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TRANSCANADA PIPELINES LIMITED ENERGY EAST PIPELINE PROJECT

Assessment of Impacts on Pipeline Safety

Ontario Energy Board

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Assist and inform the Ontario government in formulating a position on the Energy East application.

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EXECUTIVE SUMMARY

By letter dated November 12, 2013 to the Chair of the Ontario Energy Board (OEB), the Ontario Minister of Energy required the OEB to examine and report on TransCanada PipeLines Limited's (TransCanada) Energy East Pipeline project from an Ontario perspective. The objective of the report would be to assist and inform the Ontario government in formulating a position on the application. The letter set out six principles adopted by the Government of Ontario in respect of the assessment of proposed pipeline projects.

DNV GL was retained by the OEB to provide independent expert advice on the pipeline safety and natural environmental aspects of the Energy East Pipeline project within Ontario. This report addresses our assessment of impacts on pipeline safety, including integrity, engineering matters and emergency response based on the information provided in the Energy East Application. Our report titled "Assessment of Impacts on the Natural Environment," dated March 25, 2015 addresses environmental matters.

Our approach with respect to the assessment of impacts on pipeline safety was to consider the risk associated with the project. For the purposes of this assessment, risk is defined as the likelihood of an event combined with the consequences associated with the event. In this case, the event of particular concern is the failure of the pipeline. Hence, our assessment looks at two general areas of the Energy East Application:

1. Those elements of the Application that are intended to minimize the likelihood of a pipeline failure; and
2. Those elements that are intended to mitigate the consequences associated with a pipeline failure.

The elements of the Application were assessed against the principles set out in the Minister's letter.

Our findings and recommendations are summarized below.

Minimizing the Likelihood of Failures

The primary integrity-related issue for the Energy East Pipeline in Ontario is the potential for stress corrosion cracking (SCC) on the four tape-coated sections on Line 100-3.

The proposed approach in the Energy East Pipeline Application for managing the threat of SCC on the tape-coated sections on Line 100-3 is generally consistent with current industry practice. However, given that there can be some variability in the performance of the crack detection in-line inspection (ILI) tools, the ILI program may not provide full assurance of the integrity of those sections.

With respect to the conversion section, it is recommended that:

1. TransCanada be required to demonstrate that the detection reliability and sizing accuracy of the crack detection ILI tools which TransCanada plans to use on the tape-coated sections of Line 100-3 are sufficient to provide assurance of the integrity of those sections; and
2. MLV 58-59, which had a hydrotest failure in 2000, be hydrotested prior to being placed in liquid service to provide an additional, independent means of demonstrating the integrity of that section, as well as validating the results of the crack detection ILI.

With respect to the pipelines that will remain in gas service, it is recommended that:

3. the engineering assessments required to re-establish the maximum operating pressure (MOP) for the pipelines include an assessment of the risk of damage to the conversion section as a result of a failure of the gas pipelines, particularly where the pipelines cross or are in close proximity to the conversion section, and that mitigative measures are put in place where the risk is considered unacceptable.

Mitigating the Consequences of Failures

DNV GL considers that the commitments and processes described in the Energy East Application meet or exceed the requirements in applicable standards and regulations and are generally consistent with good industry practice. However, in the absence of specific details regarding valve placement, leak detection and emergency response plans, it is not possible to assess whether the Energy East Application satisfies the principles set out in the Minister's letter.

In order to address the need for additional information and to satisfy the principles in the Minister's letter, it is recommended that TransCanada:

4. provide additional information on its Valve Siting Optimization Process, including the criteria for determining whether a particular valve configuration effectively mitigates risk, and demonstrate that the process meets the requirements of CSA Z662-11 *Oil and Gas Pipeline Systems* (CSA Z662) for an engineering assessment;
5. demonstrate that potential release volumes along the pipeline route are as low as reasonably practicable;
6. identify which water crossings are considered major and thus will be protected by valves on both sides of the crossing;
7. confirm conformance with the requirements of CSA Z662, Annex E;
8. provide performance specifications for the leak detection system and provide evidence that specifications are met or exceeded in operation;
9. provide emergency service agencies and communities with site-specific analyses for product releases and spill trajectories for critical locations in Ontario and perform response capability assessments to demonstrate that TransCanada will be able to respond effectively and that impacts can be mitigated to acceptable levels; and
10. provide financial assurance of their capability to cover response, clean-up and remediation costs in the event of a pipeline failure.

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List of Acronyms and Abbreviations

AFD	Axial Flaw Detection
API	American Petroleum Institute
CP	Cathodic Protection
CSA	Canadian Standards Association
DSAW	Double Submerged Arc Welding
EA	Engineering Assessment
EMAT	Electro-Magnetic Acoustic Transducer
EMS	Emergency Management System
ERP	Emergency Response Plan
ERW	Electric Resistance Welding
ESA	Environmental and Socio-Economic Assessment
FBE	Fusion Bond Epoxy
FW	Flash Welded
ICS	Incident Command System
ILI	In-line Inspection
kPa	kiloPascals
MFL	Magnetic Flux Leakage
MLV	Mainline Valve
Mm	millimeters
MOP	Maximum Operating Pressure
NEB	National Energy Board
OEB	Ontario Energy Board
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
UT	Ultrasonic Testing

Glossary

Backfilling: One of the last steps of pipeline construction; the placing of material previously excavated back into a hole to fill the space around the pipeline or appurtenances (e.g. valves, instrument connections, cathodic protection systems, etc).

Cathodic protection (CP): As corrosion is an electrochemical process with corrosion occurring at the anode and no corrosion occurring at the cathode, cathodic protection is a process designed to make the entire pipeline a cathode by impressing a low voltage direct current on to the structure surface, thus eliminating corrosion.

Check valve: A valve designed to permit flow in a single direction only. Fluid flow in the desired direction opens the valve, whereas backflow causes the valve to close automatically.

Double Submerged Arc Welding (DSAW): DSAW pipe has a longitudinal or spiral butt joint produced by at least two weld passes, one of which is on the interior side of the pipe. The welding is shielded by or submerged under a blanket of granular flux. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode or electrodes. This welding process penetrates 100% of the pipe wall and produces a very strong bond of the pipe material.

Electric Resistance Welding (ERW): ERW pipe is manufactured by cold-forming a coil of steel into a cylinder and forming a bond at the longitudinal edges of the cylinder using a combination of electrical-resistance heating and mechanical pressure. The seam is formed without the use of welding filler material. Modern ERW pipe is produced using high-frequency induction heating of the longitudinal edges.

