**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

**MoGas Pipeline LLC** **Docket No. RP09-____**

# PREPARED DIRECT TESTIMONY OF JAMES S. TAYLOR

**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 MoGas Pipeline LLC ("MoGas").

**Q. Are you sponsoring any exhibits in connection with your testimony?**

A. Yes. I have prepared and am sponsoring Exhibit Nos. MGP-65 and MGP-66. I will discuss and explain these exhibits in the course of my testimony.

**Q. Please briefly describe your educational background and professional 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.

From September 2003 through the present, I have been associated with Brown, Williams, Moorhead & Quinn, Inc. From March 1979 through September 2003, I was employed by the Federal Energy Regulatory Commission ("FERC" or "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, I was engaged in highway design which involved the preparation of plans, specifications, and construction cost estimates. Highway construction cost estimates that I prepared were used for contractor bid evaluation purposes.

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 natural gas and oil pipeline rate proceedings:

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;
RP03-221-000, High Island Offshore System, L.L.C.;
RP06-417-000, Dominion Cove Point LNG, L.P.;
RP06-569-000, Transcontinental Gas Pipe Line Corporation;
RP07-34-000, et al., Southwest Gas Storage Company;

RP08-306-000, Portland Natural Gas Transmission System; and
RP08-350-000, Southern Star Central Gas Pipeline, Inc.

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

A. My testimony describes and explains my determination of the estimated final abandonment cost of MoGas' transmission plant.

**Q. What conclusions have you reached with respect to the final abandonment cost of MoGas' transmission plant?**

A. After developing and reviewing the two final abandonment estimate alternatives for MoGas' transmission plant, listed in Table 1 below, I recommend that my Option I estimate of $22,394,544 be adopted in this proceeding. Both of my final abandonment estimate alternatives are in March 2009 dollars.

**Table 1**

**MoGas Pipeline LLC**
**<u>Final Abandonment Estimates</u>**
(March 2009$)

| | |
|---|---|
| Option I - Abandon in-place: | $ 22,394,544 |
| Option II - Remove pipe: | $ 41,834,278 |

I provided my Option I final abandonment estimate to MoGas' witness Mr. 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. "Final abandonment" refers to the retirement of a property at the end of its service life and is equivalent to the term "final closure". There are costs associated with the retirement to ensure that the property is safely and legally removed from service and not a future risk to the public. 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).

**Final Abandonment Estimate**

**Q. Please briefly describe MoGas' transmission facilities.**

A. MoGas is a natural gas transmission system that was authorized to operate as an interstate pipeline system on April 20, 2007. A MoGas' system map is included in Statement O-1, Exhibit No. MGP-53. The majority of MoGas' transmission facilities are located in the State of Missouri with the remainder located in the State of Illinois near Wood River, Illinois. MoGas has an interconnection with Panhandle Eastern Pipe Line Company ("PEPL") at the northwestern end of its system in Pike County, Missouri and an interconnection at the northeastern end of its system with Centerpoint Energy - Mississippi River Transmission Corporation ("MRT") in Madison County, Illinois.

MoGas owns and operates approximately 51 miles of 16-inch mainline; 73 miles of 12-inch mainline; 93 miles of 10-inch mainline; the 17.8-mile, 6-inch Owensville lateral; and the 28-mile, 6-inch Salem lateral. In addition to pipelines, MoGas owns and operates the Curryville compressor station located near its PEPL interconnect; 25 meter and regulation ("M&R") stations; 26 mainline valve sites not associated with M&R stations; and numerous miscellaneous facilities necessary for system operation.

**Q. Describe the scope-of-work upon which your Option I and II estimates are based?**

A. The scope-of-work for each option is described below.

Option I – Abandon in-place:

> Clean and purge pipelines of natural gas, cap, and abandon in-place. Remove all surface facilities and restore the sites. Grout pipelines located at all railroad crossings; at highway crossings where the pipe or casing is greater than 12-inches in diameter; and at large river, large stream, and small stream crossings.

Option II – Remove pipe:

> Clean and purge pipelines of natural gas and remove and salvage all pipelines not located at crossings. Remove all surface facilities and restore the sites. Grout pipelines located at all railroad crossings; at highway crossings where the pipe or casing is greater than 12-inches in diameter; and at large river, large stream, and small stream crossings.

