INDIANA GAS COMPANY, INC.

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

A CENTERPOINT ENERGY COMPANY

(VECTREN NORTH)

IURC CAUSE NO. 45468

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	Indiana Gas Company, Inc. 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	Indiana Gas Company, Inc. 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 Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner", "Vectren North" 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 North 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 North. 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 North's COSS are Residential Sales Service - Rate 210,[1] General Sales Service – Rate 220, School/Government Transportation Service – Rate 225, Interruptible Sales Service – Rate 240, Large General Transportation Service – Rate 245 and Large Volume Transportation Service - Rate 260.[2] Long-Term Contract Service – Rate 270 is also included in the COSS, but it is not treated as a separate rate class because of the unique competitive circumstances of the customers served under this rate class and the resulting individually negotiated rates. Instead, the margin revenues (i.e., non-gas revenues) from this rate class are credited to all other rate classes in the COSS to recognize the ongoing value these

[1] Includes Unmetered Gas Lighting Sales Service – Rate 211.
[2] Natural Gas Vehicle Service (Rate 229) is excluded from Vectren North's COSS in this proceeding.

larger customers provide to the Company and its customers and to serve as an offset to the total cost of service allocated to all of the Company's other rate classes.

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 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 North?

A. Regarding the physical configuration of the Company's gas system, it is a generally dispersed, multiple city-gate transmission and distribution system, with a multi pressure-based system. The system also includes propane-air and underground storage facilities to supplement the Company's city-gate gas supplies and gas balancing capabilities.

With respect to data availability, Vectren North 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 North, 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 North'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 North 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 large portion of the utility's revenue requirements, and 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 North'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 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 North'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 North 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 North consider in designing its gas distribution system to deliver under all conditions?

A. It is my understanding that Vectren North 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 North 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 North'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 North's classification and allocation of distribution mains costs?

A. Yes. The COSS workpapers filed by Vectren North which present details of the derivation of external allocation factors provides the derivation of the customer component of distribution mains for Vectren North 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 49.24% represents the customer cost component of distribution mains and the remaining 50.76% 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 North 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.[3] The way in which various sizes of customers rely upon the Company's gas distribution system determined how each portion of Vectren North's gas distribution system was allocated to its rate classes. Specifically, the plant and associated expenses for Vectren North'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 210), School/Government Transportation Service (Rate 220/225) and the Interruptible Sales Service (Rate 240) rate classes, and to the Large General Transportation Service (Rate 245) and the Large Volume Transportation Service (Rate 260) 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 Rate 245 and Rate 260 classes do not require Vectren North'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 North's high-pressure gas distribution system. In fact, because of such gas demand requirements, these customers are not connected to Vectren North'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.

[3] Vectren North'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 North'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 to provide gas delivery service to its customers.

Q. How was general plant allocated in Vectren North'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 North'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 North'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 billing, financial and accounting functions on a corporate basis. The costs associated with customer billing investments were allocated to the Company's rate classes using the same allocation factor in the COSS that was used to assign Customer Billing and Accounting expenses (Account No. 903) to the rate classes. All other investment costs associated with the corporate-wide financial and accounting functions were allocated to the rate classes using a generalized allocation factor based on the total revenue requirement computed at an equalized rate of return for each rate class.

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 North's COSS?

A. In general, these expenses were allocated based on the cost allocation methods used for Vectren North'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 North's COSS?

A. Vectren North'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 Billing and Accounting expenses (Account No. 903) was allocated to the rate classes based on an analysis of the activities and related costs in this account to determine if there was a specific customer group, or groups (residential, commercial and industrial) that required each type of activity. The remainder of the costs in the account not associated with a specific customer group was allocated 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 2019.

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

A. Customer Assistance Expenses (Account No. 908) and Demonstration and Selling Expenses (Account No. 912) were allocated to the rate classes based on an analysis of the activities and related costs in each account to determine if there was a specific customer group, or groups (residential, commercial and industrial) that required each type of activity. All Other Customer Service and Information Expenses (Account No. 913) was directly assigned to Rates 210 and 220/225 to recognize that customers in these rate classes benefit from Vectren North's energy efficiency programs, customer education programs and weatherization programs related to the Energy Efficiency Funding Component (EEFC) in the Company's tariff. Finally, Miscellaneous Sales Expenses (Account No. 916) was directly assigned to the Company's industrial customers in Rates 245 and 260 since each of the activities in this account directly supports these types of larger customers.

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

A. Vectren North'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 North 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 North'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 North's COSS?

A. These expenses were allocated in Vectren North'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 North'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 North's propane-air facilities allocated in its COSS?

A. Vectren North currently owns and operates three (3) propane-air facilities, each with vaporizers and two which have on-site propane storage tanks, which enable the

Company to supplement its flowing gas supplies during peak day load conditions to balance its receipts and deliveries of natural gas and to maintain required operating pressures on a localized system basis to serve its sales and transportation service customers. As a result, Vectren North's propane peakshaving-related costs were allocated to the rate classes on a design day throughput basis.

Q. How were the costs of Vectren North's underground storage facilities allocated in its COSS?

A. Vectren North currently owns and operates five (5) underground storage fields, which have about 7,188,400 Mcf of total storage capacity and 165,000 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 North'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.

Q. How were the costs of Vectren North's gas transmission facilities allocated in its COSS?

A. Vectren North's gas transmission facilities generally move gas volumes from its sources of gas supplies (e.g., city-gate stations served by interstate gas pipelines and underground storage facilities) to load centers throughout Vectren North's gas system.

These facilities operate at higher pressures to move large amounts of gas volumes to satisfy the anticipated gas demands on a design day for the Company's sales and transportation service customers. As a result, Vectren North's transmission-related costs were allocated to the rate classes on a design day throughput basis.

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 North'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 210 - Residential Sales Service exhibits a lower than average rate of return on net rate base.
- Rates 220/225 - General Sales Service and School/Government Transportation Service exhibits a lower than average rate of return on net rate base.
- Rate 240 – Interruptible Sales Service exhibits a higher than average rate of return on net rate base.
- Rate 245 – Large General Transportation Service exhibits a higher than average rate of return on net rate base.
- Rate 260 - Large Volume Transportation Service exhibits a higher 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 $20.8 million.

Table 1 – Summary Results of the Company's COSS ($000)[4]

Rate Class	Class Revenue (Subsidy)/Excess	Rate of Return on Net Rate Base	Relative Rate of Return
Rate 210	($6,358)	4.83%	0.90
Rate 220/225	($4,859)	4.03%	0.75
Rate 240	$393	23.94%	4.46
Rate 245	$3,669	11.48%	2.14
Rate 260	$7,154	11.74%	2.19
Total Company	$0	5.37%	1.00

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

[4] See Petitioner's Exhibit No. 16, Attachment RAF-2, page 1 of 5, lines 32, 23, and 24.

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. Are the results of a gas utility's COSS always relevant to all types of service?

A. No. For example, Vectren North's COSS is not relevant to its Rate 270 customers, where rates are based on their unique competitive characteristics reflected in the terms and provisions of their special contracts. For these customers, the price the customer is willing to pay for gas delivery service relative to available alternatives has much more influence on their relative profitability than cost causation does, as measured by a gas utility's COSS. This view is shared by NARUC in its Gas Rate Design Manual, where it states that "[s]etting rates based on value of service bears little relationship to setting them based on cost of service. When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer." Therefore, the guidelines I discussed above are most useful when evaluating the costs to serve customers in the Company's

Residential Sales Service - Rate 210, General Sales Service – Rate 220, School/Government Transportation Service – Rate 225, Interruptible Sales Service – Rate 240, Large General Transportation Service – Rate 245, and Large Volume Transportation Service - Rate 260 classes, and much less useful when evaluating its Rate 270 customers who are priced on a competitive (i.e., value of service) basis.

V. THE COMPANY'S PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Vectren North's proposed revenue increase of $20.8 million to its various rate classes.

