FILED
January 20, 2022
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC 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, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN SERVICE; (4) APPROVAL OF MECHANISM TO MODIFY RATES PROSPECTIVELY FOR CHANGES IN FEDERAL OR STATE INCOME TAX RATES, UTILITY RECEIPTS TAX RATES, AND PUBLIC UTILITY FEE RATES; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (6) AUTHORITY TO IMPLEMENT TEMPORARY RATES CONSISTENT WITH THE PROVISIONS OF IND. CODE § 8-1-2-42.7.	)	**CAUSE NO. 45621**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S

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

January 20, 2022

Respectfully submitted,

Scott C. Franson
Attorney No. 27839-49
Deputy Consumer Counselor

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
CAUSE NO. 45621
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: My testimony discusses my analysis of Northern Indiana Public Service Company LLC's ("NIPSCO" or "Petitioner") proposed cost of service study ("COSS"), proposed rate design, and proposed monthly customer charges.

Q: What are your recommendations?

A: I recommend the Indiana Utility Regulatory Commission ("Commission") require Petitioner to use the same Peak and Average transmission allocation percentages in its Cost Of Service Study ("COSS") model as in its prior base rate case, Cause No. 44988 (Order September 19, 2018). My recommendation includes keeping the demand and annual consumption of Rate 128 HP in the Load Factor calculation as was done in Cause No. 44988.

For rate design, I recommend the margin revenue requirement of the residential rate (new numbering - "Rate 211") and large transportation high pressure rate (new numbering

- "Rate 228 HP") be equal to the fully allocated cost at Equal Rates of Return as derived from the OUCC's recommended change to Petitioner's COSS. I also recommend the Commission reject Petitioner's proposed monthly customer charge for Rates 111, 115, 121 and 125 and approve a customer charge increase not to exceed 50% of the approved margin percentage increase.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Not addressing a specific item or adjustment NIPSCO proposes does not indicate my agreement or approval. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. <u>PETITIONER'S COST OF SERVICE STUDY</u>

Q: Does Petitioner propose a change in the transmission allocation percentages derived from the system load factor set in Cause No. 44988?

A: Yes. Petitioner proposes to change the transmission allocation percentages, derived from the System Load Factor, used in Cause No. 44988. Petitioner is proposing this change even though the peak demand and annual consumption of each rate class remained relatively constant since the Final Order in Cause No. 44988. (Table 1, below.)

Q: Do you have any concerns with Petitioner's proposed allocation changes?

A: Yes. When I compared Petitioner's proposed transmission allocation to the transmission allocation used in Cause No. 44988, I found a large shift of costs from Rate 128 High Pressure ("HP") to other rate classes. The transmission allocations Petitioner is proposing transfer approximately $6.75 million per year of cost responsibility from the largest transport rate class (existing numbering - "Rate 128 HP") to the other rate classes. The residential rate class (existing numbering – "Rate 111") is being asked to pay almost $4 million per year of this transfer. My analysis of data in Table 1 indicates Petitioner's Design Day for Rate 128 HP plus Rate 128 Distribution Pressure ("DP") is similar in this Cause as compared to Cause No. 44988. The similarity suggests further investigation into why Petitioner proposes eliminating Rate 128 HP from its System Load Factor calculation is reasonable.

Q: Please describe the transmission allocation changes Petitioner proposes in its COSS.

A: Petitioner proposes removing the demand and annual consumption of Rate 128 HP to derive the System Load Factor. Transmission plant in service (FERC 367.0) is allocated based upon annual throughput and Design Day demand. The System Load Factor is used to determine the percentage of transmission allocated with each rate's annual throughput and the remainder (out of 100%) sets the percentage allocated by each rate's Design Day demand. Petitioner's proposed System Load Factor of 20% is lower because it has not included Rate 128 HP causing the corresponding Peak and Average allocation of transmission to under weigh system impacts of Rate 128 HP.

Q: Please briefly summarize and review your analysis.

A: My analysis indicates Petitioner should *not* remove Rate 128 HP from its derivation of System Load factor calculation because Rate 128 HP's peak demand is a major contributor to system peak and its annual throughput is approximately 64% of the total annual throughput.

In Petitioner's COSS, the transmission plant-in-service is allocated 80% by coincident daily demand and 20% for annual throughput. (Petitioner's Exhibit No. 17, revised page 35, lines 12-17.) I recommend including Rate 128 HP in the System Load Factor, and thus, the transmission allocation would be the same Peak and Average allocation method as used in Cause No. 44988. By including Rate 128 HP, FERC 367.0 costs would be allocated 56% with each rate's coincident daily demand and 44% with each rate's annual throughput.

A separate issue concerns Petitioner's determination of the coincident daily demand ("Design Day") for each rate class. For Rate 128 HP, my analysis indicates its winter peak daily demand will contribute more to the system peak design day than Petitioner uses in the COSS. Separately, my analysis indicates Petitioner has overestimated Rate 111's contribution to system peak design day. The OUCC recommends Petitioner adjust the coincident peak of Rate 111 downward and Rate 128 upward.

My analysis includes a comparison of Design Day and annual throughput of Rate 111 and Rate 128 HP. I analyze each rate class's contribution of its coincident peak with Petitioner's system peak demand. Also, I analyze each rate class's annual throughput as a percent of total system annual throughput.

Q: Please summarize NIPSCO's proposed transmission allocation.

A: NIPSCO proposes to change the Peak and Average allocation percentage for transmission mains (FERC 367.0) with approximately 80% of transmission to be allocated with Design Day and 20% with Annual Throughput. These percentages were derived from Petitioner's load factor calculation that excludes Rate 128 HP coincident demand and annual throughput. (Petitioner's Exhibit No. 17, page 36, lines 1-9.)

Q: Please explain the relationship of coincident demand (Design Day) with system peak.

A: The system peak demand normally occurs during a winter month. Each rate class's calculated Design Day *could* occur during system peak. The Design Day peak's largest contributing demands are a function of the coldest potential outdoor temperature which affects the heating load of Rate 111 and a function of industrial productivity with some outdoor temperature effects for Rate 128 HP.

Q: Please compare the Design Day and annual throughput per rate class between Cause No. 44988 and Cause No. 45621.

A: The following summary comparisons and calculations (Table 1) are from data provided in Petitioner's Cause No. 44988, Exhibit No. 15, Attachment 15-C and Cause No. 45621, Exhibit No. 17, Revised Attachment 17-C. (Attachment BRK-1, Design Day & Throughput Comparison.) Referencing the data in Attachment BRK-1, the number of customers in the residential class increased 2.7% and the number of customers in combined industrial transport rate class (Rate 438 vs. Rate 128 DP + Rate 128 HP) increased 7.6%.

I have concerns about the computation of Design Day for both the residential rate class and the large transport rate classes in this Cause. The number of customers for residential Rate 111 and the annual usage for Rate 111 increased 2.7% and 5.5%, respectively. (Attachment BRK-1.) But the Design Day goes up 19% for the residential class. (Table 1, below.) The large industrial transports have grown in number of customers and annual throughput by 7.6% and 5.7%, respectively. But the Design Day for the large industrial transports decreases by 3%. (*Id.*)

Table 1. Design Day & Throughput Comparison

	Annual Usage (therms)			Design Day (therms)		
	Cause No. 44988	Cause No. 45621	Difference (%)	Cause No. 44988	Cause No. 45621	Difference (%)
Residential Rate 411/111	622,207,258	656,118,909	5.5%	7,770,286	9,285,407	19%
Large Industrial Transport (Combined) Rate 428/128	2,307,465,604	2,440,205,995	5.7%	8,163,661	7,907,143	(3%)
Large Industrial Transport Rate 128 HP		2,252,999,374			5,351,149	

Q: Please briefly describe Petitioner's process to arrive at system Design Day and the contribution of each individual rate class to system Design Day and forecasted throughput.

A: Petitioner derives a theoretical system peak, occurring during a winter month, by modeling the coldest day using a heating degree day method ("HDD"). (Petitioner's Exhibit No. 16, page 13, line 1 – page 14, line 2.) Petitioner then calculates each rate class's contribution to system peak demand and annual throughput. Petitioner uses a combined HDD method and econometric method while trying to account for COVID-19 issues for the residential and commercial classes. Petitioner describes this method for residential and commercial forecasts in pages 14 through 29 of Petitioner's Exhibit No. 16. Petitioner calculates the industrial system peak and throughput through interviews with large industrial customers and historical data. (Petitioner's Exhibit No. 16, page 29, lines 12-18.)

III. ANALYSIS OF OUCC'S CHANGES TO PETITIONER'S COSS

Petitioner's Networked Transmission System

Q: Does Petitioner have a networked pipeline system supporting the demand and consumption of all rate classes including the concentration of high demand/high load factor customers of its northwest service area?

A: Yes. Petitioner's entire system has a total of 38 interstate pipeline interconnections supporting its networked system from seven different interstate pipeline companies. (Petitioner's Exhibit No. 11, page 9, line 16 – page 10, line 3.) Petitioner recognizes the system impact and the corresponding support necessary for industrial customers in the northwest portion of its service territory. (Petitioner's Exhibit No. 11, page 10, lines 10-12.) This northwest area is supported by six different interstate pipeline companies.

The largest industrial customers are served from the 483 PSI transmission loop, which is supported from Petitioner's networked transmission pipelines served by the interstate pipeline interconnection. (Attachment BRK-2, NIPSCO Response to OUCC DR 13-004.) Petitioner stated the high demand, high load factor customers served from the 483 PSI transmission mains represent 2/3 of the total system sendout during the summer months. (Petitioner's Exhibit No. 11, page 10, lines 4-9.)

System Load Factor

Q: Did Petitioner develop its System Load Factor, used for determining transmission allocation, in a similar manner to Cause No. 44988?

A: No. Petitioner did not remove any rate class for development of system load factor used for transmission allocation purposes in Cause No. 44988. In this Cause, Petitioner assigns a transmission allocation of 80% by coincident peak and 20% by annual throughput based upon a system load factor calculation unique to NIPSCO and unique to Petitioner's COSS consultant. Petitioner's prior COSS, for designing rates, used 56% of transmission allocated with design day demand and 44% allocated with annual throughput. (Attachment BRK-3, NIPSCO Response to OUCC DR 7-005.)

The OUCC discussed with Petitioner's COSS consultant if removing a rate class is unique. My understanding through my conversation with NIPSCO's COSS consultant, Mr. Amen (November 22, 2021) is that Mr. Amen has not previously filed a COSS that removed a rate class from the system load factor. The OUCC asked for clarification, and it is the OUCC's understanding Petitioner's transmission allocation method had not been used before by Mr. Amen. (Attachment BRK-4, NIPSCO Response to OUCC DR 13-014.)

Q: What is the System Load Factor if Rate 128 HP is included in the load factor calculation?

A: The System Load Factor would be the same as Cause No. 44988 if all rates are included. The System Load Factor is 43.4% using data for this Cause from Attachment BRK-1 (3,509,609,499 annual therms/365 days/22,134,411 peak day demand).

Q: What are the COSS effects on changing the calculation of the System Load factor?

A: Decreasing the System Load Factor by removing 2/3 of the throughput changes the demand and throughput allocation percentages of transmission (FERC 367.0) and other associated FERC transmission accounts. The new percentages *increase* and shift COSS transmission costs associated with peak demand *to* the residential and commercial classes and *decrease* and shift COSS transmission costs associated with annual throughput *from* the transportation class when compared to Cause No. 44988. This is especially troubling because Rate 128 HP and Rate 128 DP represent approximately 70% of forecasted annual throughput, which is a 3% increase in annual throughput from Cause No. 44988. (Attachment BRK-1, page 1, line 5; page 2, lines 5-6.)

<u>Coincident Peak – Design Day</u>

Q: Is Design Day for residential customers modeled in the same manner as industrial customers to arrive at the inputs for System Load Factor?

A: No. The Design Day for the residential class is estimated based on an econometric model and hypothetical coldest day derived from 80 HDD. The Design Day for industrials is based upon interviews with industrial customers. (Petitioner's Exhibit No. 16, page 14, lines 5-14.) Petitioner explains the HDD method for derivation of system peak demand and its use in heat sensitive load in its Exhibit No. 16, page 13, line 1 to page 14, line 2, and page 15, lines 16-18. The derivation of industrial demand is explained in Petitioner's Exhibit No. 16, page 29, lines 12-18.

Q: Does Petitioner's derivation of coincident peak demand for Rate 111 from test year 2020 cause an unreasonably high Design Day for Rate 111?

A: Yes. I compared load characteristics from Cause No. 44988 to Cause No. 45621. Both Petitioner's load characteristic exhibits are found in Attachment BRK-1. My calculations for Rate 111 indicate the annual consumption per residential customer increased approximately 5.5% but the design day demand increased approximately 19%. The number of customers in Rate 111 changed less than 2.7%.

Based on my experience and the typical operation of heating equipment, I expect the Design Day demand to be similar in growth as compared to the growth for number of customers and annual throughput. It is probable the first COVID-19 year (2020) does not represent a typical year. Petitioner recognizes this and discusses the modeling issues on pages 21-23 of Petitioner's Exhibit No. 16. But my review of Petitioner's testimony indicates the short-term affects were not included in the model. (Petitioner's Exhibit No.

16, page 23, lines 7-9.) However, my comparisons of the modeled Design Day versus growth in customer count and throughput indicate there are issues with the model.

Q: Please summarize your analysis of Petitioner's proposed Rate 111 Design Day and any changes you recommend to the Rate 111 Design Day.

A: During the COVID-19 pandemic winter months my understanding is more people were working from home and there was reduced work at process plants. Therefore, there is a high likelihood of residential heating for 2020 setting an uncharacteristic high residential peak demand. My understanding of Petitioner's testimony is this short-term effect of 2020 was not discounted or reduced to produce a longer-term forecast. Because NIPSCO made no adjustment to account for the increased residential usage or the decreased industrial usage, my analysis indicates the residential Design Day is too high and does not represent normal growth or normal space heating and other home use of natural gas.

I recalculated the Design Day for the residential rate class, Rate 111. I used the annual consumption in this Cause (Table 1) and the load factor (22%) from Cause No. 44988. Petitioner has a load factor in this Cause of 19.4%. (Attachment BRK-1.) I calculated a residential Design Day demand of 8,170,845 therms and shifted 1,114,561 peak therms to other rate classes.

Conversely, my calculations indicate the Design Day for Rate 128 HP is too low. My calculated higher Design Day for Rate 128 HP includes 66% of the removed residential coincident demand, plus additional peak demand of Rate 128 HP supported by metered data. The changes to Rate 128 HP are discussed below.

Q: Does Petitioner's derivation of coincident peak demand for Rate 128 HP using year 2020 cause an unreasonably low coincident Design Day for Rate 128 HP?

A: Yes. Petitioner calculates the Design Day for Rate 128 HP using a three-day average of the rate class peaks set in January 2018, 2019, 2020. (Attachment BRK-5, NIPSCO Response to OUCC DR 7-011.) The January 2020 peak data is approximately 15% lower than the peaks set in 2018 and 2019. I recommend not using January 2020 peaks to calculate the Design Day for Rate 128 HP because it is an outlier as compared to the other two years and because of the general state of reduced steel production. (Attachment BRK-6, American Iron and Steel Institute.)

I recommend the coincident peak for Rate 128 HP be set higher but not increase the system peak. I calculate Rate 128 HP coincident peak from 2018 and 2019 winter data, plus adding a portion of the coincident peak load removed from the residential class, to arrive at a reasonable coincident peak for Rate 128 HP, as compared to combined Rate 128 data and peak data from the top 20 Rate 128 HP customers. I disagree with Petitioner using a 3-day average of three years which lowers the peak when any single peak day of Rate 128 HP set during the winter may be coincident on the system peak based upon my analysis of data for Figure 1, Figure 2, and Figure 3 below.

The coincident peak occurrence is due to the high load factor of this rate. Because of a high load factor, at least 95%, Rate 128 HP peak occurs all the time or at least the peak demand does not vary much. If production output of these high load factor customers in Rate 128 HP increases simultaneously with the coldest outside temperatures, then the Rate 128 HP coincident peak could be higher and drive a system peak higher. To the contrary, if winter days are warmer the theoretical maximum heating requirements may never be reached and the coincident peak of Rate 128 HP becomes more dominant in the system peak.

The randomness of when the coldest day on the system can occur during the winter months and the certainty of a Rate 128 HP coincident peak mean the highest peak of Rate 128 HP should be used to determine its share of peak demand cost in the COSS. I recommend the Design Day for Rate 128 HP be set at 6,454,053 therms. This is calculated from the average of January 1, 2018, and January 30, 2019 ((5,854,037+5,591,847)/2) found in Attachment BRK-5; OUCC DR 7-011, plus 66% of the reduced residential peak demand (5,718,442+735,611=6,454,053). Setting the Rate 128 HP Design Day at 6,454,053 therms does not increase my estimated Rate 128 HP coincident peak above the Rate 128 HP customer metered peaks, and 95% load factor for Rate 128 HP, based upon Petitioner's annual consumption estimate for Rate 128 HP and my recommended coincident demand.

Q: Could the Rate 128 HP Load Factor peak occur at system peak?

A: Yes, it is possible. The annual Load Factor of 115.4% does not represent Rate 128 HP peak demand which occurs during a winter month. (Attachment BRK-1, Design Day & Throughput, page 2; Petitioner's Exhibit No. 17 – Revised Attachment 17-C.) The calculation of annual load factor for a rate class is annual consumption divided by peak day demand times 365 days/year. A Load Factor of greater than 100% indicates the peak day demand was not used in the Load Factor calculation. Petitioner uses a calculated peak day based upon an average of peak days.

Q: Why is it not appropriate to calculate a peak day based upon an average of peak days?

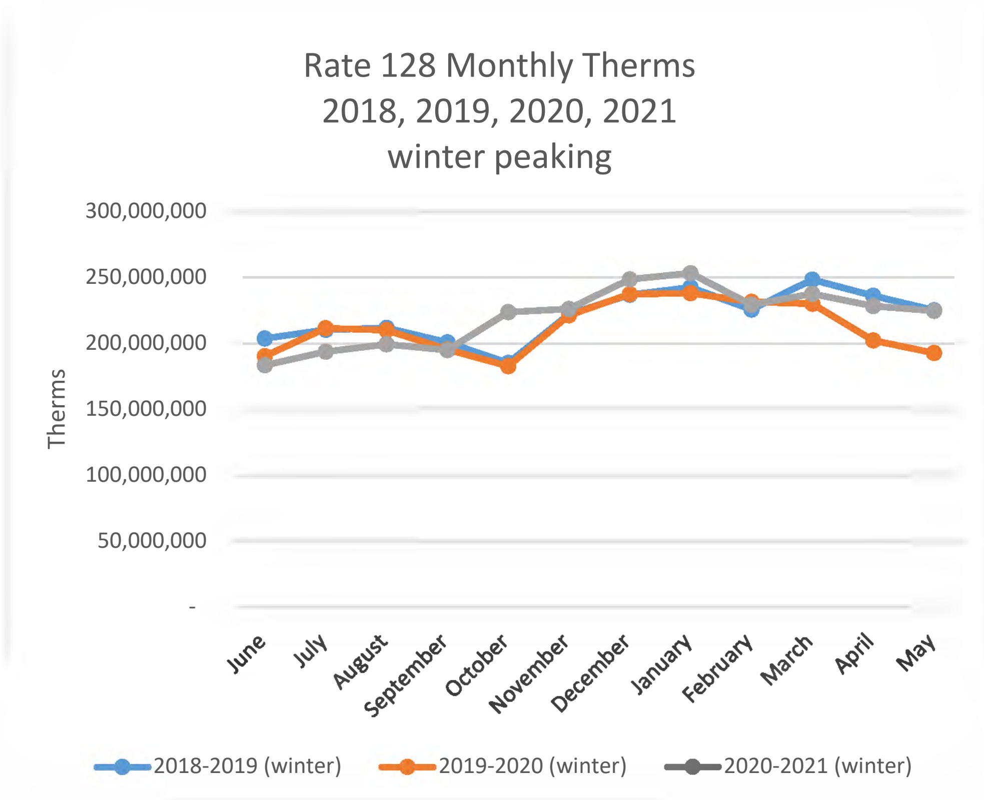
A: The most important peak day is coincident with system peak. Petitioner estimates a theoretical peak for heating loads based upon the worst possible condition of cold – 80 HDD. It is not appropriate to then use an *average* for highs and lows of metered data for other rate class demands.

Q: What method did you use to calculate a peak day?

A: I reviewed the monthly consumption, therms per month, for combined Rate 128 for years 2018, 2019, 2020, and 2021. (Attachment BRK-7, NIPSCO Original Response to OUCC DR 7-003 Attachment A.) Only the combined Rate 128 was available from Petitioner for 2018 but serves as a proxy for Rate 128 HP because Rate 128 HP represents approximately 92% of the combined annual consumption and 68% of the combined demand. (Attachment BRK-1, Design Day & Throughput Comparison, page 2; Petitioner's Exhibit No. 17 – Revised Attachment 17-C.)

