noted that a loss of support for the pipe (the condition which would remove the constraint) would be known.

Mr. Thomas questioned what ILI tools can see in terms of stress risers. Mr. Drake agreed that most could not see sharpness of a dent (a possible stress riser). There is a slope deformation tool that can see them. An operator would need to bring in that type of data to be able to assure that they are protecting the integrity of the pipe. It is a high hurdle, but it provides a technically acceptable way for operators to deal with indications without digging up a lot of benign dents.

Ms. Kelly questioned whether the proposal would be for operators to make these determinations on their own. Mr. Drake noted that he expects that OPS would review these determinations during its audits.

Dr. Willke asked if there should be a presumption that remediation is required unless an operator demonstrates it is not needed. Mr. Drake agreed.

A motion was made, seconded, and approved that:

The TPSSC recommends modifying the proposed position requiring remediation of dents without stress risers in one year to allow treating bottom-side dents as monitored conditions if the operator runs the necessary tools to perform strain calculations, meets B31.8 strain criteria, and assures that the dent involves no corrosion or stress riser.

The committee at this point discussed a concern regarding the need for a waiver provision if repairs cannot be completed in time. A motion on this issue was tabled earlier (presented here out of order).

Mr. Wunderlin questioned whether the rule incorporated sufficient waiver flexibility to address situations in which there could be an impact on customer supply. A motion was proposed to recommend that OPS consider changes to the waiver process.

Barbara Betsock informed the Committee that OPS is bound by statutory limits. OPS cannot waive completion of baseline assessments in 10 years. It can waive the 7-year reassessment interval, because there is language in the Act specifically allowing that action.

Mr. Drake pointed out that repair provisions are also of concern. Required pressure reductions can have a supply impact. Mr. Wunderlin also described a hypothetical situation in which an inspection found a line with numerous anomalies such that an operator decided to replace it instead. Replacement would take time. There needs to be an option for an operator to bring forward a plan and OPS to agree on a course of action.

Stacey Gerard noted that the proposed rule includes a notification process. Roger Huston (Cycla Corporation) described how that process is being implemented for the hazardous liquid integrity management rule. Operators can notify OPS if they are unable to meet the provisions of the rule in three instances: complete repairs in time (and unable to reduce pressure), use of "other technology" to perform assessments, and establishment of reassessment intervals longer than 5 years. Operators need not get OPS approval. OPS reviews notifications that are submitted to determine if the deviations from rule requirements are sufficient to require further inspection. If not, no action is taken. The review is coordinated via web-based databases and information regarding all notifications is available to the public on the internet (http://primis.rspa.dot.gov/iim).

Phil Bennett (AGA) noted that a pipe replacement project, as described by Mr. Wunderlin could take years, and asked if OPS could still agree to such a course of action. Ms. Gerard responded that the agency could not waive completion of the baseline assessment in 10 years, but could agree to other deviations.

Mr. Bennett then noted that the waiver provisions in the proposed rule, relating to the statutory authorization to waive the 7-year reassessment interval, do not track the statutory language. The rule provides for a waiver if there will be a cut-off of supply. The law addresses maintaining supply. Mr. Bennett noted that pressure reductions, locally or on transmission lines feeding a local supply, could result in curtailments.

Mr. Wunderlin stated that the description of the notification process resolved his concerns about repairs. He withdrew his motion. A new motion was made, seconded, and approved that:

The TPSSC recommends that OPS revise the waiver language in the proposed rule to be consistent with the language in the statute.

10. Treatment of Third Party Damage

Goal: Protect against delayed failures from third-party damage in cost-effective manner.

Questions:
1. Should additional third-party damage prevention methods be utilized instead of explicit assessments for third-party damage?
2. What methods should be used in conjunction with other assessment methods to detect delayed third party damage?
3. What role should data integration play in determining whether significant potential exists for delayed failure from third-party damage?

Comments: Industry commented that prevention is the best method to address this threat and that assessments should not be required for it. State comments agreed that protective measures should be relied upon. One public comment suggested that OPS should retain approaches that would foster development of improvements in assessment technology, such as ability to detect third-party damage.

Current position: Require enhanced prevention and mitigation measures where vulnerable to delayed failures following third party damage.

Committee discussion:

Dr. Willke asked what kind of protective measures are being considered. Mr. Israni responded with examples: increased patrols, required participation in one-call programs, more markers, more frequent surveys, monitoring construction/excavation. OPS will consider all comments that suggested protective measures. Ms. Gerard noted that the concept under consideration is an enumerated list of actions.

Mr. Thomas noted that INGAA has made a specific proposal in this regard (letter to docket dated April 17, 2003). Ms. Gerard agreed that this was the type of measures OPS is considering.

Several members expressed concerns about assuring adequate flexibility in required actions. Among these were:

- assure that requirements to monitor excavations are limited to "known" work
- do not limit patrols to aerial and foot; other methods are used to patrol pipelines such as vehicles and horse patrols
- provide flexibility in language requiring that excavations be monitored to recognize different situations, e.g, low-pressure pipeline may not have a defined right of way.