Q. **Mr. Taylor, why did you select Option I for use in this proceeding?**

A. I consider my Option I estimate to be the lower limit for MoGas' final abandonment costs and my Option II estimate to be the upper limit. Due to current uncertainty regarding the eventual scope of work required at the time of final abandonment, I chose Option I to be conservative. However, if future liabilities related to MoGas' pipelines abandoned in-place should occur, there are no provisions in Option I to recover any resulting additional costs.

**Q. Please describe how your Option I and II estimates are organized.**

A. My Option I and II estimates are summarized in Exhibit No. MGP-66, pages 1 and 2, respectively. The estimate for each option contains three sections. The first section, Pipeline Retirement, is a breakout of costs by line item that would be experienced during the final abandonment. The second section, Salvage, acknowledges the estimated gross salvage value of MoGas' transmission plant at the time of final abandonment. The third and final section, Contingency, reflects a 10 percent contingency that is calculated based on Section I of the estimate to allow for miscellaneous expenses that are expected to occur, but not specifically identified and included in line items in the estimate.

**Q. Did you personally inspect various MoGas' transmission facilities while you were preparing your estimates?**

A. Yes. During an April 27-28, 2009 field trip, I inspected numerous MoGas' transmission facilities in the general vicinity of St. Louis, Missouri. Facilities that I inspected included the Curryville compressor station; several M&R stations; two mainline valve sites; the existing PEPL interconnect; and various railroad, highway, river, and small stream crossings. During my field trip, I took numerous photographs and observed the operation of MoGas' facilities. Although the new PEPL and Rockies Express Pipeline LLC ("REX") interconnects currently under construction at the Curryville compressor station site were not in-service during the time of my field trip, it is my understanding that construction of these two interconnects will be completed prior to the end of the test period in this proceeding (December 31, 2009).

**Q. What government regulations did you review during the development of your estimates?**

A. I reviewed U.S. Department of Transportation ("U.S. DOT") minimum safety regulations (49 CFR § 192.727). U.S. DOT minimum safety regulations require pipelines abandoned in-place to be disconnected from all sources and supplies of gas; purged of gas; and the pipelines sealed at the ends. I also reviewed U.S. Department of the Army regulations that give the U.S. Army Corps of Engineers ("U.S. Army COE") the authority to clear wrecks and other obstructions within the navigable waters of the United States (33 CFR Part 245) and issue permits for the discharge of dredged or fill material into the waters of the United States (33 CFR Part 323). At the state level, I reviewed Missouri Department of Transportation regulations (7 CSR 10-3.010) pertaining to the location and relocation of utility facilities on state highways.

**Q. What other information did you rely upon during the development of your estimates?**

A. First, I familiarized myself with MoGas' maps, alignment sheets, and documentation describing and depicting the system. Second, I relied on various design drawings and photographs of MoGas' facilities. Third, I relied on the reference book, Cost Estimating Manual for Pipelines and Marine Structures, by John S. Page. Fourth, I relied on the Caterpillar Performance Handbook, Edition 34, published by Caterpillar Inc. Fifth, I relied on the Basics of Demolition Estimating, by Build Central, Inc. Sixth, I relied on the "2009 National Heavy Construction Estimator" by Craftsman Book Company. Finally, in addition to the information listed above, I also relied on equipment cost information published by the U.S. Army COE, and labor rates and construction cost information in various issues of "Engineering News Record" ("ENR").

**Q. Did you develop a detailed set of parameters upon which your final abandonment estimates are based?**

A. Yes. Exhibit No. MGP-65 includes a list of 21 parameters that describe the procedures and work necessary to retire MoGas' transmission facilities.

**Q. What tasks did you include in your two final abandonment estimates?**

A. Options I and II include the following tasks:

1. Clean and purge pipelines;
2. Pipe removal; (Not applicable to Option I)
3. Pipe handling and storage; (Not applicable to Option I)
4. Grout railroad crossings;

5. Grout highway crossings;
6. Remove vent pipes;
7. Grout large river crossings (Mississippi and Missouri rivers);
8. Grout large stream crossings;
9. Grout small stream crossings;
10. Remove remote valve sites;
11. Remove cathodic protection facilities;
12. Remove pipeline markers; (Included in Pipe removal in Option II)
13. Remove M&R facilities;
14. Remove Curryville compressor station.