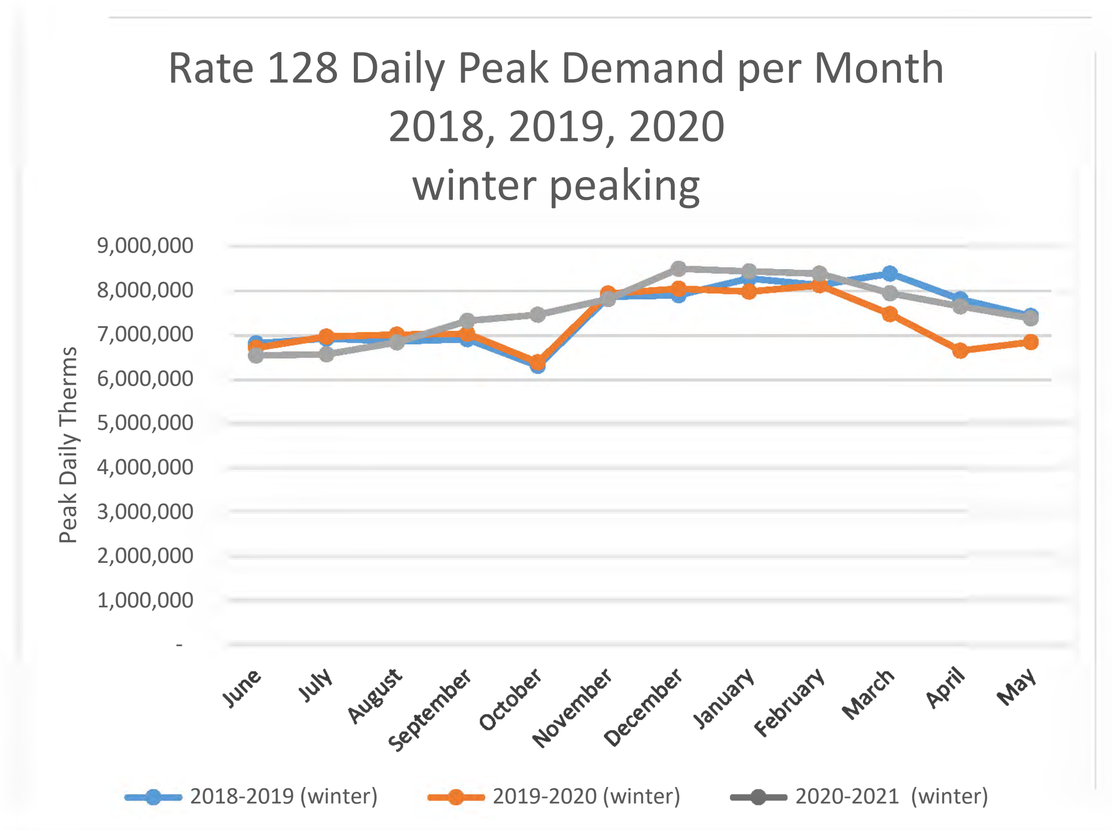
My analysis of the monthly data indicates the peak consumption months for combined Rate 128 are three winter months, Figure 1. The coincident peak of Rate 128 HP could occur on any one of the three winter months because these are the highest consumption months and have a high monthly load factor.

Figure 1



I reviewed the peak <u>daily</u> therms for December, January, and February for Rate 128 for years 2018, 2019, 2020, and 2021. (Attachment BRK-8, NIPSCO Response to OUCC DR 7-003 - Attachment B.) My analysis of the peak day per month indicates the peak day for Rate 128 HP can occur in any of the three winter months. (See Figure 2.) The coincident peak with the system peak could occur on any one day of the three winter months, and that day is typically the coldest day - Petitioner's calculated System Peak.

Figure 2



Q: What winter month is typically the coldest month?

A: January. I reviewed National Oceanic and Atmospheric Administration ("NOAA") data, and Golden Gate Weather Services (1981 - 2010 Normalized) ("Golden Gate"). The recent data from NOAA and the normalized data from Golden Gate indicates the three coldest months are December, January, and February with the coldest month being January. Table 2 contains the Golden Gate Weather Services Data for Ft. Wayne and South Bend.

Table 2. Golden Gate Weather Services (1981 - 2010 Normalized Heating Degree Days)

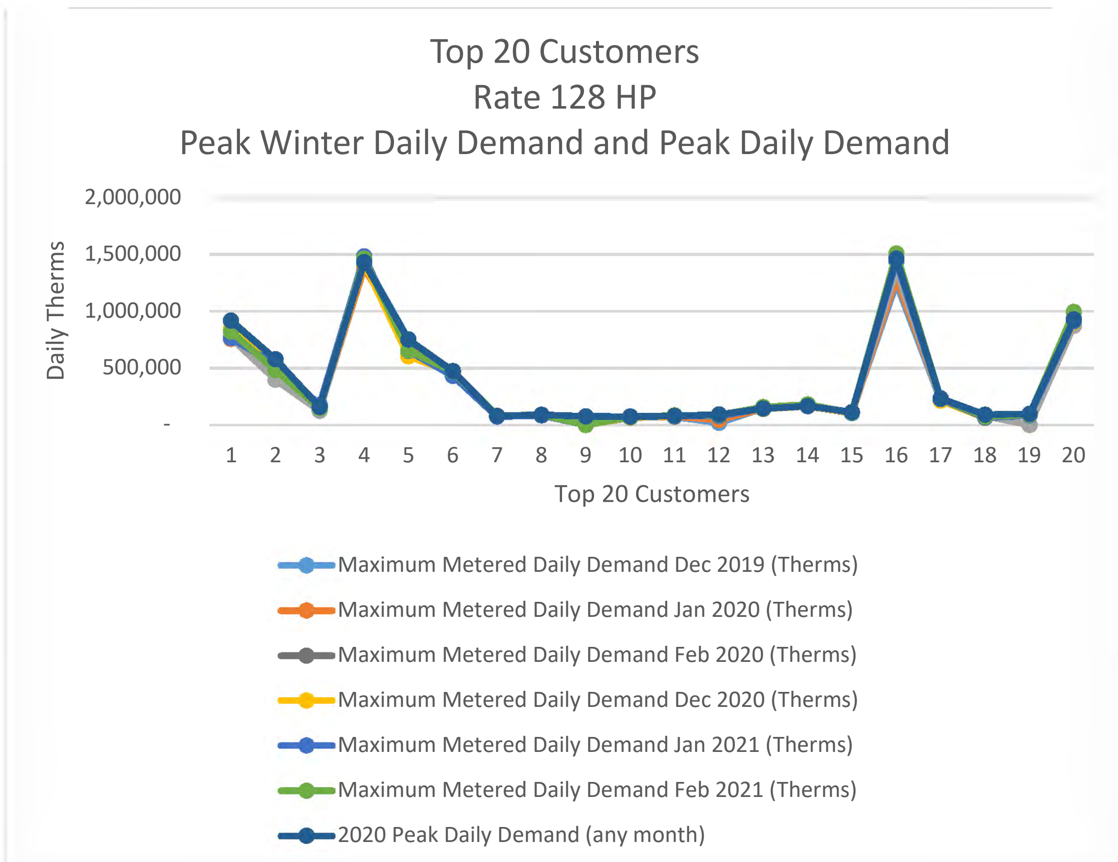
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Ft. Wayne	1243	1027	826	458	190	29	3	9	104	393	708	1111
South Bend	1257	1041	855	487	223	44	5	13	116	407	728	1122

Q: Is there additional historical peak demand data that supports your conclusion that Rate 128 HP's peak demand is coincident with System Peak – Design Day?

A: Yes. Petitioner provided demand data for the top 20 customers. (Attachment BRK-9, NIPSCO's Response to OUCC DR 7-002 Attachment A Redacted.) All 20 customers are Rate 128 HP with most customers setting daily peaks during December, January, or February. 85% of the Rate 128 HP customers have peak demands occurring during the winter months and 75% occurred during January or February.

Using the information in Attachment BRK-9, I graphically compared the top 20 customers' peak demands occurring in any month to their peak winter demand in Figure 3 below. My analysis indicates there is little deviation in magnitude, and occurrence happening during December, January, or February. There is little difference between each customer's peak demand and its winter demand. (Figure 3, below.) These winter peaks for Rate 128 HP could occur on the System Peak and be classified as the Design Day. If Petitioner knew specific process characteristics and heat load characteristics driven by HDD, a coincident peak demand could be modeled. Without this data, using the metered data provided indicates it is probable that a customer's peak will occur the same day as the System Peak thus creating a Design Day demand.

Figure 3



Q: Do you recommend using the 2020 peak day data?

A: No. As explained above, the 2020 data has too many complications relating to COVID-19. Therefore, the 2020 data will not be useful in predicting future demand nor indicative of past demand.

Q: What Design Day magnitude for Rate 128 HP do you recommend from your analysis of Petitioner's data?

A: I recommend the Design Day for Rate 128 HP be increased by two factors; 1) my calculated reduction in residential coincident demand, and 2) the average of the highest winter peak from January 2018 and January 2019. The two additional calculated factors are: 1) 735,611 therms removed from residential, and 2) 5,718,442 therms calculated by the average of the highest winter peak day, which are January 1, 2018 and January 30, 2019, (Attachment BRK-5, NIPSCO Response to OUCC DR 7-011.) I recommend the Design Day for Rate 128 HP be set at 6,454,053 therms. The new load factor for Rate 128 HP calculated with this coincident peak is 95% using Petitioner's annual consumption for Rate 128 HP. My increase in coincident demand does not increase Petitioner's calculated System Peak – 22,134,411 therms.

<u>Transmission Mains Cost Causation</u>

Q: Please provide your analysis of annual consumption - annual throughput.

A: Annual throughput is dominated by Rate 128 HP. It represents 64% of the systems' total throughput and is constant over all months as represented by its high load factor. The annual throughput of Rate 128 HP and Rate 128 DP (Rate 128 combined) is 70% of the total annual throughput and these two classes are the dominant two of the three transport rate classes. (Petitioner's Exhibit No. 17, Revised Attachment 17-C.)

Q: Why does an 80% peak demand and 20% annual throughput not replicate cost causation of transmission mains, FERC 367.0?

A: Petitioner's allocation of FERC 367.0 overlooks the fact that transmission mains have two distinct costs associated with either demand or throughput: 1) peak demand - the additional pipe cost for larger pipe diameter and 2) throughput - all remaining costs associated with installing a pipe length, annual maintenance, design, restoration, and easement costs, which are not a function of pipe diameter.

The pipe diameter allows for more peak demand capacity while the remaining costs allow for 365 days per year of throughput capacity. Therefore, allocation of the majority of costs should be attributed to the dominant throughput users. That is, the annual throughput percentage derived from the System Load Factor must include the dominant throughput users – Rate 128 HP.

Q: How does throughput represent cost causation more accurately?

A: Throughput represents all remaining costs of transmission 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 transmission system would not exist if only short duration peak demand related costs were collected because the amount collected would *only* represent the cost of increased pipe diameter and *not* all costs for installation, maintenance, design, and overheads. The allocation of an increased percentage of transmission costs based on Annual Throughput from a 365-day cost causation is essential to the collection of monthly revenue.

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.

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 allocated with a throughput allocator.

Q: In any other COSS has Mr. Amen allocated transmission with annual throughput and peak coincident demand with similar percentages as your recommendation?

A: Yes. The transmission facilities were classified as 40.86% as commodity or throughput related, and 59.14% as demand in Docket No. 13-078-U, Arkansas Oklahoma Gas Corporation, October 15, 2013 (Arkansas Public Service Commission). In his Direct Testimony on page 22, lines 3-6, Mr. Amen states the transmission facilities serve two functions, in that the facilities deliver gas supplies both during peak periods and on a year-round basis and are sized accordingly. (Attachment BRK-10, NIPSCO's response to IG DR 8-024 and Direct Testimony of Mr. Ronald J. Amen Docket No. 13-078-U.) I did not find in his testimony removal of any rate class's system load to derive the transmission allocation percentages. I agree with Mr. Amen's methodology in Docket No. 13-078-U to use all rate classes' annual throughput and peak demand for allocation of transmission costs, without eliminating consumption data, because gas facilities deliver gas during peak periods and on a year-round basis.

COSS Summary

Q: Do you agree with Petitioner's proposed COSS?

A: No. After reviewing NIPSCO's testimony and responses to data requests, I do not agree with its proposed change to the transmission mains allocation methodology and the proposed COSS. I recommend using the same transmission allocation method as Cause No. 44988.

Q: Are other costs affected by the allocation of transmission mains FERC 367.0?

A: Yes. The allocation of transmission plant in service, FERC 367.0, directly affects the allocation of FERC 367.0 depreciation. Additionally, there are other allocators in Petitioner's COSS derived from the allocated transmission mains. Two such allocators are INT_Plant and INT_Rate Base.

Q: Please describe the results of the COSS model using the OUCC's proposed transmission allocation.

A: I compared Petitioner's proposed 80% of transmission allocated with peak coincident demand (Design Day) and 20% of transmission allocated with annual throughput to the OUCC's recommendation of 56% allocated with peak coincident demand and 44% with annual throughput. The two COSS results are found as Attachment 17-F in Petitioner's Exhibit No. 17 and Attachment BRK-11.

My comparison uses the COSS fully allocated cost prior to any rate design effects. The results of my comparison indicate Petitioner's COSS method transfers approximately $6.75 million *per year* of cost responsibility *from* the largest transport rate class. And NIPSCO proposes its residential customers *pay* almost *$4 million per year* of this transfer. For this analysis, I compared Petitioner's Exhibit No. 17, Attachment 17-F, page 2 of 5, line 46 Rate Base Margin (Deficiency)/Surplus, to line 46 Rate Base Margin

(Deficiency)/Surplus of NIPSCO's Response to OUCC DR 13-012, Attachment A, page 3 of 6. (Attachment BRK-11; page 3; NIPSCO Response to OUCC DR 13-012.)

IV. RATE DESIGN: SUBSIDIES, MONTHLY CUSTOMER CHARGES, AND TARIFF CHANGES

A. Subsidies

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

A: No. Petitioner does not mitigate subsidies to all rate classes included in the COSS model. Petitioner proposes margin increases for Rates 111, 115, and 128 HP equal the COSS study results – no subsidy. Petitioner proposes Rate 121 – General Small move from receiving less than 2% subsidy to paying almost 15% subsidy. Petitioner's subsidy proposal paid by Rate 121 – General Small, increases 10 times the cost derived as cost causation calculated in Petitioner's COSS. Petitioner's rate design for Rate 121 is to *pay a subsidy to* the other rate classes of *$14 million*. (Petitioner's Exhibit No. 17, Attachment 17-F, page 2, comparing lines 46 and 53.)

The OUCC's recommended change to the COSS more closely represents cost causation; therefore, rate design subsidy would be reduced. I recommend the rate design for Rates 111, 115, and 128 HP be the same revenue requirement as modeled with the OUCC COSS changes and neither receive nor pay subsidies. Subsidy transfer is reduced because Rate 128 HP, Rate 115, and Rate 111 would pay full cost of service thus reducing the subsidy paid from Rate 121 – General Small and Rate 125 General Large to other rate classes.

B. Monthly Customer Charges

1. Rate 111 – Residential

Q: What monthly customer charge does Petitioner propose for Rate 111 – Residential Service?

A: Petitioner proposes to increase the residential customer charge from $14.00 to $24.50.

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 75%, compared to Petitioner's original proposed total margin increase for all rate classes of 25.1%. The proposed monthly customer charge of $24.50 represents approximately 60% of the margin revenue requirement for Rate 111. (Petitioner's Exhibit No. 17, Attachment 17-H, page 2, using line 3 and line 7.)

Petitioner's *proposed* monthly customer charge for any residential customer using 500 therms per year or less is approximately *50%* of the total bill including the GCA. (Petitioner's Exhibit No. 17, Attachment 17-J, page 1, Bill Impacts - Residential.) If a residential monthly customer charge of $24.50 was approved, residential customers would lose the ability to control costs based upon their usage, while Petitioner's risk of not meeting the Rate 111 revenue requirement would be substantially reduced.

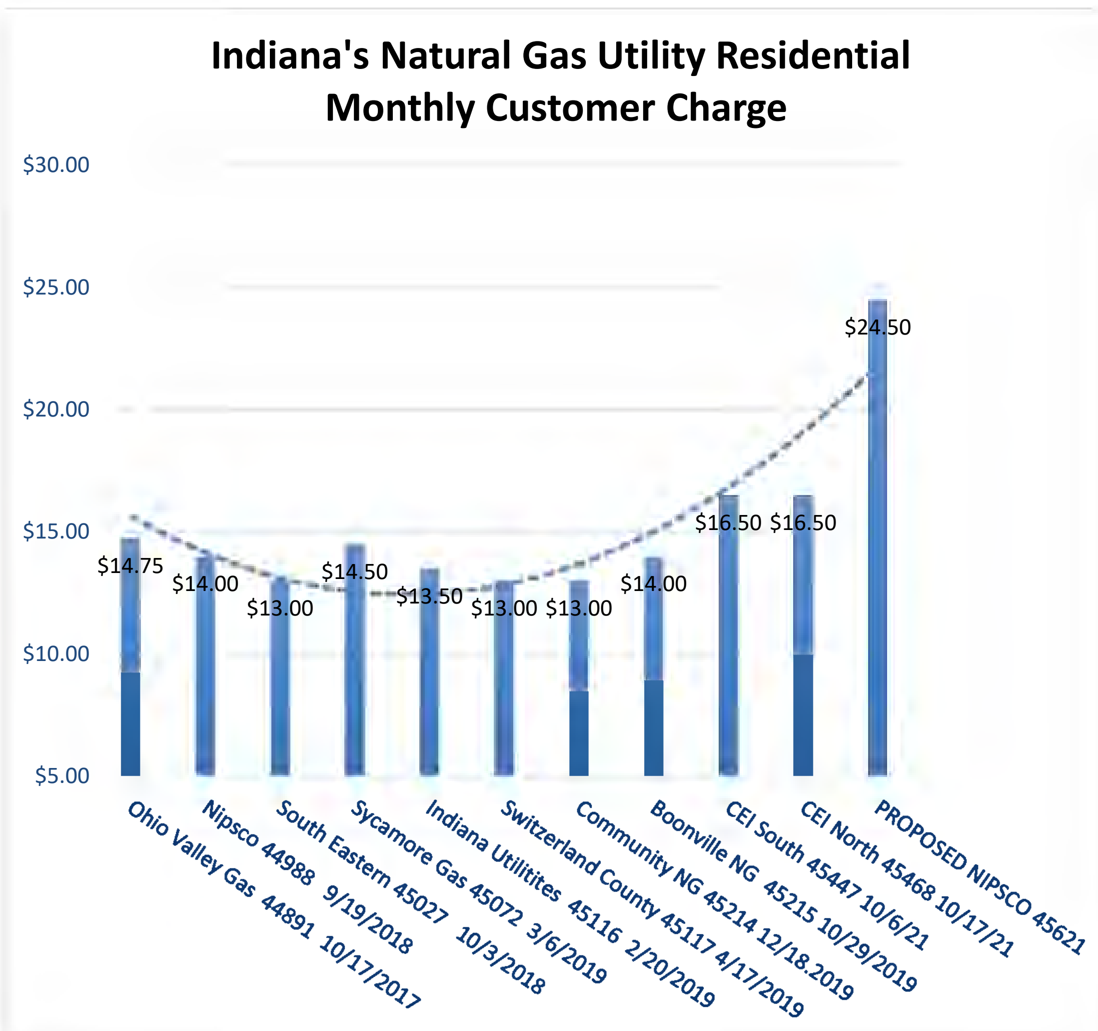
Q: Are there other monthly charges related to increases in rate base?

A: Yes. Petitioner has FMCA and TDSIC trackers. These additional monthly charges are volumetric charges but are in addition to base rate margin costs. Petitioner's risk of not meeting the Rate 111 revenue requirement is further reduced.

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

The proposed residential monthly charge of $24.50 would be the highest of Indiana natural gas utilities, as I have illustrated in Chart A. If a $24.50 monthly customer charge is approved, the monthly customer charge would be approximately 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 three times more than its requested margin unreasonable?

A: The customer charge should be proportionate to the requested margin increase. 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. 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 burden to Petitioner's customers. Too large of an increase in the customer charge, along with Petitioner's future FMCA and TDSIC filings, will cause 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 compare to other Indiana natural gas utilities?

