UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dominion Cove Point LNG, LP) **Docket No. RP06-_______**

PREPARED DIRECT TESTIMONY
OF
JAMES S. TAYLOR
ON BEHALF OF
DOMINION COVE POINT

Q. Please state your name and address.

A. My name is James S. Taylor. My business address is 1155 15TH Street, N.W, Suite 400, Washington, D.C. 20005.

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

A. I am an independent consulting engineer associated with the firm of Brown, Williams, Moorhead & Quinn, Inc.

Q. On whose behalf are you presenting testimony in this proceeding?

A. I am presenting testimony on behalf of Dominion Cove Point LNG, LP ("DCP").

Q. Please briefly describe your educational background and experience.

A. I received a Bachelor of Science degree in Civil Engineering from Virginia Polytechnic Institute in 1970 and a Master of Science degree in Public Works Engineering from George Washington University in 1981. I have also completed four courses in depreciation sponsored by Depreciation Programs, Inc.; a course in basic petroleum engineering and a course in natural gas reservoir engineering both sponsored by Oil and Gas Consultants International, Inc.; a course in natural gas underground storage sponsored by Continuing Engineering Education Corp.; and a course in construction cost estimating and bidding sponsored by George Mason University. I also attended a 3-day seminar in Houston, Texas in 2002 that focused on the heightened interest in shipping LNG to the United States to meet anticipated increased natural gas demand.

From March 1979 through September 2003 I was employed by the Federal Energy Regulatory Commission initially as a civil engineer and later as a regulatory gas utility specialist. My responsibilities with the Commission included conducting depreciation studies and various types of salvage analyses (including final abandonment studies) of electric, gas pipeline, and oil pipeline companies. I also conducted various types of gas transmission and underground storage cost allocation studies. Prior to my employment with the Commission, I was employed from June 1970 through February 1979 by the District of Columbia Department of Transportation as a highway engineer in the Bureau of Design, Engineering, and Research. During that period of time I was engaged in highway design which involved the preparation of plans, specifications, and construction cost estimates.

Q. Please describe your professional background.

A. I am a registered professional engineer in the Commonwealth of Virginia and a member of the American Society of Civil Engineers. I am also a member of the Society of Depreciation Professionals.

Q. Have you previously provided testimony in proceedings before the Federal Energy Regulatory Commission?

A. Yes, I provided testimony in the following rate case dockets:

RP83-35-000, et al., Texas Eastern Transmission Corporation;
RP85-37-000, High Island Offshore System;
RP85-150-000, Natural Gas Pipeline Company of America;
IS85-9-000, Kuparuk Transportation Company;
RP87-62-000, Pacific Gas Transmission Company;
RP88-120-000, Chandeleur Pipe Line Company;
RP88-93-000, et al., Questar Pipeline Company;
RP89-58-000, Bear Creek Storage Company;
RP89-86-000, Chandeleur Pipe Line Company;
RP90-139-000, et al., Southern Natural Gas Company;
RP91-212-000, Stingray Pipeline Company;
RP92-134-000, Southern Natural Gas Company;
RP92-236-000, et al., Williston Basin Interstate Pipeline Company;
RP93-15-000, Southern Natural Gas Company;
RP93-61-000, U-T Offshore System;
RP93-4-000, Mississippi River Transmission Corporation;
RP93-36-000, Natural Gas Pipeline Company of America;
RP94-149-000, et al., Pacific Gas Transmission Company;
IS94-23-000, et al., Gaviota Terminal Company;
IS94-22-000, et al., Chevron Pipe Line Company;
RP94-43-000, ANR Pipeline Company;
IS94-32-000, Chevron Pipe Line Company;
RP95-112-000, Tennessee Gas Pipeline Company;
RP95-409-000, Northwest Pipeline Corporation;
IS95-35-000, Gaviota Terminal Company;
RP95-167-000, Sea Robin Pipeline Company;
RP95-408-000, Columbia Gas Transmission Corporation;
RP96-190-000, Colorado Interstate Gas Company;
RP96-290-000, Michigan Gas Storage Company.
RP97-373-000, Koch Gateway Pipeline Company;
RP98-203-000, Northern Natural Gas Company;
RP98-117-000, KN Interstate Gas Transmission Company;
RP99-166-000, Stingray Pipeline Company;
RP99-485-000, Kansas Pipeline Company;
RP00-107-000, Williston Basin Interstate Pipeline Company;
RP01-245-000, et al., Transcontinental Gas Pipe Line Corporation;
RP02-13-000, Portland Natural Gas Transmission System;
RP03-162-000, Trailblazer Pipeline Company; and
RP03-221-000, High Island Offshore System, L.L.C.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is directed toward the determination of the estimated final abandonment costs in March 2006 dollars of DCP's LNG terminal and its 87.8-mile transmission pipeline and associated plant when these facilities reach the end of their service life. My testimony also discusses my determination of the Cove Point LNG terminal final abandonment estimate by vintage in March 2006 dollars.

