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December 31, 2020
INDIANA UTILITY
REGULATORY COMMISSION

CITIZENS GAS

Petition for Approval of Gas Cost Adjustments To Be Applicable in the Months of March, April and May 2021

Cause No. 37399 – GCA 149

Prefiled Direct Testimony and Attachments

Korlon L. Kilpatrick II

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TABLE OF CONTENTS

TABLE OF CONTENTS

Tab 1

INTRODUCTION

Q1. PLEASE STATE YOUR NAME.

A1. Korlon L. Kilpatrick II.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis (the "Board"). The Board is the successor trustee of a public charitable trust and manages and controls a number of businesses, including the gas utility doing business as Citizens Gas ("Citizens Gas" or "Petitioner"). Since September 2013, I have held the position of Director, Regulatory Affairs.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Arts degree with a concentration in Computer Science from Harvard College and a Master of Business Administration degree with a major in Finance from the University of North Carolina at Chapel Hill.

Q4. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A4. I began my employment with Citizens Energy Group in 2010. Prior to joining Citizens Energy Group, I worked for the Indiana Office of Utility Consumer Counselor as a Utility Analyst. In that capacity, my work focused on economic and financial analysis of various regulatory issues including demand-side management / energy efficiency issues (DSM/EE) and cost of equity analysis. I regularly attended Midcontinent ISO stakeholder committee meetings and served as the Public Consumer Advocate sector representative to their Finance subcommittee. Prior to that, I was part of the senior management team of a start-up business, and prior to that, I worked for several years as a management consultant performing economic and financial analysis for clients in various industries.

Q5. PLEASE DESCRIBE THE DUTIES AND RESPONSIBILITIES OF YOUR PRESENT POSITION.

A5. As Director of Regulatory Affairs, I am responsible for the development, implementation, and administration of Citizens Energy Group's regulated utilities' rates and charges and Terms and Conditions for Service. I prepare, or supervise the preparation of, rate design testimony for Citizens Energy Group's regulated utilities. Since 2010, I have been responsible for the preparation of GCA and FAC changes and other miscellaneous rate matters.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION ON BEHALF OF CITIZENS?

A6. Yes.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A7. The purpose of my testimony is to describe the tariff sheets and supporting schedules reflecting the gas cost adjustments that Citizens Gas proposes become effective for the months of March, April and May 2021. My testimony also discusses Citizens Gas' projection period, reconciliation period and the Monthly Price Update. Additionally, I describe Citizens Gas' supply portfolio, and provide evidence concerning the gas supply sources and firm gas supply contracts used by Citizens Gas to meet its customers' requirements. Lastly, I provide testimony on demand and supply planning activities, the prepaid gas program, the Citizens Gas hedging program, and any changes to the load forecast.

GAS COST FACTOR CALCULATIONS

EXHIBITS AND SCHEDULES

Q8. PLEASE DESCRIBE EXHIBIT NO. 1.

A8. Exhibit No. 1 is my direct testimony.

Q9. PLEASE PROVIDE A BRIEF EXPLANATION OF EACH OF ATTACHMENTS KLK - 1 THROUGH KLK - 4.

A9. Attachment KLK-1 is Petitioner's Verified Petition filed in this matter. Attachment KLK-2 is Petitioner's GCA tariff sheet (Rider A), for the periods March, April and May 2021. The rates shown on each Rider A are the result of all appropriate estimations and reconciliations, as previously authorized by the Commission. Attachment KLK-3 shows the impact of the proposed GCA rates on a residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms, compared to currently effective rates – i.e. December 2020 – and compared to the GCA rates in effect one year ago.

Attachment KLK-4 consists of all schedules required in support of the GCA rates shown in Attachment KLK-2. These schedules were prepared in a manner consistent with Petitioner's prior GCA filings and incorporate the changes approved on May 14, 1986 in Cause No. 37091. The schedules also are in compliance with the changes approved on August 31, 2011 in Cause No. 43975, August 27, 2014 in Cause No. 44374 and November 13, 2018 in Cause No. 37399-GCA 140.

Q10. PLEASE DESCRIBE ATTACHMENT KLK-4 IN MORE DETAIL.

A10. Schedules 1 through 5 of Attachment KLK-4 support the calculation of the GCA Factor. Schedule 1 is the monthly calculation of the GCA Factors based on Load Forecast (Schedule 2), the estimated purchases and gas cost (Schedule 3), allocation factors associated with the rate class and period (Schedule 4), and storage cost (Schedule 5) for the projection period of March, April and May 2021.

Schedules 6 through 12 of Attachment KLK-4 are the reconciliation of actual gas costs and recoveries for September, October and November 2020. Schedule 6 shows the actual gas costs and variance calculation of gas cost incurred versus recoveries in the reconciliation period of September, October and November 2020. Schedule 7 is the calculation of actual gas costs in the period based on purchases (Schedule 8), unnominated gas cost (Schedule 9), and storage injections/withdrawals (Schedule 10). Schedule 11 calculates the Unaccounted for Gas ("UAFG") percentage. Schedule 12 allocates the variance from the reconciliation period across the next four quarters. The variance to be included in this GCA 149 is based on components from this GCA and the three previous GCAs, as well as refunds and write-offs for the upcoming projection periods

PROJECTION PERIOD

Q11. HOW DID CITIZENS GAS PROJECT THE GAS PRICES FOR THE MONTHS OF MARCH, APRIL AND MAY 2021?

A11. The majority of the gas costs for March, April and May 2021 were projected using the NYMEX futures prices at Henry Hub for the three-month period. The index is the same index by which Citizens Gas has priced its commodity purchases in the past. The futures prices are adjusted for basis, fuel and transportation for delivery to Citizens Gas' city-gate.

Table 1

NYMEX Price as of 12/14/20	
Mar. 2021	$2.5970
Apr. 2021	$2.5960
May 2021	$2.6120

Q12. ON WHAT ARE THE OTHER GCA COMPUTATIONS CONTAINED IN ATTACHMENT KLK - 4 BASED?

A12. The rates and charges reflected in the transportation and storage costs are based upon pipeline tariffs. The other major components of estimated gas costs are non-pipeline gas costs, which are priced in accordance with the Commission's Order in Cause No. 37475, and purchases from gas suppliers other than pipelines, including financial hedge transactions, as discussed later in my testimony.

Q13. WHAT PERCENTAGE OF TOTAL PURCHASES IS MADE UP OF FINANCIALLY HEDGED TRANSACTIONS FOR THE MONTHS OF MARCH, APRIL AND MAY 2021?

A13. Financially hedged transactions account for 35.15% of total purchases for the months of March, April and May 2021.

Q14. DO PETITIONER'S GAS SUPPLIES INCLUDE ANY NON-TRADITIONAL SUPPLIES OF GAS?

A14. No. But, if there were any non-traditional gas supplies included in the GCA 149 computation, they would be priced at the lesser of the equivalent cost of pipeline gas or the authorized per unit price, as authorized by the Commission in Cause No. 37475.

Q15. DO YOU BELIEVE THAT THE PROPOSED GCA RATES FOR MARCH, APRIL AND MAY 2021 ARE ACCURATE?

A15. Yes, I do.

RECONCILIATION PERIOD

Q16. HAVE YOU COMPARED PETITIONER'S ESTIMATED GAS COSTS FOR THE PERIOD OF SEPTEMBER, OCTOBER AND NOVEMBER 2020 WITH ACTUAL GAS COSTS EXPERIENCED FOR THAT RECOVERY PERIOD PURSUANT TO IC 8-1-2-42(G)(3)(D)?

A16. Yes.

Q17. IN YOUR OPINION, ARE THE GAS COST VARIANCES INCLUDED WITHIN THIS GCA 149 PROCEEDING ACCURATE AND REASONABLE?

A17. Yes. The resulting percentages of total monthly variance to the total gas costs incurred and the average variance percentage for the trailing 12-month period ending with each of the three months September, October and November 2020 presented in the GCA reconciliation period are shown in Table 2:

Table 2

Twelve Months Ending	Actual Gas Cost	Variance	% Variance
September 2020	$73,679,061	($6,626,641)	(8.99)%
October 2020	$74,844,719	($6,644,816)	(8.88)%
November 2020	$71,955,775	($7,283,000)	(10.12)%

Q18. PLEASE EXPLAIN PETITIONER'S TWELVE-MONTH TRAILING AVERAGES FOR ANY MONTH WITHIN THE GCA RECONCILIATION

PERIOD THAT ARE GREATER THAN +/- 10% SHOWN ON ATTACHMENT KLK-4, SCHEDULE 6D.

A18. The (10.12)% variance in November 2020 is due to falling natural gas prices as well as the Petitioner's ability to purchase daily gas on the open market for less than the projected monthly prices.

Q19. DO THE PROPOSED GCA RATES INCLUDE A RECONCILIATION OF ACTUAL COSTS TO ACTUAL RECOVERIES FOR THE MONTHS OF SEPTEMBER, OCTOBER AND NOVEMBER 2020?

