SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.

A CENTERPOINT ENERGY COMPANY

(VECTREN SOUTH)

IURC CAUSE NO. 45447

DIRECT TESTIMONY

OF

RUSSELL A. FEINGOLD

VICE PRESIDENT

BLACK & VEATCH MANAGEMENT CONSULTING, LLC

ON

COST OF SERVICE STUDY AND RATE DESIGN

SPONSORING PETITIONER'S EXHIBIT NO. 16,

ATTACHMENTS RAF-1 THROUGH RAF-4

Glossary of Acronyms

A&G	Administrative and General
Black & Veatch	Black & Veatch Management Consulting, LLC
COSS	Cost of Service Study
CenterPoint	CenterPoint Energy, Inc.
Company	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.
CSIA	Compliance and System Improvement Adjustment
FERC	Federal Energy Regulatory Commission
IURC or Commission	Indiana Utility Regulatory Commission
MSFR	Minimum Standard Filing Requirements
O&M	Operations and Maintenance
PBR	Performance-Based Regulation
Petitioner	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.
PISCC	Post-in-Service Carrying Costs
TDSIC	Transmission, Distribution, and Storage Improvement Charge
Vectren	Vectren Corporation
Vectren North	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc.
Vectren Ohio	Vectren Energy Delivery of Ohio, Inc.
Vectren South	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.

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DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. By whom are you employed?

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 Black & Veatch.

A. Black & Veatch Corporation (the parent company of Black & Veatch) has provided comprehensive engineering and management services to utility, industrial, and government 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 and electric distribution companies located in the U.S. and Canada.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University in 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 Indiana Utility Regulatory 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-five (45) years of experience in the utility industry, the last forty-two (42) years of which have been in the field of utility management and economic consulting. Specializing in the 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 Petitioner's Exhibit No. 16, Attachment RAF-1 to my testimony.

Q. Please summarize your specific experience in conducting class cost of service studies and designing rates for gas and electric utilities.

A. Over my utility consulting career, I have conducted numerous class 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. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner", "Vectren South" or "the Company"), which is a wholly owned subsidiary of Vectren Corporation ("Vectren"), a subsidiary of CenterPoint Energy, Inc. ("CenterPoint").

II. SUMMARY

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

A. The purpose of my testimony is to sponsor, present and explain the Cost of Service Study ("COSS"), class revenues and rate design proposals submitted by Vectren South in this rate proceeding. My testimony specifically addresses: (1) the structure, content and results of the Company's COSS, its underlying cost allocation methods, and how its results are used for ratemaking purposes; (2) the Company's test year, non-gas revenue subsidies and excesses by rate class and its proposed class revenue apportionment; and (3) the Company's proposed rate design and the resulting rates by rate class.

Q. Would you please identify the supporting documents you are sponsoring in this proceeding?

A. I am sponsoring the following attachments:

- Petitioner's Exhibit No. 16, **Attachment RAF-1**: Background information summarizing my work experience, presentation of expert testimony, and other industry-related activities.

- Petitioner's Exhibit No. 16, **Attachment RAF-2**: COSS Summary Schedules
- Petitioner's Exhibit No. 16, **Attachment RAF-3**: Proposed Revenue Apportionment by Rate Class
- Petitioner's Exhibit No. 16, **Attachment RAF-4**: Customer Cost Analysis

I am also sponsoring the following schedules of Petitioner's Revenue Requirement and Revenue Model included in Petitioner's Exhibit No. 18:

- Schedule E-4: Class and Schedule Revenue Summary
- Schedule E-5: Typical Bill Comparisons (co-sponsored with Vectren witness Tieken)

Q. What is the source of the information contained in the schedules you are sponsoring?

A. The source of the information generally is the books and operating budgets of Vectren South. When data comes from another source, I will note that in my testimony if not made clear in the referenced schedules of the Company's case-in-chief.

Q. Has a COSS been submitted in this proceeding?

A. Yes. In compliance with the Commission's Minimum Standard Filing Requirements ("MSFRs") - Section 15, the Company has submitted a COSS based upon pro forma revenues and costs for the future test year ended December 31, 2021. The study was performed using Black & Veatch's proprietary, computer-based Gas Cost of Service Model.

Q. Was this study prepared by you or under your supervision and direction?

A. Yes.

Q. What was the source of the cost data analyzed in the Company's COSS?

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 rate classes were included in the Company's COSS?

A. The rate classes included in Vectren South's COSS are Residential Sales Service - Rate 110, General Sales Service – Rate 120, School/Government Transportation Service – Rate 125, General Transportation Service – Rate 145, Large Volume Transportation Service - Rate 160 and Contract Transportation Service – Rate 170.[1]

[1] Natural Gas Vehicle Service (Rate 129) and Storage Service (Rate 190) are excluded from Vectren South's COSS in this proceeding.

III. CONCEPTUAL BASIS FOR CONDUCTING A UTILITY'S COSS

Q. Would you please state the purpose of a COSS?

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

Q. Are there certain guiding principles which should be followed when performing a COSS?

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 specific types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the specific costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost allocation methodology for use in conducting a COSS is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand, and the costs incurred by the utility 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.

A gas utility's gas 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, coincident design day capacity requirements of all customers entitled to firm service; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. The costs incurred by a utility satisfy one or more of these operational objectives. There is generally a direct link between the way in which costs are defined and their subsequent allocation.

It is a generally accepted concept in the utility industry that customer-related costs are incurred by a gas utility 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 a 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.

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 since they vary with the amount of gas volumes utilized by the Company's default sales service customers.

Q. Please describe the general nature of gas distribution costs.

A. The delivery service costs of a gas distribution utility are primarily fixed costs. Gas utilities design and install a gas distribution system capable of meeting its customers' design day requirements at the time of initial installation. Placing these facilities in service permits the utility to serve the changes in load due to extreme weather (i.e., the design day load). Once facilities serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers.

Q. Is the fixed nature of these costs widely recognized?

A. Yes. The evidence supporting the fixed nature of these costs is quite significant. For example, utilities routinely normalize for weather both the costs and revenues of a gas utility as part of its rate case. If the costs of distribution mains were in any way related to the volume of gas consumed, it would also be necessary to weather normalize the utility's rate base, but this is not the case. It is widely recognized that the costs of distribution mains are fixed and do not vary with gas volume. Additionally, the Gas Distribution Rate Design Manual, prepared by the NARUC Staff Subcommittee on Gas, defines demand or capacity costs as follows: demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to the customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Q. Please discuss the factors which can influence the overall cost allocation framework utilized by a gas distribution utility.

A. Three standard steps or phases are followed when performing a COSS: cost functionalization, cost classification and cost allocation. The factors affecting these steps 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) the transmission and/or distribution system configuration; (2) the mainline pipeline functionality; (3) the system operating pressure configuration; and (4) the existence of any production-related facilities. 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; (3) the system operates under a multiple-pressure based or a single-pressure based configuration; and (4) the production-related facilities are used to support the peak demand or seasonal/annual demand requirements of the gas utility's customers.

With regard to data availability, the structure of the gas utility's books and records can influence its COSS framework. This structure relates to attributes such as the level of detail, segregation of data by customer or rate 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 jurisdiction. For example, any specific methodological preferences or guidelines for performing COSS or designing rates established by the state regulatory body can affect the specific cost allocation method presented by the gas utility.

Q. How do these factors relate to the specific circumstances applicable to Vectren South?

A. Regarding the physical configuration of the Company's gas system, it is a concentrated (in the greater Evansville area), multiple city-gate transmission and distribution system, with a multi pressure-based system.

With respect to data availability, Vectren South has detailed plant accounting records. Where necessary, it is a customary and accepted practice in the utility industry to rely upon current operating cost experience to derive reasonable cost estimates of customer-related facilities (e.g., services, meters and regulators) by rate class for purposes of assigning the test period costs of those facilities to the utility's rate classes. Finally, I am not aware of any methodological preferences or guidelines for performing a COSS established by the Commission.

Q. What steps did you follow to perform the Company's COSS?

A. I followed three broad steps to perform the Company's COSS: (1) functionalization; (2) classification; and (3) allocation. The first step, the functionalization process, involves separating rate base (primarily plant in service) and expense items into operational components based on the various characteristics of utility operation. For Vectren South, the functional cost categories associated with gas delivery service include production, storage, transmission and distribution.

Classification of costs, the second step, 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.

The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated using customer, demand, and commodity allocation factors.

Q. What objective are you seeking to achieve through this three-step process?

A. The functionalization and classification of the utility's total cost of service (i.e., its total revenue requirement), provides the cost analyst with groupings of costs that are fairly homogeneous, which enables the identification and application of cost allocation methods that have a closer relationship to the causation of the costs that are being assigned to the utility's rate classes.

Q. How does the cost analyst establish the cost and utility service relationships you previously described?

A. To establish these relationships, the cost analyst must analyze the utility's gas system design and operations, its accounting records and its system-wide and customer specific load data. From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all 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 specific customer groups.

Direct assignment of plant and expenses to specific customers or classes of customers is made based on special studies wherever the necessary data is 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 use facilities. Where a utility provides gas delivery services to two or more rate classes wherein one class uses fungible capacity which could be utilized by the other rate class, common costs are involved. This situation is illustrated through the utility's use of its gas distribution mains to serve multiple rate classes and a wide range of customers within these classes. As a result, 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 costs to the customer classes. The types of 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 design and operating characteristics of its gas transmission and distribution systems and the types and levels of costs incurred in connecting various sized customers to its gas distribution system.

Q. Please explain the most important considerations you relied upon in determining the cost allocation methodologies which were used to conduct Vectren South's COSS.

A. As stated above, it is important to recognize the cost causative characteristics of each of the cost elements which are to be directly assigned or allocated within any class cost of service study. Additionally, the cost analyst needs to structure data in the COSS in a format (e.g., by cost classification and function) which is supportive of the appropriate allocation of costs to the utility's customer or rate classes. 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 cost causality as opposed to value of service;
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 explain the overall approach and guidelines you used to conduct the Company's COSS.

A. Throughout the process of choosing cost allocation methods and deriving cost allocation factors for use in a utility's COSS, I always objectively determine cost causative factors that are grounded in the design and operating characteristics of the specific utility. This was also the case in conducting the COSS filed by Vectren South in this proceeding. As a result, the Company's COSS reasonably reflects the appropriate cost causation characteristics across all the Company's rate classes and derives results that objectively portray the true costs to serve each of the utility's rate classes and the customers within each rate class. These results can be used with confidence as a guide to establish the Company's class revenues and rates in this proceeding.

Q. Please describe the key issues related to the allocation of demand-related costs within a gas utility's COSS.

A. An important and complex part of the allocation process is the allocation of demand-related costs. These costs represent a relatively largely portion of the utility's revenue requirements, and the nature of the plant facilities and expenses are joint in nature, meaning that "common" allocation methods must be used instead of direct assignments. Several methodologies have been used to develop allocation factors for the demand components of costs. It is fair to say that three basic methodologies for allocating demand-related costs are the most common. 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 gas utility. 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 relative to the system peak. The Peak Demand Allocation process might focus on a single peak, such as the utility's design day which is based on the worst-case temperature conditions under which the utility's gas distribution system must be designed. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day.

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 based on system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated based on each class's 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's 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 equal 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 and, particularly distribution facilities, may be designed to serve local peaks which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated based on each group's (rate class) maximum demand, irrespective of the time of the system peak.

Q. How have demand-related costs been allocated in Vectren South's COSS?

A. The Company's COSS uses a coincident peak demand (derived on a design day basis) to allocate demand-related costs to its rate classes. Demand-related costs for the Company consist of the capacity costs (plant-related and expenses) associated with its city-gate facilities and the capacity or demand-related portion of its gas distribution system.