Engineering Assessment (EA): A documented assessment of the effect of relevant variables upon fitness for service or integrity of a pipeline system, using engineering principles, conducted by, or under the direct supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed. (Definition from CSA Z662-11 *Oil and Gas Pipeline Systems*)

Fatigue: The weakening and eventual fracture (cracking) of a material through repeated or fluctuating stresses which are less than the material's tensile strength.

Flash welding: Flash welding was accomplished by forming a steel plate into a cylinder, establishing an electric arc between the edges until semi-molten, then forcing the edges together until molten steel was forced out of the joint and formed a bead. Flash welding is no longer used to manufacture pipe.

Fusion bond epoxy (FBE): Fusion bond epoxy is a thermosetting coating. FBE powder is sprayed onto the pipe surface after it has been cleaned and heated. The epoxy powder melts, flows and cures onto the steel pipe surface and forms a bonded epoxy coating film with water resistance and elevated dielectric strength properties.

Hydrostatic test: Pressure testing of sections of a pipeline by filling the pipeline with water and increasing the pressure to a level that is typically above the intended maximum operating pressures of the pipeline. The objective of a hydrostatic test is to demonstrate the strength and leak integrity of the pipeline section being tested.

Incident Command System (ICS): A standardized on-scene emergency management system designed to facilitate effective and efficient response to an emergency by integrating response agencies and resources within a common organizational structure.

In-line inspection (ILI): The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline.

Notch toughness: A measurement of a material's ability to absorb energy in the presence of a flaw. As the notch toughness of a material increases, so does its resistance to fracture initiation or propagation.

Polyethylene tape coating: A coating system involving a flexible plastic ribbon or sheet backing that is coated on one side with a polymeric adhesive. In some cases some tape products require a separate liquid primer to be applied to the pipe surface immediately prior to application of the tape; the primer interacts with the adhesive on the tape backing to form an adhesive system. Tape coatings are applied onto the pipe surface after it has been cleaned and dried of moisture. The plastic is wrapped around the pipe in spiral fashion with tension and an overlap onto itself, and the adhesive system and application tension holds it in place. There may be multiple layers applied.

Seam weld: The longitudinal weld, created at the pipe mill when the steel plate is formed into a cylinder and welded together. The seam weld may be created using a variety of welding techniques.

Stress Corrosion Cracking (SCC): Cracking of a material produced by the combined action of corrosion and tensile stress on a susceptible pipe material. SCC is a type of environmentally assisted cracking.

Tensile strength: The stress level at which a material will fail (or break).

Yield strength: The stress level that a material can withstand before permanent deformation occurs. At stress levels below the yield strength, the material will deform elastically; i.e. it will return to its original shape and size when the applied stress is removed.

1 INTRODUCTION

1.1 Background

On October 30, 2014, TransCanada PipeLines Limited (TransCanada) filed an application with the National Energy Board (NEB) for approvals to construct and operate the Energy East Pipeline project (the “Project”).

The project is a 4,500 kilometres (km) pipeline system designed to transport 175,000 m^3/d (1.1 million barrels per day) of crude oil from receipt points in Alberta and Saskatchewan to delivery points in Quebec and New Brunswick.[1] The Energy East Pipeline project, in its entirety, would include the conversion of approximately 3,000 km of existing natural gas transmission pipeline to the transport of crude oil, the construction of up to 1,500 kilometres of new pipe in Alberta, Saskatchewan, Manitoba, eastern Ontario, Québec, and New Brunswick to link up with the converted pipe, and four new oil terminals.[1] Within the Province of Ontario, the Project would include the conversion to oil service of 1,928 km of existing natural gas pipelines across northern and eastern Ontario,[2] the construction of 106 km of new pipeline in eastern Ontario,[3] and the addition of infrastructure such as pump stations and valves. There will be no terminals located in Ontario.

By letter[4] dated November 12, 2013 to the Chair of the Ontario Energy Board (OEB or the Board), the Ontario Minister of Energy required the OEB to examine and report on the Energy East Pipeline project from an Ontario perspective. The objective of the report would be to assist and inform the Ontario government in formulating a position on the application. The letter set out six principles adopted by the Government of Ontario in respect of the assessment of proposed pipeline projects:

1. Pipelines must meet the highest available technical standards for public safety and environmental protection;
2. Pipelines must have world leading contingency planning and emergency response programs;
3. Proponents and governments must fulfil their duty to consult obligations with Aboriginal communities;
4. Local communities must be consulted;
5. Projects should provide demonstrable economic benefits and opportunities to the people of Ontario, over both the short term and long term; and
6. Economic and environmental risks and responsibilities, including remediation, should be borne exclusively by the pipeline companies, who must also provide financial assurance demonstrating their capability to respond to leaks and spills.

The Board was further directed to consider the implications of the following:

1. impacts on Ontario natural gas consumers, in particular those in Eastern and Northern Ontario in terms of rates, reliability and access to supply;
2. impacts in Ontario on the natural environment and pipeline safety;
3. impacts in Ontario on local communities and Aboriginal communities; and
4. the short and long term economic impacts of the project in Ontario.

In order to support the preparation of the report, the Minister asked the OEB to consult with the public, First Nation and Métis communities, and stakeholder groups in Ontario. The purpose of this consultation was to provide a forum for Ontarians to express their views on the proposed Energy East Pipeline.

The consultation process was held in two parts:

- Part One – *The Impacts Important to Ontarians* – was held between January and May 2014. The purpose was to present an overview of key considerations and potential impacts of the Project in Ontario and to seek the views of Ontarians on the impacts of the Project.
- Part Two – *The OEB's Understanding of the Impacts* – was held in January and February 2015. The purpose was for the OEB to present a summary of the preliminary assessment of the impacts of the Energy East Pipeline project and to seek the views of Ontarians on the preliminary assessments.

1.2 Scope of Work

DNV GL was retained by the OEB to provide independent expert advice on the pipeline safety and natural environmental aspects of the Energy East Pipeline project within Ontario.

This report addresses our assessment of impacts on pipeline safety, including integrity, engineering matters and emergency response based on the information provided in the Energy East Application. A separate report by DNV GL titled "Assessment of Impacts on the Natural Environment" addresses environmental matters.

TransCanada's Eastern Mainline Project is outside DNV GL's scope of work.

1.3 Methodology

The approach taken with respect to the assessment of the project's impacts on pipeline safety was to consider the risk associated with the Project. For the purposes of this assessment, DNV GL defines risk as the likelihood of an event combined with the consequences associated with the event. In this case, the event of particular concern is the failure of the pipeline. Hence, our assessment looks at two general areas of the Energy East Application:

1. Those elements that are intended to minimize the likelihood of a pipeline failure; and
2. Those elements that are intended to mitigate the consequences associated with a pipeline failure.