Mr. Thomas suggested that the INGAA submission be used as a basis for considering preventive and mitigative measures. Three minor changes to the INGAA language were suggested:

- In suggested paragraph (2)(ii), replace "third party damage" with "excavation damage"
- In suggested paragraph (2)(iv), insert "known" before "excavations" as, "Monitoring all known excavations"
- Insert "may" before "include" in the paragraph following (2)(v) as, "...these measures may include, but are not limited to...".

A motion was made, seconded, and approved that:

The TPSSC recommends that OPS use the language proposed by INGAA, in its April 17, 2003, letter, as modified by Committee comments, as the basis for considering preventive and mitigative measures to be required for the third party damage threat.

11. Application of Integrity Lessons Outside HCAs

Goal: Assure protection of the entire pipeline from problems identified through assessment activities in high consequence areas.

Question: How can the requirements be clarified for the situations when an operator should look beyond the segment in a high consequence area, when segments outside the HCA are likely to have similar integrity concerns as those found inside an HCA?

Comments: Industry found the proposed requirements unwarranted, and suggested they have a tendency to divert attention to lower risk pipe, contrary to the overall intent of the rule. Industry suggested that the risk assessment process described in ASME B31.8S is the appropriate means to integrate information gained and determine what actions are needed. State comments agreed that data indicating unexpected problems needs to be considered, but that it is appropriate to take different actions for lower risk pipelines.

Current position: Require that operators who identify problems during assessments use that information to update their risk assessment and take actions in other areas potentially at risk, including outside HCAs, as appropriate.

Committee discussion:

Mr. Drake noted that industry's comments in this area had evolved over time. The current belief is that an operator cannot ignore lessons learned, but that they also can't address all pipelines with the same degree of rigor. The B31.8S risk assessment process provides a means to decide on the appropriate degree of urgency. One of the concerns regarding the proposed rule is that it appears to require that "assessments" be performed in segments outside HCAs with similar conditions. "Assessment" is a term with a particular meaning in the context of this rule, referring to ILI, pressure testing, or DA. Requiring that such actions be taken based only on similarity of conditions would be a significant burden and would potentially cause significant disruption to an operator's planned schedule for conducting assessments in HCA segments.

Ms. Gerard noted that the integrity management rule for hazardous liquid pipelines requires operators to evaluate all pipe. She would prefer that this rule be consistent.

A motion was made, seconded and approved that:

The TPSSC recommends that the rule be revised to require that operators use the risk assessment process as described in ASME B31.8S as the basis for deciding when actions need to be taken for pipeline segments not in HCAs.

12. Performance Measures

Goal: Provide current information to state and federal regulators regarding effectiveness of IM programs.

Question: Should we require monthly/quarterly/yearly electronic reporting of performance measures?

Comments: Industry supports periodic reporting, generally quarterly for program progress and annual for accidents/events. Industry objects to requirements to provide electronic access to this information. States that commented indicated that information would be obtained through inspection interactions with state operators and that the reporting of performance measures was thus of less importance.

Public comments indicated that information on performance should be made available to the public.

Current position: Require that operators maintain the 4 performance measures and update the information quarterly. Operators must maintain the information in a manner that allows OPS and state regulators to access it electronically.

Committee discussion:

Mr. Drake noted that the proposed requirement that operators maintain this information in a manner to allow electronic access is unnecessary and burdensome. In initial discussions, there was concern that sensitive or proprietary information would be needed, and that such information could be subject to freedom of information requests if it were held by DOT. As the performance measures have evolved, however, this issue has abated. There appears to be no problem in providing information to the public, as long as it is not related to a specific HCA. He suggested electronic submission of this information, for OPS to post. Other committee members agreed with this approach.

Dr. Willke suggested the need to anticipate a time when more sensitive performance measures may be needed. Mr. Drake agreed. He noted that the performance measures project had discussed the need to better manage data for statistics and trends and to provide information to guide the industry strategically. He suggested that the type of additional measures Dr. Willke referred to would not necessarily be appropriate for the public, but rather to guide OPS development of rules, etc. He asked that the record reflect a need to keep the issue of performance measures before the committee for future consideration.

The required periodicity of reporting was also discussed. Several members indicated a preference for annual, vs. quarterly, reporting. This would minimize burden, since much other information is now reported quarterly. It would also "smooth" irregularities in data that might result from seasonal affects, e.g., more assessment work conducted in the summer, and would better identify trends. Ms. Kelly and Mr. Matthews indicated that they believed information should be reported more frequently than annually.

A motion was made, seconded, and approved that:

The TPSSC recommends that the rule be revised to require operators to submit performance measures electronically (vs. maintain the information) on a semi-annual frequency.

13. Rural Churches

Goal: Identify those segments of a pipeline that present the greatest hazard to people in order to focus integrity management efforts on those segments.

Question: Should rural buildings (e.g., rural churches, etc.) be designated as moderate risk areas, requiring only CDAs or enhanced preventive and mitigative measures?

Current position: Treat like any other area where people congregate.

There was no committee discussion. A motion was made, seconded and approved that:

The TPSSC accepts the OPS position that rural buildings be addressed in the same manner as any HCA.

