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*In business to deliver*

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Docket Management System
U.S. Department of Transportation
1200 New Jersey Ave., SE
Room W-12-140
Washington, DC 20590
USA

**RE: PHMSA Docket ID 2005-23447, Notice 2. Docket No. RIN 2137-AE25**

Dear Sirs,

TransCanada PipeLines Limited (TransCanada) is a leader in the responsible development and reliable operation of North American energy infrastructure. Our network of more than 59,000 kilometres (36,500 miles) of pipeline taps into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 355 billion cubic feet of storage capacity. A growing independent power producer, TransCanada also owns, or has interests in, approximately 7,700 megawatts of power generation.

Pursuant to the proposed rulemaking notice ("Proposed Rule") issued by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administrations ("PHMSA") on March 12, 200, Federal Register Vol. 73, No. 49, 13167, TransCanada submits comments on PHMSA's proposal to amend the pipeline safety regulations to prescribe safety requirements for the operation of certain gas transmission pipeline at pressure based on higher design factors. The comments on the particular items of the Proposed Rule are documented in the attachment to this letter.

Thank you for the opportunity to provide comments on the Proposed Rule. We believe that these comments will be beneficial to the rulemaking process and lead to a more refined rule.

Yours truly,

Joe Zhou, Ph.D., P.Eng.
Technology Leader
Engineering

**COMMENTS OF TRANSCANADA PIPELINES LIMITED ON NOTICE OF PROPOSED RULEMAKING**

Date: May 11, 2008

Pipeline Safety: Standards for Increasing the
Maximum Allowable Operating Pressure
For Gas Transmission Pipelines

Docket ID PHMSA-2005-23447; Notice 2
Docket No. RIN 2137-AE25

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Industry has been working with PHMSA on these criteria for 3 years. In addition, TransCanada, through the special permit process, has been working with PHMSA to set reasonable requirements. Some of the requirements set by PHMSA are not supported by any technical data or information and some other requirements can be improved. TransCanada therefore will be providing comments on those items.

Also during the special permit process, companies are inclined to agree with PHMSA requirements in order to get the permit as expeditiously as possible; costs of delays are not tenable. Therefore, companies have agreed to non-technically based requirements in order to get the permit. These issues will be addressed by the industry in the response for individual items.

## GENERAL COMMENTS

Many of the proposed requirements seem to ignore the requirements and criteria set forth in Subpart O and the referenced ASME B31.8S standard. These proposed requirements do not have a technical basis and their need is not explained whereas the requirements in Subpart O and in ASME B31.8S are based on science and technical research. Where the elements of integrity management are required, it is recommended that reference to Subpart O be made instead of stating new, unjustified and conflicting requirements.

The term of higher stress level has been used frequently throughout of the Proposed Rule. While it might be applicable to the cases of pressure uprating of existing pipelines, it is not applicable to other cases. The maximum operating stress is limited by, among other factors, the design factor and the SMYS (or grade) of the pipe material and high design factor does not necessarily lead to high operating stress. For an example, a X65 pipe designed with 0.8 design factor would have lower operating stress than a X80 pipe design with 0.72 design factor. It is suggested that the term of high stress level should be replaced with high design factor.

## COMMENTS ON THE PREAMBLE

The preamble has a few errors that TransCanada wishes to point out so that the final rule will be correct. In addition, comments on some questions posed in the preamble are provided. These changes and comments are as follows:

B.1 The phrase "but not to exceed 80% of SMYS" at the end of paragraph one is not correct. There is no such upper limit to the pressure under which a grandfathered pipeline can operate.

B.6 Paragraph one, the review of existing permits, may be an appropriate action for PHMSA to take. PHMSA should not use this review to impose additional requirements on those operators with Special Permits nor revoke any Special Permits already granted.

B.6 Paragraph two, PHMSA should continue to expeditiously process any Special Permits they receive regardless of the status of this proposed rulemaking. The operators who have submitted the Special Permits may need to increase pressure to meet customer demand before the rulemaking is complete. Additionally, operators may need relief from both existing regulations and the proposed regulations as drafted.

C.3 Paragraph two makes reference to "level 2 of API Specification 5L'. The new edition of this specification will likely be published and effective before this rulemaking is complete. The reference, as stated will be outdated. PHMSA should review the proposed new edition of this specification and make appropriate references as part of the final rule.

C.3 Paragraph eight requires certification of serviceability for fittings and other components. It is not known what this requirement means. PHMSA should clarify this requirement.

C.4 Paragraph four requires test records for 95 percent of girth welds on existing segments. The regulatory requirement is to non-destructively inspect a low percentage of girth welds. Even though the current practice of TransCanada and the industry is to inspect all girth welds, many of the earlier vintage pipelines were constructed based on the regulatory requirement. This requirement will be very restrictive for the earlier vintage pipelines which may have a very good performance record over a very long period of time.

C.4 Paragraph six states that "since the initial strength test is a destructive test, it only detects flaws relatively close to failure during operation. This could leave in place smaller flaws that could grow more rapidly at higher stress levels". TransCanada takes exception to this statement. The pressure test eliminates all flaws that may fail at or below the pressure level of the strength test (1.25 times MAOP or greater). Any flaws left in place will likely not grow under typical operating conditions of gas pipelines. This statement is also an over simplification as the remaining flaw will not necessarily grow more rapidly at higher design factors.

C.7.4 Paragraph two states that "More frequent patrols of the right-or-way prevent damage by giving the operator more accurate and timely information about potential sources of ground disturbance and other outside forces". This statement is not supported by research or statistics. In fact research and statistics found that patrolling at greater but practical frequencies provided no benefit in the prevention of damage. Considering that patrolling has very little effect on preventing mechanical damage, TransCanada finds the frequency excessive.

C.7.7 Paragraph one implies that geometry tools are run for baseline purposes and during periodic assessments. This is not a correct statement based on the proposed regulations. Geometry tools are required for the baseline assessment but not for periodic assessments. The language in the proposed rule is correct.

C.7.8 Paragraph one states that "The higher stress levels of operation can allow more rapid growth of anomalies". This statement is not correct. The growth of anomalies is largely independent from operating stress level. In addition, pipelines designed with high design factors based on the Proposed Rule do not necessarily operate at higher stress levels.

D.2 Paragraph 4 has a statement that is not correct. "In the case of new pipelines, the ability to use an alternative MAOP will make it possible to transport more product". This statement may be true for existing pipelines but new pipelines are designed for the required capacity as certificated regardless of design factor.