A. As described earlier, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations, such as rate shock. 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 North 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 North'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 North'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 (lines 33 through 53) 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 80 through 91) 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 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 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 72 and 74), 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 210	$237,101	$16,236	6.85%
Rate 220/225	$69,990	$5,201	7.43%
Rate 240	$776	$11	1.36%
Rate 245	$13,663	$184	1.35%
Rate 260	$24,925	$311	1.25%
Rate 270	$6,751	($1,183)	-17.53%
Misc. Revenue	$5,140	$0	0.0%
Total Company	$358,344	$20,759	5.79%

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[5]	Percent Change
Rate 210	($6,358)	($5,104)	-19.72%
Rate 220/225	($4,859)	($4,302)	-11.45%
Rate 240	$393	$369	-6.17%
Rate 245	$3,669	$3,059	-16.64%
Rate 260	$7,154	$5,979	-16.43%
Total Company	$0	$0	

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

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

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 210	$411,964	$16,236	3.94%
Rate 220/225	$149,597	$5,201	3.48%
Rate 240	$1,852	$11	0.57%
Rate 245	$13,663	$184	1.35%
Rate 260	$24,925	$311	1.25%
Rate 270	$6,751	($1,183)	-17.53%
Misc. Revenue	$5,140	$0	0.0%
Total Company	$613,892	$20,759	3.38%

Q. Referring to Table 4, please explain why Rate 270 customers will realize a decrease in revenues since the rates for customers served in this rate class are set on a negotiated basis.

A. In total, the Company's Rate 270 customers will realize a decrease in revenues under the Company's proposed class revenue apportionment based on how the gas delivery rates are derived for each of these long-term contract customers. First, the level of gas delivery rates negotiated by the Company for certain of its long-term contract customers served under Rate 270 are derived as a percentage of the Customer Facilities Charge and Distribution Charges under Rate 260. Since the class revenues and rates for Rate 260 customers are proposed to increase, this action will also cause the proposed rates for these Rate 270 customers to increase. The remaining Rate 270 customers will not be subject to a similar rate increase since their negotiated rates were set without reference to the prevailing charges under Rate 260. The resulting increase in revenues to this rate class reduces the proposed increase to each of the Company's other rate classes.

Next, in this rate case the capital investments Vectren North recovered through the CSIA charge for each of Vectren North's rate classes will be included in its base rates which will be increased on an equivalent basis from the reduction in the CSIA charges. For those Rate 270 customers that pay negotiated rates derived as a percentage of the Customer Facilities Charge and Distribution Charges under Rate 260, these customers will continue to pay for a portion of the capital investments previously recovered through the CSIA charges through an increase in their negotiated rates caused by the increase in the base rates for Rate 260. However, as described earlier, there are other Rate 270 customers that pay distribution charges set on a negotiated basis (rather than tied to the distribution charges under Rate 260) and the CSIA charges under Appendix K. With the above-described reduction to the Company's CSIA charges, the pricing provisions in the long-term contracts for these customers do not enable the negotiated rates to be increased to continue to recover a portion of the capital investments previously recovered from these customers through the CSIA charges in Appendix K. As a result, there will be a reduction in the level of CSIA revenue generated from Rate 270 customers that the Company proposes to recover from all other rate classes. The combined effect of these two adjustments to the Rate 270 customers is indicated in Petitioner's Exhibit No. 16, Attachment RAF-3 under the column entitled, Rate 270 Adjustments.

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 North'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[6]	Percent of Total
Rate 210	$253,337	67.74%
Rate 220/225	$75,190	20.11%
Rate 240	$787	0.21%
Rate 245	$13,847	3.70%
Rate 260/270	$30,803	8.24%
Total Company	$373,963	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. Vectren North is proposing this methodology in future CSIA or TDSIC recovery since the cost of gas has no relation to the TDSIC projects, and recovery thereof. If the Company allocates future CSIA or TDSIC charges based on revenue including the cost of gas, it does not allocate an appropriate share to the industrial customers. The primary reason to use non-gas revenue rather than total revenue is that the TDSIC investments from past years when rolled into base rates represent a portion of the utility's non-gas (margin) revenue requirement in the current rate case so it is reasonable to also allocate those same types of investments in subsequent years on each class' share of the utility's total non-gas revenues.

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

Q. How should the Commission apportion the change in non-gas revenues by rate class if it authorizes a different revenue increase than the $20.8 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. THE COMPANY'S PROPOSED RATE DESIGN

Q. Can you please describe the key objectives you sought to achieve in the design of Vectren North'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 North:

- 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 North'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 Petitioner's Exhibit No. 16, Attachment RAF-4, page 8 of 8 (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[7]	Proposed Customer Facility Charge
	$/Customer/Month	*$/Customer/Month*	*$/Customer/Month*
Rate 210	$26.20	$20.16	$21.50
Rate 220/225	$60.89		
Group 1		$17.00	$18.25
Group 2		$46.00	$49.50
Group 3		$93.00	$100.00
Rate 240	$172.17	$175.00	$175.00
Rate 245	$221.02	$200.00	$205.00
Rate 260	$664.26	$1,100.00	$1,100.00

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 in a manner to maintain the relative rate differentials on a percentage basis between rate blocks that exist under current rates.

Q. Has the Company provided bill comparisons which show the impact of Vectren North'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

[7] Includes the fixed CSIA charge for the Residential Sales Service rate class - Rate 210.

bills in Schedule E-5 and Vectren North 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 North'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 North'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; and (3) customer impact considerations.
- The Commission should approve the rate design proposed by the Company because it reasonably satisfies the key rate design objectives I presented earlier in my testimony, including: (1) achieve fair and equitable rate levels that are reflective of the cost to serve; (2) avoid undue discrimination between and within

rate classes; (3) rates should be stable, understandable, and provide customer choices; (4) create economically efficient pricing for natural gas delivery service; (5) rates should encourage energy conservation and energy efficiency; and (6) rates should allow a utility to recover its revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Cause No. 45468

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: December 18, 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)

Cause No. 45468

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

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Rate 210 - Residential Sales Service	Rate 220/225 - General & School/ Government Transportation Service	Rate 240 - Interruptible Sales Service	Rate 245 - Large General Transportation Service	Rate 260 - Large Volume Transportation Service
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
1	**Rate Base**						
2	Plant in Service	3,199,756	2,281,608	627,819	2,195	97,615	190,518
3	Accumulated Reserve	(1,692,249)	(1,230,415)	(323,639)	(1,288)	(47,419)	(89,488)
4	Other Rate Base Items	103,292	53,535	37,603	1,087	6,338	4,729
5	Total Rate Base	1,610,799	1,104,728	341,783	1,994	56,535	105,759
6	**Total Revenue at Current Rates**						
7	Retail Revenue	346,454	237,101	69,990	776	13,663	24,925
8	Gas Cost Revenue	255,547	174,864	79,608	1,076	-	-
9	Miscellaneous Revenue	5,140	3,933	1,084	2	56	65
10	Other Revenue	6,751	4,692	1,719	16	116	207
11	Total Revenue	613,892	420,589	152,400	1,870	13,835	25,197
12	**Expenses at Current Rates**						
13	Natural Gas City Gate Purchases	255,547	174,864	79,608	1,076	-	-
14	Operation and Maintenance and Sales Expense	92,060	66,696	16,745	103	3,063	5,453
15	Administrative and General Expense	42,398	30,965	8,392	66	1,195	1,780
16	Depreciation and Amortization Expense	111,837	77,141	28,569	91	2,193	3,844
17	Taxes Other Than Income	12,953	9,236	2,542	9	395	771
18	IURT and IURC Revenue Taxes	8,558	5,857	2,127	26	194	354
19	Total Expenses Excl. Income Taxes - Current	523,353	364,758	137,983	1,371	7,040	12,202
20	Income Prior to Taxes	90,538	55,831	14,418	500	6,794	12,995
21	Income Taxes	4,018	2,478	640	22	302	577
22	Operating Income - Current	86,520	53,353	13,778	477	6,493	12,419
23	Current Rate of Return	5.37%	4.83%	4.03%	23.94%	11.48%	11.74%
24	Current Relative Rate of Return	1.00	0.90	0.75	4.46	2.14	2.19
25	**Present Revenue at Equal Rates of Return**						
26	Present Return	5.37%	5.37%	5.37%	5.37%	5.37%	5.37%
27	Present Operating Income @ Equal Return	86,520	59,338	18,358	107	3,037	5,681
28	Income Taxes	4,018	2,755	852	5	141	264
29	Other Expenses	514,795	358,901	135,856	1,344	6,846	11,848
30	IURT and IURC Revenue Taxes	8,558	5,952	2,192	21	142	252
31	Total Revenue @ Equal Rates of Return	613,892	426,947	157,259	1,477	10,165	18,044
32	Present (Subsidy)/Excess	-	(6,358)	(4,859)	393	3,669	7,154

