BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
Complainant	:	
v.	:	Docket No. R-2018-3006818
PEOPLES NATURAL GAS COMPANY LLC,	:	
Respondent	:	

PREPARED DIRECT TESTIMONY OF
RUSSELL A. FEINGOLD,
VICE PRESIDENT
BLACK & VEATCH MANAGEMENT CONSULTING, LLC

DATE SERVED: January 28, 2019
DATE ADMITTED: ____________

Peoples Statement No. 11

PREPARED DIRECT TESTIMONY
OF RUSSELL A. FEINGOLD

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black & Veatch Management Consulting, LLC ("Black & Veatch") as a Vice President and I lead its Rates & Regulatory Services Practice.

Q. PLEASE DESCRIBE THE FIRM OF BLACK & VEATCH CORPORATION.

A. Black & Veatch Corporation (the parent company of Black & Veatch) has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University - St. Louis and a Master of Science Degree in Financial Management from Polytechnic Institute of New York University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") OR ANY OTHER REGULATORY AUTHORITY?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC"), the National Energy Board of Canada, and numerous state and provincial regulatory commissions, including this Commission. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies.

In addition to traditional utility costing and rate design concepts and issues, my testimony addressed revenue decoupling concepts and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Regulation ("PBR") concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States.

Q. WHAT HAS BEEN THE NATURE OF YOUR WORK IN THE UTILITY CONSULTING FIELD?

A. I have over forty-three (43) years of experience in the utility industry, the last forty (40) years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. In addition to my presentation of expert testimony in utility regulatory proceedings that was just discussed, I have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in **Appendix A** to my testimony.

Q. PLEASE SUMMARIZE YOUR SPECIFIC EXPERIENCE IN CONDUCTING COST OF SERVICE STUDIES AND DESIGNING RATES FOR GAS AND ELECTRIC UTILITIES.

A. Over my utility consulting career, I have conducted numerous cost of service studies for gas and electric utilities to provide guidelines for use in evaluating the utilities' class revenue levels and rate structures. In addition to these cost studies, which are based on a utility's embedded or historical costs, I have conducted long-run and short-run marginal cost, avoided cost, and unbundled service and cost studies. Finally, I have reviewed, evaluated, designed and implemented rate structures and other innovative pricing approaches for numerous gas and electric utilities operating in North America and abroad.

Q. FOR WHAT PURPOSE HAVE YOU BEEN RETAINED BY PEOPLES NATURAL GAS COMPANY LLC?

A. I have been retained by Peoples Natural Gas Company LLC ("Peoples" or the "Company") as a consultant specializing in utility costing and related regulatory matters. Specifically, the Company requested that I conduct a cost of service study to determine the embedded costs of serving its customers and to develop its class revenue and rate design proposals.

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

A. The purpose of my testimony is to present the results of the cost of service studies filed by the Company in this proceeding and to discuss the underlying methodology used in the studies and how its results are used for ratemaking purposes, and to present and discuss Peoples' proposed class revenues, rate design and the resulting rates by rate class.

Q. PLEASE LIST THE FILING REQUIREMENTS THAT YOU ARE SPONSORING AS A WITNESS.

A. Please refer to **Peoples Exhibit RAF-1** for a complete list of the filing requirements for which I am the responsible witness.

Q. ARE YOU SPONSORING ANY OTHER EXHIBITS AS PART OF YOUR TESTIMONY?

A. Yes. I am also sponsoring the following exhibits related to the Company's cost of service studies, class revenue and rate design proposals:

- Peoples Exhibit RAF-2: Minimum Customer Cost Analysis[1]
- Peoples Exhibit RAF-3: Derivation of the Total Gathering Cost of Service
- Peoples Exhibit RAF-4: Proposed Class Revenue Apportionment
- Peoples Exhibit RAF-5: Proposed Rates
- Peoples Exhibit RAF-6: Residential Monthly Bill Comparisons
- Peoples Exhibit RAF-7: Derivation of the Merchant Function Charge (Rider E)
- Peoples Exhibit RAF-8: Derivation of the Gas Procurement Charge (Rider G)
- Peoples Exhibit RAF-9: Derivation of Supplier Services – Revenue and Cost Comparison
- Peoples Exhibit RAF-10: Derivation of the Purchase of Receivables – Administration Adder

The structure and supporting computations contained in each of these exhibits will be explained later in my testimony.

PEOPLES PROPOSED RATE CLASSES

Q. WHAT ARE THE RATE CLASSES THAT PEOPLES' PROPOSES TO ESTABLISH IN THIS PROCEEDING?

[1] Presented in addition to the Company's required customer cost analysis it has filed in Item IV-B-9 of Exhibit IV.

A. Peoples is proposing to merge the existing rate classes of its Equitable Division into the existing rate classes of its Peoples Division so there will be one uniform set of rate classes and tariffs for Peoples' combined operations after the completion of this rate case. Table 1 below shows how the current rate classes for the Equitable Division will be merged with the current rate classes of the Peoples Division to create Peoples' proposed uniform set of rate classes.

Table 1 – Peoples' Proposed Rate Class Configuration

Peoples Division and Combined Divisions	Equitable Division
Sales Service	
Residential Service – Rate RS	Residential Service – Rate RS
Small General Service – Rate SGS	General Service Small - Rate GSS (0 - 1,000 MCF/Year)
Medium General Service – Rate MGS	General Service Large – Rate GSL (1,000 – 25,000 MCF/Year)
Large General Service – Rate LGS	General Service Large – Rate GSL (Over 25,000 MCF/Year)
Transportation Service	
Residential Service – Rate GS-T	Firm Delivery Service – Rate FDS
Small General Service – Rate GS-T SGS	General Delivery Service – Rate GDS (0 - 1,000 MCF/Year)
Medium General Service – Rate GS-T MGS	General Delivery Service – Rate GDS (1,000 - 25,000 MCF/Year)
Large General Service – Rate GS-T LGS	General Delivery Service – Rate GDS (Over 25,000 MCF/Year)

PEOPLES' COST OF SERVICE STUDIES

Q. HAS A COST OF SERVICE STUDY BEEN SUBMITTED IN THIS PROCEEDING?

A. Yes. Exhibit 11, Schedule 1 (53.53 IV-B-1) of the Company's filing contains a series of cost of service studies based upon pro forma revenues and costs for the future test year ending

October 31, 2020, at present and proposed rates. The studies were performed using Black & Veatch's proprietary, computer-based Gas Cost of Service Study ("COSS") Model.

Q. WERE THESE COST OF SERVICE STUDIES PREPARED BY YOU OR UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes, they were.

Q. WHAT WAS THE SOURCE OF THE COST DATA ANALYZED IN PEOPLES' COST OF SERVICE STUDIES?

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

Q. WHAT CLASSES OF SERVICE WERE INCLUDED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. The customer classes reflected in Peoples' cost of service studies are Residential Service (RS), Small General Service (SGS), Medium General Service (MGS), and Large General Service (LGS).

Q. DO THESE RATE CLASSES INCLUDE BOTH SALES AND TRANSPORTATION SERVICE CUSTOMERS?

A. Yes. These customer classes are configured as combined classes that include both sales service and transportation service customers. Therefore, the RS class includes residential customers served under Peoples' Rates RS and GS-T, the SGS class includes small commercial and industrial customers served under Peoples' Rates SGS and GS-T, the MGS class includes medium-sized commercial and industrial customers served under Peoples' Rates MGS and GS-T, and the LGS class includes large commercial and industrial customers served under Peoples' Rates LGS and GS-T. A gas utility's class cost of service study should recognize that sales service and transportation service customers both require delivery service to physically move gas on its gas system. For example, it costs a gas utility the same amount to have a service line and meter in place at a customer's premises, irrespective of whether the gas moving through the service line and meter is customer-owned gas transported by the utility, or gas it owns that is sold to the customer. Similarly, the volume of gas used by a customer during a peak period establishes the customer's contribution to the system peak. A gas utility's pipeline system does not need to be larger or smaller if the customer, instead of the utility, owns the gas as it moves through its gas system. Therefore, the allocation of distribution costs for sales service and transportation service for the same customer should be based on allocation factors that include both sales and transportation load characteristics.

Q. PLEASE EXPLAIN WHY THE COST OF SERVICE STUDIES YOU PREPARED DO NOT INCLUDE A RATE CLASS FOR GATHERING SERVICE.

A. Peoples' cost of service studies do not include a separate rate class for gathering service since Peoples is proposing that its gathering service rates be set on a negotiated basis using value of service considerations rather than cost of service as a guide. As such, a cost of service study for

Peoples which includes a gathering service rate class would provide no value in determining the revenue and rate levels for gathering service to local producers that are reflective of the value-based considerations associated with producers' access to Peoples' gathering system. Nevertheless, as I explain later in this testimony. I have determined the cost of service associated with Peoples' gathering system and compared that to the contributions by producers under present and proposed charges for informational purposes.

Peoples' witness Joseph Gregorini (Peoples Statement No. 2) discusses the various competitive and business considerations that were evaluated in determining the level of its gathering service rates that are proposed to be charged to local gas producers connected to Peoples' gas system.

Q. DID YOU PREPARE COST OF SERVICE STUDIES FOR THE COMPANY ON A COMBINED BASIS AS WELL AS FOR EACH OF ITS TWO OPERATING DIVISIONS?

A. Yes. I have prepared cost of service studies at present and proposed rates for the Company on a combined divisional basis and I have also prepared, for informational purposes, separate cost of service studies for the Peoples Division and Equitable Division at present rates.

Q. PLEASE DESCRIBE IN MORE DETAIL THE COMPANY'S COST OF SERVICE STUDIES PRESENTED IN EXHIBIT 11, SCHEDULE 1 WHICH CONSISTS OF 53.53 IV-B-1(A) THROUGH IV-B-1(I).

A. This Exhibit is structured as follows:

- IV-B-1(A) - presents Peoples' cost of service study at present rates based on a design day demand allocation method with a customer component of distribution mains.
- IV-B-1(B) - presents Peoples' cost of service study at present rates based on a peak and average demand allocation method without a customer component of distribution mains.
- IV-B-1(C) - presents the summary page of Peoples' cost of service study at proposed rates based on a design day demand allocation method with a customer component of distribution mains.
- IV-B-1(D) - presents the summary page of Peoples' cost of service study at proposed rates based on a peak and average demand allocation method without a customer component of distribution mains.
- IV-B-1(E) - presents a summary of results for Peoples' four cost of service studies described above.
- IV-B-1(F) - presents summary pages of the cost of service study for the individual Peoples Division at present rates based on a design day demand allocation method with a customer component of distribution mains.
- IV-B-1(G) - presents summary pages of the cost of service study for the Peoples Division at present rates based on a peak and average demand allocation method without a customer component of distribution mains.
- IV-B-1(H) - presents summary pages of the cost of service study for the Equitable Division at present rates based on a design day demand allocation method with a customer component of distribution mains.

- IV-B-1(I) - presents summary pages of the cost of service study for the Equitable Division at present rates based on a peak and average demand allocation method without a customer component of distribution mains.

Page 2 of Exhibit 11, Schedule 1 presents the table of contents for the cost of service studies presented in this proceeding. Then, the structure for each of the cost of service studies provided in IV-B-1(A) and IV-B-1(B) is described below:

Page 2 presents a unit cost analysis. *Pages 3-12* present the detailed results of the cost of service study by FERC or primary account. *Pages 13-22* present the details of the Functionalization phase. *Pages 23-52* present the details of the Classification phase. *Pages 53-122* present the details of the Company's functionalized and classified revenue requirement by customer class.

Both cost of service studies presented in IV-B-1(A) and IV-B-1(B) are prepared on a combined divisional basis and they are structured in the same format. The rate base is presented on lines 1 through 96. Expenses including O&M, customer accounting, A&G, depreciation, taxes other than income, gross receipts tax and income tax are presented on lines 97 through 251. Revenue is presented on lines 252 through 263. Net income at present rates is presented on line 265. A summary of revenue, expenses and net income is presented on lines 267 through 297. The revenue requirement at the system average rate of return is presented on lines 301-315.

The summaries of the cost of service studies provided in IV-B-1(C) and IV-B-1(D) present revenue under proposed rates, expenses and net income under proposed rates on lines 1 through 39. The rate of return on net rate base under proposed rates is presented on line 41.

The structure for each of the cost of service studies provided in IV-B-1(F) through IV-B-1(I) is described as follows: *Page 2* presents a unit cost analysis and *Pages 3-12* present the summary results of the cost of service study by FERC or primary account.

Q. HAS A COMPETE DESCRIPTION AND BACK-UP CALCULATIONS FOR ALL THE ALLOCATION FACTORS USED IN THE FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION PHASES OF PEOPLES' COST OF SERVICE STUDIES BEEN PROVIDED?

A. Yes. Exhibit 11, Schedule 3 (53.53 IV-B-3) provides this detailed cost allocation factor information.

Q. PLEASE DISCUSS THE FACTORS WHICH YOU BELIEVE CAN INFLUENCE THE OVERALL COST ALLOCATION FRAMEWORK UTILIZED BY A GAS DISTRIBUTION UTILITY.

A. In undertaking a cost of service study, the overall framework within which a gas distribution utility performs its cost of service study can be influenced by various factors. By overall framework, I mean the three standard steps or phases followed by a utility when performing a cost study - cost functionalization, cost classification, and cost allocation. In my opinion, these factors can include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the gas utility. The physical configuration of the utility's gas system refers to considerations such as: (1) transmission and/or distribution system configuration; (2) mainline pipeline functionality; and (3) system operating pressure configuration. These considerations include determining whether: (1) the distribution system is a centralized grid/single city-gate or a dispersed/multiple city-gate configuration; (2) the gas utility has an integrated transmission and distribution system or a distribution-only operation; and (3) the system operates under a multiple-pressure based or a single-pressure based configuration.

Regarding data availability, the structure of the gas utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by rate/customer class, operating unit or geographic region, and the types of load data available.

State regulatory policies and requirements refer to the particular approaches used to establish utility rates in the state. For example, any specific methodological preferences or guidelines for performing cost of service studies or designing rates established by the state regulatory body can affect the various cost allocation methods presented by the gas utility.

Q. HOW DO THESE FACTORS RELATE TO THE SPECIFIC CIRCUMSTANCES APPLICABLE TO THE COMPANY?

A. Regarding the physical configuration of the Company's gas system, it is a dispersed/multiple city-gate, integrated transmission/distribution system, with upstream gas gathering facilities, underground storage, and a multi pressure-based system. The Company has detailed plant accounting records for many of its distribution-related facilities, separate plant data for its gathering system, and details for some of the larger operating expense categories. Finally, over the years, this Commission appears to have given consideration in evaluating cost of service for gas utilities to both cost of service studies using a demand/customer allocation method and demand/commodity allocation of distribution mains.

Q. WOULD YOU STATE THE PURPOSE OF A COST OF SERVICE STUDY?

A. A cost of service study is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and to help determine the individual class revenue requirements to be used in developing prospective rates for each class.

Q. ARE THERE CERTAIN GUIDING PRINCIPLES WHICH SHOULD BE FOLLOWED WHEN PERFORMING A CLASS COST OF SERVICE STUDY?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question - which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There is generally a direct link between the manner in which costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant which is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Gas supply-related contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs which vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

Q. WHAT STEPS DID YOU FOLLOW TO PERFORM THE COMPANY'S COST OF SERVICE STUDIES?

A. I followed three broad steps to perform the cost of service studies: (1) functionalization; (2) classification; and (3) allocation. The first step or phase, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. For Peoples, the functional cost categories associated with gas service include: gas supply, gathering, storage, transmission, and distribution. I should note that the gas supply function simply reflects Peoples' gas supply costs and gas cost revenues that are presented and reviewed within Peoples' annual 1307(f) process. Classification of costs, the second phase, further separates the functionalized plant and expenses into the three cost-defining characteristics of services rendered, as previously discussed: (1) customer; (2) demand or capacity; and (3) commodity or energy. The final phase is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, commodity or revenue-related allocation factors.

Q. HOW DOES THE COST ANALYST ESTABLISH THE COST AND UTILITY SERVICE RELATIONSHIPS YOU PREVIOUSLY DISCUSSED?

A. To establish these relationships, the cost analyst must analyze the Company's gas system design and operations, its accounting records, and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM "DIRECT ASSIGNMENT?"

A. The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups.

Direct assignment of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. IS IT REALISTIC TO ASSUME THAT A LARGE PORTION OF THE PLANT AND EXPENSES OF A UTILITY CAN BE DIRECTLY ASSIGNED?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expenses cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. AS PART OF YOUR WORK, DID YOU REVIEW AND ANALYZE THE COMPANY'S GAS SYSTEM DESIGN AND OPERATIONS?

A. Yes. Since it is widely recognized that a utility's plant in service components provide the most direct link to a utility's gas service requirements, I initially focused my efforts on better understanding the nature and operation of the Company's gas system. This effort included review of the Company's gathering, storage, transmission, and distribution systems and the types and levels of costs incurred in connecting various sized customers to its distribution system.

Q. PLEASE EXPLAIN THE MOST IMPORTANT CONSIDERATIONS YOU RELIED UPON IN DETERMINING THE COST ALLOCATION METHODOLOGIES WHICH WERE USED TO PERFORM THE COMPANY'S CLASS COST OF SERVICE STUDY.