A19. Yes. The proposed GCA rates to be effective March, April and May 2021 include the effect of reconciling actual gas costs incurred for the months of September, October and November 2020 to actual cost recoveries. In accordance with the Commission's August 14, 1986 Order in Cause No. 37091, the gas supply variance was calculated for each customer demand class and is summarized by class on Attachment KLK–4, Schedule 12B, page 1, lines 1 through 5 and Schedule 12B, page 2, lines 1 through 3. The actual gas supply cost incurred compared to actual gas supply revenue for each month, as depicted in Schedule 6, is shown in Table 3:

Table 3

	Net of Schedule 6 and 12C		Schedule 12
	Actual Gas Cost	**Actual Recoveries**	**Cost in Excess of Recoveries**
September 2020	$2,084,367	$2,202,767	($118,400)
October 2020	$5,161,040	$6,027,211	($866,171)
November 2020	$8,340,407	$9,815,685	($1,475,278)
Total	$15,585,814	$18,045,663	($2,459,849)

Q20. WHAT PERCENTAGE OF TOTAL PURCHASES WAS MADE UP OF FINANCIALLY-HEDGED TRANSACTIONS FOR THE MONTHS OF SEPTEMBER, OCTOBER AND NOVEMBER 2020?

A20. Financially-hedged transactions accounted for 33.39% of total purchases for the months of September, October and November 2020.

Q21. HAS PETITIONER RECEIVED ANY NEW REFUNDS THAT ARE INCLUDED IN THIS GCA?

A21. No.

MONTHLY PRICE UPDATE

Q22. PLEASE DESCRIBE THE HISTORY OF THE MONTHLY PRICE UPDATE MECHANISM.

A22. In Cause No. 37399-GCA75, the Commission approved the use of a Monthly Price Update mechanism for twelve (12) quarterly GCAs, beginning with GCA 75 and ending with GCA 86. The Second Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 23, 2005 in Cause No. 37399-GCA 75 extended the monthly price update mechanism for another twelve (12) quarterly GCAs beginning with GCA 87 and ending with GCA 98. The Third Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 3, 2007 in Cause No. 37399-GCA75, extended the Monthly Price Update Mechanism beginning September 1, 2008 and it continues until further Order of the Commission.

Q23. HAS THE GCA PROCESS, AS DESCRIBED IN IC 8-1-2-42(G) AND INSTITUTED PURSUANT TO THE COMMISSION'S AUGUST 14, 1986 ORDER

IN CAUSE NO. 37091, BEEN CHANGED IN ANY SUBSTANTIAL WAY BY THE CITIZENS GAS MONTHLY GCA MECHANISM?

A23. No. The GCA schedules filed with the GCA Petition, and potentially updated 20 days later, remain unchanged. Pursuant to IC 8-1-2-42(g), the Commission reviews all relevant Quarterly GCA evidence, conducts a summary hearing, and issues an order approving the Benchmark Prices and GCA factors for each month of the quarter.

No less than three days prior to the beginning of each month during the Quarterly GCA period, Citizens Gas files with the Commission a Monthly Price Update for the upcoming month. The GCA factors contained in the Monthly Price Update become effective on the first day of the next calendar month, without further hearing.

Q24. PLEASE DESCRIBE THE MPU FILING.

A24. Pursuant to the Commission's Order in Cause No. 44374, the MPU shall be filed no later than three business days before the beginning of the calendar month in which the rates will go into effect. The Cause No. 44374 Order allows for Petitioner to change the mix of volumes between spot, fixed, and storage injections and withdrawal volumes as long as the total volumes remain unchanged from Petitioner's total volumes approved in the applicable GCA period. The MPU is permitted to change the unit price of spot, fixed and storage gas based on current market conditions and subject to applicable price caps.

Q25. WHEN CITIZENS GAS FILES ITS MONTHLY PRICE UPDATE WITH THE COMMISSION, WHAT IS INCLUDED IN THE FILING?

A25. The Monthly Price Update includes the following: (1) a reference to Gas Daily (or other comparable publication) indicating the NYMEX close price being utilized in the Monthly Price Update; (2) a schedule reflecting adjustments made to the NYMEX close price for use in GCA schedules and comparing to the same calculation made in the Quarterly GCA; (3) certain GCA schedules that are impacted; (4) the revised tariff sheet for the upcoming month (Rider A); and (5) residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms compared to current effective rates and compared to the rates in effect one year ago.

Q26. FOR PURPOSES OF IDENTIFYING THE BENCHMARK PRICES AS A REQUIREMENT OF THE MONTHLY PRICE UPDATE MECHANISM, WHAT ARE THE MONTHLY BENCHMARK PRICES FOR MARCH, APRIL AND MAY 2021?

A26. Table 4 shows the Monthly Benchmark Prices as established by NYMEX +/- basis as of December 14, 2020 by pipeline for March, April and May 2021 included in this filing.

TABLE 4

Benchmark Prices								
	Panhandle Eastern	Texas Gas	Midwestern Gas	Panhandle PrePay	PEAK B	Rockies Express East	PEAK A	TGT-REX
Mar. 2021	$2.4513	$2.4779	$2.4777	$2.1197	$2.3895	$2.1116	$2.2620	$2.4451
Apr. 2021	$2.4111	$2.4750	$2.3780	$2.0795	$2.3885	$2.2336	$2.2610	$2.3950
May 2021	$2.4198	$2.4961	$2.3613	$2.0882	$2.4045	$2.1908	$2.2770	$2.3784

Q27. HAS PETITIONER PROPERLY APPLIED ITS GCA RATES SINCE ITS LAST GCA PROCEEDING IN CAUSE NO. 37399 GCA 148?

A27. Yes.

Q28. ARE PETITIONER'S BOOKS AND RECORDS UNDER REVIEW BEING KEPT ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS, AS PRESCRIBED BY THE COMMISSION?

A28. Yes.

GAS SUPPLY

ASSET MANAGEMENT AGREEMENT

Q29. PLEASE DESCRIBE THE ASSET MANAGEMENT AGREEMENT ("AMA") BETWEEN EXELON GENERATION COMPANY, LLC ("EXELON") AND CITIZENS GAS.

A29. Pursuant to the AMA, Exelon administers a collection of contracts (the "Portfolio Contracts"), including contracts with Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission, and Rockies Express Pipeline ("REX") to meet Citizens Gas' requirements. The AMA was entered into on April 1, 2018 and the term will expire on March 31, 2021.

Q30. HAS CITIZENS GAS BEEN ABLE TO ESTABLISH A NEW AMA?

A30. Yes. Citizens Gas began working on the Request for Proposal (RFP) back in early August 2020 and has completed that process. Exelon exercised their Right of First Refusal in their current agreement and matched the selected bid. The new contract is still being finalized. However, it is expected that this process will go smoothly as draft agreements were included in the RFP package. The term of the new AMA will commence on April 1, 2021 and be effective through March 31, 2024.

Q31. WHAT IS THE EXTENT OF GAS DELIVERABILITY AVAILABLE TO CITIZENS GAS UNDER THE AMA?

A31. A breakdown of the monthly maximum daily deliverability available to Citizens Gas from each of its supply sources is reflected in the table below. The table includes deliverability available from Exelon via the AMA, delivered supplies from BP Canada, maximum deliverability from on-system underground storage, and maximum deliverability from a liquefied natural gas ("LNG") facility.

Table 5

	Exelon	BP	Storage	LNG	Winter Rex Service	Total
Mar. 2021	135,866	20,000	80,000	100,000	25,000	360,866
Apr. 2021	180,995	20,000	80,000	100,000	8,000	388,995
May 2021	257,044	20,000	80,000	100,000	0	457,044

Q32. PLEASE DESCRIBE GENERALLY THE GAS SALES AND DELIVERY PROVISIONS OF THE AMA.

A32. Under the AMA, Citizens Gas reserves its baseload firm gas supplies with Exelon based on the projected daily requirements Citizens Gas has for each month. Exelon then provides the amount of gas commodity Citizens Gas uses to meet the needs of its customers on a daily, seasonal, and peak day basis. In addition, Exelon provides Citizens Gas with annual agency service for purchases made from the Indiana Municipal Gas Purchasing Authority ("IMGPA").

Q33. WHAT ROLE DOES EXELON PLAY WITH REGARD TO CITIZENS GAS' SUPPLY CONTRACTS?

A33. Exelon administers contracts with producers and gas marketers for firm, long-term (at least one year) gas supplies sufficient to meet Citizens Gas' maximum daily requirements each month. This arrangement ensures the amount of capacity held on the respective pipelines is matched with firm gas supplies. The gas supply contracts provide for "take or release" volumes on a monthly basis. This "take or release" provision gives Citizens

Gas or Exelon, on behalf of Citizens Gas, the right to nominate with the producer or supplier any volume greater than the contract minimum up to the contract maximum in any month. These contracts with producers and gas marketers are the same type of contracts which have been included in Citizens Gas' previous GCA filings. In addition, Citizens Gas enters into hedging transactions to meet its gas supply needs, pursuant to our hedging strategy, and Exelon provides agency services for Citizens Gas' purchases from the IMGPA.

Q34. HAS CITIZENS GAS FORECASTED ITS GAS REQUIREMENTS FOR PURPOSES OF THIS PARTICULAR GCA PROCEEDING?

A34. Yes, it has. Petitioner's Attachment KLK-4, Schedules 2A, 2B, and 2C depict Citizens Gas' estimated throughput and retail sales volumes for the twelve months ending February 2022. These forecasts use the same methodology Citizens Gas followed in its past GCA proceedings.