While pipeline failures can include everything from small leaks to full ruptures, our assessment was focused primarily on ruptures.

The criteria used in our assessment were the principles set out in the Minister's letter to the OEB, in particular:

1. Pipelines must meet the highest available technical standards for public safety and environmental protection; and
2. Pipelines must have world leading contingency planning and emergency response programs.

In determining what represents "the highest available technical standards" or "world leading contingency planning and emergency response programs", we considered whether the provisions of the Energy East Application are appropriate for the specific threats to the pipeline and the site-specific conditions under which the pipeline is intended to operate. It is important to note that meeting “the highest available technical standard” does not necessarily equate to meeting the most stringent technical requirements. Pipelines are linear projects that are subjected to differing conditions along the entire length of the pipeline. Accordingly, the pipeline must be custom-designed and constructed in consideration of the general and site-specific loading conditions along its route and throughout its design life. A one-size-fits-all approach based exclusively on the most stringent technical requirements will not necessarily result in the safest pipeline.

Our assessment was guided by professional judgment and our review and consideration of the following, which, in our opinion, collectively reflect “the highest technical standard”:

1. *CAN/CSA Z662-11 Oil and Gas Pipeline Systems (CSA Z662).*

   The CSA Z662 Standard is a designated National Standard of Canada for pipelines and is incorporated by reference into federal and provincial pipeline regulations. CSA Z662 sets out the requirements for the design, construction, operation and maintenance of oil and gas pipelines. The Canadian Standards Association first published pipeline standards in 1967 for oil pipelines[5] and in 1968 for gas pipelines[6]. The standards were combined in 1994 as the inaugural edition of CSA Z662[7]. The current standard, CSA Z662-11 Oil and Gas Pipeline Systems[8], was published in 2011 and is the sixth edition of the standard, and, with the corresponding Commentary[9], totals 660 pages. Since its original publication in the 1960s, the pipeline standard has been continually amended to include advances in technology, lessons learned from pipeline accidents, and requirements intended to address conditions encountered in the oil and gas pipeline industry in Canada. As such, the standard has worldwide recognition and acceptance. The Standard also includes recommended practices and non-mandatory annexes that exceed the minimum mandatory requirements of the Standard.

2. *Code and regulatory requirements and advisories for pipelines in various jurisdictions.*

   Federal and provincial pipeline regulatory agencies in Canada have incorporated the CSA Z662 standard into their regulations. In addition, regulatory agencies usually impose supplementary requirements that are applicable to pipelines within their respective jurisdictions. In the case of the National Energy Board, the Onshore Pipeline Regulations include additional requirements for management systems, pipeline design and material specifications, welding, construction, pressure testing, and operation and maintenance. Regulatory agencies also issue safety advisories in response to specific technical issues.

3. *Regulatory conditions imposed on NEB-regulated oil pipeline projects.*

   We conducted a review of decisions by the National Energy Board on recent public hearings involving oil pipeline projects in order to determine what conditions were imposed on those pipeline projects. Such conditions further supplement the requirements set out in the CSA Z662 Standard and the NEB Onshore Pipeline Regulations. Hearings that were of particular relevance include the Enbridge Energy Ltd. Northern Gateway Project, the Enbridge Line 9B Reversal Project and the TransCanada Keystone Pipeline Project.

4. *Industry recommended practices*.

Industry recommended practices, guidance documents and best practices typically represent proven, leading edge practice that are intended to address specific technical issues. For example, the *CEPA SCC Recommended Practice*[10] sets out practices that are intended primarily to address the threat posed by transgranular stress corrosion cracking (SCC) on pipelines. Those recommended practices represent a higher technical standard than would be required for pipelines not affected by SCC.

5. *Reports on selected topics*.

   We conducted a review of pipeline accident reports and published research on areas of concern that were identified as part of our assessment of the Energy East Pipeline Application.

1.4 Limitations

The assessment is based on the information in the Energy East Application.

1.5 Outline of Report

Section 2 contains our assessment of those elements of the Application that factor into minimizing the likelihood of a pipeline failure. Section 3 is our assessment of those elements that factor into mitigating the consequences of a failure.

2 MINIMIZING THE LIKELIHOOD OF FAILURES

2.1 Threats to the Pipeline

A number of issues and concerns relating to the safety of the Energy East Pipeline were raised during the two rounds of meetings with First Nations, Métis and communities along the pipeline route. With respect to the Ontario portion of the Energy East Pipeline project, Ontarians repeatedly expressed concerns about the integrity of the existing gas pipeline and whether it was suitable for conversion to oil service.

There was less concern expressed for the integrity of the proposed 106 km of new pipeline in eastern Ontario. TransCanada's Application describes the requirements for the new section, although some of the information is at a high level. DNV GL notes that the information that is available indicates that the requirements for the new section will meet or exceed the requirements of the CSA Z662 standard and the NEB Onshore Pipeline Regulations and our assessment is that these requirements are generally appropriate for the conditions under which the pipeline will operate.

Therefore, in our assessment of the aspects of the Energy East Application that factor into minimizing the likelihood of failure on the Energy East Pipeline, we focused on the integrity of the conversion sections. The purpose of pipeline integrity management is to prevent failures. The pipeline integrity management process requires a thorough understanding of the threats to a pipeline in order that measures can be implemented that effectively manage those threats.

In assessing the suitability of the existing gas pipeline for conversion to liquid service, TransCanada considered the following threats or hazards:[11]

- External and internal corrosion
- Stress corrosion cracking (SCC)
- Manufacturing defects
- Welding and fabrication defects
- Equipment failure
- Third-party mechanical damage
- Incorrect operations
- Weather and outside forces

We reviewed TransCanada's assessment of all of the threats as detailed in its Application. However, based on the reported failure history of the conversion sections and the failure statistics for oil pipelines, in general, we paid particular attention to external corrosion, environmentally assisted cracking, and failures associated with seam weld defects. Our assessment is that the other threats identified in the Application are secondary and can be effectively managed in accordance with the commitments made in the Application.

The aspects of the Application that were relevant to these three primary threats were the mechanical properties, manufacturing process, and external coating of the pipe in the conversion sections. We compared the information presented in the Application for those three elements to the corresponding requirements for a new oil pipeline. We also reviewed TransCanada's approach for managing those threats, particularly through their in-line inspection program.