A. As stated above, it is important to recognize the cost causative characteristics of the cost elements which are allocated within any class cost of service study. Additionally, the cost analyst needs to develop data in a form which is compatible with and supportive of rate design proposals. Of further concern is the availability of data for use in developing alternative cost allocation factors. In evaluating any cost allocation methodology, consideration should be given to:

1. Recognition of <u>cost causality</u>;

2. Results which are representative of the true costs of serving different types of customers;

3. A sound rationale or theoretical basis;

4. Stability of results over time;

5. Logical consistency and completeness; and

6. Ease of implementation.

Q. PLEASE DESCRIBE THE KEY ISSUES RELATED TO THE ALLOCATION OF DEMAND-RELATED COSTS WITHIN A GAS UTILITY'S COST OF SERVICE STUDY?

A. A complex part of the allocation process is the allocation of demand-related costs. Any number of methodologies has been used to develop allocation factors for the demand components of costs. In fact, it is not unusual for more than one demand cost allocation methodology to be used in a cost of service study. Despite numerous methods to allocate demand costs, it is fair to say that three basic methodologies form the foundation for the allocation process. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the Company. Under this methodology, demand related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group. The Peak Demand Allocation process might focus on a single peak, such as the highest daily demand occurring during the test period. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day. In some instances, it may be appropriate to determine the peak demand responsibility on an hourly basis rather than a daily basis where hourly requirements dictate a company's investment in distribution facilities.

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand. The portion of these facilities is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand).

A more simplistic version of this methodology is the Peak and Average methodology. This cost methodology gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's demand-related costs on a commodity-related basis. The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's (rate class), maximum demand, irrespective of the time of the system peak.

Q. HOW HAVE DEMAND-RELATED COSTS BEEN ALLOCATED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. Peoples' cost of service studies use either a coincident peak demand or peak and average allocation factor, both derived on a design day basis, for allocating its capacity related costs to the various customer classes. Capacity costs for the Company consist of the capacity costs associated with city-gate facilities and the capacity portion of the Company's distribution system.

Q. WHY DOESN'T AVERAGE DEMAND (I.E., ANNUAL GAS THROUGHPUT VOLUMES DIVIDED BY 365 DAYS) INFLUENCE THE OCCURRENCE OF DEMAND-RELATED COSTS?

A. If a gas utility's system was sized and installed to accommodate average gas demands, it would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, it is clear that a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system. As such, cost causation with respect to demand related costs is unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the gas utility's system by customers with low load factors. Clearly, under-utilization of a gas utility's system is a result that it can hardly encourage, recognizing that higher system utilization will result in lower unit costs to all customers served by the gas utility.

For the above-stated reasons, it is inappropriate to rely upon only a commodity-based allocation factor, as derived from annual gas throughput volume, for purposes of allocating demand related costs to a gas utility.

Q. WHY DID YOU CHOOSE TO UTILIZE THE COMPANY'S DESIGN DAY DEMAND RATHER THAN ITS ACTUAL PEAK DAY DEMAND AS A DEMAND ALLOCATION FACTOR?

A. Use of a gas utility's design day demand is superior to using its actual peak day demand, or an historical average of multiple peak day demands over time, for purposes of deriving demand allocation factors for a number of reasons. These include:

1. A gas utility's system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.
2. Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.
3. Design day demand provides more stable cost allocation results over time.

Q. PLEASE EXPLAIN WHY THE COMPANY'S DESIGN DAY DEMAND BEST REFLECTS THE FACTORS THAT ACTUALLY CAUSE COSTS TO BE INCURRED?

A. The Company must consistently rely upon design day demand in the acquisition of its upstream gas supply-related resources and in the design of its own distribution facilities required to service its firm service customers. And perhaps more importantly, design day demand directly measures the gas demand requirements of the Company's firm service customers which create the need for the Company to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of the Company's operations than to utilize its design peak day requirements within its cost of service study.

Q. WHAT LEVEL OF FIRM DEMAND REQUIREMENTS MUST THE COMPANY CONSIDER IN DESIGNING ITS GAS DISTRIBUTION SYSTEM TO DELIVER GAS UNDER ALL CONDITIONS?

A. Peoples designs its system, and has sufficient capacity, to serve the delivery or transportation requirements of all its sales and transportation service customers. Therefore, the demands of all customers will be treated on an equivalent basis for purposes of cost allocation based on peak demands.

Q. WHY IS USE OF DESIGN DAY DEMAND CLOSELY RELATED TO THE CHANGE IN THE COMPANY'S FIXED PLANT INVESTMENT OVER TIME?

A. The change in its design day demand serves as the primary input into the Company's ongoing decisions to install distribution system facilities to meet firm customer demands for gas delivery service.

Regarding plant investment for meeting growth, the construction cost estimates associated with connecting a new customer to the Company's gas distribution system are always based upon the capacity level necessary to meet each customer's peak hour demands. An excellent proxy for the peak hour demands used in distribution cost estimating is the customer's design day demand.

Q. PLEASE EXPLAIN WHY USE OF DESIGN DAY DEMAND PROVIDES MORE STABLE COST ALLOCATION RESULTS OVER TIME?

A. By definition, a gas utility's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it was not a stable demand determinant, the design of a gas utility's system and supply portfolio would tend to vary and make the installation of facilities a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocators available based on either actual peak day demand or the averaging of multiple peak days.

Q. HOW WAS INVESTMENT IN DISTRIBUTION MAINS CLASSIFIED AND ALLOCATED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. It is widely accepted that distribution mains (Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the gas utility's system. Therefore, to ensure that the rate classes that cause the incurrence of this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a gas utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the gas utility's system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the gas utility.

Q. IS THE METHOD USED TO DETERMINE A CUSTOMER COMPONENT OF DISTRIBUTION MAINS A GENERALLY ACCEPTED TECHNIQUE FOR IDENTIFYING CUSTOMER-RELATED COSTS?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach; and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the gas utility system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the gas utility's distribution system, regardless of his peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach, which is the method utilized in the Company's cost studies, is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, (1) Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners (NARUC), and (2) Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. DID YOU MAKE ANY ADJUSTMENT TO THE RESULTING CUSTOMER COST COMPONENT FOR DISTRIBUTION MAINS BASED ON THE USE OF THE MOST COMMONLY INSTALLED, MINIMUM SIZE UNIT APPROACH?

A. Yes. To recognize that the minimum sized distribution main (a 2-inch diameter main) also has some level of capacity carrying capability, an adjustment was made to the level of the customer cost component to exclude a portion of the costs of distribution mains from the customer cost classification category. Those excluded costs were classified as capacity-related and treated in the same manner as other capacity-related costs for cost allocation purposes.

Q. HOW DID YOU RECOGNIZE THE FACT THAT THE COMPANY OPERATES BOTH LOW PRESSURE AND REGULATED PRESSURE DISTRIBUTION MAINS?

A. This operating condition was recognized in the Company's cost of service studies by treating the plant and associated expenses for its low pressure gas distribution system differently compared to the treatment of the plant and associated expenses for its regulated pressure gas distribution system. The manner in which various sizes of customers rely upon the Company's gas distribution system determined how each portion of Peoples' gas distribution system was allocated to its rate classes. Specifically, the plant and associated expenses for Peoples' regulated pressure distribution mains were assigned to all rate classes, while the plant and associated expenses for its low pressure distribution mains were assigned only to the Residential Service, Small General Service, and Medium General Service rate classes. This treatment reflects the fact that larger customers (primarily industrial customers) included in the Company's Large General Service rate class do not require Peoples' low pressure distribution mains to receive gas utility service. The nature of their gas loads and higher gas delivery pressure requirements dictate that they be served from Peoples' regulated pressure gas distribution system. In fact, because of such gas demand requirements, these customers are not connected to Peoples' low pressure gas distribution system, nor can they be served indirectly through a back-feeding of gas from such facilities. As a result, the cost causative characteristics of these plant and expense elements dictate that they should be treated for cost allocation purposes in the manner just described.

Q. IF THESE ARE YOUR PREFERRED METHODS FOR THE ALLOCATION OF DEMAND-RELATED COSTS AND THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION MAINS, WHY HAVE MULTIPLE COST OF SERVICE STUDIES BEEN FILED IN THIS PROCEEDING?

A. By performing cost of service studies under various cost allocation methodologies, the boundaries of cost responsibility may be identified. The results can then be used as a tool to guide the Company's revenue allocation and rate design.

Given adequate time and resources, each individual investment and expense could be analyzed to determine how it is used and what created the need for the investments and operating expenses and classified accordingly. Such a detailed cost classification study would, perhaps, be more accurate, but very costly to perform. However, the results of such a detailed and extensive cost of service study (assuming that data is available to accomplish it) may not be any more useful for revenue allocation and rate design than the cost of service studies filed in this proceeding, particularly when the cost analyst considers: (1) the need to ameliorate customer impacts; (2) the limitations of cost tracking of rates designed for a broad class of customers; and (3) the time and financial constraints in preparing a rate filing. The use of more than one cost allocation methodology attempts to recognize the level of judgment inherent in performing cost of service studies and provides this Commission with a reasonable and useable range of results.

In view of these considerations, and to minimize the potential controversy associated with selecting particular cost allocation methods, I have decided to use two common demand cost allocation methods (the peak method and the peak and average method), with and without a customer component of distribution mains, to determine a range of rate of return values for purposes of evaluating class cost responsibility. I describe that evaluation later in my testimony.

Q. PLEASE DESCRIBE THE SPECIAL STUDIES YOU CONDUCTED FOR PURPOSES OF ALLOCATING OTHER DISTRIBUTION PLANT INVESTMENT?

A. Regarding the Company's major plant accounts, a combination of direct assignments and weighting factors were developed to allocate the following plant accounts: Services - Account No. 380, Meters - Account No. 381, and Industrial Measuring & Regulating Station Equipment - Account No. 385. The weighting factors reflect any differences in the unit costs that the customer groups cause the Company to incur. For example, the average cost of a meter to serve a Residential Service customer was approximately $187.00, compared to the average cost of a meter to serve a Medium General Service customer of approximately $1,246.00. In addition, the cost of a service line which could serve a residential customer costs less, on a per unit basis, than the cost of a service line to serve an industrial service customer. The use of weighting factors takes these unit cost differences into account when assigning costs to these two customer classes.

Q. PLEASE DESCRIBE THE METHOD USED TO ALLOCATE RESERVE FOR DEPRECIATION AND DEPRECIATION EXPENSES?

A. These items were allocated on the same basis as their associated plant accounts.

Q. HOW WERE DISTRIBUTION-RELATED OPERATION AND MAINTENANCE EXPENSES ALLOCATED IN THE COMPANY'S CLASS COST OF SERVICE STUDY?

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's operation and maintenance expenses generally are thought to support the utility's corresponding plant-in-service accounts. That is, the existence of the particular plant facilities necessitates the incurrence of cost (i.e., expenses) by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a specific plant account will be the same basis as used to allocate the corresponding expense account. For example, Maintenance of Services - Account No. 892, is allocated on the same basis as its investment in Services - Account No. 380. With the Company's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. HOW WERE THE COSTS OF THE COMPANY'S GATHERING SYSTEM ALLOCATED IN ITS COST OF SERVICE STUDIES?

A. Peoples' gathering system is used to transport gas supplies delivered to its gas distribution system for its system supply and its end-use customers from local production facilities located within its service area. The plant and associated expenses for Peoples' gathering system were allocated to its classes of service based on the percentage of annual gas volumes in each class supplied by Pennsylvania gas producers that moved through the Company's gathering system. It is important to note that a portion of the costs of Peoples' gathering system allocated to its classes of service was effectively assigned to the local gas producers connected to Peoples' gas system by crediting the revenues proposed to be generated from the gathering services provided by Peoples to the same rate classes that received an allocated portion of Peoples' gathering cost of service.

Q. HOW WERE THE COSTS OF THE COMPANY'S UNDERGROUND STORAGE FACILITIES ALLOCATED IN ITS COST OF SERVICE STUDIES?

A. Peoples currently owns and operates the Dice Storage Field, which has 1,530,000 Mcf of storage capacity and 32,000 Mcf of maximum daily withdrawal capacity. Peoples' underground storage is used to generally support the unplanned daily balancing requirements of its sales and transportation service customers. Based on an historical review of the daily withdrawal activity of this facility, it was determined that gas volumes are primarily withdrawn from this storage facility on most days during the months of December through May. As a result, Peoples' storage-related costs were allocated to the rate classes in proportion to the total gas sales and transportation volumes for each class during the six-month period of December through May.

Q. HOW WERE ADMINISTRATIVE AND GENERAL EXPENSES ALLOCATED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. Peoples' cost of service studies allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Specifically, administrative and general expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant or rate base; (3) O&M expenses; or (4) some combination of the above categories. In the Company's cost of service study, each of its administrative and general accounts was related to one or more of these categories. These categories were then used as a basis to establish an appropriate allocation factor for each account. The allocation factors chosen were broad-based to specifically recognize the Company-wide nature of administrative and general expenses.

Specifically, supervision, office supplies and expenses, administrative expenses transferred (Account Nos. 920, 921 and 922) and employee pensions and benefits (Account No. 926) were allocated using a labor-related allocation factor derived based on all labor costs incurred by the Company. Similarly, the plant and O&M allocation factors discussed above were derived based on the Company's total plant investment and total O&M expenses, respectively. For example, total plant in service by function was used to allocate property insurance (Account No. 924) and injuries and damages (Account No. 925) to the rate classes.

Outside services (Account No. 923) include support activities provided to Peoples directly by its outside service providers and internal service organization. These activities generally relate to various general business functions that support the Company's gas utility operations. Due to the general nature of these costs and their corporate-wide applicability, these costs were allocated to the Company's customer classes using a labor-based allocation factor reflecting labor-related costs across all of Peoples' cost accounts.

Q. HOW WERE TAXES OTHER THAN INCOME TAXES ALLOCATED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. Peoples' cost of service studies allocated these expenses in a manner to reflect the specific cost causative factors associated with the Company's specific tax expense categories. Specifically, these taxes can be cost classified based on the tax assessment method established for each tax category (i.e., property and payroll). As a result, taxes other than income taxes of a utility typically can be grouped into the following categories: (1) plant; (2) labor; and (3) gas supply-related. In the cost of service study, each of Peoples' taxes other than income taxes accounts was related to one of the above stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. HOW WERE INCOME TAXES ALLOCATED IN THE COMPANY'S COST OF SERVICE STUDIES?

A. Income Taxes were allocated to each rate class based on its net income before federal and state income taxes at present rates. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues, previously allocated expenses and the various adjustments made by the Company for tax computation purposes. The component of income tax expenses based on the tax deferral created by investments in plant was allocated to each customer class based on the class' allocation of Gross Plant.

Income Taxes included in the change in revenue requirements were computed directly by grossing up the required return on rate base at the expected effective tax rate. The additional Income Taxes were then allocated to each customer class based on its proposed net income multiplied by the new effective tax rate.

Q. PLEASE DISCUSS THE RESULTS OF THE COMPANY'S COST OF SERVICE STUDIES.

A. Referring to IV-B-1(E) of Exhibit 11, Schedule 1, the following cost of service study results at present rates for the future test year are indicated:

1. Residential Service exhibits a below average rate of return under the cost of service study based on a design day demand allocation method with a customer component of distribution mains, and a slightly above average rate of return under the cost of service study based on a peak and average demand allocation method.
2. Small General Service exhibits an average rate of return under the cost of service study based on a design day demand allocation method with a customer component of distribution mains, and a below average rate of return under the cost of service study based on a peak and average demand allocation method.
3. Medium General Service exhibits an above average rate of return under the cost of service study based on a design day demand allocation method with a customer component of distribution mains, and a slightly above average rate of return under the cost of service study based on a peak and average demand allocation method.

4. Large General Service exhibits an above average rate of return under the cost of service study based on a design day demand allocation method with a customer component of distribution mains, and a below average rate of return under the cost of service study based on a peak and average demand allocation method.

Q. PLEASE DESCRIBE THE CONTENTS OF EXHIBIT 11 SCHEDULE 4.

A. Exhibit 11, Schedule 4 which consists of 53.53 IV-B-9 - Cost Analysis Supporting Minimum Charges for All Rate Schedules - presents the components of the customer-classified costs for each of Peoples' customer classes. This information is extracted from the cost of service studies which are presented in Exhibit 11, Schedule 1.

Q. HAVE YOU ALSO PREPARED A MINIMUM CUSTOMER ANALYSIS THAT RELIES UPON THIS COMMISSION'S PAST REGULATORY PREFERENCES AND PRECEDENTS ADDRESSING THIS ISSUE?

A. Yes. While I believe that the Company's customer cost analysis presented in Exhibit 11, Schedule 4 is the most appropriate method to derive a gas utility's customer-related cost of service for purposes of setting its monthly customer charges, I do recognize that in the past this Commission has relied, at least in part, on a minimum customer analysis approach that excludes certain costs that, in my opinion, are also appropriately classified as customer-related costs. As a result, I have also prepared a minimum customer analysis that was guided by the Commission's decision in the Aqua Pennsylvania Rate Case in Docket R-00038805. This cost analysis is presented in **Peoples Exhibit RAF-2.** It shows that the level of the monthly customer charge for the Company's Residential Service rate class should be equal to at least $24.41 per month.

Q. HOW CAN COST OF SERVICE STUDY RESULTS SUCH AS THESE PROVIDE GUIDELINES FOR RATE DESIGN?

A. Results of a cost of service study provide cost guidelines for use in evaluating class revenue levels and class rate structures. With regard to rate class revenue levels, the rate of return results show that certain rate classes are being charged rates that recover less than their indicated costs of service. Obviously, because this condition exists, rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. By adjusting rates in accordance with the cost study, rate class revenue levels can be brought closer in line with the indicated costs of service resulting in movement of rate class rates of return toward the system average rate of return and resulting in rates that are more in line with the cost of providing service.