Q. Why doesn't the Company use average demand (i.e., annual throughput volumes divided by 365 days) to allocate demand-related costs?

A. Using only average demand to allocate demand related costs is inappropriate because it does not reflect the cost causative characteristics of demand-related costs. If a gas utility's system was sized and installed to accommodate average gas demands, it would be unable to accommodate the design day demands upon which the system was built. That is, by sizing plant investment for design day demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, a design day demand 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 is not in the utility's interest to encourage.

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

Q. Why did you choose to utilize Vectren South's design day demands rather than its actual peak day demands as a demand allocation factor?

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

1. A gas utility's system is designed, and consequently costs are incurred, to meet its design day demand. In contrast, costs are not incurred on the basis of an average of peak demands over time.
2. Design day demand is directly related to the level of change in customers' maximum daily demands for gas and to the associated 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 cause costs to be incurred.

A. Vectren South must consistently rely upon design day demand in the design of its own distribution facilities required to serve its firm service customers. This requirement will ensure that the utility has sufficient gas distribution system capacity to continue to provide reliable gas service during design day (worst case) conditions. 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 it to acquire resources, build facilities and incur hundreds of millions of dollars in fixed costs on an ongoing basis. Based on my experience, there is no better way to capture the true cost causative factors of the Company's gas operations than to utilize its design day demand requirements within its COSS.

Q. What level of firm demand requirements must Vectren South consider in designing its gas distribution system to deliver under all conditions?

A. It is my understanding that Vectren South designs its gas system, and has sufficient capacity, to serve the maximum delivery service requirements of all its firm sales and transportation service customers. I would consider this to be a reasonable approach, and one that is common across the gas utility industry. Therefore, the demands of all firm customers will be treated on an equivalent basis for purposes of cost allocation based on using the design day demands of the Company's rate classes.

Q. Why is the use of design day demands closely related to the change in the Company's fixed plant investment over time?

A. Changes in design day demands serve as the primary input into the Company's ongoing decisions to install distribution system facilities to meet firm customer demands for gas delivery service. Simply stated, when customers' design day demands increase to a certain point, the Company needs to consider additional fixed plant investments, as it needs to be able to meet its design day demands.

Q. Please explain why the use of design day demand provides relatively stable cost allocation results over time.

A. A gas utility's design day demand is the primary determinant of its planned capacity requirements and utilization. As described earlier, the design day demand is a measure of firm customers' maximum daily gas usage under pre-defined, worst-case weather conditions. As such, design day demand will not vary to the same degree as the utility's actual peak day demands, because those demands can increase or decrease in any year compared to the peak day demands experienced in past years based on whether the specific day was relatively colder or warmer. Therefore, use of design day demand provides a more stable basis, and one more tied to the basis of investment decisions, than any of the other demand allocators available based on either actual peak day demand or the averaging of multiple peak day demands.

Q. In addition to the allocation of demand-related costs, are there any other aspects of a gas utility's COSS worthy of focus?

A. Yes. For similar reasons, another critical element of a gas utility's COSS is the cost classification, allocation methods, and related allocation factors used to assign the plant and expenses associated with distribution mains to the utility's classes of service.

Q. Please describe the system operating conditions that provide a foundation for the choice of classification and allocation methods for the costs of distribution mains.

A. Gas customers in a utility's residential and commercial service classes have exhibited declining use per customer due to the improved efficiency of capital stock replacement and improvements to the housing thermal envelope. This improved efficiency over time lowers the utility's design day requirements compared to the design day requirements at the time when the original plant was designed and installed to serve customer loads. As a result, the growth in transmission plant and distribution plant for gas customers primarily reflects the growth in number of customers using gas service. That is, a utility's system of distribution mains must be extended over time to permit new customers to receive gas service. Therefore, the primary driver of new distribution mains cost is the addition of new customers. Further, there are substantial economies of scale associated with the gas distribution infrastructure such that the unit cost of capacity for gas delivery declines with size at a relatively rapid rate.

Q. Please discuss the economies of scale associated with gas distribution service.

A. Scale economies for a gas distribution utility reflect the relationship between the installed cost of pipe by size and type, coupled with the increased capacity from pressure and pipe diameter. For example, doubling the size of the gas main results in more than a doubling of the available capacity of the main, at a cost for Vectren South that is less than double the cost of the smaller size main. For a lower pressure system, increasing pipe size from two-inch to four-inch allows almost six times the amount of gas to flow. The resulting cost causation results in larger customers imposing lower unit costs of design day capacity on the gas utility's distribution system than do smaller customers.

Q. Can you please explain how the costs of gas distribution mains should be classified and allocated in a gas utility's COSS?

A. Yes. There are two cost factors that influence the level of distribution main facilities installed by a gas utility in expanding its gas distribution system. First, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid over time to connect new customers to the system. Secondly, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the coincident peak gas demand placed on the gas utility's system by its firm customers. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment and the related operation and maintenance (O&M) expenses based on both the number of customers served by the gas utility and its design day demands.

To further explain, the customer component of distribution mains is premised upon the concept of a "minimum system." The "minimum system" for a gas distribution utility is the smallest hypothetical system a gas utility would construct to connect its customers. The classification of the costs associated with the minimum system as customer-related, rather than capacity-related, recognizes the fact that the gas utility must install a network of distribution mains simply to have a physical connection with its customers, regardless of the level of demand a specific customer will actually impose on the gas system. A customer cannot be served at any level if the customer is not physically interconnected with the utility's gas distribution system.

Using the minimum system concept as a foundation, it is widely recognized that a large portion of a gas utility's total cost of distribution mains must be borne regardless of customers' peak day or annual use. To illustrate this point, it is useful to summarize a gas utility's process for physically connecting new customers. To extend gas service to a typical residential subdivision, the utility must first design the gas system. Based on this design, the utility determines the length and size of pipe needed to serve the area and procures the necessary material. A field crew is then dispatched to the site, together with the materials and equipment required to install the natural gas facilities.

The activities necessary to install gas mains include digging a trench, installing the main into the trench, and backfilling the trench. Pipeline boring (i.e., a trenchless installation method) may be necessary to install some main segments if the utility is unable to open trench a portion of the line due to existing surface conditions along the route of the main. After the main is installed, it will be pressure tested, tied into the existing gas system, and purged and filled with natural gas. The main is then ready to provide utility service to the new customers. These steps are necessary regardless of how much gas the new customers are projected to use during the year or during a peak day. The design work must still be completed, the crews, materials, and equipment dispatched to the site, the trench dug, the main installed in the trench, the trench backfilled, testing performed, and the other activities performed.

The additional costs associated with any larger mains required are mostly the incremental costs of the larger mains themselves, the additional labor involved with digging a wider trench for very large mains, and possibly the need for additional equipment to handle larger diameter pipe. As a result, a large percentage of the costs of providing gas delivery service to a gas utility's customers are incurred before they ever use one unit of gas. These are the costs the gas utility must incur simply to extend its gas distribution system to customers, irrespective of whether they will demand a small or large volume of gas on a peak day. As a result, the costs of such a minimum system are fundamentally customer-related in nature.

Q. What methods are used in the gas utility industry to determine the customer component of distribution mains?

A. Based on my experience, the two most commonly used methods in the gas utility industry for determining the customer cost component of distribution mains facilities consist of: (1) the zero-intercept method; and (2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept method, which is the method utilized in Vectren South's COSS, a customer cost component is developed through statistical regression analyses to determine the unit cost (i.e., cost per foot) associated with a zero-inch diameter distribution main. This concept can also be thought of as estimating the fixed costs per foot that the utility incurs to design and install a gas distribution main regardless of the main's diameter.

The most commonly installed, minimum-sized unit method is intended to reflect the engineering considerations associated with installing distribution mains to serve the utility's gas customers. That is, this method utilizes actual installed investment units to determine the minimum gas distribution system rather than a statistical analysis based upon investment characteristics of the utility's entire gas distribution system.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies are Electric Utility Cost Allocation Manual, by John J. Doran et al., National Association of Regulatory Utility Commissioners (NARUC) and Gas Rate Fundamentals, American Gas Association. Both of these authorities describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. In its publication, "Gas Distribution 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. Have you prepared an analysis which supports Vectren South's classification and allocation of distribution mains costs?

A. Yes. The COSS workpapers filed by Vectren South which present details of the derivation of external allocation factors provides the derivation of the customer component of distribution mains for Vectren South using the zero-intercept method based on the Company's historical costs of distribution mains, adjusted to current cost levels using the Handy Whitman index. The resulting percentage of 48.14% represents the customer cost component of distribution mains and the remaining 51.86% represents the demand cost component.

The customer cost component is then allocated to the Company's rate classes based on the number of customers in each rate class for the test year, and the demand cost component is allocated to the rate classes based on the design day demand allocation factor.

Q. How did you recognize in the Company's COSS the fact that Vectren South operates its distribution mains at different pressures?

A. This operating condition was recognized in the Company's COSS by treating the plant and associated expenses for its high-pressure gas distribution system differently compared to the treatment of the plant and associated expenses for its medium- and low-pressure gas distribution systems.[2] The way in which various sizes of customers rely upon the Company's gas distribution system determined how each portion of Vectren South's gas distribution system was allocated to its rate classes. Specifically, the plant and associated expenses for Vectren South's high-pressure distribution mains were assigned to all rate classes. Then, the plant and associated expenses for its medium- and low-pressure distribution mains were assigned to the Residential Sales Service (Rate 110) and School/Government Transportation Service (Rate 125) rate classes, and to the General Transportation Service (Rate 145), Large Volume Transportation Service (Rate 160) and the Contract Transportation Service (Rate 170) rate classes after first excluding those customers served directly from the Company's high-pressure distribution mains. This treatment reflects the fact that larger customers (primarily industrial customers) in the Company's Rate 170 class, and to a lesser extent in the Rate 145 and Rate 160 classes, do not require Vectren South's medium- and 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 Vectren South's high-pressure gas distribution system. In fact, because of such gas demand requirements, these customers are not connected to Vectren South's medium- and low-pressure gas distribution systems, 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.

[2] Vectren South's high-pressure distribution system operates at pressures greater than 60 pounds per square inch ("psig"), its medium-pressure system operates between 1-60 psig and its low-pressure system operates at less than 1 psig (i.e., utilization pressure).

Q. Earlier in your testimony you discussed the use of special studies to assign plant and expenses to a utility's rate classes. Please describe the special studies you conducted to assign the Company's other distribution plant investment to its rate classes.

A. Regarding Vectren South's major plant accounts, a series of direct assignments were developed to allocate the following plant accounts: Services - Account No. 380, Meters - Account No. 381, Meter Installations - Account No. 382, House Regulators – Account No. 383, and Industrial Measuring & Regulating Station Equipment - Account No. 385. In particular, the special studies reflect the differences in the unit costs that specific customer groups cause the Company to incur.

Q. How was general plant allocated in Vectren South's COSS?

A. The general plant accounts (Account Nos. 389-398) are composed of facilities and equipment that primarily supports the Company's transmission and distribution plant and its related labor force. On that basis, each account was allocated to Vectren South's rate classes using a composite allocation factor based either on total transmission and distribution plant or on total labor expenses depending on the nature of the specific account.

Q. How was intangible plant allocated in Vectren South's COSS?

A. Intangible plant primarily consists of Miscellaneous Intangible Plant (Account No. 303), which includes a variety of computer software investments that support the Company's customer service and delivery functions and related tariff modifications. These investments were allocated to the Company's rate classes using a composite allocation factor based on an equal weighting of labor-related expenses and the number of customers.