Q35. HOW ARE THE PROJECTED GAS SUPPLY QUANTITIES DETERMINED FOR CITIZENS GAS?

A35. In planning for its gas supply requirements, Citizens Gas calculates the total gas required on a daily, monthly and seasonal basis, assuming normal weather, as reflected in Attachments KLK-4, Schedules 2A, 2B, and 2C. Citizens Gas then considers all available supply sources in preparing a proposed gas supply plan to meet its gas supply requirements. Based upon deliverability, storage inventory levels, transportation costs, gas costs, and other inherent limitations, Citizens Gas determines the optimum supply plan to meet its retail gas requirements.

HEDGING STRATEGY

Q36. PLEASE BRIEFLY DESCRIBE CITIZENS GAS' USE OF PHYSICAL AND/OR FINANCIAL HEDGES AS PART OF ITS HEDGING STRATEGY.

A36. The primary objective of Citizens Gas in utilizing hedging instruments is to minimize the risk of price volatility and exposure in the competitive natural gas market on behalf of its gas customers. However, Citizens Gas does not enter into hedging transactions without considering the current environment and anticipated future conditions. In order to provide greater price certainty for its customers, Citizens Gas utilizes hedging instruments to mitigate the inevitable market fluctuation in gas costs incurred to meet its system supply needs. All of the hedging transactions are tied to the projected physical volumes of natural gas required to serve Citizens Gas' system supply customers. I want to emphasize, however, that use of hedging instruments does not assure Citizens Gas that it will be able to lock-in future gas purchases at prices below the actual market price at the time the gas is purchased and delivered.

Q37. PLEASE DESCRIBE GENERALLY THE GAS PROCUREMENT PROCESS CITIZENS GAS UTILIZES.

A37. Citizens Gas takes a blended approach to gas supply procurement looking to obtain a reliable supply while mitigating market volatility for its customers. Citizens Gas uses a blend of gas purchased at current market prices, gas purchased and injected into storage during summer months, and financial hedges that collar or cap the cost of purchased gas. On a monthly basis, Citizens Gas creates a plan that meets the projected demands of the system under normal weather. Each day, Citizens Gas will optimize swing purchases, as well as storage utilization, to meet the needs of the system based on short-term forecasts.

Q38. PLEASE DESCRIBE THE HEDGING INSTRUMENTS CITIZENS GAS CONSIDERS AND UTILIZES.

A38. Citizens Gas considers and utilizes financial instruments to mitigate price volatility. Establishing a floor (put) and a ceiling (call), below and above which the purchaser will not pay, creates a collar. If gas prices fall below the established floor, Citizens Gas effectively pays the floor price. If gas prices rise above the established ceiling, Citizens Gas' purchase price effectively is capped at the ceiling price. A collar limits the purchaser's upward gas price exposure by establishing the ceiling; however, when gas prices fall below the floor price, the purchaser is obligated to pay the floor price. When the risk is evenly balanced between the purchaser and the counter-party, cost-less collars can be entered into, which do not require a premium. When more protection is purchased than risk assumed, a premium is required to put the collar into place. The collar allows for a lower floor than typically is available from a fixed price transaction; however, with a collar the purchaser also is at risk of paying a price higher than the fixed price quote (i.e., if market prices rise subsequent to the purchase of the collar).

Financial hedges to establish ceilings or floors may be purchased as well. When a floor is purchased, and the price of the commodity falls below the strike price, the purchaser effectively pays the established floor price. When a ceiling is purchased, and the price of the commodity rises above the strike price, the purchase effectively is capped at the established ceiling price. Premiums always are necessary when floors and ceilings are purchased and they become part of the cost of the hedging strategy.

Historically, Citizens Gas has used physical hedges to mitigate price volatility as well. In Citizens Gas' case, physical hedges are transactions through which a purchase price is agreed upon with the counter-party and locked in.

Q39. PLEASE DESCRIBE HOW CITIZENS GAS STRUCTURES ITS SUPPLY PORTFOLIO TO HEDGE AGAINST GAS PRICE VOLATILITY.

A39. Financial hedges are utilized to hedge up to anticipated baseload sendout volumes. Withdrawals from storage hedge heat load, up to optimum withdrawal levels (assuming normal weather). When considered together, these two hedging tactics hedge each month's lowest historical sendout. Costless collars are put in place to hedge an increment of sendout greater than the lowest historical sendout, and financial caps are put in place to hedge an additional increment of sendout against extreme increases in gas prices.

Q40. WHY DOESN'T CITIZENS GAS SIMPLY HEDGE 100 PERCENT OF ITS NORMAL WEATHER SENDOUT?

A40. Three primary factors have caused Citizens Gas to refrain from simply hedging 100 percent of its normal weather sendout: (1) there are practical limits on the ability of Citizens Gas to utilize greater quantities of physically-hedged gas; (2) the missed opportunity to take advantage of falling prices to lower gas costs; and (3) the potential financial exposure associated with financial hedges.

Q41. PLEASE ELABORATE ON THE FOREGOING FACTORS.

A41. Physical hedges result in a situation where Citizens Gas must take delivery of the volumes of gas hedged. Under certain operating or weather conditions, constraints on Citizens Gas' system may limit its ability to physically take the hedged volumes. To mitigate the risk associated with a potential inability to take physically-hedged volumes, Citizens Gas limits physically-hedged volumes to no more than retail base load volumes.

In order to purchase gas for its customers at the lowest gas cost reasonably possible, Citizens Gas believes it must leave some level of its gas purchases priced at index to take advantage of falling gas prices, in the event gas prices drop below the prices at which the hedges were established.

Citizens Gas assumes some risk associated with the use of financial hedges. On a daily basis, as the difference between bid and ask prices changes, margin calls may be made by the brokerage house. These calls can be significant during times of rising prices and require the use of Citizens Gas' working capital. Limitations on the use of Citizens Gas' working capital funds also restrict the level of financial hedges that can be put in place.

Q42. IS IT POSSIBLE THAT CITIZENS GAS MIGHT MAKE CHANGES IN ITS HEDGING STRATEGY IN THE FUTURE?

A42. Yes. Citizens Gas will continue to monitor market activity and adjust the portfolio allocation accordingly. Citizens Gas' hedging strategy will continue to focus on mitigating price volatility while at the same time the strategy will allow for appropriate operational flexibility and protection against upward price swings.

Q43. DOES CITIZENS GAS INCUR ADDITIONAL COSTS IN THE ADMINISTRATION OF ITS HEDGING STRATEGY THAT ARE NOT RECOVERED IN BASE RATES AND WHICH SHOULD BE RECOVERABLE IN THE GCA?

A43. Yes, in addition to the premiums described above, which are other expenses related to gas costs, Citizens Gas incurs other similar costs as well, including, but not limited to, brokerage fees, commission fees, clearing fees, exchange fees, National Futures Association fees, and transaction fees. In addition, Citizens Gas recognizes gains and losses on the settlement of the contract. Attachment KLK-4, Schedule 3, pages 1, 2, and 3; 8A; 8B; and 8C include certain "Hedging Transaction Costs." The Hedging Transaction Costs reflected in this GCA consist of costs necessary to administer the financial hedge program. Citizens Gas' hedging strategy is intended to address commodity purchases and transactions made to mitigate gas price volatility (i.e., to help stabilize Petitioner's retail natural gas prices). As a result, Citizens Gas incurs unavoidable costs which are associated with its hedging strategy. In my opinion, those costs are reasonably incurred and are expenses related to gas costs that should be included for purposes of obtaining Commission approval to recover them through the GCA mechanism.

Q44. HAS PETITIONER'S HEDGING STRATEGY BEEN CONSISTENT WITH PREVIOUS YEARS?

A44. While the overall approach has been consistent -- i.e. a hedging target for winter sendout currently at 80 percent, the mix of hedge components that Petitioner uses has changed from time to time in response to market dynamics. Storage has been and continues to be a significant component of the hedging volume mix. The volumes not covered by storage are hedged using fixed-price contracts and / or financial hedges. Initially, Citizens Gas used more fixed-priced contracts. However, as the dynamics of the market have changed, the mix between fixed-price and financial hedges has shifted to financial hedges being the dominant non-storage hedge component.

Q45. WHY DID PETITIONER MAKE THE SHIFT FROM FIXED-PRICE CONTRACTS TO FINANCIAL HEDGES?

A45. Petitioner had used a mix of fixed-price contracts and financial hedges for a period of time. However, Petitioner wanted to gain greater operational flexibility and to take advantage of falling natural gas prices for the benefit of its gas customers.

