FILED
March 31, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA GAS COMPANY, INC. D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN NORTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, (3) APPROVAL OF A NEW TAX SAVINGS CREDIT RIDER, (4) APPROVAL OF VECTREN NORTH'S ENERGY EFFICIENCY PORTFOLIO OF PROGRAMS AND AUTHORITY TO EXTEND PETITIONER'S ENERGY EFFICIENCY RIDER ("EER"), INCLUDING THE DECOUPLING MECHANISM EFFECTUATED THROUGH THE EER, (5) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO GAS PLANT IN SERVICE, (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, AND (7) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO WHICH VECTREN NORTH WOULD CONTINUE ITS CUSTOMER BILL ASSISTANCE PROGRAMS.	)	**CAUSE NO. 45468**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S

PUBLIC'S EXHIBIT NO. 7 – TESTIMONY OF OUCC WITNESS BRIEN R. KRIEGER

With the current requirement that all staff work from home, signatures for affirmations are not available at this time.

March 31, 2021

Respectfully submitted,

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INDIANA GAS COMPANY, INC.
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
CAUSE NO. 45468
TESTIMONY OF OUCC WITNESS BRIEN R. KRIEGER

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Brien R. Krieger and my business address is 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a utility analyst in the Natural Gas Division. For a summary of my educational and professional experience and general preparation for this case, please see Appendix BRK-1.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss my review and analysis of Indiana Gas Company, Inc.'s d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner" or "Vectren North") cost of service study ("COSS"), proposed rate design, tariffs, and monthly customer charge.

Q: Please summarize your recommendations concerning Petitioner's COSS, rate design, monthly customer charge, and tariff.

A: My recommendations are as follows.

1. Redefine the Low Pressure/Medium Pressure Distribution Plant-in-Service assets (FERC 376) of Commodity and Demand proportions to 49.2% and 50.8% respectively. Allocate Commodity with annual volumes and allocate Demand with design day demand using these two allocators defined by those customers served by the Low Pressure/Medium Pressure Distribution system.

2. For Rate 210 - Residential Sales Service, reduce the proposed monthly customer charge from $21.50 to $12.00.

3. Approve Petitioner's proposed future allocation of TDSIC and compliance costs included in the CSIA.

4. Approve Petitioner's proposed tariff language changes, including closing Rate 240 Interruptible Sales Service to new customers.

II. OVERVIEW OF ANALYSIS AND KEY TERMS

Q: Please describe the subsequent sections of your testimony and how the sections relate to each other.

A: My testimony has nine sections. The first section is a summary of recommendations, my analysis is contained within sections III through VIII, and Section IX gives the Commission specific recommendations based on sections III through VIII.

Section III is an overview of Petitioner's system and the operation of the system. It is important to visualize Petitioner's entire natural gas system and understand how the various system components work together to transport or move natural gas to all customer types from interstate pipelines. For example, large industrial customers may receive gas from high pressure larger diameter pipes while residential customers may receive gas from small plastic pipes at the end of a cul-de-sac in a residential neighborhood. The system design and its usage determine how costs should be shared or allocated to the various rate classes.

Section IV is a review of Petitioner's prior COSS and its relation to Petitioner's natural gas system. While my analysis is independent of Petitioner's prior COSS, my conclusions are supported by the prior COSS. The design of Petitioner's system and the customer mix remain similar to the prior COSS presented in Cause No. 43298, Petitioner's last rate case.

Section V is my stand-alone analysis of Petitioner's COSS for this Cause. My analysis presents Petitioner's allocation methods and why I recommend different allocation factors for Distribution assets. Section V contains my recommended changes due to Petitioner not using the Commodity function in conjunction with Demand (which Petitioner does use separately), with both functions typically used to describe the usage characteristics of natural gas pipe mains. Transmission mains and Distribution mains deliver or transport natural gas through the system for use by large volume users or small residential users, with the combination of usage characteristics being driven by both annual volumes and peak demand.

In Sections VI, VII and VIII, I present my analysis of Distribution mains and recommend COSS changes and rate design changes. My recommendations to rate design are not a function of Petitioner's COSS methodology, and the residential monthly customer charge I recommend can stand alone with the remainder of residential revenue requirements recovered in residential volumetric rates. I analyze Petitioner's proposed monthly customer charge increases versus applicable FERC accounts that I consider represent customer charges, Petitioner's proposed increased margin revenue, and customer charges of other Indiana utilities. Regardless of the COSS methodology used, my recommendations of a lower residential monthly customer charge remain. I recommend a reduced monthly customer charge more reflective of the requested margin increase and closer to the monthly customer charge of other Indiana natural gas utilities.

Q: Please define the key terms you use in your analysis.

A: I use a few key terms in my analysis of Petitioner's COSS, which are typical in the analysis of any COSS. I use the term "Commodity" to describe the use of Petitioner's assets for delivery or to transport natural gas to support throughput of natural gas to the customer. Annual Throughput, a Commodity allocator, is an allocation method to assign each rate class' usage characteristics of parts of the system and is viewed as each calendar month's usage contributing to that rate's total annual consumption.

The use of a "Design Day" is interchangeable with the use of peak daily consumption of a rate class but is not interchangeable with "Heating Degree Day Design Day." The Heating Degree Day peak design is a function of outdoor temperature, but not all peak design day loads are driven by outdoor temperature. In other words, a "heating" design day occurs when it is cold, thereby necessitating heat. A Heating Degree Day impacts residential customers much more than, for example, industrial customers, whose use is not weather-dependent.

III. <u>OVERVIEW OF PETITIONER'S SYSTEM OPERATION</u>

Q: Please describe Vectren North's system.

A: Petitioner serves Lafayette, Bloomington, Terre Haute, Huntington, Muncie, Richmond, Jeffersonville, and Columbus, Indiana. Petitioner's system reaches out to smaller Indiana cities and serves "donut" counties surrounding Marion County. In response to OUCC Data Request ("DR") 5.13, Petitioner provided a system map including city gates ("take-points") and indicated the approximate location of its top twenty-five annual volumetric customers. All ten Rate 270-Long Term Contract Service ("Rate 270") and fifteen large transportation customers in tariff Rate 260-Large Volume Service ("Rate 260") are Petitioner's top twenty-five volumetric users of natural gas.

There are approximately 45 supply-points from interstate pipelines that cross central Indiana in a north-south and east-west direction within Petitioner's service territory supplying Petitioner's integrated network system. Petitioner classifies its system in three different pressures that are assigned to different FERC accounting categories: Transmission (FERC 367), High-Pressure Distribution (FERC 376), and Medium/Low Pressure Distribution (FERC 376). Petitioner has four underground storage fields and storage equipment (FERC 350-356) and two propane plants.

Transmission and High-Pressure distribution ("HPD") mains feed the Low Pressure/Medium Pressure Distribution ("LP/MP") mains in localized cities and suburbs outside of Marion County. Vectren North's system map indicates there are no dedicated or primary feeds from Transmission mains or HPD mains to exclusively serve the large volume users. The large volume users are dispersed throughout Petitioner's natural gas system.

Q: Please describe Petitioner's operation and how it impacts your analysis of Petitioner's COSS.

A: My analysis indicates Petitioner's system's operation of its take-points, transmission mains and storage fields, both during the summer months and the winter months, are necessary for annual operation of Petitioner's system. I reach this conclusion based on my review of Petitioner's system map and Petitioner's response to my question concerning normal operations. (OUCC DR 5.14, Attachment BRK-1.) Biannually, Petitioner forecasts and develops seasonal (heating/cooling or winter/summer) take-point flow allocation tables for internal operational guidance and to determine transport customer delivery options. Petitioner's normal winter and normal summer operations utilize commodity assets of the natural gas system related to city gate, storage, and the transmission mains. Operations, especially during the summer month transmission construction period, may require atypical operational changes causing certain transmission segments or storage wells to carry additional capacity while maintenance is performed on out of service segments. This indicates the plant is used to serve all customers throughout the year.

IV. PETITIONER'S PRIOR COSS AND RATE DESIGN – CAUSE NO. 43298

Q: When did Petitioner perform its last COSS?

A: Petitioner's most recent COSS was performed in Cause No. 43298 with a rate base cutoff date of December 31, 2006.