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

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Rate 210 - Residential Sales Service	Rate 220/225 - General & School/ Government Transportation Service	Rate 240 - Interruptible Sales Service	Rate 245 - Large General Transportation Service	Rate 260 - Large Volume Transportation Service
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
33	**Revenue Requirement at Equal Rates of Return**						
34	Required Return	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%
35	Required Operating Income	101,802	69,819	21,601	126	3,573	6,684
36	**Expenses at Required Return**						
37	Natural Gas City Gate Purchases	255,547	174,864	79,608	1,076	-	-
38	Operation and Maintenance and Sales Expense	92,060	66,696	16,745	103	3,063	5,453
39	Administrative and General Expense	42,398	30,965	8,392	66	1,195	1,780
40	Amortization and Depreciation Expense	111,837	77,141	28,569	91	2,193	3,844
41	Taxes Other Than Income	12,953	9,236	2,542	9	395	771
42	IURT and IURC Revenue Taxes - Current	8,558	5,857	2,127	26	194	354
43	State Income Tax - Current	2,363	1,620	502	3	83	155
44	Federal Income Tax - Current	1,655	1,134	351	2	58	109
45	Federal Income Tax - Increase	4,062	2,785	862	5	143	267
46	State Income Tax - Increase	1,012	693	215	1	36	66
47	IURT and IURC Revenue Taxes - Increase	316	220	80	1	5	10
48	Uncollecible - Increase	87	78	9	-	0	-
49	Total Expenses - Required	532,848	371,288	140,001	1,383	7,367	12,809
50	Total Revenue Requirement at Equal Return	634,651	441,107	161,602	1,509	10,940	19,493
51	Current Miscellaneous Revenue	5,140	3,933	1,084	2	56	65
52	Current Other Revenue	6,751	4,692	1,719	16	116	207
53	Total Base Revenue @ Equal Rates of Return	622,760	432,483	158,799	1,491	10,768	19,220
54	Revenue (Subsidy)/Excess before Increase	(20,759)	(20,518)	(9,202)	361	2,895	5,705
55	**Proposed Revenue by Class**						
56	Total Base Revenue as Proposed	623,943	428,201	154,798	1,862	13,847	25,235
57	Miscellaneous Revenue	5,140	3,933	1,084	2	56	65
58	Other Revenue	5,568	3,870	1,418	13	96	171
59	Total Revenue as Proposed	634,651	436,003	157,299	1,878	13,999	25,472
60	Revenue (Subsidy)/Excess after Increase	-	(5,104)	(4,302)	369	3,059	5,979
61	Base Revenue Increase as Proposed	21,942	16,236	5,201	11	184	311
62	Change in Miscellaneous Revenue	-	-	-	-	-	-
63	Change in Other Revenue	(1,183)	(822)	(301)	(3)	(20)	(36)
64	Total Revenue Increase as Proposed	20,759	15,414	4,899	8	164	274
65	Precent Total Revenue Change	3.38%	3.66%	3.21%	0.42%	1.19%	1.09%
66	Other Expenses	514,882	358,980	135,864	1,344	6,846	11,848
67	IURT and IURC Revenue Taxes	8,874	6,097	2,199	26	196	356
68	Income Prior to Taxes	110,894	70,927	19,236	507	6,957	13,268
69	Income Taxes	9,092	5,815	1,577	42	570	1,088
70	Operating Income	101,802	65,112	17,659	466	6,386	12,180
71	**Proposed Return**	6.32%	5.89%	5.17%	23.36%	11.30%	11.52%
72	Proposed Relative Rate of Return	1.00	0.93	0.82	3.70	1.79	1.82
73	**Current Return**	5.37%	4.83%	4.03%	23.94%	11.48%	11.74%
74	Current Relative Rate of Return	1.00	0.90	0.75	4.46	2.14	2.19

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

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Rate 210 - Residential Sales Service	Rate 220/225 - General & School/ Government Transportation Service	Rate 240 - Interruptible Sales Service	Rate 245 - Large General Transportation Service	Rate 260 - Large Volume Transportation Service
		($000)	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
75	**Revenue by Class - Equal Increase by Class on Non-Gas Revenues**						
76	Total Base Revenue as Proposed	622,760	426,171	153,791	1,898	14,481	26,418
77	Miscellaneous Revenue	5,140	3,933	1,084	2	56	65
78	Other Revenue	6,751	4,692	1,719	16	116	207
79	Total Revenue as Proposed	634,651	434,796	156,594	1,917	14,653	26,691
80	Base Revenue Increase as Proposed	20,759	14,207	4,194	47	819	1,493
81	Change in Miscellaneous Revenue	-	-	-	-	-	-
82	Change in Other Revenue	-	-	-	-	-	-
83	Total Revenue Increase as Proposed	20,759	14,207	4,194	47	819	1,493
84	Precent Total Revenue Change	3.38%	3.38%	2.75%	2.49%	5.92%	5.93%
85	Other Expenses	514,882	358,980	135,864	1,344	6,846	11,848
86	IURT and IURC Revenue Taxes	8,874	6,076	2,207	27	200	364
87	Income Prior to Taxes	110,894	69,740	18,522	545	7,607	14,479
88	Income Taxes	9,092	5,718	1,519	45	624	1,187
89	Operating Income	101,802	64,022	17,004	501	6,984	13,292
90	**Resulting Return**	6.32%	5.80%	4.98%	25.11%	12.35%	12.57%
91	Proposed Relative Rate of Return	1.00	0.92	0.79	3.97	1.95	1.99

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Vectren North 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 210 - Residential Sales Service	Rate 220/225 - General & School/ Government Transportation Service	Rate 240 - Interruptible Sales Service	Rate 245 - Large General Transportation Service	Rate 260 - Large Volume Transportation Service
	Functional Revenue Requirement		*($000)*	*($000)*	*($000)*	*($000)*	*($000)*	*($000)*
1	**Gas Production**							
2	Demand	F1D	$ 1,215	$ 651	$ 332	$ 1	$ 70	$ 161
3	Commodity	F1E	$ 268,409	$ 183,533	$ 83,503	$ 1,125	$ 88	$ 160
4	Customer	F1C	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal		$ 269,623	$ 184,183	$ 83,835	$ 1,126	$ 158	$ 322
6	**Underground Storage**							
7	Demand	F2D	$ 3,691	$ 1,994	$ 981	$ 2	$ 215	$ 498
8	Commodity	F2E	$ 7,381	$ 4,038	$ 1,955	$ 178	$ 873	$ 337
9	Customer	F2C	$ -	$ -	$ -	$ -	$ -	$ -
10	Subtotal		$ 11,071	$ 6,032	$ 2,936	$ 180	$ 1,088	$ 835
11	**Transmission**							
12	Demand	F3D	$ 54,060	$ 29,194	$ 14,390	$ 36	$ 3,146	$ 7,294
13	Commodity	F3E	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	F3C	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal		$ 54,060	$ 29,194	$ 14,390	$ 36	$ 3,146	$ 7,294
16	**Distribution**							
17	Demand	F4D	$ 78,656	$ 43,197	$ 21,494	$ 54	$ 4,503	$ 9,408
18	Commodity	F4E	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	F4C	$ 221,240	$ 178,501	$ 38,947	$ 114	$ 2,045	$ 1,634
20	Subtotal		$ 299,896	$ 221,698	$ 60,441	$ 167	$ 6,548	$ 11,042
21	**Total**							
22	Demand		$ 137,621	$ 75,035	$ 37,196	$ 93	$ 7,934	$ 17,362
23	Commodity		$ 275,789	$ 187,571	$ 85,458	$ 1,302	$ 961	$ 497
24	Customer		$ 221,240	$ 178,501	$ 38,947	$ 114	$ 2,045	$ 1,634
25	**Total Revenue Requirement**		$ 634,651	$ 441,107	$ 161,602	$ 1,509	$ 10,940	$ 19,493
26	Demand		21.68%	17.01%	23.02%	6.15%	72.53%	89.07%
27	Commodity		43.46%	42.52%	52.88%	86.32%	8.78%	2.55%
28	Customer		34.86%	40.47%	24.10%	7.53%	18.69%	8.38%