A: In other natural gas Orders issued by the Commission, five out of eleven residential monthly charge increases are less than half of the total margin increase. (Table 3, below.) The remaining customer charge increases are close to the requested margin increase percentage, or the Commission-approved customer charge is close to the same magnitude as other utilities. I recommend the residential monthly charge increases should not exceed 50% of the total requested margin increase percentage.

Petitioner's proposed residential monthly customer charge does not compare equitably with its rate class margin or the total margin increases. NIPSCO's proposed 75% residential customer charge increase, from $14.00 to $24.50, is almost *three* times the percentage of the original requested residential rate margin increase (28.8%), and original total margin increase (24.8%), and is not typical of Indiana natural gas utilities. In recent natural gas orders (Table 3), many residential monthly charges are less than half of the total margin increase, and most do not exceed the proposed margin increase.

Table 3. 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%
CEI South	45447	10/6/21	42.8%	$11.00	$16.50	50%
CEI North	45468	11/17/21	5.79%	$11.25	$16.50	47%

Q: What magnitude of NIPSCO's calculated fixed costs is in the proposed Residential Monthly Customer Charge?

A: Petitioner proposes to collect 60% of its residential "fixed cost" in the residential customer charge (Petitioner's Exhibit No. 2, page 24, line 13-15) but provides no description of why it considers the majority of its margin cost as fixed cost. The proposed 75% increase in the residential monthly customer charge is not a gradual increase.

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

A: I recommend NIPSCO's monthly residential customer charge be set at $15.75/month, which is a 12.5% increase over the current charge. A moderate increase is an important ratepayer protection in this instance, as Petitioner's proposal would result in more than 30% of all residential customers paying more than 40% of their total bill towards fixed charges. These percentages are derived from Petitioner's Exhibit No. 17, Attachment 17-J, and represent customers using 500 therms per year and less.

Increasing customer charges should be highly scrutinized because high fixed charges hurt the customers' ability to control their bills by using less natural gas. My recommendation is a reasonable balance between Petitioner's proposal and preserving the customers' ability to retain control of their utility bills. Finally, it is appropriate to temper Petitioner's proposed residential customer charge increase because it is not within the range of fixed customer charges of other natural gas utilities in Indiana. A $15.75 fixed monthly residential customer charge more closely aligns with recent Commission-approved residential customer charges for natural gas utilities.

2. Remaining Rates: Rates 115, 121, 125, 128 DP, 128 HP, 130, 134A, and 138

Q: What Monthly Service Charges do you recommend for Rates 115, 121, and 125?

A: I recommend these monthly customer charges be set with the same method I recommend for the residential rate class – Rate 111. The increase to the monthly customer charge should not exceed 50% of Petitioner's proposed margin increase. I recommend the following monthly customer charges: Rate 115 = $19.75, Rate 121 = $59.75, and Rate 125 = $450.00.

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

A: I do not oppose Petitioner's proposed increases to Rates 128 DP, 128 HP, 130, 134A, and 138.

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 discussed the existing Alternative Regulatory Plan ("ARP") used for setting rates, each rate tariff, and included the new tariff sheets. (Petitioner's Exhibit No. 2, pages 33 – 45.) I found no substantive changes requiring further analysis.

I. RECOMMENDATIONS

Q: Does the OUCC's reduced revenue requirement affect the rate design?

A: Yes. The OUCC recommends a decrease to Petitioner's proposed revenue requirement, as described by OUCC witness Mark Grosskopf. For purposes of setting Petitioner's Phase I and Phase II rates, I recommend NIPSCO rerun the proposed COSS model using the OUCC's recommended COSS adjustments and the revenue requirements ultimately approved by the Commission in this Cause. I recommend that, in setting Petitioner's Phase

I and Phase II rates, such rates should be designed to achieve the following as a subset of Petitioner's rate design objectives. (Petitioner's Exhibit No. 2, page 18, lines 4-17.)

- No rate class's revenue allocation should increase by more than 150% of the system increase.
- All existing subsidies for major rate classes should be reduced by 25%.
- Any change in a rate or a charge should not violate the Commission's stated preference for gradualism.

Q: Please summarize your recommendation to modify Petitioner's COSS and proposed rate design.

A: I recommend the Commission:

1. Reject Petitioner's proposed monthly customer charge for residential customers, Rate 111, and adopt the OUCC's recommended monthly customer charge of $15.75/month.
2. Reject Petitioner's proposed monthly customer charge for Rates 115, 121, 125, and set the increase of the monthly customer charges at $19.75, $59.75, and $450.00, respectively.
3. Reject Petitioner's transmission allocation using Peak and Average percentages of 80% demand and 20% Annual Throughput.
4. Adopt the OUCC's COSS recommendation to use a Peak and Average transmission allocation percentage of 56% demand and 44% Annual Throughput.
5. Reject Petitioner's 3-day average method for calculating the Design Day of Rate 128.
6. Reduce the Design Day of Rate 111 to 8,170,845 therms.
7. Increase the Design Day of Rate 128 HP to 6,454,053 therms.
8. Have Petitioner rerun its COSS based upon the OUCC's recommended changes to the Peak and Average transmission allocation of 56% demand and 44% Annual Throughput, and increased Design Day demand for Rate 128 HP.
9. Have Petitioner design rates based upon the OUCC's recommendations for Rate 111 and Rate 128 HP paying the fully allocated costs from the OUCC's recommended COSS allocation.

Q: Does this conclude your testimony?

A: Yes, it does.

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

I. PROFESSIONAL EXPERIENCE

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, 45447, and 45468. 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 Charges ("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, 45400, 45560, 45611, and 45612.

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.

II. BACKGROUND OF TESTIMONY ANALYSIS

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

A: I reviewed NIPSCO's Petition, Testimony, and Attachments for this Cause. I reviewed Petitioner's direct testimony of Erin E. Whitehead, Steven Sylvester, Melissa Bartos, Andrew S. Campbell, and Ronald J. Amen with my focus on the COSS.

Q: Please describe your analysis of NIPSCO's evidentiary support in this Cause.

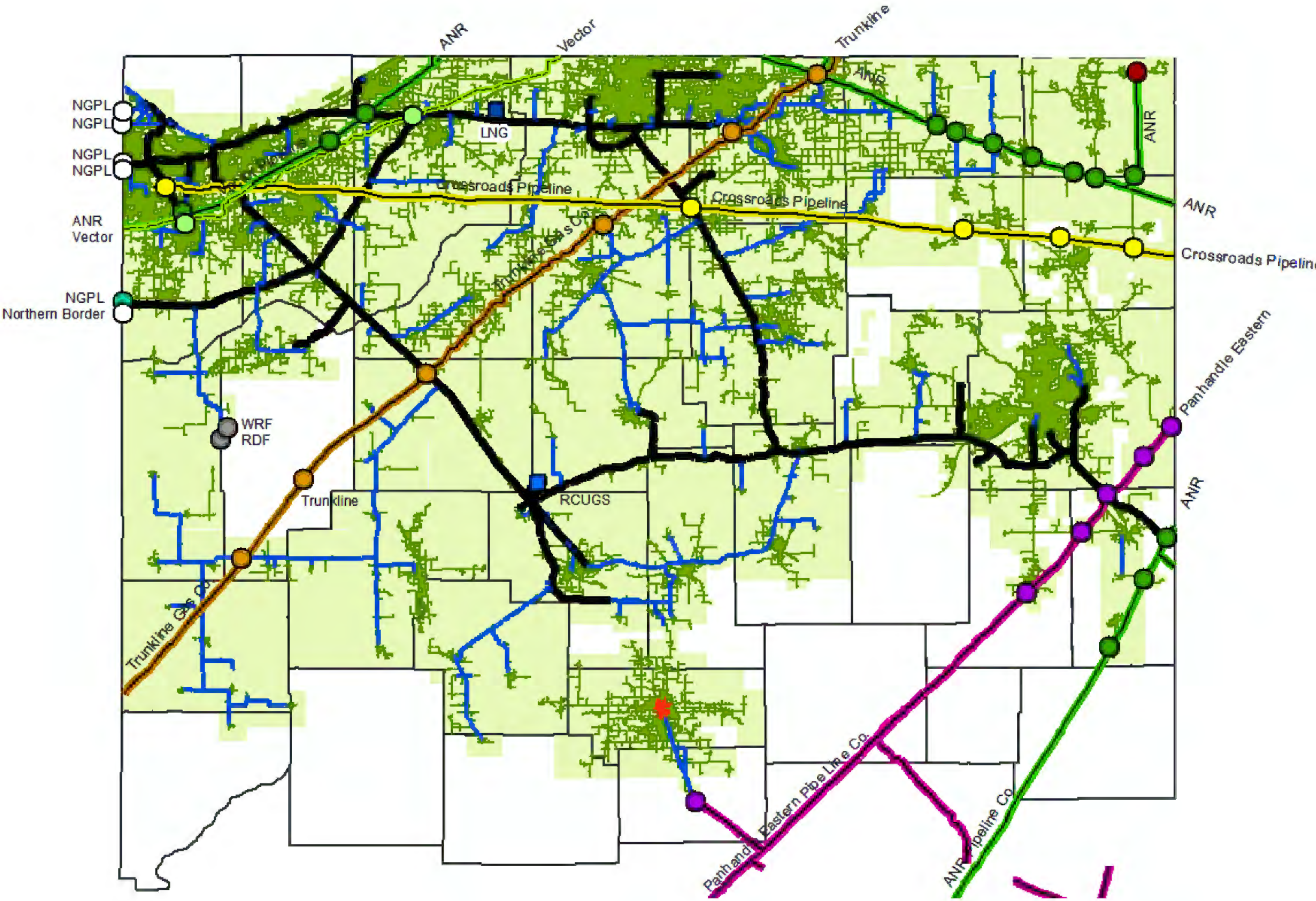
A: I reviewed the testimonial and evidentiary support provided by NIPSCO. I analyzed Petitioner's COSS and responses to DR's concerning its COSS to determine if Petitioner's revenue requirements represent the rate class responsibility of its share of cost. I also reviewed Petitioner's system maps along with the location of the highest volume users to assess customer use of transmission and distribution mains.

Northern Indiana Public Service Company
Load Characteristics of 400 Series Customers

Line No.			Number of Customers	Annual Usage (therms)	Design Day (therms)
1	Residential	411	754,839	622,207,258	7,770,286
2	Multi-Family	415	5,067	7,571,986	91,863
3	General Service Small	421	66,213	315,561,686	3,589,478
4	General Service Large	425	680	121,839,923	840,613
5	Large Transp.	428	157	2,307,465,604	8,163,661
6	C&I Off-Peak Interruptible	434	3	2,105,207	-
7	General Transportation	438	94	50,738,639	303,128
8	**Total**	**Total**	827,052	3,427,490,303	20,759,029

Northern Indiana Public Service Company
Load Characteristics of 100 Series Customers
2020 Customers, Normalized Throughput, Design Day

Line	Rate Schedule	Rate Code	Number of Customers	Annual Usage (therms)	Design Day (therms)	Load Factor
1	Residential	111	775,765	656,118,909	9,285,407	19.4%
2	Multiple Family	115	4,830	7,138,184	103,615	18.9%
3	General Small	121	67,284	294,488,709	3,952,915	20.4%
4	General Large	125	658	62,536,063	649,993	26.4%
5	Large Transport-DP	128 DP	105	187,206,621	2,555,994	20.1%
6	Large Transport-HP	128 HP	64	2,252,999,374	5,351,149	115.4%
7	Interruptible	134	2	1,055,641	-	
8	General Transport	138	89	48,065,999	235,338	56.0%
9	Total		848,797	3,509,609,499	22,134,411	
			-		-	


ANR
Vector
Trunkline
ANR
NGPL
NGPL
NGPL
NGPL
LNG
Crossroads Pipeline
Crossroads Pipeline
ANR
Vector
Trunkline Gas Co
ANR
ANR
Crossroads Pipeline
NGPL
Northern Border
Panhandle Eastern
WRF
RDF
Trunkline
RCUGS
ANR
Trunkline Gas Co
Panhandle Eastern Pipe Line Co.
ANR Pipeline Co.

Cause No. 45621
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Seventh Set of Data Requests

OUCC Request 7-005:
Please provide the Transmission Design Day percentage and Annual Throughput percentage used for the Transmission mains allocation in the COSS in Cause No. 44988.
Objections:
Response:
The Transmission mains allocation in the COSS in Cause No. 44988 was 56% on Design Day peak and 44% on Annual Throughput. See Cause No. 44988, Petitioner's Exhibit No. 15, page 8, lines 15 -17 and continuing on page 9, lines 1 -2.

Cause No. 45621
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Thirteenth Set of Data Requests

OUCC Request 13-014:
Referencing Petitioner's responses to OUCC DR 7.18 and 7.19. Is Petitioner aware of any state Commission orders that exclude high load factor rate classes from the system load factor calculation, which is then used for transmission allocation using the Peak and Average method? If yes, please provide a list of the orders, including the name of the utility, Cause No., and date of the order.
Objections:
Response:
No.

Design Day NIPSCO - Customers Served at High Pressure

		311	315	321	325	328	338		
	Actual Therms	311	315	321	325	328	338		
1	Jan					215,319,922	545,673		
	Feb					203,221,431	488,907		
	Mar					202,636,028	420,857		
	Apr					163,942,030	343,115		
	May					172,367,625	286,219		
	Jun					164,670,165	241,542		
	Jul					174,574,367	249,565		
	Aug					181,794,744	251,041		
	Sep					183,684,142	703,918		
	Oct					196,014,503	671,481		
	Nov					202,248,823	342,347		
	Dec					226,481,911	465,224		
	Annual	-	-	-	-	2,286,955,691	5,009,888		
	Customers								
	Jan					63	9		
	Feb					63	9		
	Mar					63	9		
	Apr					63	9		
	May					63	9		
	Jun					63	9		
	Jul					63	9		
	Aug					63	9		
	Sep					63	9		
	Oct					63	9		
	Nov					63	9		
	Dec					63	9		
	Therms/Customer/Day							Billing Days	Calendar Days
	Jan					110,250.9	1,955.8	32.52	31
	Feb					111,232.3	1,873.2	29.76	29
	Mar					103,756.3	1,508.4	30.14	31
	Apr					86,741.8	1,270.8	30.29	30
	May					88,257.9	1,025.9	28.67	31
	Jun					87,127.1	894.6	30.67	30
	Jul					89,387.8	894.5	32.00	31
	Aug					93,084.9	899.8	30.19	31
	Sep					97,187.4	2,607.1	31.24	30
	Oct					100,365.8	2,406.7	29.67	31
	Nov					107,010.0	1,268.0	28.19	30
	Dec					115,966.2	1,667.5	31.14	31
	Annual					1,190,368	18,272		
2	Jan HDD	1188	1188	1188	1188	1223	1223		
3	Design HDD	80	80	80	80	80	80		
	Design Peak Day								
4	January Customers	-	-	-	-				
5=Avg	Base Therms/Customer/Day	0.0	0.0	0.0	0.0				
6=5*4	Base Therms/Day in January	0	0	0	0				
7	January Days	32.52	32.52	32.52	32.52				
8=1-(6*7)	TS Therms in January	0	0	0	0				
9=8/2	TS Therms/HDD	0	0.00	0.00	0.00				
10=9*3	TS Therms at Design	0	0	0	0				
11=10+6	Trial Design Day - Therms	0	0	0	0	5,351,149	26,103		
	Trial Design Day Load Factor January	0%	0%	0%	0%				
12	Trial Design Day Total Therms	5,377,252							
13	Design Day Therms Jan 2020	5,377,252							
14=13/12	scale to model design	118%							
15=11*14	Scaled Design Day	0	0	0	0	5,351,149	26,103		
		5,377,252							

Design Day Allocation

Calculate design day for each rate using the base/temperature-sensitive approach.
* Base Therms/Customer/Day calculated from July-Sep using the average of the two months with minimum Therms/Customer/Day
* Base Therms/Day for January = Base Therms/Customer/Day * January Days
* TS Therms/HDD = (January Total Therms - Base Load Therms) / January HDD
* TS Therms at Design = (TS Therms/HDD) * HDD on Design Day
* Trial Design Day = (Base Therms/Day + (TS Therms at Design)
* Scale to model design day using ratio of model design day to trial design day

				HDD
Three Day Peak - 2020				
January 18, 2020	4,781,176	16,233	4,797,409	45
January 19, 2020	4,966,537	19,179	4,985,716	51
January 20, 2020	4,908,386	22,033	4,930,419	41
Three Day Peak - 2019				
January 29, 2019	5,719,654	26,977	5,746,631	67
January 30, 2019	5,591,847	26,545	5,618,392	77
January 31, 2019	5,317,883	24,515	5,342,398	63
Three Day Peak - 2018				
January 1, 2018	5,512,854	30,562	5,543,416	70
January 2, 2018	5,854,037	35,039	5,889,076	62
January 3, 2018	5,507,969	33,846	5,541,815	51
3-Year Average Three Day Peak	5,351,149	26,103		

American Iron and Steel Institute

AISI Releases Annual Statistical Report For 2020

June 30, 2021

Washington, D.C. – The American Iron and Steel Institute (AISI) today announced the release of its 2020 Annual Statistical Report (ASR), which provides comprehensive data on the American steel industry and select data on the North American steel industry as a whole.

“The steel industry remains a key focus of national and international policy, and AISI’s data continues to be a key resource,” said AISI President and CEO, Kevin Dempsey. “Our Annual Statistical Report (ASR) remains the industry standard for reporting on the steel market in the United States. I encourage anyone who is interested in steel industry data to purchase a copy.”

The report highlights that, in 2020, shipments from domestic steel mills measured 81.0 million net tons (NT), down 15.8 percent from the previous year. U.S. raw steel production was 80.2 million net tons in 2020, a 17.1 percent decrease from 2019. The report also shows that steel imports into the United States fell for the third year in a row. Total steel imports decreased 21 percent in 2020 compared to the previous year, while finished steel imports decreased 23 percent over the same period and captured an 18 percent share of apparent steel consumption. The report also notes that the construction and automotive industries continued as the leading end-use markets for shipments of U.S. steel products.

The AISI ASR report is the most comprehensive reference of its kind, providing extensive coverage of the American steel industry and selected statistical data on the Canadian, Mexican and world steel industries. It features dozens of charts and graphs, including selected statistical highlights on shipments, apparent supply, imports, employment and raw steel data over a 10-year period; selected financial highlights; shipments by products and markets over a 10-year period; raw steel production (including selected state-level production data) and capacity utilization; and detailed imports and exports data.

A copy of the 2020 Annual Statistical Report can be purchased by visiting the Platts Steel Data and Analysis website or by calling 1-800-PLATTS-8.

#####

Contact: Lisa Harrison
202.452.7115 / lharrison@steel.org

AISI serves as the voice of the American steel industry in the public policy arena and advances the case for steel in the marketplace as the preferred material of choice. AISI also plays a lead role in the development and application of new steels and steelmaking technology. AISI's membership is comprised of integrated and electric arc furnace steelmakers, and associate members who are suppliers to or customers of the steel industry. For more news about steel and its applications, view AISI's website at www.steel.org. Follow AISI on Facebook or Twitter (@AISISteel).