**COMMENTS ON PROPOSED CHANGES TO PARAGRAPH 192.7– INCORPORATION BY REFERENCE**

In general, TransCanada supports the use of consensus standards to provide the technical foundation for any regulatory actions; particularly those developed under the provisions established by the American National Standards Institute (ANSI). Specifically, TransCanada supports the incorporation of the standard, ASTM A 578/A579M-96 (re-approved 2001) "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications" for use in inspecting plate manufactured for pipe orders to be used for operation using the alternative design basis and life cycle management proposed by PHMSA.

**COMMENTS ON PROPOSED PARAGRAPH 192.112**

This new paragraph sets the eligibility requirements for a new or existing pipeline to operate at the alternative maximum allowable MAOP. TransCanada's comments to the new language are as follows:

<u>Paragraph (a) – General Standards for Steel Pipe</u>
PHMSA proposes the use of a ratio of the diameter over the nominal wall thickness, referred to as D/t, to address the threat of damage during construction and atypical loads and mechanical damage during operation of the pipeline. TransCanada believes that while consideration of the relationship between wall thicknesses relative to pipe diameter is important, there is no hard and fast threshold that applies under all circumstances. D/t limitations are particularly inappropriate for high strength pipe. For pipe grades X-80 and above, the D/t ratios may exceed 100 to 1. Ovality and denting issues can be managed for these higher D/t pipelines, and for that matter any pipe under this regulation through the construction practices proposed by PHMSA in 192.328(a)(1), Quality Assurance (during construction), 192.620(d)(9), Baseline Internal Inspection Using Geometry Tool, and by provisions in the existing ASME code that relate to analyses of instantaneous and sustained loads during operation (ASME B31.8, Paragraph 833.4).

With respect to carbon equivalents, the consensus standard API 5L establishes specifications for maximum carbon equivalents using the Ito-Bessyo formula (Pcm formula) for varying grades and wall thicknesses of steel pipe. PHMSA has proposed limitations that differ from those in API 5L, without technical justification. TransCanada supports use of the limits as expressed in API 5L for conventional pipe grades, absent any other information to justify differing limits. TransCanada believes that the main purpose of limitation on carbon equivalents is to ensure weldability of pipe material. As a result, carbon equivalents higher than the limits specified in API 5L should be permitted provide that weldability tests are properly done to establish the weldability of the pipe material. This alternative would be particularly important to high strength pipes and pipes for strain-based design applications.

<u>Paragraph (b) – Fracture Control</u>
In general, TransCanada agrees with the approach proposed by PHMSA with respect to fracture control. It is critical that an operator's plan considers and addresses initiation, propagation and arrest under the range of operating pressures and temperatures anticipated on the pipeline. In addition, it is important that the fracture control plan addresses the potential under-conservatism of conventional Charpy toughness equations for higher strength steels (grades X70 and above) and enriched gases. A White Paper "Fracture Control" has been developed by the Joint Industry Project on Alternative Design Basis and Life Cycle Management, and is submitted (as a part of INGAA comments) to support our comments.

TransCanada agrees that the basis for arrest proposed by PHMSA is appropriate for new pipeline design if self-arrest is attainable. The basis selected by PHMSA in effect requires that approximately 58 percent of the pipe be arrest pipe if fracture control is based on self-arrest. For the design scenario where a crack arrest design is used, TransCanada proposes that PHMSA amend the regulatory language to allow an operator to alternatively apply a crack arrest design based on an engineering analysis including an analysis of consequence. This is particular important to high pressure, large diameter pipelines currently under the consideration by the industry.

*TransCanada recommends that the language under 192.112(b)(3) be changed to read "If it is not physically possible to achieve the pipeline toughness properties of paragraphs' (b)(1) and*

*(2) of this section, a crack arrest design must be developed and implemented or mechanical crack arrestors of proper design and spacing must be used to ensure fracture arrest as described in (b)(2)(iii) of this section"*.

Paragraph (c) – Plate/Coil Quality Control
In general TransCanada believes that the consensus standard API 5L provides the foundation for the materials specification and manufacturing of line pipe. Operators (purchasers of pipe) build upon API 5L through use of materials specification and manufacturing quality management programs. The Joint Industry Project on Alternative Design Basis and Life Cycle Management has developed a White Paper "Material Specification and Manufacturing" (submitted as a part of the INGAA comments) that describes how line pipe metallurgical, chemical and dimensional properties are managed by a materials and manufacturing quality management program. Materials and manufacturing quality management programs draw upon international consensus-based standards in combination with mill and source-specific specifications, quality control measures used by the pipe mill and quality assurance used by the purchaser. The quality management program comprises four steps:

1. Pipe manufacturing mill qualification
2. Pipe standard, specifications and contracting agreements
3. Pipe manufacturing procedure specification review and agreement
4. Surveillance and auditing

The purchaser first engages in a technical evaluation of the mill to ensure that the mill is qualified to produce pipe to the purchaser's specifications. The purchaser will establish a pipe specification knowing the requirements of the project for which the pipe is being procured. The mill and purchaser engage in the development of and agreement upon a Manufacturing Procedure Specification (MPS) that establishes the materials specification to standards and the purchaser's additional requirements and manufacturing procedures and quality control/quality assurance (QA/QC) practices. The mill knows best how to source the steel, roll and weld pipe to meet the performance parameters required by the purchaser. The MPS sets out the kinds of inspections and frequencies and how exceptions are to be dealt with. The MPS is designed to locate issues before they become problems and minimize exceptions.

Steel properties are specified by the operator in the pipe specification and the mill selects the chemical formulations that are designed to ensure the slab producer, skelp mill and the pipe mill achieve the desired final properties in the finished pipes. Most alloying elements must fall within compositional limits that, together with the controlled skelp production and pipe manufacturing process, are known to lead to the appropriate mechanical properties. Solidification control during continuous casting minimizes centerline segregation and lamination from refractory and slag entrapment.

Centerline segregation and lamination in the pipe body or pipe ends, if it extends into the weld preparation, can adversely affect weld quality and may promote girth weld cracking. In particular, carbon, oxygen, sulfur and phosphorous are controlled to promote weldability and ensure toughness, and the controlled rolling (and accelerated cooling/strip coiling where applicable) using advanced thermo-mechanical parameters, and micro-alloying elements are used to assure the fine grain size and precipitation hardening effects which compensates for any loss of strength, due to the reduced carbon contents typically used in modern line-pipe steels.

It is important to recognize that API 5L provides performance-based requirements to address the outcomes of centerline segregation, or failure of the source material to meet the metallurgical and dimensional properties of the operator's pipe specification and API 5L. The operator, the pipe mill and source mill must balance the use of quality control measures and the potential for out-of-specification pipe to be formed. This is not best achieved by the imposition of a single simple prescriptive approach unrelated to the negotiated MPS. Delays always lead to increased cost, and these will be incurred by improperly imposing production constraints.