Q. Please describe the method used to allocate the Company's reserve for depreciation and depreciation expenses.

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

Q. Please describe the method used to allocate the Company's amortization expenses.

A. Each amortization category was allocated based on the specific nature of the deferral amount. The amortization of the 20% deferral associated with the Compliance and System Improvement Adjustment ("CSIA") program was allocated to the rate classes using the same TDSIC allocation factor created to periodically charge the Company's customers for the other portion of CSIA-related investment costs. The amortization of the deferred depreciation and Post-in-Service Carrying Costs ("PISCC") associated with the CSIA program was allocated to the rate classes based on total plant in service. Finally, the amortization of the deferred depreciation and AFUDC associated the Company's bare steel and cast-iron mains and services replacement program was allocated to the rate classes on the same basis as for mains and services.

Q. How were distribution-related O&M expenses allocated in Vectren South's COSS?

A. In general, these expenses were allocated based on the cost allocation methods used for Vectren South's corresponding plant accounts. A utility's O&M expenses generally are considered to support the utility's corresponding plant-in-service accounts. That is, the existence of the specific 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 Customer Account Expenses allocated in Vectren South's COSS?

A. Vectren South's COSS allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Meter reading expense (Account No. 902) was allocated to the rate classes based on the number of customers in each rate class since it was determined that there is no difference in the unit cost of reading a meter for a Residential Service customer compared to the unit cost for reading the meters of larger customers. Customer records and collection expense (Account No. 903) was allocated to the rate classes based on the number of customers in each rate class. Uncollectible accounts expense (Account No. 904) was directly assigned to each rate class based on the actual level of bad debt experienced in each rate class during the test period.

Q. How were Customer Service and Informational Expenses and Sales Expenses allocated in Vectren South's COSS?

A. Vectren South's COSS generally allocated these expenses to each rate class based on the number of customers. For Account No. 913 – All Other, the expenses in this account were allocated to the Company's rate classes based on the number of residential and commercial customers in each rate class.

Q. How were Administrative and General ("A&G") expenses allocated in Vectren South's COSS?

A. Vectren South's COSS allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Specifically, the A&G expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant or rate base; and (3) O&M expenses. In the Company's COSS, each of its A&G 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 corporate-wide nature of A&G expenses.

Specifically, Administrative and General Salaries (Account No. 920), Office Supplies and Expenses (Account No. 921), Administrative Expenses Transferred (Account No. 922), Injuries and Damages (Account No. 925) and Employee Pensions and Benefits (Account No. 926) were allocated using a labor-based allocation factor derived from the labor component of the Company's transmission and distribution O&M expenses. 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. Property Insurance (Account No. 924) was allocated on total plant in service. Outside Services (Account No. 923) and Miscellaneous Expenses (Account No. 930.2) include support activities provided to Vectren South directly by outside service providers and its corporate parent organization. These activities 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 rate classes using a composite allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs). Finally, Regulatory Commission Expenses (Account No. 928) and Rents (Account No. 931) were allocated using a generalized cost allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs).

Q. How were income taxes allocated in Vectren South's COSS?

A. Income Taxes were allocated to each rate class based on each class's income before federal income taxes. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of current class revenues, previously allocated expenses and the various adjustments made by the Company for tax computation purposes. Income Taxes for each rate class at revenues producing an equal rate of return, and at proposed revenues, were computed in a similar method considering class revenues and allocated expenses so that the amounts equaled the income taxes at proposed rates within the Company's revenue requirement.

Q. How were taxes other than income taxes allocated in Vectren South's COSS?

A. These expenses were allocated in Vectren South's COSS 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). As a result, taxes other than income taxes of a utility typically can be grouped into the three categories of plant and/or expenses and revenues (i.e., revenue requirements). In the filed COSS, each of Vectren South's 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 the costs of Vectren South's underground storage facilities allocated in its COSS?

A. Vectren South currently owns and operates four (4) underground storage fields, which have about 5,616,00 Mcf of total storage capacity and 121,500 Mcf of maximum daily withdrawal capacity. The Company's underground storage is used to generally support the winter gas heating loads of sales service customers and the unplanned daily balancing requirements of its sales and transportation service customers. Based on an historical review of the daily withdrawal activity of these facilities, it was determined that gas volumes are primarily withdrawn from these storage facilities on most days during the months of November through March. As a result, Vectren South's storage-related costs were allocated to the rate classes in proportion to the incremental gas sales and transportation volumes for each rate class during the five-month winter period of November through March.

IV. RESULTS OF THE COMPANY'S COST OF SERVICE STUDY

Q. Please discuss the results of the Company's COSS.

A. Referring to page 2 of 5 of Petitioner's Exhibit No. 16, Attachment RAF-2, Vectren

South's COSS indicates that at present rates during the test year, its rate classes are contributing to the recovery of the Company's total revenue requirement as follows:

- Rate 110 - Residential Sales Service exhibits a lower than average rate of return on net rate base.
- Rates 120/125 - General Sales Service and School/Government Transportation Service exhibits a lower than average rate of return on net rate base.
- Rate 145 - General Transportation Service exhibits a higher than average rate of return on net rate base.
- Rate 160 - Large Volume Transportation Service exhibits a higher than average rate of return on net rate base.
- Rate 170 - Contract Transportation Service exhibits a lower than average rate of return on net rate base.

Q. Please summarize the results of the Company's COSS.

A. Table 1 below presents a summary of the results of the Company's COSS that I described above at present revenue and rate levels. The COSS shows an overall revenue deficiency to the Company of $29.6 million.

Table 1 – Summary Results of the Company's COSS ($000)[3]

Rate Class	Class Revenue (Subsidy)/Excess	Rate of Return on Net Rate Base	Relative Rate of Return
Rate 110	($3,098)	0.35%	0.23
Rate 120/125	($969)	0.21%	0.13
Rate 145	$1,622	17.51%	11.44
Rate 160	$2,620	18.05%	11.79
Rate 170	($176)	0.57%	0.37
Total Company	-	1.53%	1.00

[3] See Petitioner's Exhibit No. 16, Attachment RAF-2, page 1 of 5, lines 34, 25, and 26.

Table 1 also presents the revenue subsidy/excess for each rate class and the rate of return on net rate base at present rates. Regarding 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. As a result, rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. I will explain next how these COSS results were used to guide the Company's determination of the revenues by rate class at proposed rate levels.

Q. How can COSS results such as these provide guidelines for rate design?

A. Results of a COSS provide cost guidelines for use in evaluating class revenue levels and class rate structures. Regarding 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. At the same time, though, it is recognized that there are non-cost factors such as customer impact considerations (e.g., avoiding rate shock through gradualism) and rate continuity that are often balanced with the cost to serve in apportioning the utility's proposed revenue increase among its rate classes.

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, customer and commodity rate block charges.

Q. Could you please explain why the Contract Transportation Service (Rate 170) rate class exhibited a revenue subsidy and a lower than expected rate of return on net rate base in the Company's COSS?

A. Yes. At first glance, the results for the Rate 170 rate class were counterintuitive compared to the results for the Company's Rate 145 and Rate 160 rate classes. I would have expected the results for each of these three rate classes, which include Vectren South's larger commercial and industrial customers, to show a revenue excess and a rate of return on net rate base above the Company's overall level based on the results of the Company's past COSS and on the expectations from my experience in conducting COSS for other gas utilities.

There appears to be two primary reasons why the Company's COSS yielded these results for Rate 170 in this proceeding compared to the results from the COSS that were conducted in the Company's previous rate case. First, the legislatively mandated method to derive the cost allocation factors to recover the Company's CSIA investment costs has caused a mismatch over time between the costs of the allowable investments recovered through the CSIA charges from Rate 170 customers and the way in which such investment costs are allocated to Rate 170 in the Company's COSS. The CSIA allocation factors are based on the total revenues from each of the Company's rate classes approved in its last rate case. Second, the cost allocation treatment of distribution mains in the Company's COSS (as described earlier in my testimony) is a refinement to the method used in Vectren South's last rate case to recognize its different pressure-based gas systems and the fact that certain customers (including five of the six Rate 170 customers) receive gas delivery service directly from the Company's high pressure distribution mains. In its last rate case, the Company's COSS assigned no costs of distribution mains to its Rate 170 customers.

V. THE COMPANY'S PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Vectren South's proposed revenue increase of $29.6 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; (3) customer impact considerations, such as rate shock; and (4) the benefit to the local and regional economy of sustaining larger businesses operating in Vectren South's service area. These criteria were evaluated for each of the Company's rate classes. Based on this evaluation, adjustments to the present revenue levels in all rate classes were made so that the rates proposed by Vectren South moved class revenues closer to the costs of serving those rate classes. Importantly, the Company's revenue adjustments were not determined based on a desired outcome, but instead were derived based on a careful and balanced evaluation of the chosen criteria.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of the Company's interclass revenue proposal?

A. Yes. Using Vectren South's proposed revenue increase, and the results from its COSS, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Company management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. These discussions addressed each of the criteria I listed above to find an interclass revenue proposal that reasonably balanced these criteria. Petitioner's Exhibit No. 16, Attachment RAF-3 presents details of the computations supporting the Company's class revenue apportionment process.

The first benchmark option that I evaluated under Vectren South's proposed non-gas revenue level was to adjust the revenue level for each rate class so that the relative rate of return on net rate base for each class was equal to 1.00. Petitioner's Exhibit No. 16, Attachment RAF-2, page 2 of 5 (line 54) provides these results. Based on my experience, I determined that this fully cost-based option was not the preferred solution to the interclass revenue issue due to its significant changes in class revenue levels. It should be pointed out, however, that those results represented an important guide for purposes of evaluating subsequent rate design options from a strict cost of service perspective.

The second option I considered was assigning the increase in revenues to the Company's rate classes based on an equal percentage basis of its current non-gas revenues. Petitioner's Exhibit No. 16, Attachment RAF-2, page 3 of 5 (lines 78 through 88) provides these results. This option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the COSS 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 certain of the Company's rate classes. This result indicated that class revenues were not moving towards the cost of service in a sufficiently meaningful manner under this option. While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a general range of results that provided me with further guidance to help develop the Company's class revenue proposal.

Q. What was the next step in the process of determining the Company's interclass revenue proposal?

A. After discussions with the Company concerning the costs of serving each rate class and the relative rate impacts of the various class revenue options described above, it was concluded that an appropriate interclass revenue proposal would generally assign greater than average increases to the rate classes that exhibited the greatest revenue subsidies relative to the costs to serve these rate classes, as derived in the Company's COSS. Each of these rate classes exhibited a relative rate of return on net rate base materially below 1.00 at present rates under the Company's COSS (see Table 1 above). For rate classes that exhibited revenue excesses or a relative rate of return on net rate base significantly above 1.00, it was determined that in general a smaller than average increase in non-gas revenues was warranted.

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 on <u>Petitioner's Exhibit No. 16</u>, Attachment RAF-2, page 2 of 5 (lines 71 and 73), 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 and excesses 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.

Table 2 – Proposed Class Revenue Apportionment ($000)

Rate Class	Non-Gas Revenues at Current Rates	Proposed Revenue Change	Percent Change
Rate 110	$66,291	$21,226	47.1%
Rate 120/125	$18,329	$6,077	49.6%
Rate 145	$3,805	$438	13.0%
Rate 160	$5,932	$588	11.0%
Rate 170	$4,510	$1,302	40.6%
Total Company	$98,868	$29,631	42.8%

Table 2 above summarizes the proposed revenue change for each rate class and the percent change in non-gas revenues resulting from the above-described process. In addition, Table 3 below presents a comparison of the revenue subsidies/excesses under current and proposed class revenue levels.