14. Identified Sites

The Committee held an extensive discussion regarding that portion of the definition of HCAs related to areas where people congregate and buildings containing populations of limited mobility, so-called identified sites. A common understanding of this definition is important to several of the specific rule issues discussed, including the bifurcated HCA definition option and treatment of rural churches like other HCAs. It became apparent during discussions that there was not a common understanding between committee members and between members and OPS. The discussion that ensued took place at several times over the three-day meeting. All elements of that discussion have been collected here.

Industry submitted a petition for reconsideration of the final HCA rule, by letter from AGA dated September 5, 2002. These issues are central to the petition. Barbara Betsock advised that the petition itself is not before the Committee for consideration. She further advised that the Committee was free to discuss related issues of substance. There are limitations on what can be done in this rule, given the scope of the notice of proposed rulemaking. Nevertheless, OPS desires advice from the Committee and will consider how best to address it.

Ms. Betsock suggested three options for addressing concerns in this area:

1. Proceed immediately to develop protocols by which inspection and enforcement of the rule will be implemented.
2. Develop guidance, to be published in the Federal Register. This guidance could be different

from the rule, with subsequent changes made to the rule
3. Change the rule, probably after guidance is developed.

Ms. Kelly suggested that the committee should discuss the substance, not the form, of what is needed. The Committee agreed, but indicated a strong preference to have finality and stability in this area. Mr. Drake noted that the concern was ability to have some finality in the definition of identified sites. The proposed criteria would leave it open. A facility appearing on a new database would be a potential liability for an operator. Operators want to have some definitive endpoint to their search for identified sites.

Other concerns expressed by committee members included:

1. requirement to consider all commercially available databases
2. requirement to consider 50 days per year vs. the historic 5 days/week, 10 days/year
3. threshold number of people congregating, particularly when sheltered within a structure
4. clarification on the role of public officials

Ms. Gerard noted that concerns have been expressed about the difficulty of identifying sites housing people of limited mobility. That issue was discussed with the Committee earlier, and a question was included in the preamble of the NPRM asking if the "public officials" referred to in the definition should be clarified as "public safety officials". The intent was to make these officials, who are expected to be knowledgeable about facilities in their communities requiring special care, as the definitive source for identifying populations of limited mobility. Other sources of information enumerated in the HCA definition would then become examples, but not required. She asked if this would revise the ambiguity.

Committee members continued to have concerns about the threshold for defining a facility housing persons of limited mobility. It was generally agreed that this would not encompass a house where a resident had just returned from a hospital stay. There was uncertainty about how to establish a threshold, however. Through discussion, apparent agreement was reached that local officials responsible for health and safety should be aware of any "facilities" requiring special attention due to residents of limited mobility. The Committee agreed that establishing a presumption that the facilities known to such officials is the extent of what an operator must evaluate would help.

The question of which local officials should be involved was also addressed. The Committee agreed with OPS's proposed clarification of "public safety officials", and suggested addition of "emergency response officials". The Committee further noted that each community is required to have a local emergency planning committee, and that this body could also be appropriate.

A motion was made, seconded, and approved that:

The TPSSC recommends that OPS substitute "public safety officials, emergency response officials, or local emergency planning committees" for "local officials" as used in the definition of HCAs.

The Committee also discussed the question of threshold: the number of people that constitute a congregation sufficient to justify establishing an HCA. Industry comments proposed a threshold of 50 persons inside a building, based on approximate equivalence with 20 housing units (assuming approximately 2.5 persons per house). There is general agreement on use of 20 persons as a threshold for outdoor gatherings, consistent with historical treatment in 192.5. (Some public comments suggested lowering this threshold).

Ms. Gerard commented that OPS would have difficulty treating persons of limited mobility the same as those who were not so limited, because they are less able to escape an area of danger should an accident occur. She did not suggest a different threshold, but rather that this hinge on the understanding of the local safety officials regarding what constitutes a "facility". That term was used in the preamble to the NPRM, but was not previously a part of the rule.

Further discussion suggested a hierarchy among the criteria for defining a facility housing persons of limited mobility. First, it would have to be known by local safety officials, emergency response officials, or the local emergency planning committee. Operators should not be responsible for identifying facilities not known to these groups. (Although, as pointed out by Ms. Kelly, an operator is always responsible for taking appropriate action if they have definitive knowledge). The remaining criteria in the definition would then be additional. An operator would start with the list obtained from local officials and would determine if they are:

- visibly marked, or
- licensed or registered by a federal, state or local agency, or
- on a map or list maintained by federal or state local government agencies.

Any facility identified by the local officials and found to meet one of these additional criteria would be considered an HCA, if it occurred within a potential impact circle.

The situation is different for buildings housing congregations of people of normal mobility. Such structures have been part of the definition of class 3 areas for many years. 49 CFR 192.5 defines a class 3 area, in part, as an area where the pipeline lies within 100 yards of a building that is occupied by 20 or more persons on at least 5 days per week for 10 weeks in any 12 month period. Mr. Drake pointed out that this wording excludes rural churches that are used only for weekly services, being occupied only one or two hours each week. At the same time, it would encompass religious facilities used more often, for example those that hold services several times per week, conduct bible study classes, or support other community events. The industry members of the committee supported using this same definition for HCAs, but extending the area to include the entirety of any potential impact circle calculated along the pipeline.