Fixed-price contracts are settled in an exchange for the physical product -- i.e. the actual delivery of natural gas to the purchasing counterparty. Obviously, Petitioner needs natural gas to serve its customers. However, there are times, as mentioned earlier, when it is disadvantageous for Petitioner to take delivery of the physical gas. In contrast, financial hedges are call or put options, or a combination of the two. While financial hedges are related to an underlying volume of natural gas, they are settled financially -- i.e. an exchange of goods is not required. With financial hedges, in order to physically receive the gas, Petitioner would still need to purchase natural gas on the market. In scenarios where the amount of natural gas actually needed is less than that which has been hedged, financial hedges allow Petitioner to settle the hedges financially and simply apply the gain or loss to the cost of gas actually purchased. In other words, with a financial hedge, Petitioner would not be required to accept delivery of gas that it does not need. Thus, Petitioner gains increased operational flexibility through the use of financial hedges because it can hedge the volumes needed based on its supply plan, yet "flex" the amount actually purchased based on observed customer demand. Similar to fixed-price contracts, financial hedges, and in particular call options, provide the requisite protection against unexpected and significant upward changes in the market price of natural gas. However, they also allow Petitioner to take advantage of market prices in a declining market. This is in contrast to a fixed-price contract where the purchaser must pay the agreed upon price regardless of what the market price may be. In a market where the market price of natural gas is increasing and exceeds the strike price of the options, the financial hedges are considered to be "in the money". Here, Petitioner would purchase the volumes in the market and offset that market price with proceeds from the financial settlement of the hedge. The combination of these two transactions results in a net acquisition price of the financial hedge strike price, plus the transaction cost of the hedge. In a falling market, where the market price of natural gas is decreasing and is below the strike price, financial hedges are considered to be "out of the money." In that case, Petitioner would purchase the volumes and the market and the financial hedges would expire worthless. The combination of these two transactions results in a net acquisition price of the market price, plus the transaction cost of the hedge.

Q46. IS IT REALISTIC TO BELIEVE THAT PETITIONER'S HEDGING STRATEGY, OR THAT OF ANY GAS UTILITY, WOULD GENERATE THE LOWEST COST OF NATURAL GAS?

A46. No. It is not realistic. Financial theory shows us that when hedging any asset with an option, the net cost of the asset will always be higher than the market price because of the addition of the cost of the option. Furthermore, the cost of natural gas does not have to be the absolute lowest cost in order to be recoverable in the GCA process. Rather, under Indiana Code 8-1-2-42(g)(3)(A), the petitioning gas utility must show that "…the gas utility has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the *lowest gas cost reasonably possible*...."(*emphasis* added)

PREPAID NATURAL GAS PURCHASES

Q47. PLEASE PROVIDE FURTHER INFORMATION ON CITIZENS GAS' PURCHASES FROM THE IMGPA.

A47. In cooperation with the Indiana State Treasurer's Office and the Indiana Bond Bank, Citizens Gas, Batesville Water & Gas Utility, and Lapel Gas formed the IMGPA to implement the state's first-ever prepaid natural gas program. The IMGPA is an Indiana nonprofit corporation formed in 2007 as an instrumentality of the three previously-mentioned municipal gas utilities, for the purpose of aggregating the current prepaid program. The IMPGA has enough flexibility to serve as a vehicle for future prepaid transactions, as well as to include additional municipal gas utilities.

Effective with gas delivered September 1, 2007, Citizens Gas began purchasing approximately 10% of its then annual retail load (about 3.0 Bcf per year) at a 44 cent per Dth discount from index prices. Over a 15-year period, the prepaid gas program will have provided Citizens Gas customers approximately $24 million in gas cost savings.

Q48. WILL CITIZENS GAS' MONTHLY PURCHASES OF PREPAID GAS BE DISCOUNTED THE FULL 44 CENTS PER DTH AS IT IS DELIVERED?

A48. No. On a monthly basis, Citizens Gas will pay a price equal to the "Panhandle Eastern Pipe Line Co.: Texas Oklahoma (mainline)" index price of Platts *Inside F.E.R.C.'s Gas Market Report* minus a discount of 32 cents per Dth. On November 15th after the end of each contract year ending August 31st, the IMGPA will determine the difference between its revenues and expenses for the contract year. If this difference demonstrates that the

IMGPA's revenues exceeded its expenses during the calendar year, IMGPA will make a refund to Citizens Gas equal to the ratio of Citizens Gas' calendar year prepaid gas volumes to the total prepaid gas volumes of all three municipal utilities. The refund also will be credited to customers through Citizens Gas' GCA mechanism as a reduced gas cost, and is anticipated to result in an additional 12 cents per Dth discount on the prepaid gas volumes delivered during the contract year, providing a total discount on contract year prepaid gas volumes of 44 cents per Dth.

Q49. HAS PETITIONER RECEIVED A REFUND FROM IMGPA THIS CALENDAR YEAR?

A49. No.

Q50. PLEASE PROVIDE FURTHER INFORMATION ON CITIZENS GAS' PURCHASES FROM THE PUBLIC ENERGY AUTHORITY OF KENTUCKY ("PEAK").

A50. PEAK was formed to provide discounted prepay gas to its municipal members. PEAK approached Citizens Gas about a potential prepaid gas opportunity similar to the IMGPA transaction. In February 2018, Petitioner entered into an agreement with PEAK to purchase discounted prepay natural gas. The transaction has a term of thirty years divided into five periods of six years each. During each six-year period, members of PEAK may elect to participate or not depending on the availability and the minimum threshold of the discount. If the minimum discount is not available, members have no purchase obligations for that period. Citizens' customers will receive the benefit directly through commodity purchases in the GCA.

Effective with gas delivered April 1, 2018, Citizens Gas began purchasing approximately 10,000 Dth per day at a 39 cent per Dth discount from index prices. This discount for gas purchases was effective through October 31, 2020. The discount changed to a 33.5 cent per Dth discount starting November 1, 2020 through October 31, 2023 and a 28 cent per Dth discount from November 1, 2023 through February 29, 2024

In March 2020, Petitioner entered into a second agreement with PEAK to purchase additional discounted prepay natural gas. Effective with Gas delivered November 1, 2020, Citizens Gas will begin purchasing an additional 10,000 Dth per day at a 20.75 cent per Dth discount from index prices. This discount will remain for gas purchases through April 30, 2026.

LOAD FORECAST

Q51. HAS PETITIONER'S ANNUAL LOAD FORECAST CHANGED SINCE THE PREVIOUS GCA?

A51. Yes.

Q52. PLEASE DESCRIBE THE CHANGES MADE TO PETITIONER'S ANNUAL LOAD FORECAST.

A52. Petitioner has updated sales volumes after analyzing customer usage. These updated sales volumes affect all rate classes and will continue to be analyzed on a quarterly basis. Thus, it is important to accurately reflect customer usage to minimize variances from projected volumes to actual volumes.

Q53. DOES THIS CONCLUDE YOUR TESTIMONY?

A53. Yes, it does.

VERIFICATION

The undersigned affirms under the penalties for perjury that the foregoing testimony is true to the best of his knowledge, information and belief.

Korlon L. Kilpatrick II

Tab 2

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, FOR APPROVAL OF GAS COST ADJUSTMENTS TO BE APPLICABLE IN THE MONTHS OF MARCH, APRIL AND MAY 2021	**) CAUSE NO. 37399-GCA 149**

PETITION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas (hereinafter referred to as "Petitioner"), respectfully represents and shows the Commission:

Petitioner's Characteristics and Other Matters

1. Petitioner is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including certain sections of the Public Service Commission Act, as amended. Petitioner's rates and charges and terms and conditions for gas service are subject to the approval of this Commission by virtue of the provisions of IC 8-1-11.1-3(c)(9). Petitioner's principal office is at 2020 North Meridian Street, Indianapolis, Indiana 46202.

2. Petitioner is authorized to and is engaged in rendering gas utility service in Marion County, Indiana. It owns, operates, manages and controls plant and equipment, used and useful for the distribution and furnishing of service to the public. Petitioner takes delivery of its supplies of natural gas from Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission ("Midwestern") and

Rockies Express Pipeline ("REX Pipeline").

3. The books and records of Petitioner supporting the data, calculations and allegations contained in this Petition are available for inspection and review by the Commission and the Indiana Office of Utility Consumer Counselor.

4. The names and addresses of the persons authorized to accept service of papers in this proceeding are:

Korlon L. Kilpatrick II
Director, Regulatory Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Michael E. Allen (Attorney No. 20768-49)
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Michael B. Cracraft (Attorney No. 3416-49)
Ice Miller LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200

<u>Request for Approval of Gas Cost Adjustments</u>
<u>to be Applicable During the Months of March, April and May 2021</u>

5. This Petition is an application under IC 8-1-2-42(g) for Commission approval of Petitioner's gas cost adjustments to be applicable for the March, April and May 2021 billing months. This Petition is filed in accordance with the Public Service Commission Act, as amended, and in compliance with the Commission's May 14, 1986 Order in Cause No. 37091, the Commission's December 11, 2002 Order in Cause No. 41605, the Order in Cause No. 37399-GCA75 and the Commission's August 27, 2014 Order in Cause No. 44374. Pursuant to the Stipulation and Settlement Agreement on Gas Cost Adjustment Modification Issue ("Stipulation"), approved by final Order of the Commission in Cause No. 37399-GCA75 on December 4, 2002, as such Stipulation has been thereafter amended; the resulting monthly GCA factors attached as Attachment KLK-2 are subject to change.

6. Copies of Petitioner's proposed monthly tariff sheets incorporating its gas cost adjustments in each Rider A, are attached as Attachment KLK-2. The bill impact statements are attached as Attachment KLK-3.

7. Petitioner's cost of gas, based upon the estimated average gas cost for the three months of March, April and May 2021, is estimated to total $22,920,180. Petitioner's requested gas cost adjustment rates, modified for the recovery of Indiana Utility Receipts Tax, are set forth in the following Rider A (One-Hundred Fourteenth Revised Page No. 501, One-Hundred Fifteenth Revised Page No. 501, and One-Hundred Sixteenth Revised Page No. 501) and will be applied to all bills rendered by Petitioner during its March, April and May 2021 billing months. Supporting schedules containing estimated cost data relating to the requested gas cost adjustment rates are set forth in Attachment KLK-4.