It is worth noting that internal corrosion is not included on our list as a primary threat to the pipeline. At our meetings with communities along the pipeline route, the concern regarding the corrosive nature of diluted bitumen was raised numerous times. However, recent published reports[12,13] that examined this issue have concluded that diluted bitumen does not have unique properties that make it more corrosive than other crude oils, and therefore does not pose an increased risk for internal corrosion on pipelines. Our assessment is that the measures described in the Application for controlling internal corrosion on the Energy East Pipeline are appropriate and that this threat can be managed effectively.

Another threat that was raised at the community meetings and that was not addressed in the Application is the potential for damage to the conversion section as a result of a failure of the adjacent pipelines that remain in gas service. The Application states that, after portions of the existing natural gas transmission pipeline are converted to oil service, the remaining gas pipelines will be required to operate at the maximum operating pressure (MOP) to meet commercial obligations in the Northern Ontario Line.[14] Sections of the remaining gas pipelines have been operating at pressures below the MOP, as a means of managing the integrity of those sections, and the Application describes the measures (e.g. ILI, hydrotests) that TransCanada proposes to complete in order to re-establish the MOP of the affected sections.[14] In response to an Information Request from the NEB, TransCanada further commits to conduct an Engineering Assessment (EA) where a higher operating pressure is required.[15] DNV GL recommends that the EAs include an assessment of the risk of damage to the conversion section as a result of a failure of the pipelines that remain in gas service, particularly where the pipelines cross or are in close proximity to each other, and that mitigative measures are put in place where the risk is considered unacceptable.

2.2 Overview of Existing Pipelines

The Ontario portion of the Energy East Project comprises approximately 1,928 km of existing gas pipeline infrastructure to be converted to oil service[2] and approximately 106 km of new pipeline.[3] The existing gas pipeline infrastructure has an outside diameter of 1067 mm and a maximum operating pressure (MOP) of 6895 kilopascals (kPa) and includes portions of Lines 100-3, 100-4 and 1200-2.[16]

The portions of Line 100-3 that will be used in Energy East were built between 1981 and 1996.[16] These are externally coated predominantly with plant-applied fusion bond epoxy, with the exception of four valve sections that are coated with a field-applied double wrap polyethylene tape coating. The pipe was manufactured with a double submerged arc welded (DSAW) seam. Prior to the original commissioning of the pipeline, these portions of Line 100-3 were hydrostatically tested to 125% of the intended MOP.[17] TransCanada, in its Application, states that there was one hydrostatic test failure on Line 100-3 in MLV 58 to 59 in 2000 that was attributed to stress corrosion cracking, which is a form of environmentally assisted cracking, and one mechanical damage leak in MLV 51 in 1991.[18]

The portions of Line 100-4 that will be used in Energy East were built between 1995 and 1998.[16] These portions of Line 100-4 are all externally coated with plant-applied fusion bond epoxy. The pipe was manufactured with a DSAW seam. Prior to original commissioning, these portions of Line 100-4 were hydrostatically tested to 125% of the intended MOP.[17] In the Application, TransCanada states that there has not been any in-service or hydrostatic test failure along these portions of Line 100-4.

The entire length of Line 1200-2 was built between 1991 and 2006[16] and was externally coated with plant-applied fusion bond epoxy. The pipe for the entire length of this line was manufactured with a DSAW seam. This line was hydrostatically tested to 125% of the intended MOP, with the exception of 18.1 km that was assessed using an Alternative Integrity Verification program.[17] This section will be hydrostatically tested prior to going into liquid service. TransCanada, in its Application, states that there has been no in-service or hydrostatic test failure along this pipeline.

2.3 Mechanical Properties

DNV GL notes that the ability of a pipeline to tolerate defects is dependent on its dimensional (e.g. outside diameter, pipe wall thickness) and mechanical properties (e.g. yield and tensile strength, notch toughness).

The existing gas pipeline sections planned for conversion have an outside diameter of 1067 mm and a maximum operating pressure of 6895 kPa.[16] For an identical new oil pipeline designed to the current CSA Z662 standard, DNV GL notes that the requirements for pipe wall thickness and yield and tensile strength would be the same as for the existing conversion sections.

However, since the conversion sections were designed for gas service, DNV GL notes that the pipe would have been required to have proven notch toughness (i.e. resistance to fracture initiation and propagation). Crude oil pipelines are not required by CSA Z662 to have any proven notch toughness. Thus, the existing gas pipelines inherently have a higher resistance to fracture initiation and propagation than would a new liquid pipeline manufactured in accordance with the current standard, and can therefore tolerate larger defects before failure. In effect, the proven notch toughness reduces the probability of failure resulting from defects including corrosion, cracking or mechanical damage.

2.4 Pipe Manufacturing Process

Our review of accident reports of oil pipelines indicated that there is a growing body of evidence[19] that pipe manufactured using certain processes (i.e. Electric Resistance Welded (ERW) and Electric Flash Welded (FW) pipe) are much more prone to failures associated with seam weld defects when placed in liquid, as opposed to gas, service. The reason is that those manufacturing processes are more susceptible to the formation of defects in the seam weld and those defects are much more likely to grow by pressure-cycle induced fatigue in liquid service. It was therefore important to assess whether the conversion sections may be susceptible to failures associated with seam weld defects when placed in liquid service.

In its Application, TransCanada indicated that it does not consider manufacturing related defects to be a potential threat of concern once the existing lines have been converted to liquid service. Nevertheless, TransCanada has committed to reviewing the crack detection in-line inspection data for anomalous indications in the weld region.[20]

DNV GL agrees that the likelihood of manufacturing-related defects causing a failure on the Energy East system within Ontario is minimal. There has been no documented history of manufacturing-related failures on the conversion sections, and the DSAW process used in the manufacturing of these pipelines produces a high quality weld that is not prone to seam weld defects that can grow by pressure-cycle induced fatigue. DNV GL considers that TransCanada's commitment to review in-line inspection data provides an additional layer of protection against failure resulting from seam weld defects.

2.5 Coating

In order to protect pipelines against corrosion or environmentally assisted cracking such as SCC, pipelines are externally coated and have a cathodic protection (CP) system in place. The coating forms a protective barrier between the external surface of the pipe and its environment. In the event that the coating is damaged, the CP system acts as a secondary means of protection.