Q. What conclusions have you reached with respect to the final abandonment costs of these facilities?

A. I estimate that it will cost $38,235,559 in March 2006 dollars for the final abandonment of DCP's LNG terminal and $12,600,480 in March 2006 dollars for the final abandonment of DCP's transmission facilities. Detailed final abandonment cost estimates for DCP's LNG terminal and transmission facilities in March 2006 dollars are included in Exhibit Nos. DCP-27 and DCP-29, respectively. My final abandonment cost estimate in March 2006 dollars for DCP's LNG terminal is also broken out by vintage as shown in Exhibit No. DCP-28. I provided my final abandonment cost estimates in March 2006 dollars for DCP's LNG terminal and its transmission facilities to DCP Witness Edward H. Feinstein for his use in this proceeding.

Q. Mr. Taylor, before you proceed any further, would you explain what is meant by the term "final abandonment"?

A. My use of the term "final abandonment" refers to the retirement of a property at the end of its service life and is equivalent to the term "final closure". The final abandonment of an asset may be accomplished by selling the asset in-place, abandoning the asset in-place, removing and selling the asset, removing and disposing of the asset, or removing and storing the asset in a warehouse for future reuse. There are costs associated with the retirement to ensure that the property is safely and legally removed from service. The final abandonment cost is the difference between the revenues realized from the sale or disposal of the asset (referred to as the gross salvage) and the costs associated with the retirement (referred to as the cost of removal).

Cove Point LNG Terminal Final Abandonment Estimate

Q. Please briefly describe DCP's LNG terminal facilities.

A. The Cove Point LNG terminal is located in Calvert County, Maryland on the shore of the Chesapeake Bay. It originally entered service under a previous owner in 1978 and consists of an offshore terminal, an onshore LNG tank farm, a 1.21-mile tunnel under the Chesapeake Bay that connects the offshore terminal with the LNG tank farm, and all equipment, piping, structures, etc. necessary for facility operation. It is my understanding that the Cove Point LNG terminal is one of the largest facilities of its type in the United States and its offshore terminal is capable of berthing two large LNG tankers at the same time. The onshore tank farm consists of four 375,000 barrel LNG tanks constructed in the 1970's and a recently constructed 850,000 barrel LNG tank that entered service in 2004. Major equipment necessary for operating the LNG terminal include a power generation facility consisting of three 8.45 megawatt gas turbine generators; ten 100 million cu. ft./day vaporizers; three four-stage boil-off compressors; three first-stage send-out pumps; ten second-stage send out pumps; boil-off and fuel gas heaters; two fire water tanks; fire water pumps; emergency generators; and an air separation unit. A liquefaction plant is also on site and capable of liquefying pipeline gas for storage in the LNG tanks but it has not been used since LNG imports recommenced in 2003. The 1.21-mile tunnel mentioned above houses all piping between the offshore and onshore facilities.