Q: Please summarize your analysis of Petitioner's prior COSS in Cause No. 43298.

A: Petitioner classified costs into Commodity, Customer, and Demand to set the direction for what costs should be collected in the volumetric and monthly customer charges. Petitioner's COSS witness Kerry A. Heid stated:

> Commodity costs are those that vary with the volume of gas delivered to customers and are allocated based on annual volumes. Demand costs are those incurred to deliver gas to customers at certain levels and are, therefore, dependent on customer demands. These costs are allocated based on peak day demands. Customer costs are those that vary with the number of customers served and are allocated based on number of customers.

(Attachment BRK- 2, Cause No. 43298, Exhibit No. KAH-1, page 5, lines 6-11).

Petitioner used three major cost causation allocators for Transmission and Distribution: Annual Throughput, Number of Bills, and Design Day. In the present COSS, Petitioner's annual throughput has decreased for Rate 210 and increased for Rate 260. The number of customers has increased for all rate classes except for Rate 240-Interruptible

Sales Service, but the percentage of total customers remains constant for each rate class. The peak demand has decreased for Rate 210 and increased for Rate 270. Mr. Heid stated variable costs should be recovered through volumetric rates. (Attachment BRK- 3, Cause No. 43298, Exhibit No. KAH-1, page 9, lines 24-25.) I agree with Mr. Heid's assessment because more or less consumption is the cause for the variable costs, and these variable costs should be assigned to the user's quantity of natural gas consumed.

Q: How did Petitioner treat the allocation of the large Plant-in-Service FERC accounts in Cause No. 43298 as reflected in Attachment BRK- 4, Cause No. 43298, Exhibit No. KAH-2, Schedule 2, page 1 of 3?

A: For FERC accounts 350, 352, and 354 – Underground Storage, Petitioner allocated approximately 20% of Underground Storage as Commodity and all rate classes were allocated their percentage of Commodity costs based upon Annual Throughput. The remaining 80% was divided equally into two winter Sales allocators (Design Day Sales and Winter Sales) as found in Petitioner's COSS. Design Day Sales and Winter Sales do not include the rate classes for large transport customers (Rates 225, 245, and 260), only sales for residential and general classes (Rates 210 and 220).

In Cause No. 43298, all mains, including transmission, were classified into FERC 376 - Distribution Mains. Petitioner used all three classifications – Demand, Commodity, and Customer. Demand represented 30% of the costs in FERC 376 and was allocated with design day derived from heating degree days. The Commodity classification was 30% of the costs and was allocated with annual throughput. The Customer classification represented 40% of the costs and was allocated by the number of customers. There were other large Plant-in-Service accounts such as meters, services, and house regulators that were allocated directly to the rate class that the devices served.

Q: What is a zero-intercept study?

A: A zero-intercept study determines the smallest theoretical distribution mains pipe cost size based upon the size of distribution mains in plant. Some COSS practitioners assign this theoretical pipe size and associated cost to the Customer classification and allocate by the number of customers. Other practitioners do not use this method because their analysis indicates density of customers and volumes determine a minimum pipe size, and the number of customers is the relevant characteristic used to determine the pipe size installed.

Q: Did Petitioner use a zero-intercept study in Cause No. 43298 to determine the percentages used for the cost classifications: Demand, Commodity, and Customer?

A: No. A zero-intercept study was not used to determine the cost percentage assignments of distribution mains to Demand, Commodity, or Customer. My analysis indicates Mr. Heid did not use a zero-intercept study because he wanted to balance the system's characteristics based upon his observations of system design and operation, such as customer density, annual throughput, and peak demands of the system. Allocating 40% on the number of customers indicates Demand and Commodity are drivers, comprising 60% of cost causation of Petitioner's plant.

Q: What differences exist between the COSS in the present Cause and Cause No. 43298?

A: There are two major differences. The first difference is Petitioner's designation of the plant-in-service mains. In Cause No. 43298, all of Petitioner's mains were classified as Distribution mains, FERC 376. In this case, Petitioner has reclassified mains into two FERC accounts: Transmission mains (FERC 367) and Distribution mains (FERC 376). Reclassification of mains based on pressure ratings is a normal process for U.S. Pipeline Hazardous Materials Safety Administration requirements and changes the FERC account numbers. This disaggregation of transmission mains from distribution mains from a COSS perspective provides Petitioner the opportunity for different allocations between the transmission mains and the distribution mains, thus separating cost causation between the two systems. Transmission could be allocated with characteristics that define all users, or specific customers that dominate transmission. However, in Petitioner's plant there are not large industrials that dominate the transmission system. Petitioner further separates Distribution mains into High-Pressure Distribution ("HP") and Low Pressure/Medium Pressure Distribution. ("LP/MP").

In Cause No. 43298, Mr. Heid allocated all mains as 40% Customer (allocated by the number of customers), 30% as Demand (allocated with design day sales), and 30% as Commodity (allocated with winter sales). (Attachment BRK- 4, Cause No. 43298, Exhibit No. KAH-2, Schedule 2, page 1.) In this case, Mr. Feingold allocates transmission (FERC 367) as Demand with the design day allocator. Distribution (FERC 376) is classified as Demand with design day, and Customer with number of customers. (Petitioner's Exhibit No. 16, 45468_VEDN COSS Model MSFR 15 CONFIDENTIAL on Input Accounts tab.)

The proportions of cost for Demand and Customer were assigned to Distribution based on the results of Mr. Feingold's zero-intercept calculation assignment to FERC 376. He assigned approximately 50% of distribution mains as Demand (allocated with design day) and 50% as Customer (allocated on the number of customers).

Q: Please describe how these differences affect your COSS analysis for Cause No. 45468.

A: My analysis indicates Mr. Heid's and Mr. Feingold's allocation methods for the revenue requirements of Transmission and HP Distribution produce similar COSS results, with both methods assigning costs based on rate class cost causations. The two methods have similar results because Mr. Heid's method of inclusion of customer count reduces the Commodity throughput allocator so the combination of these two allocators is similar to the Demand - design day allocation used by Mr. Feingold.

However, I disagree with Mr. Feingold's allocation method for the LP/MP Distribution because he only uses Demand and Customer allocators. Using the Customer allocator with customer count, while not including the Commodity allocator with volumes, burdens residential customers because of the dominant Residential customer count (compared to Petitioner's other rate classes). By not using both Commodity and Customer allocators, the lower annual throughput of residential customers, as compared to other rate classes, is not reflected in the allocation method used for the LP/MP distribution.

Q: Does Petitioner's decision to use 82% of the costs associated with the Customer allocation cause excessive monthly customer charges in Petitioner's rate design?

A: Yes. Including the vast majority of costs associated with the Customer allocation, without prescribing which FERC accounts are solely related to providing the customer service, unnecessarily inflates the customer charge. Petitioner presumes most of the costs contained in the Customer classification should be collected in the monthly customer charge. I was unable to find any support for or explanation why 82% of the $26.20 Customer classification for Rate 210 should be collected in Petitioner's proposed residential monthly customer charge of $21.50. (Petitioner's Exhibit No. 16, Attachment RAF-2, page 5, line 48.)

Q: How do the three major allocators compare in magnitude and usage?

A: Annual Throughput, one of the major class characteristics, has increased for Rate 260-Large Volume Transportation Service with its share of annual consumption increasing by approximately 15%, while Rate 210-Residential Sales Service has decreased annual consumption by 12%. These changes to Annual Throughput indicate allocation with Commodity – Annual Throughput should be included. The Number of Customers as a percentage of total remains relatively unchanged from the last rate case. The Design Day for all rate classes remains relatively unchanged. Tables 1, 2, and 3 compare these three major allocators.