8. Petitioner has made every reasonable effort to acquire long-term gas supplies so as

to provide gas to its retail customers at the lowest gas cost reasonably possible. Changes in Petitioner's gas cost since its last base rate proceeding in Cause No. 43975 reflect changes in natural gas purchases and the rates of its pipeline suppliers, which have been filed with the Federal Energy Regulatory Commission.

WHEREFORE, Petitioner respectfully prays that the Indiana Utility Regulatory Commission, as provided for in Indiana Code §8-1-2-42(g)(1), conduct a summary hearing on the matters set forth herein and thereafter enter an Order in a timely manner in this Cause:

(a) approving Petitioner's proposed monthly tariff sheets, *i.e.*, Rider A One-Hundred Fourteenth Revised Page No. 501, One-Hundred Fifteenth Revised Page No. 501, and One-Hundred Sixteenth Revised Page No. 501, as are attached to this Petition;

(b) authorizing and approving the monthly gas cost adjustments set forth in each Rider A (identified as Attachment KLK-2), and in the supporting schedules attached to this Petition, to become effective for Petitioner's March, April and May 2021 billing months;

(c) making such further orders and providing such further relief as may be appropriate and proper.

DATED this 31st day of December 2020.

BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST

By: /s/LaTona S. Prentice
LaTona S. Prentice
Vice President, Regulatory & External Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202
(317) 927-4529

ATTEST:

/s/Jennett M. Hill
Jennett M. Hill
Senior Vice President and
General Counsel

VERIFICATION

The undersigned affirms under the penalties for perjury that the foregoing testimony is true to the best of his knowledge, information and belief.

LaTona S. Prentice

CERTIFICATE OF SERVICE

I hereby certify that on the 31st day of December 2020, I served a copy of the foregoing Petition upon the Office of Utility Consumer Counselor by delivery or by depositing a copy in the United States mail, first class postage prepaid to the following addresses:

Office of Utility Consumer Counselor
115 West Washington Street
Suite 1500 South
Indianapolis IN 46204
infomgt@oucc.in.gov

Michael B. Cracraft (Attorney No.
3416-49) Ice Miller LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200
(317) 236-2293
E-Mail: Michael.Cracraft@icemiller.com

Michael E. Allen, (Attorney No. 20768
-49) Citizens Energy Group
2020 N. Meridian Street
Indianapolis, IN 46202
Telephone/Fax: (317) 927-4318
E-Mail: mallen@citizensenergygroup.com

Attorneys for
Petitioner, Citizens Gas

Tab 3

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Fourteenth Revised Page No. 501
Superseding Substitute One-Hundred Thirteenth Revised Page No. 501

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after March 1, 2021

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	**$**	**0.2935**
Gas Rate No. D2	Gas Supply Charge	**$**	**0.2991**
Gas Rate No. D3	Gas Supply Charge	**$**	**0.3408**
Gas Rate No. D4	Gas Supply Charge	**$**	**0.2815**
Gas Rate No. D5	Gas Supply Charge	**$**	**-**
Gas Rate No. D7	Gas Supply Charge	**$**	**0.3360**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	**$**	**0.0943**
Commodity	**$**	**0.2182**
Gas Supply Charge	**$**	**0.3125**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	**$**	**0.0015**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D4	**$**	**0.0017**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	**$**	**0.0025**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D7	**$**	**0.0015**			
Gas Rate No. D9	**$**	**0.0359**	**$**	**0.0018**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street **One-Hundred Fifteenth Revised Page No. 501**
Indianapolis, IN 46202 **Superseding One-Hundred Fourteenth Revised Page No. 501**

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after April 1, 2021

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	**$**	**0.2885**
Gas Rate No. D2	Gas Supply Charge	**$**	**0.2954**
Gas Rate No. D3	Gas Supply Charge	**$**	**0.2594**
Gas Rate No. D4	Gas Supply Charge	**$**	**0.2861**
Gas Rate No. D5	Gas Supply Charge	**$**	**-**
Gas Rate No. D7	Gas Supply Charge	**$**	**0.2558**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	**$**	**0.0722**
Commodity	**$**	**0.2415**
Gas Supply Charge	**$**	**0.3137**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	**$**	**0.0016**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D4	**$**	**0.0018**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	**$**	**0.0026**	**$**	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D7	**$**	**0.0016**			
Gas Rate No. D9	**$**	**0.0360**	**$**	**0.0018**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Sixteenth Revised Page No. 501
Superseding One-Hundred Fifteenth Revised Page No. 501

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after May 1, 2021

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.2802**
Gas Rate No. D2	Gas Supply Charge	$	**0.3139**
Gas Rate No. D3	Gas Supply Charge	$	**0.2444**
Gas Rate No. D4	Gas Supply Charge	$	**0.3024**
Gas Rate No. D5	Gas Supply Charge	$	-
Gas Rate No. D7	Gas Supply Charge	$	**0.2410**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.0678**
Commodity	$	**0.2532**
Gas Supply Charge	$	**0.3210**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0022**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0024**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0032**	$	**0.0002**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0022**			
Gas Rate No. D9	$	**0.0366**	$	**0.0018**	for Basic Delivery Service Option

Tab 4

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor March 2021
vs.
Currently Approved GCA Factor December 2020

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $2.9910	Bill At Current GCA Factor $2.9110	Dollar Increase (Decrease)	Percent Change
5	$43.11	$42.71	$0.40	0.94 %
10	$69.73	$68.92	$0.81	1.18 %
15	$96.34	$95.13	$1.21	1.27 %
20	$122.96	$121.34	$1.62	1.34 %
25	$149.57	$147.55	$2.02	1.37 %

Proposed GCA Factor March 2021
vs.
GCA Factor One Year Ago March 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $2.9910	Bill At Prior Year's GCA Factor $2.5830	Dollar Increase (Decrease)	Percent Change
5	$43.11	$41.04	$2.07	5.04 %
10	$69.73	$65.59	$4.14	6.31 %
15	$96.34	$90.13	$6.21	6.89 %
20	$122.96	$114.68	$8.28	7.22 %
25	$149.57	$139.22	$10.35	7.43 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor April 2021
vs.
Currently Approved GCA Factor December 2020

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $2.9540	Bill At Current GCA Factor $2.9110	Dollar Increase (Decrease)	Percent Change
5	$42.93	$42.71	$0.22	0.52 %
10	$69.36	$68.92	$0.44	0.64 %
15	$95.79	$95.13	$0.66	0.69 %
20	$122.22	$121.34	$0.88	0.73 %
25	$148.65	$147.55	$1.10	0.75 %

Proposed GCA Factor April 2021
vs.
GCA Factor One Year Ago April 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $2.9540	Bill At Prior Year's GCA Factor $2.3130	Dollar Increase (Decrease)	Percent Change
5	$42.93	$39.69	$3.24	8.16 %
10	$69.36	$62.89	$6.47	10.29 %
15	$95.79	$86.08	$9.71	11.28 %
20	$122.22	$109.28	$12.94	11.84 %
25	$148.65	$132.47	$16.18	12.21 %

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor May 2021
vs.
Currently Approved GCA Factor December 2020

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $3.1390	Bill At Current GCA Factor $2.9110	Dollar Increase (Decrease)	Percent Change
5	$43.85	$42.71	$1.14	2.67 %
10	$71.21	$68.92	$2.29	3.32 %
15	$98.56	$95.13	$3.43	3.61 %
20	$125.92	$121.34	$4.58	3.77 %
25	$153.27	$147.55	$5.72	3.88 %

Proposed GCA Factor May 2021
vs.
GCA Factor One Year Ago May 2020

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $3.1390	Bill At Prior Year's GCA Factor $2.3970	Dollar Increase (Decrease)	Percent Change
5	$43.85	$40.11	$3.74	9.32 %
10	$71.21	$63.73	$7.48	11.74 %
15	$98.56	$87.34	$11.22	12.85 %
20	$125.92	$110.96	$14.96	13.48 %
25	$153.27	$134.57	$18.70	13.90 %

Tab 5

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For March 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 1, ln 16)	$2,332,628	$5,436,558	$7,769,186
2	PEPL Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col A + ln 23)	-	735,053	735,053
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 3)	771,040	2,844,160	3,615,200
4	Total estimated gas cost (ln 1 through ln 3)	$3,103,668	$9,015,771	$12,119,439
5	Total Gas Supply variance (Sch 1, March, total of ln 17)	-	(946,692)	(946,692)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)	-	(9,371)	(9,371)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 27, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$3,103,668	$8,059,708	$11,163,376
9	Net Write-Off Recovery Costs (ln 8 *1.10%)			$122,797
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$11,286,173

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For March 2021
To Be Applied To March 2021

