COMMONWEALTH OF PENNSYLVANIA

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June 10, 2014

Honorable Mark A. Hoyer
Pennsylvania Public Utility Commission
Office of Administrative Law Judge
Suite 220, Piatt Place
301 Fifth Avenue
Pittsburgh, PA 15222

RE: Supplement No. 210 to Tariff Gas Pa.
P.U.C. No. 9 of Columbia Gas of
Pennsylvania, Inc.
Docket No. R-2014-2407345

Dear Judge Hoyer:

Enclosed please find the Office of Consumer Advocate's Direct Testimony of Glenn A. Watkins in the above-referenced proceeding.

Copies have been served as indicated on the enclosed Certificate of Service.

Respectfully Submitted,

Amy E. Hirakis

Amy E. Hirakis
Assistant Consumer Advocate
PA Attorney I.D. # 310094

Enclosures
cc: Rosemary Chiavetta, Secretary (Certificate of Service)
Certificate of Service
*184560

CERTIFICATE OF SERVICE

Re: Supplement No. 210 to Tariff Gas Pa. P.U.C. No. 9 of Columbia Gas of Pennsylvania, Inc.
Docket No. R-2014-2407345

I hereby certify that I have this day served a true copy of the foregoing document, the Office of Consumer Advocate's Direct Testimony of Glenn A. Watkins, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 10th day of June 2014.

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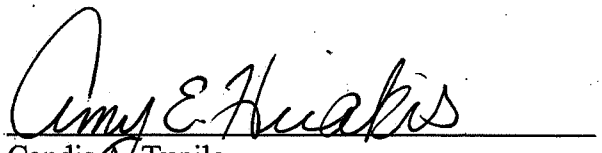

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OCA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2014-2407345
Columbia Gas of Pennsylvania, Inc.	:	

DIRECT TESTIMONY AND EXHIBIT

OF

GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 10, 2014

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, VA 23235.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience is provided in my Schedule GAW-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates, Inc. has been engaged by the Pennsylvania Office of Consumer Advocate ("OCA") to provide information and policy recommendations concerning the expansion and availability of natural gas to unserved areas in Columbia Gas of Pennsylvania's ("Columbia" or "Company") service area and to evaluate the various technical aspects of the Company's proposed New Area Service Pilot Rider ("NAS").

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION ON PREVIOUS OCCASIONS?

A. Yes. In addition to sponsoring testimony on behalf of the OCA in Columbia's last four base rate cases, I have provided testimony before this Commission on numerous occasions concerning natural gas competition, cost allocations, rate design, cost of capital and revenue requirement issues in various natural gas distribution, electric distribution, and water utility proceedings.

II. GENERAL POLICY CONSIDERATIONS

Q. HISTORICALLY, HAS THE AVAILABILITY OF NATURAL GAS TO RESIDENTIAL CONSUMERS BEEN CONSTRAINED IN PENNSYLVANIA OR SPECIFICALLY WITHIN COLUMBIA'S SERVICE TERRITORY?

A. Yes. As has been the case in many parts of the Country including Pennsylvania, the expansion of natural gas distribution infrastructure to serve new customers has been limited due to the simple fact that the economic costs of expanding distribution mains more often than not, has exceeded the perceived benefits realized by natural gas distribution companies ("NGDCs") as well as by potential new natural gas consumers (at least in short-term). In short, the problems or constraints of expanding natural gas distribution infrastructure and thereby making natural gas more available to residential consumers, have been well known and are rather straightforward. However, solutions to these constraints have been much more challenging and typically require regulatory and/or public policy guidance.

Q. PLEASE EXPLAIN AND DISCUSS THE FACTORS THAT HAVE CONSTRAINED THE EXPANSION OF NATURAL GAS INFRASTRUCTURE IN ORDER TO MAKE NATURAL GAS MORE AVAILABLE TO RESIDENTIAL CONSUMERS.

A. While I believe it is safe to say that virtually all policymakers and regulators would agree that from a societal perspective, improvements and expansions of public service infrastructure is a desired objective in general, the economic and societal costs of expanding public service infrastructure must always be considered. In this regard, the

primary factors that have hampered the expansion of natural gas facilities have been two-fold.

First, when the incremental capital costs (revenue requirements) of extending natural gas distribution mains are compared with the expected incremental revenues that will be obtained from adding new customers, a financial shortfall often exists; i.e., the incremental costs of expansion often exceeds the incremental revenues obtained from such expansion. Because natural gas distribution mains have an economic life of 40 to 50 years, virtually all project feasibility analyses consider the expected service life of each expansion and compare the present value of incremental costs to the present value of expected incremental future revenues. For projects in which the present value of costs have exceeded the present value of revenues, the most common practice in the industry has been for NGDCs to require new customers to fund any economic shortfall by making an upfront cash contribution to offset the "uneconomic" portion of the potential expansion project. As a result, potential new customers are often unwilling or unable to make such required upfront cash contributions to the NGDC. For projects evaluated to expand facilities that will primarily serve residential consumers, this economic shortfall of costs exceeding benefits (from the perspective of NGDCs) has been particularly common, and leads us to a second factor that has hampered the expansion of natural gas distribution infrastructure: that being an additional layer of costs that must be borne by prospective residential customers that consider converting to natural gas.