Table 3 – Comparison of Revenue (Subsidy)/Excess by Rate Class ($000)

Rate Class	Current (Subsidy)/Excess	Proposed (Subsidy)/ Excess[4]	Percent Change
Rate 110	($3,098)	($2,286)	(26.2%)
Rate 120/125	($969)	($613)	(36.7%)
Rate 145	$1,622	$1,250	(23.0%)
Rate 160	$2,620	$1,941	(25.9%)
Rate 170	($176)	($293)	66.7%
Total Company	-	-	-

[4] See Petitioner's Exhibit No. 16, Attachment RAF-2, page 2 of 5, line 60.

Q. What are the percentage changes in operating revenues by rate class resulting from the Company's proposed revenue apportionment?

A. The Company's percentage changes associated with its proposed revenue apportionment by rate class is summarized in Table 4 below.

Table 4 – Proposed Change in Operating Revenues by Rate Class ($000)

Rate Class	Operating Revenues at Current Rates	Proposed Revenue Change	Percent Change
Rate 110	$69,310	$21,226	30.6%
Rate 120/125	$25,140	$6,077	24.2%
Rate 145	$3,384	$438	12.9%
Rate 160	$5,371	$588	10.9%
Rate 170	$3,233	$1,302	40.3%
Total Company	$106,437	$29,631	27.8%

Q. Have you prepared a detailed comparison of the Company's present and proposed revenues by rate class?

A. Yes. Schedule E-4 contained in Petitioner's Exhibit No. 18 presents a detailed comparison of present and proposed revenues for each of Vectren South's rate classes.

Q. What is the non-gas revenue apportionment resulting from the Company's proposed revenue changes?

A. The proposed non-gas revenue apportionment is summarized in Table 5 below.

Table 5 – Proposed Non-Gas Revenue by Rate Class ($000)

Rate Class	Non-Gas Revenues[5]	Percent of Total
Rate 110	$66,291	67.05%
Rate 120/125	$18,329	18.54%
Rate 145	$3,805	3.85%
Rate 160	$5,932	6.00%

[5] See Petitioner's Exhibit No. 16, Attachment RAF-3, page 1 of 1.

Rate 170	$4,510	4.56%
Total Company	$98,868	100.00%

In addition, the last column of Table 5 provides the class revenue allocation factors based on the Company's proposed non-gas rates to be used in future CSIA or Transmission, Distribution and Storage Improvement Charge ("TDSIC") proceedings.

Q. How should the Commission apportion the change in non-gas revenues by rate class if it authorizes a different revenue increase than the $29.6 million increase proposed by the Company?

A. Under that circumstance, the Commission should apportion the authorized revenue increase by rate class using the percentages shown in Table 5.

VI. <u>THE COMPANY'S PROPOSED RATE DESIGN</u>

Q. Can you please describe the key objectives you sought to achieve in the design of Vectren South's proposed rates?

A. Yes. In general, I sought to achieve the following objectives with the rate design that I recommend and propose for a gas utility such as Vectren South:

- 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 explain how you derived the Company's proposed Customer Facility Charges (i.e., monthly customer charges) in each rate class.

A. While being cognizant of the rate design objectives I mentioned earlier, the Company's proposed Customer Facility Charges in each rate class were derived in specific consideration of: (1) the level of customer-related costs determined in the Company's COSS; (2) the percentage by which the current non-gas revenues for the given rate class was proposed to change; (3) the recovery of CSIA-related costs on a fixed monthly basis for the Company's Residential Sales Service rate class; and (4) the results of the bill comparisons which showed the impact of Vectren South's present and proposed rates on the monthly and annual gas bills of the average-sized customer and varying-sized customers in the given rate class.

Q. Can you please summarize the customer-related costs derived in the Company's COSS and compare those cost levels to the Company's current and proposed Customer Facility Charges for each of its rate classes?

A. Yes. Table 6 below presents the customer-related costs based on the results of the Company's COSS, as derived on <u>Petitioner's Exhibit No. 16</u>, Attachment RAF-4, page 10 of 10 (line 310), and the current and proposed Customer Facility Charges for each of the Company's rate classes. Table 6 shows that the level of customer-related costs incurred by the Company to serve customers in each of its rate classes are above the current levels of the Customer Facility Charges (or the average level of the Customer Facility Charges for rate classes with multiple charges for different Groups).

Table 6 – Comparison of Customer Costs and Customer Facility Charges

Rate Class	Customer Costs	Current Customer Facility Charge[6]	Proposed Customer Facility Charge
	$/Customer/Month	*$/Customer/Month*	*$/Customer/Month*
Rate 110	$35.45	$26.95	$35.00
Rates 120/125	$59.81	-	-
Group 1	-	$22.00	$35.00
Group 2	-	$44.00	$70.00
Group 3	-	$88.00	$135.00
Rate 145	$348.73		$250.00
Group 1	-	$22.00	-
Group 2	-	$44.00	-
Group 3	-	$88.00	-
Rate 160	$1,159.01	$400.00	$800.00
Rate 170	$2,632.64	$700.00	$1,600.00

Q. Please explain how you derived the Company's proposed Distribution Charges in each rate class.

A. In general, the Company's proposed Distribution Charges in each rate class, which is assessed to customers on a volumetric basis, were derived by setting the level of the charge to recover the balance of the non-gas revenues at proposed rates after accounting for the increase in non-gas revenues derived from the proposed Customer Facility Charges. For rate classes in which there were multiple rate blocks, the associated Distribution Charges were derived to maintain the relative rate differentials between rate blocks that exist under current rates.

Q. As part of the rate design process, is the Company proposing any changes to its current rate structures?

A. Yes. The Company has proposed two changes to the current rate structure for the General Transportation Service - Rate 145 rate schedule. First, the Company has

[6] Includes the fixed CSIA charge for the Residential Sales Service rate class - Rate 110.

proposed to eliminate the three separate Customer Facility Charges (i.e. for Groups 1, 2 and 3) and to combine them into one Customer Facility Charge applicable to all customers served under this rate schedule. Currently, all 75 customers in this rate class are charged the Customer Facility Charge for Group 3 because they are all larger customers compared to customers who would be assessed the Customer Facility Charges under Groups 1 and 2.[7] This proposed change recognizes that the load characteristics of the customers in this rate class are less diverse than for the customers served under Rate 120 so three separate Customer Facility Charges in Rate 145 are no longer necessary.

Next, the Company is proposing to modify the current volumetric breakpoint between the two rate blocks to better reflect the load characteristics of the customers in this rate class. Currently, the initial rate block in the Rate 145 rate schedule includes gas usage up to 500 therms per month and the tail (second) rate block includes gas usage over 500 therms per month. This rate structure is identical to the rate blocks and related breakpoint in the General Sales Service - Rate 120 rate schedule. The Company is proposing to raise the rate block breakpoint in the Rate 145 rate schedule from 500 therms per month to 2,500 therms per month to recognize that customers in that rate class are significantly larger than the customers served under the Rate 120 rate schedule. This proposed change will allow for the equitable recovery from customers of the Company's fixed customer-related costs not recovered through the

[7] The current rate structures under the Rate 120 and Rate 145 rate schedules which both include three separate Customer Facility Charges (for Groups 1, 2 and 3) were originally designed to recognize the companion relationship between sales service and transportation service, respectively, for the Company's general service customers. As a result, the current rate structures (and base rate levels) are identical for these two rate schedules.

proposed Customer Facility Charge.

Q. Has the Company provided bill comparisons which show the impact of Vectren South's present and proposed rates on the monthly gas bills of varying-sized customers in each rate class?

A. Yes. Schedule E-5 of Petitioner's Exhibit No. 18 presents monthly bill comparisons for various ranges of monthly gas consumption for the Company's customers in each of its rate class. I am sponsoring the derivation of the proposed rates and comparative bills in Schedule E-5 and Vectren South witness Tieken is sponsoring the derivation of the bill amounts under present rates.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations for Vectren South's COSS, class revenues and rate design.

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

- The results of the Company's COSS should be accepted by the Commission as a realistic reflection of cost causation and the design and operating characteristics of the Company's gas system.
- The results from the Company's COSS should be accepted by the Commission as a guide to evaluate and set Vectren South's 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 (see Table 2) 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; (3) customer impact considerations; and (4) the benefit to the local and regional economy of sustaining larger businesses operating in Vectren South's service area.
- 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 conclude your prepared direct testimony?

A. Yes, it does.

VERIFICATION

I, Russell A. Feingold, affirm under the penalties of perjury that the forgoing representations of fact in my Direct Testimony are true to the best of my knowledge, information and belief.

Russell A. Feingold

Dated: October 30, 2020

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; Energy Delivery Practice Lead
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
- National Energy Board of Canada
- 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
- 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
- Régie de l'Énergie Quebec (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 - 2020.
- 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, 2012-2019.
- 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, 2019 and 2020.

PUBLICATIONS AND PRESENTATIONS

- "Current Regulatory and Ratemaking Issues," American Gas Association Accounting Principles Committee Meeting, August 18-19, 2020.
- "The Second Time Around: Gas Utility Regulatory Responses During Periods of Extreme Uncertainty," Public Utilities Fortnightly, June 2020 Issue.
- "The Impact of COVID-19 on Utility Rate Modernization Strategies," Zpryme webinar, May 21, 2020.
- "Current Regulatory and Ratemaking Issues," American Gas Association Accounting Principles Committee Meeting, August 12-14, 2019.
- "Trends in Utility Ratemaking and Recent Regulatory Developments," American Gas Association/Edison Electric Institute Accounting Leadership Conference, June 23-27, 2019.

- "State Regulatory Update: Rates, ROEs and Other Trends Impacting Energy Utilities," American Gas Association Financial Forum, May 20-23, 2019.
- "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," PowerForward: 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, State Affairs 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 October 2020)

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
1	**Rate Base**							
2	Plant in Service	649,737	-	455,801	120,933	16,364	26,242	30,397
3	Accumulated Reserve	(217,129)	-	(154,208)	(39,542)	(5,207)	(8,392)	(9,779)
4	Other Rate Base Items	36,781	-	22,082	9,347	1,420	1,802	2,131
5	Total Rate Base	469,389	-	323,675	90,737	12,577	19,651	22,748
6	**Total Revenue at Current Rates**							
7	Retail Revenue	69,236	-	45,065.232	12,252	3,367	5,344	3,208
8	Gas Cost Revenue	36,171	-	23,460	12,711	-	-	-
9	Forfeited Discounts	538	-	426	95	4	7	5
10	Misc Service Revenue	83	-	79	4	-	-	-
11	Interdepartmental Sales	66	-	43	12	3	5	3
12	Rent from Property	342	-	236	66	9	14	16
13	Total Revenue	106,437	-	69,310	25,140	3,384	5,371	3,233
14	**Expenses at Current Rates**							
15	Natural Gas City Gate Purchases	36,171	-	23,460	12,711	-	-	-
16	Operation and Maintenance and Sales Expense	24,256	-	15,791	4,802	713	1,132	1,817
17	Administrative and General Expense	10,670	-	7,472	2,223	221	337	417
18	Depreciation and Amortization Expense	25,670	-	19,000	4,444	587	906	734
19	Taxes Other Than Income	2,468	-	1,732	459	62	100	115
20	IURT and IURC Revenue Taxes	1,485	-	965	352	47	75	45
21	Total Expenses Excl. Income Taxes - Current	100,721	-	68,421	24,991	1,631	2,549	3,129
22	Income Prior to Taxes	5,717	-	889	149	1,753	2,822	104
23	Income Taxes	(1,467)	-	(228)	(38)	(450)	(724)	(27)
24	Operating Income - Current	7,184	-	1,117	187	2,203	3,546	130
25	Current Rate of Return	1.53%		0.35%	0.21%	17.51%	18.05%	0.57%
26	Current Relative Rate of Return	1.00		0.23	0.13	11.44	11.79	0.37
27	**Present Revenue at Equal Rates of Return**							
28	Present Return	1.53%		1.53%	1.53%	1.53%	1.53%	1.53%
29	Present Operating Income @ Equal Return	7,184	-	4,954	1,389	192	301	348
30	Income Taxes	(1,467)	-	(1,012)	(284)	(39)	(61)	(71)
31	Other Expenses	99,236	-	67,456	24,639	1,584	2,474	3,084
32	IURT and IURC Revenue Taxes	1,485	-	1,010	364	25	38	48
33	Total Revenue @ Equal Rates of Return	106,437	-	72,408	26,109	1,761	2,752	3,408
34	Present (Subsidy)/Excess	-	-	(3,098)	(969)	1,622	2,620	(176)