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($57)	($8,908)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 1)	11,797	2,812,070	-	-	-
13	Total Balancing Demand Cost variance per unit of throughput (ln 11/ ln 12)	($0.005)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 1 ln 8)	0.851	0.799	1.268	0.762	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 1, ln 11)	0.008	0.008	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.854	$0.804	$1.268	$0.762	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 27)	(3,959)	(625,683)	(3,467)	(313,583)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 23)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 23)	25,248	6,017,921	46,753	2,190,796	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$21,289	$5,392,238	$43,286	$1,877,213	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 1)	11,797	2,812,070	21,846	1,023,723	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$1.805	$1.918	$1.981	$1.834	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 1, ln 4)	0.044	0.040	0.014	0.010	0.000
24	PEPL Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8)	0.178	0.174	0.097	0.170	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15)	0.013	0.013	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.894	$2.949	$3.360	$2.776	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.935	$2.991	$3.408	$2.815	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for the Period March 2021
To Be Applied to the March 2021 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
28	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($1,515)	($6,935)	$970	$7,074
29	Throughput excluding Basic - Dth (Sch 2C, ln 1)	236,592	1,664,679	267,785	21,266
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0064)	($0.0042)	$0.0036	$0.3326
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 1, ln 11)	0.008	0.008	0.008	0.008
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 1, ln 15)	0.0130	0.0130	0.0130	0.0130
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	0.0146	$0.0168	$0.0246	$0.3536
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.015	$0.017	$0.025	$0.359

Citizens Gas
Determination of Basic Balancing Charge
Estimated for March 2021
To Be Applied to March 2021

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No.D9
	Calculation of Basic Balancing Charge per unit (Dth)				
35	Basic balancing charge per unit ((Sch 1, ln 30 + ln 31 + ln 32) * .05)	0.0007	0.0008	0.0012	0.0177
36	Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.001	$0.001	$0.001	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for March 2021
To Be Applied to March 2021

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
37	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 2)	$164,877
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 1, ln 6)	807,559
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$972,436
40	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 1)	1,045,569
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.930
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.943
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 5)	$11,451
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19)	2,237,549
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$2,249,000
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 1)	1,045,569
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.151
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.182
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.125

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for April 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 2, ln 16)	$1,482,025	$6,766,918	$8,248,943
2	PEPL Unnominated Quantities cost (Schedule 4 pg 2, ln 16 col A + ln 23)	-	570,824	$570,824
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 6)	(77,660)	(433,550)	($511,210)
4	Total estimated gas cost (ln 1 through ln 3)	$1,404,365	$6,904,192	$8,308,557
5	Total Gas Supply variance (Sch 1, April, total of ln 17)	-	(647,096)	($647,096)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		(5,045)	($5,045)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 28, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$1,404,365	$6,252,051	$7,656,416
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$84,221
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$7,740,637

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for April 2021
To Be Applied to April 2021 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 23)	($39)	($6,236)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 2)	8,201	1,968,698	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11 /ln 12)	($0.005)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 2 ln 8)	0.551	0.513	0.300	0.538	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 2, ln 11)	0.007	0.007	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.553	$0.517	$0.300	$0.538	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 28)	(2,752)	(438,035)	(6,598)	(199,711)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 24)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 24)	19,450	4,669,054	98,604	1,546,260	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$16,698	$4,231,019	$92,006	$1,346,549	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 2)	8,201	1,968,698	41,575	651,976	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$2.036	$2.149	$2.213	$2.065	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 2, ln 4)	0.043	0.039	0.005	$0.011	$0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 2 ln 8)	0.198	0.193	0.040	0.207	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 2, ln 15)	0.015	0.015	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.845	$2.913	$2.558	$2.821	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.885	$2.954	$2.594	$2.861	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for April 2021
To Be Applied to the April 2021 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
28	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 23)	($1,492)	($4,460)	$795	$6,387
29	Throughput excluding Basic - Dth (Sch 2C, ln 2)	233,055	1,070,536	219,403	19,200
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0064)	($0.0042)	$0.0036	$0.3327
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 2, ln 11)	0.007	0.007	0.007	0.007
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 2, ln 15)	0.0150	0.0150	0.0150	0.0150
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	$0.0156	$0.0178	$0.0256	$0.3547
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.016	$0.018	$0.026	$0.360

Citizens Gas
Determination of Basic Balancing Charge
Estimated for April 2021
To Be Applied to April 2021

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
35	Basic balancing charge per unit ((Sch 1, ln 30 + ln 31 + ln 32) * .05)	0.0008	0.0009	0.0013	0.0177
36	Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.001	$0.001	$0.001	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for April 2021
To Be Applied to April 2021

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
37	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 2)	$130,279
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 2, ln 6)	363,330
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$493,609
40	Estimated Monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 2)	693,551
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.712
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.722
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 5)	$6,653
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19)	1,644,864
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$1,651,517
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 2)	693,551
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.381
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.415
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.137

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for May 2021

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 3, ln 16)	$955,857	$7,199,131	$8,154,988
2	PEPL Unnominated Quantities cost (Schedule 4 pg 3, ln 16 col A + ln 23)	-	599,503	599,503
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 9)	(538,900)	(4,058,580)	(4,597,480)
4	Total estimated gas cost (ln 1 through ln 3)	$416,957	$3,740,054	$4,157,011
5	Total Gas Supply variance (Sch 1, May, total of ln 17)	-	(305,811)	(305,811)
6	Total Balancing Demand variance (total of Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		(191)	(191)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 29, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$416,957	$3,434,052	$3,851,009
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$42,361
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$3,893,370

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for May 2021
To Be Applied to May 2021 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 24)	($26)	($2,861)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 3)	5,349	903,171	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11/ln 12)	($0.005)	($0.003)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 3 ln 8)	$0.256	$0.338	$0.067	$0.345	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 3, ln 11)	0.000	0.000	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.251	$0.335	$0.067	$0.345	$0.000
17	Total variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 29)	(1,796)	(200,955)	(8,918)	(94,142)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 25)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 25)	13,206	2,229,845	138,718	758,782	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$11,410	$2,028,890	$129,800	$664,640	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 3)	5,349	903,171	56,186	307,336	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$2.133	$2.246	$2.310	$2.163	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 3 ln 4)	0.033	0.043	0.002	0.012	0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 3 ln 8)	0.318	0.443	0.031	0.462	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 3, ln 15)	0.028	0.028	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$2.763	$3.095	$2.410	$2.982	$0.000
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$2.802	$3.139	$2.444	$3.024	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated For the Period May 2021
To Be Applied to the May 2021 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
28	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 24)	($1,484)	($2,393)	$675	$5,898
29	Throughput excluding Basic - Dth (Sch 2C, ln 3)	231,810	574,308	186,379	17,732
30	Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29)	($0.0064)	($0.0042)	$0.0036	$0.3326
31	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 3, ln 11)	0.000	0.000	0.000	0.000
32	PEPL balancing demand charge per unit of throughput (Sch 4, pg 3, ln 15)	0.0280	0.0280	0.0280	0.0280
33	Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32)	$0.0216	$0.0238	$0.0316	$0.3606
34	Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%))	$0.022	$0.024	$0.032	$0.366

Citizens Gas
Determination of Basic Balancing Charge
Estimated for May 2021
To Be Applied to May 2021

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
35	Basic Balancing Charge per unit ((Sch 1, ln 30 + ln 31 + ln 32) * .05)	0.0011	0.0012	0.0016	0.0180
36	Basic Balancing Charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%))	$0.001	$0.001	$0.002	$0.018

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for May 2021
To Be Applied to May 2021

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
37	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 2)	$133,440
38	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 3, ln 6)	109,912
39	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38)	$243,352
40	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 3)	363,522
41	Back-up supply capacity charge per unit (ln 39 / ln 40)	$0.669
42	Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%))	$0.678
43	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 5)	$10,372
44	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19)	897,500
45	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44)	$907,872
46	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 3)	363,522
47	Back-up supply commodity charge per unit (ln 45 / ln 46)	$2.497
48	Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%))	$2.532
49	Total Back-up Gas Supply Charge (ln 42 + ln 48)	$3.210

Citizens Gas
Allocation of Monthly Demand Cost
March 2021

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$8,860	$1,980,924	$24,440	$687,840	-	-	$2,702,064
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	1,185	264,980	3,269	92,010	-	-	361,444
6	Total monthly retail demand costs (ln 4 + ln 5)	$10,045	$2,245,904	$27,709	$779,850	-	-	$3,063,508
7	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	11,797	2,812,070	21,846	1,023,723	-	-	3,869,436
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.851	$0.799	$1.268	$0.762	-	-	$0.792
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 18)	94	22,523	1,895	13,333	2,145	170	40,160
10	Estimated monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	11,797	2,812,070	236,592	1,664,679	267,785	21,266	5,014,189
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.008	$0.008	$0.008	$0.008	$0.008	$0.008	$0.008

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 1,100,104
12a	REX Winter 2021 Demand Charges	$ 286,997
13	TGT Unnominated Demand Costs	$ 401,604
14	IMGPA Prepay Demand Costs	$ 318,563
15	Demand Cost (Sch 3 ln 15 col G)	$ 225,360
16	Demand Cost (Sch 5 ln 3 col G)	$ 771,040
17	Monthly retail demand costs (ln 12 + ln 12a +sum(ln14 + ln15 + ln16))	$ 2,702,064
18	Unnominated Demand Costs (ln 13)	$401,604
19	Total monthly demand costs (ln 17 + ln 18)	$3,103,668