Vectren North 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 210 - Residential Sales Service	Rate 220/225 - General & School/ Government Transportation Service	Rate 240 - Interruptible Sales Service	Rate 245 - Large General Transportation Service	Rate 260 - Large Volume Transportation Service
	Unit Costs							
29	**Gas Production**							
30	Demand	F1D	$ 0.10	$ 0.10	$ 0.11	$ 0.12	$ 0.09	$ 0.09
31	Commodity	F1E	$ 0.21	$ 0.40	$ 0.39	$ 0.40	$ 0.00	$ 0.00
32	Customer	F1C	$ -	$ -	$ -	$ -	$ -	$ -
33	**Underground Storage**							
34	Demand	F2D	$ 0.30	$ 0.29	$ 0.32	$ 0.35	$ 0.29	$ 0.29
35	Commodity	F2E	$ 0.01	$ 0.01	$ 0.01	$ 0.06	$ 0.01	$ 0.00
36	Customer	F2C	$ -	$ -	$ -	$ -	$ -	$ -
37	**Transmission**							
38	Demand	F3D	$ 4.37	$ 4.30	$ 4.65	$ 5.07	$ 4.20	$ 4.19
39	Commodity	F3E	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	F3C	$ -	$ -	$ -	$ -	$ -	$ -
41	**Distribution**							
42	Demand	F4D	$ 6.36	$ 6.37	$ 6.95	$ 7.59	$ 6.01	$ 5.40
43	Commodity	F4E	$ -	$ -	$ -	$ -	$ -	$ -
44	Customer	F4C	$ 29.63	$ 26.20	$ 60.89	$ 172.17	$ 221.02	$ 664.26
45	**Total**							
46	Demand (per mcf)		$ 11.12	$ 11.06	$ 12.03	$ 13.13	$ 10.59	$ 9.96
47	Commodity (per mcf)		$ 0.214	$ 0.407	$ 0.395	$ 0.460	$ 0.008	$ 0.001
48	Customer (per cust month)		$ 29.63	$ 26.20	$ 60.89	$ 172.17	$ 221.02	$ 664.26
49	Demand & Commodity (per cust month)		$ 48.07	$ 37.21	$ 119.05	$ 312.78	$ 1,078.59	$ 7,722.05
50	**BILLING DETERMINANTS**							
51	Demand		12,376,251	6,785,998	3,091,343	7,071	749,125	1,742,713
52	Commodity		1,288,159,324	460,531,158	216,325,896	2,832,652	114,619,488	493,850,131
53	Customers (Number of Bills)		7,466,090	6,814,135	639,583	660	9,252	2,460

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

Revenue Apportionment

					Equalized Rate of Return				Proportionate to Non-Gas Revenues			
Line	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)*	Current Non-Gas Revenues *($000)*	Increase on Non-Gas Revenues *($000)*	% Change (equal % on Non-Gas)	Resulting Revenue ($000)
1	Rate 210 - Residential Sales Service	$ 411,964	4.83%	0.90	$ 432,483	$ 20,518	8.7%	$ 432,483	$ 237,101	$ 14,207	6.0%	$ 426,171
2	Rate 220/225 - General & School/ Government Transportation Service	$ 149,597	4.03%	0.75	$ 158,799	$ 9,202	13.1%	$ 158,799	$ 69,990	$ 4,194	6.0%	$ 153,791
3	Rate 240 - Interruptible Sales Service	$ 1,852	23.94%	4.46	$ 1,491	$ (361)	-46.5%	$ 1,491	$ 776	$ 47	6.0%	$ 1,898
4	Rate 245 - Large General Transportation Service	$ 13,663	11.48%	2.14	$ 10,768	$ (2,895)	-21.2%	$ 10,768	$ 13,663	$ 819	6.0%	$ 14,481
5	Rate 260 - Large Volume Transportation Service	$ 24,925	11.74%	2.19	$ 19,220	$ (5,705)	-22.9%	$ 19,220	$ 24,925	$ 1,493	6.0%	$ 26,418
6	TOTAL SYSTEM BASE REVENUE	$ 602,001	5.37%	1.00	$ 622,760	$ 20,759	6.0%	$ 622,760	$ 346,454	$ 20,759	6.0%	$ 622,760

7	Proposed Revenues	634,651
8	Increase	20,759
9	System Increase (Total Revenue)	3.38%
10	System Increase (Non-Gas Revenue)	5.79%

Proposed Base Revenues

For TDSIC Allocators

11	Class	Current Non-Gas Revenues *($000)*	Targeted Percentage Increase	Proposed Increase *($000)*	Rate 270 Adjustments *($000)*	Proposed Increase After Adjustments *($000)*	Proposed Non-Gas Revenue *($000)*	Resulting Increase % (Base Rev)	Proposed Revenue *($000)*	Resulting Increase % with Gas Cost	Proposed Non-Gas Revenue *($000)*	Percent
12	Rate 210 - Residential Sales Service	$ 237,101	6.50%	$ 15,414	$ 822	$ 16,236	$ 253,337	6.85%	$ 428,201	3.94%	$ 253,337	67.74%
13	Rate 220/225 - General & School/ Government Transportation Service	$ 69,990	7.00%	$ 4,899	$ 301	$ 5,201	$ 75,190	7.43%	$ 154,798	3.48%	$ 75,190	20.11%
14	Rate 240 - Interruptible Sales Service	$ 776	1.00%	$ 8	$ 3	$ 11	$ 787	1.36%	$ 1,862	0.57%	$ 787	0.21%
15	Rate 245 - Large General Transportation Service	$ 13,663	1.20%	$ 164	$ 20	$ 184	$ 13,847	1.35%	$ 13,847	1.35%	$ 13,847	3.70%
16	Rate 260 - Large Volume Transportation Service	$ 24,925	1.10%	$ 274	$ 36	$ 311	$ 25,235	1.25%	$ 25,235	1.25%	$ 25,235	6.75%
17	Rate 270 - Long-Term Contract Service	$ 6,751	0.00%		$ (1,183)	$ (1,183)	$ 5,568	-17.53%	$ 5,568	-17.53%	$ 5,568	1.49%
18	Miscellaneous Revenue	$ 5,140					$ 5,140		$ 5,140			
19	TOTAL SYSTEM	$ 358,344		$ 20,759	$ -	$ 20,759	$ 379,104	5.79%	$ 634,651	3.38%	$ 373,963	100.00%