Even considering the performance-based requirements set forth in API 5L, TransCanada recognizes macro-etch testing is a valuable quality control method to be applied by the mill. While TransCanada agrees with PHMSA in the value of the tests, the frequency and acceptance criteria are best left to be agreed upon between the purchaser and the mill, based on mill configuration, slab source materials among others.

*TransCanada recommends that the language under 192.112(c)(2)(i) be changed to read "A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. The acceptance criteria must be agreed to between the purchaser and the mill".*

With respect to ultrasonic inspection of plate/coil or pipe, TransCanada agrees that the pipe mill must include a comprehensive plate/coil and pipe mill inspection program to check for surface defects and inclusions that can be injurious to the integrity of the pipe. This program can be conducted on plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program using as a basis, guidelines in ASTM A578 to check for imperfections such as laminations. Alternatively, TransCanada believes that the pipe mill may conduct full-body UT of the skelp or pipe. Full-body UT entails the use of a single transducer oscillating back and forth across the surface. The basis of either approach is to assure that the inspection finds defects that exceed a certain minimum size in the body of the plate or pipe, and provides coverage for 100 percent of the pipe ends back a specified length. The work group recommends that the performance criteria set forth in ASTM 578 be used for plate inspection and as a basis for establishing criteria for full-body UT.

Paragraph (d) – Seam Quality Control

As a starting point, TransCanada believes that API 5L provides the technical foundation for managing seam quality control. The pipe weld seam must meet the minimum requirements for tensile strength as specified in API 5L for the appropriate pipe grade properties. TransCanada is sponsoring the work being undertaken by the Joint Industry Project on Alternative Design Basis and Life Cycle Management. The JIP has developed a white paper on Materials Specification and Manufacturing and is submitted as part of the INGAA comments.

TransCanada agrees with PHMSA that pipe weld seam hardness test using Vickers hardness testing of a cross-section from the weld seam will be carried out across the plate, HAZ, and weld material volumes and must be performed on one length of pipe from each heat. TransCanada, however, does not agree with the use of a threshold value of 280 Vickers Hardness (Hv 10). While API 5L does provide such a threshold value for sour gas service, it does not provide a single, fixed value for the gas service addressed under 49 CFR 192; that is the transportation of non-corrosive gases. TransCanada believes that the pipe mill and the purchaser should establish a hardness maximum in the manufacturing procedure specification and quality assurance plan.

API 5L requires that the pipe weld seam must be 100 percent UT or x-ray inspected to ensure there are no defects. In addition, API 5L requires that pipe ends be non-destructively inspected by either UT or x-ray, to ensure that there are no injurious laminations or inclusions interacting the weld volume.

*TransCanada recommends that the language under 192.112(d)(2) be changed to read "There must be a hardness test method used to ensure hardness levels established between the purchaser and the mill of the following:…"*

<u>Paragraph (e) – Mill Hydrostatic Test</u>
TransCanada understands that the mill hydrostatic test is a quality control test conducted on each pipe manufactured in the mill. It is an important quality control test. TransCanada is sponsoring the work being undertaken by the Joint Industry Project on Alternative Design Basis and Life Cycle Management. The JIP has developed a White Paper "Materials Specification and Manufacturing" which is submitted as part of the INGAA comments. API 5L in the forty-third edition and for a number of years has specified a test to 90 percent of SMYS for 10 seconds. Even the Forty-Fourth edition of API 5L, effective October 1, 2008 retains the 90% SMYS for at least 10 seconds for large diameter pipe. The members of the JIP work group discussed test pressure and duration and reached the following conclusions. Testing to 95 percent of SMYS is appropriate as long as the current provisions that allow for end-loading compensation as per Appendix K are applicable. In addition, the work group found that test durations in excess of 10 seconds did not add quantifiable value to the test and the increased duration could negatively impact productivity of pipe mills. Consequently,

*TransCanada recommends that the language under 192.112(e)(1) be changed to read "A hydrostatic test of all pipe will be conducted in the pipe mill at a pressure of at least 95% of SMYS, for a duration of 10 seconds including the allowance for end loading"*

<u>Paragraph (f) - Coating</u>
Fusion bonded epoxy coatings (FBE) have proven performance in pipeline applications for over thirty years around the world. TransCanada believes that it is important to allow for alternatives to ensure improved technologies are not arbitrarily restricted. Three layer coatings especially FBE-PE and other hybrids have provided good performance in other parts of the world. Performance coatings that have been shown as semi-conductive and/or do not crack would be preferred over this "one size fits all" statement. Abrasion resistant coatings and other high integrity specialty coatings need inclusion through performance language such as non-disbonding, non-shielding, or non-cracking. Prescriptive language remains inappropriate because it risks stifling innovation. Regulations should allow petition based on coating manufacturer's data and field performances.

*TransCanada recommends that performance language be used to describe the expected coating performance rather than specify only FBE coatings. This language should be “the pipeline must be protected against external corrosion by coatings that have been shown, by testing and experience, to be non-shielding and resistant to disbondment and cracking”.*

TransCanada agrees with the quality assurance approach proposed by PHMSA at 192.112(f)(3).

<u>Paragraph (g) – Fittings and Flanges.</u>
TransCanada agrees with the provisions proposed by PHMSA. But to clarify, pipe fittings, valves and flanges, associated with line pipe and main line block valves, should be designed and purchased in accordance with applicable reference standards or their equivalent, already incorporated within 49 CFR 192. The referenced standards may be supplemented by the operator’s supplemental requirements to ensure that the materials meet the minimum engineering design specifications. In all cases, the valves and flanges should be ANSI Class 600 for pressures up to and including 1,480 psig, and ANSI 900 for pressures up to 2,200 psig. Valves should be manufactured in accordance with API 6D. High-test flanges should be manufactured in accordance with MSS SP-44 and normal flanges in accordance with ASME B16.5. Small pipe fittings should be manufactured in accordance with ASME B16.9 and large fittings with MSS SP-7. All of these materials should be pressure tested in accordance with the applicable standards.

<u>Paragraph (h) – Compressor Stations</u>
PHMSA concerns with respect to compressor station discharge temperatures relate to the long-term durability and integrity of plant and field applied fusion bond epoxy (FBE) coating for operations greater than 120$^{o}$F. The concern arises when considering operating scenarios for uncontrolled compressor discharge temperatures projected to heat the downstream pipe to a temperature that may reach 150$^{o}$F.

All pipelines built under PHMSA regulations must have two corrosion protection systems. The first line of defense against corrosion is the coating system and the second line of defense is the applied cathodic protection (CP) current. PHMSA in 49CFR192 requires a minimum test point (or close interval survey) voltage to ensure the imposed current provides sufficient protection in the event the coating has deteriorated.