Table 1: Commodity: Annual Throughput – Therms

	Rate 210	Rate 220	Rate 225	Rate 240	Rate 245	Rate 260	Total
Cause No. 43298	440,419,036	188,292,689	6,722,047	9,099,901	73,014,095	208,672,615	926,220,384
% of Total	47.55%	20.33%	0.73%	0.98%	7.88%	22.53%	
Cause No. 45468	460,531,158	209,659,941	6,665,956	2,832,652	114,619,488	493,850,131	1,288,159,324
% of Total	35.75%	16.28%	0.52%	0.22%	8.90%	38.34%	

Table 2: Customer: Number of Customers

	Rate 210	Rate 220	Rate 225	Rate 240	Rate 245	Rate 260	Total
Cause No. 43298	506,481	48,303	458	99	550	170	556,061
% of Total	91.08%	8.69%	0.08%	0.02%	0.10%	0.03%	
Cause No. 45468	567,845	51,656	1,642	55	771	205	622,174
% of Total	91.27%	8.30%	0.26%	0.01%	0.12%	0.03%	

Table 3: Demand: Design Day Therms

	Rate 210	Rate 220	Rate 225	Rate 240	Rate 245	Rate 260	Total
Cause No. 43298	5,797,214	2,228,168	160,648	24,931	641,653	1,155,554	10,008,168
% of Total	57.92%	22.26%	1.61%	0.25%	6.41%	11.55%	
Cause No. 45468	6,785,998	2,799,443	291,900	7,071	749,125	1,742,713	12,376,251
% of Total	54.83%	22.62%	2.36%	0.06%	6.05%	14.08%	

Q: Please describe the derivation of the Design Day Allocator in Table 3.

A: Both the prior Cause and this Cause use a method to derive Design Day based upon outdoor temperature, or the heating degree day method. In my analysis I refer to this outdoor temperature derived Design Day as Heating Degree Day Design Day ("HDD Design Day") to clarify that not all Design Day peaks are driven by outdoor temperature.

Q: What is your analysis of Petitioner's use of the HDD Design Day?

A: The use of Petitioner's HDD Design Day method to determine the peak Design Day has the potential to reduce the peak demand for industrial rate classes more than actual peak demand. This is because Petitioner disaggregates base load from cold outdoor temperature-driven loads for industrial customers. Petitioner's method ignores when production load creates a peak and when the production load peak occurs. Most industrial processes are not a function of HDD, as industrial spaces need less space heating, and industrial peaks are set by operational demands. Low demand periods for industrials are typically set during annual maintenance periods.

However, the peak system demand for Vectren North is set by outdoor temperature during the winter months. This is determined by comparing the monthly throughput variations for all rate classes estimated for 2021. Rate 210 and Rate 220 monthly winter peak is approximately twelve (12) times the summer month peak, and the winter peak month for Rate 260 is approximately 1.5 times greater than its summer month. (Petitioner's Exhibit No. 16, COSS External Allocators Workpaper on Tab Incr. Winter Throughput.)

V. PETITIONER'S COST OF SERVICE STUDY

Q: Please explain the COSS allocation process Petitioner uses in this Cause.

A: Petitioner's COSS method functionalized costs by using FERC accounts, and then classified those costs as Demand, Commodity, and Customer costs to be allocated to Petitioner's specific rate class characteristics. Petitioner uses the Demand and Commodity functions for Gas Production and Underground Storage. Transmission is 100% classified as Demand and Distribution is classified as Demand and Customer.

Petitioner's Plant-in-Service, allocated with rate class characteristics, is predominantly Underground Storage Plant (FERC 350-356), Transmission Mains (FERC 367), and Distribution Mains (FERC 376). The Distribution Mains are separated into two pressure classes: HP Distribution, and LP/MP Distribution.

Petitioner uses allocators to represent customer usage characteristics such as: annual throughput – a Commodity allocator, peak winter demand – a Demand allocator, incremental winter throughput – another Demand allocator, number of customers – a Customer allocator, internal records data, or internal labor accounts. Specific FERC accounts such as meters or services were directly assigned to the responsible rate class in this Cause.

Q: What revenue increase and Non-Gas margin increase does Petitioner propose?

A: Petitioner is requesting a total operating revenue increase of 3.38% with a total Non-Gas ("margin") increase of 5.79%. (Petitioner's Exhibit No. 16, page 45, Table 4 and page 44, Table 2, respectively.) The final cost allocations per rate class are also in these tables. Rate 220/225 General Sales and Government/Schools Transport have the largest margin increase of 7.43% and Rate 210 Residential Sales Service's proposed increase is 6.85%. The two remaining transportation rates and the one interruptible service rate have lower increases. Petitioner proposes a reduction in margin for Rate 270 Long-Term Contract Service. Rate 270 comprises individual customer contracts with varying margin changes, with the entire rate proposed as a decrease of 17.53%. Rate 270 is the only rate class with a proposed margin decrease.

Q: Do you disagree with the classification method and allocation of Gas Production and Underground Storage?

A: No. Petitioner classifies these two functions with Commodity and Demand. Gas Production includes the accounts associated with the gas production from the two propane production plants, is functionalized as Demand, and allocated with DESDAY. Commodity is also used in Gas Production, but Commodity represents the natural gas costs associated with collection through the GCA.

Underground Storage accounts are associated with the injection of natural gas into underground storage and removal of the natural gas for use on Petitioner's system. Commodity uses the incremental winter allocator and Demand uses the DESDAY allocator for the majority of the Underground Storage accounts. I do not disagree with Petitioner's allocation method because these functional categories are normally used to supply natural gas during the peak demand periods and for cold winter months characterized by the incremental winter allocation method.

Q: Do you disagree with the classification method and allocation of Transmission?

A: No. Petitioner's COSS allocated Transmission as Demand using one allocator, the design day allocator - DESDAY. Demand allocation with DESDAY is appropriate because approximately 75% of the winter peak month is driven by all rate classes, with the exception of Rate 260. Peak system demand is set by all rates, except for Rate 260, and is driven by outdoor cold temperatures or HDD.

Rate 260 adds to the winter peak loads but has less variation between summer month demands and winter demands. The peak demand setting rates (Rates 210, 220, 225, 240, and 245) vary between lower demand summer months and peak demands of winter months. These same five rate classes are responsible for 78% of the annual throughput; during their lowest four consumption months in summer, these rate classes represent almost 40% of the monthly throughput. (Petitioner's Exhibit No. 16, COSS External Allocators Workpaper on Incr. Winter Throughput tab.)

Q: Do you disagree with the classification method and allocation of the High-Pressure portion of Distribution (FERC 376)?

A: No.

Q: Do you disagree with the classification method and allocation of the Low/Medium Pressure portion of (FERC 376)?

A: Yes. Petitioner does not include the Commodity classification for allocation. Petitioner only uses Demand and Customer. Ignoring Commodity presumes all costs are a function of outdoor temperature and all remaining costs are a direct function of the number of customers. Neither of these costs indicate the natural gas utility has any control of system design costs or overhead costs. The customer controls the decision to procure natural gas, which includes expenses covering a service line, meter, house regulator, billing, and service maintenance.

VI. ANALYSIS LP/MP PRESSURE DISTRIBUTION

Q: Do you have concerns about the use of the design day allocator to represent peak demand for the customer on the LP/MP Distribution system?

A: No. My analysis indicates the Design Day ("DESDAY") allocator represents the monthly variation of summer to winter months. DESDAY and its associated distribution allocators (DESDAY_LowMed), defined by removing customers not served by the distribution system, are calculated as a function of outside temperature or heating degree days ("HDD"). Petitioner's rate class consumption characteristics are defined with the DESDAY allocator as evidenced by Petitioner's 2021 monthly consumption estimates provided in the External tab of Petitioner's Exhibit No. 16, COSS External Allocators Workpaper.

Q: Do you have concerns about the use of Customer to represent approximately 82% of costs of the LP/MP Distribution system?

A: Yes. Petitioner derives the Customer costs from a zero-intercept method of defining distribution main costs (FERC 376) as either a function of peak demand or customer costs. The Customer cost of FERC 376 represents 49.2% of distribution mains. To that portion of FERC 376, Mr. Feingold adds services, meters, and house regulators and then adds costs of General Plant (FERC 389-398), Other Rate Base Items, Customer Accounts and Service

Expense (FERC 901-905) and Administrative and General Expense (FERC 920-932). (Petitioner's Exhibit No. 16, Attachment RAF-4.)

Customer costs are defined more narrowly and represent direct customer costs associated with meters, service drops, meter reading, customer records and collections, and billing. The other costs are better allocated as a function of throughput because these costs can be attributed to maintaining the system and are a normal cost for the utility to do business.

The allocation of FERC 376 with only Customer and Demand also overlooks the fact that distribution main pipe has two distinct costs that are a function of pipe diameter, and all the costs associated with installing a pipe length in the ground. These two functions should be allocated as Demand and as Commodity.

