I. WITNESS INTRODUCTION

1. Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Schramm. My business address is 7135 Janes Avenue, Woodridge, Illinois, 60517.

2. Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as a Vice-President and Senior Project manager by EN Engineering, an engineering and consulting firm specializing in pipeline design services for the oil and gas industry.

3. Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.S from Iowa State University (Ames, Iowa) and am a NACE (National Association of Corrosion Engineers) certified Cathodic Protection Specialist (#3178) and Corrosion Technologist (#3178). My professional experience consists of employment in the pipeline industry with EN Engineering (present employer), NICOR Technologies, NICOR Gas (Northern Illinois Gas), Corrpro Companies, Inc. and HARCO Corporation. My responsibilities in these positions include over twenty-six (26) years of extensive experience in the direct and practical application of pipeline integrity and corrosion control including corrosion engineering analysis and design, process control and measurement, internal "smart" tooling analysis, cathodic protection design, installation and maintenance, computerized close interval potential survey, direct current voltage current survey, telluric current monitoring, measurement and investigation, stray DC interference testing and mitigation, coating selection and inspection, and material selection and purchasing.

I am currently responsible for the technical support of the Pipeline and Corrosion Control service offering including the development and maintenance of technical specifications and procedures, project oversight and quality assurance for corrosion control, cathodic protection, field failure and integrity management projects and proposals, and the qualification and training of corrosion control, field failure, and system integrity personnel.

Within the corrosion control and cathodic protection industry I have served in a Chair position for NACE T-10-A-11 Gas Industry Corrosion Problems (1995 – 2001), NACE Certification Committee (2001 – 2005), and am incoming Vice-Chair to the NACE Professional Activities Committee (PAC). In addition, I am a Certified Craft Instructor for the National Center for Construction Education (NCCER) as it relates to their *American Petroleum Institute (API) Operator Qualification Program*, a Veriforce Operator Qualification Evaluator, and, as a member of the NACE Cathodic Protection Training and Certification Program Task Group, was instrumental in the development and review of the NACE Cathodic Protection Training and Certification program.

My Resume is attached to this document as Appendix A.

4. Q. ON WHOSE BEHALF WAS THIS TESTIMONY PREPARED?

A. This testimony was prepared on behalf of the Staff of the South Dakota Public Utilities Commission (Staff).

II. PURPOSE OF THIS TESTIMONY

5. Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. The main objective of the Staff in this testimony is to ensure that TransCanada Keystone Pipeline, LP (Keystone) has met the requirements of the Federal Pipeline Safety Regulations 49CFR 195, Transportation of Hazardous Liquids by Pipeline, with respect to Keystone's application for a permit (Permit) to construct and operate a crude oil pipeline in South Dakota. This testimony deals specifically with the areas of Corrosion Control (Subpart H.)

Additional requirements in these areas have been placed upon Keystone as a condition of being granted a special permit to operate the pipeline at a hoop stress level of 80% of the specified minimum yield strength (SMYS) of the pipe material. These additional requirements will be noted in the appropriate portions of this testimony.

6. Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. The testimony will address the relevant portions of the Federal requirements related to ensuring that the design, construction, and operation of the facility will produce minimal adverse effects on the environment and the citizens of South Dakota. Each subpart of the Federal requirements will be addressed separately. At the conclusion of the testimony, I will present an overall assessment of the corrosion control program planned by TransCanada Keystone Pipeline, LP.

49CFRCh.1- Subpart H – Corrosion Control

7. Q. Is Keystone in compliance with §195.551 – What do the regulations in this subpart cover?

A. This section of code prescribes the minimum requirements for the protection of steel pipelines against corrosion. I have reviewed the PHMSA Grant of Waiver, TransCanada Petition, and the Direct Testimony of Robert Jones, Meera Kothari, Loys Gray, and Brian Thomas, and find the proposed design, construction, and installation of this pipeline meets the requirements of this subpart. Additional reference is detailed in Exhibit A.

8. Q. §195.553 – What special definitions apply to this subpart?

A. This section of code contains special definitions which apply to this subpart. I would not expect to see any documentation supplied to address this section by TransCanada or PHMSA. For clarification to later sections found below, the following definitions from this section of code are:

- Direct Assessment means any integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.
- External corrosion direct assessment (ECDA) means a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

9. Q. – Does Keystone have a plan for supervisor qualification in the areas of corrosion control and does it meet the requirements of §195.555 – What are the qualifications for supervisors?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit B.

10. Q. Must the Keystone pipeline have a coating for external corrosion control under the provisions of §195.557 – Which pipelines must have coating for external corrosion control?

A. This section of code requires that each buried or submerged pipeline to have an external coating for external corrosion control if installed after October 20, 1985. TransCanada will provide an external corrosion control coating on the Keystone pipeline that will meet all requirements with this section of code as discussed in more detail in Exhibit C.

11. Q. Has Keystone selected an approved coating for external corrosion control per §195.559 – What coating material may I use for external corrosion control?

A. TransCanada is taking a good proactive approach to coating selection and, as contained in Exhibit D, the inspection of the coating prior to installation. Fusion bonded epoxy (FBE) coatings are indeed the industry "best practice" choice and that will possess and meet all of the properties required by this section of code.

12. Q. Will Keystone's plan meet the inspection timing requirements for external corrosion control in §195.561 – When must I inspect pipe coating used for external corrosion control?

A. TransCanada is taking a good proactive approach to coating inspection, selected industry "best practice" choices, and will meet the intent of this code section. Additional detail is provided in Exhibit E.

13. Q. Must the Keystone pipeline have cathodic protection under the provisions of §195.563 – Which pipelines must have cathodic protection (CP)?

A. Based on the PHMSA Grant of Waiver requirements and the revised April 10, 2007 TransCanada Petition, detailed in Exhibit F, the proposed Keystone pipeline will be provided with cathodic protection that will meet or exceed the requirements of this code section.

14. Q. Must Keystone install cathodic protection on breakout tanks under the provisions of §195.565 – How do I install cathodic protection on breakout tanks?

A. As indicated in Exhibit G, TransCanada does not intend to install any breakout tanks as part of this petition in the State of South Dakota.

15. Q. Has Keystone provided for corrosion control test leads as contained in §195.567 – Which pipelines must have test leads and what must I do to install and maintain the leads?

A. As a recommendation, Keystone needs to provide additional documentation and clarification that acknowledges the PHMSA Grant of Waiver requirements and addresses the installation methods that will be used to install the test lead wires, connect the wire to the pipe, and the protective coating that will be used over the connection. This is discussed in more detail under Exhibit H.

16. Q. Does Keystone's plan meet the requirements in §195.569 – Do I have to examine exposed portions of buried pipe?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit I.

17. Q. Has Keystone provided information as to a cathodic protection criteria under §195.571 – What criteria must I use to determine the adequacy of cathodic protection?

A. The PHMSA Grant of Waiver and the revised April 10, 2007 TransCanada Petition both acknowledge compliance to this industry "best practice" document - meeting the requirements of this code section. Additional detail can be found in Exhibit J.

18. Q. Has Keystone provided a plan to monitor for external corrosion under §195.573 – What must I do to monitor external corrosion control?

A. The revised April 10, 2007 TransCanada Petition acknowledges the requirements to meet this code section. The April 30, 2007 PHMSA Grant of Waiver is more stringent and places additional direction and requirements with regard to this code section. Additional details can be found in Exhibit K.

19. Q. Must Keystone provide electrical isolation required under §195.575 – Which facilities must I electrically isolate and what inspection, tests, and safeguards are required?

A. TransCanada has chosen to not electrically isolate the pipeline from the pumping stations. Based on this design, TransCanada is taking a good proactive approach, has selected industry "best practices" and, as proposed, will meet the requirements of this code section. Additional detail is provided in Exhibit L.

20. Q. Must the Keystone pipeline alleviate interference currents under the provision of §195.577 – What must I do to alleviate interference currents?

A. Significant testimony and documentation has been provided with regards to this code section including: defined requirements by PHMSA in the Grant of Waiver. I would agree that TransCanada is taking a proactive approach to this issue and, as proposed, will meet the requirements of this code section. Additional detail is provided in Exhibit M .

21. Q. Will Keystone's plan meet mitigation requirements for internal corrosion under the provisions of §195.579 – What must I do to mitigate internal corrosion?

A. TransCanada has taken a more stringent approach with regard to the mitigation of internal corrosion as it relates to operating design (turbulent mode) and reduced sediment and water levels. PHMSA acknowledges this approach and places additional requirements which include operational notification requirements, cleaning intervals and the required use of corrosion coupons. This approach as presented meets the requirements of this code section. More detail is provided in Exhibit N.