The FBE concern arises out of historical experience in the pipeline industry when some pipeline systems were operated at temperatures above 120$^{o}$F, even as high as 160$^{o}$F. In many cases these early coatings were non conductive and prevented the cathodic current from completing the circuit. The pipe was “shielded” and the applied potential could not protect the surface. Corrosion is prevented by applying small voltage potential. These earlier reports refer to tar and asphalt based coatings that predominated prior to the use of FBE.

Early FBE coatings did not appear in the US until about the mid 1970’s. Over time there was evidence that some pre-FBE coatings had degraded and eventually became blistered or disbonded from the pipe. FBE however, remains conductive even when disbonded and raised proud of the pipe. FBE coatings do not block the cathodic protection current, meaning that disbondment of the coating does not interrupt the cathodic protection system, and the imposed CP continues to protect the pipe from external corrosion and SCC.

Nevertheless, there remain two major concerns:

1. absent a coated surface, the underlying steel can be prone to external corrosion and
2. stress corrosion cracking (SCC) can occur under disbonded and shielding coatings.

It is known that the pipe shielded by disbonded non-conductive coating is susceptible to SCC and more so for any pipe that has experienced temperature excursions in excess of 120ºF. The TransCanada study, which had experienced temperature excursions to 150ºF (65ºC), concluded that the disbondment of FBE coatings did not present an integrity threat to a pipeline as long as cathodic protection was present on the line.

NACE RP0394-2002, Standard for Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating, states in section 6.1.5 that a minimum coating thickness of 12 mils is required to meet the acceptance criteria for tests in the RP, including cathodic disbondment, for temperatures up to 150$^{o}$F. Pipeline operators interpret this standardized practice to mean that FBE coatings, applied with a thickness of at least 12 mils, are appropriate for operating temperatures up to 150$^{o}$F. Since the FBE has been used in pipeline construction, the normal practice is to verify the thickness, and the integrity of the pipeline coating using a high voltage Jeeping inspection, as the line is lowered into the ditch. Holidays are immediately repaired before backfilling the ditch.

The Joint Industry Project on Alternative Design Basis and Life Cycle Management has developed a White Paper "A Review of the Performance of Fusion-Bonded Epoxy Coatings on Pipelines at Operating Temperatures Above 120º F" (submitted as a part of the INGAA comments), which is a review that summarizes operating and performance case histories, as well as laboratory and field-testing of the long-term performance of FBE coatings. This paper documents that FBE coatings have demonstrated good adhesion and little disbondment in both laboratory-testing environments and after 30 years of operation at temperatures greater than 120$^{o}$F on systems in the United States, Canada and the Middle East. In addition, FBE remains conductive even when disbonded as a continuous barrier-like film proud of the pipe. Thus FBE coatings do not block the cathodic protection current, meaning that disbondment of the coating does not interrupt the cathodic protection system, and the imposed CP current continues to protect the pipe from external corrosion and SCC.

The work summarized in the JIP white paper shows that even the first generation FBE coatings having seen as many as thirty years service have performed well at temperatures above 120$^{o}$F. Even so, blistering and disbondment has been observed on in-service lines in operation above 120$^{o}$F. Laboratory tests conducted on FBE coatings in simulated environments at temperatures above 120$^{o}$F do indicate a greater degree of disbondment as the temperature is increased towards 200$^{o}$ F however any corrosion is minimized by the CP system.

FBE coating is known to be conductive, meaning that even when disbonded, cathodic protection remains effective. In-service experience described in this white paper confirms this behavior. FBE coatings do not shield the cathodic protection currents.

It is not apparent that additional laboratory testing on FBE coating at temperatures above 120$^{o}$F will add any information not already known based on the studies described in this white paper. An operator may elect to conduct additional laboratory testing.

Recognizing that there is the potential for disbondment, an operator may elect to conduct above ground surveys using close interval surveys to confirm the effectiveness of the applied potential and use direct current voltage gradient (DCVG) surveys periodically to locate holidays, if any, in the FBE coating. The conductivity of FBE coatings ensures the integrity of the second line of protection, the applied CP system, is not compromised.

*TransCanada recommends that the language under 192.112(h)(2) be changed to read "If research or testing shows that the coating will withstand …"*

**COMMENTS ON PROPOSED PARAGRAPH 192.328**

<u>Paragraph (a) – Quality Assurance</u>
TransCanada agrees with these proposed requirements.

<u>Paragraph (b) – Girth welds</u>
Item (2) in this paragraph refers to pipelines that were constructed prior to the effective date of this rule. This requirement is in the wrong area of the regulations. Paragraph 328 is a construction requirement and is not a retro-active requirement. Paragraph 620 is an operations requirement and applies retroactively to all pipelines.

*TransCanada recommend removing item (b)(2) from paragraph 192.328 and putting it in paragraph 192.620, under (c)(3) in a manner that is similar to the requirement for pressure testing. In addition, the requirement of at least 95 percent of girth welds non-destructively inspected for an existing segment should be replaced with a performance based requirement such as the integrity of girth welds of an existing segment should be demonstrated through past performance and engineering analysis.*

<u>Paragraph (c) – Depth of Cover</u>
TransCanada agrees with these proposed requirements.

<u>Paragraph (d) – Initial strength testing</u>

In a paper by John Kiefner, "Role of Hydrostatic Testing in Pipeline Integrity Assessment" the technical benefits for the test is stated as follows:

> "The purpose of hydrostatic testing a pipeline is to either eliminate any defect that might threaten its ability to sustain its maximum operating pressure or to show that none exists. A key word here is pressure. Hydrostatic testing consists of raising the pressure level above the operating pressure to see whether or not any defects with failure pressures above the operating pressure exist. If defects fail and are eliminated or if no failure occurs because no such defect exists, a safe margin of pressure above the operating pressure is demonstrated."

This statement is the underlying philosophy for all pressure tests including the post construction test addressed in this paragraph. In the case of post-construction tests, the defects that the operator is trying to find or prove do not exist are material and construction defects.

This item deals specifically with "any failures indicative of fault in material". Material is produced as specified in the pipeline safety regulations and the additional requirements of proposed 192.112. Pressure test is one well established approach to find injurious defects if they exist and validate the safety margin.

Special permits granted to date have addressed pressure test failures by requiring a root cause failure analysis. If a systemic issue was found during the test, discussions had to be held with the regional offices. The requirement stated in the special permits is:

> "Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office."

The requirement as stated in the NPRM, by stating that "the segment must not experience any failure indicative of fault in material" during the hydrotest is excessive. A root cause analysis of any test failure however is appropriate. If there is a systemic issue with the material then more needs to be done to understand and address the issue.