Q: How does pipe size impact allocation costs?

A: The volumetric delivery of natural gas is a function of the area of the pipe's circular cross section, or the equation "pi multiplied by radius squared." For example, doubling the internal radius of a pipe increases its capacity by four times. A larger pipe diameter ensures adequate peak flow at a given pressure. When pressure increases, more natural gas volumes can be delivered. Larger pipe diameters also allow for more peak demands at an incrementally smaller cost of the total cost of the main, since the total costs do not vary much with increased pipe size. This excess pipe diameter cost is best represented as Demand. Petitioner calculated this Demand cost through a zero-intercept method as 50.8% of FERC 376, but Petitioner's Demand component represents all remaining costs of a theoretical minimum sized pipe main, not just the additional pipe diameter.

Q: What costs are not related to pipe size?

A: Construction costs not related to pipe size include planning, surveying, excavation, hauling, pipe bed preparation, unloading and stringing of pipe, inspections, and backfill. These costs are required regardless of pipe diameter, so those customers using the largest volumetric annual throughput should pay for the majority of construction costs. The additional minor cost of a pipe main is the additional size or pipe diameter to handle the peak coincident demands based upon Petitioner's design parameters and operation for customer requirements. These costs are Demand costs. The bulk of the remaining costs are based upon Petitioner providing natural gas through the mains year-round. These costs are best represented by Commodity and allocated with a throughput allocator.

Q: How does throughput represent cost causation more accurately?

A: Throughput represents all remaining costs of Distribution mains, not just the incremental design day volumes available through larger pipe diameters. The extra costs of providing additional peak capacity are lower than the average costs of providing baseline throughput capacity. A gas distribution system would not exist if only short duration peak demand related costs were collected. The allocation of transmission cost on Annual Throughput is the monthly cost causation for Distribution, essential to the collection of monthly revenue.

Q: Is Petitioner's use of Customer – Number of Customers for the Distribution classification appropriate?

A: No. The utility is designed for use and operation every day of the year and was planned to serve high volumetric densities. The number of customers does not determine the volumetric density, which is apparent in the large volume rate classes. Ignoring Commodity or annual throughput ignores Petitioner's system design and operation. Using Peak demand or Petitioner's DESDAY allocator, which seldom occurs, presumes the entirety of Plant-in-Service costs associated with Distribution are a direct function of increased pipe diameter. The inclusion of Customer classification allocated with the number of customers does not accurately represent the individual customer's causation of distribution costs. More specifically, allocation of LP/MP distribution (FERC 376) disregards the variation of consumption with the pipe, volumetric density, and the actual design, whether the distribution is for a compact downtown or the distant outreaches of a rural extension. I do not recommend using number of customers for LP/MP distribution. Furthermore, the assignment of a monthly customer charge - which is collected on number of customers - is best calculated by assigning specific accounts for collection on a monthly basis and per customer, and not based on the COSS.

Q: Please explain why Customer classification should be changed to Commodity classification.

A: Many of the costs included in Petitioner's Distribution function, Customer classification contained in Petitioner's Exhibit No. 16, Attachment RAF-4 are previously incurred and overhead costs, which are simply the cost of doing business for any business enterprise. Some of these costs that should be excluded from the Customer classification are contained in General Plant (FERC 389-398), Other Rate Base Items, Customer Accounts and Service Expense (FERC 901-905) and Administrative and General Expense (FERC 920-932). These costs may not vary with usage, but that does not mean they should be assigned to the Customer classification and collected in a fixed monthly customer charge. Many of the costs of these accounts are controlled by Petitioner's system and administrative design and should not be placed in a customer's unavoidable fixed monthly charge. These costs should be included in Commodity and allocated with throughput.

Q: Are there any other COSS resources that discuss not using the Customer classification?

A: Yes. The following is an excerpt from Principles of Public Utility Rates, Second Addition, pp. 491-492 by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen: "for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible[.]"

Mr. Bonbright's analysis of what customer costs consist of includes both operating and capital costs, but he stated that customer costs are not associated with power consumption. (*Id.* at 490.) In general, he stated customer costs include a minimum service, metering, accounting, and other costs of connecting one customer. Based on my review of Bonbright's Customer Cost section, customer costs do not extend to the entirety of distribution plant-in-service, billing systems, or distribution operations.

VII. OUCC ADJUSTMENTS TO DISTRIBUTION IN PETITIONER'S COSS

Q: What are your changes to Petitioner's COSS?

A: I recommend only COSS allocation changes to Low/Medium Pressure Distribution. I recommend allocating LP/MP Distribution (FERC 376) with Commodity and Demand. I recommend the Customer classification only represent direct costs and these direct Customer costs would be collected in the Monthly Customer Charge. For the LP/MP Distribution, I agree with Petitioner's removal of customers that are not served from the LP/MP Distribution. For all these reasons, I recommend the addition of Commodity – throughput and the removal of Customer – number of customers, but still using the percentages for two classifications derived from Petitioner's zero-intercept method.

I recommend allocating the LP/MP Distribution portion of FERC 376 in the same proportions as Petitioner but recommend changing the Customer classification to Commodity classification. This changes the allocator from customer count to customer volumes for the LP/MP distribution system. Demand should remain 50.8% and changing Customer to Commodity should remain as 49.2% for FERC 376. Table 4 represents my allocation swap from Petitioner's "Customer allocated with customer count" to my recommendation of Commodity allocated with volumes. Table 5 is the comparison of LP/MP distribution plant-in-service (FERC 376), undepreciated, for my recommended allocation and Petitioner's allocation. My allocation method removes approximately $250,000 of plant-in-service from Rate 210 because this rate has lower percentages of volumes than the other rate classes when compared to percentages based upon customer count.

Table 4: OUCC COSS Adjustments to LP/MP Distribution of FERC 376 ($000)

	Rate 210	Rate 220/225	Rate 240	Rate 245	Rate 260	Total
Demand (50.8%) – LP/MP Design Day	258,361.8	117,696.0	269.2	26,942.1	51,329.9	454,599.0
Commodity (49.2%) – LP/MP Total Volumes	157,651.5	74,053.9	969.7	39,237.2	169,057.4	440,969.7
Total	416,013.3	191,749.9	1,238.9	66,179.3	220,387.3	895,568.7

Table 5: Total LP/MP Distribution Allocation Comparison of FERC 376

($000)

	Rate 210	Rate 220/225	Rate 240	Rate 245	Rate 260	Total
Petitioner	660,861.3	155,475.1	308.2	27,468.8	51,455.3	895,568.7
%	73.8%	17.4%	0.0%	3.1%	5.7%	
OUCC	416,013.3	191,749.9	1,238.9	66,179.3	220,387.3	895,568.7
%	46.5%	21.4%	0.1%	7.4%	24.6%	
Difference $	244,848.0	(36,274.8)	(930.7)	(38,710.5)	(168,932.0)	$0

Q: Do you recommend Petitioner update the proposed COSS?

A: Yes. Petitioner's COSS software operates with interdependent data and calculations embedded in the software, and other data from Petitioner is not included in that software. My COSS recommendations change the allocations for a Plant-in-Service LP/MP Distribution (FERC 376). These allocation changes affect downstream allocators because of the hierarchy and interdependency of allocators in the COSS software.

For Phase 1, Petitioner proposes updates to rate base and capital structure through June 30, 2021 that will be both actual and as a result of the Commission's Final Order. The OUCC's case-in-chief recommends changes, other than those in my testimony, that are inputs to the COSS model such as return on equity, depreciation, capital assets, and expenses. If any of the OUCC's adjustments to accounting, depreciation, authorized return, or COSS allocations are approved in the Commission's Order for this Cause, then I recommend Vectren North rerun the COSS using the outcome of the Final Order in this Cause.

In Phase 2 Petitioner proposes updates to the entire revenue requirement based upon actual revenues and expenses through December 31, 2021 with the Phase 2 implementation of rates. OUCC witness Mark Grosskopf opposes this proposal. However, if Petitioner's Phase 2 proposal is approved, then I recommend Petitioner use the COSS design from the Commission's Final Order for this Cause and provide a revenue proof with updated billing determinants for any revenues adjusted in Phase 2.