22. Q. Has Keystone selected an approved coating for Atmospheric Corrosion per §195.581 – Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit O.

23. Q. Has Keystone provided how they will monitor for atmospheric corrosion control under §195.583 – What must I do to monitor atmospheric corrosion control?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit P.

24. Q. Is Keystone's plan to correct corroded pipe adequate under the provisions of §195.585 – What must I do to correct corroded pipe?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit Q.

25. Q. Will the Keystone plan meet the requirements for determining the strength of corroded pipe under §195.587 – What methods are available to determine the strength of corroded pipe?

A. The PHMSA Grant of Waiver requires that Keystone apply the most conservative methods in order to confirm and determine the strength of corroded pipe based on remaining wall thickness. In addition the PHMSA Grant of Waiver requires that Keystone must confirm the remaining strength tools (RSTRENG), RSTRENG-0.85dL and ASME B31G are valid for this pipeline. These more stringent requirements as imposed meet and exceed the requirements of this code section. Additional detail is provided in Exhibit R.

26. Q. Will Keystone's plan meet the standards that apply for direct assessment under the provision of §195.588 – What standards apply to direct assessment?

A. In my opinion, Keystone's plan needs additional documentation and providing this additional documentation is recommended as a condition of issuing a construction permit as discussed in more detail in Exhibit S.

27. Q. Will Keystone's plan meet the requirements for the retention of corrosion control information under the provision of §195.589 – What corrosion control information do I have to maintain?

A. PHMSA places more stringent record keeping requirements on the Keystone Pipeline in their Grant of Waiver. TransCanada's Petition for the Keystone Pipeline and subsequent request for information acknowledge the requirements of this code section. Assuming plan follow-through, the Keystone Pipeline will meet the record keeping requirements contained in this code section

28. Q. Does this conclude your Testimony?

A. Yes it does

ENEngineering

David A. Schramm
Vice President, Pipeline Integrity & Corrosion Services

Education

BS, Resource Management, Iowa State University, Ames, Iowa, 1978

Professional Certifications

National Association of Corrosion Engineers International (NACE) – Cathodic Protection Specialist #3178
National Association of Corrosion Engineers International (NACE) – Corrosion Technologist #3178
Clockspring Trainer/Installer Certified
National Center for Construction and Research (NCCER) Certified Craft Instructor
National Association of Corrosion Engineers
Veriforce Operator Qualification Evaluator
Operator Qualification ISNETWORLD #00425152
West Virginia University, Appalachian Underground Course – Advanced Corrosion Control

Summary of Experience

Twenty-six (26) years of extensive experience in the direct and practical application of pipeline integrity and corrosion control including corrosion engineering analysis and design, process control and measurement, internal "smart" tooling analysis, cathodic protection design, installation and maintenance, computerized close interval potential survey, direct current voltage current survey, telluric current monitoring, measurement and investigation, stray DC interference testing and mitigation, coating selection and inspection, and material selection and purchasing.

Responsible for the technical support of the Pipeline and Corrosion Control service offering including the development and maintenance of technical specifications and procedures, project oversight and quality assurance for corrosion control, cathodic protection, field failure and integrity management projects and proposals, and the qualification and training of corrosion control, field failure and system integrity personnel.

In addition to pipelines, has additional experience with underground storage tanks, above grade storage tanks, power plant structures, condenser/chiller equipment, water well casings, lead sheath cable, underground electric cable, and marine structures.

Project Experience

Corrosion Control Operations, ***Illinois***

Managed and directed the Corrosion Control Service Group for Nicor Technologies and Nicor Gas providing corrosion control consulting services to distribution and transmission pipelines, municipal and utility organizations, and commercial and industrial customers. Responsible for the performance of all operating corrosion control programs (internal, external and atmospheric) on the Nicor Gas pipeline system including specification, performance and day-to-day operation. As a member of the Nicor Gas welding and joining, system integrity, and code committee operating task groups provided technical expertise in pipeline integrity, research and testing, corrosion control and cathodic protection issues. Having responsibility for the due diligence corrosion control and cathodic protection evaluations on acquisition projects in Argentina and Tennessee. Developed risk, quality, and integrity management programs related to corrosion control and cathodic protection operations.

David A. Schramm
Vice President, Pipeline Integrity & Corrosion Services

Project Experience (cont'd)

Corrosion Control and Research Program Services, *Illinois*

Directed and coordinated the Nicor Gas corrosion control programs for distribution, transmission, and storage facilities. Directly supervision responsibility for the completion of annual corrosion control and corrosion control activities which include: annual reading programs, close interval survey, stray current interference, and impressed current rectifier system replacement. Managed and directed the research lab for Nicor Gas and was responsible for day-to-day operation, quality performance, testing, recommendation and approval, including the performance and analysis ASTM and ANSI test standards and methods. Directly responsible for the purge routine process for all large-diameter high- pressure pipelines. Conducted, analyzed and developed corrosion control action and recommendation for all wall loss and field failure events.

Lakehead Pipe Line Company, *North Dakota, Minnesota, Wisconsin, Illinois, Michigan, and New York*

Directed the completion of all annual cathodic protection reading programs, close interval survey, stray current interference, impressed current rectifier system replacement, and field failure investigations for the Lakehead Pipe Line Company over a six (6) year period on facilities that include pipeline, compression, substation, and storage facilities.

Portal Pipe Line Company, *North Dakota*

Supervised and completed the annual cathodic protection reading program for the Portal Pipe Line Company including pipeline, gathering and wellhead systems.

Alyeska Pipeline Service Company, *Alaska*

In-state direction, supervision and related to the process of conducting, analyzing and performing telluric based close interval surveys for the Trans-Alaska Pipeline System (TAPS) over a four (4) year period. Direct responsible for the performance, provision, data quality, data analysis and report recommendations.

Deseret Generation and Transmission Company, *Utah*

Supervised, conducted and performed the design and testing services for the Deseret Generation and Transmission Company. Planned and performed a wide variety of duties involving the evaluation, design, and installation of cathodic protection systems to inhibit corrosion on pipelines, tanks, and similar underground and submerged structures including electrical continuity and protection of concrete steel cylinder pipe.

David A. Schramm
Vice President, Pipeline Integrity & Corrosion Services

Project Experience (cont'd)

Mobil Oil, *Illinois*

Conducted and analyzed all underground facilities for the potential application of cathodic protection for the Mobil-Joliet Refinery. Operational and performance responsibilities related to installation of new and existing cathodic protection systems: design, redesign, and installation of impressed current systems for tank bottoms.

Montana Power, *Montana*

Conducted, analyzed and performed close interval and leak detection surveys on large diameter - high pressure – natural gas transmission pipelines owned and operated by Montana Power near Helena, Montana.

Northern Natural Gas, *Michigan*

Conducted, analyzed and performed close interval surveys on large diameter - high pressure – natural gas transmission pipelines owned and operated by Northern Natural Gas (NNG) in the Upper Peninsula of Michigan.

Mountain Bell Telephone, *Wyoming*

Supervised, conducted, analyzed and performed the corrosion control and cathodic protection analysis of the Mountain Bell Telephone lead sheath cable running between Evanston and Cheyenne, Wyoming.

Coffeen Power Plant, *Illinois*

Supervised, conducted, analyzed, designed and installed cathodic protection systems for the Coffeen Power Plant Facilities operated by the Central Illinois Light Company (CILCO).

LaGrange Hospital, *Illinois*

Designed, analyzed and supervised the installation of galvanic anode systems designed to protect the interior water box of condenser/chiller units operated by the LaGrange Hospital.

Union 76, *Illinois, Kentucky, Indiana*

Supervised, conducted and analyzed the cathodic protection systems installed on over 250 underground gasoline and waste oil storage tanks systems owned and operated by Union 76.

O'Hare Airport, *Illinois*

Designed and supervised the installation of galvanic anode protection systems for aviation fuel pipelines related to jet-way expansions. Responsible for the cathodic protection assessment, design, and mitigation on jet-way expansions of the G & H terminals as well as field supervision on the United Airlines terminal 1 construction project.

David A. Schramm
Vice President, Pipeline Integrity & Corrosion Services

Project Experience (cont'd)	City of Viburnum, *Missouri* Designed and supervised the installation of down-hole impressed current systems for the City of Viburnum including the protection of water well casing, column and bowls.