Cause No. 45468

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

Line	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE *($000)*	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 210 - Residential Sales Service *($000)*	Rate 220/225 - General & School/ Government Transportation Service *($000)*	Rate 240 - Interruptible Sales Service *($000)*	Rate 245 - Large General Transportation Service *($000)*	Rate 260 - Large Volume Transportation Service *($000)*
1	A **PLANT IN SERVICE**										
2	**Intangible Plant**										
3	Organizational Expense	301	12	-	INT_PLT_OM	INT	10	2	0	0	0
4	Franchise & Consents	302	1	-	INT_PLT_OM	INT	1	0	0	0	0
5	Miscellaneous Intangible Plant	303	30,316	-	INT_ACCT-303	INT	25,030	4,829	13	253	191
6	Miscellaneous Intangible Plant - 15 Year	303.15	11,535	-	INT_ACCT-303.15	INT	10,042	1,375	3	71	43
7	Miscellaneous Intangible Plant - 12 Year	303.12	12,440	-	INT_RevReq	INT	10,037	2,190	6	115	92
8	Miscellaneous Intangible Plant - Fully Depr	303.99	36,663	-	INT_ACCT-303	INT	30,271	5,840	16	306	232
9	Subtotal - Intangible Plant		90,967	-			75,391	14,235	38	745	558
10	**Distribution Plant**			-							
11	Land	374.1	398	-	INT_D376_379	INT	363	34	0	0	0
12	Land Rights	374.2	8,820	-	INT_D376_379	INT	8,050	756	1	11	3
13	Structures & Improvements	375	1,256	-	INT_D376_379	INT	1,147	108	0	2	0
14	Mains (High Pressure)	376	148,992	D376_379	CUST_HP	EXT	135,983	12,764	13	184	48
15	Mains (Low/Medium Pressure)	376	440,970	D376_379	CUST_LowMed	EXT	402,499	37,779	39	527	125
16	Compressor Station Equip	377	-	D376_379	-	EXT	-	-	-	-	-
17	Compressor Station Equip-New Rate	377.1	-	D376_379	-	EXT	-	-	-	-	-
18	Meas & Reg Station Eq-Gen	378	-	D376_379	-	EXT	-	-	-	-	-
19	Meas & Reg Station Eq-City Gate	379	-	D376_379	-	EXT	-	-	-	-	-
20	Services	380	845,356	-	SERVS	EXT	681,532	159,346	164	3,080	1,233
21	Meters	381	116,788	MTRHR	MTRS	EXT	85,284	27,007	157	2,672	1,669
22	Meters-ERTs	381.1	-	MTRHR	MTRS	EXT	-	-	-	-	-
23	Meter Installations	382	94,277	MTRHR	MTRS	EXT	68,845	21,801	127	2,157	1,348
24	House Regulators	383	30,859	MTRHR	AC_383	EXT	22,885	7,192	30	560	191
25	House Regulator Install	384	29	MTRHR	AC_383	EXT	22	7	0	1	0
26	Indus Meas & Reg St Equip	385	40,138	-	AC_385	EXT	-	-	-	11,741	28,396
27	Other Equipment	387	162	-	INT_D376_379	INT	147	14	0	0	0
28	Subtotal - Distribution Plant		1,728,044	TD_PLT			1,406,759	266,807	531	20,934	33,014
29	**General Plant**										
30	Land and Land Rights	389.1	1,552	-	INT_TD_PLT	INT	1,264	240	0	19	30
31	Structures & Improvements	390	32,017	-	INT_TD_PLT	INT	26,064	4,943	10	388	612
32	Electronic Equipment	391.1	1,822	-	INT_TD_PLT	INT	1,483	281	1	22	35
33	Furniture & Fixtures	391.2	2,951	-	INT_LABOR	INT	2,396	482	2	43	28
34	Automobiles	392.1	-	-	INT_LABOR	INT	-	-	-	-	-
35	Light Trucks	392.2	17,414	-	INT_LABOR	INT	14,139	2,847	12	251	165
36	Trailers	392.3	1,310	-	INT_LABOR	INT	1,064	214	1	19	12
37	Heavy Trucks	392.4	6,093	-	INT_LABOR	INT	4,947	996	4	88	58
38	Stores Equipment	393	1,388	-	INT_LABOR	INT	1,127	227	1	20	13
39	Stores Equipment-New Rate	393.1	-	-	INT_LABOR	INT	-	-	-	-	-
40	Tools, Shop & Garage Equip	394	9,029	-	INT_LABOR	INT	7,331	1,476	6	130	85
41	Laboratory Equipment	395	2,114	-	INT_LABOR	INT	1,717	346	1	31	20
42	Power Operated Equipment	396	3,965	-	INT_TD_PLT	INT	3,228	612	1	48	76
43	Power Operated Equipment - New Rate	396.1	543	-	INT_TD_PLT	INT	442	84	0	7	10
44	Communication Equipment	397	6,400	-	INT_TD_PLT	INT	5,210	988	2	78	122
45	Miscellaneous Equipment	398	592	-	INT_TD_PLT	INT	482	91	0	7	11
46	Subtotal - General Plant		87,190	GEN_PLT			70,894	13,828	41	1,150	1,277
47	**TOTAL PLANT IN SERVICE**		1,906,201	TOTPLT			1,553,043	294,869	610	22,829	34,850

Cause No. 45468

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

Line	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE *($000)*	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 210 - Residential Sales Service *($000)*	Rate 220/225 - General & School/ Government Transportation Service *($000)*	Rate 240 - Interruptible Sales Service *($000)*	Rate 245 - Large General Transportation Service *($000)*	Rate 260 - Large Volume Transportation Service *($000)*
48	**B ACCUMULATED DEPRECIATION**										
49	**Intangible Plant**										
50	Organizational Expense	301	18	-	INT_PLT_OM	INT	15	3	0	0	0
51	Franchise & Consents	302	1	-	INT_PLT_OM	INT	1	0	0	0	0
52	Miscellaneous Intangible Plant	303	(17,555)	-	INT_ACCT-303	INT	(14,494)	(2,796)	(8)	(146)	(111)
53	Miscellaneous Intangible Plant - 15 Year	303.15	(3,461)	-	INT_ACCT-303.15	INT	(3,013)	(413)	(1)	(21)	(13)
54	Miscellaneous Intangible Plant - 12 Year	303.12	(786)	-	INT_RevReq	INT	(634)	(138)	(0)	(7)	(6)
55	Miscellaneous Intangible Plant - Fully Depr	303.99	(36,663)	-	INT_ACCT-303	INT	(30,271)	(5,840)	(16)	(306)	(232)
56	Subtotal - Intangible Plant		(58,446)	-			(48,396)	(9,184)	(24)	(480)	(361)
57	**Distribution Plant**										
58	Land	374.1	-	-	INT_D376_379	INT	-	-	-	-	-
59	Land Rights	374.2	(4,316)	-	INT_D376_379	INT	(3,940)	(370)	(0)	(5)	(1)
60	Structures & Improvements	375	(1,079)	-	INT_D376_379	INT	(985)	(92)	(0)	(1)	(0)
61	Mains (High Pressure)	376	(65,240)	-	CUST_HP	EXT	(59,543)	(5,589)	(6)	(81)	(21)
62	Mains (Low/Medium Pressure)	376	(193,089)	-	CUST_LowMed	EXT	(176,244)	(16,542)	(17)	(231)	(55)
63	Compressor Station Equip	377	-	-	-	EXT	-	-	-	-	-
64	Compressor Station Equip-New Rate	377.1	-	-	-	EXT	-	-	-	-	-
65	Meas & Reg Station Eq-Gen	378	-	-	-	EXT	-	-	-	-	-
66	Meas & Reg Station Eq-City Gate	379	-	-	-	EXT	-	-	-	-	-
67	Services	380	(642,666)	-	SERVS	EXT	(518,122)	(121,140)	(125)	(2,342)	(938)
68	Meters	381	(32,239)	-	MTRS	EXT	(23,542)	(7,455)	(43)	(737)	(461)
69	Meters-ERTs	381.1	-	-	MTRS	EXT	-	-	-	-	-
70	Meter Installations	382	(73,220)	-	MTRS	EXT	(53,468)	(16,932)	(98)	(1,675)	(1,047)
71	House Regulators	383	(22,923)	-	AC_383	EXT	(17,000)	(5,343)	(22)	(416)	(142)
72	House Regulator Install	384	(21)	-	AC_383	EXT	(15)	(5)	(0)	(0)	(0)
73	Indus Meas & Reg St Equip	385	(39,564)	-	AC_385	EXT	-	-	-	(11,574)	(27,990)
74	Other Equipment	387	(24)	-	INT_D376_379	INT	(22)	(2)	(0)	(0)	(0)
75	Subtotal - Distribution Plant		(1,074,380)	-			(852,881)	(173,470)	(312)	(17,062)	(30,655)
76	**General Plant**										
77	Land and Land Rights	389.1	-	-	INT_TD_PLT	INT	-	-	-	-	-
78	Structures & Improvements	390	(12,758)	-	INT_TD_PLT	INT	(10,386)	(1,970)	(4)	(155)	(244)
79	Electronic Equipment	391.1	(653)	-	INT_TD_PLT	INT	(531)	(101)	(0)	(8)	(12)
80	Furniture & Fixtures	391.2	(1,463)	-	INT_LABOR	INT	(1,188)	(239)	(1)	(21)	(14)
81	Automobiles	392.1	-	-	INT_LABOR	INT	-	-	-	-	-
82	Light Trucks	392.2	(9,853)	-	INT_LABOR	INT	(8,000)	(1,611)	(7)	(142)	(93)
83	Trailers	392.3	(606)	-	INT_LABOR	INT	(492)	(99)	(0)	(9)	(6)
84	Heavy Trucks	392.4	(3,333)	-	INT_LABOR	INT	(2,707)	(545)	(2)	(48)	(32)
85	Stores Equipment	393	(1,485)	-	INT_LABOR	INT	(1,206)	(243)	(1)	(21)	(14)
86	Stores Equipment-New Rate	393.1	-	-	INT_LABOR	INT	-	-	-	-	-
87	Tools, Shop & Garage Equip	394	(4,964)	-	INT_LABOR	INT	(4,031)	(811)	(3)	(72)	(47)
88	Laboratory Equipment	395	(2,209)	-	INT_LABOR	INT	(1,793)	(361)	(1)	(32)	(21)
89	Power Operated Equipment	396	(4,897)	-	INT_TD_PLT	INT	(3,986)	(756)	(2)	(59)	(94)
90	Power Operated Equipment - New Rate	396.1	-	-	INT_TD_PLT	INT	-	-	-	-	-
91	Communication Equipment	397	(3,308)	-	INT_TD_PLT	INT	(2,693)	(511)	(1)	(40)	(63)
92	Miscellaneous Equipment	398	(206)	-	INT_TD_PLT	INT	(168)	(32)	(0)	(2)	(4)
93	Subtotal - General Plant		(45,734)	-			(37,181)	(7,278)	(23)	(610)	(643)
94	**TOTAL ACCUMULATED DEPRECIATION**		(1,178,560)	-			(938,458)	(189,932)	(359)	(18,152)	(31,659)