VIII. RATE DESIGN: SUBSIDIES, REVENUE SHIFTING, MONTHLY CUSTOMER CHARGES, TARIFF CHANGES, AND FUTURE TDSIC AND CSIA ALLOCATIONS

A. Subsidies

Q: Does Petitioner propose to mitigate subsidies for all rate classes through its proposed rate design?

A: Yes. Petitioner mitigates subsidies to all rate classes included in the COSS model. Rate 270 was not included in the model and no subsidy comparison for Rate 270 was included in Petitioner's Exhibit No. 16, Table 3 Comparison of Revenue (Subsidy/Excess by Rate Class). Some Rate 270 Long-Term Contract Service contracts will receive a rate increase because these contracts are tied to rate changes of Rate 260 (Petitioner's Exhibit No. 16, page 45, lines 13-15.) 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. (*Id.,* lines 15-17.)

Q: What changes do you recommend to Petitioner's subsidy proposal?

A: I have no changes to Petitioner's proposed subsidy for the rate classes. Petitioner's proposed subsidies are gradual and move rate classes closer to the COSS results.

B. Monthly Customer Charges

1. Rate 210 – Residential Sales Service

Q: What monthly customer charge does Petitioner propose for Rate 210 – Residential Service?

A: Petitioner proposes to increase the residential customer charge from $11.25 to $21.50.

Q: Is the proposed residential monthly customer charge reasonable as compared to Petitioner's proposed margin increase?

A: No. The proposed residential monthly customer charge increase is 91% as compared to Petitioner's proposed total margin increase for all rate classes of 5.79%. The proposed monthly customer charge of $21.50 represents approximately 42.5% of the total revenue requirement for Rate 210. (Petitioner's Exhibit No. 16, Attachment RAF-2, page 4, line 27 and Attachment RAF-4, page 8, line 321.) The $21.50 monthly customer charge also represents 47.8% of Petitioner's proposed total Non-Gas revenues. (Petitioner's Exhibit No. 16, Attachment RAF-3, line 6 and Attachment RAF-4, line 321.) Petitioner's proposed monthly customer charge for any residential customer using 40 therms per month or less is approximately 50% of the total bill including the GCA. (Petitioner's Exhibit No. 18, Schedule E-5, page 1, Typical Bill Comparison – Residential.)

These comparisons indicate residential customers would lose the ability to control costs based upon their usage, while Petitioner's risk of not meeting the Rate 210 revenue requirement would be substantially reduced.

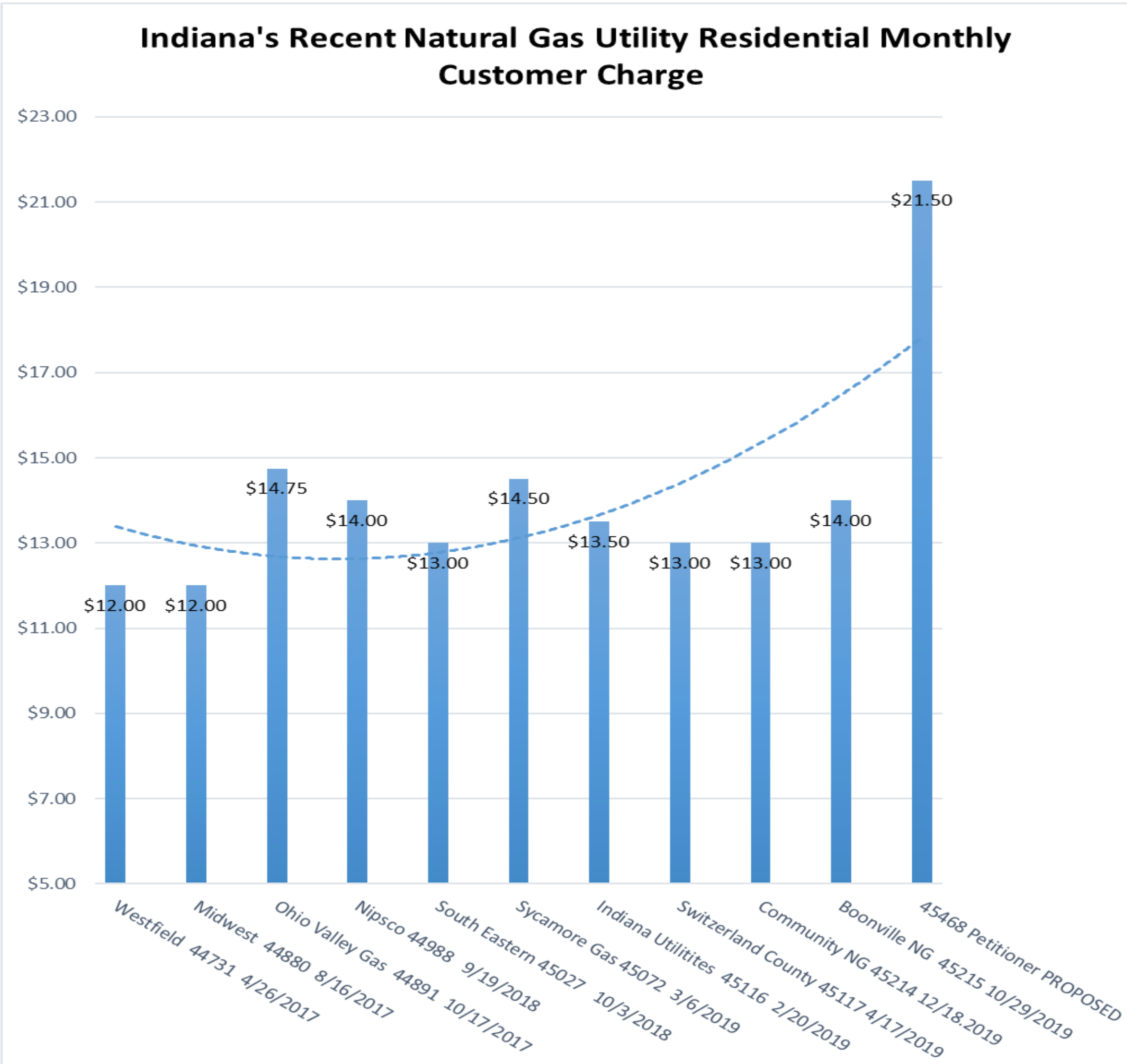
Q: Are there other monthly charges related to increases in rate base?

A: Yes. Petitioner has a Compliance and System Improvement Adjustment ("CSIA") and expects to file additional CSIA trackers subsequent to the 2021 test year. These additional charges have the potential not to be reflected in volumetric rates, and therefore would further reduce Petitioner's financial risk, and conversely, reduce customers' ability to control costs related to gas usage. Petitioner also has a decoupling mechanism which reduces Petitioner's financial risk and ensures collection of all margin costs. Low volume customers are affected the most by the imposition of a high monthly customer charge because they have less financial control over a larger percentage of their bill. Margin costs are best collected through volume consumption with the monthly customer charge reflecting the least cost possible to remain connected. Adding more costs in the monthly customer charge assures Petitioner quick collection of any reduced revenues due to lower consumption in volumetric rates that would ultimately be collected through the Sales Reconciliation Component.

Q: How does Petitioner's proposed residential monthly customer charge compare to other Indiana natural gas utilities?

The proposed residential monthly charge of $21.50 would be the highest of Indiana natural gas utilities, as I have illustrated in Chart A. If a $21.50 monthly customer charge is approved, the monthly customer charge would be 50% more than other recently approved residential monthly customer charges for a Commission-regulated natural gas utility.

Chart A – Indiana Natural Gas Utility Residential Customer Charges



Q: Why is Petitioner's request to increase its residential customer charge fifteen times more than its requested margin unreasonable?

A: The customer charge should reflect an amount similar to the requested margin increase because the increased margin is the additional revenue requirement for all depreciated assets and expenses providing service to the customer since the prior rate case. Increases that are disproportionate to the margin increase result in an exponential growth of recurring monthly customer charges and are not reflective of Petitioner's rate base growth.

Petitioner's proposed customer charge increase is not a gradual increase.