Exhibit A - §195.551

Many times documentation or information which is not directly related to corrosion will have a direct effect on the ability to provide long term corrosion control. Examples of this found below include: the installation of the pipe at a greater depth to protect against third party damage – as third party damage can lead to corrosion wall loss; or the installation and commissioning of cathodic protection during construction rather than after pipeline start-up. The following general impact items and/or project definitions are provided as reference:

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Depth of Cover: The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):

- Keystone will purchase and utilize X-70 and X-80 grade steel pipe from technically pre-qualified pipe mills.
- Coating – Pipe: The pipe will be coated externally with plant applied fusion-bonded epoxy (FBE), girth welds will be coated with field applied FBE or liquid epoxy.
- Coating – Field Welded Joints: Field welded joints will be prepared and coated with FBE or liquid epoxy in accordance with TransCanada coating specifications.
- Coatings – Directional Drills/Slick Bores – Line pipe installed in a bored or directional drill crossing will be coated with FBE and an additional protective abrasion-resistant FBE outer coating or liquid epoxy.
- Keystone will design the pipeline to exceed the depth of cover requirements for installation of new oil pipelines set out in 49 CFR §195.248, Part D. Keystone will generally provide 4 feet of cover over the pipeline as compared with 30 inch minimum required by CFR 195. Depth of cover will be a minimum of 5 feet below the bottom of road ditches and water bodies, which includes rivers, creeks, streams, ditches and drains.
- External corrosion will be addressed by utilizing high performance coatings on the mainline pipeline, including girth welds, with additional protective abrasion-resistant coatings where required (e.g., bored crossings, HDD). In addition the cathodic protection system will be installed and progressively activated during the construction phase (instead of within one year of operation) to control corrosion immediately and thereby reducing any initial growth (sic., "of wall loss by corrosion"). Keystone's mill wall thickness tolerance will be more stringent than that required by API 5L, resulting in an increased initial minimum wall thickness.

Direct Testimony of Robert Jones:

- The pipeline is proposed to enter South Dakota in Marshall County and extend southerly, exiting the state underneath the Missouri River near Yankton, South Dakota.
- The length of the pipeline in South Dakota will be approximately 220 miles and will cross 10 counties.
- There will be aboveground facilities including four pump stations, remotely activated isolation valves, and densitometers. Power lines required providing power to pump stations, remotely activated isolation valves, and densitometers will be permitted and constructed by local utilities and not by Keystone.

Direct Testimony of Meera Kothari:

- No lateral lines will be constructed in South Dakota.
- The four pump stations in South Dakota will be in Day, Beadle, Miner and Hutchinson Counties. The stations and the pumps are electrically driven and will be required to pump the crude oil through the line.
- Fourteen mainline valves will be installed in South Dakota. Seven valves will be remotely controlled.
- Corrosion can be both internal and external. Corrosion defects are defects which develop over time during operation. Fusion bonded epoxy (FBE) is a protective coating that is applied to the external surface of the pipe to prevent corrosion. A cathodic protection system installed, comprised of engineered metal allows or anodes, which are connected to the pipeline. A low voltage direct current is applied to the pipeline; the process corrodes the anodes rather than the pipeline. The two combined mitigate external corrosion.

Exhibit B - §195.555

This section of code requires that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.402(c)(3) for which they are responsible for insuring compliance. Section §195.402(c)(3) relates to the operating, maintenance, and repair of the pipeline system in accordance with each of the requirements of this subpart (§195.402) and subpart H under §195. Although this section is more applicable to an operating pipeline and not a pipeline during construction, the intent is to insure that responsible individuals be required to have a thorough knowledge of corrosion control procedures and those requirements contained under §195.402.

In relative context to this section of code, the PHMSA Grant of Waiver and the Petition of TransCanada do focus on the direction and action related to §195.587, *Methods available to determine the strength of corroded pipe.* However, none of the documents specifically reviewed describe how compliance with this section of code will be achieved. Only a small reference section contained in the *revised April 10, 2007– Petition of TransCanada document* - as it relates to the application and performance testing for field applied coatings – was found and is provided below.

TransCanada should be able to provide additional plan documentation as to how it will require pipeline supervisors and/or inspectors to have a thorough knowledge of the corrosion control procedures and those contained under §195.402 during the design (corrosion control and cathodic protection design), installation, and operation of this pipeline.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):
The application procedures used in the field have been tested and proven to provide the level of performance required when used with an approved coating material. The field applicators are trained and tested to prove they are capable of following the application procedure.

Exhibit C - §195.557

This section of code requires that each buried or submerged pipeline must have an external coating for external corrosion control if installed after October 20, 1985. As indicated below in reference, TransCanada meets all requirements with this section of code.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):

- Keystone will purchase and utilize X-70 and X-80 grade steel pipe from technically pre-qualified pipe mills.
- Coating – Pipe: The pipe will be coated externally with plant applied fusion-bonded epoxy (FBE), girth welds will be coated with field applied FBE or liquid epoxy.
- Coating – Field Welded Joints: Field welded joints will be prepared and coated with FBE or liquid epoxy in accordance with TransCanada coating specifications.
- Coatings – Directional Drills/Slick Bores – Line pipe installed in a bored or directional drill crossing will be coated with FBE and an additional protective abrasion-resistant FBE outer coating or liquid epoxy.

Exhibit D - §195.559

This section of code describes the properties that a coating material must possess in order to be used on buried or submerged pipelines. In synopsis, the requirements are:

- Be designed to mitigate corrosion;
- Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
- Be sufficiently ductile to resist cracking;
- Have enough strength to resist damage due to handling and soil stress;
- Support any supplemental cathodic protection; and
- If the coating is an insulating type, have low moisture absorption and provide a high electrical resistance.

TransCanada provides significant detail with regard to its selection of the pipeline coating, the coating to be used for bore operations, and the field coating that will be used on this pipeline.

For bore operations, TransCanada indicates their desire to use a "dual" FBE coating applied in plant using a parent FBE coating and a secondary FBE coating that is modified to have additional properties to increase its hardness and abrasive resistance properties. The advantage of this coating system is that there is no physical separation in the two coatings – as they are blended together at their interface during application. The outer layer FBE coating acts to protect the inner FBE coating which is considered to be the primary corrosion barrier. Again I would consider this to be an industry "best practice" choice which possesses all of the properties required by this section of code.

The same conclusion holds true for use of an "induction heated" field applied FBE or liquid epoxy coating indicated as the field joint coating. Again I would consider this selection to be an industry "best practice" choice which possesses all of the properties required by this section of code.

The TransCanada design parameters and the requirements contained in the PHMSA Grant of Wavier, requires the temperature of the pipeline to be held less than 150 degrees Fahrenheit in order to remain under the FBE coating limitation of 150 degrees F. TransCanada indicates a maximum temperature value on the pipeline at 100.4-degrees F

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Temperature Control: The pipeline operating temperatures must be less than 150 degrees Fahrenheit.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):

- Coatings – Temperature Rating: The pipeline will operate at a minimum value temperature of 45.5-degrees F, and a maximum value temperature of 100.4-degrees F. the FBE (150-degrees F) and liquid epoxy coating systems (185-degrees F) are rated well above and below these respective temperatures.
- Coatings – Cased Crossings: All railroads, highways and roads will be crossed without casings unless otherwise requested and will minimize carrier pipeline corrosion due to mechanical or electrolytic shorts developed by casings over time.
- TransCanada's experience has shown that following this proactive approach to preventing and detecting coating disbonding in the factory and the field results in pipelines with a high degree of integrity and safety. To date, TransCanada has not experienced integrity issues with Fusion Bond Epoxy coated pipelines, some of which have been in service for 28 years. Keystone will take additional steps to ensure a higher quality pipe coating than is required by the latest editions of NACE International's Recommended Practice, RP-0169, Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

Direct Testimony of Meera Kothari:

- TransCanada has thousands of miles of this particular grade of pipeline steel installed and in operation. TransCanada pioneered the use of FBE, which has been in use on our system for over 28 years. There have been no leaks on this type of pipe installed by TransCanada with the FBE coating and cathodic protection system during that time. When TransCanada has excavated pipe to validate FBE coating performance, there has been not evidence of external corrosion.

Q7-1: Data Request: For those pipelines that TransCanada owns or operates over the last five (5) years, which are coated with a plant applied fusion bonded epoxy coating (FBE), how many failures or incidents related to external corrosion have occurred?

