UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest Corporation) Docket No. RP06- -000

Prepared Direct Testimony of Dan A. King

Q: Please state your name and business address.

A: My name is Dan A. King. My business address is 450 1st Street S.W., Calgary, Alberta, Canada T2P 5H1.

Q: By whom are you employed and in what capacity?

A: I am a management engineer, and my title is Director of Asset Reliability for TransCanada Pipe Lines Limited.

Q: Please describe your educational background and experience.

A: I graduated with a Bachelor of Science degree in Electrical Engineering from the University of Calgary in 1983. I have approximately 23 years of experience working at TransCanada PipeLines Limited and its predecessor companies. My experience at TransCanada has included working as an Instrumentation & Control Engineer, Project Manager, Manager of various engineering groups in the company, and most recently as Director of the Pipe Engineering department.

Q: Have you ever testified before the Federal Energy Regulatory Commission?

A: No, I have not. I have testified before the National Energy Board of Canada on matters involving operating costs and pipeline integrity costs (RH-1-2002).

Q: What is the purpose of your testimony?

A: The purpose of my testimony is twofold. The first is to address the costs of retiring Gas Transmission Northwest's ("GTN") transmission pipelines, compressor stations and meter stations. A study which estimates the cost of retiring such facilities was prepared under my direction. GTN Witness Feinstein will address the calculation of negative salvage rates as a percent of gross depreciable plant based upon this study. The second purpose is to address costs related to the Maintenance of Mains and Compressor Station Equipment.

Q: What pipeline facilities are addressed by your study?

A: GTN's gas transmission assets include 1,353 miles of pipeline, 513,400 horsepower of compression and 43 receipt and delivery points.

Q: Based on your study, what are GTN's estimated retirement costs?

A: The estimated retirement costs of GTN's transmission facilities are $292,443,200 (Scenario #3). These costs are shown below and are supported in Exhibit No. GTN-22.

	Scenario #1	Scenario #2	Scenario #3
	Abandonment	Removal	Application
Pipeline	$34,213,000	$400,490,000	$233,064,000
Compression	$53,276,200	$53,794,200	$53,276,200
Metering	$6,103,000	$6,103,000	$6,103,000
Total	$93,592,200	$460,387,200	$292,443,200

Pipe Removal Length	0 miles	1,455 miles	300 miles

Q: How did you determine removal or abandonment costs for pipelines?

A: The engineering analysis entailed reviewing all of the physical assets associated with the GTN system (pipeline, compressor, and meter stations), reviewing all applicable easement agreements, developing engineering assumptions pertaining to the decommissioning and retirement of the assets, and developing a cost estimate for terminal retirement. The goal of this effort is to evaluate retirement, abandonment, and remediation options and to produce a cost estimate for the retirement of the GTN system. Three different abandonment scenarios were developed for the GTN system. Scenarios #1 and #2 are intended to establish the high and low cost bookends of the retirement and abandonment of GTN facilities based on engineering assumptions. The intent of developing these two scenarios is to better understand the full spectrum of possible abandonment costs. Scenario #3 is the case that GTN feels to be the most appropriate cost to file with FERC. These three scenarios are described in more detail below.

Q: What are the assumptions you used for the pipeline facilities in the three scenarios?

A: The assumptions are:

- Pipe facilities are categorized according to land use description: developed, cultivated, pasture, orchard/vineyard, forest, water crossings (small and large), wetlands, environmentally sensitive, road crossings (highway, paved, gravel), rail crossings, pipeline/utility crossings (above and below), and above ground piping (valve sites, risers, launchers and receivers, *etc.*).
- It is assumed that external coatings containing asbestos can be safely abandoned in place. Asbestos is stable and only an air-borne issue when disturbed. The coating will not have to be removed in the abandon-in-place case. If pipe is to be removed,

asbestos coating can be removed from the pipe on site or at the treatment facility. However, for this large-scale project it is most likely that an intermediate site would be set up for coating removal before it is delivered to the treatment facility.

- If the external pipe coating is known to be contaminated with asbestos and/or other materials it will only be removed if required by the designated land category or scenario (*see* Scenarios #1, #2, and #3 below for more information). The external coating is considered environmentally stable in its present state. If the pipe is removed, the contaminated coating will be removed as per current regulations and transported and incinerated at an approved waste treatment facility.

Q: What are the assumptions you used for the compressor and meter station facilities in the three scenarios?