Northern Indiana Public Service Company, LLC
Monthly Consumption by Rate Class (Therms)

OUCC Request 7-003
Attachment A

	Rate 111	Rate 115	Rate 121	Rate 125	Rate 128	Rate 138	Rate 134
Jan-18	138,135,174	1,970,046	67,774,452	16,320,518	252,717,398	6,515,586	28,311
Feb-18	119,279,551	1,744,413	59,806,796	15,433,678	233,149,522	7,369,313	
Mar-18	89,186,307	1,323,704	44,012,002	12,365,949	239,133,372	5,832,482	
Apr-18	81,953,143	1,190,155	39,092,631	12,120,457	230,814,529	5,879,939	
May-18	40,916,318	672,640	19,927,220	8,532,854	217,753,109	5,684,887	39,770
Jun-18	14,027,566	272,321	7,950,040	5,680,865	203,837,218	4,336,183	56,806
Jul-18	11,142,675	217,946	6,448,015	5,158,680	210,519,531	3,578,817	139,514
Aug-18	11,139,757	217,623	7,016,867	5,204,800	211,998,357	4,504,135	221,888
Sep-18	11,099,297	216,342	7,474,565	5,154,934	200,960,705	3,537,830	664,550
Oct-18	19,778,465	353,253	15,219,843	6,533,717	185,492,533	4,101,431	424,889
Nov-18	62,551,207	953,996	32,859,965	10,986,113	222,216,431	5,703,879	130,518
Dec-18	95,971,899	1,362,530	47,746,003	14,016,632	236,968,211	6,549,550	54,289
Jan-19	110,875,161	1,616,248	54,919,345	14,545,335	242,411,553	6,047,160	1
Feb-19	131,342,639	1,840,571	65,066,974	16,164,980	225,661,103	7,298,365	
Mar-19	110,409,213	1,075,865	54,988,405	15,199,698	248,329,066	6,152,379	
Apr-19	67,025,041	422,816	33,071,644	11,354,552	236,175,332	6,013,692	
May-19	38,782,131	551,486	18,445,149	7,843,851	225,178,194	4,447,791	
Jun-19	19,363,595	297,720	10,255,804	6,220,109	190,542,566	3,862,402	
Jul-19	12,515,458	190,316	7,594,456	5,445,403	211,602,413	3,812,115	106,327
Aug-19	10,245,285	(3,404)	6,593,579	5,243,727	210,269,699	3,719,629	202,096
Sep-19	11,749,521	182,028	8,353,741	4,745,764	195,605,935	3,579,368	167,919
Oct-19	17,673,065	(1,031,123)	12,761,139	7,298,441	183,057,393	3,869,914	1,202,339
Nov-19	62,434,089	784,898	37,838,281	9,904,189	221,375,644	5,855,103	862,035
Dec-19	94,850,938	737,534	51,715,349	13,311,841	237,512,039	5,990,913	456,440
Jan-20	104,131,356	(680,295)	53,141,282	15,391,282	238,104,148	5,623,011	18,280
Feb-20	106,598,982	1,151,037	53,956,607	13,663,064	231,528,138	5,836,828	
Mar-20	95,449,742	1,052,647	47,370,048	12,889,327	230,046,320	5,601,674	
Apr-20	65,218,695	725,260	29,918,190	8,718,225	202,523,666	4,836,001	
May-20	44,843,170	491,651	19,191,375	6,915,520	193,131,264	3,655,266	26,268
Jun-20	19,427,397	218,324	9,720,140	5,240,096	183,741,278	3,502,497	65,914

Jul-20	12,308,603	121,018	7,020,571	4,485,622	193,976,768	3,277,309	58,398
Aug-20	11,127,021	105,690	6,906,748	4,812,370	199,491,379	3,265,461	66,512
Sep-20	11,894,748	114,510	8,453,150	5,001,134	195,309,294	3,437,882	105,210
Oct-20	22,044,125	239,974	16,390,647	5,896,172	223,863,482	4,192,566	152,526
Nov-20	45,091,776	488,988	27,492,792	7,963,072	226,345,586	5,048,640	502,377
Dec-20	80,638,724	872,261	40,114,141	11,977,611	248,485,099	4,672,968	60,156
Jan-21	117,743,466	1,228,187	57,389,775	14,286,015	253,209,948	5,557,001	
Feb-21	122,405,158	1,278,582	62,208,031	15,168,412	229,392,634	5,999,249	
Mar-21	102,830,820	1,111,066	52,102,375	13,721,248	237,708,604	6,225,017	
Apr-21	55,540,963	607,397	27,360,989	8,898,517	228,359,607	5,147,287	
May-21	37,584,273	382,361	18,480,256	7,313,740	224,883,379	4,397,116	
Jun-21	18,931,627	201,905	10,218,895	5,590,912	214,538,231	4,116,644	67,119
Jul-21	11,876,877	114,659	7,584,880	4,857,918	214,376,453	3,530,830	61,784
Aug-21	11,038,065	97,938	7,696,911	4,866,586	209,338,595	3,811,757	76,880
Sep-21	11,390,101	105,354	8,613,011	5,025,349	195,253,354	3,803,415	111,781
Oct-21	13,454,830	137,476	12,417,672	5,209,846	197,689,948	4,268,494	159,325

Northern Indiana Public Service Company, LLC
Peak Daily Demand per Month (Therms)
Rates 128 and 138

	Rate 128	Rate 138
Jan-18	8,547,034	271,437
Feb-18	8,260,015	249,352
Mar-18	7,908,590	209,117
Apr-18	7,746,116	217,276
May-18	6,976,083	142,904
Jun-18	6,821,967	134,582
Jul-18	6,934,659	134,597
Aug-18	6,870,325	133,854
Sep-18	6,920,797	162,685
Oct-18	6,316,472	204,793
Nov-18	7,873,489	244,665
Dec-18	7,908,937	217,693
Jan-19	8,282,343	267,895
Feb-19	8,130,271	241,609
Mar-19	8,396,014	253,726
Apr-19	7,813,017	178,294
May-19	7,437,963	140,958
Jun-19	6,723,119	138,791
Jul-19	6,979,524	129,561
Aug-19	7,021,678	131,592
Sep-19	7,037,980	146,828
Oct-19	6,395,742	199,074
Nov-19	7,946,297	235,181
Dec-19	8,055,571	223,099
Jan-20	7,990,206	213,893
Feb-20	8,129,315	211,832
Mar-20	7,479,502	161,285
Apr-20	6,655,800	136,973
May-20	6,855,050	141,847
Jun-20	6,551,070	123,285
Jul-20	6,577,093	120,370
Aug-20	6,844,955	125,864
Sep-20	7,330,145	166,916
Oct-20	7,469,046	175,114
Nov-20	7,818,557	185,132
Dec-20	8,502,864	199,116
Jan-21	8,445,662	216,014
Feb-21	8,391,222	239,899
Mar-21	7,954,528	201,660
Apr-21	7,654,477	190,221

May-21	7,384,605	177,551
Jun-21	7,233,455	129,071
Jul-21	6,978,039	142,623
Aug-21	6,719,506	133,384
Sep-21	6,652,040	158,599
Oct-21	6,578,278	166,686

Northern Indiana Public Service Company **OUCC Request 7-002 Attachment A**

Customer / Site Name	2020 Peak Demand / Daily Usage (Therms)	Date of Peak Demand	Location	Pressure (psi)	Proposed Rate Class	Annual Consumption (Therms)
[redacted]	916,390	10/1/2020	EAST CHICAGO	380	228	254,848,878
	578,189	9/17/2020	WHITING	160	228	119,877,450
	157,346	12/29/2020	GARY	160	228	31,984,289
	1,432,053	2/26/2020	PORTER	295	228	396,659,593
	750,105	2/1/2020	EAST CHICAGO	483	228	181,577,912
	473,022	2/13/2020	EAST CHICAGO	483	228	112,822,373
	79,178	2/26/2020	NEW CARLISLE	295	228	17,222,859
	88,840	10/29/2020	EAST CHICAGO	385	228	30,204,774
	76,926	10/2/2020	REMINGTON	280	228	1,664,153
	73,703	3/7/2020	PORTAGE	295	228	11,819,873
	79,108	12/14/2020	VALPARAISO	200	228	20,121,771
	92,171	11/28/2020	SOUTH BEND	295	228	19,863,747
	142,262	12/14/2021	COLUMBIA CITY	500	228	38,236,925
	164,822	1/25/2020	BUTLER	160	228	49,341,803
	112,169	10/5/2020	LOGANSPORT	295	228	32,179,673
	1,463,547	12/18/2020	GARY	483	228	403,448,111
	233,345	1/21/2020	PORTAGE	275	228	59,969,859
	89,273	8/24/2020	NOTRE DAME	150	228	22,554,488
	96,946	10/9/2020	BLUFFTON	400	228	7,961,106
	928,425	3/31/2020	WHITING	483	228	271,288,159

Customer / Site Name	Maximum Metered Daily Demand Dec 2019 (Therms)	Maximum Metered Daily Demand Jan 2020 (Therms)	Maximum Metered Daily Demand Feb 2020 (Therms)	Maximum Metered Daily Demand Dec 2020 (Therms)	Maximum Metered Daily Demand Jan 2021 (Therms)	Maximum Metered Daily Demand Feb 2021 (Therms)	2020 Peak Demand (any month)
[redacted]	769,165	755,221	766,093	846,260	765,370	820,386	916,390
	554,128	498,450	398,835	517,237	529,137	483,691	578,189
	148,648	135,319	123,660	157,346	175,990	145,784	157,346
	1,443,508	1,379,557	1,432,053	1,416,521	1,481,512	1,463,960	1,432,053
	753,549	739,778	750,105	604,446	652,610	656,117	750,105
	447,639	464,021	473,022	459,659	430,489	472,130	473,022
	73,182	75,305	79,178	73,119	73,049	80,263	79,178
	86,797	84,765	87,205	85,395	84,619	89,047	88,840
	-	-	-	-	-	-	76,926
	75,105	65,761	60,919	66,832	70,987	71,280	73,703
	71,398	73,865	75,525	79,108	80,682	83,006	79,108
	20,263	44,401	86,622	86,139	77,729	88,304	92,171
	145,353	142,262	141,697	139,683	147,596	157,185	142,262
	170,329	163,734	163,404	164,822	179,048	179,764	164,822
	112,668	103,612	105,922	107,942	104,616	106,061	112,169
	1,244,849	1,288,461	1,360,240	1,463,547	1,439,658	1,508,095	1,463,547
	216,703	233,345	228,679	215,497	227,454	234,475	233,345
	79,193	80,248	81,854	62,687	65,255	71,930	89,273
	-	-	-	91,312	82,981	90,866	96,946
	903,535	892,224	872,619	904,744	913,177	993,020	928,425
						7,795,364	

[redacted]

Cause No. 45621
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Thirteenth Set of Data Requests

OUCC Request 13-005:
For each of Petitioner's top 20 customers as shown in its response to OUCC DR 7.2, state whether each customer's rate class is either high-pressure transport (Rate 128 HP) or distribution pressure transport (Rate 128 DP).
Objections:
Response:
All of NIPSCO's top 20 customers with the highest peak demand in January to December 2020 are high-pressure transport (Rate 128 HP) customers.

Cause No. 45621
Northern Indiana Public Service Company LLC's
Objections and Responses to
NIPSCO Industrial Group's Eighth Set of Data Requests

Industrials Request 8-024:
Has Mr. Amen presented testimony advocating a peak and average method for the allocation of mains costs (other than NIPSCO) in the last 10 years? If the answer is yes, please provide all such testimony.
Objections:
Response:
Yes. Mr. Amen presented testimony that included a peak and average method for transmission mains costs in Arkansas Oklahoma Gas Corporation cases Docket No. 13-078-U (Arkansas) and Cause No. PUD 201200236 (Oklahoma). The testimony can be found on the respective websites of the Arkansas Public Service Commission and the Oklahoma Corporation Commission.

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
ARKANSAS OKLAHOMA GAS CORPORATION	**)**	**DOCKET NO. 13-078-U**
FOR APPROVAL OF A GENERAL CHANGE IN	**)**	
RATES AND TARIFFS	**)**	

DIRECT TESTIMONY OF

RONALD J. AMEN

ON BEHALF OF

ARKANSAS OKLAHOMA GAS CORPORATION

OCTOBER 15, 2013

TABLE OF CONTENTS

DIRECT TESTIMONY OF RONALD J. AMEN

I. Background History of Witness

Q. Please state your name and business address.

A. My name is Ronald J. Amen. My business address is 17806 NE 109th CT, Redmond, WA 98052.

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

A. I am a Director with Black & Veatch Corporation ("B&V") and a member of the Financial & Regulatory Services Business Line of B&V's Management Consulting Division. B&V is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q. Please describe B&V's business activities.

A. B&V has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Its Management Consulting Division delivers management consulting solutions in the energy and water sectors. Our services include strategic, regulatory, financial, and information systems consulting. In the energy sector, B&V's Management Consulting Division delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

From an industry-wide perspective, B&V has extensive experience in all aspects of the North American natural gas and electric industries. Included in B&V's

relevant experience are the areas of 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. B&V has assisted numerous utility companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over thirty-five (35) years of experience in the utility industry, the last sixteen (16) 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, industrial end-users, and energy marketers in matters pertaining to costing and pricing, regulatory planning and policy development, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Appendix A to my testimony.

Q. Have you testified previously before the Arkansas Public Service Commission ("the Commission") or other utility regulatory commissions?

A. Yes. I have previously testified before the Arkansas Public Service Commission in Docket Nos. 02-024-U and 07-026-U, and have testified as an expert on utility ratemaking and regulatory issues before the utility regulatory commissions in the jurisdictions listed in Appendix A.

II. Purpose of Testimony

Q. For what purpose have you been retained by Arkansas Oklahoma Gas Corporation ("AOG" or the "Company")?

A. I have been retained by AOG as a consultant in the area of utility costing and rate design and related regulatory matters. Among the varied consulting support for AOG's general rate case, AOG has requested that I assist the Company by conducting a cost of service study, used to determine the embedded costs of serving the Company's customers. In addition, I have performed various statistical, costing and pricing analyses related to the provision of gas distribution and transportation-related services on AOG's system.

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

A. First, I will present and explain AOG's proposed measure of normal weather for purposes of setting base rates in its general rate case and adjusting for the effect of weather under AOG's Weather Normalization Adjustment ("WNA") clause to assist the Company with the recovery of its Commission authorized level of non-gas margin revenues.

Second, I will present the results of the retail natural gas cost of service study ("COSS") filed by the Company in this proceeding ("G" Schedules). I will discuss the underlying methodology and basis used in the Company's gas COSS.

Third, I will be supporting the level of revenue responsibility between customer classes as a result of the revenue requirement proposed by AOG in this proceeding and as supported by the COSS. I will discuss the use of cost of service results as a guide to be incorporated into the rate design process. Because the results of the COSS suggest shifts in revenue responsibility between customer classes, I will discuss proposed changes in the rates of all the Company's rate schedules that reflect the COSS results ("H" Schedules).

Finally, I will discuss the Company's proposals for changes to the various rate schedules, including the elimination of the Pooling Rate currently applicable to the Medium Business and Large Business Transportation customers. I will also address the level of the various rate components within the rate schedules, in particular, the monthly customer charges for Residential and Small Business customers.

III. List of Exhibits Sponsored in Testimony

Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following Schedules and Exhibits:

Schedules G – 1 through G – 5.2

Schedules H – 1 through H - 5

Direct Exhibit RJA – 1**,** Weather Normal Analysis – Tabular Results

Direct Exhibit RJA – 2, Weather Normal Analysis – Graphical Presentation

Direct Exhibit RJA – 3, Weather Normal Analysis – Five-year Comparison, Arkansas versus Oklahoma

Direct Exhibit RJA – 4, Zero Intercept Study Results

Direct Exhibit RJA – 5, Revenue Requirement by Demand, Customer, and Commodity by Rate Class (Unit Cost Report)

Direct Exhibit RJA – 6, Typical Residential Customer Bill Comparison

IV. <u>Normal Weather Determination</u>

Q. Is AOG proposing to change the weather basis upon which its customer loads are normalized for weather?

A. Yes. AOG is proposing to use a 10-year Heating Degree-Days ("HDD") average to normalize its annual gas throughput volumes for purposes of determining pro forma revenues in general rate cases and for use in its WNA clause. Historically, a 30-year HDD average using HDD data sourced from the National Oceanographic and Atmospheric Administration's ("NOAA") has been used to normalize its gas volumes for weather. Under the 10-year average, the Company's measure of normal weather will be established at 2,966 HDD for its

Arkansas service territory, compared to a 30-year average of 3,206 HDD, NOAA's most recently computed 30-year average is 3,218 HDD for the years 1981-2010 (NOAA calculates its 30-year average once every ten years).

Q. Why has the Company chosen to modify the manner in which its gas volumes are weather normalized?

A. The use of a 10-year HDD average will result in improved forecasting for normalizing AOG's gas throughput volumes. This means that the annual gas volumes established in the Company's current rate case will better reflect the expected normal weather conditions during the period in which its base rates will be in effect.

Q. Please explain the methodology to determine the most appropriate weather predictor to normalize its annual gas throughput volumes for weather.

A. First, an examination of the Company's annual HDD averages over the 82-year period from 1931 to 2012. The goal of our analysis was to determine the best predictor of future HDD levels for purposes of "normalizing" actual natural gas consumption during the test year and for the upcoming timeframe when the Company's new rates are expected to be in effect. A common forecasting technique was used that estimates the average annual HDD for a given timeframe, and then uses those results to predict weather in the forecast year. In this case, the Company's "forecast year" is based on the Pro Forma Year ended December 31, 2014. For this analysis, I tested four alternative means of forecasting HDDs: (1) a 30-year average of annual HDD data ending in 2012; (2)

a 20-year average of annual HDD data ending in 2012; (3) a 10-year average of annual HDD data ending in 2012; and (4) a 5-year average of annual HDD data, ending in 2012. A statistical comparison of the predictive capability of these four timeframes was conducted to determine which one was most appropriate.

Q. Please describe the type and source of the data used to analyze the choice of normal weather for AOG.

A. First, the Company adopted the standard NOAA definition of a heating degree-day - the difference between the average daily temperature (based on maximum and minimum daily temperatures) and 65 degrees Fahrenheit (or zero, if the average temperature is above 65 degrees Fahrenheit). All data used in the Company's weather analysis was sourced from NOAA data files and/or reports that presented temperature and HDD data on a daily basis. The Ft. Smith NOAA weather station was used to construct the 82-year data series of HDDs applicable to the Company's service area.

Q. Please describe how the HDD data was analyzed.

A. First, weather averages were calculated for the four alternatives being tested starting in 1931, so it was possible to calculate 30-year, 20-year, 10-year, and 5-year averages for the years 1901 through 2012. Each of the four alternative averages for each year were compared to the actual HDD value observed one year later. For example, the four averages for 1931 were compared with the actual HDD for 1932, recording the difference (or error) between the actual and forecasted values for each of the four averages being tested. This analysis was repeated up to 2012 – the most recent year for which actual annual HDD data existed. This analysis is comparable to the process followed within the context of a rate case. The Company attempts to use data ending in the test year – calendar 2013 – in order to predict weather in the following year when its approved rates will be in effect.

Q. How did you compare the predictive capabilities of the weather averages that were tested?

A. A statistical analysis was conducted to compare the predictive capabilities of the four selected averages. A standard statistic called the Root Mean Squared Error ("RMSE") was calculated. The RMSE statistic is a number representing the degree to which the forecasted values fail to correspond to the actual data. It is a widely used measure to assess the accuracy of point forecasts. Comparing the RMSE for the four selected averages tested provides information about which is the best predictor of the next year's HDD. A lower RMSE indicates a better predictor. While there are other statistical measures used to convey information about a forecast's performance, such as the mean error or mean absolute error, these measures tend to de-emphasize the consistency of the forecasting technique while the RMSE tends to emphasize this element of the forecast's predictive capabilities.[1] In the case of AOG, the smaller the

---

[1] See Harold E. Brooks and Charles A. Doswell III, "A Comparison of Measures-Oriented and Distributions-Oriented Approaches to Forecast Verification," NOAA/Environmental Research Laboratories, National Severe Weather Storms Laboratory, Weather and Forecasting, September 1996 issue.

RMSE, the smaller the overall difference between the actual and forecasted HDD. The formula for the RMSE is:

$$\text{RMSE} = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(HDD_i - HDD_i^F)^2}$$

Where:

n = the number of years

i = year of the observation

HDD_i = Actual observed values

HDD_i^F = Forecasted values

All RMSE values that were derived are stated in HDD.

Q. Please describe the results of this analysis.

A. Direct Exhibit RJA – 1 presents in tabular form the annual HDD data for the Company, the four sets of weather averages tested, and the forecast error and RMSE resulting from each weather average, for the Company's service area. Over the 82-year period, the 10-year HDD average outperforms the 30-year average in predicting weather the following year. In other words, 10-year averages tend to produce more precise forecasts of HDD than 30-year averages. Forecast errors can be compared by calculating the <u>percentage improvement</u> or IMP. The formula for IMP is:

$$\text{IMP} = 100 \times \frac{E_R - E_F}{E_R}$$

Where:

E_R = the RMSE error statistic generated by the reference forecast[2]

E_F = the RMSE error statistic from the alternative forecasts

The relative performance of the forecasts for the three alternative forecast timeframes tested (20-, 10- and 5-year timeframes) showed improvement over the 30-year average HDD reference forecast in all instances. In particular, the IMP for the 10-year average was the highest, at 12.37% over the 82-year period. In fact, as the number of years included in the analysis was reduced, e.g. the most recent 40, 20 and 10-year periods, the IMP for the 10-year average HDD forecast increased to 25.72%. Based on the RMSE test, therefore, the 10-year average represents a better basis for purposes of forecasting HDD during the time when the Company's approved rates in this case go into effect.

Q. Is this statistical conclusion supporting the adoption of a 10-year weather normal illustrated by examining the Company's HDD data plotted together with the 30-year and 10-year weather averages?

A. Yes. Direct Exhibit RJA – 2 presents graphical comparisons of the Company's HDD data and compares it to the 30-year and 10-year averages just discussed. Upon close examination of Direct Exhibit RJA – 2, it is readily evident that the ability of the 30-year averages to track the actual variation in HDD over time is

[2] In this instance, the reference forecast is the 30-year average HDD.