Concerning cost justification of rates within each rate class, the classified costs, as allocated to each class of service in the cost study, provide cost information that can be of assistance in determining the need for changes in the relative levels of demand charges (if they exist), customer and commodity rate block charges.

Q. ARE THE RESULTS OF A GAS UTILITY'S COST OF SERVICE STUDY ALWAYS RELEVANT TO ALL TYPES OF SERVICE?

A. No. This situation applies to Peoples' competitively situated customers, where rates are based on their competitive characteristics. For these customers, the price the customer is willing to pay for gas delivery service relative to available alternatives has much more influence on the relative profitability (i.e., rate of return on net rate base) than cost causation does, as measured by a gas utility's cost of service study. This view is shared by NARUC in its Gas Rate Design Manual, where it states that "[s]etting rates based on value of service bears little relationship to setting them based on cost of service. When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer." Therefore, the guidelines I discussed above are most useful when evaluating the costs to serve customers in the Company's RS, SGS and MGS rate classes, and less useful when evaluating its LGS rate class which includes most of the Company's competitively situated customers who are priced on a negotiated (i.e., value of service) basis. In addition, as I pointed out earlier in my testimony, cost of service study results for Peoples' gathering service to local gas producers (other than the derivation of Peoples' total functionalized cost of gathering) do not provide the sole basis for adjustments to the current level of rates for this service.

Q. PLEASE EXPLAIN HOW THE UNIT COST RESULTS PRESENTED IN EXHIBIT 11, SCHEDULE 1 WERE PREPARED.

A. Black & Veatch's COSS Model compiles the functionalized, classified and allocated expenses and rate base data for each class of service. The system average rate of return is applied to the allocated rate base to determine the required net income. This is then grossed up to account for the income tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yields the total revenue requirement for each component of cost at the system average rate of return. The computer model makes this calculation for each of the various cost components (i.e., the customer, demand and commodity portions of the supply, gathering, storage, and distribution functional categories). The functionally classified costs are unitized by dividing the total costs by the appropriate number of billing units. Customer-related costs are divided by the number of bills, demand-related costs are divided by the contribution to peak demand and commodity-related costs are divided by the number of Mcf delivered. It should be noted that a monthly customer cost is calculated for each customer class, as well as unit commodity and demand costs.

Page 2 of IV-B-1(A) and IV-B-1(B) (Exhibit 11, Schedule 1) presents the unitized cost of service study results (at the Company's proposed rate of return on rate base) described above.

Q. CAN THESE UNIT COST ANALYSES RESULTS BE USED FOR RATE DESIGN?

A. Yes, if three-part rates (i.e., customer, demand and commodity) were set at the unit cost levels, the Company's operating expenses and rate of return on investment based on its pro-forma test year would be recovered (assuming customer counts, gas deliveries and other billing determinants were as projected). The unit cost analyses also provide valuable unbundled cost information for the design of portions of the tariff. One of the most obvious applications is the use of unbundled cost information for establishing cost-based monthly customer charges. For example, Peoples' cost of service studies show that a full cost-based customer charge for its Residential Service class is supportable within a range of between $24.21 and $34.41 per month. The unit cost analysis could also be used to establish separately metered contract demand charges where the cost of demand metering can be justified or where a reasonable method of estimating customer demands can be derived.

Q. DOES PEOPLES' COST OF SERVICE STUDY DERIVE THE TOTAL FUNCTIONALIZED COST OF ITS GATHERING SYSTEM?

A. Yes. The functionalization phase of Peoples' cost of service study identifies the specific plant components and expenses that comprise the gathering function and allocates other indirect costs that are necessary to support the gathering function. This process determines Peoples' fully loaded cost of gathering service. **Peoples Exhibit RAF-3** summarizes the rate base, expenses, rate of return on rate base (as proposed) and federal income taxes that comprise Peoples' total gathering cost of service. These cost components are derived from the cost of service study presented in Exhibit 11, Schedule 1, IV-B-1(A), Pages 13 to 22, which provides each of the detailed plant and expense components that comprise Peoples' gathering function. As a point of comparison, **Peoples Exhibit RAF-3** also provides Peoples' gathering service revenues at present and proposed rates.

<u>PEOPLES' PROPOSED CLASS REVENUES</u>

Q. PLEASE DESCRIBE THE APPROACH GENERALLY FOLLOWED TO ALLOCATE PEOPLES' PROPOSED REVENUE INCREASE OF $93.1 MILLION TO ITS VARIOUS RATE CLASSES.

A. As described earlier, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for each of the Company's rate classes. Based on this evaluation, adjustments to the present revenue levels in certain rate classes were made so that the rates proposed by Peoples moved class revenues closer to the costs of serving those rate classes.

Q. DID YOU CONSIDER VARIOUS CLASS REVENUE OPTIONS IN CONJUNCTION WITH YOUR EVALUATION AND DETERMINATION OF PEOPLES' INTERCLASS REVENUE PROPOSAL?

A. Yes. Using Peoples' proposed revenue increase, and the range of results from its cost of service studies, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Company personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. Pages 1 and 2 of **Peoples Exhibit RAF-4** provide two reference points based on the cost of service studies presented by Peoples. In each case, I adjusted the revenue level for each rate class so that each would produce the proposed rate of return and the relative rate of return on net rate base for each class equal to 1.00. Page 1 of this Exhibit presents these results for Peoples' cost of service study based on the design day demand cost allocation method with a customer component of distribution mains. The second point of reference I considered in the evaluation was the midpoint of the results of Peoples' two cost of service studies to recognize the range of results that I discussed earlier in my testimony. Page 2 of this Exhibit provides the underlying computations for this option.

The analyses presented on Pages 1 and 2 of **Peoples Exhibit RAF-4** were carried forward to Tables 1 and 2 on Page 3 of this Exhibit. The results in Table 1indicated that revenue increases were required for Peoples' RS and SGS classes, and that revenue decreases were required for its MGS and LGS classes. As a matter of judgment, I decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. It should be pointed out, however, that those results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective. The results in Table 2 provided another point of reference, although the midpoint of Peoples' two cost of service studies is not the best representation of the costs of serving Peoples' customers for the reasons I discussed earlier in my testimony.

The second option I considered was assigning the increase in revenues to Peoples' rate classes based on an equal percentage basis of its current base revenues. This option is presented in Table 3 on Page 3 of this Exhibit. Obviously, this option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the cost of service study results (as measured by changes in the rate of return on net rate base for each rate class); there was only modest movement towards cost for most of Peoples' rate classes (i.e., the resulting rates of return only slightly converged to unity or 1.00). In addition, it is important to recognize that because most of the Company's competitively situated customers are included in the LGS rate class, any increase in class revenues could not be recovered from such customers. While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option presented in Table 1 and the midpoint of the cost of service study results presented in Table 2, it defined a range of results that provided me with further guidance to develop Peoples' class revenue proposal.

Q. BEFORE CONTINUING, CAN YOU PLEASE EXPLAIN THE TERMS "NON-GAS REVENUE" AND "MARGIN" THAT ARE USED IN PEOPLES EXHIBIT RAF-4?

A. Yes. The terms 'non-gas revenue" and "margin" are used synonymously when discussing a utility's ratemaking process. Peoples non-gas revenue or margin refers to the revenue amount necessary to recover its total cost of service, other than the costs of natural gas that are normally recovered through the Commission's 1307(f) proceedings. The total non-gas revenue proposed by Peoples in this proceeding is approximately $490.9 million, which is the targeted amount upon which Peoples' proposed class revenues and rates are designed.

Q. WHAT WAS THE NEXT STEP IN THE PROCESS?

A. After further discussions with the Company, I concluded that an appropriate interclass revenue proposal would assign greater than average increases to the rate classes that exhibited the greatest revenue deficiencies relative to the costs to serve these rate classes, as derived in the Company's cost of service studies. Pages 1 and 2 of **Peoples Exhibit RAF-4** show that its Residential Service rate class exhibited a relative rate of return on net rate base below 1.00 at present rates under both the cost of service study based on the design day demand method with a customer component of distribution mains and the combination (midpoint) of Peoples' two cost of service studies. For rate classes that exhibited revenue surpluses or a relative rate of return on net rate base above 1.00, the Medium General Service and Large Volume Service rate classes, I determined that a smaller than average increase in non-gas revenues was warranted. Finally, I assigned the average increase in non-gas revenues (i.e., 23.9%) to the rate class whose relative rates of return on net rate base was closer to 1.00 (Small General Service) compared to the other rate classes.

This approach resulted in reasonable movement of the class relative rates of return on net rate base towards unity or 1.00. That result is reflected in Table 4 on Page 4 of **Peoples**

Exhibit RAF-4, wherein the relative rates of return on net rate base are shown to converge towards unity or 1.00 compared to the same measure calculated under present rates. In addition, the amounts of the existing rate subsidies among the Company's rate classes were generally reduced. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable to move class revenues and rates closer to the indicated cost of service for each rate class. It should be noted that these increase amounts are designated as targets because certain pricing considerations needed to be accommodated in the actual design of the Company's proposed rates (e.g., achieving rate equivalence between the Company's sales and transportation services), the actual revenue increases by rate class varied from the target amounts based on the actual revenues generated from the final rates.

Q. YOU MENTIONED EARLIER THAT BECAUSE THE COMPANY HAS COMPETITIVELY SITUATED CUSTOMERS INCLUDED IN ITS SGS, MGS AND LGS RATE CLASSES, ANY INCREASE IN CLASS REVENUES ASSIGNED TO THOSE RATE CLASSES COULD NOT BE RECOVERED FROM SUCH CUSTOMERS. HOW WILL THE OTHER CUSTOMERS IN THESE RATE CLASSES WHO ARE CHARGED FOR GAS SERVICE UNDER THE COMPANY'S STANDARD RATES BE IMPACTED BY THE INCREASES IN REVENUES TO THESE RATE CLASSES UNDER THE COMPANY'S INTERCLASS REVENUE PROPOSAL?

A. The standard rates to these other customers were increased to recover the entirety of the revenue increase assigned to each of these three rate classes. In doing so, the Company was mindful of the unique customer impact considerations in these rate classes recognizing the fewer number of customers and decreased level of gas volumes under which any revenue increase could be recovered through the Company's standard rates. As such, it is important to understand that any greater level of revenue sought from these rate classes will have a disproportionate impact on the level of the Company's standard rates proposed for these rate classes.

PEOPLES' PROPOSED RATE DESIGN

Q. CAN YOU PLEASE DESCRIBE THE KEY OBJECTIVES YOU SOUGHT TO ACHIEVE IN THE DESIGN OF PEOPLES' PROPOSED RATES?

A. Yes. In general, I sought to achieve the following objectives with the rate design (the design of rates to recover the level of allocated costs from each class) that was proposed for Peoples:

- Achieve fair and equitable rate levels (reflective of the cost to serve).
- Avoid undue discrimination between and within rate classes.
- Rates should be stable, understandable, and provide customer choices.
- Create economically efficient pricing for natural gas delivery service.
- Rates should encourage energy conservation and energy efficiency.
- Rates should allow a utility to recover its revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under or over-collections.

Q. PLEASE DESCRIBE HOW YOU DERIVED THE RATES APPLICABLE TO RESIDENTIAL CUSTOMERS UNDER PEOPLES' SALES RATE SCHEDULE RATE RS AND TRANSPORTATION RATE SCHEDULE RATE GS-T.

A. My first step was to set the monthly customer charge. I accomplished this based on the results of the minimum customer cost analysis presented in **Peoples Exhibit RAF-2** and the customer costs derived in the unit cost analysis presented in Exhibit 11, Schedule 1 that was described earlier in my testimony. These documents present customer cost analyses that support a residential customer charge of between $24.41 and $34.41per month. Based on this cost information, I set the residential monthly customer charge at $20.00. This is an increase of $6.05 and $6.75 per month for customers in the Peoples and Equitable Divisions, respectively. I believe these proposed changes represent the minimum increases the Commission should consider adopting in this proceeding for Peoples' residential monthly customer charge in view of the materially higher customer-related costs indicated above. It is appropriate to recover customer costs through the customer charge because these costs do not change with usage and it provides more levelized annual revenues for the Company and reduces winter bills for customers when gas consumption charges are greatest.

In the next step I developed the residential delivery charge. I considered the recovery of non-gas costs from the Merchant Function Charge - Rider E, the Universal Service Charge - Rider F, Rider Supplier Choice, and the Gas Procurement Charge - Rider G, and then I designed rates to recover the remaining non-gas costs through the delivery charge. The resulting proposed residential delivery charge applicable to both sales and transportation customers is $3.8753/Mcf. Pages 1 and 6 of **Peoples Exhibit RAF-5** provide a summary of the proposed residential base rate charges and all applicable tariff riders. Column (1) of this Exhibit shows the proposed monthly customer charge and delivery charge.

Q. IS PEOPLES PROPOSING TO CHANGE THE GENERAL STRUCTURE OF ITS CURRENT RATES FOR NON-RESIDENTIAL CUSTOMERS IN THE PEOPLES DIVISION?

A. Yes. Peoples has proposed to eliminate the commercial and industrial rate designations in each of its non-residential tariffs (i.e., the Small General Service, Medium General Service and Large General Service sales and transportation rate classes) for its Peoples Division.

Q. PLEASE EXPLAIN WHY PEOPLES HAS PROPOSED THIS CHANGE.

A. Peoples has proposed this change to recognize that the end-use designation of a general service customer as commercial or industrial does not influence the underlying cost characteristics upon which rates should be based. Instead, a customer's load characteristics (e.g., annual gas consumption, peak usage, annual load factor) have a direct influence on the cost of serving the customer and should be recognized when setting rates within a class of service. Assessing monthly customer charges and volumetric delivery charges to customers based on their gas consumption levels rather than on their end-use designations provides a better reflection in rates of the cost to serve.

Q. IN DERIVING THE RATES APPLICABLE TO CUSTOMERS OTHER THAN PEOPLES' RESIDENTIAL CUSTOMERS, WAS IT NECESSARY TO ADDRESS POTENTIAL RATE IMPACTS TO CERTAIN INDUSTRIAL CUSTOMERS ASSOCIATED WITH THE ELIMINATION OF THE COMMERCIAL AND

INDUSTRIAL RATE DESIGNATIONS IN THE CURRENT TARIFF OF THE PEOPLES DIVISION?

A. Yes. Since the current delivery rate levels of industrial customers in the Peoples Division are much lower compared to the delivery rate levels of comparable sized commercial customers, the elimination of the commercial and industrial rate designations will cause disproportionate increases to the rate levels for industrial customers in the Peoples Division. As a result, it was necessary to propose a rate impact mitigation approach in this proceeding for the industrial customers in the Peoples Division.

After the completion of this rate case, Peoples' proposes to maintain the current rate distinction for the industrial customers in the Peoples Division (designated as Peoples' Transitional Industrial Ratepayers) who took gas service as of the effective date of Peoples' new rates approved in this rate case to be able to recognize the lower current rate levels for these customers relative to those of similarly sized commercial customers (and industrial customers in the Equitable Division) when applying the proposed revenue increases for the SGS, MGS and LGS rate classes (for both sales and transportation service customers). It is Peoples' expectation that in a future rate case, the remaining rate differential between its Transitional Industrial Ratepayers and commercial customers to achieve rate parity will be eliminated. Peoples witness Carol Scanlon (Peoples Statement No. 5) discusses the tariff changes that are required to implement this rate impact mitigation proposal.

Q. HOW DID YOU DETERMINE THE DEGREE TO WHICH THE CURRENT DELIVERY CHARGES OF PEOPLES' TRANSITIONAL INDUSTRIAL RATEPAYERS SHOULD BE INCREASED TO MOVE TOWARDS RATE

PARITY WITH PEOPLES' OTHER CUSTOMERS IN THE SGS, MGS AND LGS RATE CLASSES?

A. This was accomplished by examining the percentage increases in delivery charges in the SGS, MGS and LGS rate classes for Peoples' Transitional Industrial Ratepayers, its commercial customers and customers in the Equitable Division necessary to achieve the proposed revenue increases by rate class discussed earlier in my testimony. The number of Transitional Industrial Ratepayers in each of these rate classes also influenced the decision on the degree to which the delivery charges to these customers would be increased to move towards rate parity with the delivery charges of the other customer groups.

Based on this information and the application of the principle of gradualism, I established general guidelines which I used to adjust the current delivery charges for Peoples' Transitional Industrial Ratepayers to balance the resulting rate impacts with the goal of moving towards rate parity. For the SGS rate class, the proposed increase in the delivery charge to Peoples' Transitional Industrial Ratepayers approximated 1 ½ times the percent increase in revenues proposed for this rate class (approximately 26% on a non-gas or margin revenue basis). This approach resulted in the current delivery charge for Peoples' Transitional Industrial Ratepayers moving about 65 percent of the way to rate parity. For the MGS and LGS rate classes, the proposed increases in the delivery charges to Peoples' Transitional Industrial Ratepayers were established to move their rate levels between about 45 and 65 percent toward rate parity with Peoples' other two customer groups in the particular rate class. I believe these proposed rate adjustments result in a reasonable balancing of the objectives sought to be achieved for Peoples' Transitional Industrial Ratepayers.

Q. PLEASE DESCRIBE HOW YOU DERIVED THE RATES APPLICABLE TO SMALL GENERAL SERVICE CUSTOMERS UNDER PEOPLES' SALES RATE SCHEDULE RATE SGS AND TRANSPORTATION RATE SCHEDULE RATE GS-T.