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	**ACCOUNT BALANCE**	**Total Check**	**Rate 110 - Residential Service**	**Rate 120/ 125 - General & School/ Government Transportation Service**	**Rate 145 - General Transportation Service**	**Rate 160 - Large Volume Transportation Service**	**Rate 170 - Contract Transportation Service**
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
35	**Revenue Requirement at Equal Rates of Return**							
36	Required Return	6.18%		6.18%	6.18%	6.18%	6.18%	6.18%
37	Required Operating Income	29,008	-	20,003	5,608	777	1,214	1,406
38	**Expenses at Required Return**							
39	Natural Gas City Gate Purchases	36,171	-	23,460	12,711	-	-	-
40	Operation and Maintenance and Sales Expense	24,256	-	15,791	4,802	713	1,132	1,817
41	Administrative and General Expense	10,670	-	7,472	2,223	221	337	417
42	Amortization and Depreciation Expense	25,670	-	19,000	4,444	587	906	734
43	Taxes Other Than Income	2,468	-	1,732	459	62	100	115
44	IURT and IURC Revenue Taxes - Current	1,485	-	965	352	47	75	45
45	State Income Tax - Current	(239)	-	(165)	(46)	(6)	(10)	(11)
46	Federal Income Tax - Current	(1,229)	-	(847)	(238)	(33)	(51)	(59)
47	Federal Income Tax - Increase	5,801	-	4,001	1,126	155	242	278
48	State Income Tax - Increase	1,445	-	996	280	39	60	69
49	IURT and IURC Revenue Taxes - Increase	451	-	308	106	9	13	16
50	Uncollecible - Increase	110	-	105	5	0	-	-
51	Total Expenses - Required	107,060	-	72,819	26,222	1,794	2,803	3,422
52	Total Revenue Requirement at Equal Return	136,069	-	92,822	31,830	2,572	4,018	4,828
53	Current Miscellaneous Revenue	1,030	-	784	177	16	27	25
54	Total Base Revenue @ Equal Rates of Return	135,039	-	92,038	31,653	2,555	3,991	4,803
55	Revenue (Subsidy)/Excess before Increase	(29,631)	-	(23,512)	(6,690)	812	1,354	(1,595)
56	**Proposed Revenue by Class**							
57	Total Base Revenue as Proposed	135,039	-	89,752	31,040	3,805	5,932	4,510
58	Miscellaneous Revenue	1,030	-	784	177	16	27	25
59	Total Revenue as Proposed	136,069	-	90,536	31,217	3,822	5,959	4,535
60	Revenue (Subsidy)/Excess after Increase	-	-	(2,286)	(613)	1,250	1,941	(293)
				-26.2%	-36.7%	-23.0%	-25.9%	66.7%
61	Base Revenue Increase as Proposed	29,631	-	21,226	6,077	438	588	1,302
62	Change in Miscellaneous Revenue	-	-	-	-	-	-	-
63	Total Revenue Increase as Proposed	29,631	-	21,226	6,077	438	588	1,302
64	Precent Total Revenue Change	27.8%		30.6%	24.2%	12.9%	10.9%	40.3%
65	Other Expenses	99,346	-	67,561	24,644	1,584	2,474	3,084
66	IURT and IURC Revenue Taxes	1,936	-	1,288	444	54	85	65
67	Income Prior to Taxes	34,787	-	21,687	6,129	2,183	3,400	1,387
68	Income Taxes	5,779	-	3,603	1,018	363	565	230
69	Operating Income	29,008	-	18,085	5,111	1,821	2,836	1,156
70	**Proposed Return**	6.18%		5.59%	5.63%	14.48%	14.43%	5.08%
71	Proposed Relative Rate of Return	1.00		0.90	0.91	2.34	2.33	0.82
72	**Current Return**	1.53%		0.35%	0.21%	17.51%	18.05%	0.57%
73	Current Relative Rate of Return	1.00		0.23	0.13	11.44	11.79	0.37

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	**ACCOUNT BALANCE**	**Total Check**	**Rate 110 - Residential Service**	**Rate 120/ 125 - General & School/ Government Transportation Service**	**Rate 145 - General Transportation Service**	**Rate 160 - Large Volume Transportation Service**	**Rate 170 - Contract Transportation Service**
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
74	**Revenue by Class - Equal Increase by Class on Non-Gas Revenues**							
75	Total Base Revenue as Proposed	135,039	-	87,812	30,206	4,809	7,632	4,580
76	Miscellaneous Revenue	1,030	-	784	177	16	27	25
77	Total Revenue as Proposed	136,069	-	88,597	30,383	4,825	7,658	4,605
78	Base Revenue Increase as Proposed	29,631	-	19,287	5,243	1,441	2,287	1,373
79	Change in Miscellaneous Revenue	-	-	-	-	-	-	-
80	Total Revenue Increase as Proposed	29,631	-	19,287	5,243	1,441	2,287	1,373
81	Precent Total Revenue Change	27.84%		27.83%	20.86%	42.59%	42.58%	42.47%
82	Other Expenses	99,346	-	67,561	24,644	1,584	2,474	3,084
83	IURT and IURC Revenue Taxes	1,936	-	1,273	457	56	89	61
84	Income Prior to Taxes	34,787	-	19,763	5,282	3,185	5,096	1,460
85	Income Taxes	5,779	-	3,283	878	529	847	243
86	Operating Income	29,008	-	16,480	4,405	2,656	4,249	1,218
87	**Resulting Return**	6.18%		5.09%	4.85%	21.12%	21.62%	5.35%
88	Proposed Relative Rate of Return	1.00		0.82	0.79	3.42	3.50	0.87

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Functionalized and Classified Revenue Requirement and Unit Costs by Customer Class

Line	Description		TOTAL RATE BASE	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
Functional Revenue Requirement			*($000)*	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
1	**Gas Production**							
2	Demand	F1D	$ -	$ -	$ -	$ -	$ -	$ -
3	Commodity	F1E	$ 37,306	$ 24,197	$ 13,063	$ 13	$ 21	$ 12
4	Customer	F1C	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal		$ 37,306	$ 24,197	$ 13,063	$ 13	$ 21	$ 12
6	**Underground Storage**							
7	Demand	F2D	$ 5,147	$ 2,539	$ 1,127	$ 254	$ 423	$ 804
8	Commodity	F2E	$ 5,718	$ 3,209	$ 1,695	$ 204	$ 219	$ 391
9	Customer	F2C	$ -	$ -	$ -	$ -	$ -	$ -
10	Subtotal		$ 10,865	$ 5,748	$ 2,822	$ 458	$ 643	$ 1,195
11	**Transmission**							
12	Demand	F3D	$ 15,479	$ 7,619	$ 3,403	$ 778	$ 1,292	$ 2,387
13	Commodity	F3E	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	F3C	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal		$ 15,479	$ 7,619	$ 3,403	$ 778	$ 1,292	$ 2,387
16	**Distribution**							
17	Demand	F4D	$ 20,413	$ 11,558	$ 5,102	$ 1,009	$ 1,701	$ 1,043
18	Commodity	F4E	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	F4C	$ 52,006	$ 43,700	$ 7,440	$ 314	$ 362	$ 190
20	Subtotal		$ 72,419	$ 55,258	$ 12,542	$ 1,323	$ 2,063	$ 1,233
21	**Total**							
22	Demand		$ 41,039	$ 21,716	$ 9,632	$ 2,040	$ 3,416	$ 4,235
23	Commodity		$ 43,024	$ 27,406	$ 14,757	$ 217	$ 240	$ 403
24	Customer		$ 52,006	$ 43,700	$ 7,440	$ 314	$ 362	$ 190
25	**Total Revenue Requirement**		$ 136,069	$ 92,822	$ 31,830	$ 2,572	$ 4,018	$ 4,828
26	Demand		30.16%	23.40%	30.26%	79.34%	85.02%	87.72%
27	Commodity		31.62%	29.53%	46.36%	8.45%	5.98%	8.36%
28	Customer		38.22%	47.08%	23.38%	12.20%	9.00%	3.93%

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Functionalized and Classified Revenue Requirement and Unit Costs by Customer Class

Line	Description		TOTAL RATE BASE	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
Unit Costs								
29	**Gas Production**							
30	Demand	F1D	$ -	$ -	$ -	$ -	$ -	$ -
31	Commodity	F1E	$ 0.11	$ 0.36	$ 0.35	$ 0.00	$ 0.00	$ 0.00
32	Customer	F1C	$ -	$ -	$ -	$ -	$ -	$ -
33	**Underground Storage**							
34	Demand	F2D	$ 2.31	$ 2.39	$ 2.27	$ 2.24	$ 2.24	$ 2.19
35	Commodity	F2E	$ 0.02	$ 0.05	$ 0.05	$ 0.01	$ 0.00	$ 0.00
36	Customer	F2C	$ -	$ -	$ -	$ -	$ -	$ -
37	**Transmission**							
38	Demand	F3D	$ 6.95	$ 7.18	$ 6.85	$ 6.87	$ 6.83	$ 6.50
39	Commodity	F3E	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	F3C	$ -	$ -	$ -	$ -	$ -	$ -
41	**Distribution**							
42	Demand	F4D	$ 9.16	$ 10.89	$ 10.27	$ 8.91	$ 8.99	$ 2.84
43	Commodity	F4E	$ -	$ -	$ -	$ -	$ -	$ -
44	Customer	F4C	$ 38.29	$ 35.45	$ 59.81	$ 348.73	$ 1,159.01	$ 2,632.64
45	**Total**							
46	Demand (per mcf)		$ 18.42	$ 20.47	$ 19.38	$ 18.02	$ 18.06	$ 11.53
47	Commodity (per mcf)		$ 0.130	$ 0.409	$ 0.400	$ 0.011	$ 0.004	$ 0.003
48	Customer (per cust month)		$ 38.29	$ 35.45	$ 59.81	$ 348.73	$ 1,159.01	$ 2,632.64
49	Demand & Commodity (per cust month)		$ 68.50	$ 53.07	$ 137.23	$ 2,615.75	$ 12,107.16	$ 61,447.31
50	**BILLING DETERMINANTS**							
51	Demand		2,227,505	1,061,072	496,929	113,198	189,142	367,164
52	Commodity		330,588,146	66,972,421	36,862,371	19,026,719	55,393,325	152,333,310
53	Customers (Number of Bills)		1,358,363	1,232,671	124,408	900	312	72