A: The assumptions are:

- Equipment and buildings are removed together, *i.e.*, buildings are not left empty after the equipment is removed.
- Removal of the compression equipment, buildings, and associated control/auxiliary equipment is completed as a package.
- Multi-plant control buildings are removed when the final plant they serve is removed.
- Costs assume the system-wide removal program is not excessively large on a year-over-year basis where premium costs would be incurred.

Q: Please describe Scenario #1, the "least cost bookend."

A: The scenario includes plans for the pipeline facilities and the compressor and meter station facilities.

<u>Pipeline facilities</u>: - The basic assumption for Scenario #1 is that the piping will be abandoned in place, and all above-ground facilities will be removed.

- All below-ground piping, coating, fittings, foundations, *etc*., will remain abandoned in place. Above-ground piping will be cut off below grade and removed. All piping will be mechanically cleaned using cleaning pigs and chemicals to remove any potential internal contaminants (such as residual liquid hydrocarbons). All debris and cleaning solvents collected from these activities will be disposed of at appropriate waste treatment facilities. Valves will be left in the closed position or salvaged (depending on economics). Cut pipe ends will be capped (*see* exceptions: extra 'plugs' to be installed in some locations) to prevent water migration inside and along the pipeline.
- The pipe will be filled with nitrogen, and cathodic protection ("CP") of the system will be discontinued.
- All above-ground pipe and facilities will be removed and reclaimed.

<u>Compressor and Meter Station facilities:</u> - The basic assumption for Scenario #1 is that the sites will be restored consistent with industrial guidelines.

- Removal scope as per the current GTN standards and current environmental regulatory requirements. There has been an environmental assessment completed for all compressor stations on the GTN system, and there are no indications of PCB contamination.
- Removal of all below-grade foundations except pilings, removal of all below-grade high-pressure piping except where there are safety concerns with existing facilities (piping is then filled with concrete), removal of other underground facilities where it is practicable.

- Station area is remediated to current industrial guidelines. The fenced developed area remains the same size (with the removed plant areas within the fenced area). The fenced station area remains an industrial facility with a graveled surface. There are two exceptions to this assumption: the Madras and Bend Compressor Stations which reside on federal land. These stations will be returned to fully natural areas.
- The fenced developed area remains GTN-owned property.
- Ongoing monitoring of the site is required to ensure no migration of industrial level contaminants that may be present.
- Ongoing maintenance of the graveled yard area (weed control, *etc*). No reclamation of off-site, on-property areas (outside of fenced area), *i.e*., old housing areas, airstrips, drainage ponds, access roads, *etc.*

Q: Please describe Scenario #2, the "highest cost" bookend.

A: The scenario includes plans for the pipeline facilities and the compressor and meter station facilities.

<u>Pipeline facilities</u>: - The basic assumption for Scenario #2 is to remove all above- and below-ground facilities, unless impractical to do so.

- The project will be closely coordinated with environmental issues in mind.
- Procedures have been developed for different land uses, but generally:
  - The pipe will be mechanically cleaned internally using cleaning pigs and chemicals to remove any potential internal contaminants (*e.g.*, residual liquid hydrocarbons). All debris and cleaning solvents collected from these activities will be disposed of at appropriate waste treatment facilities;
  - Topsoil will be stripped and saved on site;

- – Pipe will be excavated and removed;
- – External pipe coating will be removed at an intermediate site based on probability of contamination for asbestos and/or other materials;
- – Backfill will be placed in ditches, and extra fill will be imported as required;
- – Topsoil augmentation and landscaping will be performed as appropriate;
- – Reclamation and re-vegetation will be performed as appropriate for land use consistent with owners' requests.

Compressor and Meter Station facilities: - The basic assumption for Scenario #2 is to restore the sites to agricultural guidelines.

At sites where all compression facilities are removed:

- Removal of all below-grade facilities except pilings.
- Removal of the fenced station yard area.
- Reclamation of complete property area to current agricultural land use guidelines, including removal of all contaminants, graveled/developed areas, top soiling, and re-vegetating. There are two exceptions to this assumption: In the case of the Madras and Bend Compressor Stations that reside on Federal land, these stations will be returned to fully natural areas. There has been an environmental assessment completed for all compressor stations on the GTN system, and there are no indications of PCB contamination.
- Compressor/meter station land is sold based on present market value and reverted to right-of-way as applicable (except for the Madras and Bend Compressor Stations).

Q: Please describe Scenario #3, GTN's Application Case to FERC.

A: The scenario includes plans for the pipeline facilities and the compressor and meter station facilities.