*TransCanada recommends that the language under 192.328(d) be changed to what was used in the special permits, namely "Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis which may include a metallurgical examination of the failed pipe if required. The results of this analysis must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office."*

<u>Paragraph (e) – Cathodic Protection</u>
This paragraph is not necessary. Existing paragraph 192.455 requires that cathodic protection must be installed and placed in operation within one year after the completion of construction.

*TransCanada recommends removal of this paragraph. If necessary, a reference to 192.455 can be added instead of restating the requirement.*

<u>Paragraph (f) – Interference currents</u>
TransCanada agrees with these proposed requirements with the understanding that 192.327 will govern for existing Class 1 pipe.

**COMMENTS ON PROPOSED PARAGRAPH 192.620**

<u>Paragraph (a)</u>
Stated requirements in the NPRM are more restrictive than current regulations and granted special permits. This inconsistency must be addressed in the NPRM.

The design factors set in the NPRM do not recognize that the class location may change after the pipeline has been constructed. Special provisions are provided in the existing regulations to allow for the class location change without the need for pipe replacement. This provision is contingent on a pressure test to the next class location test factor.

Waivers have been granted to pipelines operating to 80% or more of SMYS that were grandfathered and have subsequently experienced a class change from Class 1 to Class 2. In order obtain this waiver, companies agreed to in-line inspections of the pipeline and to employ additional preventative and mitigative measures such as those that are mandated within a company's Integrity Management Plan. Today, there are pipelines that have been granted waivers to operate at 80% or more of SMYS in Class 2 areas.

Waivers have been granted to pipelines operating at 60% or more of SMYS in Class 3 locations where the pressure test was not to the level required by the regulations (1.5 times MAOP). Waivers have been granted to pipelines operating at 72% or more of SMYS of design pressure in Class 3 locations, where neither the design nor the pressure test met the requirements of the regulations. The companies in these cases also agreed to in-line inspections of the pipeline and operations in accordance with the companies Integrity Management Plan. The granting of these waivers was part of the agreement reached between PHMSA and the industry in 2002 as part of the promulgation of the integrity management regulations in order to help justify the extreme cost of the regulations. Many of these pipelines contain High Consequence Areas (HCAs).

There are significant inconsistencies between current regulations, current waivers granted to existing pipelines, and the proposed regulations. While changes to existing regulations are not part of the scope of the NPRM, there is no reason to confuse the issue again with this rule; it should be made simpler and more in line with current waivers.

The proposed regulations do not have a provision for compressor station, meter station, road crossings or fabricated assemblies to operate at higher pressures. As written, a compressor station in a Class 1 area can be operated at 80% of SMYS.

*TransCanada recommends the following changes to proposed Paragraph 192.620(a):*

*For the new pipelines that meet all of the special provisions in the NPRM, it is recommended that:*

- *Class 1 pipelines be limited to operation at 80% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 2 pipelines be limited to operation at 67% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 3 pipelines be limited to operation at 56% of SMYS and pressure tested to 1.5 times MAOP*
- *Station piping be limited to operation at 56% of SMYS and pressure tested to 1.5 times MAOP*
- *Fabricated assemblies would be limited to operation at 67% of SMYS and pressure tested to 1.25 times MAOP*

- *Uncased road and railroad crossing be limited to 67 % of SMYS in Class 1 locations and to 56% of SMYS in Class 2 locations.*

*For Class location changes, it is recommended that a new paragraph be added to 192.611 to provide the following:*

- *Pipe that operates at 80% and in accordance with paragraph 192.620 and changes from Class 1 to Class 2, can continue to operate up to 80% SMYS*
- *Pipe that operates at 80% and changes from Class 2 to Class 3 or from Class 1 to Class 3 would need to have the pressure lowered to 67% of SMYS or be replaced with pipe designed at 67% SMYS or less*
- *Pipe that operates at 67% and in accordance with paragraph 192.620 and changes from Class 2 to Class 3 can continue to operate at 67%*

These class change provisions are necessary or operators will be asking for special permits in the very near future as population encroachment drives the class location to change from Class 1 to Class 2 or from Class 2 to Class 3. These criteria also provide for consistency with Special Permits previously granted and give the operator flexibility in design for all pipeline facilities.

It is important to note that the regulations require operations and maintenance activity frequency be based on the class location. The higher the class location, the more frequently the inspection or other activity is performed. These provisions address the slightly higher risk due to consequence by reducing the likelihood of an event through more frequent inspection.

A White Paper "Alternative Pipeline Design Pressures" has been developed on this topic (submitted as a part of INGAA comments). It discusses the current regulations, the special permits granted for performing Integrity Management in lieu of replacing pipe and the proposed regulations.

<u>Paragraph (b)</u>
Item (6)
The NPRM states that the segment must not experience any failures during normal operations indicative of fault in material. This requirement is excessive as the failure may be a single event. If there is a failure, a root cause analysis should be conducted in order to ascertain that the failure is not indicative of a systemic materials issue. If there is a systemic issue with the material more needs to be done to understand and address the issue.

*TransCanada recommends that the language under 192.620(b)(6) be changed to read "Any pipe failure occurring during normal operations must undergo a root cause failure analysis which may include a metallurgical examination of the failed pipe if required. The results of this analysis must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office."*

<u>Paragraph (c)</u>
Item (3)

This item shows the criteria for pressure testing in Class 1 areas but does not say anything about Class 2 or 3 areas. For pipelines that are presently in operation and are being up-rated to the higher pressures, the pressure test requirements should not be the same as required in paragraph (a) of this section.

For existing pipelines, pressure test levels may not have been to the levels stated in paragraph (a) of this section; however the tests may have been very near those levels. Some relief from this requirement should be allowed. In 192.328(b)(2) the requirement for weld NDE is somewhat reduced recognizing that every weld may have not have experienced NDE. This rationale should apply to pressure tests as well in order to gain some relief from the pressure test requirements.

In a paper written for Alliance Pipeline, and contained in the docket for their waiver or special permit for increasing operating pressure, Kiefner and Associates concluded "there would be little additional benefit gained in terms of demonstrating that the pipeline is fit for the modest proposed increase in operating stress by repeating the hydrostatic test to the incrementally higher level necessary to meet the 1.25 factor". The paper states the reason for these conclusions and included that more than ¾ of all joints were tested to 95% of SMYS, more than ½ of all joints were tested to 97% SMYS or greater and more than 1/3 of all the joints were tested to 99% of SMYS. In addition, the conclusions were justified by pipe manufacturing controls, resistance to mechanical damage, the decay of pressure with distance downstream of compression, and the minimal difference in safety factor as compared to current regulations.