Vectren South Gas COSS Model
12 Months Ended December 31, 2021

Revenue Apportionment

					Equalized Rate of Return				Proportionate to Non-Gas Revenues			
	Class	Current Revenues (Base and Gas Cost) *($000)*	Current Rate Of Return	Unitized Rate of Return	Equalized Rate of Return *($000)*	Equalized Rate of Return Increase *($000)*	% Change (Equalized Rate of Return)	Resulting Revenues *($000)*	Non-Gas Revenues *($000)*	Increase on Non-Gas Revenues *($000)*	% Change (equal % on Non-Gas)	Resulting Revenues ($000)
1	Rate 110 - Residential Service	$ 68,526	0.35%	0.23	$ 92,038	$ 23,512	52.2%	$ 92,038	$ 45,065.232	$ 19,287	42.8%	$ 87,812
2	Rate 120/ 125 - General & School/ Government Transportation Service	$ 24,963	0.21%	0.13	$ 31,653	$ 6,690	54.6%	$ 31,653	$ 12,251.887	$ 5,243	42.8%	$ 30,206
3	Rate 145 - General Transportation Service	$ 3,367	17.51%	11.44	$ 2,555	$ (812)	-24.1%	$ 2,555	$ 3,367.367	$ 1,441	42.8%	$ 4,809
4	Rate 160 - Large Volume Transportation Service	$ 5,344	18.05%	11.79	$ 3,991	$ (1,354)	-25.3%	$ 3,991	$ 5,344.363	$ 2,287	42.8%	$ 7,632
5	Rate 170 - Contract Transportation Service	$ 3,208	0.57%	0.37	$ 4,803	$ 1,595	49.7%	$ 4,803	$ 3,207.602	$ 1,373	42.8%	$ 4,580
6	Miscellaneous Revenue	$ 1,030			$ 1,030			$ 1,030				$ 1,030
7	TOTAL SYSTEM	$ 106,437	1.53%	1.00	$ 136,069	$ 29,631	42.8%	$ 136,069	$ 69,236.451	$ 29,631	42.8%	$ 136,069

8	Proposed Revenues	136,069
9	Increase	29,631
10	System Increase (Total Revenue)	27.8%
11	System Increase (Non-Gas Revenue)	42.8%

Proposed Base Revenues

	Class	Targeted Increase	Targeted Increase *($000)*	Targeted Revenue *($000)*	Allocation of Delta *($000)*	Proposed Increase/ (Decrease) *($000)*	Proposed Revenue *($000)*	Resulting Increase % (Base Rev)	Resulting Increase % with Gas Cost	Proposed Non-Gas Revenue *($000)*	Percent
12											
13	Rate 110 - Residential Service	47.1%	$ 21,226	$ 89,751	$ 0	$ 21,226	$ 89,752	47.1%	31.0%	$ 66,291	67.05%
14	Rate 120/ 125 - General & School/ Government Transportation Service	49.6%	$ 6,077	$ 31,040	$ 0	$ 6,077	$ 31,040	49.6%	24.3%	$ 18,329	18.54%
15	Rate 145 - General Transportation Service	13.0%	$ 438	$ 3,805	$ 0	$ 438	$ 3,805	13.0%	13.0%	$ 3,805	3.85%
16	Rate 160 - Large Volume Transportation Service	11.0%	$ 588	$ 5,932	$ 0	$ 588	$ 5,932	11.0%	11.0%	$ 5,932	6.00%
17	Rate 170 - Contract Transportation Service	40.6%	$ 1,302	$ 4,510	$ 0	$ 1,302	$ 4,510	40.6%	40.6%	$ 4,510	4.56%
18	Miscellaneous Revenue		$ -	$ 1,030		$ -	$ 1,030				
19	TOTAL SYSTEM		$ 29,631	$ 136,068	$ 1	$ 29,631	$ 136,069	42.8%	27.8%	$ 98,868	100.00%

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
Function & Classification : Distribution Customer
Distribution Customer

		FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
1	**ACCOUNT DESCRIPTION**		*($000)*				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
2	**A PLANT IN SERVICE**										
3	**Intangible Plant**										
4	Organizational Expense	301	3	-	INT_PLT_OM	INT	3	0	0	0	0
5	Franchise & Consents	302	0	-	INT_PLT_OM	INT	0	0	0	0	0
6	Miscellaneous Intangible Plant	303	11,578	-	INT_ACCT-303	INT	9,918	1,562	40	36	23
7	Miscellaneous Intangible Plant - 15 Year	303.15	2,366	-	INT_ACCT-303	INT	2,027	319	8	7	5
8	Miscellaneous Intangible Plant - 12 Year	303.12	5,731	-	INT_ACCT-303	INT	4,909	773	20	18	11
9	Miscellaneous Intangible Plant - Fully Depr	303.99	12,726	-	INT_ACCT-303	INT	10,901	1,717	44	39	25
10	Subtotal - Intangible Plant		32,405	-			27,757	4,372	112	100	63
				-							
11	**Distribution Plant**			-							
12	Land	374.1	153	-	INT_D376_379	INT	139	14	0	0	0
13	Land Rights	374.2	135	-	INT_D376_379	INT	123	12	0	0	0
14	Structures & Improvements	375	56	-	INT_D376_379	INT	51	5	0	0	0
15	Mains (High Pressure)	376	17,052	D376_379	CUST_HP	EXT	15,474	1,562	11	4	1
16	Mains (Low/Medium Pressure)	376	96,681	D376_379	CUST_LowMed	EXT	87,747	8,856	56	21	-
17	Meas & Reg Station Eq-Gen	378	-	D376_379	-	EXT	-	-	-	-	-
18	Services	380	130,567	-	SERVS	EXT	113,995	16,181	262	104	25
19	Meters	381	27,466	MTRHR	MTRS	EXT	19,435	7,160	326	328	217
20	Meter Installations	382	6,400	MTRHR	MTRS	EXT	4,529	1,668	76	76	51
21	House Regulators	383	504	MTRHR	AC_383	EXT	363	134	5	3	-
22	House Regulator Install	384	121	MTRHR	AC_383	EXT	87	32	1	1	-
23	Indus Meas & Reg St Equip	385	266	-	AC_385	EXT	-	-	24	75	167
24	Other Equipment	387	52	-	INT_D376_379	INT	47	5	0	0	0
25	Subtotal - Distribution Plant		279,454	TD_PLT			241,989	35,628	761	613	461
				-							
26	**General Plant**			-							
27	Land and Land Rights	389.1	287	-	INT_TD_PLT	INT	248	37	1	1	0
28	Structures & Improvements	390	5,820	-	INT_TD_PLT	INT	5,040	742	16	13	10
29	Electronic Equipment	391.1	800	-	INT_TD_PLT	INT	693	102	2	2	1
30	Furniture & Fixtures	391.2	972	-	INT_LABOR	INT	783	173	6	6	4
31	Automobiles	392.1	2,002	-	INT_LABOR	INT	1,613	357	13	12	8
32	Light Trucks	392.2	(560)	-	INT_LABOR	INT	(451)	(100)	(4)	(3)	(2)
33	Trailers	392.3	188	-	INT_LABOR	INT	152	34	1	1	1
34	Heavy Trucks	392.4	1,343	-	INT_LABOR	INT	1,082	239	8	8	5
35	Stores Equipment	393	107	-	INT_LABOR	INT	86	19	1	1	0
36	Tools, Shop & Garage Equip	394	2,452	-	INT_LABOR	INT	1,975	437	15	15	9
37	Laboratory Equipment	395	272	-	INT_LABOR	INT	219	49	2	2	1
38	Power Operated Equipment	396	75	-	INT_TD_PLT	INT	65	10	0	0	0
39	Power Operated Equipment - Fully Depreciated	396	893	-	INT_TD_PLT	INT	773	114	2	2	1
40	Communication Equipment	397	2,920	-	INT_TD_PLT	INT	2,529	372	8	6	5
41	Miscellaneous Equipment	398	484	-	INT_TD_PLT	INT	419	62	1	1	1
42	Subtotal - General Plant		18,054	GEN_PLT			15,226	2,646	73	65	45
				-							
43	**TOTAL PLANT IN SERVICE**		329,913	TOTPLT			284,972	42,645	947	779	569

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
Function & Classification : Distribution Customer
Distribution Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
			($000)				($000)	($000)	($000)	($000)	($000)
				-							
44	B **ACCUMULATED DEPRECIATION**			-							
				-							
45	**Intangible Plant**			-							
46	Organizational Expense	301	-	-	INT_PLT_OM	INT	-	-	-	-	-
47	Franchise & Consents	302	-	-	INT_PLT_OM	INT	-	-	-	-	-
48	Miscellaneous Intangible Plant	303	(6,280)	-	INT_ACCT-303	INT	(5,379)	(847)	(22)	(19)	(12)
49	Miscellaneous Intangible Plant - 15 Year	303.15	(541)	-	INT_ACCT-303	INT	(463)	(73)	(2)	(2)	(1)
50	Miscellaneous Intangible Plant - 12 Year	303.12	(357)	-	INT_ACCT-303	INT	(306)	(48)	(1)	(1)	(1)
51	Miscellaneous Intangible Plant - Fully Depr	303.99	(12,726)	-	INT_ACCT-303	INT	(10,901)	(1,717)	(44)	(39)	(25)
52	Subtotal - Intangible Plant		(19,904)	-			(17,049)	(2,685)	(69)	(62)	(39)
				-							
53	**Distribution Plant**			-							
54	Land	374.1	(1)	-	INT_D376_379	INT	(1)	(0)	(0)	(0)	(0)
55	Land Rights	374.2	(4)	-	INT_D376_379	INT	(4)	(0)	(0)	(0)	(0)
56	Structures & Improvements	375	(63)	-	INT_D376_379	INT	(57)	(6)	(0)	(0)	(0)
57	Mains (High Pressure)	376	(5,222)	-	CUST_HP	EXT	(4,739)	(478)	(3)	(1)	(0)
58	Mains (Low/Medium Pressure)	376	(29,608)	-	CUST_LowMed	EXT	(26,872)	(2,712)	(17)	(7)	-
59	Meas & Reg Station Eq-Gen	378	-	-	-	EXT	-	-	-	-	-
60	Services	380	(41,752)	-	SERVS	EXT	(36,453)	(5,174)	(84)	(33)	(8)
61	Meters	381	(11,771)	-	MTRS	EXT	(8,330)	(3,069)	(140)	(141)	(93)
62	Meter Installations	382	(1,069)	-	MTRS	EXT	(757)	(279)	(13)	(13)	(8)
63	House Regulators	383	(440)	-	AC_383	EXT	(316)	(116)	(4)	(3)	-
64	House Regulator Install	384	(118)	-	AC_383	EXT	(85)	(31)	(1)	(1)	-
65	Indus Meas & Reg St Equip	385	(29)	-	AC_385	EXT	-	-	(3)	(8)	(18)
66	Other Equipment	387	(32)	-	INT_D376_379	INT	(29)	(3)	(0)	(0)	(0)
67	0	0	-	-	-	EXT	-	-	-	-	-
68	Subtotal - Distribution Plant		(90,109)	-			(77,641)	(11,869)	(265)	(206)	(128)
				-							
69	**General Plant**			-							
70	Land and Land Rights	389.1	-	-	INT_TD_PLT	INT	-	-	-	-	-
71	Structures & Improvements	390	(2,675)	-	INT_TD_PLT	INT	(2,316)	(341)	(7)	(6)	(4)
72	Electronic Equipment	391.1	(850)	-	INT_TD_PLT	INT	(736)	(108)	(2)	(2)	(1)
73	Furniture & Fixtures	391.2	(187)	-	INT_LABOR	INT	(150)	(33)	(1)	(1)	(1)
74	Automobiles	392.1	(698)	-	INT_LABOR	INT	(563)	(124)	(4)	(4)	(3)
75	Light Trucks	392.2	736	-	INT_LABOR	INT	593	131	5	4	3
76	Trailers	392.3	43	-	INT_LABOR	INT	34	8	0	0	0
77	Heavy Trucks	392.4	(341)	-	INT_LABOR	INT	(275)	(61)	(2)	(2)	(1)
78	Stores Equipment	393	(72)	-	INT_LABOR	INT	(58)	(13)	(0)	(0)	(0)
79	Tools, Shop & Garage Equip	394	(1,065)	-	INT_LABOR	INT	(858)	(190)	(7)	(6)	(4)
80	Laboratory Equipment	395	(333)	-	INT_LABOR	INT	(268)	(59)	(2)	(2)	(1)
81	Power Operated Equipment	396	(8)	-	INT_TD_PLT	INT	(7)	(1)	(0)	(0)	(0)
82	Power Operated Equipment - Fully Depreciated	396	1,046	-	INT_TD_PLT	INT	906	133	3	2	2
83	Communication Equipment	397	(743)	-	INT_TD_PLT	INT	(643)	(95)	(2)	(2)	(1)
84	Miscellaneous Equipment	398	(149)	-	INT_TD_PLT	INT	(129)	(19)	(0)	(0)	(0)
85	Subtotal - General Plant		(5,294)	-			(4,469)	(772)	(21)	(19)	(13)
				-							
86	**TOTAL ACCUMULATED DEPRECIATION**		(115,307)	-			(99,160)	(15,326)	(355)	(287)	(180)
				-							