The portions of Line 100-3, 100-4 and 1200-2 planned for conversion to liquid service were all externally coated with plant-applied fusion bond epoxy (FBE), with the exception of four valve sections along Line 100-3, totalling approximately 99 km in length, which were externally coated with a field-applied double wrap polyethylene tape coating. These valve sections comprise MLV 58 – 59 (28.7 km), MLV 60 – 61 (31.8 km), MLV 74- 75 (24.3 km), and MLV 76A – 77 (14.6 km).[21]

Plant-applied FBE is considered a high-performance protective coating for buried pipelines. This type of coating has been in use in the Canadian pipeline industry since the mid-1970s and has an excellent performance history in the prevention of corrosion and stress corrosion cracking on pipelines.

Polyethylene tape coating systems in general have not performed as well as plant-applied FBE. Tape coating systems have greater susceptibility to disbonding from the pipe during application, backfilling and while in service. When polyethylene tape coatings disbond, moisture penetrates under the coating. Since polyethylene tape has high electrical insulating properties, the current being applied by the cathodic protection system through the soil is unable to reach the pipe surface, and the CP system is rendered ineffective. Consequently, an environment is created at the pipe surface that, under certain conditions, contributes to the formation of corrosion and stress corrosion cracking. As noted in section 2.2, there was a hydrostatic test failure on Line 100-3 in MLV 58 to 59 in 2000 that was attributed to SCC.

TransCanada, in its Energy East Application, states that the primary coating for the new section of the pipeline will be plant-applied fusion bonded epoxy.[22] Therefore, DNV GL notes that the four valve sections coated with polyethylene tape would not meet TransCanada's current coating specifications for the new pipeline.

2.6 Integrity Management and In-Line Inspection

The discussion in the preceding section points to DNV GL's conclusion that the tape-coated sections are more susceptible to corrosion and stress corrosion cracking than the FBE-coated sections. Unless there are effective, reliable means to manage these threats, DNV GL considers that the pipeline would not satisfy the principle set out in the Minister's letter of meeting the highest available technical standards for public safety and environmental protection. This section details our assessment of the integrity management measures outlined in TransCanada's Application for those threats.

In the absence of an effective coating and CP system that prevents the formation of corrosion and stress corrosion cracking, the principal means of managing these threats is the use of appropriate in-line inspection (ILI) technologies, combined with methods for analyzing the ILI results and criteria to determine whether sections of the pipeline need to be excavated, examined and repaired. TransCanada's Application states that the conversion sections will have been inspected using ILI prior to being removed from gas service.[23] TransCanada commits to developing a remediation plan to address issues identified by those inspections. In the first year of operation, the entire pipeline will be inspected again using ILI tools to establish an integrity baseline.[24] This inspection data along with other relevant data will be used to develop a pipeline maintenance plan for future integrity assessments. In addition, TransCanada has committed to performing an acoustic in-line inspection shortly after commencing liquid service to identify potentially small leaks.[16]

2.6.1 Corrosion

In its Application, TransCanada considers external and internal corrosion to be potential threats of concern once the conversion sections have been placed into liquid service. TransCanada states that:

- all four of the tape-coated portions of Line 100-3 have been subjected to integrity verification hydrostatic tests since 2006 and that there have been no test failures due to external corrosion;[21] and
- All of the Line 100-3 valve sections which include tape coating have been inspected with a high resolution magnetic flux leakage (MFL) ILI tool since 2007.[21]

TransCanada states that high resolution MFL ILI tools will be used to inspect the conversion sections for indications of metal loss while those sections are still in gas service.[25]

TransCanada has a documented process for assessing the immediate and long term acceptability of each reported metal loss feature. This process includes specific criteria for acceptance, such as a feature's depth as measured by the ILI tools, the pressure at which it is predicted to fail, its estimated growth rate, and the probability that it would fail during normal operation of the pipeline.[26] If any of these acceptance criteria is not met, the feature is considered a "defect" and must be repaired.[16]

TransCanada states in its Application that the acceptance criterion for segments of pipeline that could negatively impact a highly sensitive area will be half an order of magnitude more conservative.[27]

Our assessment is as follows:

1. The use of high resolution ILI tools such as a MFL tool is a proven, industry-accepted approach for detecting and measuring the size of both external and internal metal loss features. The pipeline industry's track record in the use of these ILI tools indicates that they provide an effective and reliable means of detecting and sizing corrosion features on a pipeline, thereby allowing for a proper evaluation of the acceptability of such features.
2. In its Application, TransCanada indicates that the failure pressures for "clusters" of metal loss features will be calculated using an R-Streng river bottom profile. The word "clusters" implies that TransCanada's corrosion assessment process involves the application of interaction rules to combine individual metal loss features in close proximity to one another into larger features (i.e. "clusters"); this is standard industry practice. However, TransCanada does not specify the interaction rules that would be applied.
3. The failure pressure based acceptance criteria that will be applied to the metal loss features as measured by the ILI tool is in accordance with CSA Z662 requirements, while the depth-based acceptance criteria is more conservative than the CSA Z662 requirements.
4. The two methods described in the Application for estimating corrosion growth rates are accepted practices in the pipeline industry. Basing growth rates on the results of multiple MFL tool runs would be expected to result in more accurate corrosion growth rates, whereas the time-average method based on a single MFL tool run generally results in conservative estimates for corrosion growth rates.

The first approach is used when there is a history of MFL inspections on the same segments of the pipeline. In the absence of historical data, the time-average method will be used.

5. The use of a more conservative acceptance criterion for the segments of pipeline that could negatively impact a highly sensitive area is a prudent approach that should result in an additional layer of protection for the pipeline in those locations.

2.6.2 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is considered by TransCanada to be a potential threat of concern for the four tape-coated sections of Line 100-3 once they have been placed into liquid service. With respect to in-line inspection, TransCanada's plans are:

- To inspect the four tape-coated sections of Line 100-3 with an Electro Magnetic Acoustic Transducer (EMAT) ILI tool while those sections are still in gas service,[27] as well as with a circumferential MFL technology commonly referred to as Axial Flaw Detection (AFD).[28] TransCanada states that the purpose of the AFD is to assist in discriminating steep-sided corrosion, which can behave like cracks, and identifying the presence of any coincidental or interacting corrosion; i.e. cracks in corroded areas or close enough to interact with a corroded area. TransCanada has also indicated that the FBE-coated sections of pipeline in Ontario will be inspected with the EMAT tool but only to confirm that no additional tape-coated pipe exists in the province.[29]
- To inspect the four tape-coated sections of Line 100-3 with a shear wave ultrasonic (UT) crack detection tool once the pipeline has been converted to liquid service.[30]

With respect to the analysis of the ILI results[31]:

- TransCanada has a documented process for assessing the immediate and long term acceptability of each reported crack related feature from both the EMAT and UT crack detection tools. As with metal loss features, this process also includes acceptance criteria.
- With respect to crack growth rate, TransCanada states that it will use a SCC dissolution growth rate while the four tape-coated sections of Line 100-3 are still in gas service, and the sum of a corrosion fatigue growth rate and a SCC dissolution growth rate once those sections are placed in liquid service.
- TransCanada states in its Application that it will determine the long term acceptability of the reported crack related features in the four tape-coated sections of Line 100-3 by taking into account applicable sizing tolerances for the EMAT and UT crack detection tools, as well as corrosion fatigue and SCC dissolution growth rates.