A. My first step was to set the monthly customer charges. I accomplished this based on the results of the minimum customer cost analysis presented in **Peoples Exhibit RAF-2** and the customer costs derived in the unit cost analysis presented in Exhibit 11, Schedule 1 that was described earlier in my testimony. These documents present customer cost analyses that support an SGS customer charge of between $24.28 and $34.00 per month. Based on this information, I set the SGS monthly customer charges at $25.00 per month (for customers using up to 499 Mcf per year) and $40.00 per month (for customers using between 500 and 999 Mcf per year). It is appropriate to recover customer cost through the customer charge because these costs do not change with usage and it provides more levelized annual revenues for the Company and reduces winter bills for customers when gas consumption charges are greatest.

In the next step I developed the SGS delivery charge. I considered the recovery of non-gas costs from the Merchant Function Charge - Rider E, Rider Supplier Choice, and the Gas Procurement Charge - Rider G, and then I designed rates to recover the remaining non-gas costs through the delivery charge. The resulting proposed SGS delivery charge is applicable to both sales and transportation customers. Pages 1 and 6 of **Peoples Exhibit RAF-5** provide a summary of the proposed small general service base rate charges and all applicable tariff riders. Column (1) of this Exhibit shows the proposed monthly customer charges and delivery charges.

Q. PLEASE DESCRIBE HOW YOU DERIVED THE RATES APPLICABLE TO MEDIUM GENERAL SERVICE CUSTOMERS UNDER PEOPLES' SALES RATE SCHEDULE RATE MGS AND TRANSPORTATION RATE SCHEDULE RATE GS-T.

A. My first step was to set the monthly customer charges. I accomplished this based on the results of the minimum customer cost analysis presented in **Peoples Exhibit RAF-**2 and the customer costs derived in the unit cost analysis presented in Exhibit 11, Schedule1 that was described earlier in my testimony. These documents present customer cost analyses that support MGS customer charges of between $61.86 and $72.72 per month. At the same time, I recognized that Peoples' current monthly customer charges for this rate class were $50.00 and $77.00 for customers in Peoples Division and $150.00 and $300.00 for customers in the Equitable Division. Based on this information, I set the MGS monthly customer charges at $100.00 per month (for customers using up to 2,499 Mcf per year) and $200.00 per month (for customers using between 2,500 and 24,999 Mcf per year). It is appropriate to recover customer cost through the customer charge because these costs do not change with usage and it provides more levelized annual revenues for the Company and reduces winter bills for customers when gas consumption charges are greatest. While these proposed rate levels are above the indicated customer-related costs, they were chosen to accommodate the need to significantly decrease the current monthly customer charges for customers in the Equitable Division and the decision to address this need in a gradual manner.

In the next step I developed the MGS delivery charge. I considered the recovery of non-gas costs from the Merchant Function Charge - Rider E, and the Gas Procurement Charge - Rider G, and then I designed rates to recover the remaining non-gas costs through the delivery charge. The resulting proposed MGS delivery charge is applicable to both sales and transportation customers.

Pages 1, 2, 6 and 7 of **Peoples Exhibit RAF-5** provide a summary of the proposed MGS base rate charges and all applicable tariff riders. Column (1) of this Exhibit shows the proposed monthly customer charges and delivery charges.

Q. PLEASE DESCRIBE HOW YOU DERIVED THE RATES APPLICABLE TO LARGE GENERAL SERVICE CUSTOMERS UNDER PEOPLES' SALES RATE SCHEDULE RATE LGS AND TRANSPORTATION RATE SCHEDULE RATE GS-T.

A. My first step was to set the monthly customer charges. I accomplished this based on the results of the minimum customer cost analysis presented in **Peoples Exhibit RAF-2** and the customer costs derived in the unit cost analysis presented in Exhibit 11, Schedule 1 that was described earlier in my testimony. These documents present customer cost analyses that support LGS customer charges of between $858.66 and $880.19 per month. At the same time, I recognized that Peoples' current monthly customer charges for this rate class ranged between $443.00 and $2,009.00 for customers in Peoples Division and $1,600.00 for customers in the Equitable Division. Based on this information, I set the LGS monthly customer charges at $700.00 per month (for customers using up to 49,999 Mcf per year), $1.300.00 per month (for customers using between 50,000 and 99,999 Mcf per year) $1,400.00 per month (for customers using between 100,000 and 199,999 Mcf per year) and $1,600.00 per month (for customers using over 200,000 Mcf per year). It is appropriate to recover customer cost through the customer charge because these costs do not change with usage and it provides more levelized annual revenues for the Company and reduces winter bills for customers when gas consumption charges are greatest. While these proposed rate levels are above the indicated customer-related costs, they were chosen to accommodate the need to decrease the current monthly customer charges for customers in the Equitable Division and for the larger customers in the Peoples Division, and the decision to address this need in a gradual manner. The derivation of the delivery charges for the LGS rate class is described below.

Q. HAS PEOPLES PROPOSED TO CHANGE THE CURRENT STRUCTURE OF THE RATE TIERS (RATE BLOCKS) FOR ITS LGS RATE CLASS?

A. Yes. Peoples has proposed to increase the number of rate tiers for the delivery charges in the sales and transportation rate schedules for the LGS rate class.

Q. WHY HAS PEOPLES PROPOSED TO INCREASE THE NUMBER OF RATE TIERS (OR RATE BLOCKS) FOR THE DELIVERY CHARGES IN THE SALES RATE SCHEDULE RATE LGS AND TRANSPORTATION RATE SCHEDULE RATE GS-T?

A. Peoples has proposed this type of rate structure change to accommodate the relatively wide range of customers served in the LGS sales and transportation rate classes and to recognize the significant differences in load characteristics among these customers which directly affects the nature of their cost characteristics. For example, the annual gas consumption of the over 200 customers in the LGS rate class ranges widely from 86 Mcf to 8.6 Bcf, with customers' annual load factors ranging between 6% and 88%. These significant variations in load characteristics have a material impact on how, and to what degree, the recovery of fixed, demand-related costs occurs across this diverse a customer base. With this group of customers, a single delivery charge assessed based on a customer's gas consumption would result in some customers being overcharged for the fixed costs associated with providing gas delivery service while others would be undercharged for such service. This occurs because a customer's load factor is a measure of how efficiently the customer utilizes the capacity of the utility's gas system, so the lower the load factor, the less efficient the customer is in using distribution system capacity to satisfy the customer's capacity requirements on a peak day compared to on an average day. The wide range of annual load factors for these customers indicates the need for multiple rate tiers to fairly recover Peoples' fixed, capacity-related costs through the delivery rate component for the LGS class.

Q. HOW DID YOU DETERMINE THE STRUCTURE OF THE RATE TIERS PROPOSED FOR PEOPLES' LGS RATE CLASS?

A. I used as a starting point the four (4) rate tiers that exist in the LGS sales and transportation rate schedules (Rate Schedules LGS and GS-T) to assess the monthly customer charges to customers. Then, I added two (2) additional rate tiers to accommodate the largest customers in the LGS rate class who use greater than 750,000 Mcf per year and greater than 2,000,000 Mcf per year. In general, the annual load factors of the LGS customers increase across these rate tiers which is indicative of the need to establish the delivery charge of each successive rate tier at a level that is less than the delivery charge for the previous rate tier to properly reflect the lower unit capacity (demand) cost of serving customers as their annual load factors increase.

Q. HOW WAS THE PROPOSED DELIVERY CHARGE FOR EACH RATE TIER DERIVED?

A. The delivery charge for the 100,000 to 199,999 Mcf rate tier (which is the rate tier that includes the annual gas consumption of the average LGS customer) was based on the proposed class revenues for the LGS rate class after first excluding the revenues derived from the proposed monthly customer charges and applicable rate riders. Then, the delivery charges for the first two rate tiers were scaled up and the delivery charges for the last three rate tiers were scaled down from the third-tier (100,000 to 199,999 Mcf) delivery charge to reflect the relative variation in customer load factors between rate tiers and level of gas consumption in each rate tier. The final step was to slightly adjust the delivery charge levels in the first tiers of the rate to align with the delivery charge levels proposed in the MGS rate class, so they would be reflective of the relatively higher customer load factors (and lower unit demand costs) in the LGS rate class compared to those in the MGS rate class.

Pages 2-5 and 7-10 of **Peoples Exhibit RAF-5** provide a summary of the proposed large general service base rate charges and all applicable tariff riders. Column (1) of this Exhibit shows the proposed monthly customer charges and delivery charges.

Q. HAVE YOU PREPARED A BILL COMPARISON WHICH SHOWS THE IMPACT OF PEOPLES' PRESENT AND PROPOSED RATES ON THE GAS BILLS OF THE AVERAGE-SIZED CUSTOMER IN EACH RATE CLASS?

A. Yes. Exhibit 11, Schedule 8 (53.53 IV-B-12) presents bill comparisons for each of Peoples' retail rate classes for the Peoples and Equitable Divisions. This document presents an annual bill comparison for a typical customer in each rate class.

Q. HAVE YOU ALSO PREPARED A MONTHLY BILL COMPARISON FOR PEOPLES' RESIDENTIAL CUSTOMERS?

A. Yes. **Peoples Exhibit RAF-6** presents monthly bill comparisons for Peoples' residential customers served in its Peoples and Equitable Divisions.

Q. WHAT DOES THIS ANALYSIS SHOW FOR RESIDENTIAL CUSTOMERS IN THE PEOPLES DIVISION?

A. Peoples' proposed rate design will increase the average customers' gas bills in the summer months, when customer bills are at their lowest levels, and will moderate the increase in customer's bills in the winter months, when bills are at their highest levels. This benefit is depicted on Page 1 of **Peoples Exhibit RAF-6.** This Exhibit shows that the annual gas bill for the average residential customer in the Peoples Division using 86 Mcf per year is proposed to increase by approximately 14.1%, with a lower percentage increase to monthly bills in March of 10.9% (during the month of highest gas consumption and highest bills) and a higher percentage increase to monthly bills in September of 25.6% (during the month of lowest gas consumption and lowest bills).

Q. WHAT DOES THIS ANALYSIS SHOW FOR RESIDENTIAL CUSTOMERS IN THE EQUITABLE DIVISION?

A. Like the results described above, Peoples' proposed rate design will increase the average customers' gas bills in the summer months, when customer bills are at their lowest levels, and will moderate the increase in customer's bills in the winter months, when bills are at their highest levels. This benefit is depicted on Page 2 of **Peoples Exhibit RAF-6.** This Exhibit shows that the annual gas bill for the average residential customer in the Peoples Division using 86 Mcf per year is proposed to increase by approximately19.7%, with a lower percentage increase to monthly bills in March of 15.9% (during the month of highest gas consumption and highest bills) and a higher percentage increase to monthly bills in September of 33.3% (during the month of lowest gas consumption and lowest bills).

Q. PLEASE DESCRIBE HOW THE PROPOSED CHARGES FOR PEOPLES' GENERAL SERVICE – STANDBY TARIFF (RATE GS-SB) WERE DERIVED.

A. The proposed non-gas charges for Peoples' standby service tariff were established based on the same proposed monthly customer charges that were derived for the Residential

Service, Small General Service and Medium General Service rate classes. Under Peoples' proposed standby service tariff, the standby customer charge shall be the monthly customer charge otherwise applicable under other rate schedules.

Q. PLEASE DESCRIBE HOW YOU DERIVED PEOPLES' MERCHANT FUNCTION CHARGE UNDER RIDER E.

A. Peoples' Merchant Function Charge (MFC) under Rider E was derived based on the gas cost portion on uncollectible expenses incurred by Peoples. **Peoples Exhibit RAF-7** provides details of the supporting calculations. Peoples proposes to revise the MFC to reflect updated write-off factors by customer class. The MFC applicable to Residential Service (RS) customers is calculated based on the updated residential write-off factor of 2.49%. The MFCs applicable to commercial and industrial customers under Rates SGS, MGS and LGS are based on the updated combined commercial write-off factor of 0.21%. The derivation of the updated write-off factors used in these calculations is supported by Peoples' witness Andrew Wachter (Peoples Statement No. 3) .

Q. PLEASE DESCRIBE HOW YOU DERIVED PEOPLES' GAS PROCUREMENT CHARGE UNDER RIDER G.

A. Peoples' Gas Procurement Charge (GPC) under Rider G was derived to reflect the cost elements approved by the Commission for this charge. **Peoples Exhibit RAF-8** provides details of the supporting calculations. The proposed GPC is $0.0801/Mcf. The costs included in the derivation of the GPC are: (1) internal labor and benefits costs incurred to provide gas supply services (personnel responsible for the planning, scheduling and purchasing of gas), and to provide legal, regulatory and accounting support services; (2) outside legal services; (3) working capital storage inventory costs; and (4) capital costs related to the portion of the Information Technology (IT) systems used to support the gas procurement function. This cost analysis excludes labor and benefits costs for the gas supply, legal, regulatory and accounting functions that support Peoples' combined sales and transportation programs such as storage and transportation capacity management and local gas management.

Q. PLEASE DESCRIBE HOW YOU DERIVED THE FEES CHARGED TO NATURAL GAS SUPPLIERS.

A. The proposed pricing of Peoples' supplier-related services was based on the results of an analysis that quantified and compared the costs and revenues at current rates for billing services under Supplier Billing Service - Rate SBS. **Peoples Exhibit RAF-9** presents the results of this comparison and the calculations of the revenue requirement for consolidated billing services. Only incremental billing costs were included in this cost analysis because all other billing-related costs are already incurred by Peoples to render bills on behalf of its sales and transportation service customers. This exhibit shows that revenues at present rates exceed the revenue requirement for these services by $55,259. Based on this result, Peoples has proposed to maintain the consolidated billing services fee for the Peoples Division at $0.15 per customer per month, and to reduce its fee for the Equitable Division from $0.30 to $0.15 per customer per month.

Q. PLEASE DESCRIBE HOW YOU DERIVED PEOPLES' PURCHASE OF RECEIVABLES – ADMINISTRATIVE ADDER.

A. Peoples' Purchase of Receivables (POR) – Administrative Adder was derived to reflect the incremental costs incurred by Peoples to implement the POR program. **Peoples Exhibit RAF-10** provides details of the supporting calculations. The proposed Administrative Adder associated with residential and SGS customers is 0.0213%.

CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH REGARD TO PEOPLES' COST OF SERVICE STUDIES, CLASS REVENUES AND RATE DESIGN.

A. My conclusions and recommendations for the Company's cost of service studies, class revenues and rate design are as follows:

- The range of results from the Company's two cost of service studies should be accepted by the Commission as a guide to evaluate and set Peoples' class revenues and rate design in this proceeding.
- The Commission should accept the Company's proposed apportionment of non-gas revenues to its rate classes because it reasonably balances the various criteria that were considered by the Company in the revenue apportionment process which included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations.
- The Commission should approve the rate design proposed by the Company because it reasonably satisfies the key rate design objectives I presented earlier in my testimony,

including: (1) achieve fair and equitable rate levels that are reflective of the cost to serve; (2) avoid undue discrimination between and within rate classes; (3) rates should be stable, understandable, and provide customer choices; (4) create economically efficient pricing for natural gas delivery service; (5) rates should encourage energy conservation and energy efficiency; and (6) rates should allow a utility to recover its revenue requirement in a manner that maintains revenue stability, and minimizes year-to-year under or over-collections.

Q. DOES THIS COMPLETE YOUR PREPARED TESTIMONY?

A. Yes. I reserve the right to submit supplemental testimony as additional issues arise during the course of this proceeding. Thank you.

EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE
RUSSELL A. FEINGOLD

EDUCATIONAL BACKGROUND

- Bachelor of Science degree in Electrical Engineering from Washington University in St. Louis
- Master of Science degree in Financial Management from Polytechnic Institute of New York University

WORK EXPERIENCE

2007 – Present	**Black & Veatch Management Consulting, LLC** Vice President and Rates & Regulatory Services Practice Lead
1996 – 2007	**Navigant Consulting, Inc.** Managing Director, Energy Practice - Litigation, Regulatory & Markets Group
1990 – 1996	**R.J. Rudden Associates, Inc**. Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division
1973 – 1978	**Port Authority of New York and New Jersey** Staff Engineer and Utility Rate Specialist Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Kentucky Public Service Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- National Energy Board (Canada)
- Nebraska Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission

- New York Public Service Commission
- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- South Dakota Public Service Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of Wyoming

EDUCATIONAL AND TRAINING ACTIVITIES

- Past Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison and University of Chicago School of Business, 1985 – 2018.

- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992, and University of Chicago School of Business, 2012-2018.
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987 edition.
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress).
- Contributing Author of "Regulation of the Gas Industry," LexisNexis Matthew Bender, 2016 and 2018.

PUBLICATIONS AND PRESENTATIONS

- "Current Regulatory and Ratemaking Issues," American Gas Association, Accounting Principles Committee Meeting, August 13-15, 2018.
- "Customer Affordability Assistance Funding Across the Energy Industry," American Water Works Association - Transformative Issues Symposium on Affordability, August 6-7, 2018.
- "Regulatory and Ratemaking Responses to a Changing Utility Industry," Mid America Regulatory Conference (MARC) Annual Meeting, June 3-6, 2018.
- "State Regulatory Update: Rates/ROEs/Tax Reform Impacts/M&A Trends," American Gas Association Financial Forum, May 20-22, 2018.
- "Properly Balancing the Costs and Benefits of DER When Designing Rates," Power Forward: Ratemaking and Regulation, Public Utilities Commission of Ohio, March 20-22, 2018.
- "Ratemaking for the Modern Utility: A Flawed Approach or Beyond Reproach?" S&P Global Market Intelligence, 2017 Utility Regulatory Conference, December 5-6, 2017.

- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 14-16, 2017.
- "Regulatory Update", American Gas Association, Risk Management Committee Meeting, July 17, 2017
- "State Regulatory Issues – Analysis & Trends," American Gas Association Financial Forum, May 20-23, 2017.
- "The Valuing and Pricing of Distributed Energy Resources: Some Inconvenient Truths," SNL Energy Utility Regulation Conference, December 14-15, 2016.
- "Pricing Concepts and Regulatory Issues for Distributed Energy Resources," American Gas Association, State Affairs Committee Meeting, October 9-12, 2016.
- "State Regulatory Update – Regulatory Responses to a Changing Utility Industry," American Gas Association Financial Forum, May 15-17, 2016.
- "State Regulatory Update: Regulatory Responses to a Changing Utility Industry" American Gas Association, Finance Committee Meeting, March 14-16, 2016.
- "Rate Restructuring Tiers and Other Pricing Twists", SNL 2015 Utility Regulation Conference, December 10, 2015.
- "Utility Ratemaking Solutions During a Time of Transition", American Gas Association, State Affairs Committee Meeting, October 4-7, 2015.
- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 17-19, 2015.
- "Utility Ratemaking Solutions for a Changing Energy Marketplace", SNL Online Course, July 15, 2015 and October 27, 2015.
- "State Regulatory and Legislative Issues", American Gas Association Financial Forum, May 17-19, 2015.
- "Rate Design and Cost Allocation Issues", SNL 2014 Utility Regulation Conference, December 8-9, 2014.
- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 18-20, 2014.

- Regulatory Update”, Southern Gas Association, 2014 Management Conference, Accounting & Financial Executives Roundtable, April 2-4, 2014.

- “Emerging Regulatory Issues for Gas Distribution Companies,” American Gas Association, Finance Committee Meeting, March 17-19, 2014.

- “Balancing Rising Costs & Customer Expectations,” co-authored with Will Williams and Jeff Evans, Western Energy Institute, WE Magazine, Winter 2013 issue.

- “Current Trends in Utility Rates and Economic Regulation,” Western Energy Institute, WE Magazine, Fall 2013 issue.

- “Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England,” American Gas Association State Affairs Committee Meeting, October 6-9, 2013

- “Utilities 2.0 Roundtable,” 2013 National Town Meeting on Demand Response and Smart Grid, July 10-11, 2013

- “State Regulatory and Legislative Issues,” American Gas Association Financial Forum, May 5-7, 2013

- “Providing Natural Gas to Unserved and Underserved Areas,” American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 28-31, 2012

- “State Regulatory Issues Affecting Gas Utilities,” American Gas Association Accounting Principles Committee Meeting, August 13-15, 2012

- “State Regulatory Landscape and Future Trends Affecting Utilities,” American Gas Association Financial Forum, May 6-8, 2012.

- “The Continuing Saga of Fixed Cost Recovery: Arguments in Utility Rate Proceedings,” American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 30 - November 2, 2011.

- “State Regulatory Issues Affecting Utilities,” American Gas Association Accounting Principles Committee Meeting, August 15-17, 2011.

- “State Regulatory Issues Affecting Utilities,” Edison Electric Institute/American Gas Association Accounting Leadership Conference, June 26-29, 2011.

- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 15-17, 2011.
- "2011 Forecast – Regulatory Issues and Risks for Utilities," American Gas Association Finance Committee Meeting, March 16-18, 2011.
- "State Regulatory Issues Affecting Utilities," Edison Electric Institute and American Gas Association Accounting Leadership Conference, June 27-30, 2010.
- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 17-19, 2010.
- "A Utility's Regulatory Compact: Where's the Right Balance? – RMEL Electric Energy Magazine, Issue 1 – Spring 2010.
- "Communicating Ratemaking and Regulatory Concepts to a Utility's Stakeholders," American Gas Association, Communications and Marketing Committee Meeting, March 16-17, 2010.
- "Managing Regulatory Risk Workshop", Rocky Mountain Electric League, October 8, 2009.
- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association, 2009 Financial Forum, May 3, 2009.
- "Financial Incentives for Energy Efficiency: Lessons Learned to Date," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 7, 2009.
- "Breaking the Link Between Sales and Profits: Current Status and Trends," Energy Bar Association, Electricity Regulation and Compliance Committee, February 17, 2009.
- "State Ratemaking Issues for Gas Distribution Utilities," Energy Law Journal, Volume 29, No. 2, 2008 (Report of the Natural Gas Regulation Committee).
- "Current Issues in Cost Allocation and Rate Design for Utilities," SNL Energy, Utility Rate Cases Today: The Issues and Innovations, November 6, 2008.
- "Current Issues in Revenue Decoupling for Gas Utilities," American Gas Association, Financial and Investor Relations Webcast, October 16, 2008.

- “Addressing Utility Business Challenges Through the State Regulatory Process,” American Gas Association, 2008 Legal Forum, July 20-22, 2008.
- “Earning on Natural Gas Energy Efficiency Programs,” American Gas Association Rate and Regulatory Issues Conference Webcast, May 23, 2008.
- “State Regulatory Directions: Utility Challenges and Solutions,” American Gas Association Financial Forum, May 4, 2008.
- “Ratemaking and Financial Incentives to Facilitate Energy Efficiency and Conservation,” The Institute for Regulatory Policy Studies, Illinois State University, May 1, 2008.
- “Update on Revenue Decoupling and Innovative Rates,” American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, March 10, 2008.
- “Update on Revenue Decoupling and Utility Based Energy Conservation Efforts,” American Gas Association, Rate and Regulatory Issues Conference Webcast, May 30, 2007.
- “A Renewed Focus on Energy Efficiency by Utility Regulators,” American Gas Association, Rate and Regulatory Issues Seminar and Committee Meetings, March 26, 2007.
- “The Continuing Ratemaking Challenge of Declining Use Per Customer,” American Public Gas Association, Gas Utility Management Conference, October 31, 2006.
- “Understanding and Managing the New Reality of Utility Costs in the Natural Gas Industry,” Financial Research Institute, Public Utility Symposium, University of Missouri – Columbia, September 27, 2006.
- “Ratemaking and Energy Efficiency Initiatives: Key Issues and Perspectives,” American Gas Association, Ratemaking Webcast, September 14, 2006.
- “Ratemaking Solutions in an Era of Declining Gas Usage and Price Volatility,” Northeast Gas Association, 2006 Executive Conference, September 10-12, 2006.
- “Rethinking Natural Gas Utility Rate Design,” American Gas Foundation and The NARUC Foundation, Executive Forum, Ohio State University, May 2006.

- "Rate Design, Trackers, and Energy Efficiency – Has the Paradigm Shifted?" Energy Bar Association, Midwest Energy Conference, March 2006.
- "Key Regulatory Issues Affecting Energy Utilities," American Gas Association, Lunch 'n Learn Session, November 2005.
- "Decoupling, Conservation, and Margin Tracking Mechanisms," American Gas Association, Rate & Regulatory Issues – Audio Conference Series, October 2005.
- "In Search of Harmony, [Utilities and Regulators] Respondents Weigh in with Needed Actions", Public Utilities Fortnightly, November 2005
- "The Use of Trackers as a Regulatory Tool," Midwest Energy Association – Legal, Regulatory, and Government Relations Roundtable, October 9-11, 2005.
- "Rate Design and the Regulatory Environment," American Gas Association Finance Committee Meeting, October 2005.
- "Creative Utility Regulatory Strategies in a High Price Environment," American Gas Association Executive Conference, September 2005.
- "Revenue Decoupling Programs: Aligning Diverse Interests," The Institute for Regulatory Policy Studies, Illinois State University, May 2005.
- "Key Regulatory Issues Affecting Energy Utilities" American Gas Association Financial Forum, May 2005.
- "Energy Efficiency and Revenue Decoupling: A True Alignment of Customer and Shareholder Interests," American Gas Association Rate and Regulatory Issues Seminar and Committee Meetings, April 2005.
- "Rate Case Techniques: Strategies and Pitfalls" American Gas Association, Rate & Regulatory Issues – Audio Conference Series, March 2005.
- "Regulatory Uncertainty: The Ratemaking Challenge Continues" Public Utilities Fortnightly, Volume 142, No. 11, November 2004.
- "Current Trends in Utility Rate Cases and Pricing: Surveying the Landscape," Platts Rate Case & Pricing Symposium, October 25-26, 2004.
- "State Regulatory Oversight of the Gas Procurement Function" Energy Bar Association, Natural Gas Regulation Committee, Energy Law Journal, Volume 25, No. 1, 2004.

- "Cost Allocation Across Corporate Divisions", American Gas Association, Rate and Strategic Issues Committee Meeting, April 2003.
- "Unbundling Initiatives – How Far Can We Go?" American Gas Association Restructuring Seminar: Service and Revenue Enhancements for the Energy Distribution Business, December 2002.
- "Utility Regulation and Performance-Based Ratemaking (PBR)," PBR Briefing Session sponsored by BC Gas Utility Ltd., April 2002.
- "LDC Perspectives on Managing Price Volatility" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.
- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.
- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999
- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.

- "Asset and Resource Migration Strategies," presented at the Strategic Marketing for The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.

- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.

- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.

- "State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.

- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.

- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.

- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.

- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.

- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.

- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.

- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.

- “The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail),” presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.

- “Key Methodological Considerations in Developing Gas Long-Run Avoided Costs,” presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.

- “Mega-NOPR Impacts on Transportation Arrangements for IPPs,” co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing ’92, June 1992.

- “Cost Allocation in Utility Rate Proceedings,” presented before the Ohio State Bar Association - Annual Convention, May 1992.

- “The Long and the Short of LRACs,” presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.

- Seminar organizer and moderator at the American Gas Association seminar, “Integrated Resource Planning: A Primer,” December 1991.

- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.

- “Strategic Perspectives on the Rate Design Process,” presented before the Executive Enterprises, Inc. conference, “Natural Gas Pricing and Rate Design in the 1990s,” September 1990.

- “Distribution Company Transportation Rates,” presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.

- “Design of Distribution Company Gas Rates,” presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.

- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, “Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing,” 1988-1990.

- "Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.
- "So You Think You Know Your Customers!" presented before the American Gas Association–Annual Marketing Conference, April 1990.
- "Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.
- "Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.
- "Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.
- "Gas Transportation Rates - An Integral Part of a Competitive Marketplace," American Gas Association, Financial Quarterly Review, Summer 1987.
- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," American Gas Association, Financial Quarterly Review, October 1983.
- "Demand-Commodity Rates: A Second-Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.
- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Rate Committee of the American Gas Association
- Member, Energy Bar Association

- Life Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of January 2019)

WITNESS AREAS OF RESPONSIBILITY
(LIST OF SECTION)

Section	**Subject Matter**
53.53	
III-A-45	Explanation of any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate case.
III-A-47	Schedule showing rate of return on facilities allocated to serve wholesale customers
IV-B-1	Cost of Service Studies under Present and Proposed Tariffs
IV-B-2	Statement of Testimony Describing the Complete Methodology of the Cost of Service Studies
IV-B-3	Complete Description and Back-Up Calculations for All Allocation Factors
IV-B-7	Graph of present and proposed base rates on hyperbolic cross section paper
IV-B-9	Cost Analysis Supporting Minimum Charges for All Rate Schedules
IV-B-10	Cost analysis supporting demand charges for all tariffs which contain demand charges.
IV-B-12	Supply a tabulation of base rate bills for each rate schedule comparing the existing rates to proposed rates. The tabulation should show the dollar difference and the per cent increase or decrease.
Exhibit	
VI.III.COS.2	Detailed explanation describing how contributions in aid of construction and customer advances are reflected in the Company's cost of service study.

VI.III.COS.8 Company's rate design models and cost of service study on an IBM PC-compatible computer disk in Lotus 1-2-3-or Quattro format. If the models consist of more than one file, please include information on all files on the disk and what they contain. If not available in Lotus 1-2-3 or Quattro format, please provide in ASCII format.

VI.III.COS.19 Workpapers showing the development of each allocation factor reflected in the Company's cost of service study. Include a description of each allocation factor, all calculations performed to develop the allocators and all supporting documentation, studies or other information relied upon to determine the allocators.

VI.III.COS.20 All workpapers, calculations and supporting documentation for the functionalization and classification performed for the Company's cost of service study.

Section – 53.53	Exhibit
III.A.45	Ex 13, Sch. 11
III.A.47	Ex 11, Sch. 9
IV.B.1	Ex. 11, Sch. 1
IV.B.2	Ex. 11, Sch. 2
IV.B.3	Ex. 11, Sch. 3
IV.B.7	Ex. 11, Sch. 7
IV.B.9	Ex. 11, Sch. 4
IV.B.10	Ex. 11, Sch. 5
IV.B.12	Ex. 11, Sch. 8
IV.B.19	Ex 17, COS-19
IV.B.20	Ex 17, COS-20
Exhibit	
VI.III.COS.2	Ex.17, COS-2
IV.III.COS.8	Ex. 17, COS-8
IV.III.COS.19	Ex.17, COS-19
IV.III.COS.20	Ex. 17, COS-20

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
1	**1: RATE BASE**							
2	**I. GAS PLANT IN SERVICE**							
3	**A. INTANGIBLE PLANT**							
4	Organization	301	0	DISTPT-C	0	0	0	0
5	Franchise and Consents	302	0	DISTPT-C	0	0	0	0
6	Miscellaneous Intangible Plant	303	83,103,211	DIST_303-C	75,587,382	5,561,267	1,498,968	455,594
7	**Subtotal - INTANGIBLE PLANT**	301-303	83,103,211		75,587,382	5,561,267	1,498,968	455,594
8	**B. PRODUCTION PLANT**							
9	Other Land & Land Rights-Land	325	0	DISTPT-C	0	0	0	0
10	Gas Well Structures	326	0	DISTPT-C	0	0	0	0
11	Field Compressor Station Structures	327	0	DISTPT-C	0	0	0	0
12	Field M&R Station Structures	328	0	DISTPT-C	0	0	0	0
13	Other Structures	329	0	DISTPT-C	0	0	0	0
14	Producing Gas Wells-Well Construction	330, 331	0	DISTPT-C	0	0	0	0
15	Field Lines	332	0	DISTPT-C	0	0	0	0
16	Field Compressor Station Equipment	333	0	DISTPT-C	0	0	0	0
17	Field M&R Station Equip-Company	334	0	DISTPT-C	0	0	0	0
18	Drilling & Cleaning Equipment	335	0	DISTPT-C	0	0	0	0
19	Other Equipment-Other	337	0	DISTPT-C	0	0	0	0
20	**Subtotal - PRODUCTION PLANT**	325-337	0		0	0	0	0
21	**C. NATURAL GAS STORAGE & PROCESSING PLANT**							
22	Land and Land Rights	350	0	DISTPT-C	0	0	0	0
23	Structures and Improvements	351	0	DISTPT-C	0	0	0	0
24	Wells-Well Equipment	352	0	DISTPT-C	0	0	0	0
25	Lines	353	0	DISTPT-C	0	0	0	0
26	Compressor Station Equipment - Other	354	0	DISTPT-C	0	0	0	0
27	M&R Equipment-Meters & Gauges	355	0	DISTPT-C	0	0	0	0
28	Other Equipment	357	0	DISTPT-C	0	0	0	0
29	**Subtotal - STORAGE PLANT**	350-363	0		0	0	0	0
30	**D. TRANSMISSION PLANT**							
31	Land & Land Rights	365	0	DISTPT-C	0	0	0	0
32	Structures & Improvements	366	0	DISTPT-C	0	0	0	0
33	Mains	367	0	DISTPT-C	0	0	0	0
34	Compressor Station Equipment	368	0	DISTPT-C	0	0	0	0
35	M&R Station Equipment	369	0	DISTPT-C	0	0	0	0
36	Other Equipment	371	0	DISTPT-C	0	0	0	0
37	**Subtotal - TRANSMISSION PLANT**	365-371	0		0	0	0	0