As a result of discussion, Mr. Drake suggested that the definition has three components: facilities housing people of limited mobility, outdoor areas where people gather, and buildings in which people congregate.

A motion was made, seconded and approved that:

The TPSSC recommends that an identified site be defined as any of the following occurring within a potential impact circle:

- ***A facility housing persons of limited mobility that is known to public safety officials, emergency response officials or local emergency planning committee and which meets one of the following three criteria: 1) is visibly marked, 2) is licensed or registered by a Federal, state, or local agency, or 3) is listed on a map maintained by or available from a Federal, state, or local agency, or***
- ***An outdoor area where people congregate that is known to public safety officials, emergency response officials or local emergency planning committee and which is occupied by 20 or more people on 50 days per year, or***
- ***A building occupied by 20 or more people 5 days per week, 10 weeks in any 12-month period (the days and weeks need not be consecutive).***

15. Other Issues Related to the Proposed Integrity Management Rule

The Committee discussed four additional issues related to the proposed integrity management rule:

1. Overlap of baseline and reassessments

Mr. Drake noted that this issue has been discussed in the public meetings. Congressional staffer Graham Hill stated at the February INGAA/AGA workshop that Congress intended that the 10-year baseline period be completed before the 7-year reassessment period began.

Ms. Betsock responded that the law is clear on its face, and that the clear language requires that reassessments of individual segments begin 7 years after their baseline assessment. This necessarily leads to an overlap of baseline and reassessments in the eighth, ninth, and tenth years. Congress has not otherwise spoken to this issue. Mr. Hill's comments are only the observations of one Congressional staff member and cannot lead to an interpretation counter to the plain meaning of the law.

Mr. Drake responded that he believes that the RSPA interpretation of the language of the act is faulty.

2. Treatment of prior assessments

Mr. Drake objected to the limitation on consideration of assessments conducted prior to the enactment of the law. The proposed rule would establish a limit of December 12, 1997. Assessments conducted before that period would not be allowed to be treated as baseline assessments. Mr. Drake contends that this limitation is unreasonable, and that operators should be allowed to consider prior assessments as long as they substantially meet the requirements of the rule and current inspection standards.

Mr. Drake further noted that an operator is penalized by counting a prior assessment, in that a reassessment is required to be conducted within seven years of the date of that assessment. If an operator credits an assessment conducted in 1997, for example, then the reassessment is required in 2004, only two years after enactment of the law, despite the fact that the segment involved would have been remediated as necessary. An application of risk assessment to prioritize assessments within the 10-year baseline period would almost certainly have scheduled assessment on that segment for near the end of the 10-year period.

Ms. Betsock noted that this outcome was dictated by the language in the Act. Mr. Drake suggested that the Act could be interpreted not to require any reassessments before 7 years after its enactment. He proposed, therefore, that the rule require that reassessments for pipeline segments for which prior assessments are credited as baselines must be completed by no later than seven years after its enactment.

A motion was made, seconded, and approved that:

The TPSSC recommends that assessments conducted prior to the rule be allowed as baseline assessments without time limit as long as they substantially meet the requirements of the

rule, and that reassessments for segments covered by such assessments not be required until December 12, 2009, to the extent allowed by law.

3. Performance-based option

Mr. Drake objected to the provisions of the proposed rule establishing criteria for entry into the performance-based option.

Mr. Israni responded that these criteria were unclear. OPS intended that two valid assessments be conducted before a pipeline segment can be included in a performance-based program. It is acceptable for one of those assessments to have been conducted prior to the baseline, rather than after. The final rule will be clarified in this regard. The language "state of the art" used in this section is also unclear and will be replaced in the final rule.

4. Reporting

Ms. Kelly noted that reporting and notification requirements in the proposed rule directed operators to make reports to OPS. State authorities need to be aware of these reports for intrastate pipelines, and for interstate pipelines in states in which the State acts as an interstate agent. It was determined to be the consensus opinion of the committee that the reporting requirements should be revised to reflect appropriate notification of state authorities.

Cost-Benefit Analysis of the Proposed Integrity Management Rule

Charlie Muraska, representing the Office of Chief Counsel, Small Business Administration, addressed the Committee regarding the requirements of the Regulatory Flexibility Act. Agencies promulgating rules must assure no unreasonable impact on small businesses. The Office of Chief Counsel takes the position of small businesses in reviewing rulemakings, not that of the SBA or the Administration. The Office is concerned that OPS did not adequately evaluate the proposed rule for potential impacts on small businesses.

Marvin Fell (OPS) added that OPS has not done a good job of finding the small businesses. The agency is working with APGA to try to improve.

Terry Boss (INGAA) noted that there could be impacts on many small businesses as a result of increased costs or restricted supply of gas resulting from this rule. Mr. Muraska responded that these would likely be indirect impacts, which are treated differently.

Mr. Fell then discussed the cost-benefit analysis supporting this proposed rule. He noted that cost-benefit analysis is a crude tool. Some costs were likely underestimated in this analysis. Costs, and perhaps benefits, will likely change as a result of decisions made at this meeting. Those decisions, however, are matters of policy. They are informed by cost-benefit results, but not driven by them.