Cause No. 45468

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

Line	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE *($000)*	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 210 - Residential Sales Service *($000)*	Rate 220/225 - General & School/ Government Transportation Service *($000)*	Rate 240 - Interruptible Sales Service *($000)*	Rate 245 - Large General Transportation Service *($000)*	Rate 260 - Large Volume Transportation Service *($000)*
95	**C OTHER RATEBASE ITEMS**			-							
96	Acquisition Adjustment - Cost		9,577	-	INT_RTBASE	INT	7,966	1,500	4	62	45
97	Acquisition Adjustment - Amort		(7,460)	-	INT_RTBASE	INT	(6,205)	(1,168)	(3)	(48)	(35)
98	Gas in Underground Storage		-	-	-	EXT	-	-	-	-	-
99	Utility Material & Supplies		2,447	-	INT_TD_PLT	INT	1,992	378	1	30	47
100	Liquefied Petroleum Gas		-	-	-	EXT	-	-	-	-	-
101	Prepaid Gas Delivery		-	-	-	EXT	-	-	-	-	-
102	PISCC - BS/CI		10,966	-	INT_D376_380	INT	10,009	939	1	14	4
103	PISCC - CSIA		18,204	-	TDSICALLOC	EXT	4,955	12,669	39	208	333
104	Subtotal - Other Rate Base Items		33,734	-			18,716	14,318	41	265	393
				-							
105	**TOTAL RATE BASE**		761,375	RTBASE			633,301	119,255	292	4,942	3,584
106	**D OPERATING AND MAINTENANCE EXPENSES**			-							
107	**Distribution Expenses**			-							
108	Operation Supervision and Engineering	870	5,889	-	INT_DISTEXP	INT	4,850	925	4	69	41
109	Mains and Services Expenses	874	8,762	DISTEXP	INT_D376_380	INT	7,997	751	1	11	3
110	Meas. and Regulating Station Expenses - General	875	-	DISTEXP	-	EXT	-	-	-	-	-
111	Removing and Resetting Meters	878	4,514	DISTEXP	MTRS	EXT	3,296	1,044	6	103	65
112	Customer Installation Expenses	879	3,899	DISTEXP	INT_MTRHR	INT	2,853	903	5	87	52
113	Other Expenses	880	5,446	-	INT_DISTEXP	INT	4,486	855	4	64	38
114	Rents	881	28	-	INT_DISTEXP	INT	23	4	0	0	0
115	Subtotal - Operating Expense		28,538	-			23,505	4,481	20	334	198
116	Maint. Supervision and Engineering	885	728	-	INT_DMAINT	INT	629	95	0	3	1
117	Maint. of Structures and Improvements	886	318	DMAINT	INT_D376_379	INT	290	27	0	0	0
118	Maint. of Mains	887	2,680	DMAINT	INT_MAINS	INT	2,446	230	0	3	1
119	Maintenance of Compressor Station Equip	888	-	DMAINT	-	EXT	-	-	-	-	-
120	Maint. of Meas. and Reg. Station Equip. - General	889	-	DMAINT	-	EXT	-	-	-	-	-
121	Maintenance of Services	892	1,513	DMAINT	SERVS	EXT	1,220	285	0	6	2
122	Maintenance of Meters and House Regulators	893	551	DMAINT	INT_MTRHR	INT	403	128	1	12	7
123	Maintenance of Other Equipment	894	243	DMAINT	INT_D376_379	INT	222	21	0	0	0
124	Subtotal - Maintenance Expense		6,033	-			5,210	785	1	25	12
125	Subtotal - Distribution Expense		34,571	-			28,715	5,266	21	358	210
126	**OPERATING AND MAINTENANCE EXPENSES**		34,571	-			28,715	5,266	21	358	210

Cause No. 45468

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

Line		ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE *($000)*	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 210 - Residential Sales Service *($000)*	Rate 220/225 - General & School/ Government Transportation Service *($000)*	Rate 240 - Interruptible Sales Service *($000)*	Rate 245 - Large General Transportation Service *($000)*	Rate 260 - Large Volume Transportation Service *($000)*
127	E	**CUSTOMER ACCOUNTS AND SERVICE EXPENSE**										
128		**Customer Accounts Expense**										
129		Supervision	901	314	-	INT_CUSTACCT	INT	286	27	0	1	0
130		Meter Reading Expenses	902	2,235	CUSTACCT	MTREAD	EXT	2,040	191	0	3	1
131		Customer Billing and Accounting	903	6,809	CUSTACCT	ACT_903	EXT	6,205	564	0	29	10
132		Uncollectible Accounts	904	2,135	CUSTACCT	UNCOLLECT	EXT	1,921	209	-	6	-
133		Miscellaneous Customer Accounts Expenses	905	817	-	INT_CUSTACCT	INT	743	71	0	3	1
134		Subtotal - Customer Accounts Expense		12,311	-			11,195	1,062	1	41	12
135		**Customer Service & Information Expense**										
136		Customer Assistance Expenses	908	216	-	ACT_908	EXT	66	85	0	32	32
137		Informational & Instructional Advertising	909	49	-	CUST	EXT	45	4	0	0	0
138		Misc. Customer Service & Informational	910	119	-	CUST	EXT	109	10	0	0	0
139		Demonstration and Selling Expenses	912	459	-	ACT_912	EXT	145	67	0	122	125
140		All Other	913	5,446	-	ACT_913	EXT	4,982	464	-	-	-
141		Subtotal - Customer Service & Information Expense		6,289	-			5,347	630	0	155	157
142		**Sales Expense**										
143		Total Miscellaneous Sales Expenses	916	36	-	ACT_916	EXT	-	-	-	18	18
144		Subtotal - Sales Expense		36	-			-	-	-	18	18
145		**ACCOUNTS AND SERVICE EXPENSE**		18,636	-			16,542	1,692	1	213	187
146	F	**ADMINISTRATIVE AND GENERAL EXPENSE**										
147		Administrative and General Salaries	920	12,721	-	INT_LABOR	INT	10,329	2,080	8	184	120
148		Office Supplies and Expenses	921	6,267	-	INT_LABOR	INT	5,089	1,024	4	91	59
149		Outside Services Employed	923	(787)	-	INT_PLT_OM	INT	(656)	(112)	(0)	(9)	(10)
150		Injuries and Damages	925	2,400	-	INT_LABOR	INT	1,949	392	2	35	23
151		Vectren Corporate Administrative Expenses Allocation	923	2,090	-	INT_PLT_OM	INT	1,741	298	1	24	27
152		Property Insurance	924	446	-	INT_TOTPLT	INT	363	69	0	5	8
153		Injuries and Damages	925	2,175	-	INT_LABOR	INT	1,766	356	1	31	21
154		Employee Pensions and Benefits	926	14	-	INT_LABOR	INT	11	2	0	0	0
155		Regulatory Commission Expenses	928	396	-	INT_PLT_OM	INT	330	57	0	4	5
156		Rents	931	21	-	INT_PLT_OM	INT	18	3	0	0	0
157		Miscellaneous General Expenses	930.2	1,021	-	INT_PLT_OM	INT	850	146	0	12	13
158		Maintenance of General Plant	932 (935)	531	-	INT_GEN_PLT	INT	432	84	0	7	8
159		Subtotal - Administrative and General Expense		27,295	-			22,221	4,399	17	384	274
160		**ADMINISTRATIVE AND GENERAL EXPENSE**		27,295	-			22,221	4,399	17	384	274