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
38	**E. DISTRIBUTION PLANT**							
39	Land and Land Rights	374	0	DISTPT-C	0	0	0	0
40	Structures and Improvements	375	0	DISTPT-C	0	0	0	0
41	Low Pressure Mains	376	0	;ust_Avg(Low Pressure	0	0	0	0
42	Regulated Pressure Mains	376	0	Cust_Avg	0	0	0	0
43	M & R Station Equipment	378	0	DISTPT-C	0	0	0	0
44	Services	380	632,413,944	Service_Invest	590,954,989	33,668,295	7,462,456	328,204
45	Meters	381	126,828,614	Meter_Invest	105,952,549	14,515,233	5,992,268	368,564
46	Meter Installations	382	90,344,063	Meter_Invest	75,473,377	10,339,663	4,268,483	262,540
47	Industrial M & R Station Equipment	385	10,644,190	M&R Equipment	0	646,956	5,069,737	4,927,497
48	Other Property on Customers Premise	386	14,644,532	Meter_Invest	12,234,033	1,676,032	691,910	42,557
49	Other Equipment	387	0	DISTPT-C	0	0	0	0
50	**Subtotal - DISTRIBUTION PLANT**	374-387	874,875,343		784,614,949	60,846,179	23,484,853	5,929,361
51	**F. GENERAL PLANT**							
52	Land and Land Rights	389	117,603	DISTPT-C	106,787	8,012	2,303	501
53	Structures and Improvements	390	7,257,148	DISTPT-C	6,589,691	494,397	142,126	30,935
54	Office Furniture and Equipment	391	4,962,571	DISTPT-C	4,506,152	338,078	97,188	21,154
55	Transportation Equipment	392	0	DISTPT-C	0	0	0	0
56	Stores Equipment	393	0	DISTPT-C	0	0	0	0
57	Tools, Shop and Garage Equipment	394	0	DISTPT-C	0	0	0	0
58	Laboratory Equipment	395	0	DISTPT-C	0	0	0	0
59	Power Operated Equipment	396	0	DISTPT-C	0	0	0	0
60	Communication Equipment	397	0	DISTPT-C	0	0	0	0
61	Miscellaneous Equipment	398	0	DISTPT-C	0	0	0	0
62	Other Tangible Plant	399	0	DISTPT-C	0	0	0	0
63	**Subtotal - GENERAL PLANT**	389-399	12,337,323		11,202,630	840,486	241,617	52,590
64	**TOTAL PLANT IN SERVICE**		970,315,877		871,404,961	67,247,933	25,225,438	6,437,545
65	**G. UTILITY PLANT**	105	0	DISTPT-C	0	0	0	0
66	**TOTAL UTILITY PLANT**		970,315,877		871,404,961	67,247,933	25,225,438	6,437,545

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
67	**II. DEPRECIATION RESERVE**							
68	Intangible Plant	303	39,269,336	DIST_Intang-C	35,717,811	2,627,918	708,336	215,271
69	Production Plant	325-337	0	DISTPT-C	0	0	0	0
70	Storage Plant	350-357	0	DISTPT-C	0	0	0	0
71	Transmission	365-371	0	DISTPT-C	0	0	0	0
72	Distribution Land Structures & Improvements	374-375	0	DISTPT-C	0	0	0	0
73	Distribution Mains	376	0	MAINSPT-C	0	0	0	0
74	Distribution M&R General	378	0	DISTPT-C	0	0	0	0
75	Distribution Services	380	257,018,152	Service_Invest	240,168,897	13,683,068	3,032,802	133,385
76	Distribution - Meters	381	28,466,508	Meter_Invest	23,780,904	3,257,924	1,344,956	82,724
77	Distribution - Meters Installations	382	37,863,819	Meter_Invest	31,631,412	4,333,424	1,788,951	110,032
78	Industrial M & R Station Equipment - Other	385	4,876,879	M&R Equipment	0	296,418	2,322,816	2,257,645
79	Other Property on Customers Premises	386	13,387,293	Meter_Invest	11,183,737	1,532,144	632,509	38,903
80	Other Equipment	387	0	DISTPT-C	0	0	0	0
81	General Plant	389-399	4,631,258	DISTPT-C	4,205,310	315,507	90,700	19,742
82	**TOTAL DEPRECIATION RESERVE (PLANT IN SERVICE)**		385,513,244		346,688,071	26,046,402	9,921,070	2,857,702
83	Retirement Obligation		0	DISTPTXL-CUST	0	0	0	0
84	**TOTAL - DEPRECIATION RESERVE**		385,513,244		346,688,071	26,046,402	9,921,070	2,857,702
85	**III. OTHER RATE BASE ITEMS**							
86	Gas Storage Underground - NonCurrent		0	DISTPT-C	0	0	0	0
87	Gas Stored Underground - Current		0	DISTPT-C	0	0	0	0
88	Materials and Supplies		0	DISTPT-C	0	0	0	0
89	Prepayments		0	DISTO&M-C	0	0	0	0
90	Cash Working Capital		0	DISTPT-C	0	0	0	0
91	Deferred Income Taxes		0	DISTPT-C	0	0	0	0
92	Customer Advances and Deposits		0	Cust_Deposit	0	0	0	0
93	**Total - OTHER RATE BASE ITEMS**		0		0	0	0	0
94	**TOTAL RATE BASE (Excl. Working Capital)**		584,802,633		524,716,890	41,201,530	15,304,369	3,579,843
95	Gas Purchases Cash Working Capital		0	DISTO&M-C	0	0	0	0
96	**TOTAL RATE BASE**		584,802,633		524,716,890	41,201,530	15,304,369	3,579,843

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
97	**2: EXPENSES**							
98	**I. OPERATION & MAINTENANCE EXPENSE**							
99	**A. NATURAL GAS PRODUCTION EXPENSES**							
100	1. Natural Gas Production and Gathering							
101	Operation Supervision & Engineering	750	0	DISTPT-C	0	0	0	0
102	Production Maps	751	0	DISTPT-C	0	0	0	0
103	Gas Wells Expense	752	0	DISTPT-C	0	0	0	0
104	Field Lines Expense	753	0	DISTPT-C	0	0	0	0
105	Field Compressor Station Expense	754756	0	DISTPT-C	0	0	0	0
106	Other Expense	759	0	DISTPT-C	0	0	0	0
107	Rents	760	0	DISTPT-C	0	0	0	0
108	Subtotal - Operation Accounts	751-760	0		0	0	0	0
109	Maint Supervision & Engineering	762	0	DISTPT-C	0	0	0	0
110	Producing Gas Wells Maintenance	763	0	DISTPT-C	0	0	0	0
111	Field Lines	764, 787	0	DISTPT-C	0	0	0	0
112	Field Meas/Reg	765, 766	0	DISTPT-C	0	0	0	0
113	Other Equipment	769	0	DISTPT-C	0	0	0	0
114	Subtotal - Maintenance Accounts	762-787	0		0	0	0	0
115	Subtotal - Production and Gathering	751-787	0		0	0	0	0
116	2. Other Gas Supply Expenses							
117	Nat Gas Well Head Purchases	800	0	Not_Applicable	0	0	0	0
118	Gas used for Compressor Station Fuel - Credit	810	0	Not_Applicable	0	0	0	0
119	Gas used for Other Util Ops-Credit	812755	0	Not_Applicable	0	0	0	0
120	Other Gas Supply Expenses	813	0	Not_Applicable	0	0	0	0
121	Subtotal - Other Gas Supply Expenses		0		0	0	0	0
122	**Subtotal - PRODUCTION EXPENSES**	751-813	0	0	0	0	0	0

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
123	**B. STORAGE, TERMINALING & PROCESSING EXPENSES**							
124	Wells Expense	816	0	DISTPT-C	0	0	0	0
125	Lines Expenses	817	0	DISTPT-C	0	0	0	0
126	Compressor Station Expenses	818	0	DISTPT-C	0	0	0	0
127	Compressor Station Fuel	819	0	DISTPT-C	0	0	0	0
128	Meas/Reg Station Expenses	820	0	DISTPT-C	0	0	0	0
129	Gas Losses	823	0	DISTPT-C	0	0	0	0
130	Other Expenses	824	0	DISTPT-C	0	0	0	0
131	Storage Well Royalties	825	0	DISTPT-C	0	0	0	0
132	Subtotal - Operations Accounts	816-825	0		0	0	0	0
133	Maint. of Structures & Improvements	831	0	DISTPT-C	0	0	0	0
134	Maint. of Reservoirs and Wells	832	0	DISTPT-C	0	0	0	0
135	Maint. of Lines	833	0	DISTPT-C	0	0	0	0
136	Maint. of Compressor Station Equipment	834	0	DISTPT-C	0	0	0	0
137	Maint. of Meas/Reg Station Equipment	835	0	DISTPT-C	0	0	0	0
138	Maint. Of Other Equipment	837	0	DISTPT-C	0	0	0	0
139	Subtotal - Maintenance Accounts	831-837	0		0	0	0	0
140	**Subtotal - STORAGE EXPENSES**	816-837	0		0	0	0	0
141	**C. TRANSMISSION EXPENSES**							
142	Supvervision/Engineering	850	0	DISTPT-C	0	0	0	0
143	Compressor Station Labor & Expenses	853	0	DISTPT-C	0	0	0	0
144	Mains Expense	856	0	DISTPT-C	0	0	0	0
145	Meas/Reg Station Expenses	857	0	DISTPT-C	0	0	0	0
146	Transmission/Compressor Ga	858	0	DISTPT-C	0	0	0	0
147	Other Expenses	859	0	DISTPT-C	0	0	0	0
148	Rents	860	0	DISTPT-C	0	0	0	0
149	Subtotal - Operation Accounts	856-860	0		0	0	0	0
150	Maint. of Structures & Improvements	862	0	DISTPT-C	0	0	0	0
151	Maint. of Mains	863	0	DISTPT-C	0	0	0	0
152	Maint. Of Compressor Station	864	0	DISTPT-C	0	0	0	0
153	Maint. Of Meas/Reg Station Equipment	865	0	DISTPT-C	0	0	0	0
154	Maint. of Communication Equipment	866	0	DISTPT-C	0	0	0	0
155	Maint of Other Equipment	867	0	DISTPT-C	0	0	0	0
156	Subtotal - Maintenance Accounts	863-867	0		0	0	0	0
157	**Subtotal - TRANSMISSION EXPENSES**	850-865	0		0	0	0	0

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
158	**D. DISTRIBUTION EXPENSES**							
159	Operation Supervision & Engineering	870	(773,904)	DISTO&M_LABOR-C	(703,213)	(55,569)	(14,310)	(812)
160	Distribution Load Dispatching	871	0	DISTPT-C	0	0	0	0
161	Mains and Services Expenses	874	4,256,620	)ISTMAIN-SERVICE-(	3,961,076	251,390	42,546	1,608
162	Meas. & Reg. Station Expenses	875	0	DISTPT-C	0	0	0	0
163	Meas. & Reg. Station Expenses - City Gate	877	0	DISTPT-C	0	0	0	0
164	Meter & House Regulator Expenses	878	5,800,677	DISTMETER-REG-C	4,845,882	663,874	274,064	16,857
165	Customer Installations Expenses	879	5,354,119	Service_Invest	5,003,121	285,041	63,178	2,779
166	Other Expenses	880	0	DISTO&M-C	0	0	0	0
167	Rents	881	0	DISTO&M-C	0	0	0	0
168	Maint. of Structures & Improvements	886	0	DISTPT-C	0	0	0	0
169	Maint. of Mains	887	0	MAINSPT-C	0	0	0	0
170	Maint. of Compressor Station Equip.	888	0	DISTPT-C	0	0	0	0
171	Maint. of Meas. & Reg. Station Expenses-General	889	0	DISTPT-C	0	0	0	0
172	Maint. of Meas. & Reg. Station Expenses-Indust.	890	0	M&R Equipment	0	0	0	0
173	Maint. of Services	892	987,954	Service_Invest	923,187	52,596	11,658	513
174	Maint. of Meters & House Regulators	893	388,121	DISTMETER-REG-C	324,236	44,420	18,338	1,128
175	Maint. of Other Equipment	894	0	DISTO&M-C	0	0	0	0
176	**Subtotal - DISTRIBUTION EXPENSES**	870-894	16,013,587		14,354,289	1,241,753	395,474	22,072
177	**Total - OPERATION & MAINTENANCE EXPENSES**		16,013,587		14,354,289	1,241,753	395,474	22,072
178	**II. CUSTOMER ACCOUNTS EXPENSES**							
179	Supervision	901	0	CUST-902_903	0	0	0	0
180	Meter Reading Expenses	902	4,799,922	CUST-902	4,107,589	368,596	195,411	128,327
181	Customer Records & Collection Expense	903	17,132,673	CUST-903	15,993,032	1,020,735	111,593	7,313
182	Uncollectible Accounts	904	15,502,183	Write-offs	15,121,513	355,028	23,433	2,210
183	**Subtotal - CUSTOMER ACCOUNTS EXPENSES**	902-904	37,434,779		35,222,133	1,744,360	330,436	137,851
184	**III. CUSTOMER SERVICE & INFORMATIONAL EXPENSES**							
185	Supervision	907	437,767	CUST-908-910	420,250	15,698	1,819	0
186	Customer Assistance Expenses	908	2,892,225	CUST-908	2,884,801	7,424	0	0
187	Info. & Instructional Advertising Expnese	909	3,206,633	Cust_Avg_xLGS	2,970,162	211,151	25,320	0
188	Misc. Customer Serv. & Inform. Expen.	910	4,280	Cust_Avg	3,963	282	34	2
189	**Subtotal - CUSTOMER SERVICE**	907-910	6,540,906		6,279,177	234,555	27,173	2
190	**IV. SALES EXPENSES (C-8)**							
191	Supervision	911	0	CUST-912	0	0	0	0
192	Demonstrating & Selling Expenses	912, 913	1,371,405	CUST-912	431,769	19,663	5,574	914,398
193	Miscellaneous Sales Expenses	916	0	CUST-912	0	0	0	0
194	**Subtotal - SALES EXPENSES**	911-916	1,371,405		431,769	19,663	5,574	914,398
195	**Total-CUSTOMER ACCOUNTS, SERVICES & SALES EXPENSES**	901-916	45,347,090		41,933,079	1,998,577	363,183	1,052,251

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
196	**V. ADMINISTRATIVE & GENERAL EXPENSES**							
197	A. Labor-Related:							
198	Administrative & General Salaries	920	13,473,686	DISTLABOR-C	12,012,538	889,114	217,393	354,641
199	Office Supplies & Expenses	921	4,938,723	DISTLABOR-C	4,403,145	325,901	79,684	129,992
200	Admin. Expenses Transferred-Credit	922	(13,074,496)	DISTLABOR-C	(11,656,638)	(862,772)	(210,952)	(344,134)
201	Outside Services Employed	923	8,902,955	DISTLABOR-C	7,937,478	587,497	143,646	234,335
202	Employee Pensions and Benefits	926	11,810,501	DISTLABOR-C	10,529,716	779,363	190,558	310,865
203	Subtotal - A&G Labor-Related	920-923, 926	26,051,369		23,226,239	1,719,103	420,329	685,699
204	B. Plant-Related:							
205	Property Insurance	924	144,348	DISTPT-C	131,072	9,834	2,827	615
206	Injuries and Damages	925	4,021,121	DISTPT-C	3,651,289	273,941	78,750	17,141
207	Maintenance of General Plant	932	86,707	DISTGENPTXL-C	78,732	5,907	1,698	370
208	Subtotal - A&G Plant-Related		4,252,176		3,861,093	289,682	83,276	18,126
209	C. Other-Related:							
210	Franchise Requirements	927	0	DISTL/P-C	0	0	0	0
211	Regulatory Commission Expenses	928	685,745	DISTREVREQ-C	624,199	43,848	11,246	6,452
212	Duplicate Charges - Credit	929	0	DISTL/P-C	0	0	0	0
213	Misc. Gen'l Expenses	930	0	Cust_Avg	0	0	0	0
214	Rents	931	0	DISTL/P-C	0	0	0	0
215	Subtotal - A&G Other-Related	927-931	685,745		624,199	43,848	11,246	6,452
216	**Total - ADMINISTRATIVE & GENERAL EXPENSES**	920-932	30,989,290		27,711,531	2,052,632	514,850	710,276
217	**TOTAL - OPERATING EXPENSES (Excl. Depr.,**		92,349,967		83,998,899	5,292,962	1,273,507	1,784,599
218	**Taxes, and Gas Supply Expense)**							
219	**VI. DEPRECIATION EXPENSE**							
220	Intangible Plant	403	10,212,386	DIST_Intang-C	9,288,776	683,417	184,210	55,983
221	Production Plant	403	0	DISTPT-C	0	0	0	0
222	Storage Plant	403	0	DISTPT-C	0	0	0	0
223	Transmission	403	0	DISTPT-C	0	0	0	0
224	Distribution Land Structures & Improvements	403	0	DISTPT-C	0	0	0	0
225	Distribution Mains	403	0	MAINSPT-C	0	0	0	0
226	Distribution M&R General	403	0	DISTPT-C	0	0	0	0
227	Distribution Services	403	15,295,585	Service_Invest	14,292,857	814,303	180,487	7,938
228	Distribution - Meters	403	4,930,443	Meter_Invest	4,118,889	564,277	232,948	14,328
229	Distribution - Meters Installations	403.10	1,741,537	Meter_Invest	1,454,879	199,315	82,282	5,061
230	Industrial M & R Station Equipment - Other	403.11	225,744	M&R Equipment	0	13,721	107,520	104,503
231	Other Property on Customers Premises	403.12	269,216	Meter_Invest	224,903	30,811	12,720	782
232	Other Equipment	403.13	0	DISTPT-C	0	0	0	0
233	General Plant	403.14	876,195	DISTPT-C	795,609	59,691	17,160	3,735
234	**Total - DEPRECIATION EXPENSE**	403	33,551,106		30,175,914	2,365,534	817,327	192,331