When evaluating the desirability of residential energy users converting to gas, it is most important to understand that the overwhelming use of natural gas by residential consumers is for space heating purposes. Although natural gas can and is used for cooking and hot water heating, this natural gas usage pales in comparison to the requirements for space heating. As such, in virtually every instance in which natural gas expansion feasibility projects are considered, it is imperative that the vast majority of the potential new customers use natural gas for space heating if there is any possibility of the project being economically viable. Notwithstanding any requirements for upfront deposits to the NGDC, this presents a cost benefit question to existing residences (primarily homeowners) of whether the annual fuel savings of converting from electric, oil, or propane heat to natural gas heat will even exceed the equipment cost of converting

to natural gas. In other words, homes with electric, propane, or oil heating may need to replace existing equipment with natural gas furnaces.[1] Furthermore, while it is often the case that from a pure economic perspective that considers the long-term potential savings of converting to natural gas over many years, the reality is, many residential consumers place primary weight on the upfront cash requirements of converting to, and installing, natural gas equipment -- again, notwithstanding any additional deposit requirements imposed by the NGDC.

While the cost of space heating conversions are not an issue for new homes or projects that would serve new developments, the historical reluctance of existing residences to convert to natural gas have been the result of two primary factors. The first being upfront deposit requirements and the second being the costs of converting existing space heating equipment. With regard to new residential developments, a similar problem exists and has been exacerbated since the Great Recession beginning in 2008. That is, historically NGDCs have required residential developers to make either upfront refundable deposits until such new homes are built and customers are using natural gas or provide non-refundable contributions to pay for the expected economic shortfall of expanding natural gas mains into the new development. Whether real or perceived, these upfront cash contributions to make natural gas available have at the very least, increased developers' cash working capital requirements and at most, reduced their profit margins. As such, there has been some reluctance of developers to install natural gas equipment in areas not currently served by a NGDC distribution main.

Q. IF THERE IS A POTENTIAL MAINS EXPANSION PROJECT THAT WAS DEEMED "UNECONOMIC" BY THE NGDC, DOES THIS NECESSARILY MEAN THAT SHAREHOLDERS WILL NOT EARN A FAIR RETURN ON THEIR INVESTMENT IN THIS PROJECT ABSENT ANY CUSTOMER CONTRIBUTIONS?

A. No. Because of the manner and methods in which NGDC distribution rates are established, incremental new investment is simply rolled into the utility's overall rate

[1] This is not as significant for most propane heating customers in that only minor modifications to existing equipment may be required. Additionally, some oil furnaces may be converted to function using natural gas thereby avoiding furnace replacement costs.

base. As such, because distribution rates are traditionally established based on average overall system costs, the rates paid by all ratepayers (existing and new) would conceivably fund any economic shortfall resulting from any particular project. However, due to traditional best business practices considered by NGDCs and regulators, the socialization of uneconomic projects between new and existing customers has historically not been condoned or accepted -- at least within the natural gas industry.

Q. AS PART OF YOUR PRACTICE THROUGHOUT THE COUNTRY, HAVE YOU OBSERVED ANY TRENDS AWAY FROM THE TRADITIONAL VIEWS THAT THE ONLY JUSTIFIABLE EXPANSION PROJECTS ARE THOSE WHICH ARE ECONOMICALLY VIABLE ON A DIRECT UTILITY BASIS?

A. Yes. In the regulatory arena, our focus has historically been very narrow in scope until recently. That is, traditionally, regulatory policy has most often only evaluated the direct costs and benefits of potential utility expansion projects while other societal costs and benefits have largely been ignored. In the last several years, I have seen a transition away from this perspective and have been involved in numerous cases in which broader costs and benefits have also been considered. The vast majority of these cases involved natural gas and water utility industries relating to the expansion of facilities for the overall public benefit, but may not have passed traditional direct utility-only cost benefit analyses. Specific examples include the approval of new surface water treatment facilities in New Jersey and Arizona that were, in and of themselves, not required to meet the demands of their current (or expected short-term future) customers and were "uneconomical" from a direct cost/benefit perspective. However, the long-term benefits of new surface water treatment facilities were deemed to outweigh the lack of a direct economic feasibility analysis.[2] Furthermore, the benefits accruing to the public overall by promoting and advocating the expansion of water utility mains to unserved areas has been recognized in several jurisdictions even though the direct costs of such water utility mains expansions may not pass a traditional economic cost/benefit test. In these instances, it has been common for regulatory agencies to require minimum allowances