Additional elements for managing integrity with respect to SCC are as follows:

- TransCanada will implement a voluntary 20% reduction in the maximum operating pressure until the preliminary report from the UT crack detection tool confirms that there are no cracking features that pose an immediate integrity threat to the given section of pipeline.[32]
- TransCanada states that it will remediate, during the conversion integrity program, any features with a predicted failure pressure of 110% MOP or less within six years of the inspection tool run.

This predicted failure pressure acceptance criterion is increased to a more conservative 115% MOP or less for those segments of pipeline that could negatively impact a highly sensitive area.[33]

Our assessment is as follows:

1. TransCanada's plan to run a UT crack detection ILI tool once the pipeline is in liquid service is a proactive step, and the voluntary 20% reduction in MOP until the results of the UT inspection confirm the integrity of the pipeline is prudent.

2. With respect to the proposed approach for estimating crack growth rates, additional information would be required to allow for a proper assessment of whether the approach would result in sufficiently conservative remaining life calculations.

3. The use of a more conservative acceptance criterion for the segments of pipeline that could negatively impact a highly sensitive area is a prudent approach that should result in an additional layer of protection for the pipeline in those locations.

4. The use of high resolution crack detection ILI tools is an accepted industry approach for detecting and sizing crack related features. Indeed, crack detection ILI provides valuable information on the condition of the pipeline and should continue to be used and the technology further improved.

   However, a recent study[34] examined the reliability of ILI crack detection tools with respect to characterizing the nature and severity of ERW line pipe seam anomalies and determined that there are limitations with current technology; in particular, the inability of the tools to reliably detect and accurately size crack related features in the seam of ERW pipes. In the case of the Energy East pipeline, the concern is not that crack detection ILI tools may not detect or accurately size seam defects on the conversion sections. As previously noted, the conversion sections were constructed with DSAW pipe, which are much less prone to seam defects. Rather, the concern is whether crack detection ILI technology might exhibit similar limitations with respect to SCC.

   Given that there can be some variability in the performance of the crack detection ILI tools, TransCanada should be requested to demonstrate that the detection reliability and sizing accuracy of the crack detection ILI tools TransCanada plans to use on the tape-coated sections of Line 100-3 are sufficient to provide assurance of the integrity of those sections.

   Consideration should also be given to requiring that MLV 58-59, which had a hydrostatic test failure in 2000,[18] be hydrostatically tested prior to being placed in liquid service to provide an additional, independent means of demonstrating the integrity of that section, as well as validating the results of the crack detection ILI.

2.7 Conclusions and Recommendations

The primary integrity-related issue for the Energy East Pipeline in Ontario is the potential for stress corrosion cracking on the four tape-coated sections on Line 100-3.

The proposed approach in the Energy East Pipeline Application for managing the threat of SCC on the tape-coated sections on Line 100-3 is generally consistent with current industry practice. However, given that there can be some variability in the performance of the crack detection ILI tools, the ILI program may not provide full assurance of the integrity of those sections.

With respect to the conversion section, it is recommended that:

1. TransCanada be required to demonstrate that the detection reliability and sizing accuracy of the crack detection ILI tools TransCanada plans to use on the tape-coated sections of Line 100-3 are sufficient to provide assurance of the integrity of those sections; and
2. MLV 58-59, which had a hydrostatic test failure in 2000, be hydrostatically tested prior to being placed in liquid service to provide an additional, independent means of demonstrating the integrity of that section, as well as validating the results of the crack detection ILI.

With respect to the pipelines that will remain in gas service, it is recommended that the engineering assessments include an assessment of the risk of damage to the conversion section as a result of a failure of the gas pipelines, particularly where the pipelines cross or are in close proximity to the conversion section, and that mitigative measures are put in place where the risk is considered unacceptable.

3 MITIGATING THE CONSEQUENCES OF FAILURES

At the community meetings held along the pipeline route, Ontarians expressed concerns regarding the adequacy of emergency response measures in the event of a spill, particularly around bodies of water. In assessing the Energy East Pipeline Application, we were guided by the principle set out in the Minister's letter that "pipelines must have world leading contingency planning and emergency response programs." In order to satisfy the principle in the Minister's letter, measures must be in place such that the consequences associated with a failure of the pipeline can be mitigated to acceptable levels.

TransCanada's Application states that the Energy East Pipeline will transport three general categories of crude oil: conventional light crude oil, synthetic crude oil and diluted bitumen.[35] The consequences of a pipeline accident will differ depending on the category of product released. Light crude oil is generally more flammable than heavier grades and will pose a comparatively greater risk to public safety if released in a location close to populated areas, whereas diluted bitumen may pose greater risk of environmental damage, particularly if spilled into water bodies. For an oil pipeline, the factors that contribute to the consequences of a failure are the volume and type of product released and the location where the product is released.

In our assessment, we focused on the elements of the Application that mitigate the consequences of a pipeline failure; i.e. valve types and placement, the leak detection system, and emergency response.

3.1 Valve Type and Placement

DNV GL notes that valve type and placement are critical in limiting the volume of product released as a result of a pipeline rupture. In its Application, TransCanada states that:

- mainline valves will be installed to allow sections of the pipeline to be isolated in a controlled manner for normal operation and maintenance activities, or to minimize the effects of an accidental release;[36]
- valve assemblies will be located to protect significant water crossings and limit the potential worst case discharge volume;[37] and
- all mainline valves will be remotely controlled and monitored, with the exception of check valves at certain river crossings.[36] (Check valves are not remotely controlled; they automatically open or close depending on the direction of fluid flow.)