My estimated tasks are predicated on using the most economical method of retirement compatible with MoGas' right-of-way ("ROW") agreements, environmental considerations, U.S. DOT regulations pertaining to minimum safety requirements, and U.S. Army COE regulations pertaining to navigable waters and dredge and fill permits.

**Q. Please explain what steps MoGas would take to clean and purge its pipelines.**

A. First, MoGas would pig its pipeline system using scraper pigs to remove any potential accumulation of hydrocarbons in the pipelines. I estimated that MoGas would conduct two separate pig runs to insure that its pipelines are free of any hydrocarbon accumulations. There is no allowance in my estimates for any more extensive pipeline cleaning. Second, after the last scheduled delivery to its shippers, MoGas would isolate its pipelines from all receipt points and "bleed-off" and salvage its line pack at selected delivery points until an abandonment pressure of approximately 200 psig is reached. Third, MoGas would isolate its pipelines from all delivery points and then blow-down or flare the remaining line pack in its pipelines at valve sites. At this point, MoGas' pipelines would be filled with natural gas at atmospheric pressure. Fourth and finally, using evacuation equipment, MoGas would displace the remaining natural gas in its pipelines with air at atmospheric pressure.

**Q. How did you develop the cost to remove pipelines in Option II?**

A. As shown in Exhibit No. MGP-66, pages 4-7, I first developed the equipment and labor spread necessary to remove a 16” diameter pipeline. Then, I calculated the cost to remove the 16” pipeline on a per-foot basis. Finally, I used my estimated cost per-foot to remove a 16” pipeline to estimate the cost per-foot to remove pipelines smaller than a 16” pipeline. To do this I employed the Six-Tenths sizing model. The equation for the Six-Tenths sizing model follows:

$$cost_1/cost_2 = (size_1/size_2)^{0.6}$$

The Six-Tenths sizing model is typically used in the chemical industry for making pro-rata 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 chemical industry and gas transmission industry employ similar piping and equipment. The Six-Tenths sizing model is useful because it takes into consideration the economies of scale that occur during construction (or demolition) when the size of tanks, pipe, or equipment differ.

**Q. Mr. Taylor, why did you include line items in each option for grouting pipelines at all railroad crossings?**

A. Generally speaking, grout consisting of a mixture of Portland cement and water is used to fill underground cavities. Grouting of pipelines at railroad crossings is necessary to insure that subsidence of railroad track bed does not occur should the retired pipeline corrode and lose its load-bearing capacity. Where pipeline exists within a casing at railroad crossings, the pipeline would first be removed and the casing then grouted. Each of my options includes line items for grouting cased and uncased pipelines at all railroad crossings.

**Q. Similarly, why did you include line items in each option for grouting pipelines and casings that exceed 12-inches in diameter at paved highway and road crossings?**

A. I estimated that grouting pipelines and casings at paved highway and road crossings, where a pipeline or casing is greater than 12 inches in diameter, would minimize the danger of any significant voids forming in the roadbeds due to pipeline corrosion and collapse at highway crossings. Where a pipeline is less than 12-inches in diameter but resides within a casing greater than 12-inches in diameter, the pipeline would first be removed and the casing then grouted. My reduction in the number of paved highway and road crossings that require grouting takes into consideration instances where highway officials may allow small-diameter pipe and casing to be retired in-place without grouting.

**Q. Why did you include line items in each option for grouting pipelines at large river, large stream, and small stream crossings?**

A. Should the U.S. Army COE believe that an abandoned MoGas' pipeline would pose a hazard to navigation on any water body, it would most likely mandate removal of the pipeline. Such removal would be an environmentally disruptive and expensive undertaking. Grouting pipelines at large river, large stream, and small stream crossings would increase the mass of the pipe, minimize the possibility of pipe movement, and, thus, reduce or eliminate the need to remove pipe at these water crossings. Grouting would also insure that any residual hydrocarbons on the pipe wall do not enter the water body.

**Q. How did you estimate the number of large stream crossings where grouting is required?**

A. MoGas' alignment sheets indicated that in addition to the Mississippi River and Missouri River, six smaller rivers are crossed by MoGas' pipelines. I included these six smaller rivers in the "large stream" category that require grouting. These six smaller rivers are listed in the general workpapers portion of my final abandonment estimate.