[2] These projects were approved to mitigate the continued reliance on ground water supplies that were being depleted.

for the expansion of water mains and service lines and/or establish rules and regulations in which the required rate of return of a potential project is less than the overall allowable total return on rate base.[3]

Perhaps largely stimulated by the widening of the cost differential between natural gas and other energy sources, there has been more and more of a policy movement to make natural gas more available to unserved areas and customers throughout the Country. For example, in Virginia, the State Corporation Commission approved the wide expansion of Virginia Natural Gas' ("VNG") mains to serve entirely new communities in which natural gas was not available. In the VNG case, more than 120 miles of new transmission and distribution mains were approved and allowed in the Company's rate base even though it was known and acknowledged that it would take years, if not decades, of build-out within these new communities before the expansion projects passed traditional utility economic cost/benefit tests.

In Delaware, there is a recent state-wide policy to make natural gas more available. For this State's two largest NGDCs, policies and programs have been implemented to advance and achieve this natural gas expansion policy. For Chesapeake Utilities, Inc. ("Chesapeake"), a surcharge mechanism has been implemented for new customers in unserved areas. The Chesapeake mechanism is very similar in concept to that approved for the UGI Companies in Pennsylvania. For Delmarva Power & Light's ("DP&L") gas operations, the determination of upfront customer requirements has been modified to reflect: (a) an allowance of 150 feet of mains expansion as well as an allowance for 150 feet of new service line at no charge to the customer and (b) the economic Discounted Cash Flow ("DCF") model will be conducted utilizing the utility's cost of debt instead of its overall cost of capital.

[3] For example, 52 Pa. Code § 65.22 requires that for major water utilities, mains extension project feasibility studies and any resulting customer contributions be evaluated at the utility's weighted cost of debt instead of its weighted cost of total capital.

Q. EARLIER YOU INDICATED THAT THERE HAS BEEN A WIDENING OF THE COST DIFFERENTIAL BETWEEN NATURAL GAS AND OTHER ENERGY SOURCES. CAN YOU PROVIDE INFORMATION AS TO THE LEVEL OF THIS COST DIFFERENTIAL AND THE SAVINGS THAT RESIDENTIAL HOUSEHOLDS WITHIN COLUMBIA'S SERVICE AREA CAN EXPECT TO ACHIEVE BY SWITCHING TO NATURAL GAS COMPARED TO OTHER ENERGY SOURCES?

A. Yes. The major substitutes for residential natural gas space heating and usage are electricity, heating oil, and propane. Based on data provided in Columbia's current and pending rate case, the average Columbia residential customer utilizes slightly less than 5 dekatherms ("Dth") of natural gas per month. Using this 5 Dth average as a proxy for the amount of natural gas that potential new customers from unserved or underserved areas will utilize, I have compared the equivalent costs of electricity, heating oil, and propane with the delivered price of natural gas from Columbia. Specifically, for electricity, I have utilized the incremental delivered price (including generation and riders) for PPL Electric's ("PPL") residential customers[4] on a kWh basis, and then converted this to a Dth energy equivalent.[5] The incremental delivered price of electricity is about 11.92¢ per kWh, which translates to a cost of $34.92/Dth.

With respect to heating oil and propane, these commodities are much more seasonally volatile such that I have used recent prices during the heating season of $4.00 per gallon for heating oil and $3.10 per gallon for propane. These oil and propane prices translate to $29.63/Dth and $33.84/Dth, respectively.[6] According to Columbia's current Tariff effective April 1, 2014, the delivered price for residential service is $9.94/Dth. In addition, I have considered the current customer charge of $16.76 per month and applied this to the average usage of 5 Dth per customer to arrive at a weighted effective cost of $13.29/Dth for natural gas. As such, the following is a comparison of Columbia's residential natural gas and alternative energy sources on a per dekatherm basis:

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[4] The fixed monthly customer charge was not included in the incremental price since all customers will continue to receive electric service even if they convert to natural gas for heating and/or other purposes.

[5] 1 kWh = 3412.142 BTU and 1 Dth = 1 million BTU.

[6] BTU content of 135,000 per gallon of oil and 91,600 per gallon of propane.

Source of Energy	Delivered Price Per Dth
Natural Gas	$13.29
Electricity	$34.92
Heating Oil	$29.63
Propane	$33.84

When the above prices of various energy sources are applied to average usage of 5 Dth per month the following annual savings per customer are obtained:

Source of Energy	Annual Savings
Natural Gas vs. Electricity	$1,298
Natural Gas vs. Oil	$980
Natural Gas vs. Propane	$1,233

As can be seen above, residential consumers of energy within Columbia's service area could realize significant savings if natural gas were available and was utilized as their heating source.