Mr. Fell objected to industry contentions that there will be significant supply interruptions as a result of the proposed rule. He distributed an analysis (from the docket) performed by the Department of Energy in that regard. The principal conclusion of the analysis was that the planning horizon inherent in the proposed rule was sufficient for operators to conduct assessments in a manner that would avoid significant impacts.

Ms. Kelly noted that the costs estimated in the analysis will likely change as a result of the actions taken by the Committee at this meeting. The Committee is obligated to vote on the cost benefit analysis. OPS will revise the analysis, reflecting the recommendations made at this meeting, and will distribute the revised analysis to the Committee. A meeting will then be held, most likely by telephone, for discussion of and voting on the analysis.

Dr. Willke noted that it is difficult to quantify all the benefits and costs. In this case, we end up with large unquantified benefits, such as improved public safety. He suggested that one means of characterizing the costs and benefits of this rule is to compare it to alternatives, describing the incremental costs compared to such alternatives. Ms. Gerard noted that the alternative suggested by NTSB, to consider essentially all areas where people are in proximity to the pipeline, would be one benchmark to consider.

Mr. Drake agreed. He noted that industry is on record as supporting this rule. Nevertheless, it is important to document the intangibles and the likely costs as best we can. The analysis will, in part, inform other agencies and interested parties regarding the potential economic impacts of the rule.

Mr. Comstock noted that there likely will be costs to small operators from service interruptions associated with assessments. This could be quantified. Mr. Wunderlin agreed. He noted that El Paso is currently conducting inspections on pipelines that are the sole supply for Phoenix and Tucson. Southwest Gas is working to minimize the impact. They have estimates of over $100,000 to provide LNG and standby fuel to account for supply interruptions.

Technical Pipeline Safety Standards Committee
May 28-30, 2003
Washington, DC
Minutes

Excess Flow Valves

The Committee heard from Nashville Fire Chief Steve Halford, National Director of the International Association of Fire Chiefs, on the subject of excess flow valves.

Chief Halford reported that Gary Breeze, Executive Director of the Association had submitted a letter to the docket dated May 6, 2003, responding to the cost-benefit analysis on installation of excess flow valves. The letter offered 7 specific comments on the analysis by Volpe Institute. The Association believes that the Volpe analysis validates use of excess flow valves, and that their installation should be required.

The frequency of gas line breakage and resulting damage can be significant. The costs to install the valves appear reasonable. The Chief contended that public safety requirements are not always driven by strict cost-benefit analysis. Firefighters respond to gas leaks every year. These leaks pose a threat to them and to the community of death, injury, and serious property damage. The Chief believes that most active leaks could be prevented by installing excess flow valves in gas supply lines.

Approximately 4 million valves have been installed voluntarily. NTSB has called for their installation. OPS required their installation on new or renewed lines in 1999, unless operators notify customers of the benefits and availability of the valves. This wasn't what the Association wanted, but it was a good start. Notification is not always to the end consumer. For new construction, it is often to the builder, who has an incentive to minimize costs.

We must consider costs. For EFVs, however, they clearly do not outweigh benefits. The costs for the valves are small, and can be passed on to the consumer. Preventing one death outweighs the nominal costs.

Richard Huriaux (OPS) reported that NTSB has recently recommended requiring installation of EFVs for new or renewed service as long as the service is consistent with available hardware. Mr. Huriaux noted that existing requirements in 192.381 set performance standards for EFVs, and that requirements in 192.383 establish requirements for operators to notify customers of their availability. Technology and costs in this area have improved. Most new and renewed service lines are now having EFVs installed by operator decision. There is no policy or regulatory proposal on the table at this time. The cost-benefit analysis was performed to consider possible regulatory action. Comments have been received. OPS is seeking advice from the Committee. All will inform the policy decision.

Marvin Fell described the comments on the analysis. More than 30 have been received. Comments came from manufacturers of EFVs, Fire Chiefs, AGA, APGA, operators, the public, and NTSB. The comments varied, and included questions about the methodology for normalizing the data. Generally manufacturers and members of the public were in favor. Operators believed the analysis was done incorrectly and that installation should not be mandated. Volpe has agreed that there are errors in the analysis, and will make changes.

Mr. Wunderlin noted that Southwest Gas is separately providing information to Mr. Fell. He noted that the analysis addressed installation on commercial and industrial applications in addition to residential. This significantly changes the issue. There is a potential to shut down industrial operations, with potential for millions of dollars in damage, in the event of inadvertent operation of these valves.

John Erickson (AGA) reported that industry review of the analysis indicated it did a good job of qualitatively describing the benefits. It did not use data for incidents on pipes operating at greater than 10 psi. The estimated benefit was ten times the actual. Costs related to installation also need to be considered.

Mr. Lemoff noted that there is no question that EFVs will operate for a complete pipe break. It is not so obvious for small/partial breaks. At high pressures, they work well. At 7 inches of pressure, for residential service, they are difficult to size correctly. He would ask the staff to be diligent about determining if incidents are ones an EFV would actually prevent.