<u>Pipeline facilities</u>: – The basic assumption for Scenario #3 is to remove all above-ground pipelines and associated facilities and some underground pipeline facilities. There will be compliance with all easement agreements that require removal of the below-ground pipeline facilities.

- When pipe facilities are to be removed, the project will be closely coordinated with environmental issues in mind. Procedures have been developed for different land use categories, but generally, the pipe will be mechanically cleaned internally using cleaning pigs and chemicals to remove any potential internal contaminants (*e.g.*, residual liquid hydrocarbon liquids). All debris and cleaning solvents collected from these activities will be disposed of at appropriate waste treatment facilities.
- In situations where the land category requires the removal of the pipe and the external pipe coating is likely contaminated with asbestos and/or other materials, the coating will be removed at an intermediate site and disposed of at appropriate waste treatment facilities.
- For pipeline facilities abandoned in place, the cathodic protection system will be discontinued.
- From the review of land use areas for the GTN system, there are no present areas that are classified as being environmentally sensitive.
- The following engineering assumptions are applied to the following land category areas:

- – Developed Land: Remove all piping;
- – Cultivated Land (includes orchard and vineyards): Fill with nitrogen and abandon in place;
- – Pasture and Forested Land: Fill with nitrogen and abandon in place;
- – Small water crossing: Fill pipe with concrete and abandon in place, except for exposed pipe;
- – Large water crossings: Fill pipe with concrete and abandon in place, except for exposed pipe;
- – Wetlands: Remove all piping;
- – Environmentally sensitive (no present areas on GTN system): Fill with nitrogen and abandon in place;
- – Highways/Paved Roads: Fill with concrete and abandon in place;
- – Gravel roads: Either abandon in place or remove (assumes 50% abandoned in place and 50% removed); and
- – Rail crossings: Abandon in place and fill with concrete;
- – Pipeline/Utility crossings: Either abandon in place or remove (assumes 50% abandoned in place and 50% removed);
- – Above ground piping: Remove and restore land.

<u>Compressor and Meter Station facilities</u>: - The basic assumption for Scenario #3 is to restore to industrial guidelines. This is the same as in Scenario #1.

- Adopt the low-cost bookend (site restoration to industrial guidelines) as per current GTN standards and current environmental regulatory requirements.

- It is possible that environmental standards for industrial sites will become more stringent with time, and guidelines for unused compressor and meter station sites will be developed. However, possible future standards are considered too speculative at this time, and the lower-cost present day standards are considered appropriate for the current study. Should requirements become more definitive in the future, they will be incorporated, and the retirement analysis will be revised in a future year.

Q: Please describe the basis for your estimates.

A: All estimates are in 2006 dollars. We employed a 15% percent contingency to the base estimates to account for project unknowns.

Q: On what basis have you concluded that GTN's pipeline will (or will not) largely be removed?

A: The appropriate retirement of GTN's pipeline system is based on a review of land use areas, including environmentally sensitive areas, and a determination of an appropriate abandonment strategy to address future safety and environmental issues. The engineering review and corresponding assumptions to determine this strategy are described above. For all pipeline segments designated for retirement in the future, a detailed engineering assessment will be conducted as these projects are initiated to determine the precise method and strategy for abandonment of pipeline facilities.

Q: How did you determine the removal costs for the pipeline?

A: The removal costs for pipeline facilities are based on the engineering assumptions and associated activities described above. Since there are very few actual removal/abandonment projects to base these costs on in recent history for GTN, cost estimates for these engineering assumptions are based on GTN's experience for performing operating, maintenance and small-scale construction projects.

Q: Was the sale of line pack accounted for in your calculation of the overall pipeline removal?

A: Yes, it was.

Q: What value did you place on removed pipe, valves and other equipment sold for salvage?

A: $43,591,800.

Q: What costs were used for right-of-way damages?

A: $18,105,000.

Q: How did you determine removal costs for compressor stations?

A: The removal costs are based on the engineering assumptions contained in Scenario #3, where the sites are restored to industrial guidelines.

Q: Please describe how removal costs for meter stations were determined.

A: The removal costs are based on the engineering assumptions contained in Scenario #3, where the sites are restored to industrial guidelines.

Q: What environmental costs were assumed in the study?

A: Only normal and routine costs were assumed. These involved primarily restoring the site to its original and vegetative condition.

Q: Did you include any costs for asbestos removal?