Q. MR. WATKINS, AS HAS BEEN THE CASE WITH OTHER ENERGY SOURCES, THE PRICE OF NATURAL GAS HAS HISTORICALLY BEEN VOLATILE OVER THE YEARS. IS THE CURRENT COST DIFFERENTIAL BETWEEN NATURAL GAS AND OTHER SOURCES OF ENERGY EXPECTED TO CONTINUE?

A. Yes. As is well known in the industry, there has been a large increase in the supply of natural gas in the United States, which has driven the price of this commodity down substantially. All forecasts that I have seen and am aware of predict natural gas prices to remain at relatively low levels for the next several years. For example, the United States Department of Energy Information Administration's ("EIA") current (April

2014) long-term forecast of energy prices predicts the following national average residential delivered prices of energy per dekatherm (nominal dollars)[7]:

Residential Delivered Price Per Dth
(Nominal Dollars)[8]

Energy Source	Year 2012	2020	2030
Natural Gas	$10.46	$13.13	$18.18
Electricity	$34.83	$40.94	$49.78
Heating Oil	$27.30	$27.94	$38.50
Propane	$24.12	$26.94	$34.67

As can be seen above, although nominal natural gas prices are projected to increase substantially between 2012, 2020, and 2030, it is expected that natural gas will remain far less expensive than other alternative energy sources well into the future.

Q. OTHER THAN THE COMPARATIVE PRICE ADVANTAGE OF NATURAL GAS, ARE THERE ADDITIONAL PUBLIC INTEREST ADVANTAGES PERTAINING TO THE USE OF NATURAL GAS COMPARED TO OTHER ENERGY SOURCES THAT POLICYMAKERS AND REGULATORS SHOULD CONSIDER?

A. Yes. On a national and global basis, there is significant concern regarding carbon dioxide emissions and society's "carbon foot print." In general, natural gas has fewer emissions than other traditional energy heating sources. To illustrate, the EIA has estimated the following average pounds of CO_2 per Dth of energy used by fuel type[9]:

Natural Gas	117
Heating Oil	161
Propane	139
Bituminous Coal	206

[7] Annual Energy Outlook 2014, With Projections to 2014, U.S. Energy Information Administration, April 2014, Table A3.

[8] Includes commodity, transportation, and distribution costs

[9] "Frequently Asked Questions, How much carbon dioxide is produced when different fuels are burned?," U.S. Energy Information Administration, http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

From a carbon emissions standpoint, it is clear that natural gas is far superior to heating oil, somewhat better than propane, and likely somewhat more preferred over electricity, at least in Pennsylvania.

Q. DO YOU HAVE ANY CONCLUDING COMMENTS AND RECOMMENDATIONS REGARDING THE GENERAL POLICY OF MAINS EXTENSIONS IN ORDER TO MAKE NATURAL GAS MORE AVAILABLE IN UNSERVED AREAS WITHIN COLUMBIA'S SERVICE AREA?

A. Yes. While it is clear that there are many public interest benefits associated with expanding natural gas distribution infrastructure in order to serve additional energy consumers, there is no better time than the current for policymakers and regulators to reevaluate the constraints under which natural gas mains are extended. Indeed, the natural gas industry has been plagued for decades with traditional methods that only consider the direct utility costs and benefits of expanding mains at no cost to existing ratepayers, and allows for a fair rate of return to NGDC shareholders. In this regard, if it is agreed that the expansion of natural gas availability will benefit the public there are only three potential stakeholders that can fund such expansions without governmental assistance: NGDC shareholders, new customers, or existing ratepayers. Clearly, NGDCs cannot be expected to fund capital improvements or expansions without a reasonable opportunity to earn a fair rate of return on their investments. Therefore, this leaves only two possibilities: new or existing ratepayers to fund such expansions.

It is evident that prior policies of requiring new customers to totally fund such expansions with upfront cash contributions have simply not worked very well. As such, innovative new plans and policies such as new service area surcharges, programs to minimize upfront cash contributions of new residential natural gas customers, and mechanisms with a modest sharing of the cost of expansions between new and existing customers should be explored. Indeed, and while some approaches are more preferred than others and should be evaluated on a case by case basis, there is no single approach that I am aware of that will result in a "win-win" situation for all stakeholders under all circumstances -- at least in the short-term. In this regard, policymakers and regulators should encourage and evaluate various plans and proposals to promote the expansion of

natural gas service on a case-by-case basis to determine the level of achievement and expansion that can reasonably be expected from a given plan and at the same time, evaluate the expected impact of costs and benefits to all stakeholders.

Q. AS A GENERAL MATTER, IS IT FAIR TO SAY THAT AT ONE TIME VIRTUALLY EVERY PUBLIC UTILITY CONSUMER WAS A "NEW CUSTOMER" AND THAT AS A NEW CUSTOMER THEY RECEIVED BENEFITS FUNDED BY EXISTING CUSTOMERS?