Dr. Willke commented that the conceptual analysis was good. The benefits are likely overstated and costs may be understated. The likelihood is that the cost-benefit is always going to be near 1. The calls to require installation as a matter of public confidence will not go away. He believes it would be useful for industry to bring forward an argument regarding whether installation would improve public confidence.

Mr. Huriaux noted that this is an exploratory analysis, and that any rule would be supported by its own analysis.

Operator Qualification

Ms. Gerard reported that Congress has directed OPS to develop standards for operator qualification. Inspection protocols have been developed via a public meeting process. NTSB has reviewed this process. They have indicated, informally, that they think the protocols are a positive development, but that there remains an issue of enforceability concerning operator use of training. She is seeking advice from the Committee.

The law requires that operators notify OPS of changes in their plans. That means a new rule, but it should be a minor rulemaking. Ms. Gerard specifically wants Committee advice about adding some other minor changes to that rule, consistent with the public discussions on operator use of training. In the protocols, there were two areas where actions regarding training were not enforceble. Those would be addressed by rule change.

Mr. Drake noted that the OQ rulemaking was done under a very different context. It is very performance-based. We have learned the need for more detail in developing the standards. A team was established, including representatives of industry and government, to develop the protocols and reach closure. He suggested that this team be reconstituted to see if they can address the gap of concern to NTSB.

Industry members representing interests on the task force agreed with this approach. Daron Moore, who chaired industry activities, estimated that the committee could be reassembled and determine how to resolve the issue in about 3 weeks. Ben Cooper (AOPL) reported that his members have a very strong interest in closing the related NTSB recommendations. Bob Cave (APGA) agreed.

No action was requested of the Committee and none was taken.

Changes to Part 193

Buck Furrow (OPS) presented changes included in a May 1, 2003, notice of proposed rulemaking modifying Part 193 requirements for liquified natural gas (LNG).

A principal element of this proposed rule is changing references to National Association of Fire Protection standard 59A to reflect the current version (2001).

Paul Gustillo (AGA) noted that industry is still assembling comments on the proposed rule. Initial review has identified as a major concern making Chapter 9 of the standard retroactive to existing plants. (Mr. Furrow contended that OPS has always considered these fire standards to apply retroactively). Operators are also suggesting review of procedures every two years, coincident with training, rather than the one year proposed. There is also concern about mandatory evacuation of buildings during fire drills. AGA is still collecting and analyzing comments.

Ms. Gerard noted that a Committee recommendation on this rule is required. It was included on this agenda, even though the comment period is still open, because it was not clear that the Committee would have another opportunity to consider it. Since the Committee now plans to meet by telephone to discuss the integrity management cost-benefit analysis, this could be added to that agenda.

Mr. Furrow noted that OPS has heard from several companies on the need for an early indication of whether OPS will adopt the new standards. New facilities are now being designed, and the choice of standards can affect that design.

Patricia Outtrim (PTL) reported that she has also heard from industry on the need to bring the codes current. The LNG industry would support an update to 2001, but she indicated that a vote by the Committee would help provide assurance to the industry that this action is likely to occur.

Paul Gustillo reported that the initial comments from industry have indicated no disagreement with the design, siting, and construction provisions of the 2001 standard.

Ms. Gerard asked that the Committee support the proposed rule with the proviso that OPS will consider the AGA comments. Several members objected to such a vote as too open-ended. Mr. Lemoff noted that the comments are all directed towards the O&M requirements. He suggested that the issue be separated out and that the Committee vote on the design provisions.

A motion was made, seconded and approved that:

The TPSSC supports the proposed change to Part 193 to adopt the 2001 version of NFPA Standard 59A with respect to the design provisions of that standard.

Ms. Gerard thanked the Committee for its patience and advice. She noted that there is much work left to be done. OPS plans to return to the Committee on the following issues:

- Research
- Operator Qualification
- LNG
- Direct Assessment

The meeting was adjourned at approximately 1PM on May 30, 2003.

Attachment A – Handout by Jim Wunderlin

Recommeded Regulations for Plastic Transmission Pipeline - TPSSC Meeting

By Jim Wunderlin

The OPS question is: What assessment requirements should be applicable to plastic transmission pipelines?

Summary/Justification

I would like to say a few words about plastic transmission pipe because I operate some plastic pipe that is considered transmission line by the functional definition. Plastic pipe does not have a percent SMYS so it is not classified as low or high stress. Plastic pipe operates at low pressures, usually less than 100 psi. We estimate that there are approximately 600 miles of plastic transmission pipelines, nationally, and of that maximum 300 miles in Class 3 and 4.

Plastic transmission pipelines was not considered by Congress or discussed in the NPRM, so we believe OPS has the power to exclude plastic pipelines from the integrity management regulation. We agree with OPS that there should be no integrity assessment under 192.723 for plastic pipe. The assessment methods are not appropriate. The third party damage preventive and mitigative measures under 192.614 can provide added protection to plastic transmission pipelines. There is also an existing plastic pipe database to document and trend plastic material performance. We support the idea that operators should consider trends that are reported out of the Plastic Pipe Database Regulator/Industry Group to determine if there are any that are applicable to their pipe that warrant attention.