*R7-1: **Response:** There have been no failures or incidents on this type of pipe during the last five years on TransCanada's owned and operated pipelines that are coated with plant-applied FBE. TransCanada has not experienced a failure due to external corrosion on this type of pipe with FBE coating in over 28 years of experience.*

Q7-2: Data Request: Please provide additional information on the type and description of the coating that will be used for directional bored or thrust-bore locations? What quality control testing will be performed after bore operations to evaluate as-installed coating condition for acceptability?

*R7-2: **Response:** Directional bored pipe will be coated with plant-applied fusion bond epoxy ("FBE") to serve as the primary corrosion barrier. An additional topcoat of plant-applied FBE, formulated for abrasion resistance (i.e., the abrasion-resistant* *coating), will be applied to protect the primary FBE coating from damage during the directional drilling operation.*

One full, additional joint of pipe is typically pulled through the bore location and is visually inspected for damage. This will provide an indication of the coating condition for the remaining joints within the bore location. The information will be recorded and incorporated in the performance testing for the cathodic protection system in the area.

Exhibit E - §195.561

This section of code requires that all external pipeline coatings be inspected with specific reference to the inspection of the pipe just prior to lowering into the ditch or submergence. It also requires the repair of any damage discovered.

Protective coatings on buried or submerged structures are required by code on this pipeline and are the initial defense in controlling pipeline corrosion. Protective coatings provide corrosion prevention by isolating the external surface of the pipeline from the surrounding environment. When used in conjunction with cathodic protection, they reduce cathodic protection current requirements and improve current distribution.

In addition to the specific reference to the inspection of the pipe just prior to lowering into the ditch or submergence, PHMSA in the Grant of Waiver is requesting a coating application quality control program to address surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repairs. TransCanada acknowledges this requirement in their petition document dated as "revised – April 10, 2007.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Pipe Coating: The application of corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair.
- Field Coating: Keystone must implement a field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application, temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures. Keystone will perform follow-up tests on field-applied coating to confirm adequate adhesion to metal and mill coating.
- Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must be resistant to abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

Revised April 10, 2007 – **Petition of TransCanada (Excerpt):**

- (sic., "A") Test (sic., "of the") coating systems to insure that they meet the strict material property requirements of NACE RP-0394 Application, Performance, and Quality Control of Plant-Applied, Fusion Bonded Epoxy External Pipe Coating. Cure, flexibility, impact resistance, blast profile, interfacial contamination, thickness and cathodic disbondment resistance are some of the properties evaluated.
- Perform a pre trial to insure that the coating factory or application plant is capable of applying the coating such that the requirements of the above referenced specifications are met on a consistent basis in the finished product.
- Perform regular non-destructive and destructive tests during plan application on coated pipe samples obtained from the process to confirm the coated pipe meets the specified requirements. Unacceptable coated pipes are rejected and run through the process again until an acceptable product is produced.
- Inspect the coated pipe for "holidays" or coating defects prior to leaving the plant and repair any deficiencies found.
- Take care in handling the pipe in stockpiling, transportation and stringing to minimize any coating damage that may occur.
- Inspect the pipes after welding for "holidays" and again, all deficiencies are repaired prior to backfilling.
- Coat girth weld areas in the field using coating materials that have been previously tested and approved to provide acceptable levels of long term performance. The application procedures used in the field have been tested and proven to provide the level of performance required when used with an approved coating material. The field applicators are trained and tested to prove they are capable of following the application procedure. Periodic process parameter and coating cure tests insure that the girth weld coating us properly applied and will provide the high degree of protection required. Welds with unacceptable cure process parameters are cleaned off and recoated.
- TransCanada's experience has shown that following this proactive approach to preventing and detecting coating disbonding in the factory and the field results in pipelines with a high degree of integrity and safety. To date, TransCanada has not experienced integrity issues with Fusion Bond Epoxy coated pipelines, some of which have been in service for 28 years. Keystone will take additional steps to ensure a higher quality pipe coating than is required by the latest editions of NACE International's Recommended Practice, RP-0169, Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

Q7-4: Data Request: Describe TransCanada's quality control and inspection process as it relates to the protection of the external pipe coating as the pipe is lowered into the ditch or submerged? And during backfill operations?

R7-4: Response: *In order to verify that the construction specifications are followed by the construction contractor, Keystone will implement a quality control and quality* *assurance plan ("QC/QA Plan"). The QC/QA Plan will establish technical inspection policies and procedures (including those for protection of the external pipe coating) and delineate the duties and responsibilities of each construction inspector assigned to the Keystone project:*

Keystone will have a lowering-in inspector assigned to the project to ensure that the external pipe coating is protected during this operation. Pipe will not be lowered into the ditch without the lowering-in inspector being present. Prior to lowering-in, the inspector will ensure that the contractor inspects all external pipe surfaces for coating defects and damage with a properly calibrated operable holiday detector and that any coating flaws are immediately marked and repaired. Additionally, the lowering-in inspector will ensure that the ditch bottom is free of rock and other construction debris and confirm that the ditch bottom is prepared and any required support pillows or padding have been placed. During lowering-in, the inspector will inspect the pipe handling equipment for properly manufactured slings, belts and cradles to protect the external pipe coating and the pipe handling to prevent it from swinging or rubbing against the sides of the ditch or making contact with the sidebooms.

Where pipe is submerged during lowering-in and is not concrete coated, the inspector will inspect the ditch spoil materials for the presence of rock or other debris that could damage the external pipe coating and, if these materials are present, require installation of rick shield or wood lagging to protect the external pipe coating prior to lowering in the pipe.

Keystone will also have a padding and backfill inspector assigned to ensure that the pipe and external coating are protected from physical damage. The padding and backfill inspector will confirm that any specified cathodic protection appurtenances have been installed and, where rocky or frozen ditch spoils are encountered, that acceptable padding material is made utilizing mechanical padders from the ditch spoil or imported padding material is placed over the pipe prior to backfilling or rock shield or wood lagging is utilized.

Keystone's QC/QA Plan will include periodic audits by construction management to confirm that inspections are being properly performed and documented.

Exhibit F - §195.563

This section of code requires that each buried or submerged pipeline must be cathodically protected if the pipeline is to be installed after October 20, 1985. The cathodic protection system must be in operation not later than 1 year after the pipeline is constructed.

For this pipeline, PHMSAs' Grant of Waiver specifically requires that the initial CP system be operational within six months of placing a pipeline segment into service – a more stringent requirement.

In the revised April 10, 2007 Petition, TransCanada indicates that they will be taking a more proactive approach to the application of cathodic protection and will install and commission into service CP systems along with pipeline construction.

Although not as common as historical practice, a pipeline operator under the code reference §195.563(a) could take up to a year after a pipeline is constructed to provide operational cathodic protection. Under this scenario, a pipeline completed in May of 2007 would not need to demonstrate the operation and the appropriate level of cathodic protection until May of 2008. The intent of the PHMSA Grant of Wavier is not to reduce code requirements but to acknowledge increased requirements (either at the Operator's commitment or by PHMSA requirement). As such, the 6-month stipulation that the initial CP system must be operational within six months of placing a pipeline segment in service is considered to be more stringent and mimics the increased intent by TransCanada to provide for the installation of cathodic protection timed to occur with each construction spread.

There are issues related to pipe construction where the commission of the rectifier into service (energize) can create safety issues to workers and welding operations during construction. As interpreted as intent of this section, and consistent with these potential safety issues, it is my opinion that TransCanada/Keystone must have an operational CP system within 6 -months of completion of an (electrically continuous) pipeline segment of pipe that is in-service (has been tested, dewatered, and nitrogen filled as in the case of first year build). This effectively increases the code requirement to just ½ the timeline allowed by code and increases the requirement to pipeline segment rather than pipeline.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Cathodic Protection (CP): The initial CP system must be operational within six months of placing a pipeline segment in service.

Revised April 10, 2007 – Petition of TransCanada (Excerpt): The pipeline will include an impressed current cathodic protection (CP) system in accordance with 49 CFR §195.563 which will be progressively activated during the construction phase.

Q7-3: Data Request: Will the entire pipeline and all appurtances (valves, stations, etc.) as proposed, be protected exclusively using an impressed type cathodic protection system? Or will additional types of cathodic protection systems be used?

R7-3: Response: *The entire pipeline and all appurtances will be protected exclusively using an impressed current cathodic protection system.*

Q7-5: Data Request: Describe where TransCanada is proposing to locate and how easements are to be secured for the proposed impressed current rectifier and groundbed systems?