A. Absolutely. Whether it be natural gas, electric, or water service, new customers of a utility system receive benefits that have previously been paid for by existing ratepayers. This is largely due to the manner in which traditional public utility rates are established based on historical (embedded) average costs and the declining revenue requirement of plant as equipment matures (is depreciated). Therefore, while existing ratepayers must fund a utility's infrastructure (plant) during the most expensive early years, new customers that come online later in the life of such investments, reap the benefit of lower-priced infrastructure.

III. COLUMBIA'S NAS PROPOSAL

Q. PLEASE BRIEFLY DESCRIBE COLUMBIA'S PROPOSED NAS PILOT RIDER.

A. The Company proposes an optional rider mechanism that will enable new customers who would ordinarily be required to make an upfront cash contribution associated with a mains extension to "finance" all or a portion of this required contribution over the course of 20-years at an interest rate equal to the Company's approved cost of capital (approximately 8%). Under the Company's proposal, the maximum amount that can be financed would be that amount that would equate to a monthly payment of $35.00. Therefore, with an 8.00% interest rate, the maximum amount that can be financed would be $4,184, wherein any remaining required contribution must be recovered as a lump sum upfront payment. Furthermore, this "loan" *per se* will be amortized and as it is paid down, the customer's principal payments would be credited to Contributions in Aid of Construction ("CIAC"), while the interest

payments would be treated as other income and credited to all ratepayers in the context of base rate cases.

As a very broad example, suppose there is a main extension project with a total capital cost of $5,000, and only $4,000 of investment can be justified as economically feasible, such that the customer's upfront cash contribution requirement is $1,000. The customer will have the option of paying this $1,000 in a lump sum upfront payment or "financing" this $1,000 over 20-years at approximately 8% interest. Columbia will then book the entire $5,000 as an increase to plant-in-service (rate base). If the customer elects to make an upfront contribution, $1,000 will immediately be booked as CIAC (which will be an offset to rate base). If the customer elects to "finance" the $1,000 over 20-years, the monthly principal portion of the total payment will be booked to CIAC, while the remaining interest portion of the total payment will be booked to interest (other income). In this way, the beginning gross rate base will be $5,000 wherein the $1,000 customer contribution requirement (CIAC) will increase gradually over the 20-year term. Other salient features of Columbia's proposal are: (1) this is a four-year pilot program; (2) it is available only to residential customers; and (3) will be capped at $1,000,000 total annual investment by Columbia.

Q. HOW DOES COLUMBIA DETERMINE THE AMOUNT OF CONTRIBUTIONS REQUIRED BY A CUSTOMER FOR A GIVEN MAINS EXTENSION PROJECT?

A. Columbia utilizes a DCF model that evaluates the expected revenues and costs (overwhelmingly capital costs) associated with constructing a new main, installing a service line (as applicable), and installing a new meter and regulator over a 40-year timeframe in which future cash flows are discounted at the Company's overall cost of capital (approximately 8%). To the extent there is a revenue shortfall on a present value basis; i.e., the present value of expected revenue inflows are less than the present value of cash outflows (primarily capital expenditures and income taxes), the customer contribution is that which would produce a net present value of the project equal to the cost of capital. In other words, the required customer contribution reflects the uneconomic portion of the project. As a point of clarification, for projects in which the

present value of the cash inflows are expected to exceed the present value of cash outflows (the internal rate of return is greater than the cost of capital), no customer contribution is required.

Q. UNDER THE COMPANY'S PROPOSED NAS RIDER, IF A NEW CUSTOMER ELECTS TO "FINANCE" THEIR DEPOSIT REQUIREMENT OVER 20-YEARS, WILL THIS RESULT IN SOME SOCIALIZATION, OR COST SHIFTING, OF COSTS BETWEEN EXISTING RATEPAYERS AND THE NEW CUSTOMER?

A. To some degree yes. Remembering that the entire cost of an expansion project will immediately be booked to gross plant-in-service and shared by all ratepayers, the CIAC offset will grow gradually over the 20 year financing term. As such, it will not be until the later years of the financing term that ratepayers will receive much benefit of the CIAC offset. However, all ratepayers will receive benefits of the interest income earned through loan payments. In toto, existing ratepayers will be funding the majority of the uneconomic costs in the early years, and this socialization of costs will decline over time.

Q. IS COLUMBIA'S USE AND APPLICATION OF A DCF MODEL APPROPRIATE FOR EVALUATING THE FEASIBILITY OF PROSPECTIVE INDIVIDUAL MAINS EXTENSION PROJECTS?

A. While the use of a DCF modeling approach in general provides a sound basis for evaluating the feasibility of individual projects, I have concerns and disagree with certain aspects of how Columbia applies its DCF model for determining customer contributions and/or the amount that must be financed under its proposed NAS rider.