The monthly customer charge is supposed to represent the cost of being connected to the distribution system, but not to all system assets. Substantially altering the collection method of total revenue requirements by moving more costs into the customer charge significantly reduces Petitioner's financial risk and shifts the financial risk to Petitioner's customers. Too large of an increase in the customer charge, along with Petitioner's future CSIA filings, has the potential for an even higher percentage of customers' bills to be beyond their cost control.

Q: How does Petitioner's request to increase its residential customer charge fifteen times more than its requested margin compare to other Indiana natural gas utilities?

A: In other natural gas Orders issued by the Commission (Table 6), four out of nine residential monthly charge increases are less than half of the total margin increase with the remaining customer charge increases close to the requested margin increase percentage. I recommend the residential monthly charge increases should not exceed the total requested margin increase percentage.

Table 6: Indiana Utilities Residential Customer Charge Increase versus Total Margin Increase

Natural Gas Utility	Cause No.	Order	Requested Margin Increase	Prior Customer Charge	Approved Customer Charge	Approved Customer Charge (Percentage Increase)
Midwest	44880	8/16/2017	17.0%	$12.00	$12.00	0.0%
Ohio Valley Gas	44891	10/17/2017	17.8%	$14.50	$14.75	1.7%
NIPSCO	44988	9/19/2018	46.5%	$11.00	$14.00	27.3%
South Eastern	45027	10/3/2018	32.5%	$11.00	$13.00	18.2%
Sycamore Gas	45072	3/6/2019	16.4%	$12.00	$14.50	20.8%
Indiana Utilities	45116	2/20/2019	11.1%	$11.67	$13.50	15.7%
Switzerland County	45117	4/17/2019	15.5%	$10.86	$13.00	19.7%
Community NG	45214	12/18/2019	24.1%	$13.00	$13.00	0.0%
Boonville NG	45215	10/29/2019	14.8%	$12.00	$14.00	16.7%

Q: Did you calculate a residential monthly customer charge from FERC accounts appropriate to include in a residential monthly customer charge?

A: Yes. The following FERC plant-in-service accounts from Petitioner's COSS were included and depreciated with a weighted cost of capital of 7.23% to the rate base: operations and maintenance expenses related to meter reading, meter replacements, service maintenance, billing, and taxes. The results of the analysis indicate a residential monthly customer charge of $11.88. (Attachment BRK-5.) This amount will be lower if my recommended change to the allocation of FERC 376 is applied.

Q: What monthly residential customer charge is appropriate in this Cause?

A: I recommend Vectren North's monthly residential customer charge (Rate 210) be set at $12.00, which more closely aligns with recent Commission-approved residential customer charges for Indiana natural gas utilities. Also, an increase from $11.25 to $12.00 is a 6.5% increase, which is similar to Petitioner's proposed margin increase.

There are additional reasons to keep the monthly customer charge at a reasonable amount. Petitioner's TDSIC (Cause No. 44430) will end with Petitioner's upcoming TDSIC-14 filing. After a Final Order is issued in this Cause, those costs will be put into rate base, and the TDSIC charges, which are currently recovered through a fixed monthly charge for Rate 210, will be reset to zero.

The most recent TDSIC charge in TDSIC-13 was $6.34 per month on top of the $11.25 residential customer charge from Petitioner's last rate case. The OUCC anticipates Petitioner will file future petitions for Compliance or TDSIC recovery, and these charges, if approved, would be a further increase to customers' bills.

2. Remaining Rates: Rates 220, 225, 240, 245, and 260.

Q: What Monthly Service Charge do you recommend for the remaining rates?

A: I do not oppose Petitioner's proposed increases to Rates 220, 225, 245, and 260. Petitioner proposes increases similar to its proposed margin increase percentage. Petitioner does not change the monthly customer charge for Rate 240 – Interruptible Sales Service.

C. Tariff Changes

Q: Does Petitioner have any Rate Changes or Tariff language changes other than the monthly customer charges you do not agree with?

A: No. Petitioner proposes Rate 240– Interruptible Sales Service be closed to new customers. Petitioner states customers continue to leave this tariff and there is plenty of capacity. (Petitioner's Exhibit No. 17, page 11, lines 17-20.) I agree with closing Rate 240 to new customers.

Petitioner proposes the following other changes the OUCC does not oppose:

- Changes to the current locations served.
- Changes to tariff definitions.
- Removal of tariff language for Rate 220 General Sales Service pertaining to contracts, because contracts are not used in Rate 220.
- Revision of the contract language for Rates 229, 240, 245, and 260.
- Revision of the responsibilities for communication equipment for metering purposes for Rates 245, 260 and 270.
- Revision of the Pooling services for Rates 280 and 285.

D. Future TDSIC and CSIA Allocations

Q: Do you agree with Petitioner's proposal to use non-gas revenues for any future TDSIC allocations?

A: Yes. Petitioner explains the reasons for using non-gas revenues for allocations for any future TDSIC or CSIA cost recovery. (Petitioner's Exhibit No. 16, page 47, lines 8-19.) My analysis indicates Petitioner's investments are system improvements to benefit Petitioner's delivery system regardless of whether the natural gas is purchased from Petitioner or from a third party, which can occur for transportation customers. Using margin revenue for allocation of TDSIC and Compliance costs allocates infrastructure costs to all customers regardless of their consumption. This is equitable, so all customers are treated equally whether they purchase gas from Petitioner or purchase gas from a third party as a transportation customer.

IX. RECOMMENDATIONS

Q: What are your COSS recommendations?

A: I recommend adjustments to the allocation of Distribution Plant-in-Service. I recommend Petitioner rerun the COSS model, including changes to allocation and other OUCC adjustments to revenue requirements based upon accounting expense adjustments, depreciation, and rate of return approved in this Cause during Petitioner's Phase 1 update. For Phase 1, I recommend:

- Petitioner rerun the COSS based upon the following allocations.
  1. Low/Medium Pressure Distribution Plant-in-Service (FERC 376) allocated 49.2% to Commodity – LP/MP Sales, and 50.8% to Demand – LP/MP Design Day.
  2. Let the allocators that were derived as a function of Demand for FERC 376 now be a function of Commodity.

Petitioner proposes to make revenue requirement changes based upon actual revenues and expenses with the Phase 2 implementation of rates. OUCC witness Mark Grosskopf opposes this proposal. However, if Petitioner's Phase 2 proposal is approved, then I recommend:

- Petitioner use the COSS design from the Commission's Final Order for this Cause and provide a revenue proof with updated billing determinants for any revenues adjusted in Phase 2.

Q: What are your rate design recommendations?

A: I recommend Rate 210 – Residential Sales Service monthly customer charge to be set at $12.00. The revenue associated with this residential monthly customer charge should be removed in equal amounts from the Residential classifications of Demand and Commodity. I also recommend approval of Petitioner's proposed future TDSIC and CSIA allocation based upon margin rates.

Q: What are your Tariff language recommendations?

A: I recommend approval of Petitioner's request to close the interruptible sales service (Rate 240) to new customers. I also recommend approval of the following tariff revisions proposed by Petitioner:

- Changes to the current locations served;
- Changes to tariff definitions;
- Removal of the contract language from general sales service Rate 220;
- Revisions to the contract language for Rates 229, 240, 245, and 260;
- Revisions to the Measurement Requirement Provisions for Rates 245, 260 and 270; and
- Revisions to pooling services for Rates 280 and 285.

Q: Does this conclude your testimony?

A: Yes, it does.

APPENDIX BRK-1 TO THE TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER

Q: Please describe your educational background and experience.

A: I graduated from Purdue University in West Lafayette, Indiana with a Bachelor of Science Degree in Mechanical Engineering in May 1986, and a Master of Science Degree in Mechanical Engineering in August 2001 from Purdue University at the IUPUI campus.

From 1986 through mid-1997, I worked for PSI Energy and Cinergy, progressing to a Senior Engineer. After the initial four years as a field engineer and industrial representative in Terre Haute, Indiana, I accepted a transfer to corporate offices in Plainfield, Indiana where my focus changed to industrial energy efficiency implementation and power quality. Early Demand Side Management ("DSM") projects included ice storage for Indiana State University, Time of Use rates for industrials, and DSM Verification and Validation reporting to the IURC. I was an Electric Power Research Institute committee member on forums concerning electric vehicle batteries/charging, municipal water/wastewater, and adjustable speed drives. I left Cinergy and worked approximately two years for the energy consultant ESG, and then worked for the OUCC from mid-1999 to mid-2001.