Citizens Gas
Allocation of Monthly Demand Cost
April 2021

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$3,750	$838,526	$10,346	$291,163	-	-	$1,143,785
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	769	171,932	2,121	59,700	-	-	234,522
6	Total monthly retail demand costs (ln 4 + ln 5)	$4,519	$1,010,458	$12,467	$350,863	-	-	$1,378,307
7	Estimated monthly retail sales- Dth (Sch 2B, ln 2)	8,201	1,968,698	41,575	651,976	-	-	2,670,450
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.551	$0.513	$0.300	$0.538	-	-	$0.516
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 19)	61	14,577	1,726	7,927	1,625	142	26,058
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	8,201	1,968,698	233,055	1,070,536	219,403	19,200	3,519,093
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.007	$0.007	$0.007	$0.007	$0.007	$0.007	$0.007

	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 1,091,871
12a	REX Winter 2021 Demand Charges	$ 91,839
13	TGT Unnominated Demand Costs	$ 260,580
14	IMGPA Prepay Demand Costs	$ 90,195
15	Demand Cost (Sch 3 ln 15 col G)	$ (52,460)
16	Demand Cost (Sch 5 Ln 6 Col G)	$ (77,660)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 1,143,785
18	Unnominated Demand Costs (ln 13)	$260,580
19	Total Monthly demand costs (ln 17 + ln 18)	$ 1,404,365

Citizens Gas
Allocation of Monthly Demand Cost
May 2021

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$1,367	$305,678	$3,771	$106,141	-	-	$416,957
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	0	0	0	0	-	-	0
6	Total monthly retail demand costs (ln 4 + ln 5)	$1,367	$305,678	$3,771	$106,141	-	-	$416,957
7	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	5,349	903,171	56,186	307,336	-	-	1,272,042
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.256	$0.338	$0.067	$0.345	-	-	$0.328
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 20)	0	0	0	0	0	0	0
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	5,349	903,171	231,810	574,308	186,379	17,732	1,918,749
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

Line	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 957,755
12a	REX Winter 2021 Demand Charges	$ -
13	TGT Unnominated Demand Costs	$ -
14	IMGPA Prepay Demand Costs	$ 93,202
15	Demand Cost (Sch 3 ln 15 col G)	$ (95,100)
16	Demand Cost (Sch 5 Ln 9 Col G)	$ (538,900)
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 416,957
18	Unnominated Demand Costs (ln 13)	$0
19	Total Monthly demand costs (ln 17 + ln 18)	$416,957

Citizens Gas
Determination of Gas Cost Adjustment (GCA)
Estimation Period March 1, 2021 through May 31, 2021
UAF Component in Rates ($/DTH)

Line No.		A March 2021	B April 2021	C May 2021	D Total
1	Volume of pipeline gas purchases (Sch. 3) - Dths	2,354,384	2,824,877	3,015,480	8,194,741
2	Volume of Gas (injected into) withdrawn from storage (See Schedule 3B) - Dths	1,581,934	(108,308)	(1,713,847)	(240,221)
3	Total volume supplied - Dths	3,936,318	2,716,569	1,301,633	7,954,520
4	Less: Gas Division usage - Dths	(14,066)	(9,669)	(12,126)	(35,861)
5	Total volume of gas available for sale - Dths (ln 3 + ln 4)	3,922,252	2,706,900	1,289,507	7,918,659
6	UAF Percentage 1.360%	1.360%	1.360%	1.360%	
7	UAF Volumes - Dths (ln 5 * ln 6)	53,343	36,814	17,537	107,694
8	Average Commodity Rate - Schedule 3A	$2.3091	$2.3955	$2.3874	
9	UAF Costs (ln7 * ln8)	$123,174	$88,188	$41,868	$253,230
10	Schedule 2B Retail sales volumes	3,869,436	2,670,450	1,272,042	7,811,928
11	UAF Component in rates - $ per Dth (ln9 / ln10) 1/	$0.0318	$0.0330	$0.0329	

1/ For informational purposes only.

Citizens Gas
Allocation of Net Write-Off Recovery Cost
March 2021

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$516	$111,622	$316	$10,258	$85	$122,797
3	Estimated retail sales- Dth (Sch 2B, ln 1)	11,797	2,812,070	21,846	1,023,723	0	3,869,436
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.044	$0.040	$0.014	$0.010	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
April 2021

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$354	$76,555	$217	$7,036	$59	$84,221
3	Estimated retail sales- Dth (Sch 2B, ln 2)	8,201	1,968,698	41,575	651,976	0	2,670,450
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.043	$0.039	$0.005	$0.011	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
May 2021

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$178	$38,506	$109	$3,539	$29	$42,361
3	Estimated retail sales- Dth (Sch 2B, ln 3)	5,349	903,171	56,186	307,336	0	1,272,042
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.033	$0.043	$0.002	$0.012	$0.000	

Citizens Gas
Estimated Total Throughput for Twelve Months Ending February 2022

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total Throughput Subject to GCA
	Estimated Total Throughput Volumes (Dth) for Twelve Months Ending February 2022							
1	March 2021	11,797	2,812,070	252,774	1,670,817	390,049	541,694	5,679,201
2	April 2021	8,201	1,968,698	248,895	1,075,576	317,203	755,760	4,374,333
3	May 2021	5,349	903,171	247,434	578,648	267,475	751,812	2,753,889
4	First Quarter	25,347	5,683,939	749,103	3,325,041	974,727	2,049,266	12,807,423
5	June 2021	3,815	349,491	232,447	347,516	239,743	724,740	1,897,752
6	July 2021	3,222	301,132	232,257	334,554	237,343	504,184	1,612,692
7	August 2021	3,219	299,531	231,993	334,269	236,909	727,198	1,833,119
8	Second Quarter	10,256	950,154	696,697	1,016,339	713,995	1,956,122	5,343,563
9	September 2021	4,333	355,340	234,167	408,924	252,043	717,720	1,972,527
10	October 2021	4,966	677,949	262,287	635,075	302,808	786,222	2,669,307
11	November 2021	9,461	1,886,703	275,265	1,171,871	371,100	540,480	4,254,880
12	Third Quarter	18,760	2,919,992	771,719	2,215,870	925,951	2,044,422	8,896,714
13	December 2021	17,126	3,713,462	309,699	2,110,096	456,196	582,490	7,189,069
14	January 2022	19,845	4,078,254	299,937	2,539,510	480,438	592,286	8,010,270
15	February 2022	18,221	4,047,734	272,934	2,353,362	432,096	548,856	7,673,203
16	Fourth Quarter	55,192	11,839,450	882,570	7,002,968	1,368,730	1,723,632	22,872,542
17	Total Throughput - Dth	109,555	21,393,535	3,100,089	13,560,218	3,983,403	7,773,442	49,920,242
	Quarterly Allocation Factor							
18	First Quarter (line 4/line 17)	0.231364	0.265685	0.241639	0.245205	0.244698	0.263624	0.256557
19	Second Quarter (line 8/line 17)	0.093615	0.044413	0.224735	0.074950	0.179242	0.251642	0.107042
20	Third Quarter (line 12/line 17)	0.171238	0.136489	0.248934	0.163410	0.232452	0.263001	0.178219
21	Fourth Quarter (line 16/line 17)	0.503783	0.553413	0.284692	0.516435	0.343608	0.221733	0.458182
	Current Throughput Allocation Factor							
22	Allocation of March 2021 Estimated Throughput (line 1/line 1, column G)	0.002077	0.495153	0.044509	0.294199	0.068680	0.095382	1.000000
23	Allocation of April 2021 Estimated Throughput (line 2/line 2, column G)	0.001875	0.450057	0.056899	0.245883	0.072515	0.172771	1.000000
24	Allocation of May 2021 Estimated Throughput (line 3/line 3, column G)	0.001942	0.327963	0.089849	0.210120	0.097126	0.273000	1.000000
25	Allocation of Quarter Estimated Throughput (line 4/line 4, column G)	0.001979	0.443801	0.058490	0.259618	0.076106	0.160006	1.000000
	Monthly Allocation Factors							
26	March 2021 (line 1/line 4)	0.465420	0.494739	0.337436	0.502495	0.400162	0.264336	0.443430
27	April 2021 (line 2/line 4)	0.323549	0.346362	0.332257	0.323478	0.325428	0.368795	0.341547
28	May 2021 (line 3/line 4)	0.211031	0.158899	0.330307	0.174027	0.274410	0.366869	0.215023
29	Total Throughput Allocation Factor (line 17/line 17, col. G)	0.002195	0.428554	0.062101	0.271638	0.079795	0.155717	1.000000

Citizens Gas
Estimated Retail Sales Volume for Twelve Months Ending February 2022