Q. PLEASE EXPLAIN.

A. In addition to the capital costs associated directly with installing new mains, the Company's model also reflects the capital costs required to install a meter and regulating equipment, as well as a service line to each new customer. In this regard, Columbia's treatment and requirements for service line investment are somewhat atypical from other NGDCs in the Country. As a matter of statute in Pennsylvania, customers in the western portion of Columbia's service area must install, own, and maintain their own service lines

within their property.[10] For customers in the eastern portion of the Company's service area, the Company owns and maintains the service line and according to Tariff Rule 8.1, the Company will provide an allowance of up to approximately 50 feet of new service line for each new customer. It should also be remembered that within the definition of "service lines" there are two separate distinctions. These distinctions are: (1) the service line from the distribution main to the customer's property line and (2) the service line on the customer's property from the property line to the meter. It is my understanding that in the western portion of Columbia's service area, the Company remains responsible for the installation and ownership of the service line from the main to the customer's property line.

With these caveats noted, there is no distinction in Columbia's DCF model between the various types of service line and/or whether allowances of up to 50 feet are embedded within the model. That is, there is simply a single entry for "service line investment" within the DCF model, and my evaluation of actual individual projects reveals there is no way to make a determination as to whether Columbia's field personnel (who actually make inputs and run the model) properly reflect allowances or ownership. However, based on informal conversations with the Company, I have been informed that field personnel are aware of these nuances and properly reflect allowances and ownership within its DCF modeling scenarios. In this regard and absent my other recommendations that will be discussed later in my testimony, I recommend that specific separate entries be required for Company-owned service lines, allowances, and customer-owned service lines to ensure that individual field personnel appropriately apply the model in accordance with the Public Utility Code and the Company's approved Tariff.

The next concern I have relates to meter and regulator equipment. As indicated earlier, for each potential project, Columbia includes the capital costs of metering and regulating equipment within its DCF model. However, this may not comport with the Commission's regulations. Specifically, 52 Pa. Code § 59.17, Furnishing of Meters and Regulations, states:

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[10] 66 Pa. C.S. § 1510.

> (a) *Installation.* Except as provided in § 59.31 (relating to service from production or transmission lines), **a public utility shall provide and install at its own expense and shall continue to own, maintain and operate equipment necessary for the regulation and measurement of gas furnished to its customers.** If meters or regulators not required by this section are furnished by the utility for the convenience of the customer, a reasonable charge for the meters or regulators may be made. Nothing in this subsection may be construed to require the utility to install regulating equipment on any gas piping system of a customer beyond the point of delivery at the meter outlet of the utility. [Emphasis added]

Therefore, because Columbia includes the capital (installation) costs of providing a meter within each DCF project feasibility analysis, for those projects in which a deposit is required, the customer is essentially paying for the cost of the meter. For example, suppose that under Columbia's current practices in which the installation costs of a meter are included within the DCF model, an upfront customer contribution of $1,000 is required. However, if the exact same model was run but metering costs were input at zero, the required customer contribution would only be $800. As such, the customer is being required to contribute an upfront meter installation cost of $200.

Q. DO YOU HAVE CONCERNS REGARDING THE LIKELY EFFECTIVENESS OF THE NAS RIDER AS PROPOSED BY COLUMBIA?

A. Yes. I acknowledge and understand that the proposed NAS rider is a voluntary program and will provide an additional option to potential new customers. In this regard, the Company's proposal will provide some benefit to potential new customers and will likely result in a small amount of mains extensions that would otherwise not occur absent the financing provisions within the NAS rider. However, I am concerned that if approved as proposed by Columbia, this rider will have only a very small marginal impact on making natural gas more available to energy consumers within the Company's service area.

My first concern relates to Columbia's proposed financing interest rate of approximately 8%. There is no doubt that the vast majority of potential new residential customers under which this NAS rider program would apply are homeowners. Current market interest rates are such that home equity loans are in the range of 3.5% to 4.5%,

which are also generally tax deductible for income tax purposes, such that the effective interest rate to homeowners is considerably low. Given that many, if not most, homeowners could finance the upfront contribution with a home equity loan with an effective interest rate of somewhere around 3%, it would make little sense to finance the same amount at approximately 8% (which is not deductible for income tax purposes). As such, I believe it is fair to say that most homeowners are savvy enough to recognize the exceptionally high interest rate proposed by Columbia and this in and of itself, will result in limited participation and success. Furthermore, it should be noted that under Columbia's proposal, the financing term will be fixed at 20-years. For customers that finance their mains extension contribution with a monthly payment of $35.00 (finances $4,184), they will actually pay more in interest than principal over the term of the financing agreement ($4,215 in interest and $4,184 in principal).

The next point concerns the inclusion of metering and service line investments within the determination of a potential customer's contribution requirements (whether paid upfront or financed). It seems to me that as a policy matter, the primary objective of this proposed program is to promote the expansion of Columbia's mains to unserved areas and make natural gas more available to residential energy consumers. Given the purpose of this program is to extend Columbia's distribution mains, it is logical that other costs required to connect a new customer (i.e., services and metering costs) not be reflected in the determination of customer contributions.