Cause No. 45468

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

Line	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE *($000)*	INTERNAL ALLOCATOR REFERENCE	ALLOCATOR	INT/EXT ALLOCATOR	Rate 210 - Residential Sales Service *($000)*	Rate 220/225 - General & School/ Government Transportation Service *($000)*	Rate 240 - Interruptible Sales Service *($000)*	Rate 245 - Large General Transportation Service *($000)*	Rate 260 - Large Volume Transportation Service *($000)*
161	G **DEPRECIATION AND AMORTIZATION EXPENSE**										
162	**Intangible Plant**										
163	Organizational Expense	301	-	-	INT_PLT_OM	INT	-	-	-	-	-
164	Franchise & Consents	302	-	-	INT_PLT_OM	INT	-	-	-	-	-
165	Miscellaneous Intangible Plant	303	3,032	-	INT_ACCT-303	INT	2,503	483	1	25	19
166	Miscellaneous Intangible Plant - 15 Year	303.15	0	-	INT_ACCT-303.15	INT	0	0	0	0	0
167	Miscellaneous Intangible Plant - 12 Year	303.12	376	-	INT_RevReq	INT	303	66	0	3	3
168	Miscellaneous Intangible Plant - Fully Depr	303.99	1,325	-	INT_ACCT-303	INT	1,094	211	1	11	8
169	Subtotal - Intangible Plant		4,732	-			3,900	760	2	40	30
170	**Distribution Plant**										
171	Land	374.1	-	-	INT_D376_379	INT	-	-	-	-	-
172	Land Rights	374.2	85	-	INT_D376_379	INT	77	7	0	0	0
173	Structures & Improvements	375	14	-	INT_D376_379	INT	13	1	0	0	0
174	Mains (High Pressure)	376	2,607	-	CUST_HP	EXT	2,380	223	0	3	1
175	Mains (Low/Medium Pressure)	376	7,717	-	CUST_LowMed	EXT	7,044	661	1	9	2
176	Compressor Station Equip	377	-	-	-	EXT	-	-	-	-	-
177	Compressor Station Equip-New Rate	377.1	-	-	-	EXT	-	-	-	-	-
178	Meas & Reg Station Eq-Gen	378	-	-	-	EXT	-	-	-	-	-
179	Meas & Reg Station Eq-City Gate	379	-	-	-	EXT	-	-	-	-	-
180	Services	380	40,239	-	SERVS	EXT	32,441	7,585	8	147	59
181	Meters	381	5,244	-	MTRS	EXT	3,829	1,213	7	120	75
182	Meters-ERTs	381.1	5,534	-	MTRS	EXT	4,041	1,280	7	127	79
183	Meter Installations	382	460	-	MTRS	EXT	336	106	1	11	7
184	House Regulators	383	0	-	AC_383	EXT	0	0	0	0	0
185	House Regulator Install	384	425	-	AC_383	EXT	316	99	0	8	3
186	Indus Meas & Reg St Equip	385	28	-	AC_385	EXT	-	-	-	8	20
187	Other Equipment	387	-	-	INT_D376_379	INT	-	-	-	-	-
188	Subtotal - Distribution Plant		62,353	-			50,476	11,176	24	432	245
		385									
189	**General Plant**										
190	Land and Land Rights	389.1	-	-	INT_TD_PLT	INT	-	-	-	-	-
191	Structures & Improvements	390	720	-	INT_TD_PLT	INT	586	111	0	9	14
192	Electronic Equipment	391.1	163	-	INT_TD_PLT	INT	133	25	0	2	3
193	Furniture & Fixtures	391.2	184	-	INT_LABOR	INT	149	30	0	3	2
194	Automobiles	392.1	-	-	INT_LABOR	INT	-	-	-	-	-
195	Light Trucks	392.2	-	-	INT_LABOR	INT	-	-	-	-	-
196	Trailers	392.3	-	-	INT_LABOR	INT	-	-	-	-	-
197	Heavy Trucks	392.4	-	-	INT_LABOR	INT	-	-	-	-	-
198	Stores Equipment	393	-	-	INT_LABOR	INT	-	-	-	-	-
199	Stores Equipment-New Rate	393.1	-	-	INT_LABOR	INT	-	-	-	-	-
200	Tools, Shop & Garage Equip	394	300	-	INT_LABOR	INT	243	49	0	4	3
201	Laboratory Equipment	395	24	-	INT_LABOR	INT	19	4	0	0	0
202	Power Operated Equipment	396	-	-	INT_TD_PLT	INT	-	-	-	-	-
203	Power Operated Equipment - New Rate	396.1	25	-	INT_TD_PLT	INT	20	4	0	0	0
204	Communication Equipment	397	330	-	INT_TD_PLT	INT	269	51	0	4	6
205	Miscellaneous Equipment	398	29	-	INT_TD_PLT	INT	24	5	0	0	1
206	Subtotal - General Plant		1,776	-			1,444	279	1	23	29
207	**Amortization Expense**										
208	Amortization of CSIA Program 20% Deferral		7,234	-	TDSICALLOC	EXT	1,969	5,035	15	83	132
209	Amortizatoin of CSIA Program Expense		789	-	INT_TOTPLT	INT	643	122	0	9	14
210	Amortization of BS/CI Program Expense		550	-	INT_D376_380	INT	502	47	0	1	0
211	Other Adjustments		-	-	INT_TOTPLT	INT	-	-	-	-	-
212	Subtotal - Amortization Expense			-			3,114	5,204	16	93	147
213	**DEPRECIATION AND AMORTIZATION EXPENSE**		77,434	-			58,934	17,418	43	587	451

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214	H TAXES										
215	**Taxes Other Than Income & Revenue**										
216	Property Taxes	408.1	7,717	-	INT_TOTPLT	INT	6,287	1,194	2	92	141
217	Subtotal - Taxes Other Than Income		7,717	-			6,287	1,194	2	92	141
218	**Income & Revenue Taxes**										
219	Revenue Taxes	408.1	2,983	-	TOTREV	EXT	2,042	741	9	68	124
220	State Income Taxes	408.1	1,115	-	INT_RTBASE	INT	927	175	0	7	5
221	Federal Income Taxes	409.1	(1,659)	-	INT_RTBASE	INT	(1,380)	(260)	(1)	(11)	(8)
222	Deferred Income Taxes	411.1	2,440	-	INT_RTBASE	INT	2,029	382	1	16	11
223	Subtotal - Income Taxes		4,879	-			3,618	1,038	10	80	132
224	**TOTAL TAXES**		12,595	-			9,905	2,232	12	172	274
225	I REVENUES										
226	Retail Revenue	48x	120,774	-	BASEREV	EXT	82,654	24,398	271	4,763	8,689
227	Gas Cost Revenue	48x	-	-	-	EXT	-	-	-	-	-
228	Forfeited Discounts	487	1,243	-	LT_FEES	EXT	988	219	1	17	19
229	Misc Service Revenue	488	549	-	MISCREV	EXT	383	159	0	3	4
230	Interdepartmental Sales	495	-	-	BASEREV	EXT	-	-	-	-	-
231	Rent from Property	495	-	-	INT_RTBASE	INT	-	-	-	-	-
232	Special Contracts		2,353	-	INT_RevReq	INT	1,899	414	1	22	17
233	Subtotal -Revenue		124,920	-			85,923	25,191	273	4,804	8,729
234	**TOTAL REVENUES**		124,920	-			85,923	25,191	273	4,804	8,729
235	**NET INCOME**		(45,611)	-			(50,395)	(5,817)	178	3,088	7,333