A: Only for pipeline segments designated for removal that have potential for asbestos in the external coating. In situations where the pipeline is designated for removal, there are costs assumed to remove the external coating and for proper disposal at a waste treatment facility. There is no cost assumed for pipeline segments designated as abandoned in place that have a similar potential for asbestos in the external coating. We felt that asbestos is only a concern in the external pipe coating if the pipeline is being disturbed through removal and, thus, the potential exists for the asbestos fibers to become airborne.

Q: Does this conclude your testimony on retirement of the GTN system?

A: Yes, it does. My testimony on costs related to the Maintenance of Mains and Maintenance of Compressor Station Equipment follows.

Q: Maintenance of Mains is expected to be $10.0 million higher than for the base period. What costs are included in this account?

A: This cost represents pipeline integrity costs. A breakdown of cost components and a comparison with the base period is include in the following table:

($ millions)	Base Period	As Adjusted	Increase/ (Decrease)
Program Development	0.4	0.2	(0.2)
SCC Management	-	6.2	6.2
Corrosion Management	0.3	1.7	1.4
Cathodic Protection	0.2	0.4	0.2
Class Location Upgrades	-	2.0	2.0
Other Programs	0.1	0.5	0.4
Total Pipeline Integrity Expense	1.0	11.0	10.1

Q: Why is there an increase in the Pipeline Integrity spending?

A: The increase is attributable to a number of factors including new expenditures to manage the Stress Corrosion Cracking ("SCC") threat, to manage the Corrosion threat, and to perform class location upgrades on the A line as the population encroaches upon the pipeline. Additionally, annual cathodic protection costs will increase due to a requirement for additional maintenance and general integrity expenditures required to comply with Pipeline Safety Act of 2002.

Q: What are the plans for managing the SCC threat?

A: A program to manage the SCC threat involves hydrostatically testing the first valve sections downstream of the compressor stations. There are 12 compressor stations in the GTN system. Three valve sections will be hydrotested each year, requiring four years to complete testing of all first valve sections. The findings from the yearly hydrotests will be evaluated to determine how to modify the program going forward. Typically, hydrostatic testing for SCC reoccurs at regular intervals. In addition, independent SCC investigative digs (excavation and examination) will be completed.

Q: What is the need for managing the SCC threat?

A: A program to manage the SCC threat is necessary for the A line. The reasons are numerous and include the age of the pipeline (45 years), coating type (asphalt), and the history of SCC in the area (*e.g.,* Williams Northwest Pipeline, with two SCC ruptures in 2003). SCC is not considered a threat on the B or C lines.

Q: What is the need for the class location upgrades?

A: Some areas of the pipeline are experiencing moderate population growth. As the population encroaches upon the pipeline, the required class location may change from Class 1 (less than 10 dwellings per area) to Class 2 (greater than 10 dwellings and less than 46 dwellings per area) or from Class 2 to Class 3 (greater than 46 dwellings per area). Under 49 C.F.R. 192 Subpart A, areas may also change from Class 1 to Class 3. An increase in class location by one class (1 to 2, or 2 to 3) triggers a requirement alternatively to: replace the pipe (with a thicker wall or higher grade pipe); perform a hydrotest on the pipe (to a level appropriate for the higher class location); appropriately de-rate the pipeline; or apply for a waiver. An increase in class location by two classes can only be remediated by pipe replacement, de-rating of the pipeline, or a waiver. According to the Department of Transportation guidance on waiver requirements for class changes (Docket No. RSPA-04-17401), the waiver approach is not applicable for the A line. Typically it is more cost-effective to hydrotest the pipe.

Q: What is the Pipeline Improvement Safety Act of 2002?

A: The Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, mandates significant changes and new requirements in the way that the natural gas industry ensures the safety and integrity of its pipelines. The law applies to natural gas transmission pipeline companies. Central to the law are the requirements it places on each pipeline operator to prepare and implement an "integrity management program," which among other things, requires operators to identify so-called "high consequence areas" ("HCA") on their systems, conduct risk analyses of these areas, perform baseline integrity assessments of each pipeline segment, and inspect the entire pipeline system according to a prescribed schedule and using prescribed methods.

Q: How much has it cost GTN in operating and maintenance costs to ensure compliance with the Pipeline Improvement Safety Act of 2002?

A: GTN will have invested approximately $10 million between 2004 and 2007 to ensure compliance with the act. GTN has invested approximately $6 million for in-line inspection of the pipelines and subsequent excavations and repairs. Approximately $4 million is attributable to Direct Assessments (SCC and External Corrosion). The Act requires periodic re-inspection of the pipeline. This level of expenditures is expected to continue indefinitely.