*TransCanada recommends that Item 3 of Paragraph C be changed to the following:*
*(i) Perform a strength test as described in 192.505 to at least the factor stated in (a) of this section times the maximum allowable operating pressure, or*
*(ii) For a segment in existence prior to the effective date of this regulations, for which the pressure test levels do not meet the requirements of 192.620(a)(ii) of this paragraph, certify, under paragraph (c)(1) of this section, that a strength test was conducted and provide an engineering assessment discussing the relationship of the pressure test to actual operating pressure and the effects of remaining defect size, pipe toughness, fracture control properties and fatigue on the pipeline.*

<u>Paragraph (d)</u>
Item (1) – Assessing threats:
The way in which item 1 is written implies that operation at the higher design factor increases the risk and that the procedures used will mitigate the risk. The slight increase in risk if any however is already mitigated through all of the additional design, materials, construction, and operations requirements of these proposed regulations. It is unclear what procedures are being talked about.

*TransCanada recommends that this item be revised to: the operator must include in their design, construction, material, operations, and maintenance procedures and specifications, provisions to mitigate risk for operation at the higher design factor.*

Item (2) – Notifying the public:

This item appears to require a special notification to the public near pipelines that will be operating at higher pressures. The justification for this requirement has not been provided other than to state the information is necessary to people potentially impacted by a failure. Everyone along the pipeline could be affected by a failure. Notification about pipelines is already required by 192.616 "Public awareness".

*TransCanada recommends item (d)(2) be revised to change the title of the section to "Assessing potential impact area". In addition, delete item (d)(2)(ii) in its entirety.*

Item (3) – Responding to an emergency in an area defined as a high consequence area.
This item states the requirements for timing of valve closure in an HCA. TransCanada is not aware of any study or research that supports this requirement. The requirement seems arbitrary and is contrary to research and operational experience.

Especially onerous is the requirement for additional pressure monitoring upstream and downstream of the valve. TransCanada is not aware of any benefit in monitoring the pipeline pressure upstream and downstream of the valve. Pressure monitoring requires additional equipment and the resultant maintenance where the benefit is not known and has not been justified. Given a rupture of the pipeline, the pressure will read zero after the valves are closed upstream and downstream of the rupture site. Upstream of the first closed valve the pressure will equalize to the upstream compressor station discharge pressure. Downstream of the second closed valve the pressure will equalize to the downstream compressor station suction pressure. There is no need for pressure monitoring.

In addition, the requirement to be able to remotely open the valve is contrary to many companies operations policies. Many operators believe that if the situation is so serious that remote closure of the valve is required, on-site personnel should make the determination that the area is safe prior to re-pressurizing the segment and therefore do not allow remote opening of the valve.

*TransCanada recommends that 192.620(d)(3)(iii) be changed to read "Remote valve control must include the ability to close the valve and monitor the position (open and close) of the valve".*

Item (4) - Patrolling
The patrolling frequency proposed in the NPRM is excessive. TransCanada is not aware of any technical justification for the proposed frequency however it does recognize that it follows the frequency mandated for hazardous liquid pipelines.

A review of the incident data for both gas and hazardous liquid transmission lines does not show any benefit from the increased patrolling frequency for hazardous liquid lines. In 2007 there were 466 hazardous liquid incidents reported for the approximately 160,000 miles of pipeline. Of these there were 26 due to third party damage. For gas pipelines there were 127 incident reports for the approximately 300,000 miles of pipeline. Of these 14 were due to third party damage. There were approximately 3.7 times more incidents reported for hazardous liquid pipelines for a population equal to 53% of the gas pipeline mileage. The comparable failure incident rates due to mechanical damage are $1.625*10^{-4}$ per year per mile (26/160000) for liquid transmission lines and $0.467*10^{-4}$ per year per mile (14/300000) for gas transmission lines. In other words, the lines patrolled 26 times a year have on average about 3.5 times higher incident rate compared to the lines patrolled 2 times a year (twice per year is an average required number of patrols based on one per year for Class 1, two per year for Class 2 and four per year for Class 3).

A report by CFER Technologies for PRCI shows that unless patrolling is done daily, there is not much chance of prevention of outside force damage. In addition, B31.8 only requires once per year in Class 1 and 2 even when Class 1 pipe can operate at 80%.

*TransCanada recommends changing the patrolling requirements to two times per year Class 1, four times per year in Class 2 and six times per year in Class 3.*

This increase in frequency is akin to the frequency for the next higher class location, as are others of the additional requirements in the NPRM. For example, the requirement in the NPRM for NDE to 100% of all girth welds in Class 1 areas operating at 80% of SMYS is the same as required in Class 3 areas in the existing regulations.

Depth of Cover

The language used in the NPRM for maintaining depth of cover is confusing. The first sentence says to maintain depth of cover to the requirements stated in 192.327 or 192.328. The second sentence says that if observed conditions indicate the possible loss of cover, perform a depth of cover survey and replace cover as necessary. The first sentence statement requiring that cover be maintained is a requirement that can not be obtained in any practical sense. The second sentence statement is more in line with a performance requirement that can be obtained and is event driven.

Based on the incidents where depth of cover was recorded, no correlation was found between depth of cover and third party damage. There are situations where the removal of cover may pose a threat of damage to the pipeline due to third party activities such as in agricultural situations. In these cases the restoration of cover may be appropriate.

There may be situations where cover can not be permanently restored. In these situations there may be more appropriate measures that can be employed, such as the addition of a barrier or some other prevention or mitigation measure.

For existing pipelines that were installed in accordance with 192.327, the depth of cover requirements in a Class 1 area was 30 inches. Some removal of cover may have occurred during the life of the pipeline due to agriculture, normal soil erosion or other factors. This paragraph, as written would require the operator to maintain cover to 30 inches for existing pipelines which may result in significant environmental disturbance to replace cover over long segments of pipeline.

*TransCanada recommends changing the language to eliminate the first sentence so that it reads "If observed conditions indicate the possible loss of cover in an area where damage to the pipeline may result due to the loss of cover, replace the cover or provide appropriate prevention and mitigation measures as necessary".*

Damage Prevention

The requirement to review the damage prevention program in light of consensus standards and practices and incorporate the appropriate practices into the damage prevention program seems appropriate. The language in this requirement may lead to many interpretations by the companies and by inspection personnel due to its ambiguity. The requirement, as stated, does not identify the standards or practices to be reviewed, however it may be assumed that the CGA best practices are what are being referred to in this requirement. An operator may chose to follow one standard or practice; however inspection personnel may believe the operator should follow another. Another issue during inspections may be the determination of which items in a standard or practice should be followed by the operator.