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236 J	**LABOR BALANCE**										
237	**Distribution Expenses**										
238	Operation Supervision and Engineering	870	1,550	-	INT_DISTEXP	INT	1,277	243	1	18	11
239	Mains and Services Expenses	874	867	-	INT_D376_380	INT	791	74	0	1	0
240	Meas. and Regulating Station Expenses - General	875	-	-	-	EXT	-	-	-	-	-
241	Removing and Resetting Meters	878	3,994	-	MTRS	EXT	2,916	924	5	91	57
242	Customer Installation Expenses	879	3,746	-	INT_MTRHR	INT	2,741	867	5	83	50
243	Other Expenses	880	2,581	-	INT_DISTEXP	INT	2,126	405	2	30	18
244	Rents	881	-	-	INT_DISTEXP	INT	-	-	-	-	-
245	Subtotal - Operating Expense		12,738	-			9,852	2,514	13	224	136
246	Maint. Supervision and Engineering	885	640	-	INT_DMAINT	INT	553	83	0	3	1
247	Maint. of Structures and Improvements	886	14	-	INT_D376_379	INT	13	1	0	0	0
248	Maint. of Mains	887	586	-	INT_MAINS	INT	535	50	0	1	0
249	Maintenance of Compressor Station Equip	888	-	-	-	EXT	-	-	-	-	-
250	Maint. of Meas. and Reg. Station Equip. - General	889	-	-	-	EXT	-	-	-	-	-
251	Maintenance of Services	892	1,218	-	SERVS	EXT	982	230	0	4	2
252	Maintenance of Meters and House Regulators	893	358	-	INT_MTRHR	INT	262	83	0	8	5
253	Maintenance of Other Equipment	894	106	-	INT_D376_379	INT	96	9	0	0	0
254	Subtotal - Maintenance Expense		2,922	-			2,441	456	1	16	8
255	Subtotal - Distribution Expense		15,660	-			12,293	2,970	14	240	144
256	**OPERATING AND MAINTENANCE EXPENSES**										
257	**CUSTOMER ACCOUNTS AND SERVICE EXPENSE**										
258	**Customer Accounts Expense**										
259	Supervision	901	303	-	INT_CUSTACCT	INT	276	26	0	1	0
260	Meter Reading Expenses	902	1,689	-	MTREAD	EXT	1,542	145	0	2	1
261	Customer Billing and Accounting	903	3,283	-	ACT_903	EXT	2,992	272	0	14	5
262	Uncollectible Accounts	904	-	-	UNCOLLECT	EXT	-	-	-	-	-
263	Miscellaneous Customer Accounts Expenses	905	447	-	INT_CUSTACCT	INT	406	39	0	1	0
264	Subtotal - Customer Accounts Expense		5,722	-			5,215	482	0	18	6
265	**Customer Service & Information Expense**										
266	Customer Assistance Expenses	908	211	-	ACT_908	EXT	65	83	0	32	32
267	Informational & Instructional Advertising	909	-	-	CUST	EXT	-	-	-	-	-
268	Misc. Customer Service & Informational	910	35	-	CUST	EXT	32	3	0	0	0
269	Demonstration and Selling Expenses	912	89	-	ACT_912	EXT	28	13	0	24	24
270	All Other	913	-	-	ACT_913	EXT	-	-	-	-	-
271	Subtotal - Customer Service & Information Expense		334	-			125	99	0	55	56
272	**Sales Expense**										
273	Total Miscellaneous Sales Expenses	916	-	-	ACT_916	EXT	-	-	-	-	-
274	Subtotal - Sales Expense		-	-			-	-	-	-	-
275	**ACCOUNTS AND SERVICE EXPENSE**		6,056	-			5,340	580	0	74	62
276	**TOTAL O&M LABOR EXPENSE**		**21,716**	**LABOR**			**17,633**	**3,550**	**14**	**314**	**205**

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Vectren North Gas COSS Model
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277	K **REVENUE REQUIREMENT SUMMARY**										
278	**PLANT IN SERVICE**										
279	Intangible Plant		90,967	-			75,391	14,235	38	745	558
280	Manufactured Gas Production		-	-			-	-	-	-	-
281	Underground Storage Plant		-	-			-	-	-	-	-
282	Transmission Plant		-	-			-	-	-	-	-
283	Distribution Plant		1,728,044	-			1,406,759	266,807	531	20,934	33,014
284	General Plant		87,190	-			70,894	13,828	41	1,150	1,277
285	Subtotal - Plant in Service		1,906,201	-			1,553,043	294,869	610	22,829	34,850
286	**ACCUMULATED DEPRECIATION**										
287	Intangible Plant		(58,446)	-			(48,396)	(9,184)	(24)	(480)	(361)
288	Manufactured Gas Production		-	-			-	-	-	-	-
289	Underground Storage Plant		-	-			-	-	-	-	-
290	Transmission Plant		-	-			-	-	-	-	-
291	Distribution Plant		(1,074,380)	-			(852,881)	(173,470)	(312)	(17,062)	(30,655)
292	General Plant		(45,734)	-			(37,181)	(7,278)	(23)	(610)	(643)
293	Subtotal - Accumulated Depreciation		(1,178,560)	-			(938,458)	(189,932)	(359)	(18,152)	(31,659)
294	**OTHER RATEBASE ITEMS**		33,734	-			18,716	14,318	41	265	393
295	**TOTAL RATEBASE**		761,375	-			633,301	119,255	292	4,942	3,584
296	**RETURN ON RATEBASE**		48,119	-			40,025	7,537	18	312	227
297	**EXPENSES**										
298	Other Gas Supply		-	-			-	-	-	-	-
299	Manufactured Gas Production		-	-			-	-	-	-	-
300	Stored Gas Expenses		-	-			-	-	-	-	-
301	Transmission Expenses		-	-			-	-	-	-	-
302	Distribution Expenses		34,571	-			28,715	5,266	21	358	210
303	Customer Accounts Expense		12,311	-			11,195	1,062	1	41	12
304	Customer Service & Information Expense		6,289	-			5,347	630	0	155	157
305	Sales Expense		36	-			-	-	-	18	18
306	Administrative and General Expense		27,295	-			22,221	4,399	17	384	274
307	Depreciation and Amortization Expense		77,434	-			58,934	17,418	43	587	451
308	Taxes Other Than Income & Rev		7,717	-			6,287	1,194	2	92	141
309	Income and Revenue Taxes		4,879	-			3,618	1,038	10	80	132
310	Subtotal - Expenses		170,531	-			136,318	31,007	94	1,716	1,395
311	**REVENUE**		124,920	-			85,923	25,191	273	4,804	8,729
312	**INCOME**		(45,611)	-			(50,395)	(5,817)	178	3,088	7,333
313	**REVENUE DEFICIENCY (EXCESS)**		93,730				90,419	13,354	(160)	(2,776)	(7,107)
314	**REVENUE GROSS UP**										
315	Federal Income Tax		1,916	-	INT_RTBase	INT	1,594	300	1	12	9
316	State Income Tax		477	-	INT_RTBase	INT	397	75	0	3	2
317	IURT and IURC Fee		110	-	INT_RevReq	INT	89	19	0	1	1
318	Uncollectible		87	-	UNCOLLECT	EXT	78	9	-	0	-
319	Subtotal - Revenue Gross Up		2,591	-			2,158	403	1	17	12
320	**GROSS REVENUE DEFICIENCY (EXCESS)**		96,321	-			92,578	13,756	(159)	(2,759)	(7,095)
321	**TOTAL REVENUE REQUIREMENT**		221,240	RevReq			178,501	38,947	114	2,045	1,634