Q: What costs are attributable to the Medford and Coyote Springs Laterals?

A: The following costs are proportionately (by length) attributable to the Laterals: Program Development, Cathodic Protection, and Other Programs. The length of the total system is 1,353 miles. The Medford Lateral is 88 miles long; the Coyote Springs Lateral is 18.5 miles long. The Medford Lateral Pipeline Integrity costs are $71,600 (6.5 % of $1.1 million). The Coyote Springs Lateral Pipeline Integrity costs are $15,100 (1.4 % of $1.1 million). The SCC management, Corrosion management, and Class Location upgrade costs will be primarily attributable to the A line with some more limited costs attributable to the B line.

Q: Adjusted Costs for Maintenance of Compressor Station Equipment (Account 864) are $1.2 million higher than the base period. Please explain why.

A: There are two main reasons for this variance. TransCanada's methodology for planned maintenance intervals was different and more rigorous than what had been in place previous to the acquisition of GTN, and there were unplanned events that drove the actual spending up. There was no significant change in utilization on the GTN line from the time the 2005 Budget was set.

Q: What assumptions were used to determine the Repair and Overhaul costs?

A: Overhauls are forecasted using Time Since New hours, Time Since Overhaul hours, overhaul history, and seasonal utilization forecasts. Overhaul costs are based on historical costs plus historical inflation levels for overhauls. Therefore, the Test Period costs are reflective of the number of planned events combined with a statistical amount for unplanned repairs and accessories such as starters, pumps, chip detectors, *etc*.

Q: How were the adjusted costs included in Maintenance of Compressor Station Equipment (Account No. 864) determined?

A: The compressor repair and overhaul costs included in this account have two components: The first is the Planned Preventative Maintenance program for the Repair and Overhaul of GTN major rotating equipment (gas generators, power turbines and gas compressors); the second is the Unplanned Maintenance that occurs on the GTN major rotating equipment (gas generators, power turbines and gas compressors).

Q: What do these costs include?

A: The adjusted costs for compressor repair and overhaul include materials, services, and brokerage fees for all gas generator, gas compressor, and power turbine repairs.

Q: What is "Planned" maintenance?

A: The Planned Preventative Maintenance Program is based on the utilization of the equipment and the set maintenance intervals for major and minor overhauls on each type of rotating equipment. The Planned Preventive Maintenance Program maintenance intervals and work scope are determined by a maintenance interval optimization tool ("MINO").

Q: What is the MINO tool?

A: The MINO tool is used to value the current maintenance program and to optimize maintenance intervals. Relevant data (*i.e.*, repair and overhaul costs and failure rates) are analyzed to determine the effectiveness of the current maintenance frequency. "What if" scenarios (work scope management and frequency of intervention) are analyzed in order to optimize maintenance intervals to deliver the overall lowest life-cycle maintenance costs. TransCanada's experience with operating and maintaining a large rotating equipment fleet enables the use of this tool.

Q: What constitutes "Unplanned" maintenance?

A: Unplanned work includes equipment failures and repairs that were unforeseen and therefore not part of the planned program.

Q: How was the adjusted planned maintenance amount determined?

A: The adjusted planned maintenance amount was developed based on forecasted utilization of the compression equipment. The adjusted cost was determined based on utilization hours, maintenance frequency, and scope of work (determined by the MINO tool). The cost of the planned work depends on the type of unit being overhauled, the scope of work being undertaken, and the historical cost of the work.

Q: How was the adjusted unplanned maintenance amount determined?

A: This amount was developed based on historical statistics relating to accessory and equipment failure costs. A weighted average formula is used to calculate the number and cost of unplanned events over a certain period (typically five years), weighted towards the most recent years. This approach is used to arrive at an appropriate amount to be used in the Test Period for the unplanned portion of the program.

Q: Why do costs in this account increase significantly over the Base Period?

A: The costs going forward increase significantly over the base period partially due to the fact that 2005 was a low year where little maintenance was being performed by GTN. Spending is somewhat cyclical, depending on the number of planned maintenance events in a given year. TransCanada also has a more rigorous approach to planned maintenance intervals, so the frequency of overhauls being performed has increased going forward, thus increasing the planned costs. When the maintenance intervals provided by tools such as MINO are adhered to, the result is that we have fewer equipment failures. Equipment failures tend to be uncontrolled and sometimes catastrophic, resulting in secondary damages to equipment and therefore higher costs. By maintaining these intervals, we have fewer failures and lower overall costs

Q: Does this conclude your testimony?

A: Yes, it does.