The next concern I have relates to Columbia's proposal that the NAS rider would apply to new developments in which new homes have yet to be built. As I understand Columbia's proposal, Columbia would change its current policy of requiring contributions from developers, and instead install new mains in developments at no cost to the developer and when new homes are built and occupied, the new homeowner will then be required to either pay their proportionate share of an upfront cash contribution or finance this amount over 20 years. While there is no doubt that the homes built in these new developments will have natural gas heating equipment and appliances installed, the new homeowners will obviously need to subscribe to Columbia as its NGDC provider. I am extremely concerned that these potential new homeowners will have no idea that they will be obligated to pay Columbia an upfront cash contribution or finance this amount for

20 years until after they have purchased their new home and moved in.[11] Clearly, it is much easier and more economical for each new homeowner to simply roll the contribution requirement into the cost of the new home. As such, while there may be other innovative ideas or plans to help developers, I do not believe the Company's plan is appropriate for new developments.

The next concern I have relates to any lack of reporting requirements by Columbia pertaining specifically to the NAS rider. If Columbia's proposed plan or modification thereof is approved, the Commission should require certain reporting requirements by Columbia that I recommend later in this testimony.

Finally, there is no prohibition of Columbia extending its mains to areas already served by another NGDC. While I acknowledge that there is little realistic probability that a new residential customer would elect to make an upfront cash contribution or finance the cost of extending a Columbia main when another NGDC already has service available in that customers' area and am fully aware of the current Gas-on-Gas investigation that is pending before the Commission, any such duplicative facilities are not in the best public interest and should not be allowed in the NAS Rider.

IV. OCA RECOMMENDATIONS

Q. GIVEN YOUR CONCERNS AND DISAGREEMENTS WITH COLUMBIA'S PROPOSED NAS PILOT RIDER, WHAT ARE YOUR RECOMMENDATIONS?

A. As noted earlier in my testimony, there has yet to be a single plan or approach developed that truly promotes the expansion of natural gas availability to unserved areas and at the same time, is a "win-win" scenario for all stakeholders in the short-term. In this regard, I have noted other approaches that are currently being utilized to promote the expansion of natural gas availability and recommend not reinventing the wheel as far as Columbia's proposed NAS rider is concerned. Rather, recognizing that this is a pilot program, I recommend certain modifications to Columbia's proposal that will result in a

[11] Under Columbia's proposal, upfront contributions or financing will not begin until a meter is set, which will not occur until after the new home has been sold by the developer.

realistic chance of success in making gas more available to residential energy consumers within Columbia's service area.

My recommended modifications to Columbia's proposal as filed are as follows:

(1) For NAS projects, the Company's DCF model shall use as inputs its most recent Commission-approved capital structure, wherein the cost of debt will reflect the weighted cost of long-term and short-term debt, and the cost of equity within the model will also use the weighted cost of long-term and short-term debt such that the discount rate will equal the Company's weighted cost of debt (note: the model will continue to reflect an equity return except that instead of utilizing the Commission's approved return on equity, the DCF model will utilize the Company's cost of debt as a surrogate for equity return).

(2) For any NAS project, the projected capital costs of all service lines, meters, and regulating equipment shall be excluded from the DCF model.

(3) An NAS applicant will not pay for any costs of the meter or the Company's service line from the main to the applicant's property line. In the Company's eastern service area, Columbia will also provide up to 50' of service line on the applicant's property at no charge to the applicant per Tariff Rule No. 8.

(4) For purposes of calculating an applicant's surcharge amount under the NAS pilot, the annual interest rate shall be 3.00%.

(5) Applicants shall have the option of the following surcharge (financing) mechanisms:

(a) A 20-year term, capped at $35.00 per month, wherein the applicant shall pay upfront any excess above the amount that will be collected through the surcharge or

(b) A 10-year term, with no payment cap, with a maximum amount of $8,000 permitted to be recovered through the surcharge.

(6) The Company should commit $2 million annual funding for the NAS pilot (amount of financing only).

(7) The following items should be required to be reported annually by Columbia to the Commission, I&E and OCA during the period of the pilot program:

(a) investment per project including the economic model results and surcharge calculation details;

(b) total distance of NAS main installed;

(c) number of customers connected by project and number of subsequent connections to NAS extensions;

(d) NAS revenues received by principal and interest;

(e) annual NAS participant average use per customer (by residential and commercial sectors if applicable);

(f) average NAS participant investment cost per customer (by residential and commercial sectors if applicable);

(g) the number of customers along NAS extensions who have not yet connected and, to the extent available, why;

(h) direct program expenses;

(i) data on collections, including efforts for unpaid surcharge amounts; and,

(j) the number of applicants turned down for insufficient credit.

(8) In all rate case filings within the NAS pilot program period, the Company should provide to the statutory parties a separation of the projected investment in NAS pilot capital costs from all other projected capital expenditures.