TransCanada, in its Application, describes the Valve Siting Optimization Process used for the preliminary placement of mainline valves. The objective of the Valve Siting Optimization Process is to determine valve placement that effectively mitigates risk, while having regard for release volume analyses, local topography, local feedback, existing land use, etc. Valve site locations will be confirmed during detailed design, taking into consideration site-specific factors and feedback from regulatory authorities, landowners, stakeholders and Aboriginal communities.[36]

Further, TransCanada states that, as part of the valve placement process, mainline valves will be placed in proximity to both the upstream and downstream sides of major watercourse crossings, except where a valve will not materially reduce release volumes to the watercourse. The upstream valve will be a remotely operated valve, and the downstream valve assembly will consist of a check valve and a manual valve.[38] The check valve allows for automatic shut-off and to prevent backflow in the event of a failure. DNV GL notes that TransCanada does not identify which watercourse crossings are considered major. Rather, TransCanada states that valve site locations will be confirmed during detailed design, taking into consideration site-specific factors and feedback from regulatory authorities, landowners, stakeholders and Aboriginal communities.

We based our assessment of valve type and placement outlined in the Application primarily on the requirements of the CSA Z662 standard:

1. Clause 4.4.3 of CSA Z662 requires that companies perform an engineering assessment to determine the appropriate spacing for valves, unless the valve spacing as given in Table 4.7 is adopted. However, Table 4.7 does not specify a maximum valve spacing limit for crude oil pipelines. DNV GL therefore considers that an engineering assessment would represent the highest standard for determining valve placement, and that one criterion for valve placement is that potential release volumes are as low as reasonably practicable.

   The Valve Siting Optimization Process described in the Application appears to be a reasonable approach for determining preliminary valve locations, but there is not enough detail in the Application to assess whether the process would qualify as an engineering assessment. Other than providing the preliminary locations for valves, TransCanada does not provide details on the process. For example, TransCanada does not specify the criteria for determining whether a particular valve configuration effectively mitigates risk. In order to properly assess the acceptability of the process and the proposed valve locations, additional detail is required.

2. The CSA Z662 standard does not require the use of remotely controlled valves. TransCanada's approach of using remotely operated valves for mainline valves exceeds the requirements of CSA Z662 and allows for a fast response time to isolate a failed section of the pipeline and to minimize the amount of product released. The closure of a manual valve can take hours depending on the distance required to travel to a valve site and manually close it, whereas remotely operated valves can be closed within minutes.

3. CSA Z662 requires the installation of valves on both sides of major water crossings, but does not specify that those valves be remotely controlled. In its Application, TransCanada commits to meeting this requirement, but does not specify which watercourse crossings are considered major. In addition, the CSA standard recommends that consideration be given to the installation of check valves at major water crossings, which TransCanada has adopted.

We recommend that TransCanada:

1. provide additional information on the Valve Siting Optimization Process, including the criteria for determining whether a particular valve configuration effectively mitigates risk, and demonstrate that the process meets the requirements of CSA Z662 for an engineering assessment;

2. demonstrate that potential release volumes along the pipeline route are as low as reasonably practicable; and

3. identify which water crossings are considered major and thus will be protected by valves on both sides of the crossing.

3.2 Leak Detection

The second factor considered in mitigating the consequences of a failure is the time it takes to shut down the pipeline system after a failure.

TransCanada, in its Application, states that the pipeline will be monitored, controlled, and protected through a multi-layered approach[39] that includes:

- Supervisory Control and Data Acquisition (SCADA) system, which provides for the monitoring of the pipeline system and remote control of local facilities;
- qualified and trained control room operators to monitor the pipeline system 24 hours a day, seven days a week;
- local facility control systems to monitor and control local facilities (pump station or terminal or valve site);
- pressure control and overpressure protection system; and
- a leak detection system.

The SCADA system is a computer-based data acquisition system that gathers operating data (e.g. operating pressure, temperature, flow rates, alarms, etc.) from geographically remote field locations along the pipeline system and transmits the data via communication links (i.e. underground fibre and/or copper cable, satellite, cellular radio tower) to a control center for display, control and reporting. The SCADA system enables the control center operators to remotely control the pipeline by adjusting pump station pressures, starting and stopping pumping units, and opening and closing remotely controlled valves. The Energy East SCADA system would use a real-time transient model, with a modified volume balance model as a backup.[40]

In the Application, TransCanada states that it will implement a leak detection strategy that meets current regulatory requirements and industry standards, including CSA Z662 and American Petroleum Institute (API) Recommended Practice 1130 *Computational Pipeline Monitoring for Liquids*.[40] The leak detection strategy includes both real-time and non-real-time methods. In combination with the SCADA system, the leak detection system will include a real-time transient model leak detection system (primary system) and a modified volume balance leak detection system (secondary system). The real-time leak detection methods will be complemented by non-real-time methods (e.g. in-line inspection, aerial and ground patrols) to provide additional and independent leak detection capability.

Regarding the time for the control room to detect and respond to a leak, TransCanada states that:

- If the leak detection system sounds an alarm indicating a potential leak, the control center operator has a maximum of 10 minutes to conclusively explain the cause of the alarm as a non-leak using established procedures. If a leak cannot be ruled out by the operator, a pipeline shutdown is immediately initiated. If additional indications of a potential leak are noted at any point during the initial 10 minutes, the pipeline shutdown is immediately initiated.[41]
- Based on current design information, pipeline shutdowns, including pump shutdown and valve closure, are expected to be completed within 12 minutes of the initiation of a shutdown. This estimate is subject to refinement during detailed design.[41]

The theoretical maximum volume release would include the initial volume released between the time of the failure and the pipeline shutdown (i.e. pump shutdowns and valve closures) and the volume released from drain down.

Our assessment is as follows:

1. The use of a combination of real-time and non-real-time leak detection methods represents best industry practice.

2. With respect to the standards for the real-time leak detection system, API 1130 is a recommended practice for computational pipeline monitoring for liquids, and is mandatory in the United States. API 1130 is a more stringent standard than Canadian federal requirements. TransCanada has committed to following API 1130. However, TransCanada does not specify whether the leak detection system would also conform to CSA Z662 Annex E *Recommended practice for liquid hydrocarbon pipeline system leak detection*. Annex E, which complements the requirements in API 1130, is voluntary for federally-regulated pipelines in Canada, but it has been adopted into regulation by both Alberta and Saskatchewan. A 2010 paper[42] comparing the two concluded that Annex E was an improvement upon API 1130, although both provide beneficial guidance, and therefore that pipeline operators "should use both documents."

3. TransCanada, in its Application, does not provide details regarding the specifications for the leak detection system (i.e. reliability, sensitivity, accuracy, robustness). Such information would be required to allow for a proper assessment of the acceptability of the system.