"dampened" because of the greater number of years included in the weather averages and the inherent lag in the computation of these averages. In contrast, the exhibit shows that the 10-year average more closely tracks the ongoing variation in HDD. This occurs because of the fewer number of years used to compute the average and the "rolling" aspect of the computation. Page 2 of the exhibit presents together the 30-year and 10-year averages with the actual HDD.

The 10-year average more accurately reflects the changing trends of the weather, which is exactly what is sought when using this average for ratemaking purposes, as a measure of normal weather in the Company's service area.

Q. What benefit should AOG's Arkansas customers expect from a weather normal that more closely tracks recent weather trends?

A. With a weather normal that more accurately reflects current trends in weather patterns, customers' volumetric distribution rates, which are based on normal weather, will be more accurate and therefore will result in smaller weather related adjustments to the distribution rates under AOG's WNA clause.

Q. Can you provide recent evidence of the benefit to customers of smaller weather-related rate adjustments where 10-year weather normal is used?

A. Yes. AOG has utilized a 10-year weather normal in the neighboring Oklahoma jurisdiction since 2007. Direct Exhibit RJA – 3 illustrates the magnitude of the differences between the rate adjustments under the Company's respective WNA clauses in its Arkansas versus Oklahoma jurisdictions. Over the previous five years, the annual HDD differences from normal in Arkansas ranged between a high of 1,007 HDDs and a low of 124 HDDs. During that same 5-year period, the annual HDD differences from normal in Oklahoma ranged between a high of 725 HDDs and a low of 4 HDDs. The corresponding annual WNA revenues as a percentage of distribution revenue in Arkansas ranged from a high of 23.73% in fiscal 2012 to a low of 2.18% in fiscal 2009. The annual WNA revenues in Oklahoma over the 5-year period ranged from a high of 17.64% in fiscal 2012 to a low of 0.45% in fiscal 2011, indicating smaller relative variations from normal weather and therefore smaller adjustments to customers' bills.

V. <u>Cost of Service Study</u>

A. Purpose and Guiding Principles of Cost of Service

Q. Please state the purpose of a COSS.

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

Q. Are there certain guiding principles that 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 particular types of costs? To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

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

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

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account.

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

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

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

B. Process Steps to the Cost of Service Study

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

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include:

production, transmission, distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics 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 class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

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

A. All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does one establish the cost and utility service relationships you previously discussed?

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

Q. Please explain what you mean by the term "direct assignment."

A. The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods.

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

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

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

C. G and H Schedules

Q. Please describe the information contained in the G and H Schedules.

A. The G schedules contain the results of the cost of service analysis of the Company's Arkansas operations. The H Schedules contain the rate design analysis for the Arkansas rate classes. The information presented in the various schedules is summarized below:

G – 1 Cost of Service Study Summary

G – 2 Rate Base Allocation to Arkansas Rate Classes

G – 3 Revenue and Expense Allocation to Arkansas Rate Classes

G – 4 Development of Allocation Factors

G – 5.2 Arkansas Customer Load Data

H – 1 Revenues by Rate Class at Present and Proposed Rates

H – 2 Rate Schedule Revenues by Detailed Rate Components at Present and Proposed Rates

H – 3 Typical Bill Analysis at Varying Levels of Consumption by Rate Schedule

H – 4 Bill Frequency Analysis does not apply to AOG since there are no block rates in the rate design

H – 5 Derivation of Rate Designs by Rate Schedule

Q. How are the rate classes structured for purposes of the COSS?

A. The COSS evaluated five rate classes: Residential, Small Business, Compressed Natural Gas (CNG), Medium Business, and Large Business. The Medium and Large Business classes include the costs and revenues of both the sales and transportation customers. As explained in Company witness Callan's testimony, a new CNG class has been established consisting of the Company's investment and associated operation and maintenance costs in its two CNG public refueling stations.

D. Cost of Service Study Results

Q. Please summarize the results of the COSS.

A. As shown on Schedule G – 1, the COSS indicates that at current rates the Company's overall rate of return is 1.0226% (Line 28), which is below the proposed overall rate of return of 6.7353%. Overall, AOG's Arkansas operations require an increase in rate schedule revenue of 26.67%. The class rates of return vary from a negative 0.6679% to 3.6319%. At the proposed overall rate of return, all classes have operating income deficiencies (Line 32).

Q. Please describe the information presented in Schedules G – 2 and G – 3.

A. Schedule G – 2 presents the allocation of the Company's rate base by Federal Energy Regulatory Commission ("FERC") account to the various rate classes. Schedule G – 3 presents the allocation of the Company's functionalized Operations and Maintenance ("O&M") expenses by FERC account to the rate classes. The allocation factor employed in the COSS for each account is shown in column (4) of the Schedules G – 2a and G – 3a.

Q. Please describe the information presented in Schedule G – 4.

A. The external and internal allocation factors employed in the COSS are described in Substitute Schedule G – 4. The resulting class-by-class values for each of the external and internal allocation factors are shown in this schedule.

Q. Please describe the information presented in Schedule G – 5.2.

A. Substitute Schedule G – 5.2 presents the operating characteristics of the AOG system for the test year.

Q. How were Transmission plant costs treated in the COSS?

A. Transmission plant costs were classified 59.14% as demand-related and 40.86% as commodity-related. Demand costs were allocated on the basis of peak day and the commodity costs were allocated on the basis of normal throughput volumes.

Q. Why was the Company's investment in Transmission plant classified 59.14% as demand-related and 40.86% as commodity-related?

A. The Transmission facilities serve two functions, in that the facilities deliver gas supplies both during peak periods and on a year-round basis and are sized accordingly. A review of Arkansas Operating Statistics shows that 59.14% of the Company's weather normalized sales occur during the winter (peak) period. Based on this fact, 59.14% of this plant was classified as demand-related and 40.86% as commodity-related. This approach to the classification of Transmission plant was accepted by the Commission in a prior AOG general rate proceeding.[3]

E. Classification and Allocation of Distribution Mains

Q. How did the Company's COSS classify and allocate investment in Distribution Mains?

A. The Company classified 34.5% of its investment in distribution mains as customer related and 65.5% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on AOG's system. The demand related investment was allocated to the customer classes on the basis of their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

---

[3] Arkansas Public Service Commission Order in Docket No. 05-006-U, dated December 1, 2005, pages 38-40.

Q. Please explain the basis for the Company's choice of classification and allocation methods?

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

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

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

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

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

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, <u>Electric Utility Cost Allocation</u>

Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

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

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

Q. With respect to the Company's specific operating conditions, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, a cost analysis of the Company's investment in distribution mains, by size of main installed, was conducted. This analysis, known as the zero-intercept method, typically uses linear regression analysis to compare unit costs of the various sized distribution mains installed on AOG's gas system against the size (diameter) of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. The linear regression analysis can be expressed formulaically as follows:

$$y = mx + b$$

Where: y = average cost per installed foot of AOG's distribution mains

m = cost per installed foot, per inch of pipe diameter

x = diameter of distribution mains

b = minimum cost per installed foot (the zero-intercept)

This equation determines that regardless of the main's diameter, the average cost of a distribution main on AOG's gas system will be at least equal to a minimum cost per installed foot. This per foot cost component is exclusively related to the simple fact that AOG incurs this cost to install a main, regardless of its size. That is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of AOG's distribution mains as distinguished from the per foot demand cost component, which is equal to a cost per foot times the diameter of the distribution main.

Q. Has the Zero Intercept method of analysis been employed previously by the Company and accepted by the Commission for the purpose of determining a customer component of distribution mains?

A. Yes. The Company used the zero intercept approach in its last three rate cases. In Docket No. 02-024-U, the Company's zero intercept analysis was accepted with modifications by the Commission Staff as an appropriate method to determine the customer component of distribution mains. In its Order in Docket No. 05-006-U, the Commission found that "there is a properly recognized customer component of distribution mains costs" and accepted the application of the zero intercept method as a reasonable statement of the zero capacity, customer related portion of the Company's distribution mains costs.[4]

Q. Did you perform any additional analysis to address common statistical weaknesses of the zero-intercept linear regression?

A. Yes. A common statistical limitation of the zero-intercept regression analysis is the lack of sufficient data points, due to the limited number of pipe sizes that are typically employed in the construction of distribution mains. This was addressed by compiling unit cost data points for the "m" variable in the formula for each vintage year in which a particular pipe size was installed. In addition a corresponding capacity variable was developed for each unit cost data point that represented the average volume of gas (in cubic feet) per 1,000 feet of gas

[4] Arkansas Public Service Commission Order in Docket No. 05-006-U, dated December 1, 2005, pages 34-35.

pipeline, based on its size (diameter) and operating pressure (PSIG). A multiple regression analysis was performed utilizing the weighted least squares method, which applies a weighting factor to the data points of the independent and dependent variables based on the total amount of footage installed for that pipe size in the respective vintage years. The supplemental regression analyses provided statistically significant results and, while somewhat higher, approximated the linear regression results from the Company's prior rate case, which was a composite 34.5% classification of distribution mains as customer related. The results of this analysis, based on the Company's investment in plastic and steel mains, are shown in Direct Exhibit RJA – 4.

Q. Do the results of the zero-intercept method described above therefore support the 34.5% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the weighted average of the regression results for plastic and steel mains of $6.15 per foot cost of the "zero inch" distribution main to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 41.39% of the total investment in distribution mains, on a current cost (year 2013) basis. For purposes of maintaining stability in the classification of distribution mains, given the similar results between the multiple regression results described above and the linear regression from the Company's prior rate cases, AOG has elected to retain the 34.5% customer component.

Q. Would one expect there to be a strong correlation between the number of customers served by AOG and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of AOG's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by AOG represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

Q. How were the remaining Distribution Plant costs treated in the COSS?

A. Where possible, costs were directly allocated to the customer classes based on the data contained in the Company plant records. Direct assignment accounted for the bulk of the costs in FERC Account Nos. 380 (Services); 381 (Meters); 382 (Meter Installations); 383 (House Regulators); and 385 (Industrial M&R Equipment). Plant costs associated with the Company's two CNG public refueling stations were directly assigned to the new CNG class. These costs are recorded in Account Nos. 374.1 (Land – CNG), 381 (Meters), 385 (Industrial Measurement & Regulating Equipment), 390 (Structures & Improvements), 394 (Shop Equipment), and 397 (Communication Equipment). The costs in Account No. 374 (Land) were classified and allocated based on the prior allocation of the plant in Account Nos. 376 through 379.

Q. How were the General Plant costs classified and allocated in the COSS?

A. General Plant costs were classified and allocated to the rate classes based on an internal allocation factor generated from the results of the classification and allocation of transmission and distribution plant costs.

Q. How were O&M expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the O&M expenses followed the treatment of the related plant accounts with the exception of Account Nos. 870 (Distribution Operations Supervision and Engineering), 880 (Distribution Other), and 881 (Distribution Rents). The distribution supervision, office and rent expenses were allocated on internal factors based on the classification and allocation of the directly allocated distribution O&M expenses.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS?

A. All of these expenses were classified as customer-related costs and allocated based on the number of customers by class. Exceptions to this treatment were Account Nos. 901 (Supervision) and 904 (Bad Debt Write-offs). Supervision expenses were allocated based on the other directly allocated costs in the category. Bad debt expenses were assigned to the residential and small business classes based on the historical expense levels for these two classes.

Q. Please explain the treatment of Administrative and General expenses in the COSS?

A. The majority of the Administrative and General ("A&G") expenses were classified and allocated based on either labor or plant according to the nature of the underlying costs, that is, whether the particular A&G expense was labor-related or plant-related. Gas Supply Management (formerly Pooling Service) related expenses from Account 920 (A&G Salaries) were directly assigned to the Medium and Large Business classes. Account 928 (Regulatory Commission) expenses, which consist of legal, consulting and other outside services fees related to the processing of the Company's general rate case as well as certain state and federal regulatory assessments, were allocated on the basis of total O&M expenses, not including A&G expenses. Use of a total O&M allocation factor for Regulatory Commission expense generally captures the broad nature of administrative costs such as this and reflects the rate case process, whereby the Company's rate base, associated return on invested capital, and annual operating expenses are evaluated.

Q. Please explain how Depreciation expenses and Taxes Other Than Income were treated in the COSS?

A. The classification and allocation of Depreciation expenses followed the allocation of the plant to which these costs are related. Taxes Other Than Income were allocated on the basis of either labor (e.g., Payroll taxes) or plant (e.g., Arkansas Ad Valorem taxes) depending on the nature of the tax, that is, the basis upon which the tax or fee is assessed.

VI. Revenue Allocation and Rate Design Principles

Q. How can the COSS results provide guidelines for rate design?

A. COSS results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the rate of return results show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q. Do the COSS results provide guidance in establishing rates within each rate class as well?

A. Yes. The classified costs, as allocated to each class of service within the COSS, provide useful cost information in determining the level of customer, demand and commodity charges.

Q. Please explain how the classified costs can be used for rate design.

A. Direct Exhibit RJA – 5 provides a summary of the Company's functionalized revenue requirement per unit of peak demand, annual throughput (commodity) and customer count for each rate class. If the classified costs presented in this schedule were used to set three-part rates (Customer, Demand and Commodity), the Company's operating expenses and return on investment in its pro forma revenue requirement would be recovered.

Q. Should other factors be considered that would prevent the Company from simply translating the unit costs into rates for the various tariff services?

A. Yes. Completely restructuring a utility company's rates mechanistically to match the COSS is usually not desirable due to the resulting adverse impact on certain customer classes, particularly for smaller, low load factor customers. However, the use of three part rates has become more widely accepted as the unbundling of utility services continues to evolve and the sale of the gas commodity in a competitive market is distinguishable from utility delivery service. The unit costs do provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either demand metering is available or algorithm-based billing demands can be determined. Demand based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service. The Company is proposing to increase the demand charge for its Large Business rate class, as discussed later in my testimony.

Q. Please describe other considerations or criteria that should be used in the design of utility rates.

A. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, customer impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices where appropriate, such as the case with the developing market for CNG, could be a factor. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound rate-making practice to recover a substantial portion of fixed costs, such as customer related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate schedule. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well founded energy consumption decisions. However, where volumetric rates are employed to recover fixed costs, weather normalization adjustment mechanisms as well as revenue decoupling mechanisms can serve to improve cash flow, reduce the over- and under-recovery of non-gas revenues, and reduce customer bill volatility.

Q. How then are the foregoing guidelines and criteria incorporated into the rate design process?

A. A reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations can impact the rate design process. Both quantitative and qualitative factors must be considered in reaching a final rate design. Thus, it is necessary to allow the rate design process to be influenced by judgmental evaluations.

VII. <u>Proposed Revenues by Class</u>

Q. What total gas revenue requirement is the Company utilizing in its proposal?

A. The Company has used a total revenue requirement of $ 27,983,768, as shown on Schedule A – 1. Net of miscellaneous other revenue of $790,344, the Rate Schedule Revenue Requirement is $27,193,424.

Q. Have the results of the COSS been used in establishing the class-by-class revenue responsibility levels?

A. Yes. The class-by-class revenue responsibility levels at the Company's proposed revenue requirement and at equalized rates of return are shown on Line 35 of Schedule G – 1.

Q. Have the class rates of return under the Company's present rates been identified?

A. Yes. The class-by-class rates of return under the Company's current rates are established on Line 28 of Schedule G – 1.

Q. Have the identified class rate of return differences been reflected in the Company's proposed revenue levels?

A. Yes. The Company's proposed class-by-class revenue levels, discussed below, are shown on Line 48 of Schedule G – 1.

Q. Please describe the approach followed to apportion the proposed revenue deficiency of $5,725,455 to the Company's various rate classes.

A. As described earlier, the allocation of revenues among rate classes consists of deriving a reasonable balance between various guidelines and criteria that relate to the design of utility rates. The following criteria were considered in this process: (1) cost of service results, (2) class contribution to present revenue levels, (3) customer impacts and (4) the Company's belief that all classes should receive a revenue increase necessary to eliminate its respective class revenue deficiency, which is in keeping with the approach adopted by the Commission in the Company's 2005 general rate case.[5] After evaluating these criteria for each of the Company's rate classes, adjustments were made to class revenue levels so as to design rates that would move class revenue levels to the full cost of serving those classes.

[5] Order No. 7, APSC Docket No. 05-006-U, Section VIII. Rate Design, page 42.

Q. Please explain the adjustments made to the class revenue levels under the Company's approach.

A. As shown on the Earned Return on Rate Base line 28 of Schedule G – 1, the realized rates of return from the Company's current rates range from negative 0.6679% to positive 3.6319%. As discussed earlier, one of the Company's primary considerations was to eliminate the difference between these relative rates of return by class so as to reach the levelized rate of return for the system.

The bulk of the increase in non-gas cost responsibility is borne by the Residential and Small Business classes of customers, approximately $4.7 million of the total revenue deficiency of $5,725,455 (Line 34). The Residential class increase is 96% of the system average increase and moves the class to a 1.00 revenue-to-cost ratio, that is, 100% of the class' fully allocated cost of service. The Small Business class is providing a rate of return at current rates of 0.6557%; a revenue increase equivalent to 115% of the system average increase is proposed for this class. This level of revenue increase will also bring the Small Business class to a revenue-to-cost ratio of 1.00.

Q. Have there been other increases to rate schedules as a result of the revenue responsibility changes?

A. Yes. The Large Business class received increase of $843,841. The revenues of the Medium Business class were increased by $132,018 or 148% of the system average increase; this class had exhibited the lowest rate of return at existing rates of -0.6679%. In all instances, the revenue-to-cost ratios for these four classes at proposed revenues will be 1.00, representing parity with their fully allocated cost of service. A summary of the revenues by rate class, at both present and proposed rates is presented on Schedule H – 1. The new CNG rate class received an increase of $113,937, which places this class at a revenue-to-cost ratio of 0.89. The Company determined that the CNG class should not receive a greater level of increase to insure that the retail price of CNG at its public refueling stations remains competitive with other public CNG stations in neighboring areas in the interest of encouraging more wide spread usage of CNG as a vehicular fuel, an environmentally sound alternative to gasoline. The Company believes that the revenue subsidy for this CNG class of $13,939 is necessary to encourage the growth of CNG as a vehicular fuel and will add support to the efforts of both State and Federal policy makers to promote domestic, clean burning alternatives to gasoline.

VIII. <u>Proposed Rate Design</u>

Q. How were the proposed rates for each rate schedule calculated?

A. Detailed calculations for each rate component of each rate schedule and the resulting proposed revenues are included in Schedule H – 2. As the schedule shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes.

A. Increased Level of Monthly Customer Charges

Q. Do the proposed rate schedules include increases to the existing monthly customer charges?

A. Yes. The schedule of proposed rates includes an increase to the Residential monthly customer charge from $9.90 to $12.50. In addition, the Small and Medium Business classes receive increases in their monthly customer charges from $13.75 to $20.00 for Small Business and from $300.00 to $500.00 for Medium Business. The Large Business class will have a monthly customer charge of $1,700.00, which is 94% of the full cost level for this class. The new CNG class will not have a customer charge as the CNG is sold by the Company to its retail customers on a volumetric basis (price per gallon of CNG) through its public refueling stations.

Q. Please summarize the reasons why the Company is proposing to increase the service charge levels and the relationship to the rate design principles you discussed earlier.

A. The Company has proposed monthly residential and small business customer charges at levels that recover roughly 50% of their full customer cost responsibility. The $12.50 Residential customer charge would bring this charge to approximately 51% of its full customer cost level, while the $20.00 customer charge for the Small Business class will equate to 44% of full cost. These proposed customer charges reduce customer bill volatility, alleviate some of the instability in the Company's margin recovery, are fair to customers within the

Residential and Small Business classes, are easily understood, and convey more appropriate price signals with respect to recovery of fixed distribution costs.

Q. Please elaborate.

A. As mentioned earlier in my testimony, the Company utilized the unit costs from the COSS to identify costs related to providing monthly service to customers. The level of customer-related costs is shown for the Residential class of customers in Direct Exhibit RJA – 5 to be $24.57. The corresponding level of customer costs for the Small Business class of customers is shown in this schedule to be $45.72.

Establishing higher monthly customer charges helps to equalize the contribution each customer within a class makes towards recovery of customer costs attributable to this class. This method of customer cost recovery is preferable to including such costs in the distribution rates, which has the effect of causing some customers to pay too much while others pay too little.

The customer charges provide for recovery of a portion of the Company's fixed customer costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether gas is consumed and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as customer costs are not related to usage, they should be recovered to the extent possible through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers should easily understand a customer cost based charge. A customer cost based charge is easily explained since the rate is based on customer costs. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is cold, and conversely should not pay less when the weather is warm.

Q. Please explain how the Company's proposed increase to the Customer Charge will impact the average Residential customer's gas bills.