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
235	**VII. TAXES OTHER THAN INCOME TAXES**							
236	A. General Taxes							
237	Payroll Taxes	408.15	3,180,030	DISTLABOR-C	2,835,173	209,847	51,309	83,702
238	Plant Related Taxes	408.17	2,357,331	DISTPT-C	2,140,522	160,594	46,166	10,049
239	Gas Related	408.18	0	DISTPT-C	0	0	0	0
240	Subtotal - General Taxes		5,537,361		4,975,695	370,441	97,475	93,750
241	**TOTAL EXPENSES (excl. GRT & Gas Purchases)**	408.1	131,438,433		119,150,507	8,028,937	2,188,309	2,070,679
242	B. Revenue Taxes: (GRT)							
243	State Gross Earnings	408.11	0	Rev_GRT	0	0	0	0
244	Municipal Tax	408	0	Rev_MuniTax	0	0	0	0
245	**Subtotal - Revenue Taxes (GRT)**		0		0	0	0	0
246	C. Income Taxes							
247	Fed & State Income Taxes Based on Net Income	409	5,745,071	DIST_PreTax-C	12,298	962,762	2,534,366	2,235,645
248	Other	409	0	DISTREVREQ-C	0	0	0	0
249	**Subtotal - Income Taxes**		5,745,071		12,298	962,762	2,534,366	2,235,645
250	**TOTAL TAXES (Excl. General Taxes)**		5,745,071		12,298	962,762	2,534,366	2,235,645
251	**TOTAL EXPENSES**		137,183,504		119,162,805	8,991,699	4,722,675	4,306,324
252	**3: OPERATING REVENUES**							
253	Sales & Transportation Operating Revenues	480-485	212,106,636	Non-gas_Revenue	149,392,480	17,997,471	24,053,696	20,662,989
254	Gas Revenues		0	Gas_Revenue	0	0	0	0
255	Forfeited Discounts	487	2,477,073	Collections	2,342,140	75,131	43,089	16,712
256	Miscellaneous Service Revenues		1,829,989	ConnectionFee	1,173,721	586,065	68,638	1,565
257	Gathering		0	Non-gas_Revenue	0	0	0	0
258	Intercompany Software License Fees		64,628	Non-gas_Revenue	45,519	5,484	7,329	6,296
259	Pooling		1,086,102	Transport-Thru	145,644	62,355	214,070	664,033
260	Direct Customer Cashouts		16,462	LGS_Direct	0	0	0	16,462
261	Royalties		176	Non-gas_Revenue	124	15	20	17
262	Tax Discount		177	Non-gas_Revenue	124	15	20	17
262	Rent from Gas Property		85,587	DISTPT-C	77,715	5,831	1,676	365
263	**Total - OPERATING REVENUES**		217,666,830		153,177,469	18,732,367	24,388,538	21,368,457
264	Other Income	412	0	DISTREVREQ-C	0	0	0	0
265	**NET INCOME**		80,483,326		34,014,664	9,740,667	19,665,863	17,062,132
266	Return		**13.76%**		**6.48%**	**23.64%**	**128.50%**	**476.62%**

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
267	**SUMMARY**							
268	**OPERATING REVENUES**							
269	Sales & Transportation Operating Revenues		212,106,636		149,392,480	17,997,471	24,053,696	20,662,989
270	Gas Revenues		0		0	0	0	0
271	Forfeited Discounts		2,477,073		2,342,140	75,131	43,089	16,712
272	Miscellaneous Service Revenues		1,829,989		1,173,721	586,065	68,638	1,565
273	Gathering		0		0	0	0	0
274	Intercompany Software License Fees		64,628		45,519	5,484	7,329	6,296
275	Pooling		1,086,102		145,644	62,355	214,070	664,033
276	Direct Customer Cashouts		16,462		0	0	0	16,462
277	Royalties		176		124	15	20	17
278	Tax Discount		177		124	15	20	17
278	Rent from Gas Property		85,587		77,715	5,831	1,676	365
280	Total Operating Revenues		217,666,830		153,177,469	18,732,367	24,388,538	21,368,457
281	**EXPENSES**							
282	Production Expenses		0		0	0	0	0
283	Natural Gas Storage, Terminaling & Proc. Exp.		0		0	0	0	0
284	Transmission Expenses		0		0	0	0	0
285	Distribution Expenses		16,013,587		14,354,289	1,241,753	395,474	22,072
286	Total Operating Expenses		16,013,587		14,354,289	1,241,753	395,474	22,072
287	CUSTOMER ACCOUNTS, SERVICES, & SALES EXPENSES		45,347,090		41,933,079	1,998,577	363,183	1,052,251
288	ADMINISTRATIVE & GENERAL EXPENSES		30,989,290		27,711,531	2,052,632	514,850	710,276
289	DEPRECIATION EXPENSE		33,551,106		30,175,914	2,365,534	817,327	192,331
290	**TAXES OTHER THAN INCOME TAXES**		5,537,361		4,975,695	370,441	97,475	93,750
291	**Other Income**		0		0	0	0	0
292	**INCOME BEFORE INCOME TAXES**		86,228,397		34,026,962	10,703,429	22,200,229	19,297,777
293	**FEDERAL INCOME TAXES**							
294	Federal Income Taxes-Current		5,745,071		12,298	962,762	2,534,366	2,235,645
295	State Net Income Tax		0		0	0	0	0
296	Subtotal - Income Taxes		5,745,071		12,298	962,762	2,534,366	2,235,645
297	**NET OPERATING INCOME**		80,483,326		34,014,664	9,740,667	19,665,863	17,062,132
298	**RATE BASE**		584,802,633		524,716,890	41,201,530	15,304,369	3,579,843
299	**RATE OF RETURN**		13.76%		6.48%	23.64%	128.50%	476.62%
300	**Unitized**		1.72		0.81	2.96	16.07	59.59

Peoples Natural Gas Company LLC - Combined
Design Day Method for the 12 Months Ending October 31, 2020

Minimum Customer Cost Analysis

	Account Description	Account Code	Distribution Customer Dollars	Allocation Factor	Residential Service	Small General Service	Medium General Service	Large General Service
301	**REVENUE REQUIREMENTS ANALYSIS**							
302	**System Average Rate of Return Achieved**		8.00%		8.00%	8.00%	8.00%	8.00%
303	**RATE BASE**		584,802,633		524,716,890	41,201,530	15,304,369	3,579,843
304	**OPERATING EXPENSES**		16,013,587		14,354,289	1,241,753	395,474	22,072
305	**CUST. ACCTS., SERVICES, & SALES EXP.**		45,347,090		41,933,079	1,998,577	363,183	1,052,251
306	**ADMINISTRATIVE & GENERAL EXPENSES**		30,989,290		27,711,531	2,052,632	514,850	710,276
307	**DEPRECIATION EXPENSE**		33,551,106		30,175,914	2,365,534	817,327	192,331
308	**GENERAL TAXES**		5,537,361		4,975,695	370,441	97,475	93,750
309	**TOTAL**		131,438,433		119,150,507	8,028,937	2,188,309	2,070,679
310	**RETURN ON RATEBASE**		46,772,572		41,966,908	3,295,302	1,224,045	286,316
311	**FIT ON RETURN**	Ratio of Taxes to Return	10,104,850	21.60%	9,066,624	711,924	264,445	61,856
312	**State Income Tax on Return**		0		0	0	0	0
313	**Increase in Uncoll**		0		0	0	0	0
314	**Additional Late Fees**		0		0	0	0	0
315	**TOTAL REVENUE REQUIREMENT**		**188,315,855**		**170,184,039**	**12,036,164**	**3,676,800**	**2,418,852**
316	**Number of Bills per Rate Class**		7,529,853	BILLCUST	6,971,958	495,642.22	59,436	2,817
317	**Minimum Customer Charge Design Day Method**				**$ 24.41**	**$ 24.28**	**$ 61.86**	**$ 858.66**

Peoples Natural Gas Company LLC
Gathering Cost of Service [1]

Cost Component	Amount
Rate Base	
Plant in Service	
Intangible Plant	$6,303,250
Production Plant	$124,160, 959
General Plant	$6,003,790
Total Plant in Service	$136,467,999
Depreciation Reserve	
Intangible Plant	$2,977,641
Production Plant	$53,322,074
General Plant	$2,253,738
Total Depreciation Reserve	$58,553,454
Other Rate Base Items	
Materials and Supplies	$134,191
Prepayments	$268,603
Cash Working Capital	$1,474,819
Deferred Income Taxes	($8,709,824)
Total Other Rate Base Items	($6,832,212)
Total Net Rate Base	$71,082,334
Expenses	
Natural Gas Production and Gathering	$9,791,837
Administrative & General	$5,231,285
Depreciation Expense	$3,926,018
Taxes Other Than Income Taxes	$697,338
Total Expenses	$19,646,478
Return on Net Rate Base	$5,685,172
Federal Income Taxes on Return	$1,228,237
Total Gathering Cost of Service	**$26,559,887**
Gathering Service Revenues	
At Present Rates (HTY)	$15,544,187
At Proposed Rates (FPFTY)	$8,929,271

[1] See Exhibit 11, Schedule 1, IV-B-1(A), Functionalization Phase, Pages 13 to 22.

Peoples Natural Gas Company LLC
Proposed Class Revenue Apportionment
Design Day Demand Cost Allocation Method

	Total	Residential Service	Small General Service	Medium General Service	Large General Service
Rate Base at 10/31/2020	$ 2,052,311,067	$ 1,490,104,849	$ 192,472,030	$ 211,340,081	$ 158,394,107
Net Utility Income at Present Rates	$ 94,525,688	$ 50,698,852	$ 8,861,179	$ 18,603,276	$ 16,362,381
Rate of Return at Present Rates	4.61%	3.40%	4.60%	8.80%	10.33%
Increase - Net Utility Income	$ 69,618,351	$ 68,479,879	$ 6,532,753	$ (1,700,276)	$ (3,694,005)
Net Utility Income at Proposed Rates	$ 164,144,039	$ 119,178,731	$ 15,393,932	$ 16,903,000	$ 12,668,376
Rate of Return at Proposed Rates	8.00%	8.00%	8.00%	8.00%	8.00%
Increase in Operating Revenue	$ 94,848,212	$ 89,711,180	$ 8,742,518	$ (494,454)	$ (3,111,033)
Operating Revenues at Present Rates	$ 667,019,391	$ 477,024,122	$ 64,896,196	$ 69,410,154	$ 55,688,918
Operating Revenues at Proposed Rates	$ 761,867,603	$ 566,735,302	$ 73,638,714	$ 68,915,701	$ 52,577,886

Peoples Natural Gas Company LLC
Proposed Class Revenue Apportionment
Using Combined Design Day and Peak & Average Demand Cost Allocation Methods

	Total	Residential Service	Small General Service	Medium General Service	Large General Service
Rate Base at 10/31/2020	$ 2,052,311,067	$ 1,401,067,261	$ 198,146,572	$ 243,854,059	$ 209,243,174
Net Utility Income at Present Rates	$ 94,525,688	$ 57,871,190	$ 8,415,343	$ 15,975,231	$ 12,263,924
Rate of Return at Present Rates	4.61%	4.13%	4.25%	6.55%	5.86%
Increase - Net Utility Income	$ 69,618,351	$ 54,186,306	$ 7,432,439	$ 3,528,240	$ 4,471,366
Net Utility Income at Proposed Rates	$ 164,144,039	$ 112,057,496	$ 15,847,782	$ 19,503,471	$ 16,735,289
Rate of Return at Proposed Rates	8.00%	8.00%	8.00%	8.00%	8.00%
Increase in Operating Revenue	$ 94,848,212	$ 72,993,513	$ 9,780,319	$ 5,619,590	$ 6,454,790
Operating Revenues at Present Rates	$ 667,019,391	$ 477,082,818	$ 64,877,562	$ 69,387,865	$ 55,671,146
Operating Revenues at Proposed Rates	$ 761,867,603	$ 550,076,331	$ 74,657,881	$ 75,007,455	$ 62,125,936

Peoples Natural Gas Company LLC
Proposed Class Revenue Apportionment

Table 1 - Cost-Based Non-Gas Revenue Apportionment - Design Day Demand Cost Allocation Method

Rate Class	Non-Gas Revenue at Current Rates	Rate of Return	Relative ROR	Revenue Change	Percent Change	Rate of Return	Relative ROR	Percent of Total Increase
Residential Service	273,991,108	3.40%	0.74	89,711,180	32.7%	8.00%	1.00	94.6%
Small General Service	33,951,754	4.60%	1.00	8,742,518	25.7%	8.00%	1.00	9.2%
Medium General Service	45,000,023	8.80%	1.91	(494,454)	-1.1%	8.00%	1.00	-0.5%
Large General Service	43,112,951	10.33%	2.24	(3,111,033)	-7.2%	8.00%	1.00	-3.3%
Total Company	396,055,837	4.61%	1.00	94,848,212	23.9%	8.00%	1.00	100.0%

Table 2 - Cost-Based Non-Gas Revenue Apportionment - Midpoint of Cost of Service Study Results

Rate Class	Non-Gas Revenue at Current Rates	Rate of Return	Relative ROR	Revenue Change	Percent Change	Rate of Return	Relative ROR	Percent of Total Increase
Residential Service	274,049,660	4.13%	0.90	72,993,513	26.6%	8.00%	1.00	77.0%
Small General Service	33,933,162	4.25%	0.92	9,780,319	28.8%	8.00%	1.00	10.3%
Medium General Service	44,977,788	6.55%	1.42	5,619,590	12.5%	8.00%	1.00	5.9%
Large General Service	43,095,227	5.86%	1.27	6,454,790	15.0%	8.00%	1.00	6.8%
Total Company	396,055,837	4.61%	1.00	94,848,212	23.9%	8.00%	1.00	100.0%

Table 3 - Non-Gas Revenue Apportionment on an Equal Percentage of Margin Basis - Design Day Demand Cost Allocation Method

Rate Class	Non-Gas Revenue at Current Rates	Rate of Return	Relative ROR	Revenue Change	Percent Change	Rate of Return	Relative ROR	Percent of Total Increase
Residential Service	273,991,108	3.40%	0.74	65,615,916	23.9%	6.67%	0.83	69.2%
Small General Service	33,951,754	4.60%	1.00	8,130,831	23.9%	7.74%	0.97	8.6%
Medium General Service	45,000,023	8.80%	1.91	10,776,692	23.9%	12.38%	1.55	11.4%
Large General Service	43,112,951	10.33%	2.24	10,324,772	23.9%	14.97%	1.87	10.9%
Total Company	396,055,837	4.61%	1.00	94,848,212	23.9%	8.00%	1.00	100.0%

Table 4 - Proposed Class Revenue Apportionment

Rate Class	Non-Gas Revenue at Current Rates	Rate of Return	Relative ROR	Revenue Change	Percent Change	Rate of Return	Relative ROR	Percent of Total Increase
Residential Service	273,991,108	3.40%	0.74	79,862,244	29.1%	7.45%	0.93	84.2%
Small General Service	33,951,754	4.60%	1.00	8,742,577	25.8%	8.00%	1.00	9.2%
Medium General Service	45,000,023	8.80%	1.91	4,950,003	11.0%	10.12%	1.26	5.2%
Large General Service	43,112,951	10.33%	2.24	1,293,389	3.0%	10.28%	1.29	1.4%
Total Company	396,055,837	4.61%	1.00	94,848,212	23.9%	8.00%	1.00	100.0%

	Proposed Base Rate Charges	Rider B - Gas Costs: Capacity	Rider B - Gas Costs: AVC Capacity	Rider B - Gas Costs: GCA	Rider B - Gas Costs: Commodity	BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
SALES															
Residential Service															
Customer Charge	$ 20.00								$ 0.0067				$ -	$ -	$ 20.01
Capacity		$ 1.0398	$ 0.6225					$ 0.0259							$ 1.6882
PTC - Commodity Charge				$ (0.0418)	$ 2.9474			$ 0.0723			$ 0.0801				$ 3.0580
Delivery Charge	$ 3.8753									$ 0.4094		$ -	$ -	$ -	$ 4.2847
State Tax Surcharge							$ -								$ -
Total per MCF															$ 9.0309
Small General Service															
Customer Charge															
0-499	$ 25.00								$ 0.0067				$ -	$ -	$ 25.01
500 - 999	$ 40.00								$ 0.0067				$ -	$ -	$ 40.01
Capacity		$ 0.3848	$ 0.5745												$ 0.9593
PTC - Commodity Charge		$ 0.6550		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.6490
Delivery Charge	$ 2.8312											$ -	$ -	$ -	$ 2.8312
State Tax Surcharge							$ -								$ -
Total per MCF															$ 7.4395
Small General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
0-499	$ 25.00								$ 0.0067				$ -	$ -	$ 25.01
500 - 999	$ 40.00								$ 0.0067				$ -	$ -	$ 40.01
Capacity		$ 0.3848	$ 0.5745												$ 0.9593
PTC - Commodity Charge		$ 0.6550		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.6490
Delivery Charge	$ 2.4430											$ -	$ -	$ -	$ 2.4430
State Tax Surcharge							$ -								$ -
Total per MCF															$ 7.0513
Medium General Service															
Customer Charge															
1,000 - 2,499	$ 100.00												$ -	$ -	$ 100.00
2,500 - 24,999	$ 200.00												$ -	$ -	$ 200.00
Capacity		$ 0.3848	$ 0.3750												$ 0.7598
PTC - Commodity Charge		$ 0.6550		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.6490
Delivery Charge	$ 2.4794											$ -	$ -	$ -	$ 2.4794
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.8882

	Proposed Base Rate Charges	Rider B - Gas Costs				BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
		Capacity	AVC Capacity	GCA	Commodity										
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
Medium General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
1,000 - 2,499	$ 100.00												$ -	$ -	$ 100.00
2,500 - 24,999	$ 200.00												$ -	$ -	$ 200.00
Capacity		$ 0.3848	$ 0.3750												$ 0.7598
PTC - Commodity Charge		$ 0.6550		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.6490
Delivery Charge	$ 2.1315											$ -	$ -	$ -	$ 2.1315
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.5403
Large General Service															
Customer Charge															
25,000 - 49,999	$ 700.00												$ -	$ -	$ 700.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
25,000 - 49,999	$ 2.4581											$ -	$ -	$ -	$ 2.4581
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.7070
Large General Service															
Customer Charge															
50,000 - 99,999	$ 1,300.00												$ -	$ -	$ 1,300.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
50,000 - 99,999	$ 2.4109											$ -	$ -	$ -	$ 2.4109
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.6598
Large General Service															
Customer Charge															
100,000 - 199,999	$ 1,400.00												$ -	$ -	$ 1,400.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
100,000 - 199,999	$ 2.3636											$ -	$ -	$ -	$ 2.3636
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.6125