R7-5: Response: *Keystone anticipates using deep well anode groundbeds, and locating these facilities within the fenced pump station sties. Pump station sites are being acquired in fee. If any intermediate deep well anode groundbeds are required, Keystone anticipates locating them within fenced mainline valve sites. Mainline valve sites are being acquired with the pipeline easement.*

Q7-11: Data Request: Please provide additional detail on how TransCanada's proposed to install and progressively activate the cathodic protection system especially under a multiple spread scenario?

R7-11: Response: *Keystone's pipeline construction contractor will install cathodic protection ("CP") test lead wires to the proposed pipeline and will facilitate the installation of any necessary test leads by foreign utilities crossed by Keystone. Keystone will use a CP contractor to install CP rectifiers, junction boxes, deep well groundbeds, and test stations, as well as to commission and startup the CP system.*

Keystone proposes to construct one pipeline spreads in 2008 and two in 2009. The CP contractor will install the deep well ground beds, junction boxes and rectifiers simultaneously with the pipeline construction. Upon completion of the pipeline construction in 2008, the CP system on that portion of the pipeline will be commissioned and started up by the CP contractor. The 2009 work will be completed in similar manner.

Exhibit G - §195.565

This section of code requires cathodic protection to be installed to the bottom of an above-grade breakout tank more than 500 barrels in capacity if installed after October 2, 2000.

Q7-12: Data Request: Please provide the number of breakout type tanks that will be installed in the State of South Dakota and the means that will be used for the application of cathodic Protection.

R7-12: Response: *There are no breakout tanks to be installed in South Dakota*

Deleted: ¶

Exhibit H - §195.567

This section of code requires that all pipelines under cathodic protection must have electrical test leads for external corrosion control. Further this code section requires that:

- o The leads are located at intervals frequent enough to determine the adequacy of cathodic protection.
- o Looping or slack is provided during installation so that undue stress on the connection or wire does not occur.
- o Lead attachments are prevented from causing stress concentration on the pipe.
- o Each connection is coated to the pipeline (and bared wire) with an electrical insulating material compatible with the pipe coating and the insulation on the wire.
- o The test lead wires are maintained in a condition that enables future electrical measurements to be made.

Based on review of the documentation available and pertinent to this code section, a discrepancy exists between the language used in the revised April 10, 2007 petition by TransCanada and the PHMSA Grant of Waiver. Specifically, PHMSA is requiring more stringent requirements for the location of test points in and adjacent to HCA segments and requires that upon commission testing of the pipeline be completed within 6 months and address the proper number and location of CP test stations, AC interference mitigation, and AC grounding programs. PHMSA also requires that remedial action must occur (when test station readings fail to meet 49 CFR 195, Subpart H requirements within six months. Remedial actions must include a close interval survey on each side of the affected test station.

As described in the revised April 10, 2007 Petition and the PHMSA Grant of Waiver, the information and procedures will meet or exceed the requirements contained in this code section with regard to the location of test points and what must occur when a test station is "lost" or "unusable" during construction activities or during pipeline operations.

Most likely due to the stage of this petition, no documentation could be found that relates and addresses that middle three (3) bullets items describing how the wires will be installed (loop or slack), what methods of attachment will be used to prevent stress risers, and how the connection will be coated.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

Revised April 10, 2007 – Petition of TransCanada (Excerpt): Test stations will be attached to the pipeline at intervals averaging one mile and not exceeding two miles, and at all public road and railroad crossings. Test leads and CP bond wires will be installed on the Keystone Pipeline at foreign pipeline crossings and installed on the foreign pipeline being crossed, when approved by the owner of the foreign pipeline.

Q7-11: Data Request: Please provide additional detail on how TransCanada's proposed to install and progressively activate the cathodic protection system especially under a multiple spread scenario?

R7-11: Response: Keystone's pipeline construction contractor will install cathodic protection ("CP") test lead wires to the proposed pipeline and will facilitate the installation of any necessary test leads by foreign utilities crossed by Keystone. Keystone will use a CP contractor to install CP rectifiers, junction boxes, deep well groundbeds, and test stations, as well as to commission and startup the CP system.

Keystone proposes to construct one pipeline spreads in 2008 and two in 2009 in South Dakota. The CP contractor will install the deep well ground beds, junction boxes and rectifiers simultaneously with the pipeline construction. Upon completion of the pipeline construction in 2008, the CP system on that portion of the pipeline will be commissioned and started up by the CP contractor. The 2009 work will be completed in similar manner.

Exhibit I – 195.569

This section of code requires that if you have knowledge that any portion of the buried pipeline will be exposed, you must examine the exposed portion for evidence of corrosion if the pipe is bare or if the coating is deteriorated. If you find external corrosion at a level that requires corrective action you must investigate in all directions to determine if any additional corrosion exists in the vicinity that might require correction action. The investigation can be done by visual and/or indirect methods.

This code section is more applicable to a pipeline that is in operation rather than the during the construction and installation process – for the simple fact that the pipeline has not been placed in an environment long enough for corrosion (time dependent threat) to have occurred. In addition, during lay-in operations the pipeline is required and has undergone a 100% visual inspection prior to burial.

Most pipeline companies have detailed Operations and Maintenance procedures with regard to the inspection of pipe when exposed. TransCanada should be able to provide additional plan documentation as to how it will meet this code regulation during pipeline operation. This process should be followed during the exposure of any section of pipe after backfill operations are complete – regardless of how long the pipe has been buried or submerged.

Exhibit J - §195.571

This section of code requires that cathodic protection under this subpart must comply with one or more of the criteria contained in paragraphs 6.2 and 6.3 of the National Association of Corrosion Engineers (NACE) Standard RP 0169.

Both the TransCanada Petition and the PHMSA Grant of Waiver acknowledge the use of RP-0169 as the criteria for cathodic protection that will be used.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

Q7-14: Data Request: Please provide the criteria for cathodic protection that will be used for this pipeline and related appurtances? Please provide the procedures that will be used to ensure the requirements for the criterion are met?

R7-14: Response: The criteria for cathodic protection that will be used for this pipeline will correspond with the requirements of 49 CFR Part 195 Subpart H and NACE recommended practice RP 0169 (sic., "SP-0169 as of 2007"). Keystone's Integrity Management Plan will ensure the requirements for the criteria are met.

Exhibit K - §195.573

This section of code requires (cathodically) protected pipelines similar to this project to be monitored with activities to include:

- Conduct an annual test to determine the level of cathodic protection applied (each calendar year not to exceed 15 months from the last inspection).
- Assess the facility and determine the circumstances in which a close-interval survey (CIS) or compatible technology is practicable and necessary – with the implication that if you determine that a CIS is required that it is performed.
- Perform testing to determine the performance of impressed current rectifiers and other devices for operation. Rectifiers are to be inspected at a minimum at least six times each calendar year and at intervals not exceeding 2.5 months. Interference bonds (where failure of the bond would jeopardize integrity are to be inspected at a minimum of at least six times each calendar year and at intervals not exceeding 2.5 months. All other bond locations are to be inspected each calendar year not to exceed 15 months from the last inspection.

The revised April 10, 2007 TransCanada Petition acknowledges the requirements to meet this code section. The April 30, 2007 PHMSA Grant of Waiver is more stringent and places additional direction and requirements with regard to this code section. This includes:

- That a corrosion survey be completed within six months of placing the respective CP system(s) in operation.
- That the corrosion survey must also address the proper number and location of CP test station, AC interference mitigation and AC grounding locations.
- The requirement to install test stations with High Consequence Areas (HCA) at a defined interval increases the monitoring requirements for cathodic protection in within the HCA.
- A close interval survey (CIS) must be performed on the pipeline within two years of the pipeline in-service date.
- The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Pipeline Inspection: The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.
- Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.
- Initial Close Interval Survey (CIS) – Initial: A CIS must be performed on the pipeline within two years of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

Q7-13: Data Request: Please provide any detail of, if any, the measurements that will be obtained during pipeline construction that relate to §195, subpart H? What measurements will be taken during pipeline operation?

R7-13: Response: *Measurements that will be obtained during pipeline construction relating to 49 CFR Part 195 Subpart H includes:*

- *Part 195.561 – The external coating will be checked for holidays using visual inspection and electronically using a holiday detector ("jeep").*
- *Part 195.563 – Measurements will be taken to determine soil resistivities to enable design of the cathodic protection system.*
- *Part 195.575 – Keystone will electrically interconnect and cathodically protect its pipeline and aboveground facilities as a single unit and therefore, measurements related to isolation equipment are not required.*
- *Part 195.577 – Electrical measurements will be taken to identify any HVAC and HVDC interference currents, and interference with any close paralleling pipelines.*

During operations, monthly rectifier readings to check for voltage, current, and resistance will be performed consistent with Part 195.573(c). An annual test lead survey will also be performed to check system performance, and an annual equipment and maintenance check will be conducted on the rectifiers consistent with Part 195.573(a).