*TransCanada recommend changing the requirement so it reads "Review of CGA best practices and incorporation of the applicable practices into the operator's damage prevention program"*

Right-of-Way Plan

The requirement to develop and implement a right-of-way plan is duplicative of an operator's damage prevention program and other requirements in the regulations. This additional program is not necessary or justified. The intent as stated is to protect the segment from damage due to excavation and this requirement is the same as required in an operator's damage prevention programs, as stated in 192.614. Paragraph (a) of this section states "… each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation damage…".

The other conditions required by the proposed plan are already covered in 192.613 "Continuing surveillance", 192.705 "Transmission Lines: Patrolling", 192.706 "Transmission Lines: Leakage surveys". These items are addressed in an operator's manual of operations and maintenance procedures as required by 192.605 "Procedural manual for operations, maintenance, and emergency response".

*TransCanada recommends removing 192.620(d)(4)(ii) and 192.620(d)(4)(vi) from the proposed regulations.*

Item (5) – Controlling internal corrosion:

This proposed regulation is somewhat duplicative yet in conflict with the new regulation at 192.476 "Internal corrosion control: Design and construction of transmission line". The new regulation provides specific requirements for new pipelines for the control of internal corrosion. The new regulation also has a provision for "change to existing transmission line" which would apply to any pipeline that is presently in operation and would be up-rated based on the NPRM. With conflicting regulations, the operator may not be able to meet both requirements.

This proposed regulation also sets limits on gas quality. These limits may be in conflict with gas quality requirements set by FERC in an operator's tariff. In addition, there is no justification in the NPRM for the limits set.

The proposed regulation requires the use of cleaning pigs and inhibitors and sampling of accumulated liquids. This is required regardless of the gas quality, whether or not there is liquid water and whether or not there are other prevention and mitigation options available to the operator. The language used in 192.476 is better stated and covers all the same issues without mandating work that may not be needed.

In response to the new regulations at 192.476, INGAA developed guidelines in order to assist pipeline operators in determining the requirements of this regulation. These guidelines "Internal Corrosion Control: Design and Construction of Transmission Line" are submitted as a part of INGAA comments. In addition, a White Paper, "Management of Time Dependent Threats" has been developed (submitted as a part of INGAA comments) which discusses the concerns and remediation of gas quality issues.

*TransCanada recommends revising 192.620(d)(5) to read "develop and implement a program to monitor gas quality to prevent internal corrosion and to remediate any gas quality excursions where internal corrosion may result"*

Item (6) – Controlling interference that can impact external corrosion:
TransCanada agrees with the proposed requirements.

Item (7) – Confirming external corrosion control through direct assessment:
The requirements in the NPRM and existing regulations provide several layers of protection for corrosion control. There are specific and comprehensive requirements for coating application at both the mill and in the field. There are coating continuity checks after the coating is applied and again before the pipe is lowered into the ditch and backfilled. Cathodic protection test stations are installed during construction. A geometry tool is run after construction which checks for pipe and associated coating damage that may have been caused during construction. Interference surveys are conducted within 6 months of placing the pipeline in operation. Cathodic protection is added within one year of placing the pipeline in operation. A close interval survey is conducted within six months of placing the cathodic protection in service. An in-line inspection with an MFL tools is performed within three years of placing the pipeline in service.

The proposed rule requires operators to "assess the integrity of the coating and adequacy of the cathodic protection through an indirect method such as close-interval survey, direct current voltage gradient or alternating current voltage gradient". Close-interval surveys are used to confirm the adequacy of cathodic protection. Voltage gradient surveys are used to determine coating defects. Neither tool can meet both requirements. This implies that two separate surveys are required.

This proposed requirement also states that remediation of the coating must be performed based on NACE RP-0502 for any indication that is severe or moderate. This requirement is in conflict with the NACE standard which determines severe or moderate based on two or more above ground methods, not one.

The proposed regulation therefore implies that Direct Assessment must be conducted on the pipeline after construction and installation of the cathodic protection systems. These requirements together are excessive and not necessary. These requirements are in addition to a pressure test and in-line inspection with an MFL tool. This means that the pipeline must be assessed using all three tools identified in Subpart O of the pipeline safety regulations.

The close interval survey may be appropriate in order to confirm that the cathodic protection system is operating as designed. The coating survey is not necessary; any coating anomaly is protected from corrosion by the cathodic protection system. In addition the requirement to base and respond to results based on the NACE ECDA standard is not necessary.

The requirement to perform the close interval survey within 6 months is excessive and in many cases not possible. CIS is not performed in winter months in cold climates and the time between completion of construction in the fall and CIS in the summer will exceed six months.

A White Paper "Management of Time Dependent Threats" has been developed (submitted as a part of INGAA comments) and discusses the requirements and needs for corrosion control activities.

*TransCanada recommends revising 192.620(d)(7)(i) to read " Within one year of placing the cathodic protection of a new segment in operation or within one year after recalculating the maximum allowable operating pressure of an existing segment under this section, perform a close-interval survey to determine the adequacy of the cathodic protection system"*

*TransCanada recommends revising 192.620(d)(7)(ii) to read "Remediate the coating or ensure cathodic protection levels are appropriate to mitigate corrosion"*

This new requirement states that results of the above ground assessment results must be integrated with the ILI results within 6 months for performing the ILI. This timing is burdensome and not necessary. The value of this data integration is not explained or justified.

*TransCanada recommend revising 192.620(d)(7)(iii) to read "Within one year…".*

This new requirement states that test stations be installed at half-mile intervals in HCA's and that at least one station is in each HCA (see item B). In addition, this item does not seem to fit under the topic of periodic assessments. This item may better fit under 192.328(e) as a construction requirement. In addition, location of a test station within the HCA may not be practical. For example a pipeline section that is physically 600 feet from a church and in a farm field, is classified as HCA due to the presence of the church. It is not practical to place the test station in the HCA which is in the farm field. The need for the ½ mile spacing is not justified and is contrary to consensus standards.

*TransCanada recommends that this item should be moved to 192.328(e) and that it could be clearer if it states that "no location in an HCA can be further than one mile from a cathodic protection test station".*

This new requirement states that there must be periodic close interval surveys of the pipelines in HCA's and that they are performed in association with subpart O. This statement is not clear.

Subpart O addresses integrity management and allows the use of one of three assessment techniques. Item 10 of this paragraph requires periodic in-line inspections at a frequency determined by the operator. This item implies that CIS is required at different intervals than the ILI interval. The need for close interval surveys is not justified or explained in the NPRM.