Q. Did you personally visit the Cove Point LNG terminal prior to commencing your final abandonment estimate?

A. Yes. I toured both the offshore and onshore portions of the LNG terminal on March 8-9, 2006. During my site visit, I took numerous photographs and discussed LNG terminal operations and final abandonment considerations with DCP officials.

Q. What is the basis for the scope of work in your Cove Point LNG terminal final abandonment estimate?

A. During my visit to the LNG terminal, I received a copy of a December 1993 abandonment estimate for the Cove Point LNG terminal prepared by Mustang Engineering, Inc. for Cove Point's owner at that time. Based on my discussions with company officials, my site inspection of the LNG facilities, and a careful review of various LNG terminal plans, I accepted the list of plant and equipment included in the Mustang estimate as an accurate representation of plant and equipment in-service at the time of the 1993 estimate and used this prior estimate as an initial baseline for my current estimate. Because major equipment has been added to the terminal since 1993, including the $21,909,701 liquefaction plant (1995), the $15,426,681 air separation unit (2003), a $1,911,194 metering facility (2003), and the $41,460,408 LNG storage tank mentioned above, I expanded the scope of work in the 1993 estimate to account for these more recent plant additions.

I also reviewed the agreement between DCP, the Sierra Club and the Maryland Conservation Council dated March 1, 2005. This document sets the legal requirement for what must be done to meet environmental standards for the onshore portion of DCP's LNG terminal when it undergoes final abandonment. When all conditions in this document have been met by

DCP, DCP is obligated to tender title to the Cove Point site first to the State of Maryland and then, if necessary, to conservation groups.

Q. Please briefly discuss the legal requirements for the final abandonment of the onshore portion of the Cove Point LNG terminal listed in the DCP/Sierra Club, et al. agreement.

A. The agreement between DCP and the Sierra Club, et al. lists several conditions that DCP must implement before it may tender the terminal property to a third party. (1) All above-ground structures such as buildings, tanks, pipes, etc will be either removed from the LNG terminal or buried on site. (2) Hazardous waste will be disposed of in accordance with applicable legal requirements. (3) All below-ground structures will be abandoned in-place but filled with suitable material to prevent subsidence. (4) All below-ground pipelines will be abandoned in-place. (5) All roadways and pavement will be broken up and either removed or buried on the premises. (6) All debris and nonsalvagable material will be buried on-site or removed from the premises. (7) After all demolition and salvage are completed, the LNG terminal site will be graded using existing fill from the tank dikes and elsewhere within the disturbed area and seeded with grass. The agreement does allow certain above ground facilities to remain in place such as the main earthen dam, the secondary earthen dam, the dam spillways, and all other sedimentation control impoundments and earthen dams existing within the LNG terminal site.

Q. Since the DCP/Sierra Club, et al. agreement is silent with respect to the offshore terminal, what legal obligations govern the abandonment of the offshore terminal?

A. As stated in the agreement, all below ground onshore structures will be abandoned in-place but filled with suitable material to prevent subsidence. This includes the onshore access shaft to the tunnel leading to the offshore terminal. In addition, based on the agreement all roadways and pavement will be broken up and either removed or buried on the premises and a small onshore boat dock will be demolished. With the onshore tunnel access shaft closed, all roadways broken up and disposed of and the small onshore boat dock demolished, there would be no access to the offshore terminal in the Chesapeake Bay except by boat from another onshore location. In addition, because of its location, the offshore terminal would be a hazard to shipping and would require proper marking and lighting based on U.S. Coast Guard requirements to prevent collisions with ships. These expenditures would serve no useful purpose. Thus, the offshore facility will be removed when the onshore portion of the terminal is demolished.