A. The Company's proposed $2.60 increase to the customer charge coupled with the increased volumetric distribution charge will provide a larger percentage increase in the average customer's monthly bills in the summer ($3.59 in July and August) and shoulder months ($4.09 in October), when customer bills are at their lowest levels, and a smaller percentage increase customer's bills in the winter months (about $13.00 in January and February), when bills are at their highest levels, as depicted in Direct Exhibit RJA – 6. The average monthly increase for a Residential customer using 590 Ccf will be $6.84. Schedule H – 3 presents annual bill comparisons at present and proposed rates for various ranges of gas consumption, by rate class.

APSC FILED Time: 10/15/2013 10:44:13 AM: Recvd 10/15/2013 10:30:25 AM: Docket 13-078-u-Doc. 34

Q. At the proposed levels, will the customer charges result in substantial recovery of the overall fixed costs for these classes?

A. More than $17 million of fixed, mostly demand-related costs representing approximately 67% of the total fixed costs of the Company will still be recovered through the volumetric rates for gas service.

B. Elimination of the Pooling Rate

Q. Please discuss why a Pooling Rate was separately identified in prior AOG rate cases?

A. To assist the Medium and Large Business classes with availing themselves of the benefits of their transportation service option, the Company has historically allowed the pooling of gas supplies for nomination and delivery purposes. As this service was not a cost free service, the Company had performed a study to identify the costs related to this service in its last two rate cases. The Company directly assigned these costs to the Medium and Large Business classes, which have the transportation service option.

Q. What costs have historically been assigned to the Pooling Rate?

A. Typically, the majority of costs assigned to the Pooling Rate were administrative labor costs. The Company compiled the time recorded by gas system control and load dispatching, distribution operations, accounting, and administrative personnel involving activities related to the managing of customers' supply nominations, reconciling nominations with both deliveries on their behalf and customers' usage, and monthly billing. An allocation of employee benefits costs (Account No. 926) was then made based on the direct labor costs.

Q. Please explain the reasoning for proposing to eliminate the Company's Pooling Rate.

A. The Company has eliminated the separate Pooling Rate applicable to Medium and Large Business transportation customers because the administrative activities of managing gas supply-related requirements for both sales and transportation customers has become ever-present for the Medium and Large customer classes. Whether the Medium and Large Business customers are purchasing their gas supply from AOG or third parties, the amount of gas supply monitoring and direct communication between them and Company personnel charged with performing the administrative activities described above are essentially the same. The administrative activities related to the management of gas supply for these two classes are critical to insuring the integrity of system supply for the remainder of the Residential and Small Business customers on the AOG system.

Q. Has the Company continued to track the costs related to providing the supply management services for the Medium and Large Business customers?

A. Yes. The supply management administrative costs applicable to the Medium and Large Business classes recorded in Account Nos. 851(System Control and Load Dispatching), 871 (Distribution Load Dispatching), and 920 (Administrative and

General Salaries) have been directly assigned to the two customer classes. These customer classified costs will be recovered via the monthly Customer Charges included in the Medium and Large Business rate schedules.

C. Demand Charge for the Large Business Class

Q. Has the Company made other changes to any of the schedules?

A. Yes. The Company has revised the Demand Charge for the Large Business rate schedule. As indicated earlier, the use of demand charges in three-part rate structures by gas LDCs is prevalent in today's competitive gas marketplace. Demand charges reduce intra-class subsidies by lowering the average cost of utility service for high load-factor customers and thereby encourage efficient use of the distribution system. The Company proposes to raise the current Demand Charge for the LB rate schedule from $1.50 to $3.00 per Mcf of peak demand. The demand volume upon which the charge will be levied is also being revised to consist of the individual LB customer demands on the system three-day peak. The revision to the demand billing determinant reflects the significant impact that large customer loads occurring on the day before and day after a system peak day can have on the Company's efforts to insure adequate system capacity and supply are present to reliably provide natural gas service to all customers during critical peak periods.

D. Rate Component Calculations

Q. Have the rate schedules been changed to reflect the new rate levels being proposed by the Company in this proceeding?

A. Yes. The revised rate schedules appear in Schedule H - 10, sponsored by Company witness Callan.

IX. Weather Normalization Adjustment Clause

Q. Is the Company proposing any changes to the WNA tariff clause?

A. The Company proposes no changes to the operation of the WNA. However, due to the proposed change to a 10-year period for the purpose of determining the normal level of HDD used within the WNA, it is necessary to change the definition of "Normal Degree Days" in the tariff clause and to replace the schedule of "Daily Normal HDD for WNA Billing." The proposed changes are shown on the WNA tariff included in Schedule H – 10, sponsored by Company witness Callan.

X. Concluding Remarks

Q. Please summarize how the interests of AOG and its customers are served by implementing the Company's recommendation to establish a new measurement basis for normal weather and the proposed changes to fixed charges within the various rate schedules.

A. Under a weather normal basis that more accurately reflects current trends in weather patterns, customers' volumetric distribution rates will be more accurate and therefore will result in smaller weather related adjustments to the distribution rates under AOG's WNA clause. A comparison of the recent magnitude of the differences between the rate adjustments under the Company's respective WNA clauses in its Arkansas and Oklahoma jurisdictions illustrates the benefit of moving to a 10-year rolling average as the basis for determining normal weather.

In my professional opinion, the Company's proposed increases to the various monthly customer charges reduce customer bill volatility; alleviate some of the instability in the Company's margin recovery; are fair to customers within the Residential and Small Business classes and should be easily understood by them; and convey more appropriate price signals with respect to recovery of fixed distribution costs. The proposed increase to the demand charge in the LB Rate Schedule reduces cross-subsidization within the rate class and encourages efficient use of the distribution system by these large customers. For these reasons, I urge the Commission to approve AOG's weather normal and rate design proposals.

Q. Does this conclude your direct testimony?

A. Yes.

CERTIFICATE OF SERVICE

I, Shannon Mirus, hereby certify that a copy of the foregoing Direct Testimony and Direct Exhibits of Ronald J. Amen have been served on all parties of record via electronic mail on this 15th day of October, 2013.

By: */s/ Shannon Mirus*
Shannon Mirus, Arkansas Bar No. 2007265
Arkansas Oklahoma Gas Corporation
Vice President-General Counsel
P. O. Box 2414
Fort Smith, AR 72902-2414
T: 479/783-3181, Extension 2212
F: 479/784-2095
E: smirus@aogc.com

Ronald J. Amen
Director – Black & Veatch Corporation

Ronald J. Amen provides financial, regulatory, strategic, operations and litigation support to his energy clients. Mr. Amen has over thirty-five years of combined experience in utility management and consulting in the areas of regulatory affairs, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: regulatory policy, strategy and analysis; resource strategy, planning and financial analysis; cost allocation and pricing issues; business process design and organizational structures; and expert witness testimony. Prior to joining Black & Veatch, Mr. Amen's consulting experience included Concentric Energy Advisors, Inc. and Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations and Director – Rates for Indiana Energy (now Vectren), and management positions in Information Systems and Distribution Operations at Ohio Valley Gas Corporation. Mr. Amen is a graduate of the University of Nebraska. He is an Associate Member of the American Gas Association.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

» Provided case management, revenue requirement, cost of service and rate design support for a *Southwestern electric/gas utility's* general rate cases in its two State regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal-fired power plant, and the valuation of renewable energy credits related to a wind power facility.

» Provided due diligence on behalf of a *confidential energy company* related to the purchase of a gas/electric utility, including a review of the regulatory and market related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

» Provided regulatory due diligence support for a *confidential energy company* client related to a proposed merger with a multi-jurisdictional gas/electric company, including an evaluation of the regulatory landscape in the various applicable State jurisdictions, recent regulatory decisions, and current regulatory issues.

» Performed due diligence on behalf of a *confidential energy company* client related to the acquisition of a U.S. interstate pipeline, involving a market assessment related to its customer contracts and their prospective alternatives.

» Provided management of an *Eastern electric/gas utility* with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using a proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures and construction cost control areas.

» Provided management of an *Eastern gas utility* with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on NOI, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

- Engaged by a *Canadian gas utility* to assist with the development of a Transmission asset ownership strategy. The project included researching examples from other jurisdictions in North America for transmission ownership structures, the supporting rationale, and the resulting regulatory treatment.
- Provided expert witness testimony for an *Eastern gas utility* on the subject of new area expansion programs in the U.S. for the client's general rate case proceeding. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.
- For a *Pacific Northwest electric/gas utility*, redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client's residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

Resource Planning, Strategy and Financial Analysis

- Retained by a *Western Canadian gas utility* to help develop a gas supply incentive mechanism in cooperation with the BCUC staff and the Company's other stakeholders. Concentric provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.
- Engaged as a member of a consultant team that served as the independent evaluator in a *Western electric utility's* competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission, and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the PPA, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced bi-weekly confidential reports to the commission regarding the process and its results.
- Assisted a *Pacific Northwest gas utility* with the development of its long-term Integrated Resource Plan ("IRP") for its Oregon and Washington service territories. The IRP includes the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.
- Engaged by a *Pacific Northwest electric/gas utility* to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.
- As part of a review of a *Pacific Northwest electric/gas utility's* gas procurement strategy and hedging analytics, provided gas LDC case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.
- For a *Pacific Northwest electric/gas utility*, provided resource planning strategy and analysis for the Company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.
- Engaged by a *Pacific Northwest electric/gas utility* as a member of a consulting team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multi-track solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

- Provided an evaluation of the functions provided by a *Midwestern gas/electric utility*'s underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.
- For a *Southern gas/electric utility*, conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.
- Engaged by a *Midwestern municipal electric utility* as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.
- For a *European electric utility*, provided strategy and analysis support, including a review of the natural gas value chain in the U.S., as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

Cost Allocation, Pricing Issues and Rate Design

- Retained by a *Southwestern electric utility* to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Concentric reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the U.S. Southwest. In addition, Concentric has analyzed our client's 2009-2011 residential data to determine what sort of conservation effect the Company may expect by implementing an inclining block rate structure. Concentric provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use ("TOU") rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.
- Supported a N*ortheastern electric utility* in its decoupling proposal for the Company's general rate case. Work included: (1) research on the financial implications of decoupling; (2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; (3) identification of rate adjustment mechanisms that would work together with the Company's proposed decoupling mechanism; and (4) preparing pre-filed testimony and testifying at hearings in support of the Company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.
- For a N*ortheastern gas/electric utility,* conducted class allocated cost of service studies for the client's New England natural gas operations. This included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.
- For a *Midwestern energy company,* class allocated cost of service studies were conducted for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in three general rate cases before the Indiana Utility Regulatory Commission.

- Conducted class allocated cost of service studies for a *Midwestern electric utility's* Minnesota electric operations. Work included reconfiguring the Company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a Fixed/Variable study for Production costs, and a Primary – Secondary study for poles, transformers and conductors. Concentric performed a Time of Use analysis to determine the appropriate rate differentials for its Peak and Off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.
- On behalf of a *Midwestern gas utility*, provided cost of service and rate design support for the Company's general rate case filings in its two State jurisdictions and in support of a Section 311 transportation filing before the Federal Energy Regulatory Commission (FERC). Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment (WNA) mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the Company's largest customer classes. Conducted a pre-filing "Decoupling" workshop for the utility commission staff.
- Provided Cost of Service and Rate Design support for a *Pacific Northwest gas utility*'s general rate case, including expert witness testimony. Assisted the client with an earlier revenue neutral reconfiguration of its Commercial / Industrial sales and transportation service offerings. The earlier initiative included collaborative work with an industrial customer stakeholder group.
- For a *Midwestern energy company* assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of Revenue Decoupling mechanisms for its two regulated gas utility subsidiaries. Served as the cost of service witness in two general rate case filings.
- Representing a *Pacific Northwest electric/gas utility* in two general rate proceedings, provided Cost of Service and Rate Design support, including expert witness testimony in support of the utility's proposed gas Revenue Decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for Infrastructure Replacement, Electric Power Cost Adjustment mechanisms and Gas Supply Pricing Options of utilities in North America.
- Engagement director for Cost of Service and Rate Design support for the general rate proceedings of a U.S. Energy Company's *Midwestern and Northeastern gas utilities*, including expert witness testimony on cost of service, rate design and declining use-per-customer. Rate design support included a proposed ten-year weather normal, and the introduction of straight-fixed variable rates (*Midwestern* LDC). This was the third consecutive rate case engagement for the *Northeastern* LDC.
- For a *Midwestern gas/electric utility* assisted the Company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.
- Served as engagement manager for cost of service and rate design support for a *Western Canadian gas utility* client. Represented the client in its capital investment recovery proceeding for a major pipeline project, a cross-provincial transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's PBR and unbundling initiatives and a global rate design proceeding. Cost of service support included a review of its gas cost portfolio allocation to firm sales customer classes, a survey of the trends in gas cost allocations and incentive mechanisms in North America, and serving as a facilitator for an all-party cost allocation and rate design workshop.
- For a N*ortheastern gas utility*, served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a state-wide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

- Engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case for a *Midwest gas transmission/distribution utility*. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.
- For a *South American gas utility*, an affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.
- For a *Canadian energy marketer*, provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.
- For a *Pacific Northwest gas utility,* negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of annual throughput, and maintained contribution to system costs.
- For a *Pacific Northwest gas utility,* obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and re-designed rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.
- Provided case strategy and cost of service support for the biennial cost allocation proceedings of *two utility subsidiaries of a Western U.S. energy company*.

Utility System Operations and Organizational Development

- Concentric was engaged by a *Pacific Northwest electric/gas utility* to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("New Business Investment") and the management policies and practices that influence the new business capital investment. Concentric examined the inter-relationships of our client's management policies and practices in the functional areas related to New Business Investment and developed an understanding of the nature of the costs captured by the New Business Investment process. Concentric benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or inter-relationships between management policies and practices, as well as other exogenous factors, and the resulting impact on New Business Investment.
- Engaged by a *Pacific Northwest electric/gas utility* to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Concentric reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. In addition, Concentric compiled and provided examples of capital planning documents and procedures, viewed by Concentric as "Best Practices," from other electric utilities and other relevant transmission entities.
- For a *Midwestern energy company,* provided audit support for one of the Company's gas and electric utilities during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning process to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

- For a *Midwestern energy company,* performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas utilities, electric utilities, and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.
- Engaged by a *Western multi-state water utility* to manage the implementation of a new revenue decoupling mechanism into its 24 separate rate areas. Changes to the following processes and related procedures were required: rate setting, meter reading, billing, revenue and financial reporting. Microsoft Project was used to manage and track the implementation throughout the following organizations: Rates, Accounting, Information systems, Communications, and Customer Service.
- For a *Northwestern gas/electric utility*, conducted an evaluation of the Company's key accounts (Top 100) and business account services organization. Work included compilation of "best practices" from peer group utilities, recommendations related to staffing levels, roles and responsibilities, and the interrelationships with the customer service (call center), revenue management and community relations organizations of the utility.
- For an *Eastern gas utility*, provided market monitoring strategies and action plans based on an analysis of competitive threats and discussions with the client's customers and other utilities facing similar issues. Intent of recommended monitoring strategies and corresponding action plans to result in increased customer growth (meters) and/or customer retention, including a prioritized implementation approach to the monitoring strategies and action plans, based on benefits to the client and time to implement.
- For a *Southern gas/electric utility*, conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.
- Engaged by a *Midwestern municipal electric utility* as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process, which involved establishing the organization structure, span of control, job descriptions, qualifications, and salary ranges. We worked closely with the head of new organization, the municipal utility management, and the relevant municipal government agencies; and facilitated numerous management and stakeholder meetings.
- Provided research and consulting support for a *Midwestern gas/electric utility* to establish performance metrics and benchmarks from peer group companies for the client's performance management system.
- For a *Midwestern energy company*, Mr. Amen was responsible for marketing, customer service, distribution system construction, operation and maintenance, for a regional operating service territory of the company's gas utility. Among other gas operations responsibilities, Mr. Amen managed a field sales force responsible for sales plan development, including market analysis, program design, and cost-effectiveness evaluations for the following customer segments and/or trade alley groups: residential home builders and commercial developers; HVAC contractors; large commercial and industrial key accounts; public institutions; and governmental facilities.

  <u>Business Process Redesign and Organizational Restructuring</u> – While serving in the aforementioned utility management capacity as Regional Director, Mr. Amen managed the successful integration of an acquired gas utility company into a regional operation.

  <u>Re-engineering Operations</u> – Mr. Amen was a member of a management team that restructured the company's field organization into six regional operations (reduced from 26 district offices) resulting in a streamlined organization, which provided enhanced customer service while substantially reducing operating costs. The nine core management team members facilitated the work of over forty individual study groups during the eighteen-month transition period. This same management team redesigned the capital budgeting process and established new standards governing the use of construction contractors.

Expert Witness Testimony Presentation

- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

PROFESSIONAL HISTORY

Black & Veatch Corporation (Present)
Director

Concentric Energy Advisors, Inc. (2007 – 2013)
Vice President

Navigant Consulting, Inc. (1997 – 2007)
Director

Puget Sound Energy, Inc. (1997)
Manager – Federal Regulatory Affairs

Washington Natural Gas Company (1993 – 1997)
(merged with Puget Power and Light to form Puget Sound Energy in 1997)
Director – Rates and Tariffs

Indiana Energy (now Vectren) (1984 – 1993)
Regional Director – Distribution Operations
Director – Rates

Ohio Valley Gas Corporation (1978 – 1984)
Data Processing Manager
Assistant District Manager – Distribution Operations

EDUCATION

B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska, 1978

PROFESSIONAL ASSOCIATIONS

Associate Member, American Gas Association
Past Member, Marketing & Regulatory Committees of the Pacific Coast Gas Association
Past Member, Rate Committee of the American Gas Association
Past Member, Statistics and Load Forecasting Methods Committee of the American Gas Assocation

---

PUBLICATIONS/PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS OKLAHOMA GAS CORPORATION FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	**))))**	**DOCKET NO. 13-078-U**

DIRECT EXHIBITS OF

RONALD J. AMEN

ON BEHALF OF

ARKANSAS OKLAHOMA GAS CORPORATION

OCTOBER 15, 2013

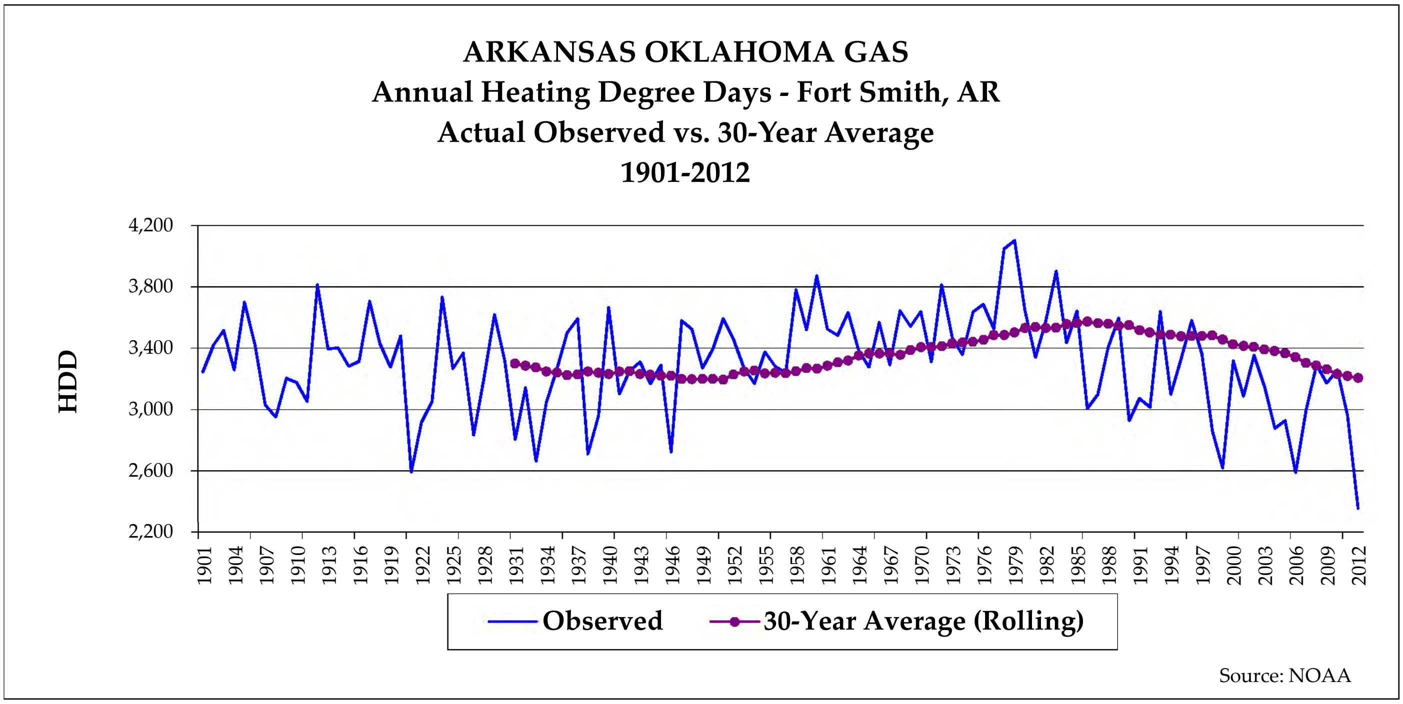
Weather Normal Analysis – Tabular Results