Exhibit L - §195.575

This section of code requires the electrical isolation of a buried or metallic or submerged pipeline from other metallic structures unless by design it is electrically interconnected and cathodically protected with the pipeline as a single structure. Where necessary to electrically isolate a portion of the pipeline - to facilitate the application of corrosion control - you must install one or more electrically insulating devices. And where installed, you must inspect and test to assure the isolation is adequate.

In addition, if you install an insulating device in area where a combustible atmosphere could exist or reasonably foreseen, you must take precautions to prevent arcing. And finally, if a pipeline is in close proximity to an electrical transmission tower footing, ground cable, counterpoise (buried ground cables that connect between towers) or other areas where it is reasonable to foresee fault currents or an unusual risk for lightning, you must protect the pipeline against this type of damage and take protective measures at insulating devices.

By design the casing pipe at a cased pipeline crossing is electrically isolated from the carrier pipe (the pipeline carrying the product). This is achieved through the use of electrically isolating casing spacers. An installation completed in this manner complies with the intent of code. I would agree with the Testimony of Meera Kothari that industry "best practice" has moved away from designing and building pipelines that are cased and, as proposed, TransCanada indicates that they are not intending to make use of cased crossings.

TransCanada indicates that the pump station and pipeline will be protected as a single unit and therefore electrical isolation will not be required. Under this design the cathodic protection system will not only protect the pipeline but the electrical ground system within the pump station and that which is common to the incoming AC power supply system. This is simply a matter of cathodic protection design philosophy and one that is common to many pipeline systems operating in the United States today.

The advantages of this design include (but are not limited to):

- Elimination of stray current issues on the AC grounding system.
- The application of cathodic protection to the AC grounding system to mitigate corrosion loss of electrical ground.
- Reduced maintenance and monitoring activities in context to locations where electrical isolation and the protective devices that would exist.
- Common grounding path in the event of electrical ground fault conditions.

It should be noted that TransCanada indicates the pipeline will not be collocated with any AC power lines or corridors within the State of South Dakota.

Direct Testimony of Meera Kothari:

- Casings have been proven to be a significant risk for the development of corrosion. TransCanada, along with the rest of the pipeline industry, has moved away from designing and building pipelines that are cased.

Q7-8: Data Request: Please confirm the amount of pipeline rights-of-way through the State of South Dakota that will cohabitate with an AC power line or corridor? Also where applicable, indicate the size of the AC power line(s)?

***R7-8: Response:** Keystone's proposed pipeline routing will not be collocated with any AC power lines or corridors in South Dakota*

Q7-15: Data Request: Please provide additional information on how the pipeline will be electrically constructed in philosophy? Will pump stations be protected independently or under common protection with the pipeline? Where will electrical isolation be installed?

***R7-15: Response:** Keystone will electrically interconnect and cathodically protect its pipeline and aboveground facilities, including pump stations, as a single unit. An electrical isolation design philosophy will not be used. Therefore, there will be no need for electrical isolation between each pump station and pipeline.*

Q7-16: Data Request: Please describe how any points of electrical isolation will be protected from electrical surges or lightning?

***R7-16: Response:** There will be no points of electrical isolation, as Keystone will not electrically isolate pump stations from the pipeline.*

Q7-17: Data Request: Will electrical ground at motorized valves and pump stations facilities be electrically independent from the pipeline or protected in common with the pipeline cathodic protection system?

***R7-17: Response:** The electrical ground at motorized valves and pump station facilities will be protected in common with the pipeline cathodic protection system.*

Exhibit M - §195.577

This section of code requires a program to identify, test for, and minimize the detrimental effects if the pipeline is exposed to stray electrical currents. In addition, you must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

Significant documentation has been provided with regards to this code section. A summary follows:

- A large section of documentation relates to the assessment and protection of the pipeline when collocated with high voltage electric transmission lines.
  - Within the State of South Dakota, the Keystone pipeline will not be installed collocated with any high voltage electric transmission lines. Based on the PHMSA Grant of Waiver, this does not eliminate Keystone from the requirement to conduct an AC assessment survey and installing mitigation equipment (as required) along this section of the pipeline.

- Both the TransCanada Petition and PHMSA Grant of Waiver acknowledge and address interference surveys and the requirements to document the results and take corrective actions to mitigate any adverse effects.
  - As detailed in the table at the end of this section, approximately 1 mile of pipeline cohabitates with other foreign pipeline systems.

- The design of the cathodic protection system (impressed current, deep anode groundbed systems at station locations and mainline valve sites is described with the intent to reduce stray current effects on other metallic facilities and reduce issues with animal livestock. The end effect of this design minimizes earth gradient potential differences.

- TransCanada acknowledges the issues with Telluric currents and describes an operational plan to address this issue if it is found along the pipeline.

- Protection of AC ground in the stations can eliminate potential adverse effects on neighboring AC and electrically continuous grounding systems.

In this particular case, collocation or cohabitation is when differently operated pipelines or even electrically and independently isolated pipelines are installed in common rights-of way. When multiple pipelines are installed in a common rights-of-way, additional measures are required to ensure that a proper and representative pipe-to-soil is obtained over the line being inspected and can at times increase the difficulty locating the pipeline. Since TransCanada has provided that there are there are three (3) actual pipeline crossings with other regulated pipeline facilities in South Dakota and no common rights-of-way this is not an issue.

Code requires a 12-foot minimal spacing between electrically independent structures. Although spacing between facilities plays a role in, stray current interference and its detection relies more on the understand of where foreign operated cathodic protection systems are located with respect to the pipeline being tested; and based on those locations, where interference might occur. Once determined, specific site testing is performed to confirm or rule-out if this condition exists. Typically uncongested rights-of-way (as in the case reported by TransCanada) reduce the number of locations that would need to be assessed. This condition is also affected by the soil resistivity values along the pipeline rights-of-way. Based on the information provided by TransCanada, the testing as proposed is consistent with that required to detect, monitor and mitigate stray current interference.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Interference Currents Control: Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An inducted AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within six months after placing the pipeline into service.
- Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices 0169 and 0177 (NACE RP0169 and NACE RP0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the effects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):

- The proposed Keystone pipeline is not co-located with high voltage power transmission lines and exposure to inducted alternating current (AC) electric currents is therefore minimal. Corrosion due to AC interference is very rate. Research by PRCI (GRI8187) concluded AC corrosion is possible only in special circumstances of current density and holiday size. The concern for AC interference in personnel safety (step and touch potentials). Keystone will install CP and stray current mitigation facilities during pipeline construction. The requirements of OSHA 1910.269(n) Grounding for Protection of Employees, 1910.269 Appendix C Protection from Step and NACE PR0177 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion

Control Systems will be met. Specifically, step and touch potential will be maintained at no more than 15 Volts RMS AC. During operation, the effectiveness of the original mitigation designs will be evaluated and modification made as required.

- Telluric currents are currents flowing in the crust of the planet earth as a result of inductive and capacitive effects from the aurora borealis. The aurora borealis is produced when solar wind charged particles are trapped by the earth's magnetic field. Trans Canada has been doing research on the effects of telluric currents on pipelines with Carlton University and the Geomagnetic Laboratory of Natural Resources Canada for over 10 years. TransCanada originally performed research on telluric currents as part of the pre-engineering for the Alaska Highway Gas Pipeline Project in the late 1970's and early 1980's. Earth magnetic fields can make it difficult to perform CP surveys, but have little to no effect on pipeline integrity. Methods for correcting for earth currents are used on a regular basis in CP surveys at TransCanada. The methodology employs a satellite based CP power source interruption system which is synchronized with stationary reference cell data collectors on both sides of the survey region. Baseline ground potentials are recorded in sync with the pipe-to-soil survey potentials in order that the CP survey potential readings can be corrected for the deviations produced by Telluric Currents.

Direct Testimony of Meera Kothari:

- Federal pipeline regulations require pipelines to have a minimum clearance of 12 inches from foreign utilities. Typical industry practice is to under cross an existing utility.

Q7-7: Data Request: How is TransCanada addressing the location of the impressed current groundbeds with respect to animal livestock?