**Q. Similarly, how did you estimate the number of small stream crossings where grouting is required?**

A. My review of MoGas' alignment sheets indicated that grouting would be required at 107 small stream crossings that I considered to be "significant". I selected 95 of these small stream crossings because, unlike minor streams and ditches, they were specifically identified on MoGas' alignment sheet profile drawings. The remaining 12 small streams crossings were selected based on my review of the Salem lateral alignment sheet plan drawings because the Salem lateral alignment sheets did not include similarly-detailed profile drawings.

**Q. Does your inclusion of grouting costs at large river, large stream, and small stream crossings take into consideration a variety of potential final abandonment costs at these locations?**

A. Yes. At large river, large stream, and small stream crossings, where scouring would most likely expose MoGas' pipelines, MoGas may reasonably decide to remove its pipelines to avoid future liability. Inclusion in my estimates of the cost to grout pipelines at these water crossings takes into consideration a variety of potential final abandonment costs at these locations that MoGas will likely face when its pipelines reach the end of their service lives.

**Q. Mr. Taylor, what is the basis for your Curryville compressor station removal estimate?**

A. My estimate reflects the tasks, time, and equipment and labor spread necessary to retire the Curryville compressor station. First, miscellaneous material and fencing would be removed to make the site ready for demolition work. Second, valves, blow-downs, and yard piping would be removed. This work involves excavation, cutting, lifting, and hauling. Third, station equipment would be disconnected, lifted, and stockpiled for transportation to a salvage yard by a salvage contractor. Fourth, buildings would be demolished and material stockpiled for transportation by a salvage contractor. Fifth, compressor blocks and concrete slabs would be broken up and removed to three feet below ground surface. This work also involves excavation, cutting, lifting, and hauling. Finally, the site would be restored by backfilling, grading, placing top soil, seeding, and fertilizing.

**Q. Do the line items in each of your options include site restoration costs?**

A. Yes. Estimated costs to restore disturbed areas to pre-existing conditions are included in pipeline contractor costs in each demolition line item.

**Q. What labor rates did you use in each option?**

A. I used September 2008 union labor rates for Kansas City, Missouri. I adjusted these rates to reflect deflation that occurred between September 2008 and March 2009. I then added a 25 percent factor for labor overhead, which consists of taxes and insurance that contractors must pay. Social Security taxes, state and federal unemployment taxes, and workers compensation insurance are included in this cost category. I also included an adjustment factor of 1.17 for overtime pay in each labor rate. Exhibit No. MGP-66, page 66 includes a summary of the labor rates that I used in each option.

**Q. Did you include a per diem allowance in each option?**

A. Yes. I included a per diem allowance of $90 per day in each option. I chose this per diem allowance after reviewing Missouri per diem rates in the United States Internal Revenue Service document: “Publication 1542 Per Diem Rates” (Rev. October 2008). My per diem allowance is based on the assumption that two pipeline contractor demolition workers would share one room (1/2 of the maximum lodging allowance) and includes a full allowance for meals and incidental expenses for each worker. Typically, contractors must pay per diem allowances to their employees to compensate them for working in areas far from their home base.

**Q. What equipment rates did you use in each option?**

A. I used the equipment rates listed in the Construction Equipment Ownership and Operating Expense Schedule, Region V, published by the U.S. Army COE, July 2007 (Amended September 2007) and escalated these rates to March 2009 using ENR construction cost indices. MoGas’ transmission facilities are located within Region V which includes several states including Missouri and the western portion of Illinois. 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 estimates, based on Appendix C of this publication entitled “Guide for Selecting Operating Conditions” and upon my knowledge of MoGas’ transmission facilities. Exhibit No. MGP-66, page 67 includes a summary of the equipment rates that I used in each option.

**Q. What factors did you employ in each option to reflect the indirect costs incurred by pipeline contractors?**

A. The indirect cost factors used in each option for pipeline 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 determine the pipeline contractor equipment and labor spread and time needed to carry out specific demolition activities in each option?**

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.

**Q. Mr. Taylor, did you include environmental costs in each option?**

A. Yes. Typically, each pipeline retirement line item contains a factor, based on five percent of pipeline contractor costs, to allow for the costs of monitoring the final abandonment activity, conducting tests for hazardous materials, and writing reports. In addition, as discussed earlier in my testimony, estimated site restoration costs are included in pipeline contractor costs as required. I did not include any provisions in either option for handling and disposing of hazardous materials.