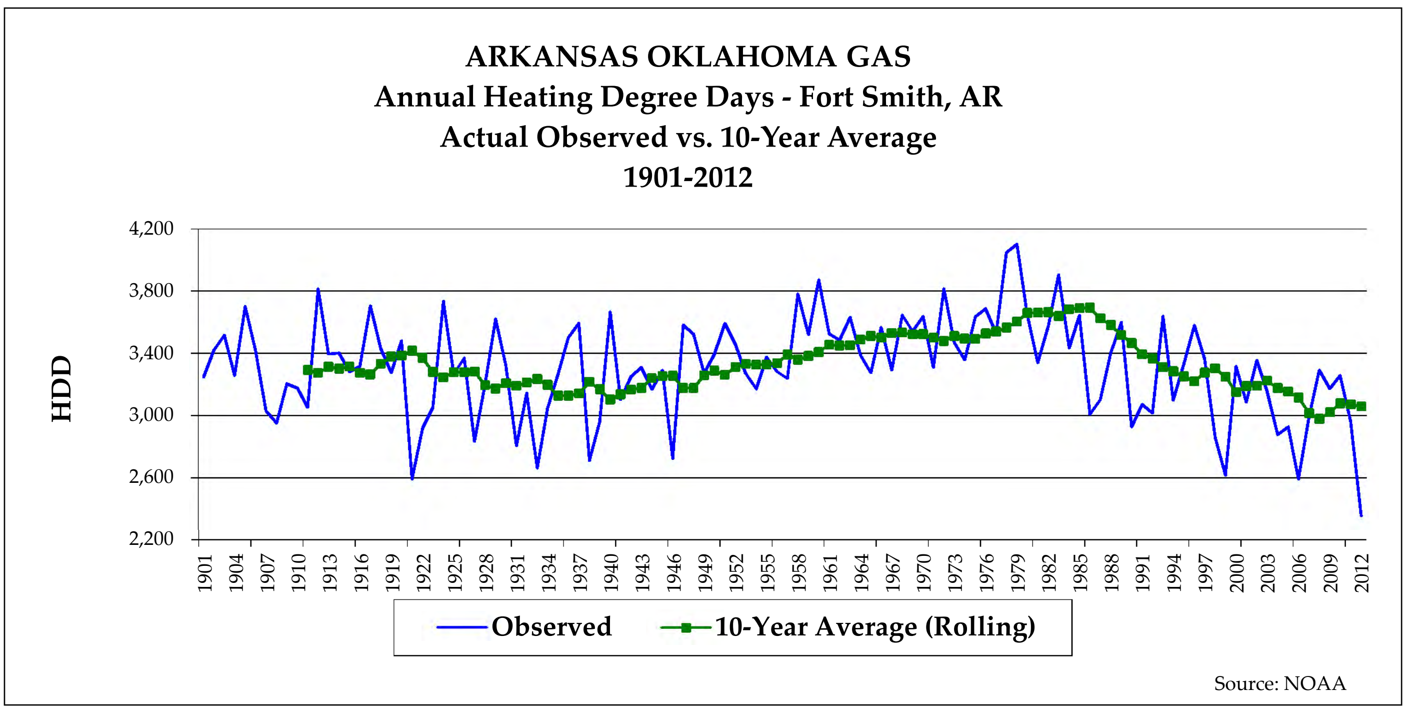
	Forecast Error Squared (82 years)			
	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)
Sum	9,306,539	7,925,733	7,146,874	7,512,507
Mean	113,494	96,655	87,157	91,616
Root Mean Squared Error (RMSE)	336.89	310.89	295.22	302.68
IMP		7.72%	12.37%	10.15%

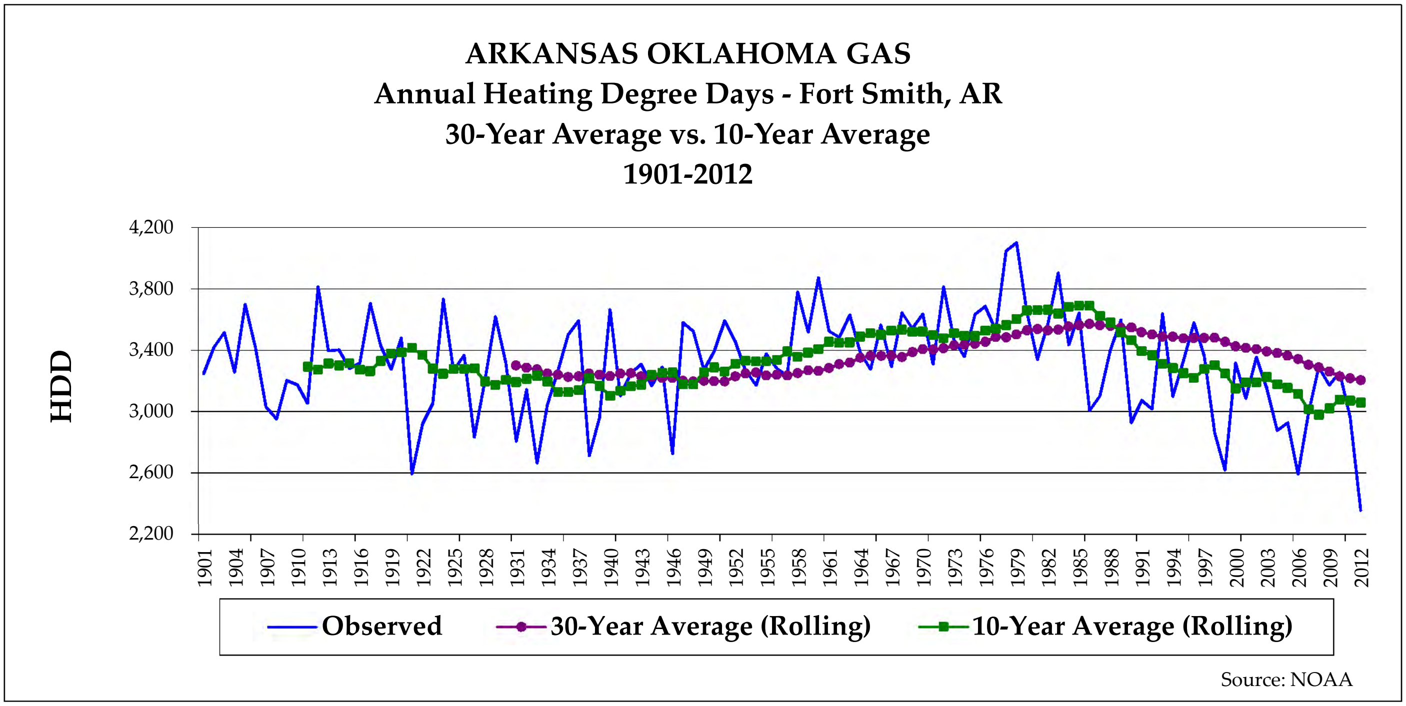
	Forecast Error Squared (40 years)			
	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)
Sum	5,762,058	4,705,731	4,113,489	4,176,830
Mean	144,051	117,643	102,837	104,421
Root Mean Squared Error (RMSE)	379.54	342.99	320.68	323.14
IMP		9.63%	15.51%	14.86%

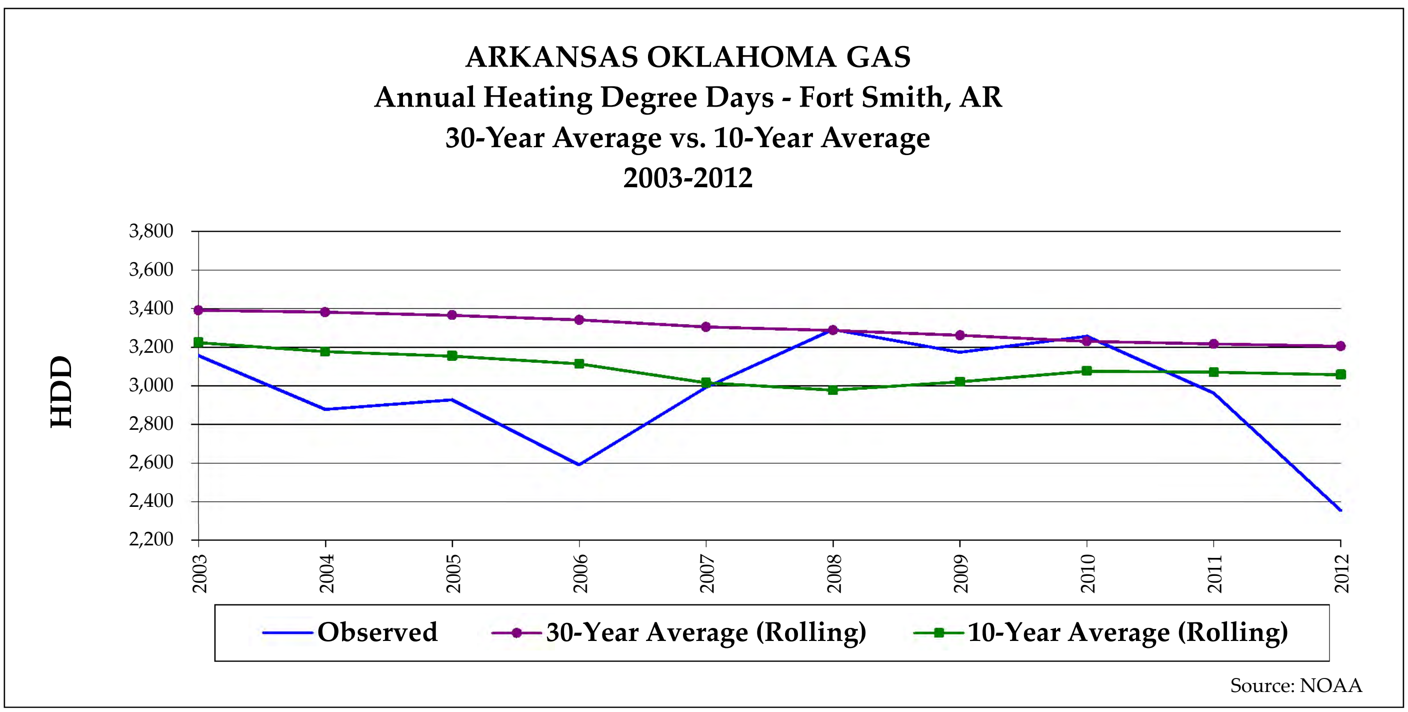
	Forecast Error Squared (20 years)			
	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)
Sum	3,389,315	2,420,761	2,025,173	2,428,046
Mean	169,466	121,038	101,259	121,402
Root Mean Squared Error (RMSE)	411.66	347.91	318.21	348.43
IMP		15.49%	22.70%	15.36%

	Forecast Error Squared (10 years)			
	30-Year Average (Rolling)	20-Year Average (Rolling)	10-Year Average (Rolling)	5-Year Average (Rolling)
Sum	1,959,078	1,232,993	1,081,040	1,248,828
Mean	195,908	123,299	108,104	124,883
Root Mean Squared Error (RMSE)	442.61	351.14	328.79	353.39
IMP		20.67%	25.72%	20.16%


ARKANSAS OKLAHOMA GAS
Annual Heating Degree Days - Fort Smith, AR
Actual Observed vs. 30-Year Average
1901-2012
HDD
Observed
30-Year Average (Rolling)
Source: NOAA


ARKANSAS OKLAHOMA GAS
Annual Heating Degree Days - Fort Smith, AR
Actual Observed vs. 10-Year Average
1901-2012
HDD
Observed
10-Year Average (Rolling)
Source: NOAA


ARKANSAS OKLAHOMA GAS
Annual Heating Degree Days - Fort Smith, AR
30-Year Average vs. 10-Year Average
1901-2012
HDD
Observed
30-Year Average (Rolling)
10-Year Average (Rolling)
Source: NOAA


ARKANSAS OKLAHOMA GAS
Annual Heating Degree Days - Fort Smith, AR
30-Year Average vs. 10-Year Average
2003-2012
HDD
Observed
30-Year Average (Rolling)
10-Year Average (Rolling)
Source: NOAA

Weather Normal Analysis – Five-year Comparison, Arkansas versus Oklahoma

Five-year Comparison of WNA to Distribution Revenue

	8/31/2012	8/31/2011	8/31/2010	8/31/2009	8/31/2008
Arkansas (30 Year Normal = 3326):					
Distribution Revenue	10,030,991.05	12,602,882.67	14,051,248.95	13,047,676.92	12,760,229.78
WNA Revenue	2,380,695.71	695,762.55	(326,010.65)	283,992.86	462,270.33
Total	12,411,686.76	13,298,645.22	13,725,238.30	13,331,669.78	13,222,500.11
WNA % of Distribution Revenue	23.73%	5.52%	-2.32%	2.18%	3.62%
Weather % Difference from Normal	30.28%	8.36%	-3.73%	4.96%	6.37%
HDD Difference from Normal - AR	1,007	278	(124)	165	212
ACTUAL HEATING DEGREE DAYS	2,319	3,048	3,450	3,161	3,114
HDD Difference from Normal - OK	725	(4)	(406)	(117)	(70)
Weather % Difference from Normal	23.82%	-0.13%	-13.34%	-3.84%	-2.30%
Oklahoma (10 Year Normal = 3044):					
Distribution Revenue	2,867,701.24	3,614,120.17	4,042,967.02	3,704,508.96	3,815,746.98
WNA Revenue	505,960.15	16,313.64	(323,490.11)	(95,303.78)	(31,744.57)
Total	3,373,661.39	3,630,433.81	3,719,476.91	3,609,205.18	3,784,002.41
WNA % of Distribution Revenue	17.64%	0.45%	-8.00%	-2.57%	-0.83%

ARKANSAS OKLAHOMA GAS CORPORATION
Arkansas Jurisdiction
Plant Data as of February 28, 2013

Summary

	Total Adjusted Cost	Total Footage	Adj. Unit Cost	Avg. Cost per Installed Foot	% Customer Component	$ Customer Component
Plastic	48,316,582.00	4,489,242	10.76274837	5.10	47.39%	22,895,134
Steel	61,099,882.15	2,870,409	21.28612409	7.80	36.64%	22,389,190
Total	**109,416,464.15**	**7,359,651.00**		**$ 6.15**		**45,284,324**
						41.39%

Customer Cost Component:	**41.39%**
Demand Cost Component:	**58.61%**

Plastic

Pipe Diameter	Adj. Cost	Footage	Adj. Unit Cost
0.7500	5,159.86	448	11.52
1.0000	28,260.09	1,370	20.63
1.2500	500,708.52	42,582	11.76
2.0000	27,198,454.09	3,203,791	8.49
3.0000	763,454.70	47,120	16.20
4.0000	15,372,441.48	1,014,291	15.16
6.0000	3,945,858.04	172,051	22.93
8.0000	502,245.21	7,589	66.18
	48,316,582.00	4,489,242	10.76

Average Cost per installed footage (Zero Intercept)	5.10	
Total Installed Plastic Footage	4,489,242	
Customer Component	22,895,134	47.39%

Steel

Pipe Diameter	Adj. Cost	Footage	Adj. Unit Cost
0.7500	28,922.51	1,614	17.92
1.0000	2,369,367.39	291,206	8.14
1.2500	9,817,635.70	826,812	11.87
1.5000	11,052.27	912	12.12
2.0000	14,662,916.58	918,056	15.97
3.0000	7,132,474.21	280,987	25.38
4.0000	11,134,645.72	311,521	35.74
5.0000	102,881.85	1,368	75.21
6.0000	6,770,611.61	127,862	52.95
7.0000	33,756.63	872	38.71
8.0000	6,866,746.71	90,578	75.81
10.0000	2,138,010.69	18,317	116.72
12.0000	30,860.29	304	101.51
	61,099,882.15	2,870,409	21.29

Average Cost per installed footage (Zero Intercept)	7.80	
Total Installed Steel Footage	2,870,409	
Customer Component	22,389,190	36.64%

Revenue Requirement by Demand, Customer, and Commodity by Rate Class (Unit Cost Report)

	System Total	Residential	Small Business	AR-CNG	Medium Business Sales & Transport	Large Business Sales & Transport
Intangible						
Demand	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -
Production						
Demand	$ 0.3202	$ 0.3202	$ 0.3202	$ 0.3202	$ 0.3202	$ 0.3202
Customer	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ 0.0181	$ 0.0181	$ 0.0181	$ 0.0181	$ 0.0181	$ 0.0181
Transmission						
Demand	$ 3.4838	$ 3.6358	$ 3.6358	$ 3.6358	$ 3.1438	$ 3.1438
Customer	$ 0.2133	$ -	$ -	$ -	$ 226.8804	$ 257.8186
Commodity	$ 0.1972	$ 0.2191	$ 0.2191	$ 0.2191	$ 0.1780	$ 0.1780
Distribution						
Demand	$ 10.2907	$ 10.3175	$ 10.3175	$ 10.3175	$ 10.2308	$ 10.2308
Customer	$ 28.0149	$ 24.5653	$ 45.7150	$ 1,088.7888	$ 646.8700	$ 1,413.3640
Commodity	$ 0.0756	$ 0.0812	$ 0.0812	$ 0.0812	$ 0.0707	$ 0.0707
TOTAL						
Demand	$ 14.0947	$ 14.2735	$ 14.2735	$ 14.2735	$ 13.6948	$ 13.6948
Customer	$ 28.5011	$ 24.5653	$ 45.7150	$ 4,861.9091	$ 986.7102	$ 1,799.5460
Commodity	$ 0.2909	$ 0.3184	$ 0.3184	$ 0.3184	$ 0.2667	$ 0.2667
Total Fixed (SFV Charge per month)	$ 46.8887	$ 33.3044	$ 90.4235	$ 5,140.2420	$ 2,626.1498	$ 10,584.7452
Peak Day	***59,037***	***24,504***	***16,259***	***39***	***1,556***	***16,679***
Average Customers	***45,254***	***40,022***	***5,191***	***2***	***13***	***26***
Total Normal Throughput (Mcf)	***8,645,361***	***2,371,391***	***1,654,604***	***14,607***	***209,465***	***4,395,294***

ARKANSAS OKLAHOMA GAS CORPORATION - Arkansas Jurisdiction
Estimated Average Monthly Bill Comparison Under Proposed Rates
Residential

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
		Present Rates		**Proposed Rates**		
1	**Customer Charge**	$9.90		$12.50		
2	**Volumetric Charge**	$0.3401		$0.42636		
3	**PGA Rate**	$0.49627		$0.49627		
		AVERAGE CCF PER CUSTOMER	REVENUE AT PRESENT RATES	REVENUE AT PROPOSED RATES	MONTHLY BILL CHANGE AMOUNT	MONTHLY BILL CHANGE PERCENT
4	Jan-14	118	$108.39	$121.15	$12.76	11.77%
5	Feb-14	123	$113.10	$126.35	$13.25	11.71%
6	Mar-14	73	$71.08	$80.00	$8.91	12.54%
7	Apr-14	46	$48.29	$54.85	$6.56	13.59%
8	May-14	22	$28.30	$32.80	$4.50	15.89%
9	Jun-14	12	$19.77	$23.39	$3.62	18.30%
10	Jul-14	11	$19.52	$23.11	$3.59	18.40%
11	Aug-14	11	$19.52	$23.11	$3.59	18.40%
12	Sep-14	12	$19.65	$23.25	$3.61	18.35%
13	Oct-14	17	$24.36	$28.45	$4.09	16.80%
14	Nov-14	46	$48.29	$54.85	$6.56	13.59%
15	Dec-14	98	$91.58	$102.61	$11.03	12.04%
16	Total	590	$611.86	$693.93	$82.07	13.41%
	Monthly Average		$50.99	$57.83	$6.84	

Cause No. 45621
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Thirteenth Set of Data Requests

OUCC Request 13-012:
Please provide the results of NIPSCO's COSS, based upon a 56% Design Day per rate class and 44% Annual Throughput for only transmission mains (the same transmission allocation used in Cause No. 44988). All other inputs and forecasts, including NIPSCO's high-pressure distribution and all other 2022 forecasts should remain the same as NIPSCO's original proposal. Provide the results using the same format as Petitioner's Exhibit No. 17, Attachment 17-F.
Objections:
Response:
Please see OUCC Request 13-012 Attachment A presenting a variation of the COSS where 56% of transmission mains are allocated on Design Day and 44% are allocated on Annual Throughput.