<u>Recommended Language</u> (New text is underlined)

While it appears we are in agreement with OPS on the management of plastic pipe, there is no language in the briefing book. We suggest the following language consistent with the justifications discussed.

- We can add one sentence to exclude plastic from 192.763.
- Section 192.614 is being modified for low stress pipe, and one line is needed for plastic pipe.
- The existing section "d" in 192.614 becomes section f because of two new sections.

§ 192.763(b) What pipeline segments are covered?

Transmission pipeline segments as defined in See. 192.3 that are in a high consequence area, as defined in Sec. 192.761, <u>except it does not cover plastic pipe that meets the functional definition of a transmission pipeline.</u>

§ 1 92.614 Damage Prevention Program

(d) Unless they meet the requirements of 192.763, transmission pipelines that operate at a hoop stress less than 30% SMYS within Class 3 and 4 locations must comply with paragraph 192.763(j)(4)(iv).

<u>*(e) Plastic transmission pipelines within Class 3 and 4 locations must comply with paragraph*</u>

192.763(j)4)(iv).

(~~d~~*f*) A damage prevention program under this section is not required for the following pipelines:
(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and ...

Backup Notes

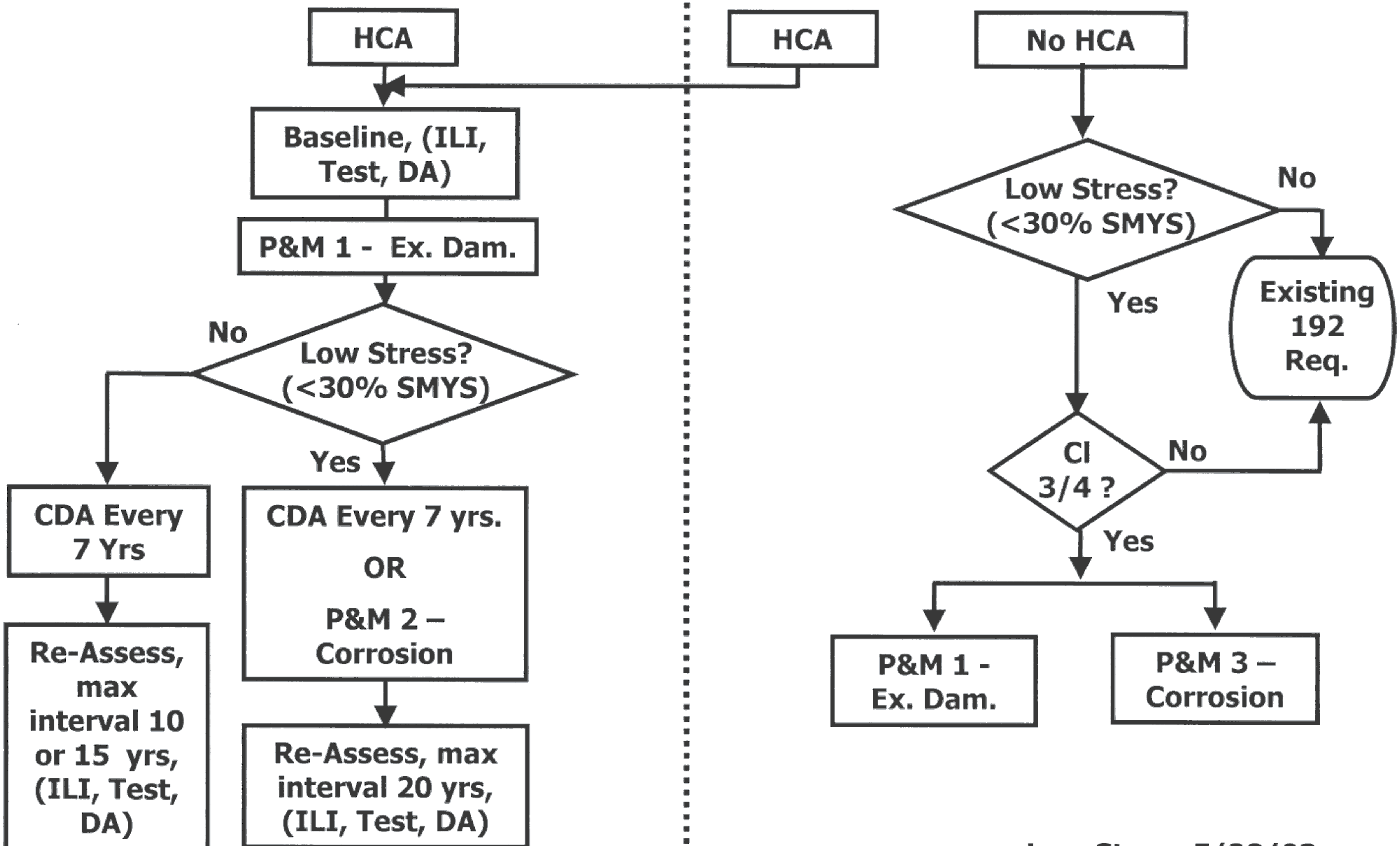
1. Plastic pipe does not corrode, so the corrosion preventive and mitigative measures in 192.763 are not appropriate.
2. Cathodic protection is not appropriate for plastic pipe.
3. The suggested enhanced leak surveys for steel pipe may be based upon the potential for corrosion leaks. There is no data that increased leak surveys are appropriate for plastic pipe.
4. For plastic pipe, third-party excavation damage is the primary threat.