Q. Please describe your final abandonment estimate for the Cove Point LNG terminal.

A. As shown in Exhibit No. DCP-27, my LNG terminal final abandonment estimate consists of seven sections. The first two sections, Project Management and Contract Expense, reflect the estimated costs that DCP will experience planning for the retirement and managing the actual retirement in a safe and expeditious manner. The third section, Property Tax, takes into the consideration that even after Cove Point's LNG terminal is removed from service; DCP must continue to pay property taxes on this facility until the property is deeded over to a third party. The fourth section, Onshore Demolition Work, is a 12-part breakout of costs that will be experienced during the demolition of the LNG tank farm and associated onshore plant. The fifth section, Offshore Demolition Work, is a three-phase breakout of the work required to demolish the offshore terminal. The sixth section, Salvage, acknowledges the gross salvage value of DCP's LNG plant at the time of final abandonment. Finally, the seventh section, Contingency, reflects a 10 percent contingency that is calculated based on sections I, II, IV, and V of my estimate to allow for expenses that will occur but that are not specifically included as line items in the estimate.

Q. What is the major cost component of onshore demolition work?

A. The cost to purge, clean, and dismantle the five LNG tanks is by far the biggest line item. DCP's LNG tanks have an inner and outer wall separated by approximately three-feet of perlite insulation.

Q. How did you estimate the cost to demolish the five LNG tanks?

A. First, I reviewed a December 2004 demolition estimate of $7,500,000 for the recently constructed 850,000 bbl tank (also referred to as "Tank E"). This demolition estimate was submitted by CB&I, the builder of Tank E, to Dominion Transmission, Inc., an interstate pipeline affiliate of DCP. The line items in this estimate are shown in Exhibit No. DCP-27, page 30. After my initial review, I accepted CB&I's estimated purging and cleaning costs, construction labor costs, insulation removal costs, and electrical costs. These line items total $4,850,000. I also included an allowance of $330,000 for knocking down the reinforced earth retaining walls and grading earthen dikes pertaining to Tank E in the site work portion of my onshore demolition estimate. Management, engineering, environmental work, contingency, and salvage for Tank E demolition are included elsewhere in my estimate.

I then used my adjusted demolition estimate of $4,850,000 for Tank E to develop an estimate to demolish the four smaller 375,000 bbl LNG tanks in the tank farm. To do this I employed the Six-Tenths sizing model used in the chemical industry for making preliminary estimates of the cost to construct chemical processing equipment that is similar in design but varies in size from chemical processing equipment whose size and cost are known. The equation for the Six-Tenths sizing model follows:

$$\text{cost}_1/\text{cost}_2 = (\text{size}_1/\text{size}_2)^{0.6}$$

As shown in Exhibit No. DCP-27, page 29, using the Six-Tenths sizing model, I calculated the estimated cost to purge, clean, and demolish a smaller 375,000 bbl tank to be $2,968,309. As with Tank E, the cost to knock down retaining walls and grade the dikes of the four smaller tanks is included in the site work portion of the onshore demolition estimate and management, engineering, environmental work, contingency, and salvage are included elsewhere in my estimate. My total estimated direct cost to purge, clean, and dismantle the five LNG tanks is $16,723,237.

Q. How did you estimate the cost to dismantle the existing air separation unit, liquefaction plant, and new metering facility referred to above?

A. I estimated the cost to dismantle the air separation unit ("ASU") to be $366,383 which is 20 percent of the cost to install the facility of $1,831,916. My estimate was based on discussions with company officials, a review of a company estimate to dismantle the ASU, a plot plan of the ASU, and my personal inspection of the ASU. Because the liquefaction plant is roughly equivalent in size and function to the ASU, I estimated the cost to dismantle the liquefaction plant to be the same as the cost to dismantle the ASU or $366,383. Finally, my estimated cost to demolish the new meter station is $67,411 which is equivalent to the cost to demolish DCP's OX M&R station because I consider these facilities to be roughly equivalent. The OX M&R station is a small M&R facility located in Fairfax County, Virginia. The cost to demolish the OX M&R station is included in my demolition estimate of DCP's transmission facilities.

Q. How did you estimate the final abandonment costs for onshore LNG plant in-service prior to 1994 excluding the four 375,000 bbl LNG tanks?