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
Function & Classification : Distribution Customer
Distribution Customer

1		ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
				($000)				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
87	C	**OTHER RATEBASE ITEMS**			-							
88		Utility Material & Supplies		1,324	-	INT_TD_PLT	INT	1,146	169	4	3	2
89		Gas in Underground Storage		-	-	-	EXT	-	-	-	-	-
90		PISCC - BS/CI		740	-	INT_D376_380	INT	672	68	0	0	0
91		PISCC - CSIA		5,164	-	TDSICALLOC	EXT	3,462	922	253	385	141
92		Subtotal - Other Ratebase Items		7,227	-			5,279	1,159	258	389	143
					-							
93		**TOTAL RATE BASE**		221,833	RTBASE			191,092	28,478	850	881	533
					-							
94	D	**OPERATING AND MAINTENANCE EXPENSES**			-							
					-							
95		**Other Gas Supply**			-							
96		Natural Gas City Gate Purchases	)0, 803, & 8(	-	-	-	EXT	-	-	-	-	-
				-	-	-	EXT	-	-	-	-	-
				-	-	-	EXT	-	-	-	-	-
97		Subtotal - Other Gas Supply Expenses		-	-			-	-	-	-	-
					-							
98		**Distribution Expenses**			-							
99		Operation Supervision and Engineering	870	1,526	-	INT_DISTEXP	INT	1,186	309	12	12	8
100		Mains and Services Expenses	874	947	DISTEXP	INT_D376_380	INT	859	87	1	0	0
101		Meas. and Regulating Station Expenses - General	875	-	DISTEXP	-	EXT	-	-	-	-	-
102		Removing and Resetting Meters	878	701	DISTEXP	MTRS	EXT	496	183	8	8	6
103		Customer Installation Expenses	879	1,087	DISTEXP	INT_MTRHR	INT	769	283	13	13	8
104		Other Expenses	880	1,238	-	INT_DISTEXP	INT	962	250	10	10	6
105		Rents	881	0	-	INT_DISTEXP	INT	0	0	0	0	0
106		Subtotal - Operating Expense		5,499	-			4,272	1,112	44	43	28
107		Maint. Supervision and Engineering	885	387	-	INT_DMAINT	INT	340	46	1	0	0
108		Maint. of Structures and Improvements	886	43	DMAINT	INT_D376_379	INT	39	4	0	0	0
109		Maint. of Mains	887	661	DMAINT	INT_MAINS	INT	599	61	0	0	0
110		Maintenance of Services	892	834	DMAINT	SERVS	EXT	728	103	2	1	0
111		Maintenance of Meters and House Regulators	893	116	DMAINT	INT_MTRHR	INT	82	30	1	1	1
112		Maintenance of Other Equipment	894	97	DMAINT	INT_D376_379	INT	88	9	0	0	0
113		Subtotal - Maintenance Expense		2,138	-			1,877	253	4	3	1
114		Subtotal - Distribution Expense		7,637	-			6,149	1,364	48	46	30
					-							
115		**OPERATING AND MAINTENANCE EXPENSES**		7,637	-			6,149	1,364	48	46	30
					-							

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
Function & Classification : Distribution Customer
Distribution Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
			($000)				($000)	($000)	($000)	($000)	($000)
116	**E CUSTOMER ACCOUNTS AND SERVICE EXPENSE**			-							
				-							
117	**Customer Accounts Expense**			-							
118	Supervision	901	58	-	INT_CUSTACCT	INT	53	5	0	0	0
119	Meter Reading Expenses	902	177	CUSTACCT	MTREAD	EXT	161	16	0	0	0
120	Customers Billing and Accounting	903	1,058	CUSTACCT	CUST	EXT	960	97	1	0	0
121	Uncollectible Accounts	904	354	CUSTACCT	UNCOLLECT	EXT	339	15	0	-	-
122	Miscellaneous Customer Accounts Expenses	905	152	-	INT_CUSTACCT	INT	139	12	0	0	0
123	Subtotal - Customer Accounts Expense		1,799	-			1,652	145	1	0	0
				-							
124	**Customer Service & Information Expense**			-							
125	Customer Assistance Expenses	908	40	-	CUST	EXT	36	4	0	0	0
126	Informational & Instructional Advertising	909	4	-	CUST	EXT	4	0	0	0	0
127	Misc. Customer Service & Informational	910	14	-	CUST	EXT	12	1	0	0	0
128	Demonstration and Selling Expenses	912	389	-	CUST	EXT	353	36	0	0	0
129	All Other	913	1,053	-	ACT_913	EXT	956	96	1	0	-
130	Subtotal - Customer Service & Information Expense		1,500	-			1,361	137	1	0	0
				-							
131	**Sales Expense**			-							
132	Total Miscellaneous Sales Expenses	916	4	-	CUST	EXT	3	0	0	0	0
133	Subtotal - Sales Expense		4	-			3	0	0	0	0
				-							
134	**ACCOUNTS AND SERVICE EXPENSE**		3,302	-			3,017	283	2	1	0
				-							
135	**F ADMINISTRATIVE AND GENERAL EXPENSE**			-							
				-							
136	Administrative and General Salaries	920	2,894	-	INT_LABOR	INT	2,332	516	18	17	11
137	Office Supplies and Expenses	921	1,487	-	INT_LABOR	INT	1,198	265	9	9	6
138	Outside Services Employed	923	(242)	-	INT_PLT_OM	INT	(206)	(34)	(1)	(1)	(1)
139	Injuries and Damages	925	583	-	INT_LABOR	INT	470	104	4	3	2
140	Vectren Corporate Administrative Expenses Allocation	923	449	-	INT_PLT_OM	INT	382	62	2	1	1
141	Property Insurance	924	120	-	INT_TOTPLT	INT	104	15	0	0	0
142	Injuries and Damages	925	599	-	INT_LABOR	INT	483	107	4	4	2
143	Employee Pensions and Benefits	926	4	-	INT_LABOR	INT	3	1	0	0	0
144	Regulatory Commission Expenses	928	152	-	INT_PLT_OM	INT	130	21	1	0	0
145	Rents	931	8	-	INT_PLT_OM	INT	7	1	0	0	0
146	Miscellaneous General Expenses	930.2	249	-	INT_PLT_OM	INT	213	35	1	1	1
			-	-	-	EXT	-	-	-	-	-
147	Maintenance of General Plant	932 (935)	63	-	INT_GEN_PLT	INT	54	9	0	0	0
148	Subtotal - Administrative and General Expense		6,368	-			5,168	1,103	38	36	23
				-							
149	**ADMINISTRATIVE AND GENERAL EXPENSE**		6,368	-			5,168	1,103	38	36	23

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
Function & Classification : Distribution Customer
Distribution Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE ($000)	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service ($000)	Rate 120/ 125 - General & School/ Government Transportation Service ($000)	Rate 145 - General Transportation Service ($000)	Rate 160 - Large Volume Transportation Service ($000)	Rate 170 - Contract Transportation Service ($000)
				-							
150	**G DEPRECIATION AND AMORTIZATION EXPENSE**			-							
				-							
151	**Intangible Plant**			-							
152	Organizational Expense	301	-	-	INT_PLT_OM	INT	-	-	-	-	-
153	Franchise & Consents	302	-	-	INT_PLT_OM	INT	-	-	-	-	-
154	Miscellaneous Intangible Plant	303	1,125	-	INT_ACCT-303	INT	964	152	4	3	2
155	Miscellaneous Intangible Plant - 15 Year	303.15	158	-	INT_ACCT-303	INT	135	21	1	0	0
156	Miscellaneous Intangible Plant - 12 Year	303.12	478	-	INT_ACCT-303	INT	409	64	2	1	1
157	Miscellaneous Intangible Plant - Fully Depr	303.99	-	-	INT_ACCT-303	INT	-	-	-	-	-
158	Subtotal - Intangible Plant		1,760	-			1,508	237	6	5	3
				-							
159	**Distribution Plant**			-							
160	Land	374.1	-	-	INT_D376_379	INT	-	-	-	-	-
161	Land Rights	374.2	2	-	INT_D376_379	INT	2	0	0	0	0
162	Structures & Improvements	375	0	-	INT_D376_379	INT	0	0	0	0	0
163	Mains (High Pressure)	376	433	-	CUST_HP	EXT	393	40	0	0	0
164	Mains (Low/Medium Pressure)	376	2,456	-	CUST_LowMed	EXT	2,229	225	1	1	-
165	Meas & Reg Station Eq-Gen	378	-	-	-	EXT	-	-	-	-	-
166	Services	380	7,299	-	SERVS	EXT	6,372	904	15	6	1
167	Meters	381	1,294	-	MTRS	EXT	915	337	15	15	10
168	Meter Installations	382	257	-	MTRS	EXT	182	67	3	3	2
169	House Regulators	383	6	-	AC_383	EXT	4	2	0	0	-
170	House Regulator Install	384	1	-	AC_383	EXT	0	0	0	0	-
171	Indus Meas & Reg St Equip	385	8	-	AC_385	EXT	-	-	1	2	5
172	Other Equipment	387	1	-	INT_D376_379	INT	1	0	0	0	0
173	Subtotal - Distribution Plant		11,757	-			10,100	1,575	36	27	19
				-							
174	**General Plant**			-							
175	Land and Land Rights	389.1	-	-	INT_TD_PLT	INT	-	-	-	-	-
176	Structures & Improvements	390	100	-	INT_TD_PLT	INT	87	13	0	0	0
177	Electronic Equipment	391.1	5	-	INT_TD_PLT	INT	4	1	0	0	0
178	Furniture & Fixtures	391.2	54	-	INT_LABOR	INT	43	10	0	0	0
179	Automobiles	392.1	-	-	INT_LABOR	INT	-	-	-	-	-
180	Light Trucks	392.2	-	-	INT_LABOR	INT	-	-	-	-	-
181	Trailers	392.3	-	-	INT_LABOR	INT	-	-	-	-	-
182	Heavy Trucks	392.4	-	-	INT_LABOR	INT	-	-	-	-	-
183	Stores Equipment	393	4	-	INT_LABOR	INT	3	1	0	0	0
184	Tools, Shop & Garage Equip	394	57	-	INT_LABOR	INT	46	10	0	0	0
185	Laboratory Equipment	395	1	-	INT_LABOR	INT	0	0	0	0	0
186	Power Operated Equipment	396	4	-	INT_TD_PLT	INT	3	1	0	0	0
187	Power Operated Equipment - Fully Depreciated	396	8	-	INT_TD_PLT	INT	7	1	0	0	0
188	Communication Equipment	397	166	-	INT_TD_PLT	INT	144	21	0	0	0
189	Miscellaneous Equipment	398	12	-	INT_TD_PLT	INT	10	2	0	0	0
190	Subtotal - General Plant		410	-			348	58	2	1	1
				-							
191	**Amortization Expense**			-							
192	Amortization of CSIA Program 20% Deferral		1,963	-	TDSICALLOC	EXT	1,316	351	96	147	54
193	Amortizatoin of CSIA Program Expense		187	-	INT_TOTPLT	INT	162	24	1	0	0
194	Amortization of BS/CI Program Expense		51	-	INT_D376_380	INT	46	5	0	0	0
195	Other Adjustments		33	-	INT_TOTPLT	INT	29	4	0	0	0
196	Subtotal - Amortization Expense			-			1,552	384	97	147	54
197	**DEPRECIATION AND AMORTIZATION EXPENSE**		16,161	-			13,508	2,255	140	181	77