Option 1

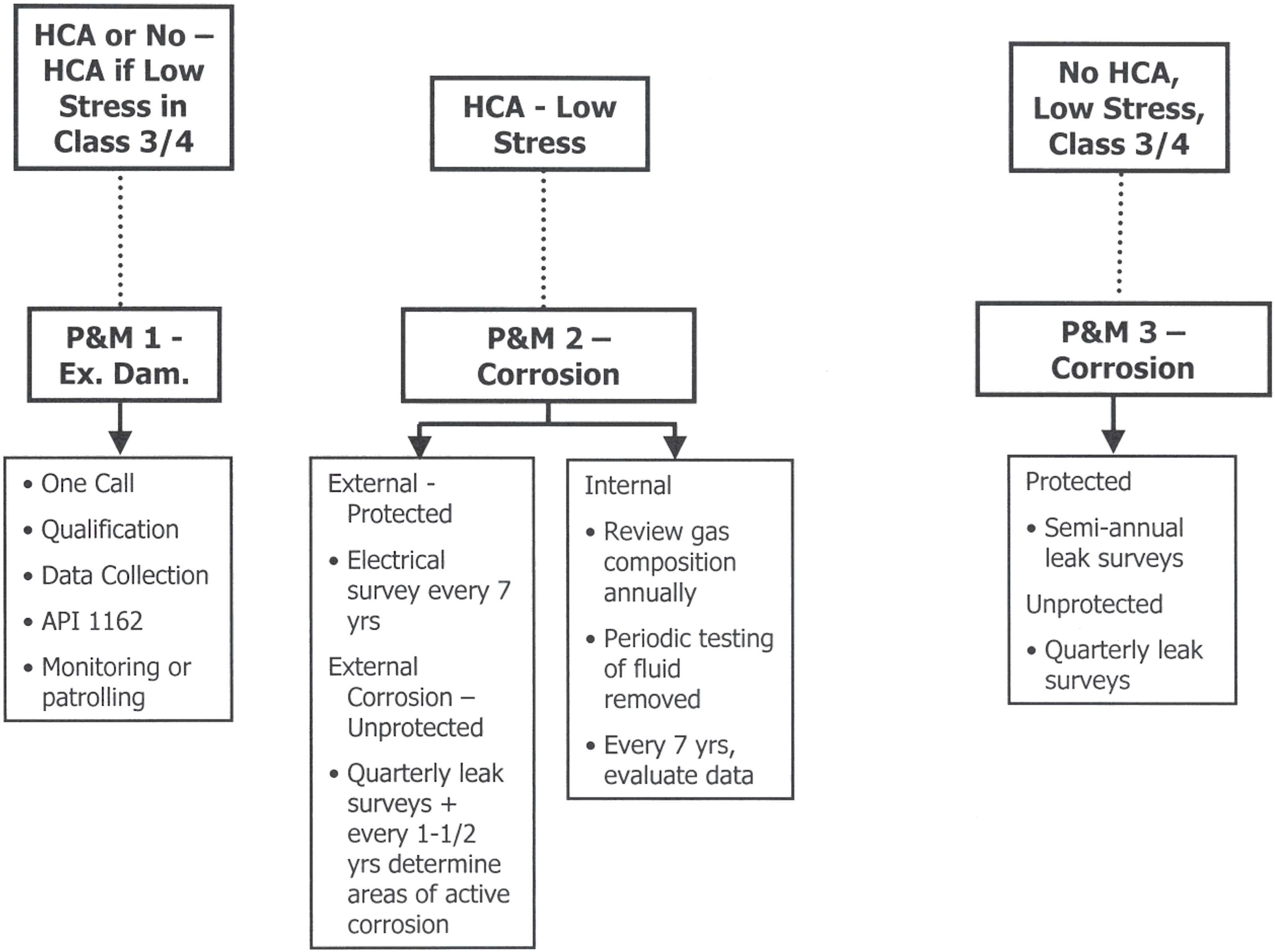
Operator declares All Cl 3 and Cl 4 HCAs and finds identified sites within PIC in Cl 1 and Cl 2

Option 2

Operator uses C-FER equation. 20 bldgs. or identified sites in PIC in Cl 1, 2, 3, and 4



Low Stress 5/28/03


HCA or No – HCA if Low Stress in Class 3/4
P&M 1 - Ex. Dam.
• One Call
• Qualification
• Data Collection
• API 1162
• Monitoring or patrolling
HCA - Low Stress
P&M 2 – Corrosion
External - Protected
• Electrical survey every 7 yrs
External Corrosion – Unprotected
• Quarterly leak surveys + every 1-1/2 yrs determine areas of active corrosion
Internal
• Review gas composition annually
• Periodic testing of fluid removed
• Every 7 yrs, evaluate data
No HCA, Low Stress, Class 3/4
P&M 3 – Corrosion
Protected
• Semi-annual leak surveys
Unprotected
• Quarterly leak surveys