	Proposed Base Rate Charges	Rider B - Gas Costs					Rider	Proposed Rider	Rider Supplier	Rider	Proposed Rider	Rider	Rider	Rider	Bill Display
		Capacity	AVC Capacity	GCA	Commodity	BB&A	STAS	MFC	Choice	USR	GPC	Rate Credit	DSIC	TCJA	Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
Large General Service															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
200,000 to 749,999	$ 2.2454											$ -	$ -	$ -	$ 2.2454
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.4943
Large General Service															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
750,000 to 1,999,999	$ 1.9617											$ -	$ -	$ -	$ 1.9617
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.2106
Large General Service															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
Over 2,000,000	$ 1.5127											$ -	$ -	$ -	$ 1.5127
State Tax Surcharge							$ -								$ -
Total per MCF															$ 5.7616
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
25,000 - 49,999	$ 700.00												$ -	$ -	$ 700.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
25,000 - 49,999	$ 2.1248											$ -	$ -	$ -	$ 2.1248
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.3737

	Proposed Base Rate Charges	Rider B - Gas Costs				BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
		Capacity	AVC Capacity	GCA	Commodity										
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
50,000 - 99,999	$ 1,300.00												$ -	$ -	$ 1,300.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
50,000 - 99,999	$ 2.0840											$ -	$ -	$ -	$ 2.0840
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.3329
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
100,000 - 199,999	$ 1,400.00												$ -	$ -	$ 1,400.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
100,000 - 199,999	$ 2.0432											$ -	$ -	$ -	$ 2.0432
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.2921
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
200,000 to 749,999	$ 1.9409											$ -	$ -	$ -	$ 1.9409
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.1898
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
750,000 to 1,999,999	$ 1.7553											$ -	$ -	$ -	$ 1.7553
State Tax Surcharge							$ -								$ -
Total per MCF															$ 6.0042

	Proposed Base Rate Charges	Rider B - Gas Costs						Proposed Rider	Rider Supplier		Proposed Rider				
		Capacity	AVC Capacity	GCA	Commodity	BB&A	Rider STAS	MFC	Choice	Rider USR	GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
Large General Service - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity		$ 0.0812	$ 0.2151												$ 0.2963
PTC - Commodity Charge		$ 0.9586		$ (0.0418)	$ 2.9474			$ 0.0083			$ 0.0801				$ 3.9526
Delivery Charge															
Over 2,000,000	$ 1.5127											$ -	$ -	$ -	$ 1.5127
State Tax Surcharge							$ -								$ -
Total per MCF															$ 5.7616

	Proposed Base Rate Charges	Rider B - Gas Costs Capacity	AVC Capacity	GCA	Commodity	BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
TRANSPORTATION															
GS-T (Residential)															
Customer Charge	$ 20.00								$ 0.0067				$ -	$ -	$ 20.01
Capacity		$ 1.0398	$ 0.6225					$ 0.0259							$ 1.6882
Delivery Charge	$ 3.8753									$ 0.4094		$ -	$ -	$ -	$ 4.2847
State Tax Surcharge							$ -								$ -
Total per MCF															$ 5.9729
GS-T (SGS)															
Customer Charge															
0-499	$ 25.00								$ 0.0067				$ -	$ -	$ 25.01
500 - 999	$ 40.00								$ 0.0067				$ -	$ -	$ 40.01
Capacity			$ 0.5745			$ 0.3848									$ 0.9593
Delivery Charge	$ 2.8312											$ -	$ -	$ -	$ 2.8312
State Tax Surcharge							$ -								$ -
Total per MCF															$ 3.7905
GS-T (SGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
0-499	$ 25.00								$ 0.0067				$ -	$ -	$ 25.01
500 - 999	$ 40.00								$ 0.0067				$ -	$ -	$ 40.01
Capacity			$ 0.5745			$ 0.3848									$ 0.9593
Delivery Charge	$ 2.4430											$ -	$ -	$ -	$ 2.4430
State Tax Surcharge							$ -								$ -
Total per MCF															$ 3.4023
GS-T (MGS)															
Customer Charge															
1,000 - 2,499	$ 100.00												$ -	$ -	$ 100.00
2,500 - 24,999	$ 200.00												$ -	$ -	$ 200.00
Capacity			$ 0.3750			$ 0.3848									$ 0.7598
Delivery Charge	$ 2.4794											$ -	$ -	$ -	$ 2.4794
State Tax Surcharge							$ -								$ -
Total per MCF															$ 3.2392

	Proposed Base Rate Charges	Rider B - Gas Costs: Capacity	AVC Capacity	GCA	Commodity	BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
GS-T (MGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
1,000 - 2,499	$ 100.00												$ -	$ -	$ 100.00
2,500 - 24,999	$ 200.00												$ -	$ -	$ 200.00
Capacity			$ 0.3750			$ 0.3848									$ 0.7598
Delivery Charge	$ 2.1315											$ -	$ -	$ -	$ 2.1315
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.8913
GS-T (LGS)															
Customer Charge															
25,000 - 49,999	$ 700.00												$ -	$ -	$ 700.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
25,000 - 49,999	$ 2.4581												$ -	$ -	$ 2.4581
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.7544
GS-T (LGS)															
Customer Charge															
50,000 - 99,999	$ 1,300.00												$ -	$ -	$ 1,300.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
50,000 - 99,999	$ 2.4109												$ -	$ -	$ 2.4109
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.7072
GS-T (LGS)															
Customer Charge															
100,000 - 199,999	$ 1,400.00												$ -	$ -	$ 1,400.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
100,000 - 199,999	$ 2.3636												$ -	$ -	$ 2.3636
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.6599

	Proposed Base Rate Charges	Rider B - Gas Costs Capacity	AVC Capacity	GCA	Commodity	BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
GS-T (LGS)															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
200,000 to 749,999	$ 2.2454												$ -	$ -	$ 2.2454
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.5417
GS-T (LGS)															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
PTC - Commodity Charge															$ -
750,000 to 1,999,999	$ 1.9617												$ -	$ -	$ 1.9617
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.2580
GS-T (LGS)															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
Over 2,000,000	$ 1.5127												$ -	$ -	$ 1.5127
State Tax Surcharge							$ -								$ -
Total per MCF															$ 1.8090
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
25,000 - 49,999	$ 700.00												$ -	$ -	$ 700.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
25,000 - 49,999	$ 2.1248												$ -	$ -	$ 2.1248
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.4211

	Proposed Base Rate Charges	Rider B - Gas Costs				BB&A	Rider STAS	Proposed Rider MFC	Rider Supplier Choice	Rider USR	Proposed Rider GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
		Capacity	AVC Capacity	GCA	Commodity										
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
50,000 - 99,999	$ 1,300.00												$ -	$ -	$ 1,300.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
50,000 - 99,999	$ 2.0840												$ -	$ -	$ 2.0840
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.3803
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
100,000 - 199,999	$ 1,400.00												$ -	$ -	$ 1,400.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
100,000 - 199,999	$ 2.0432												$ -	$ -	$ 2.0432
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.3395
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
200,000 to 749,999	$ 1.9409												$ -	$ -	$ 1.9409
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.2372
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
750,000 to 1,999,999	$ 1.7553												$ -	$ -	$ 1.7553
State Tax Surcharge							$ -								$ -
Total per MCF															$ 2.0516

	Proposed Base Rate Charges	Rider B - Gas Costs						Proposed Rider	Rider Supplier		Proposed Rider				
		Capacity	AVC Capacity	GCA	Commodity	BB&A	Rider STAS	MFC	Choice	Rider USR	GPC	Rider Rate Credit	Rider DSIC	Rider TCJA	Bill Display Total Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15=SUM 1 to 14)
GS-T (LGS) - Peoples' Transitional Industrial Ratepayers															
Customer Charge															
> 200,000	$ 1,600.00												$ -	$ -	$ 1,600.00
Capacity			$ 0.2151			$ 0.0812									$ 0.2963
Delivery Charge															
Over 2,000,000	$ 1.5127												$ -	$ -	$ 1.5127
State Tax Surcharge							$ -								$ -
Total per MCF															$ 1.8090

Peoples Natural Gas Company LLC
Residential Monthly Bill Comparisons

Peoples Division

Month	Usage (Mcf)	Present Rates Monthly Bill	Proposed Rates Monthly Bill	Monthly Change in Bill Amount	Monthly Change in Bill Percent
January	9.6	$ 94.70	$ 106.70	$ 12.00	12.7%
February	13.7	$ 129.17	$ 143.73	$ 14.56	11.3%
March	15.3	$ 142.62	$ 158.18	$ 15.56	10.9%
April	13.1	$ 124.13	$ 138.31	$ 14.19	11.4%
May	10.9	$ 105.63	$ 118.44	$ 12.81	12.1%
June	6.2	$ 66.11	$ 76.00	$ 9.88	15.0%
July	3.5	$ 43.41	$ 51.61	$ 8.20	18.9%
August	1.9	$ 29.96	$ 37.17	$ 7.20	24.0%
September	1.6	$ 27.44	$ 34.46	$ 7.02	25.6%
October	1.6	$ 27.44	$ 34.46	$ 7.02	25.6%
November	2.4	$ 34.16	$ 41.68	$ 7.52	22.0%
December	6.2	$ 66.11	$ 76.00	$ 9.88	15.0%
Total	86.0	$ 890.89	$ 1,016.74	$ 125.85	14.1%

Bill Component	Present Rates	Proposed Rates
Monthly Service Charge	$ 13.95	$ 20.00
Rider DSIC	$ 0.6975	$ -
Rider TCJA	$ (0.6728)	$ -
Rider Supplier Choice	$ 0.0115	$ 0.0067
Base Cost of Gas	$ 4.5679	$ 4.5679
Delivery Rate	$ 3.1330	$ 3.8753
Rider STAS	$ (0.0072)	$ -
Rider MFC	$ 0.1024	$ 0.0982
Rider USR	$ 0.4667	$ 0.4094
Rider GPC	$ 0.1055	$ 0.0801
Rider Rate Credit	$ -	$ -
Rider DSIC	$ 0.1904	$ -
Rider TCJA	$ (0.1511)	$ -

Peoples Natural Gas Company LLC
Residential Monthly Bill Comparisons

Equitable Division

Month	Usage (Mcf)	Present Rates Monthly Bill	Proposed Rates Monthly Bill	Monthly Change in Bill Amount	Monthly Change in Bill Percent
January	9.6	$ 90.43	$ 106.70	$ 16.27	18.0%
February	13.7	$ 123.52	$ 143.73	$ 20.21	16.4%
March	15.3	$ 136.43	$ 158.18	$ 21.75	15.9%
April	13.1	$ 118.68	$ 138.31	$ 19.64	16.5%
May	10.9	$ 100.92	$ 118.44	$ 17.52	17.4%
June	6.2	$ 62.99	$ 76.00	$ 13.00	20.6%
July	3.5	$ 41.21	$ 51.61	$ 10.41	25.3%
August	1.9	$ 28.29	$ 37.17	$ 8.87	31.4%
September	1.6	$ 25.87	$ 34.46	$ 8.58	33.2%
October	1.6	$ 25.87	$ 34.46	$ 8.58	33.2%
November	2.4	$ 32.33	$ 41.68	$ 9.35	28.9%
December	6.2	$ 62.99	$ 76.00	$ 13.00	20.6%
Total	86.0	$ 849.54	$ 1,016.74	$ 167.20	19.7%

Bill Component	Present Rates	Proposed Rates
Monthly Service Charge	$ 13.25	$ 20.00
Rider DSIC	$ 0.6625	$ -
Rider TCJA	$ (0.9508)	$ -
Rider Supplier Choice	$ 0.0001	$ 0.0067
Base Cost of Gas	$ 4.5679	$ 4.5679
Delivery Rate	$ 3.1687	$ 3.8753
Rider STAS	$ (0.0304)	$ -
Rider MFC	$ 0.1024	$ 0.0982
Rider USR	$ 0.2040	$ 0.4094
Rider GPC	$ 0.1055	$ 0.0801
Rider DSIC	$ 0.1790	$ -
Rider TCJA	$ (0.2274)	$ -

Peoples Natural Gas Company LLC
Derivation of the Merchant Function Charge

Calculation of Uncollectible Natural Gas Costs

Line No.	Description				
1	Natural Gas Supply Charge	$	3.9454	/Mcf	
	Uncollectible Write-Off Factor				
2	Residential				2.49%
3	SGS				0.21%
4	MGS				0.21%
5	LGS				0.21%

Line No.	Description				
	Merchant Function Charge (MFC)				
6	Residential	(Line 1 x Line 2)	$	0.0982	/Mcf
7	SGS	(Line 1 x Line 3)	$	0.0083	/Mcf
8	MGS	(Line 1 x Line 4)	$	0.0083	/Mcf
9	LGS	(Line 1 x Line 5)	$	0.0083	/Mcf

Peoples Natural Gas Company LLC
Derivation of the Gas Procurement Charge

Gas Procurement Cost Analysis - 12 Mos. Ended October 31, 2020

Line No.				Gas Procurement Costs - FPFTY
1	Labor and Benefits			
2	Gas Supply			$ 297,553
3	Accounting Support			$ 44,431
4	Legal Support			$ 71,219
5	Regulatory Support			$ 179,264
6	Total Labor & Benefits			$ 592,467
7	Non-Labor Costs			
8	Outside Services - Legal Support			$ 129,400
9	Total Non-Labor Costs			$ 129,400
10	Other Costs			
11	Storage Inventory - Current Gas	$	31,115,826	
12	Pre-Tax Return		10.45%	
13	Revenue Requirement	$	3,251,604	$ 3,251,604
14	Gastar System - FPFTY Rate Base	$	49,396	
15	Pre-Tax Return		10.45%	
16	Revenue Requirement	$	5,162	$ 5,162
17	O&M IT Support Costs			$ 73,121
18	DD&A Expense - Gastar			$ 18,176
19	Total Other Costs			$ 3,348,062
20	Total GPC Costs			$ 4,069,929
21	Sale Volumes - Mcf			50,820,315
22	GPC - $/Mcf			$ 0.0801

Peoples Natural Gas Company LLC
Derivation of Supplier Services – Revenue and Cost Comparison

Supplier Service - Revenue and Cost Comparison

	NGS Service Revenues at Present Rates			Revenue Requirement - Cost Based NGS Fees			Proposed NGS Fee Structure		
	FPFTY Total Bills	Present Fee	FPFTY Revenues	FPFTY Total Bills	Cost Rate	FPFTY Revenues	FPFTY Total Bills	Proposed Rate	FPFTY Revenues
	(1)	(2)	(3)=(1)*(2)	(4)	(5)	(6)=(4)*(5)	(7)	(8)	(9)=(7)*(8)
Billing Service - Peoples	988,816	$ 0.1500	$ 148,322	988,816	$ 0.1363	$ 134,741	1,243,358	$ 0.1500	$ 186,504
Billing Service - Equitable	254,542	$ 0.3000	$ 76,363	254,542	$ 0.1363	$ 34,685			
Total			$ 224,685			$ 169,426			$ 186,504
					Revenues in Excess of Costs	$ 55,259			

Peoples Natural Gas Company LLC
Derivation of Supplier Services – Revenue and Cost Comparison

Incremental Billing Service - Revenue Requirement

Line No.	Supplier Rate Maintenance & Billing Support	Hours
1	Monthly Commodity Rate Maintenance	24
2	Monthly Supplier Payments -- pulling data from reports	40
3	Print/record/scan various reports to support invoice	68
4	Research & respond to supplier questions and billing group questions related to supplier portion of bill	72
5	Total Hours per Month	204
6	Hourly Employee Rate	$ 69.21
7	Total Labor Costs per Month	$ 14,118.84
8	TOTAL COSTS	
9	Annual Labor	$ 169,426
10	Incremental Mailing Costs	$ -
11	Total Incremental Costs	$ 169,426
12	Annual Supplier Bills Issued	1,243,358
13	Cost per Bill Issued	$ 0.1363

Peoples Natural Gas Company LLC
Derivation of the Purchase of Receivables – Administration Adder

Line No.				FPFTY October 31, 2020
1	Rate Base 1/		$	136,385
2	Rate of Return 2/	8.00%	$	10,907
3	O&M Expenses (POR Education)		$	-
4	Depreciation Expense	10%	$	89,924
5	Federal Income Taxes		$	10,427
6	State Income Taxes		$	1,157
7	Total POR Administration Costs		$	112,416
8	Residential and Small General Sales Revenues 3/		$	527,430,126
9	Purchase of Receivables - Administration Adder			0.0213%

1/ Rate Base

Capital - POR Development & Administration	$	899,241
Accumulated Depreciation	$	(689,418)
Deferred Taxes	$	(73,438)
Total Rate Base	$	136,385

		Capitalization	Cost of Capital	Weighted Component
2/	LT Debt	45.12%	4.22%	1.90%
	Debt - CapEx	1.22%	4.69%	0.06%
	Common Equity	53.66%	11.25%	6.04%
	Overall Return	100.00%		8.00%

3/ Estimated revenues based on FPFTY RS and SGS sales revenues @ proposed rates.