A. First, after a careful review of all available material, I accepted quantities in the 1993 Mustang estimate for onshore LNG plant with the exception of asbestos siding removal quantities. During my LNG site inspection discussed earlier, I was advised by DCP officials that asbestos siding was removed from the generator building after 1993 and I reduced the scope of demolition work by eliminating this quantity from my estimate. I then selected unit costs in current dollars and applied them to pre-1994 LNG terminal quantities to estimate the direct cost to terminally abandon items in-service prior to 1994. My unit costs are based on current information in construction publications, company provided information on asbestos siding removal costs, and unit costs in the Mustang estimate escalated to March 2006 dollars using Engineering News Record (ENR) construction cost indices.

Q. Please describe the basis for your offshore LNG terminal demolition estimate.

A. First, as mentioned above, I inspected the offshore LNG terminal in March 2006 at which time I took photographs of various offshore terminal components. Second, I reviewed plans of the offshore LNG terminal. Third, I reviewed Mustang's demolition estimate for the offshore terminal. Fourth, I reviewed the well-known reference book, <u>Cost Estimating Manual for Pipelines and Marine Structures</u>, by John S. Page. Fifth, I reviewed a recent technical paper that describes the decommissioning of offshore platforms using abrasive cutters. After reviewing the above material, I accepted Mustang's proposed three-phase demolition approach because I believe it is the most efficient way to retire the offshore LNG terminal.

During Phase I, crews operating on the deck of the offshore LNG terminal would remove pipe insulation, pipe, and equipment. The removed pipe insulation, pipe, and equipment would be loaded onto material barges using a 50-ton derrick barge and transported to Baltimore for salvage. During Phase II, a 250-ton derrick barge would lift the pipe trestles and roadways onto material barges for disposal at sea. At the same time a 100-ton derrick barge would lift walkways, deck platform material broken up by a concrete demolition crew working on the offshore terminal deck, and mooring dolphin caps onto material barges for disposal at sea. During Phase III, pile caps would be cut using abrasive cutting equipment. After pile caps are removed, steel and concrete piles would be cut using abrasive cutting equipment and lifted onto material barges for disposal by a 100-ton derrick barge. During Phase III a 250-ton derrick barge would be used to lift four sections of the offshore access shaft to the tunnel after it has been cut with abrasive cutting equipment, and place them onto a material barge. Finally, a sonar scan of the site would be taken and leftover debris removed from the bottom of the Bay using a 50-ton derrick barge spread.

Q. What is the major cost component of offshore demolition work?

A. The major cost component of offshore demolition work is the cost of derrick barge spreads required for cutting, lifting, and transporting demolished material to salvage yards or to designated burial sites at sea. Offshore demolition is largely a cutting operation. Derrick barge spreads are necessary to assist with the cutting operation. Once material is cut, it can then be lifted onto material barges and towed to salvage yards or designated burial sites by tugs. Because of the large number of piles, road panels, trestles, mooring dolphins, breasting dolphins, walkways, and platforms that make up the offshore terminal, I believe that smaller, relatively inexpensive barge spreads, would be used to accomplish the offshore demolition. It would be wasteful, in my opinion, to employ large derrick barge spreads with high day rates only to have them continuously repositioned to accomplish relatively minor lifts or to have them standby idle due to weather delays. The offshore demolition project could take a year to complete. Sizing equipment correctly is a very important prerequisite if demolition costs are to be kept to a minimum.

Q. What size derrick barge spreads did you include in your estimate to demolish the offshore terminal?

A. As described above, I included barge spreads with 50-ton, 100-ton, and 250-ton derrick barges in my offshore demolition estimate. The larger 250-ton derrick barge would be used to accomplish heavier lifts such as the estimated four lifts required to remove the offshore access shaft to the tunnel connecting the offshore terminal with the onshore LNG tank farm.