4. Regulations and standards do not specify a time limit for analyzing and responding to an alarm. Thus, the procedure to initiate the shutdown of the pipeline within 10 minutes of receiving an alarm exceeds code and regulatory requirements and represents a high standard. Alarm management has been a long-standing issue for the pipeline industry. Depending on factors such as the transient operating conditions of the pipeline, the complexity of the pipeline system, and the design of the leak detection system, operating control centers can receive frequent false alarms. The improper analysis of and response to alarms has been a contributing factor in numerous pipeline accidents, sometimes resulting in tragic consequences.[43,44] In the absence of a procedure mandating a shutdown within a specified time, there is an increased risk that a pipeline will not be shut down in a timely manner following a failure. The 10-minute rule is intended to remove any discretion on the part of the control center operator where an alarm cannot be conclusively explained as a non-leak and thereby ensure a timely shutdown of the pipeline system.

It is recommended that TransCanada:

1. confirm conformance with the requirements of CSA Z662 Annex E; and

2. provide performance specifications for the leak detection system and provide evidence that specifications are met or exceeded in operation.

3.3 Emergency Management

TransCanada, in its Application, states that specific Emergency Response Plans (ERPs) will be developed for the Energy East project in accordance with TransCanada's Emergency Management System (EMS).[45] The basic components of TransCanada's EMS, all of which will be incorporated in each of the project-specific ERPs, include:

- identifying potential emergencies arising from human activity or natural hazards based on a formalized risk-determination process;
- assigning responsibilities;
- activation and notification procedures;
- tactics to respond to spills;
- strategic locations of emergency response equipment;
- consultation and coordination, where appropriate, with local industries, municipalities and other government agencies to develop ERPs;
- identifying requirements for outside assistance/emergency response;
- communicating with personnel, the public and government agencies during an emergency;
- requirements for follow-up investigations, communication and reporting;
- process for establishing emergency operations centres and incident command posts;
- communicating plans in an appropriate manner;
- requirements for providing assistance to persons dislocated by the emergency;
- training requirements to ensure personnel are trained and outside resource personnel are aware of their emergency preparedness roles and responsibilities;
- exercise requirements to test ERPs and evaluate effectiveness of personnel training in ERP implementations; and
- a system to evaluate emergency preparedness and response.[46]

TransCanada has adopted the Incident Command System (ICS), an established framework for emergency response, as the basic response structure within its emergency management program.[47]

TransCanada's Environmental and Socio-Economic Assessment (ESA) for the project includes theoretical site-specific analyses for 12 potential release sites that represent the types of environmental settings traversed by the Project.[48] TransCanada states that information from these analyses will help inform ERP development. In addition, hypothetical spill-response scenarios were developed.[49] The latter are not site-specific studies and were intended to focus on spill-response tactics for the types of terrain and marine environments along the pipeline route.

TransCanada makes reference to the 2010 pipeline accident at Marshall, Michigan[44] and the need for response capability for sunken or submerged oil. In its Application, TransCanada states that it already has tactical plans and equipment, is engaged in further identifying and procuring equipment and resources required to effectively respond to sunken and submerged oil, and is ensuring personnel are appropriately trained.[50]

The hypothetical spill-response scenarios are not intended to take the place of emergency response plans, which TransCanada has committed to developing at a later stage. TransCanada states that ERPs will be developed in consultation with emergency service agencies, including local, provincial and federal agencies, and local Aboriginal groups, and will be filed with the NEB and distributed to applicable emergency service agencies, as necessary, before Project commissioning.[45]

Our assessment is as follows:

1. The Incident Command System is an on-scene incident management framework designed to enable effective and efficient response to an emergency within an integrated organizational structure. ICS is widely used by both industry and government and is consistent with world leading contingency planning and emergency response programs.

2. Since site-specific Emergency Response Plans are not yet available for review, we are unable to assess whether they satisfy the principles set out in the Minister's letter. TransCanada states that ERPs will be developed in consultation with emergency service agencies and local Aboriginal groups. In order that emergency service agencies and communities may be properly informed during these consultations, TransCanada should provide them with additional information.

3. One of the principles in the Minister's letter was that "economic and environmental risks and responsibilities, including remediation, should be borne exclusively by the pipeline companies, who must also provide financial assurance demonstrating their capability to respond to leaks and spills." Communities raised the concern that they may have to bear part of the cost associated with the response and clean-up in the event of a pipeline failure. Costs for a major spill can be of the order of $1 Billion or more. TransCanada should be required to provide financial assurance of their response capability.

It is recommended that TransCanada:

1. provide emergency service agencies and communities with site-specific analyses for product releases and spill trajectories for critical locations in Ontario;

2. perform response capability assessments to demonstrate that TransCanada will be able to respond effectively and that impacts can be mitigated to acceptable levels; and

3. provide financial assurance of their capability to cover response, clean-up and remediation costs in the event of a pipeline failure.

3.4 Conclusions and Recommendations

DNV GL considers that the commitments and processes described in TransCanada's Energy East Application meet or exceed the requirements in applicable standards and regulations and are generally consistent with good industry practice. However, in the absence of specific details regarding valve placement, leak detection and emergency response plans, it is not possible to assess whether the Energy East Application satisfies the principles set out in the Minister's letter.

In order to address the need for additional information and to satisfy the principles in the Minister's letter, it is recommended that TransCanada:

1. provide additional information on its Valve Siting Optimization Process, including the criteria for determining whether a particular valve configuration effectively mitigates risk, and demonstrate that the process meets the requirements of CSA Z662 for an engineering assessment;
2. demonstrate that potential release volumes along the pipeline route are as low as reasonably practicable;
3. identify which water crossings are considered major and thus will be protected by valves on both sides of the crossing;
4. confirm conformance with the requirements of CSA Z662 Annex E;
5. provide performance specifications for the leak detection system and provide evidence that specifications are met or exceeded in operation;
6. provide emergency service agencies and communities with site-specific analyses for product releases and spill trajectories for critical locations in Ontario;
7. perform response capability assessments to demonstrate that TransCanada will be able to respond effectively and that impacts can be mitigated to acceptable levels; and
8. provide financial assurance of their capability to cover response, clean-up and remediation costs in the event of a pipeline failure.

ENDNOTES

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[22] Energy East Pipeline Ltd., *Energy East Project Application,* Volume 4A, A4D8V1, PDF page 7

[23] Energy East Pipeline Ltd., *Energy East Project Application,* Volume 5, A4D8X6, PDF page 5

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[48] Energy East Pipeline Ltd., *Energy East Project Application,* Volume 7, A4D9F0, PDF page 11. Also see studies of 11 "sites of interest" in *Energy East Project ESA,* Volume 6, A4E1F5.

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