*TransCanada recommends deletion of 192.620(d)(7)(iv) in its entirety once item (d)(7)(iv)(B) is moved to paragraph 192.328(e).*

Item (8) – Controlling external corrosion through cathodic protection:
This item states requirements for action to be taken if a test point reading falls below criteria. Since the test stations are required in or near HCA's and are rather closely spaced, and with specific requirements on what to do if the readings fall below criteria, the need for CIS is not justified.

This proposed requirement states that remediation must be completed within 6 months. This requirement is excessive and not justified. Based on the seasons and associated land use issues as well as the time it takes to obtain permits, a one-year timeframe is more appropriate.

*TransCanada recommends changing 192.620(d)(8)(i) to read "… within one year…".*

This item requires a CIS after remediation for a CP issue. This requirement is excessive and not justified. The reason for a failed reading may not require CIS to confirm restoration of CP. Example include loss of power, a cable cut, a short, etc. all of which can be fixed and have no bearing on the effectiveness of the CP on the segment. The operator does need to confirm that the remedial action was appropriate and effective, however CIS in not always necessary or may be inappropriate.

*TransCanada recommends changing 192.620(d)(8)(ii) to read "After remedial action to address the loss of CP, the operator must confirm that the remedial action did restore the CP system to criteria as identified in 192 subpart I".*

Item (9) – Conducting a baseline assessment of integrity:
This item requires the use of DA for segments that are not piggable. These segments may be designed per 192.111 and therefore would not be required to follow the requirements of 192.620. In addition, DA may not be appropriate for periodic assessments at these locations. Previous waivers have allowed operators to develop a corrosion control plan that does not require DA but is entirely appropriate for the subject segments.

Pressure testing is also an alternative to DA where ILI can not be performed and should be considered as an option as well

*TransCanada recommends changing 192.620(d)(9)(iii) to read "…use either DA or pressure testing to assess that segment or develop and implement a corrosion control plan to address corrosion of the segment".*

Item 10 – Conducting periodic assessments of integrity:

TransCanada agrees with the proposed requirements.

Item (11) – Making repairs:
Item 11(i) requires the use of the most conservative calculation for determing remaining strength. This statement seems to imply that more than one calculation must be performed and the most conservative prediction must be used regardless of inherent conservatisms of the predictive models. Each calculation method results in slightly different answers with none being consistently more appropriate than the others. This requirement is excessive and has not been justified.

The idea of tool tolerance is addressed in the Protocols used by PHMSA for expectations of an operator's integrity management program. If Subpart O is referenced in lieu of this proposed requirement, there is no need for this requirement.

Item 11(ii) in general, proposes that immediate repair must be made based on the criteria set forth. These proposed requirements are extremely conservative and in many cases are not achievable. These criteria are not consistent with Subpart O requirements and have not been technically justified. These issues have been addressed in a White Paper "Safety Factors for Assessing Pipeline Anomalies" (submitted as a part of INGAA comments) which states that the requirements outlined in ASME B31.8S and incorporated into Subpart O of part 192 are appropriate for pipelines operating up to 80% of SMYS.

Item 11(ii)(A) sets dent criteria to those applicable to new pipelines even if the pipeline is already in operation. The dent criteria applicable to new pipelines are primarily used as quality control criteria for construction, not as integrity assessment criteria. For existing pipelines, this is not a readily achievable requirement and is not technically justified. The requirements under 192.933(d) are the appropriate criteria to apply to existing pipelines.

Item 11(iii) in general proposes that repairs must be made within one year based on the criteria set forth. These proposed requirements are extremely conservative and in many cases are not achievable. These criteria are not consistent with Subpart O requirements and have not been technically justified. Again, these issues have been addressed in the White Paper "Safety Factors for Assessing Pipeline Anomalies".

Early Special Permits required that any anomaly with a predicted failure pressure to MAOP ratio of 1.1 or less was an immediate repair condition. A one year condition was an anomaly with a predicted failure pressure to MAOP ratio of 1.25 or less. Later Special Permits tightened these already conservative requirements by adding wall loss factors so that an immediate repair condition also included any wall loss of 60% or more and a one year condition included any wall loss of 40% or more. These additional factors are not technically justified and add much more conservatism than is necessary.

Item 11(iv) is not clear. The terminology is not consistent with Subpart O requirements in the regulations or ASME b31.8S. If an indication from an ILI or DA assessment does not require an examination or evaluation, it is not determined to be a defect. Based on the assessment information, the indications not remediated are classified and used to determine the next integrity assessment. This paragraph seems to repeat the requirements of 10(i) of this paragraph yet the terminology or intent seems to conflict. Paragraph 10(i) is the appropriate language to use to require subsequent inspections and references Subpart O where the requirements are more clearly stated.

TransCanada would prefer that paragraph 192.620(d)(11) as written be deleted in its entirety and replacing it with the statement "examination, evaluation and remediation of any indication or anomaly must be in accordance with Subpart O of this part". However, some recognition for more conservative repair criteria may be justified for pipelines operating at the higher design factor.

*TransCanada recommends modification of 192.620(d)11) to read as follows:*
*(i) Do the following when evaluating an anomaly:*
*(A) Use a method for determining remaining strength of a corroded pipeline that is appropriate for the pipe being evaluated*
*(B) Take into account the tolerance of the tools used for the assessment*
*(ii) Repair a defect immediately if any of the following apply:*
*(A) For new pipelines, a dent discovered during the baseline assessment under (d)(9) of this section and the defect meets the criteria in 192.309(b). For existing pipelines, a dent discovered during the baseline assessment under (d)(9) of this section and the defect meets the criteria in 192.933(d).*
*(B) The defect meets the criteria for immediate repair condition in 192.933(d)(1)(iii)*
*(C) A corrosion defect with a predicted failure pressure to MAOP ratio of 1.1 or less; or with pitting depths of 80% or more.*
*(iii) If paragraph (d)(ii) of this section does not require an immediate repair, repair a defect within one year if any of the following apply:*
*(A) The defect meets the criteria for a one-year condition in 192.933(d)(2)*
*(B) A corrosion defect with a predicted failure pressure to MAOP ratio of 1.25 or less; or with pitting depths of 70% of more.*

The criteria as they relate to the predicted failure pressure to MAOP ratio will address any issues of remaining strength of the pipeline. The pit depth criteria will address any issue with the potential for a corrosion leak. The 80% value for immediate repair conditions is consistent with the various methodologies for determining remaining strength of pipelines. Any corrosion with depths of 80% or more is outside the parameters of the methodologies and provides conservatism. The 70% value for one-year repair conditions allows for extreme pitting corrosion over the one year period without exceeding the 80% methodology parameters.

Paragraph (e)
TransCanada agrees with the proposed requirements.