Q. What is the basis for your derrick barge rates?

A. I obtained a quote for current derrick barge spread rates from a local contractor who performs work in the Chesapeake Bay area and also reviewed derrick barge rates in the Mustang estimate. After my review of these rates, I selected the derrick barge spread rates shown in Exhibit No. DCP-27, page 32.

Q. How did you determine the day rates for various crews performing demolition work on the deck of the offshore terminal?

A. I used 2004 labor and equipment rates of a local Chesapeake Bay contractor and escalated these rates to the March 2006 price level using ENR construction cost indices. I estimated labor and equipment spreads for each spread based on a review of the Mustang estimate and on my own experience and judgment. Please refer to Exhibit No. DCP-27, pages 31-32 for derivation of day rates for crews working on the offshore terminal deck.

Q. Are environmental costs included in your Cove Point LNG terminal estimate?

A. Yes. The Project Management and the Contract Expense portions of my estimate include provisions for preparing an environmental assessment in conjunction with DCP's FERC abandonment application, conducting tests for hazardous materials, and monitoring final abandonment activities. My estimate also includes direct costs to remove asbestos siding. The DCP/Sierra Club, et al. agreement requires that the owner shall dispose of all hazardous materials in accordance with applicable federal and state codes.

Q. Did you consider salvage in your Cove Point LNG terminal estimate?

A. Yes. As shown in Exhibit No. DCP-27, pages 25-28, I allowed salvage value for equipment and valves equal to the direct cost to remove the equipment and valves. For material scrap value, I allowed $120 per ton for carbon steel scrap, $1,200 per ton for stainless steel scrap, $1,200 per ton for aluminum scrap, and $1 per pound for insulated electrical cable. In addition, I implicitly considered salvage in my estimate for items such as asphalt rubble, concrete rubble, and miscellaneous steel building material because I included no disposal costs for these materials. I believe recyclers would accept these materials with no charge to the demolition contractor.

Q. Mr. Taylor, does your LNG terminal final abandonment estimate reasonably reflect the costs to retire this facility?

A. Yes. I believe my estimate is a realistic assessment of what it would cost to retire a facility of this size and complexity.

DCP Transmission Final Abandonment Estimate

Q. Please briefly describe DCP's transmission facilities.

A. DCP's transmission facilities extend from the Cove Point terminal in Calvert County, Maryland to its Pleasant Valley compressor station near Centerville, Virginia and then on to its westernmost terminus at the Loudon compressor station in Loudon County, Virginia. The major DCP transmission pipeline, TL-522, is a 36-inch diameter, 87.8-mile transmission pipeline that extends from the Cove Point terminal to the Loudon compressor station. TL-522 is bi-directional and has several receipt and delivery points. DCP also has four shorter pipelines including TL-523, a 36-inch diameter 2.1-mile pipeline that connects its Pleasant Valley compressor station near Centerville, Virginia with Transcontinental Gas Pipe Line Corporation. DCP has interconnections at its Loudon Compressor station with Columbia Gas Transmission Corporation and Dominion Transmission, Inc. The Pleasant Valley compressor station was constructed at a cost of $14,816,056 and consists of two compressor units totaling 6,900 hp. DCP's Loudon compressor station was constructed at a cost of $26,538,093 and consists of three compressor units totaling 11,840 hp. DCP has three M&R stations, the Loudon, Pleasant Valley, and OX stations. The Loudon and Pleasant Valley M&R stations were recently reconfigured to accommodate the new compressor stations.

Q. Did you personally visit DCP's transmission facilities while you were conducting your final abandonment estimate?

A. Yes. I visited DCP's Loudon and Pleasant Valley compressor and M&R stations on April 6, 2006. During my visit to the facilities mentioned above, I took numerous photographs and discussed pipeline operations with Dominion Transmission, Inc.'s pipeline superintendent responsible for operating DCP's transmission facilities.