Vectren South Gas COSS Model
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Distribution Customer

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			($000)				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
				-							
198	**H TAXES**			-							
				-							
199	**Taxes Other Than Income & Revenue**			-							
200	Property Taxes	408.1	1,253	-	INT_TOTPLT	INT	1,083	162	4	3	2
201	Subtotal - Taxes Other Than Income		1,253	-			1,083	162	4	3	2
				-							
202	**Income & Revenue Taxes**			-							
203	Revenue Taxes	408.1	567	-	TOTREV	EXT	369	134	18	29	17
204	State Income Taxes	408.1	(113)	-	INT_RTBASE	INT	(97)	(14)	(0)	(0)	(0)
			-	-	-	EXT	-	-	-	-	-
205	Federal Income Taxes	409.1	(972)	-	INT_RTBASE	INT	(837)	(125)	(4)	(4)	(2)
206	Deferred Income Taxes	411.1	393	-	INT_RTBASE	INT	338	50	2	2	1
207	Subtotal - Income Taxes		(124)	-			(227)	46	15	26	16
				-							
208	**TOTAL TAXES**		1,129	-			856	208	19	29	18
				-							
209	**I REVENUES**			-							
				-							
210	Retail Revenue	48x	26,462	-	BASEREV	EXT	17,224	4,683	1,287	2,043	1,226
211	Gas Cost Revenue	48x	-	-	-	EXT	-	-	-	-	-
212	Forfeited Discounts	487	206	-	LT_FEES	EXT	163	36	2	3	2
213	Misc Service Revenue	488	32	-	MISCREV	EXT	30	1	-	-	-
214	Interdepartmental Sales	495	25	-	BASEREV	EXT	16	4	1	2	1
215	Rent from Property	495	161	-	INT_RTBASE	INT	139	21	1	1	0
216	Subtotal -Revenue		26,886	-			17,573	4,746	1,290	2,048	1,230
				-							
217	**TOTAL REVENUES**		26,886	-			17,573	4,746	1,290	2,048	1,230
				-							
218	**NET INCOME**		(7,711)	-			(11,125)	(467)	1,043	1,756	1,082

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
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Distribution Customer

		ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
1				($000)				($000)	($000)	($000)	($000)	($000)
					-							
219	J	**LABOR BALANCE**			-							
					-							
220		**Distribution Expenses**			-							
221		Operation Supervision and Engineering	870	545	-	INT_DISTEXP	INT	423	110	4	4	3
222		Mains and Services Expenses	874	133	-	INT_D376_380	INT	121	12	0	0	0
223		Meas. and Regulating Station Expenses - General	875	-	-	-	EXT	-	-	-	-	-
224		Removing and Resetting Meters	878	554	-	MTRS	EXT	392	145	7	7	4
225		Customer Installation Expenses	879	937	-	INT_MTRHR	INT	663	244	11	11	7
226		Other Expenses	880	558	-	INT_DISTEXP	INT	433	113	4	4	3
227		Rents	881	-	-	INT_DISTEXP	INT	-	-	-	-	-
228		0	0	-	-	-	EXT	-	-	-	-	-
229		0	0	-	-	-	EXT	-	-	-	-	-
230		0	0	-	-	-	EXT	-	-	-	-	-
231		0	0	-	-	-	EXT	-	-	-	-	-
232		Subtotal - Operating Expense		2,726	-			2,032	624	26	26	17
233		Maint. Supervision and Engineering	885	347	-	INT_DMAINT	INT	304	41	1	0	0
234		Maint. of Structures and Improvements	886	-	-	INT_D376_379	INT	-	-	-	-	-
235		Maint. of Mains	887	224	-	INT_MAINS	INT	203	21	0	0	0
236		Maintenance of Services	892	551	-	SERVS	EXT	481	68	1	0	0
237		Maintenance of Meters and House Regulators	893	89	-	INT_MTRHR	INT	63	23	1	1	1
238		Maintenance of Other Equipment	894	51	-	INT_D376_379	INT	46	5	0	0	0
239		0	0	-	-	-	EXT	-	-	-	-	-
240		0	0	-	-	-	EXT	-	-	-	-	-
241		Subtotal - Maintenance Expense		1,261	-			1,098	158	3	2	1
242		Subtotal - Distribution Expense		3,988	-			3,130	781	30	28	18
					-							
243		**OPERATING AND MAINTENANCE EXPENSES**			-							
					-							

Vectren South Gas COSS Model
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Distribution Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 110 - Residential Service	Rate 120/ 125 - General & School/ Government Transportation Service	Rate 145 - General Transportation Service	Rate 160 - Large Volume Transportation Service	Rate 170 - Contract Transportation Service
			($000)				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
244	**CUSTOMER ACCOUNTS AND SERVICE EXPENSE**			-							
				-							
245	**Customer Accounts Expense**			-							
246	Supervision	901	56	-	INT_CUSTACCT	INT	52	5	0	0	0
247	Meter Reading Expenses	902	105	-	MTREAD	EXT	95	10	0	0	0
248	Customers Billing and Accounting	903	485	-	CUST	EXT	440	44	0	0	0
249	Uncollectible Accounts	904	-	-	UNCOLLECT	EXT	-	-	-	-	-
250	Miscellaneous Customer Accounts Expenses	905	83	-	INT_CUSTACCT	INT	76	7	0	0	0
251	Subtotal - Customer Accounts Expense		728	-			662	65	0	0	0
				-							
252	**Customer Service & Information Expense**			-							
253	Customer Assistance Expenses	908	40	-	CUST	EXT	36	4	0	0	0
254	Informational & Instructional Advertising	909	-	-	CUST	EXT	-	-	-	-	-
255	Misc. Customer Service & Informational	910	7	-	CUST	EXT	6	1	0	0	0
256	All Other	913	23	-	CUST	EXT	21	2	0	0	0
257	Subtotal - Customer Service & Information Expense		70	-			63	6	0	0	0
				-							
258	**Sales Expense**			-							
259	Total Miscellaneous Sales Expenses	916	-	-	CUST	EXT	-	-	-	-	-
260	0	0	-	-	-	EXT	-	-	-	-	-
261	0	0	-	-	-	EXT	-	-	-	-	-
262	0	0	-	-	-	EXT	-	-	-	-	-
263	Subtotal - Sales Expense		-	-			-	-	-	-	-
				-							
264	**ACCOUNTS AND SERVICE EXPENSE**		798	-			726	72	1	0	0
				-							
265	**TOTAL O&M LABOR EXPENSE**		**4,786**	**LABOR**			**3,856**	**853**	**30**	**29**	**18**

Vectren South Gas COSS Model
12 Months Ended December 31, 2021
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			($000)				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
				-							
				-							
266	**K REVENUE REQUIREMENT SUMMARY**			-							
				-							
267	**PLANT IN SERVICE**			-							
268	Intangible Plant		32,405	-			27,757	4,372	112	100	63
269	Natural Gas Production		-	-			-	-	-	-	-
270	Underground Storage Plant		-	-			-	-	-	-	-
271	Transmission Plant		-	-			-	-	-	-	-
272	Distribution Plant		279,454	-			241,989	35,628	761	613	461
273	General Plant		18,054	-			15,226	2,646	73	65	45
274	Subtotal - Plant in Service		329,913	-			284,972	42,645	947	779	569
				-							
275	**ACCUMULATED DEPRECIATION**			-							
276	Intangible Plant		(19,904)	-			(17,049)	(2,685)	(69)	(62)	(39)
277	Natural Gas Production		-	-			-	-	-	-	-
278	Underground Storage Plant		-	-			-	-	-	-	-
279	Transmission Plant		-	-			-	-	-	-	-
280	Distribution Plant		(90,109)	-			(77,641)	(11,869)	(265)	(206)	(128)
281	General Plant		(5,294)	-			(4,469)	(772)	(21)	(19)	(13)
282	Subtotal - Accumulated Depreciation		(115,307)	-			(99,160)	(15,326)	(355)	(287)	(180)
				-							
283	**OTHER RATEBASE ITEMS**		7,227	-			5,279	1,159	258	389	143
				-							
284	**TOTAL RATEBASE**		221,833	-			191,092	28,478	850	881	533

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			($000)				*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
				-							
285	**RETURN ON RATEBASE**		13,709	-			11,809	1,760	53	54	33
				-							
286	**EXPENSES**			-							
287	Other Gas Supply		-	-			-	-	-	-	-
288	Stored Gas Expenses		-	-			-	-	-	-	-
289	Transmission Expenses		-	-			-	-	-	-	-
290	Distribution Expenses		7,637	-			6,149	1,364	48	46	30
291	Customer Accounts Expense		1,799	-			1,652	145	1	0	0
292	Customer Service & Information Expense		1,500	-			1,361	137	1	0	0
293	Sales Expense		4	-			3	0	0	0	0
294	Administrative and General Expense		6,368	-			5,168	1,103	38	36	23
295	Depreciation and Amortization Expense		16,161	-			13,508	2,255	140	181	77
296	Taxes Other Than Income & Rev		1,253	-			1,083	162	4	3	2
297	Income and Revenue Taxes		(124)	-			(227)	46	15	26	16
298	Subtotal - Expenses		34,597	-			28,698	5,212	247	292	148
				-							
299	**REVENUE**		26,886	-			17,573	4,746	1,290	2,048	1,230
300	**INCOME**		(7,711)	-			(11,125)	(467)	1,043	1,756	1,082
				-							
301	**REVENUE DEFICIENCY (EXCESS)**		21,420	-			22,935	2,227	(991)	(1,701)	(1,049)
				-							
302	**REVENUE GROSS UP**			-							
303	Federal Income Tax		2,736	-	INT_RTBase	INT	2,357	351	10	11	7
304	State Income Tax		681	-	INT_RTBase	INT	587	87	3	3	2
305	IURT and IURC Fee		172	-	INT_RevReq	INT	145	25	1	1	1
306	Uncollectible		110	-	UNCOLLECT	EXT	105	5	0	-	-
307	Subtotal - Revenue Gross Up		3,699	-			3,193	468	14	15	9
				-							
308	**TOTAL REVENUE REQUIREMENT**		52,006	RevReq			43,700	7,440	314	362	190
309	**Customers (Number of Bills)**		1,358,363				1,232,671	124,408	900	312	72
310	**Customer Cost (per Customer/ Month)**		$ 38.29				$ 35.45	$ 59.81	$ 348.73	$ 1,159.01	$ 2,632.64