R7-7: Response: To protect animal livestock against the potential for adverse impacts, Keystone will install deep groundbed cathodic protection systems within the fenced pump station and mainline valve sites.

Q7-8: Data Request: Please confirm the amount of pipeline rights-of-way through the State of South Dakota that will cohabitate with an AC power line or corridor? Also where applicable, indicate the size of the AC power line(s)?

R7-8: Response: Keystone's proposed pipeline routing will not be collocated with any AC power lines or corridors in South Dakota.

Q7-9: Data Request: For areas of cohabitation with AC power (as applicable) or any other locations where electrical shock is possible, what safety precautions will be taken to prevent electrical shock to employees or the general public? What safety precautions or monitoring will be taken to prevent excessive AC current from discharging from small pipeline holidays?

R7-9: Response: There are no locations in South Dakota where the Keystone Pipeline will collocate with AC power lines. There is a potential for electrical shock at certain areas, including electrical substations and electrical switchgear buildings located within the pump station and mainline valve sites. Because the pump station and mainline valve sites will be fenced, the general public will be protected from electrical shock. These facilities will be designed in accordance with the applicable codes and regulations to protect employees and other authorized personnel from electrical shock.

Stray current discharging from pipeline holidays will be mitigated through interference surveys and adjustments to the cathodic protection system during operations, which will be done as part of the Integrity Management Program.

Q7-10: Data Request: Please confirm the amount of pipeline rights-of-way through the State of South Dakota that will cohabitate with another foreign pipeline system? Also where applicable indicate the type (gas, liquid, etc.) of product contained in the foreign pipeline?

R7-10-Response: Keystone's proposed pipeline routing will be collocated with existing pipelines as follows:

Begin MP	***End MP***	***Sic "(Distance Calculated)"***	***Existing Pipeline***	***Product***	***Type***
427.2	*427.8*	*0.6 miles*	*Kaneb*	*Refined Product*	*Liquid*
436.5	*436.7*	*0.2 miles*	*Local Gas Pipeline*	*Natural Gas*	*Gas*
436.7	*436.9*	*0.2 miles*	*Kaneb*	*Refined Product*	*Liquid*

Exhibit N - §195.579

This section of code requires that if you transport any hazardous liquid that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid and take adequate steps to mitigate internal corrosion.

If inhibitors are used, then they must be of sufficient quantity to protect the entire system, coupons or other monitoring equipment must be installed to determine the effectiveness of the inhibitor. The monitoring equipment must be examined at least twice per year and not to exceed 7.5 month intervals

This section of code requires procedures and action to perform an inspection of the internal surface of the pipe whenever you remove a section of pipe from the pipeline. If corrosion is found, you must investigate and take corrective action.

As described below, the revised April 10, 2007 TransCanada Petition indicates a more stringent limit level to sediment and water levels than industry standards and has designed the pipeline to operate in a turbulent flow mode. The PHMSA Grant of Waiver acknowledges this more stringent level as a requirement to construct. This Grant of Waiver includes operational notification requirements, cleaning intervals and the required use of corrosion coupons.

During construction, sufficient activities are in place to remove any leftover hydro-test water and, during construction hold-up, a nitrogen purge will in place to prevent internal corrosion and to monitor pressure (of the nitrogen) for any indication of wall loss.

The approach as outlined meets or exceeds the requirements contained in this code section.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Pipeline Inspection: The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.
- Internal Corrosion: Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other

internal corrosion threats. Keystone will send their analysis's and further actions, if any, to PHMSA.

Revised April 10, 2007 – Petition of TransCanada (Excerpt):

- Internal corrosion will be addressed utilizing a more stringent tariff S&W requirement to reduce the corrosivity of the transported liquid, and ultimately resulting in lower corrosion rates. Internal corrosion will also be addressed through a pipeline design resulting in turbulent flow in all flow regimes to prevent the drop out of water or solids and, as set out above, through the use of a more stringent mill wall thickness tolerance. In addition, Keystone proposes to utilize a cleaning program to confirm the effectiveness of its program. Effectiveness of the internal corrosion program will be reported to PHMSA for the first five years of operation.

Direct Testimony of Meera Kothari:

- A tariff specification of 0.5% solids and water by volume is contained in Keystone's transportation agreement with its shippers. This specification is lower than the industry standard of 1% to minimize the potential for internal corrosion. The pipeline is designed to operate in turbulent flow to minimize water drop out, which is also a potential cause of internal corrosion. During operations the pipeline is cleaned using in-line inspection tools. The pipeline is inspected with a smart in-line inspection tool, which measures and records internal and external metal loss.

Q7-18: Data Request: Please describe any activities and parameters that will be used to reduce the risk for internal corrosion after completion of the hydro-test, during and immediately after the de-watering process?

R7-18: Response: In 2008, once the pipeline is tested and dewatered, the pipeline will be purged of air and filled with nitrogen. In 2009, filling the pipeline with crude oil will immediately follow once the pipeline is tested and dewatered.

Q7-19: Data Request: Please describe what measurements will be taken or designed into to this pipeline to monitor the pipeline and appurtances for internal corrosion during its operation?

R7-19: Response: Keystone has conducted an internal corrosion ("IC") susceptibility study (oil/water flow model). The follow model results indicate:

- *No considerable risk of IC at normal operating conditions*
- *Risk of water stratification and IC resulting from "near minimum flow" (worst case) condition showed allowance of 40% - 75% reduction in flow rate below minimum operation flow rate of 340,000 bpd for water drop-out to occur; and*
- *Residual risk to be mitigated through Integrity Management Program*

Keystone will monitor the product for compliance with the specification of 0.5% sediment and water, (the current U.S. industry standard is 1%). Keystone will conduct sampling for sulphur (sic, "Sulfur"), micro-carbon residue ("MCR") and total acid number

("TAN") to determine product quality. If there is any indication of corrosion effects Keystone will implement mitigation methods which may include one or more of the following methods to manage internal corrosion susceptibility: corrosion coupons; use of cleaning and MFL tools to identify anomalies; and chemical treatment (Corrosion Inhibitors and/or Biocides).

Exhibit O - §195.581

This section of code requires the pipeline or portion of the pipeline to be cleaned and protectively coated if it is exposed to the atmosphere. This must be done with a coating material suitable for the prevention of atmospheric corrosion. This section of code applies to all atmospherically exposed locations unless demonstrated by test, investigation, or experience - appropriate to the environment - that only a light surface oxide will develop or that any atmospheric corrosion that occurs will not affect the safe operation of the pipeline before the next scheduled inspection. This exemption does not apply to locations of interface between soil and air (such as at pipe risers, valve stems etc.).

The revised April 10, 2007 TransCanada Petition and the PHMSA Grant of Waiver generally focus on those areas of pipe manufacture and construction which are significant to the integrity of the pipeline and which are difficult to resolve once the pipeline is buried. As such, the issue of an atmospheric coating – at this stage of the project – would not be expected and has not been address nor defined in any reviewed document.

TransCanada should be able to provide additional plan documentation as to how it will protect the above grade portions of this pipeline (and related appurtances) from atmospheric corrosion. Response from TransCanada should address the protective coating for atmospheric coating and provide specific reference as to how the interface area between the soil and air (such as at risers) will be addressed. This should include, but not be limited to:

- .Project timeline as it relates to the application of a protective coating and how this timeline protects the safe operation of the pipeline
- Surface preparation
- Material specifications
- Procedures for installation
- Quality control measures and procedures

- If TransCanada will not be using a protective coating:
    - Than documentation should be provided as to how TransCanada will demonstrate by test, investigation, or experience - appropriate to the environment - that only a light surface oxide will develop or that any atmospheric corrosion that occurs will not affect the safe operation of the pipeline.

Exhibit P - §195.583

This section of code requires the inspection for atmospheric corrosion of each pipeline or portion of pipeline exposed to the atmosphere occur at least once every 3 calendar years, with intervals not exceeding 39 months between inspections.

This inspection must give particular attention to the pipe at the soil-to-air interface, under thermal insulation, under disbonded coatings, at pipe supports, at deck penetrations, and on spans over water. If atmospheric corrosion is found during the inspection you must address and provide/restore atmospheric corrosion protection consistent with §195.581.

The revised April 10, 2007 TransCanada Petition and the PHMSA Grant of Waiver generally focus on those areas of pipe manufacture and construction which are significant to the integrity of the pipeline and which are difficult to resolve once the pipeline is buried. As such, the inspection of an atmospheric coating – at this stage of the project – would not be expected and has not been address nor defined in any reviewed document.