**Q. Similarly, did you include an allowance for MoGas' inspection costs in each option?**

A. Yes. The Curryville compressor station includes an allowance for MoGas' inspection costs of $1,000 per day and the remaining demolition line items typically include an allowance of $500 per day for MoGas' inspection costs. These allowances include MoGas' labor, per diem, and transportation costs.

**Q. Did you also include an allowance for MoGas' management and overhead costs in each option?**

A. Yes. Each demolition line item also contains a MoGas' management and overhead factor, based on 15 percent of pipeline contractor costs, environmental costs, and pipeline company inspection costs, to allow for the costs to manage and carryout the project. The 15 percent MoGas' management and overhead factor is the same as the management and overhead factor that I used in developing pipeline contractor indirect costs as discussed earlier in my testimony. The 15 percent MoGas' management and overhead factor includes the following cost items: project management, FERC abandonment application, miscellaneous permits, engineering, construction management, ROW, project security, and general and administrative overhead.

**Q. Do you anticipate significant ROW costs during final abandonment?**

A. Yes. First, ROW easement holders must be notified in writing of the final abandonment. Second, legal documents must be drafted and executed to transfer full use of the ROW back to the easement holder. Third, MoGas and its contractors must obtain permits to work in the ROW and conduct abandonment activities. ROW notification costs, legal costs, and permit costs described above are included in my 15 percent allowance for MoGas' management and overhead costs in each line item.

In addition to the ROW costs discussed above, pipeline contractor demolition activities during final abandonment work will result in damage payments to affected ROW holders. Due to the potential magnitude of ROW damages when significant quantities of pipe are removed, I included a damage payments allowance of $2 per foot in my Option II line item, "Pipe removal". My damage payments allowance is based on my review of actual ROW damage costs reflected in Commission Docket CP03-43-000, Texas Eastern Transmission, LP., pages 8-10.

**Q. Did you consider salvage in each final abandonment option?**

A. Yes. I included gross salvage value allowances for compressor station equipment, buildings, valves, pipe, and line pack. For compressor station equipment, I estimated that gross salvage would equal the cost of removal. I estimated that gross salvage value for buildings, valves, and pipe would be $125 per ton at the work site, which is approximately 60 percent of the current value of carbon steel scrap at the scrap yard. The reduced salvage value at the work site takes into consideration the cost of preparing the material for shipment to the scrap yard and the cost of transporting the material to the scrap yard.

I estimated line pack gross 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 $3.78 per Dth which was the NYMEX Henry Hub natural gas settlement price at the end of March 2009. My line pack salvage calculations are shown in Exhibit No. MGP-66, page 65. Supporting line pack calculations are shown in Exhibit No. MGP-66, pages 71-72.

**Q. Please comment on the 10 percent contingency used in each option.**

A. I believe my 10 percent contingency is at the low end of the range of contingencies used in similar final abandonment estimates.

**Q. Mr. Taylor, how would you characterize your recommended Option I final abandonment estimate?**

A. I believe my Option I final abandonment estimate is conservative-low. First, Option I is based on removing only above-ground facilities and abandoning MoGas' transmission pipelines in-place. My estimated costs, based on this scope of work, are significantly lower than if I had chosen Option II, which includes estimated costs for removal and disposal of all MoGas' pipelines not located at crossings. Second, no hazardous waste disposal costs are included in Option I. Finally, the estimated ROW costs included in my 15 percent factor for MoGas' management and overhead 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, MoGas would either have to negotiate payments with these easement holders to absolve MoGas of future liability or take steps to remove its transmission pipelines from the ROW. Either way, this would raise the cost of final abandonment considerably.

**Q. Mr. Taylor, does this conclude your prepared direct testimony?**

A. Yes, it does.

**AFFIDAVIT**

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|---|---|---|
| COMMONWEALTH OF VIRGINIA | ) | |
| | ) | ss. |
| COUNTY OF FAIRFAX | ) | |

James S. Taylor, being first duly sworn, deposes and states that he is the James S. Taylor whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of James S. Taylor"; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein 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 Commonwealth of Virginia, County of Fairfax, this 30 day of JUNE, 2009.

Notary Public

REG # 7027746

(SEAL)

My Commission Expires:

JUNE 30, 2010