I completed my Master's in Engineering in 2001, with a focus on power generation, including aerospace turbines and left the OUCC to gain experience and practice in turbines. I was employed by Rolls-Royce (2001-2008) in Indianapolis working in an engineering capacity for military engines. This work included: fuel-flight regime performance, component failure mode analysis, and military program control account management.

From 2008 to 2016 my employment included substitute teaching in the Plainfield, Indiana school district, grades 3 through 12. I passed the math Praxis exam requirement for teaching secondary school. During this period, I also performed contract engineering work for Duke Energy and Air Analysis. I started working again with the OUCC in 2016.

Over my career I have attended various continuing education workshops at the University of Wisconsin and written technical papers. While previously employed at the OUCC, I completed Week 1 of NARUC's Utility Rate School hosted by the Institute of Public Utilities at Michigan State University. In 2016, I attended two cost of service/rate-making courses: Ratemaking Workshop (ISBA Utility Law Section) and Financial Management: Cost of Service Ratemaking (AWWA).

In 2017, I attended the AGA Rate School sponsored by the Center for Business and Regulation in the College of Business & Management at the University of Illinois Springfield and attended Camp NARUC Week 2, Intermediate Course held at Michigan State University. I completed the Fundamentals of Gas Distribution on-line course developed and administered by Gas Technology Institute in 2018. In October 2019, I attended Camp NARUC Week 3, Advanced Regulatory Studies Program held at Michigan State University by the Institute of Public Utilities.

My current responsibilities include reviewing and analyzing Cost of Service Studies ("COSS") relating to cases filed with the Commission by natural gas, electric and water utilities. Additionally, I have taken on engineering responsibilities within the OUCC's Natural Gas Division, including participation in "Call Before You Dig-811" incident review and natural gas emergency response training.

Q: Have you previously filed testimony with the Commission?

A: Yes. I have provided written testimony concerning COSS in Cause Nos. 44731, 44768, 44880, 44988, 45027, 45072, 45116, 45117, 45214, 45215, and 45447. Additionally, I have provided written testimony for Targeted Economic Development ("TED") projects in 2017/2018/2020 and various Federal Mandate Cost Adjustment ("FMCA") and Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") petitions. I filed testimony or provided analysis in the following FMCA or TDSIC 7-Year Plan or Tracker petitions: Cause Nos. 44003, 44429, 44430, 44942, 45131, 45007, 45264, 45330 and 45400.

While previously employed by the OUCC, I wrote testimony concerning the Commission's investigation into merchant power plants, power quality, Midwest Independent System Operator, and other procedures. Additionally, I prepared testimony and position papers supporting the OUCC's position on various electric and water rate cases during those same years.

Q: Please describe the general review you conducted to prepare this testimony.

A: I reviewed Vectren North's Petition, Testimony, COSS, and Tariffs for this Cause, Cause No. 45468. I focused on Petitioner's testimony necessary for my COSS, rate design, and tariff analysis. I primarily used the testimony, attachments, exhibits, and workpapers of Russell A. Feingold, Petitioner's Exhibit No.16, and Katie J. Tieken, Petitioner's Exhibit No. 17. Additionally, I reviewed the Customer Cost section of the book Principles of Public Utility Rates, Second Edition by James C. Bonbright.

I also reviewed Petitioner's prior Petition (Cause No. 43298), Testimony, Stipulation and Settlement Agreement, and the Commission Order. I participated in OUCC case team meetings concerning Petitioner’s case. On February 9, 2021, I participated in an informal discussion on the COSS with Petitioner’s COSS witness, Mr. Russell Feingold.

Q 5.14: Please provide an explanation of normal winter and normal summer operation of the natural gas system related to city gate usage, storage usage, and the transmission mains.

Objection:

Vectren North objects to the request on the grounds and to the extent it is overbroad and unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence and on the separate and independent grounds and to the extent it is vague and ambiguous and provides no basis from which Vectren North can determine what information is sought. Vectren North is unable to determine from the Request what an "explanation of normal winter and normal summer operation..." is meant to include nor what the term "normal" means for purposes of the Request.

Subject to and without waiver of the foregoing objections, Vectren North responds as follows:

Response:

Petitioner provides the following high-level description of the gas system operation:

- Using forecasted customer demand, Vectren Gas Supply acquires sufficient gas from interstate pipelines at Vectren North's city gate stations to combine with available storage field capacities to meet customer demand on a daily basis.
- Biannually, Gas Control and Gas Supply develop seasonal (heating/cooling) city gate flow allocation tables to provide guidelines on typical gas flow capabilities for internal operational guidance and to determine transport customer delivery options.
- Transmission pipelines are primarily used to move gas from the city gate stations to distribution systems or to/from storage fields.
- Generally, the primary differences between winter and summer Vectren North system operation are related to storage field operation and system impact due to transmission line projects. Gas is purchased and injected into the storage fields in the summer months and withdrawn during the winter months to meet a portion of customer demand. Certain large transmission line projects may require changes to typical city gate and storage field operation during the summer months.

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State of Indiana
Indiana Utility Regulatory Commission

PETITION OF INDIANA GAS COMPANY, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN NORTH") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO TRACK ITS UNACCOUNTED FOR GAS COSTS AND THE GAS COST COMPONENT OF ITS BAD DEBT EXPENSE IN ITS GAS COST ADJUSTMENT FILINGS; (4) APPROVAL OF A DISTRIBUTION REPLACEMENT ADJUSTMENT TO RECOVER THE COSTS OF A PROGRAM FOR THE ACCELERATED REPLACEMENT OF CAST IRON MAINS AND BARE STEEL MAINS AND SERVICE LINES; (5) APPROVAL OF REVISIONS TO THE SALES RECONCILIATION COMPONENT OF THE ENERGY EFFICIENCY RIDER APPROVED IN CAUSE NOS. 42943 AND 43046 TO PROVIDE FOR RECOVERY OF 100% OF THE DIFFERENCE BETWEEN ACTUAL AND APPROVED MARGINS; (6) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR GAS SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES; AND (7) CONSIDERATION AND APPROVAL IN PHASE II OF THE PROCEEDING OF AN ALTERNATIVE REGULATORY PLAN FOR A REVENUE STABILIZATION PLAN	)	FILED JUN 01 2007 INDIANA UTILITY REGULATORY COMMISSION CAUSE NO. 43298

VECTREN

Prepared Testimony and Exhibits
of
Indiana Gas Company, Inc.
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(Vectren North)

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Direct Testimony and Exhibits for KA Heid, SE Albertson

Supplemental Direct Testimony and Exhibits for MS Hardwick

specific details as recorded in Vectren North's books and records or were based on special studies performed by me or under my direct supervision. Where direct assignment was not possible, the investment or cost was allocated to the rate classes using the most appropriate method considering the type of investment or cost involved. For example, investment and cost items were identified as being commodity, demand, or customer related. Commodity costs are those that vary with the volume of gas delivered to customers and are allocated based on annual volumes. Demand costs are those incurred to deliver gas to customers at certain levels and are, therefore, dependent on customer demands. These costs are allocated based on peak day demands. Customer costs are those that vary with the number of customers served and are allocated based on number of customers. Other costs are directly related to specific plant investments, and these costs were allocated in the same manner as the plant to which they relate.

Q. Please provide an overview of the rate classes that form the basis for your cost of service study.

A. The rate classes to which costs are being allocated are as follows:

Residential Sales Service, Rate Schedule 210: Rate 210 is a firm sales service applicable to Residential Sales customers. Rate 211 is applicable to Unmetered Gas Lighting Service and has traditionally been combined with Rate 210 for cost of service allocation and rate design purposes.

General Sales Service, Rate Schedule 220: Rate 220 is a firm sales service applicable to any customer whose:

1. Annual Usage is less than 500,000 therms, and
2. whose Maximum Daily Usage is less than 15,000 therms.

School Transportation Service, Rate Schedule 225: Rate 225 is a transportation service applicable to any customer that:

1. has an Annual Usage of less than 50,000 therms, and
2. for which payment of bills is the responsibility of an Educational Institution.