Q. What is the scope of work included in your DCP transmission final abandonment estimate?

A. I estimated that the work to retire DCP's transmission facilities would include the following tasks:

1. Clean and purge system of hydrocarbons and abandon pipeline in-place;
2. Grout highway and railroad crossings;
3. Grout small stream and river crossings;
4. Remove remote mainline valves;
5. Remove pipeline drips;
6. Remove cathodic protection ground beds;
7. Remove pipeline markers;
8. Demolish the Loudon and Pleasant Valley compressor stations;
9. Demolish the Loudon, Pleasant Valley, and Ox M&R stations.

My estimated scope of work is predicated on using the most economical method of retirement compatible with ROW agreements, environmental considerations, and safety considerations.

Q. Please describe your final abandonment estimate for DCP's transmission facilities.

A. As shown in Exhibit No. DCP-29, my transmission final abandonment estimate consists of six sections. The first two sections, Project Management and Contract Expense, reflect the costs that DCP will experience planning for the retirement and managing the actual retirement project in a safe and expeditious manner. The third section, Property Tax, takes into the consideration that even after DCP's transmission facilities are removed from service, DCP must continue to pay property taxes on these facilities until the properties are deeded over to third parties. The fourth section, Pipeline Retirement, is a breakout of costs by line item that will be experienced during the retirement. The fifth section, Salvage, acknowledges the gross salvage value of DCP's transmission plant at the time of final abandonment. Finally, the sixth section, Contingency, reflects a 10 percent contingency that is calculated based on sections I, II, and IV of the estimate to allow for expenses that will occur but that are not specifically included as line items in my estimate.

Q. Mr. Taylor, did you include environmental costs in your DCP transmission final abandonment estimate?

A. Yes. The Project Management and the Contract Expense portions of my estimate include provisions for preparing an environmental assessment in conjunction with DCP's FERC abandonment application, conducting tests for hazardous materials, and monitoring final abandonment activities. I did not include any provisions in my estimate for handling and disposing of hazardous materials.

Q. Do you anticipate significant right-of-way costs during the transmission final abandonment?

A. Yes. The Contract Expense portion of my estimate includes an allowance for ROW costs estimated to occur during final abandonment. First, ROW easement holders must be notified in writing of the final abandonment. Second, legal documents must be drafted and executed transferring full use of the ROW back to the easement holder. Third, even though my estimate assumes that DCP's pipelines will be abandoned in-place, ROW must still be accessed at highway and railroad crossings, small stream and river crossings, remote valve sites, drips, cathodic protection ground bed sites, compressor stations and M&R stations. Therefore, I included ROW damage payments of $1000 to each of the 448 ROW easement holders to compensate them for loss of access to their property during demolition activities.

Q. What labor rates did you use in your estimate?

A. I used September 2005 union labor rates for Baltimore Maryland and escalated those rates to March 2006 using ENR construction cost indices. I then added a 25 percent factor for labor burden which consists of taxes and insurance that contractors must pay. Social security taxes, state and federal unemployment taxes, and workmen's compensation insurance are included in this cost category. My labor rates are based on a standard 40-hour work week with no consideration given to overtime pay or per diem. Please see Exhibit No. DCP-29, page 60 for a summary of labor rates used in my estimate.

Q. What equipment rates did you use in your estimate?

A. I used the equipment rates listed in the <u>Construction Equipment Ownership and Operating Expense Schedule, Region II</u>, published by the U.S. Army Corps of Engineers, August 2005 and escalated these rates to March 2006 using ENR construction cost indices. Region II includes the States of Maryland and Virginia. Hourly equipment rates are included in this publication for contractor owned and operated equipment working in "average" or "severe" conditions. I assumed "average" operating conditions for my cost estimate based on Appendix C of the schedule entitled "Guide for Selecting Operating Conditions" and upon my knowledge of DCP's transmission facilities. Please see Exhibit No. DCP-29, page 61 for a summary of equipment rates used in my estimate.

Q. Please list the factors used in your estimate to define indirect costs experienced by pipeline demolition contractors.