Northern Indiana Public Service Company
12 Months Ending December 31, 2022
OUCC 13-12 Attachment 1
Summary of Cost of Service Study Results with Transmission Mains Allocated 56% using Design Day and 44% Annual Throughput; HP Mains 100% Design Day

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
1	**Rate Base**									
2	Plant in Service	$ 4,004,668,453	$ 2,540,638,750	$ 20,431,177	$ 715,407,322	$ 88,620,160	$ 228,624,030	$ 379,190,249	$ 41,313	$ 31,715,453
3	Accumulated Reserve	(1,705,969,359)	(1,178,523,431)	(9,014,656)	(312,639,126)	(34,294,213)	(69,124,346)	(91,192,055)	(26,047)	(11,155,485)
4	Other Rate Base Items	117,758,507	74,976,348	756,147	29,072,085	5,011,334	2,547,277	5,061,597	125	333,595
5	**Total Rate Base**	**$ 2,416,457,600**	**$ 1,437,091,666**	**$ 12,172,668**	**$ 431,840,281**	**$ 59,337,281**	**$ 162,046,960**	**$ 293,059,791**	**$ 15,390**	**$ 20,893,562**
6	**Margin at Current Rates**									
7	Delivery Sales Margin	$ 420,431,618	$ 269,858,395	$ 2,139,828	$ 90,958,439	$ 11,283,437	$ 8,958,749	$ 32,224,394	$ 194,747	$ 4,813,629
8	TDSIC Margin	21,203,255	13,484,447	160,038	4,936,053	1,149,714	93,115	1,217,201	-	162,686
9	FMCA Margin	17,842,809	11,983,283	104,301	3,166,741	426,371	139,692	1,844,715	-	177,706
10	Miscellaneous Service Margin	6,053,907	4,593,443	43,681	1,080,608	122,905	78,869	115,490	328	18,582
11	**Total Margin at Current Rates**	**$ 465,531,588**	**$ 299,919,568**	**$ 2,447,848**	**$ 100,141,841**	**$ 12,982,428**	**$ 9,270,426**	**$ 35,401,799**	**$ 195,075**	**$ 5,172,603**
12	Gas Costs	348,721,758	230,259,799	2,473,589	95,301,332	18,917,152	112,993	1,485,782	-	171,111
13	**Total Sales Revenue**	**$ 814,253,346**	**$ 530,179,367**	**$ 4,921,437**	**$ 195,443,173**	**$ 31,899,580**	**$ 9,383,419**	**$ 36,887,581**	**$ 195,075**	**$ 5,343,714**
14	**Expenses at Current Rates**									
15	O&M and A&G Expenses	$ 223,421,804	$ 155,494,175	$ 1,202,544	$ 36,957,998	$ 4,569,896	$ 9,785,503	$ 12,943,133	$ 41,239	$ 2,427,316
16	Depreciation and Amortization Expense	122,068,414	83,480,777	639,639	20,468,400	2,147,294	5,233,315	9,337,157	742	761,090
17	Taxes Other Than Income	34,955,761	22,796,077	189,865	6,901,914	958,106	1,358,964	2,466,671	4,000	280,163
18	Income Taxes	4,023,043	1,803,751	19,660	1,693,346	250,933	(336,052)	503,785	7,049	80,571
19	**Total Expenses at Current Rates**	**$ 384,469,022**	**$ 263,574,779**	**$ 2,051,708**	**$ 66,021,659**	**$ 7,926,230**	**$ 16,041,730**	**$ 25,250,747**	**$ 53,031**	**$ 3,549,140**
20	**Operating Income at Current Rates**	**$ 81,062,566**	**$ 36,344,789**	**$ 396,140**	**$ 34,120,182**	**$ 5,056,198**	**$ (6,771,304)**	**$ 10,151,053**	**$ 142,044**	**$ 1,623,463**
21	**Current Rate of Return**	**3.35%**	**2.53%**	**3.25%**	**7.90%**	**8.52%**	**-4.18%**	**3.46%**	**922.94%**	**7.77%**
22	**Current Revenue at Equal Rates of Return**									
23	Current Rate of Return	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%
24	Current Operating Income at Equal ROR	$ 81,062,566	$ 48,208,724	$ 408,345	$ 14,486,528	$ 1,990,530	$ 5,436,033	$ 9,830,993	$ 516	$ 700,896
25	Income Taxes - Equal ROR	4,023,043	2,392,544	20,266	718,950	98,788	269,784	487,901	26	34,785
26	Other Expenses - Equal ROR	380,445,979	261,771,028	2,032,048	64,328,313	7,675,296	16,377,782	24,746,961	45,981	3,468,569
27	**Total Margin @ Equal Rates of Return**	**$ 465,531,588**	**$ 312,372,297**	**$ 2,460,659**	**$ 79,533,791**	**$ 9,764,614**	**$ 22,083,599**	**$ 35,065,856**	**$ 46,523**	**$ 4,204,250**
28	**Current Class (Subsidies)/Excesses**	**$ -**	**$ (12,452,729)**	**$ (12,811)**	**$ 20,608,050**	**$ 3,217,814**	**$ (12,813,173)**	**$ 335,943**	**$ 148,552**	**$ 968,353**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022
OUCC 13-12 Attachment 1
Summary of Cost of Service Study Results with Transmission Mains Allocated 56% using Design Day and 44% Annual Throughput; HP Mains 100% Design Day

Line No.	Revenue Requirement Summary	Account Balance	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
29	**Revenue Requirement at Equal Rates of Return**									
30	Required Return	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
31	Required Return	$ 166,010,637	$ 98,728,197	$ 836,262	$ 29,667,427	$ 4,076,471	$ 11,132,626	$ 20,133,208	$ 1,057	$ 1,435,388
31	**Operating Income (Deficiency)/Surplus**	**$ (84,948,071)**	**$ (62,383,408)**	**$ (440,122)**	**$ 4,452,755**	**$ 979,727**	**$ (17,903,930)**	**$ (9,982,155)**	**$ 140,987**	**$ 188,076**
32	**Expenses at Required Return**									
33	O&M and A&G Expenses	223,421,804	155,494,175	1,202,544	36,957,998	4,569,896	9,785,503	12,943,133	41,239	2,427,316
34	Increase in Uncollectibles	336,250	307,502	4,715	23,117	687	-	-	-	229
35	Depreciation and Amortization Expense	122,068,414	83,480,777	639,639	20,468,400	2,147,294	5,233,315	9,337,157	742	761,090
36	Taxes Other Than Income	34,955,761	22,796,077	189,865	6,901,914	958,106	1,358,964	2,466,671	4,000	280,163
37	Increase TOTI	1,830,885	1,088,846	9,223	327,194	44,958	122,779	222,044	12	15,830
38	Income Taxes	4,023,043	2,392,544	20,266	718,950	98,788	269,784	487,901	26	34,785
39	Gross Up - Income Taxes	28,208,298	16,775,759	142,097	5,041,048	692,668	1,891,640	3,421,007	180	243,899
40	**Total Expenses at Required Return**	**$ 414,844,455**	**$ 282,335,679**	**$ 2,208,348**	**$ 70,438,621**	**$ 8,512,398**	**$ 18,661,985**	**$ 28,877,913**	**$ 46,198**	**$ 3,763,312**
41	**Total Revenue Requirement at Equal Rates of Return**	**$ 580,855,092**	**$ 381,063,877**	**$ 3,044,610**	**$ 100,106,049**	**$ 12,588,869**	**$ 29,794,611**	**$ 49,011,120**	**$ 47,256**	**$ 5,198,700**
42	LESS									
43	Current Miscellaneous Revenue Margin	6,053,907	4,593,443	43,681	1,080,608	122,905	78,869	115,490	328	18,582
44	Additional Miscellaneous Revenue Margin	-	-	-	-	-	-	-	-	-
45	**Total Rate Margin at Equal Rates of Return**	**$ 574,801,185**	**$ 376,470,434**	**$ 3,000,929**	**$ 99,025,441**	**$ 12,465,964**	**$ 29,715,742**	**$ 48,895,630**	**$ 46,928**	**$ 5,180,118**
46	**Base Rate Margin (Deficiency)/Surplus**	**$ (115,323,504)**	**$ (81,144,309)**	**$ (596,762)**	**$ 35,792**	**$ 393,559**	**$ (20,524,186)**	**$ (13,609,321)**	**$ 147,819**	**$ (26,097)**

Northern Indiana Public Service Company
12 Months Ending December 31, 2022
OUCC 13-12 Attachment 1
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class with Transmission Mains Allocated 56% using Design Day and 44% Annual Throughput; HP Mains 100% Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Rate Base									
1	**Storage**									
2	Demand	$ 9,257,985	$ 6,213,534	$ 68,289	$ 2,570,556	$ 405,606	$ -	$ -	$ -	$ -
3	Commodity	$ 77,835,846	$ 51,117,498	$ 558,947	$ 22,050,518	$ 4,108,882	$ -	$ -	$ -	$ -
4	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 87,093,830	$ 57,331,032	$ 627,236	$ 24,621,074	$ 4,514,488	$ -	$ -	$ -	$ -
6	**LNG**									
7	Demand	$ 5,447,958	$ 3,604,617	$ 40,137	$ 1,541,920	$ 261,284	$ -	$ -	$ -	$ -
8	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Subtotal	$ 5,447,958	$ 3,604,617	$ 40,137	$ 1,541,920	$ 261,284	$ -	$ -	$ -	$ -
11	**Transmission**									
12	Demand	$ 698,387,516	$ 251,665,356	$ 2,799,013	$ 107,905,372	$ 18,457,942	$ 69,609,987	$ 239,979,415	$ -	$ 7,970,430
13	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal	$ 698,387,516	$ 251,665,356	$ 2,799,013	$ 107,905,372	$ 18,457,942	$ 69,609,987	$ 239,979,415	$ -	$ 7,970,430
16	**Distribution**									
17	Demand	$ 578,874,556	$ 296,664,493	$ 3,310,438	$ 126,293,820	$ 20,766,973	$ 81,662,834	$ 43,279,910	$ -	$ 6,896,088
18	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 399,872,546	$ 365,240,364	$ 2,304,554	$ 31,948,560	$ 289,994	$ 49,946	$ 2	$ 946	$ 38,181
20	Subtotal	$ 978,747,102	$ 661,904,857	$ 5,614,992	$ 158,242,380	$ 21,056,967	$ 81,712,779	$ 43,279,912	$ 946	$ 6,934,269
21	**On-Site**									
22	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Customer	$ 632,746,162	$ 451,381,652	$ 3,018,807	$ 137,714,601	$ 14,912,534	$ 10,394,763	$ 9,605,501	$ 5,929	$ 5,712,375
25	Subtotal	$ 632,746,162	$ 451,381,652	$ 3,018,807	$ 137,714,601	$ 14,912,534	$ 10,394,763	$ 9,605,501	$ 5,929	$ 5,712,375
26	**Cust. Accounts**									
27	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Customer	$ 14,035,032	$ 11,204,153	$ 72,482	$ 1,814,934	$ 134,067	$ 329,430	$ 194,963	$ 8,515	$ 276,488
30	Subtotal	$ 14,035,032	$ 11,204,153	$ 72,482	$ 1,814,934	$ 134,067	$ 329,430	$ 194,963	$ 8,515	$ 276,488
31	**Total**									
32	Demand	$ 1,291,968,014	$ 558,148,000	$ 6,217,878	$ 238,311,668	$ 39,891,805	$ 151,272,821	$ 283,259,325	$ -	$ 14,866,518
33	Commodity	$ 77,835,846	$ 51,117,498	$ 558,947	$ 22,050,518	$ 4,108,882	$ -	$ -	$ -	$ -
34	Customer	$ 1,046,653,740	$ 827,826,169	$ 5,395,843	$ 171,478,095	$ 15,336,594	$ 10,774,139	$ 9,800,466	$ 15,390	$ 6,027,044
35	**TOTAL RATE BASE**	$ 2,416,457,600	$ 1,437,091,666	$ 12,172,668	$ 431,840,281	$ 59,337,281	$ 162,046,960	$ 293,059,791	$ 15,390	$ 20,893,562

Northern Indiana Public Service Company
12 Months Ending December 31, 2022
OUCC 13-12 Attachment 1
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class with Transmission Mains Allocated 56% using Design Day and 44% Annual Throughput; HP Mains 100% Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Functional Revenue Requirement									
36	**Storage**									
37	Demand	$ 5,371,130	$ 3,604,856	$ 39,619	$ 1,491,338	$ 235,317	$ -	$ -	$ -	$ -
38	Commodity	$ 6,562,003	$ 4,309,495	$ 47,122	$ 1,858,984	$ 346,402	$ -	$ -	$ -	$ -
39	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Subtotal	$ 11,933,133	$ 7,914,351	$ 86,741	$ 3,350,322	$ 581,719	$ -	$ -	$ -	$ -
41	**LNG**									
42	Demand	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
43	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Subtotal	$ 11,226,056	$ 7,427,669	$ 82,707	$ 3,177,278	$ 538,401	$ -	$ -	$ -	$ -
46	**Transmission**									
47	Demand	$ 107,919,847	$ 38,889,135	$ 432,524	$ 16,674,312	$ 2,852,254	$ 10,756,634	$ 37,083,340	$ -	$ 1,231,648
48	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	Subtotal	$ 107,919,847	$ 38,889,135	$ 432,524	$ 16,674,312	$ 2,852,254	$ 10,756,634	$ 37,083,340	$ -	$ 1,231,648
51	**Distribution**									
52	Demand	$ 106,012,332	$ 54,125,822	$ 603,983	$ 23,042,046	$ 3,788,891	$ 14,899,215	$ 8,292,267	$ -	$ 1,260,108
53	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	$ 96,870,774	$ 85,404,209	$ 572,765	$ 9,602,764	$ 523,456	$ 145,166	$ 533,244	$ 3,018	$ 86,153
55	Subtotal	$ 202,883,106	$ 139,530,031	$ 1,176,748	$ 32,644,809	$ 4,312,347	$ 15,044,381	$ 8,825,511	$ 3,018	$ 1,346,261
56	**On-Site**									
57	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	Customer	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
60	Subtotal	$ 189,827,155	$ 141,858,515	$ 944,117	$ 37,143,432	$ 3,654,525	$ 2,565,295	$ 2,252,170	$ 1,842	$ 1,407,259
61	**Cust. Accounts**									
62	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	Customer	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
65	Subtotal	$ 57,065,796	$ 45,444,176	$ 321,774	$ 7,115,895	$ 649,623	$ 1,428,301	$ 850,100	$ 42,396	$ 1,213,532
66	**Total**									
67	Demand	$ 230,529,364	$ 104,047,482	$ 1,158,832	$ 44,384,975	$ 7,414,863	$ 25,655,849	$ 45,375,607	$ -	$ 2,491,756
68	Commodity	$ 6,562,003	$ 4,309,495	$ 47,122	$ 1,858,984	$ 346,402	$ -	$ -	$ -	$ -
69	Customer	$ 343,763,725	$ 272,706,900	$ 1,838,656	$ 53,862,090	$ 4,827,604	$ 4,138,762	$ 3,635,514	$ 47,256	$ 2,706,944
70	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 580,855,092	$ 381,063,877	$ 3,044,610	$ 100,106,049	$ 12,588,869	$ 29,794,611	$ 49,011,120	$ 47,256	$ 5,198,700
71	Demand	39.69%	27.30%	38.06%	44.34%	58.90%	86.11%	92.58%	0.00%	47.93%
72	Energy	1.13%	1.13%	1.55%	1.86%	2.75%	0.00%	0.00%	0.00%	0.00%
73	Customer	59.18%	71.56%	60.39%	53.81%	38.35%	13.89%	7.42%	100.00%	52.07%

Northern Indiana Public Service Company
12 Months Ending December 31, 2022
OUCC 13-12 Attachment 1
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class with Transmission Mains Allocated 56% using Design Day and 44% Annual Throughput; HP Mains 100% Design Day

Line	Description	TOTAL	Residential 111	Multiple Family 115	General Small 121	General Large 125	Large Transport - DP 128 DP	Large Transport - HP 128 HP	Interruptible 134	General Transport 138
	Unit Costs									
74	**Storage**									
75	Demand	$ 0.24	$ 0.39	$ 0.38	$ 0.38	$ 0.36	$ -	$ -	$ -	$ -
76	Commodity	$ 1.77	$ 6.41	$ 6.46	$ 5.36	$ 3.48	$ -	$ -	$ -	$ -
77	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	**LNG**									
79	Demand	$ 0.51	$ 0.80	$ 0.80	$ 0.80	$ 0.83	$ -	$ -	$ -	$ -
80	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	**Transmission**									
83	Demand	$ 4.88	$ 4.19	$ 4.17	$ 4.22	$ 4.39	$ 4.21	$ 6.93	$ -	$ 5.23
84	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	**Distribution**									
87	Demand	$ 4.79	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ 1.55	$ -	$ 5.35
88	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Customer	$ 9.55	$ 9.21	$ 9.79	$ 11.84	$ 71.13	$ 114.53	$ 694.33	$ 125.73	$ 80.00
90	**On-Site**									
91	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	Customer	$ 18.71	$ 15.31	$ 16.14	$ 45.81	$ 496.60	$ 2,023.97	$ 2,932.51	$ 76.73	$ 1,306.76
94	**Cust. Accounts**									
95	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	Customer	$ 5.62	$ 4.90	$ 5.50	$ 8.78	$ 88.27	$ 1,126.90	$ 1,106.90	$ 1,766.52	$ 1,126.87
98	**Total**									
99	Demand	$ 10.41	$ 11.21	$ 11.18	$ 11.23	$ 11.41	$ 10.04	$ 8.48	$ -	$ 10.59
100	Commodity	$ 0.0018	$ 0.0064	$ 0.0065	$ 0.0054	$ 0.0035	$ -	$ -	$ -	$ -
101	Customer (per cust month)	$ 33.87	$ 29.42	$ 31.44	$ 66.43	$ 656.01	$ 3,265.41	$ 4,733.74	$ 1,968.98	$ 2,513.62
102	Customer (Onsite/Metering & Cust Acts)	$ 24.33	$ 20.21	$ 21.65	$ 54.59	$ 584.87	$ 3,150.88	$ 4,039.41	$ 1,843.25	$ 2,433.62
103	Demand & Customer (per cust month)	$ 56.59	$ 40.65	$ 51.25	$ 121.18	$ 1,663.58	$ 23,507.44	$ 63,816.56	$ 1,968.98	$ 4,827.43
104	**BILLING DETERMINANTS**									
105	Demand	22,134,411	9,285,407	103,615	3,952,915	649,993	2,555,994	5,351,149	0	235,338
106	Demand - Distribution	16,757,159	9,285,407	103,615	3,952,915	649,993	2,555,994	0	0	209,235
107	Commodity	3,707,233,778	671,804,472	7,291,448	346,915,023	99,542,792	193,916,786	2,333,755,050	1,055,641	52,952,568
108	Customers (Number of Bills)	10,148,325	9,268,598	58,482	810,749	7,359	1,267	768	24	1,077

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Brien R. Krieger

Brien R. Krieger
Utility Analyst II
Indiana Office of Utility Consumer Counselor
Cause No. 45621
Northern Indiana Public Service Company LLC

1/20/22
Date

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 January 20, 2022.

Nicholas K. Kile
Hillary J. Close
Lauren M. Box
Barnes & Thornburg LLP
Email: Nicholas.kile@btlaw.com
Email: Hillary.close@btlaw.com
Email: Lauren.box@btlaw.com

Jennifer A. Washburn
Citizens Action Coalition
jwashburn@citact.org

Todd A. Richardson
Aaron A. Schmoll
Ellen Tennant
LEWIS & KAPPES, P.C.
Email: TRichardson@lewis-kappes.com
ASchmoll@lewis-kappes.com
ETennant@Lewis-kappes.com

Joseph P. Rompala
Tabitha L. Balzer
LEWIS & KAPPES, P.C.
Email: JRompala@lewis-kappes.com
TBalzer@lewis-kappes.com

Robert E. Heidorn
Kathryn A. Bryan
NiSource Corporate Services - Legal
Email: rheidorn@nisource.com
Email: kbryan@nisource.com

Robert K. Johnson, Esq.
Steel Dynamics Inc.
Email: rjohnson@utilitylaw.us

Robert C. Sears
Erin E. Whitehead
Northern Indiana Public Service Company LLC
Email: rsears@nisource.com
Email: ewhitehead@nisource.com

Copy to:
Reagan Kurtz
Citizens Action Coalition
rkurtz@citact.org

Debi McCall
NiSource Corporate Services - Legal
Email: demccall@nisource.com

Scott C. Franson
Attorney No. 27839-49
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Telephone
317/232-5923 – Facsimile