(9) Rider NAS should not be available to applicants in areas where mains of another natural gas company are already available for the applicants to take service.

(10) Rider NAS should not be available to developers and will be applicable only to homeowners.

With these modifications, there should be much more acceptance and participation in the NAS program, thereby making natural gas more available to energy consumers within Columbia's service area.

Q. MR. WATKINS, WILL YOUR RECOMMENDED LOWER FINANCING INTEREST RATE OF 3.00%, THE USE OF COLUMBIA'S WEIGHTED COST OF DEBT INSTEAD OF ITS OVERALL COST OF CAPITAL, AND EXCLUSION OF SERVICE AND METERING COSTS WITHIN THE DETERMINATION OF CUSTOMER CONTRIBUTIONS HAVE ANY ADVERSE IMPACT ON THE COMPANY'S SHAREHOLDERS?

A. No. Under my recommendations, all projects that go forward will simply be rolled into rate base and recovered in the normal course of business through the traditional regulatory process. In this regard, while some may question a concern of regulatory lag, I note the following:

(a) This is true with any new plant investment and is simply the result of how rate regulation is performed in Pennsylvania;

(b) NGDCs (including Columbia) are allowed to, and do, utilize fully forecasted future test years within their general rate cases such that reasonable projections of expansions will be reflected within Columbia's rate request using forward looking (future) expected mains expansion projects; and

(c) In between rate cases, Columbia will recover interest and principal payments from NAS participants. While the principal payments will eventually be booked as CIAC (and hence, a reduction to rate base), these rate base reductions will not be realized until the Company's next base rate case. Furthermore, although ratepayers will receive the benefit of annual interest income once a rate case is filed, the Company will keep the interest income it earns in between rate cases.

Q. WILL YOUR RECOMMENDED LOWER FINANCING INTEREST RATE OF 3.00%, THE USE OF COLUMBIA'S WEIGHTED COST OF DEBT INSTEAD OF ITS OVERALL COST OF CAPITAL, AND EXCLUSION OF SERVICE AND METERING COSTS WITHIN THE DETERMINATION OF CUSTOMER CONTRIBUTIONS HAVE AN IMPACT ON EXISTING RATEPAYERS?

A. To a small degree existing rates may include more of the costs of these expansion projects than under Columbia's proposal. It is important to recognize, though, that the economics of expansion projects go both ways. For some expansion projects that produce a net present value of benefits greater than costs (even if discounted at the

Company's cost of capital), wherein no new customer contribution is required, the new customer will be contributing more revenues to the system as a whole than as otherwise required, thereby directly benefiting existing ratepayers. In other words, when the net present value of a potential project is negative, that new customer must make a cash contribution (or finance it) equal to the present value deficiency amount. However, when the net present value of a potential project is positive, that customer does not receive a cash credit for connecting to the system, but rather, the benefits of that new customer simply accrue to all existing ratepayers.

Q. TO WHAT EXTENT HAVE ACTUAL MAINS EXTENSION PROJECTS PRODUCED A POSITIVE NET PRESENT VALUE OF SYSTEM BENEFITS EXCEEDING SYSTEM COSTS?

A. As a result of informal discovery with Columbia, the Company provided a list of every new mains extension feasibility project studies conducted since its last rate case. This list included 191 mains extension project feasibility studies. Of this total, 92 projects were approved by the potential customer. Of these 92 projects that met customers' acceptance, 52 projects had a positive net present value of benefits exceeding costs (utilizing Columbia's current practice of incorporating the total cost of capital, and including service and meter costs). As such, somewhat more than half of these customer-accepted projects resulted in situations in which the new customer reduced the cost to serve existing customers.

Q. HAVE YOU CALCULATED THE IMPACT ON RATES OF THESE POTENTIAL PROJECTS?

A. Yes. At the extreme, we will ignore the positive benefits to existing ratepayers resulting from new customer additions that had a positive present value for a mains extension project and also assume that all new extensions do not contribute a single dollar of revenue toward system costs (i.e., projects go forward but no revenue is derived from any new customers under the NAS program). Under the Company's proposal to cap the NAS financing annually at $1,000,000 of capital expenditures, this equates to an approximate annual revenue requirement in the first year (which will decline over time)

of approximately $145,000. If this $145,000 revenue requirement is divided by Columbia's total number of residential customers of 384,331,[12] an impact of slightly less than 38¢ per customer per year results. This impact is itself greatly overstated in that it assumes absolutely no revenue contribution from any new customers, it does not recognize that in reality, new customers will be paying full tariff rates, and those that do elect to finance upfront construction costs will be contributing cash through their loan payments (and thereby reducing rate base through CIAC and increasing interest income crediting to all ratepayers).

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

184564

[12] Per Columbia general rate case, Filing Exhibit No. 111 (Class Cost of Service Study).

SCHEDULE

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI=s administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society