TransCanada should be able to provide additional plan documentation as to how it will monitor and inspect the above grade portions of this pipeline (and related appurtances) for atmospheric corrosion. Response from TransCanada should address the protective coating for atmospheric coating and provide specific reference as to how the interface area between the soil and air (such as at risers) and under thermal insulation will be addressed. This should include, but not be limited to:

- Procedures related to inspection performance
- Assessment criteria that will be used
- Response timelines for resolution of any issues found
- Procedures related to repair and restoration

Exhibit Q - §195.585

This section of code requires that if you find pipe generally corroded so that the remaining wall thickness is less than that required for the maximum operating pressure (MAOP) of the pipe you must replace the pipe. This must be done unless you:

- Reduce the maximum operating pressure commensurate with the strength of the pipe needed for service ability based on actual remaining wall thickness; or
- Repair the pipe by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe.

If pipe is found to have localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure (MAOP) commensurate with the strength of the pipe based on remaining wall thickness in the pits.

This section of code is more applicable to an operating pipeline. The revised April 10, 2007 TransCanada Petition and the PHMSA Grant of Waiver generally focus on those areas of pipe manufacture and construction which are significant to the integrity of the pipeline and which are difficult to resolve once the pipeline is buried. The pipeline is under continual inspection prior to installation as documented subsequent to this Exhibit.

TransCanada should be able to provide additional plan documentation as to how it will monitor and inspect portions of this pipeline (and related appurtances) if found to have generalized corrosion or localized corrosion pitting - either during installation and/or operation. This should include, but not be limited to:

- Procedures related to inspection performance and the operating actions that will occur.
- Assessment criteria that will be used
- Response timelines for resolution of any issues found
- Procedures related to repair and restoration

Exhibit R - §195.587

This section of code indicates you may use the procedure in ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines"* or the procedure developed by AGA/Battelle, *"A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)"* to determine the strength of corroded pipe based on remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall and the application is subject to the limitations set out in the respective procedures.

Both the revised April 10, 2007 TransCanada Petition and the PHMSA Grant of Waiver acknowledge the use of tools such as ASMEB31G, and the Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (RSTRENG). The TransCanada Petition provides a high level assessment related to the use of these tools and the applicability for this pipeline project.

The PHMSA Grant of Waiver requires that Keystone apply the most conservative methods in order to confirm and determine the strength of corroded pipe based on remaining wall thickness. In addition the PHMSA Grant of Waiver requires that Keystone must confirm that the remaining strength tools (RSTRENG), RSTRENG-0.85dL and ASME B31G are valid for this pipeline. It addition it applies a more stringent requirement for Anomaly Evaluation and Repair Criteria.

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the special permit area must be performed based upon the following:
    - Immediate Repair Conditions: Follow 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) =<1.16
    - 60-day Conditions: No changes to 195.452(h)(4)(ii).
    - 180-day Conditions: Follow 195.452 (h)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days;
        - Calculated FPR =<1.32
        - Areas of general corrosion with predicted metal loss greater than 40 percent.
        - Predicted metal loss is greater than 40 percent of nominal wall that is located as a crossing of another pipeline.
        - Gouge or groove greater than 8 percent of nominal wall
- Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval.
- Anomaly Assessment Methods: Keystone must confirm the remaining strength (RSTRENG) effective area, RSTRENG-0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure,

operating stress level and operating temperature, Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters.

Revised April 10, 2007 – Petition of TransCanada (Excerpt Appendix G): A review of literature sources and direct contacts with organizations that have been connected with the development validation of methods for the development and validation of methods for the assessment of the remaining strength of corroded pipe (RSTRENG) indicated that the database of validating tests does not extend beyond an SMYS of 70,000 psi. However, methods such as RSTRENG and ASME B31G contain no factors that are grade-dependent other than the flow stress. All other factors are purely geometry-dependent. The usual definition of flow stress for strength grades up to X70 has been SMYS + 10,000 psi for RSTRENG and 1.1 x SMYS for ASME B31G. For X80, this would lead to a flow stress equal or close to the specified minimum tensile strength. While some work indicates that, for modern high-toughness steels, tensile strength may be a better failure criterion than yield strength or flow stress, it is more consistent with the philosophy of approaches based on the Battelle surface flaw equation, like RSTRNG and ASME B31G, to continue to use a flow stress that is intermediate between yield and tensile strength. Accordingly, for higher-grade materials such as X80, a more appropriate minimum flow stress criterion is the mean of SMYS and specified minimum tensile strength (SMTS). Keystone will use this criterion, as required and assuming X80 materials are used, in any application of remaining strength calculations during the operation of the Keystone Pipeline.

Exhibit S - §195.588

This section of code requires that if you use direct assessment on an onshore pipeline you must evaluate the effects of external corrosion using the requirements of this section (does not apply if you are using a direct assessment type of method (i.e., CIS) for other reasons other than for Direct Assessment.

The requirements for the performance of Direct Assessment include:

- Must follow the NACE Standard RP0502
- Must develop and implement an ECDA plan that includes pre-assessment, indirect examination, direct examination, and post assessment.

In addition to the requirements contained in the NACE Standard RP0502 the following is required:

- Pre-assessment:
  - Provisions for applying more restive criteria for ECDA when conducted the first time on a pipeline segment.
  - Document the basis on which the selection of the two different, but complementary indirect assessment tools are chosen for each ECDA region.
  - Utilize an indirect inspection method not in NACE 502 demonstrate the applicability, validation process, equipment used, application procedure, and utilization of data.
- Indirect Examinations
  - Provisions for applying more restive criteria for ECDA when conducted the first time on a pipeline segment.
  - Provide a criteria for identifying and documenting those indications that must be considered for excavation including:
    - Known sensitivities of equipment
    - Procedures for using each tool
    - The approach used
  - Provide documentation for each indication identified to include:
    - The urgency of excavation and direct assessment

This section of code is more applicable to an operating pipeline. The revised April 10, 2007 TransCanada Petition and the PHMSA Grant of Waiver generally focus on those areas of pipe manufacture and construction which are significant to the integrity of the pipeline and which are difficult to resolve once the pipeline is buried. TransCanada should be able to provide additional plan documentation as to how, when, or if it will use a direct assessment methodology consist with the requirements of this code section and the PHMSA Grant of Waiver requirements. This should include, but not be limited to:

- Provide documents that define the Keystone Direct Assessment methodology and acknowledges the requirements of this code section and the PHMSA Grand of Waiver
- Provide procedures/guidelines that will be used to evaluate where Direct Assessment will be required
- Provide the anticipated locations where Direct Assessment will be used

April 30, 2007– PHMSA Grant of Waiver (Excerpt- Grant subject to following conditions):

- Direct Assessment Plan: Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).

Exhibit T - §195.589

This section of code requires that current records and maps to show the location of: cathodically protection pipelines; cathodically protection facilities including galvanic anodes; and neighboring structures if (electrically) bonded to the cathodic protection system. In addition, records or maps are required to be maintained showing the stated number anodes, installed in a stated manner or spacing and the specific distances to each buried anode.

For each analysis, check, demonstration, examination, inspection, review, survey, and test required by this subpart records must be kept in sufficient detail to demonstrate the adequacy of corrosion control measures. The records must be kept for five (5) years unless the records are related to §§195.569, 195.573(a) and (b), and 195.579(b)(3) and (c). These records must be retained for as long as the pipeline remains in service.

Based on review of documents and response it appears that TransCanada acknowledges the requirements of this code section.

Q7-13: Data Request: Please provide any detail of, if any, the measurements that will be obtained during pipeline construction that relate to §195, subpart H? What measurements will be taken during pipeline operation?

R7-13: Response: *Measurements that will be obtained during pipeline construction relating to 49 CFR Part 195 Subpart H includes:*

- *Part 195.561 – The external coating will be checked for holidays using visual inspection and electronically using a holiday detector ("jeep").*
- *Part 195.563 – Measurements will be taken to determine soil resistivities to enable design of the cathodic protection system.*
- *Part 195.575 – Keystone will electrically interconnect and cathodically protect its pipeline and aboveground facilities as a single unit and therefore, measurements related to isolation equipment are not required.*
- *Part 195.577 – Electrical measurements will be taken to identify any HVAC and HVDC interference currents, and interference with any close paralleling pipelines.*

During operations, monthly rectifier readings to check for voltage, current, and resistance will be performed consistent with Part 195.573(c). An annual test lead survey will also be performed to check system performance, and an annual equipment and maintenance check will be conducted on the rectifiers consistent with Part 195.573(a).