Interruptible Sales Service, Rate Schedule 240: Rate 240 is an interruptible sales

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Q. What effect will the proposed rates have on the annual revenues from gas sales to be collected from each rate class?

A. Petitioner's Exhibit KAH-5, Schedule 1, contains a summary of present and proposed revenues from gas sales by rate class.

IV. PROPOSED SCHEDULE OF RATES AND CHARGES

Q. Have you developed rates and charges that produce the results described in the preceding section?

A. Yes. These proposed rates and charges are reflected in the Tariff for Gas Service sponsored by Vectren North witness Albertson in Petitioner's Exhibit SEA-10. Petitioner's Exhibit KAH-5, Schedule 2, contains the Calculation of Revenues at Present and Proposed Rates. Petitioner's Exhibit KAH-5, Schedule 3, contains the Calculation of Margins (non-gas revenues) at Present and Proposed Rates. Schedules 2 and 3 demonstrate that the proposed rates and charges generate the appropriate level of revenues.

Q. Please explain how you developed Vectren North's proposed rates for this proceeding.

A. Based upon the desired revenue distribution to each rate class as previously described in my testimony, the primary objective was to design rates that recover the appropriate amount of revenue from each rate class. However, additional considerations also guided my rate design. Vectren North's current Customer Facilities Charges are significantly below the indicated fixed costs of providing service. Vectren North's fixed costs should be recovered through the fixed monthly Customer Facilities Charges. Similarly, variable costs should be recovered through volumetric charges. To the extent that fixed costs are allowed to be recovered in the rate design as though they were commodity costs, the rate design will result in a misalignment in the pricing results with the costs incurred to serve customers. I concluded that a reasonable rate design would provide for Vectren North to structure its rates to recover a greater portion of its costs through the monthly Customer Facilities Charge, and I have applied this reasoning in developing the proposed rates.

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VECTREN ENERGY DELIVERY OF INDIANA - NORTH
IURC CAUSE NO. 43298
COST OF SERVICE STUDY
ALLOCATION OF RATE BASE

DATA: 12 MONTHS ENDED DECEMBER 31, 2006
TYPE OF FILING: CASE-IN-CHIEF
WITNESS: HEID

PETITIONER'S EXHIBIT KAH-2
SCHEDULE 2
PAGE 1 OF 3

		No.	Allocation Method	Total	Rate 210	Rate 220	Rate 225	Rate 240	Rate 245	Rate 260
	GROSS PLANT									
(1)	*Total Manufactured Gas Production*	5	*Design Day Sales*	$11,008,006	$7,927,117	$3,046,799	$0	$34,091	$0	$0
(2)	Total Natural Gas Production Plant	2	Annual Sales	$87,838	$60,654	$25,931	$0	$1,253	$0	$0
(3)	Total Underground Storage Plant									
(4)	Commodity	1	Annual Throughput	$7,041,249	$3,348,123	$1,431,426	$51,102	$69,179	$555,063	$1,586,357
(5)	Demand	5	Design Day Sales	$14,082,498	$10,141,128	$3,897,757	$0	$43,612	$0	$0
(6)	Winter	14	Winter Sales	$14,082,498	$9,860,345	$4,035,891	$0	$186,262	$0	$0
(7)	Total Distribution Plant									
(8)	Mains									
(9)	Customer	3	Number of Bills	$229,733,657	$209,250,199	$19,955,974	$189,083	$40,867	$227,367	$70,166
(10)	Commodity	1	Annual Throughput	$168,419,502	$80,083,699	$34,238,246	$1,222,305	$1,654,683	$13,276,535	$37,944,034
(11)	Demand	4	Design Day Throughput	$168,419,502	$97,556,702	$37,496,059	$2,703,425	$419,548	$10,797,868	$19,445,900
(12)	Land and Land Rights	103	Mains Plant	$15,908,892	$10,863,568	$2,574,587	$115,541	$59,390	$682,374	$1,613,432
(13)	Compressor Station Equipment	1	Annual Throughput	$1,562,593	$743,015	$317,662	$11,341	$15,352	$123,179	$352,044
(14)	Structures and Improvements	103	Mains Plant	$2,559,900	$1,748,057	$414,277	$18,592	$9,556	$109,801	$259,617
(15)	Measuring and Regulating Equipment	103	Mains Plant	$40,874,759	$27,911,795	$6,614,894	$296,859	$152,591	$1,753,224	$4,145,395
(16)	Services	8	Services Study	$407,672,833	$363,967,654	$41,638,321	$638,367	$137,973	$909,693	$380,825
(17)	Meters - Account 381 & 385	7	Account 381-385 Meters Study	$72,833,351	$48,820,864	$20,112,278	$190,564	$395,746	$1,803,929	$1,509,971
(18)	Meter Installations - Account 381 & 385	7	Account 381-385 Meters Study	$56,858,321	$38,112,655	$15,700,917	$148,766	$308,944	$1,408,261	$1,178,779
(19)	House Regulators - Account 381 & 385	7	Account 381-385 Meters Study	$23,020,541	$15,430,880	$6,356,916	$60,232	$125,084	$570,170	$477,259
(20)	Measuring and Regulating Equipment - Industrial	18	Account 385 Meters Study	$21,733,576	$0	$5,762,029	$54,595	$2,146,162	$7,933,600	$5,837,190
(21)	Other Distribution Equipment	109	Subtotal Distribution Plant	$160,054	$109,212	$25,919	$1,162	$600	$6,879	$16,282
(22)	Total General and Intangible Plant	110	Subtotal Gross Plant	$58,474,454	$43,105,903	$9,480,507	$265,447	$270,054	$1,869,508	$3,483,034
(23)	Total Gross Plant			$1,314,534,022	$969,041,570	$213,126,389	$5,967,379	$6,070,947	$42,027,454	$78,300,283

Vectren North
Residential Customer Cost Analysis

	Company COC	Source
Gross Plant		
Services	$681,532,023	Grand Total Tab
Meters	$85,284,122	Grand Total Tab
Meter Installations	$68,845,375	Grand Total Tab
House Regulators	$22,885,229	Grand Total Tab
House Regulators Install	$21,641	Grand Total Tab
Total Gross Plant	**$858,568,390**	
Accum. Depreciation Reserve		
Services	-$518,121,916	Grand Total Tab
Meters	-$23,541,996	Grand Total Tab
Meter Installations	-$53,468,153	Grand Total Tab
House Regulators	-$17,000,338	Grand Total Tab
House Regulators Install	-$15,424	Grand Total Tab
Total Depr. Reserve	**-$612,147,827**	
Total Rate Base	**$246,420,563**	
Operation & Maintenance Expenses		
Operations Remove & Reset Meters	$3,295,994	Grand Total Tab
Oper Customer Install Exp	$2,852,901	Grand Total Tab
Services Maintenance	$1,219,632	Grand Total Tab
Maint Meter & House Reg	$403,396	Grand Total Tab
Meter Reading	$2,040,132	Grand Total Tab
Customer Billing & Accounting	$6,205,395	Grand Total Tab
Total O&M Expenses	**$16,017,450**	
Depreciation Expense		
Services	$32,440,924	Grand Total Tab
Meters	$3,829,257	Grand Total Tab
Meters-ERTs	$4,041,223	Grand Total Tab
Meter Installations	$335,761	Grand Total Tab
House Regulators	$221	Grand Total Tab
House Regulators Install	$315,526	Grand Total Tab
Total Depreciation Expense	**$40,962,912**	
Revenue Requirement		
Interest	$3,937,589	See Cost of Capital
Equity Return	$13,878,950	See Cost of Capital
Income Tax	$4,594,542	See Tax Gross Up
Total	**$22,411,081**	
Revenue For Return	$22,411,081	
O&M Expenses	$16,017,450	
Depreciation Expense	$40,962,912	
Subtotal Customer Revenue Requirement	$79,391,443	
Plus: IURT, IURC & Uncollectible @ 1.95%	$1,548,133	General Inputs Tab
Total Customer Revenue Requirement	$80,939,576	
Number of Bills	6,814,140	Input-Allocators Tab
Monthly Cost	**$11.88**	

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***OUCC'S TESTIMONY OF BRIEN R. KRIEGER*** has been served upon the following counsel of record in the captioned proceeding by electronic service on March 31, 2021.

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