A. The indirect cost factors used in my estimate for pipeline demolition contractors include a 5 percent factor for mobilization, a 15 percent factor for overhead, and a 10 percent factor for profit. These indirect cost factors are based on my past experience and knowledge of the construction industry. I believe they are a reasonable reflection of the indirect costs a prudent contractor and owner would expect to incur during a pipeline retirement of this scale.

Q. How did you estimate the time for construction crews to carry out specific construction activities in your transmission final abandonment estimate?

A. I relied on my past experience and judgment gained from performing first-hand estimates as a highway engineer and developing and analyzing abandonment estimates of regulated gas pipeline, oil pipeline, and electric companies while working at the Commission.

Q. Why did you include line items in your estimate for grouting highway and railroad crossings?

A. Grouting of highway and railroad crossings is necessary to insure that subsidence of highway pavement and railroad track bed does not occur should the retired 36-inch pipeline corrode and lose its load-bearing capacity. Where pipeline exists within casing at railroad and highway crossings, the pipeline would first be removed and the casing then grouted.

Q. Similarly, why did you include line items in your estimate for grouting small stream and river crossings?

A. Small stream and river crossings are grouted to insure that any residual hydrocarbons on the pipe wall do not enter the stream or river and, also, to increase the mass of the pipe on the stream or river bottom to minimize the possibility of pipe movement. Should the U.S. Army Corps of Engineers believe that an abandoned pipeline would pose a hazard to river traffic; it would most likely mandate removal of the pipeline from the river bed which would be a very expensive and environmentally disruptive undertaking.

Q. Did you consider salvage in your DCP transmission final abandonment estimate?

A. Yes. I included salvage value allowances for compressor station equipment, pipe, valves, and for recovered line pack. For compressor station equipment, I estimated that salvage value would equal the direct cost to remove the equipment. I estimated that salvage value for pipe and valves would be $120 per ton. I estimated line pack salvage based on my assumption that line pack would be recovered until pipeline pressure reaches 200 psig at which point the pipe would be blown-down. Recoverable line pack was priced at $7.31 per Dth which was the spot price of natural gas at Cove Point on April 3, 2006. My line pack calculations are shown in Exhibit No. DCP-29, pages 65-66. I also implicitly considered salvage in my estimate for items such as asphalt rubble, concrete rubble, masonry rubble, steel building material, small tanks, etc, because I included no disposal costs or cleaning costs for these materials. I believe recyclers would accept these materials with no charge to the demolition contractor.

Q. How would you characterize your transmission final abandonment estimate?

A. I believe my transmission final abandonment estimate is conservatively low for a number of reasons. First, my estimate is based upon removing only above-ground facilities and abandoning DCP's transmission pipelines in-place. I believe my estimated costs, based on this scope of work, are significantly lower than if I had assumed complete removal and disposal of the pipeline. Second, labor and equipment costs in my estimate are based on a standard 40-hour work week with no consideration given to overtime or per diem costs. Third, no hazardous waste disposal costs are included in my estimate. Finally, my estimated ROW costs are based on the assumption that ROW easement holders will accept future liability for the pipeline abandoned in-place on their property without additional payment. However, should these ROW easement holders balk at accepting liability for pipeline abandoned in-place on their property, DCP would either have to negotiate payments with these easement holders to absolve DCP of future liability or take steps to remove its transmission pipeline from the ROW. Either way, this would raise the cost of final abandonment considerably.

Q. Mr. Taylor, does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Dominion Cove Point LNG, LP) Docket No. RP06-____-000

AFFIDAVIT OF
JAMES S. TAYLOR

James S. Taylor, being first duly sworn, deposes and says that he is the James S. Taylor whose "Prepared Direct Testimony of James S. Taylor" appears on the proceeding pages; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth herein are true and correct to the best of his knowledge, information, and belief; and that he does adopt the same testimony in this proceeding.

James S. Taylor

Subscribed and sworn before me, a Notary Public, in and for the District of Columbia, this 27 day of June, 2006.

Notary Public
District of Columbia

My Commission expires: Nov. 14, 2007