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total Retail Sales Subject to GCA
	Estimated Retail Sales Volumes (Dth) for Twelve Months Ending February 2022						
1	March 2021	11,797	2,812,070	21,846	1,023,723	0	3,869,436
2	April 2021	8,201	1,968,698	41,575	651,976	0	2,670,450
3	May 2021	5,349	903,171	56,186	307,336	0	1,272,042
4	First Quarter	25,347	5,683,939	119,607	1,983,035	0	7,811,928
5	June 2021	3,815	349,491	50,087	161,336	0	564,729
6	July 2021	3,222	301,132	50,681	155,684	0	510,719
7	August 2021	3,219	299,531	50,603	156,763	0	510,116
8	Second Quarter	10,256	950,154	151,371	473,783	0	1,585,564
9	September 2021	4,333	355,340	47,787	184,824	0	592,284
10	October 2021	4,966	677,949	53,638	221,284	0	957,837
11	November 2021	9,461	1,886,703	44,029	538,133	0	2,478,326
12	Third Quarter	18,760	2,919,992	145,454	944,241	0	4,028,447
13	December 2021	17,126	3,713,462	50,283	1,202,698	0	4,983,569
14	January 2022	19,845	4,078,254	32,442	1,553,880	0	5,684,421
15	February 2022	18,221	4,047,734	21,497	1,523,445	0	5,610,897
16	Fourth Quarter	55,192	11,839,450	104,222	4,280,023	0	16,278,887
17	Total Retail Sales - Dth	109,555	21,393,535	520,654	7,681,082	0	29,704,826
	Quarterly Retail Allocation Factor						
18	First Quarter (line 4/line 17)	0.231364	0.265685	0.229725	0.258171	0.000000	0.262985
19	Second Quarter (line 8/line 17)	0.093615	0.044413	0.290732	0.061682	0.000000	0.053377
20	Third Quarter (line 12/line 17)	0.171238	0.136489	0.279368	0.122931	0.000000	0.135616
21	Fourth Quarter (line 16/line 17)	0.503783	0.553413	0.200175	0.557216	0.000000	0.548022
22	Annual (line 17 / line 17, Column F)	0.003688	0.720204	0.017528	0.258580	0.000000	1.000000
	Current Retail Sales Allocation Factor						
23	Allocation of March 2021 Estimated Throughput (line 1/line 1, column F)	0.003049	0.726739	0.005646	0.264566	0.000000	1.000000
24	Allocation of April 2021 Estimated Throughput (line 2/line 2, column F)	0.003071	0.737215	0.015569	0.244145	0.000000	1.000000
25	Allocation of May 2021 Estimated Throughput (line 3/line 3, column F)	0.004205	0.710017	0.044170	0.241608	0.000000	1.000000
26	Allocation of Quarter Estimated Retail Sales (line 4/line 4, column F)	0.003245	0.727597	0.015311	0.253847	0.000000	1.000000
	Monthly Retail Allocation Factors						
27	March 2021 (line 1/line 4)	0.465420	0.494739	0.182648	0.516240	0.000000	0.495324
28	April 2021 (line 2/line 4)	0.323549	0.346362	0.347597	0.328777	0.000000	0.341843
29	May 2021 (line 3/line 4)	0.211031	0.158899	0.469755	0.154983	0.000000	0.162833

Citizens Gas
Estimated Total Throughput Excluding Basic Volume (Dth) for Twelve Months Ending February 2022

Line No.			A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total Throughput Subject to GCA
	Estimated Total Throughput Excluding Basic Volumes (Dth) for Twelve Months Ending February 2022								
1	March 2021		11,797	2,812,070	236,592	1,664,679	267,785	21,266	5,014,189
2	April 2021		8,201	1,968,698	233,055	1,070,536	219,403	19,200	3,519,093
3	May 2021		5,349	903,171	231,810	574,308	186,379	17,732	1,918,749
4	First Quarter		25,347	5,683,939	701,457	3,309,523	673,567	58,198	10,452,031
5	June 2021		3,815	349,491	216,907	343,556	167,983	16,920	1,098,672
6	July 2021		3,222	301,132	216,757	330,648	166,353	16,864	1,034,976
7	August 2021		3,219	299,531	216,493	330,363	166,105	16,864	1,032,575
8	Second Quarter		10,256	950,154	650,157	1,004,567	500,441	50,648	3,166,223
9	September 2021		4,333	355,340	218,567	404,784	176,143	17,280	1,176,447
10	October 2021		4,966	677,949	246,240	630,177	208,196	18,910	1,786,438
11	November 2021		9,461	1,886,703	258,944	1,165,991	253,560	20,880	3,595,539
12	Third Quarter		18,760	2,919,992	723,751	2,200,952	637,899	57,070	6,558,424
13	December 2021		17,126	3,713,462	293,023	2,102,966	310,062	23,312	6,459,951
14	January 2022		19,845	4,078,254	283,135	2,532,008	326,182	24,056	7,263,480
15	February 2022		18,221	4,047,734	256,337	2,346,586	294,056	22,624	6,985,558
16	Fourth Quarter		55,192	11,839,450	832,495	6,981,560	930,300	69,992	20,708,989
17	Total Throughput excl. Basic - Dth		109,555	21,393,535	2,907,860	13,496,602	2,742,207	235,908	40,885,667
	Current Throughput Excl. Basic Allocation Factor								
18	Allocation of March 2021 Estimated Throughput (line 1/line 1, column G)		0.002353	0.560823	0.047184	0.331994	0.053405	0.004241	1.000000
19	Allocation of April 2021 Estimated Throughput (line 2/line 2, column G)		0.002330	0.559434	0.066226	0.304208	0.062346	0.005456	1.000000
20	Allocation of May 2021 Estimated Throughput (line 3/line 3, column G)		0.002788	0.470708	0.120813	0.299314	0.097136	0.009241	1.000000
21	Total Throughput Excl. Basic Allocation Factor (line 17/line 17, col. G)		0.002680	0.523252	0.071122	0.330106	0.067070	0.005770	1.000000
	Monthly Total Throughput less Basic								
22	March 2021	(line 1/line 4)	0.465420	0.494739	0.337287	0.502997	0.397563	0.365408	0.479733
23	April 2021	(line 2/line 4)	0.323549	0.346362	0.332244	0.323471	0.325733	0.329908	0.336690
24	May 2021	(line 3/line 4)	0.211031	0.158899	0.330469	0.173532	0.276704	0.304684	0.183577

Citizens Gas
Purchased Gas Cost - Estimated
March 2021

Line No.	Month and Supplier	A Estimated Purchases Demand	B Commodity MCF	C Commodity DTH	D Supplier Rates Estimated Demand $/DTH	E Commodity $/DTH	F Other $/MCF	G Estimated Costs Demand (A x D)	H Commodity (C x E)	I Other	J Total (G+H+I)
	March 2021										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			-		$2.4513			-		-
2	Texas Gas Transmission - TOR			-		2.4779			-		-
3	TGT-REX			-		2.4451			-		-
4	Indiana Municipal Gas Purchasing Authority - TOR			18,538		2.4513			45,442		45,442
5	Indiana Municipal Gas Purchasing Authority - Prepay			511,252		2.1197			1,083,701		1,083,701
6	PEAK B			310,000		2.3895			740,745		740,745
7	Rockies Express Pipeline - TOR			562,331		2.1116			1,187,418		1,187,418
8	PEAK A			310,000		2.2620			701,220		701,220
9	Midwestern Gas Transmission Purchases			-		2.4777			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								73,555		73,555
12	Boil-off / Peaking purchase			42,263		2.5970			109,757		109,757
13	Net Demand Cost Charges - AMA							1,501,708	-		1,501,708
13a	REX Winter 2021 Demand Charges							286,997			286,997
14	Demand Cost Charges -IMGPA - Prepay	17,090			18.6403			318,563	-		318,563
15	Texas Gas - NNS - (Injections)/Withdrawls			600,000	0.3756	2.4912		225,360	1,494,720		1,720,080
16	Total			2,354,384				$2,332,628	$5,436,558	-	$7,769,186

Citizens Gas
Purchased Gas Cost - Estimated
April 2021

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	April 2021										
Exelon Generation Company, LLC											
1	Panhandle Eastern Pipeline - TOR			744,071		$2.4111			1,794,030		1,794,030
2	Texas Gas Transmission - TOR			241,655		2.4750			598,096		598,096
3	TGT-REX			241,655		2.3950			578,764		578,764
4	Indiana Municipal Gas Purchasing Authority - TOR			5,250		2.4111			12,658		12,658
5	Indiana Municipal Gas Purchasing Authority - Prepay			144,750		2.0795			301,008		301,008
6	PEAK B			300,000		2.3885			716,550		716,550
7	Rockies Express Pipeline - TOR			905,233		2.2336			2,021,928		2,021,928
8	PEAK A			300,000		2.2610			678,300		678,300
9	Midwestern Gas Transmission Purchases			-		2.3780			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								195,419		195,419
12	Boil-off / Peaking purchase			42,263		2.5960			109,715		109,715
13	Net Demand Cost Charges - AMA							1,352,451	-		1,352,451
13a	REX Winter 2021 Demand Charges							91,839			91,839
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.0390			90,195	-		90,195
15	Texas Gas - NNS - (Injections)/Withdrawls			(100,000)	0.5246	2.3955		(52,460)	(239,550)		(292,010)
16	Total			2,824,877				$1,482,025	$6,766,918	-	$8,248,943

Citizens Gas
Purchased Gas Cost - Estimated
May 2021

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	May 2021										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			984,907		$2.4198			$2,383,278		$2,383,278
2	Texas Gas Transmission - TOR			651,655		2.4961			1,626,596		1,626,596
3	TGT-REX			241,655		2.3784			574,752		574,752
4	Indiana Municipal Gas Purchasing Authority - TOR			5,425		2.4198			13,127		13,127
5	Indiana Municipal Gas Purchasing Authority - Prepay			149,575		2.0882			312,343		312,343
6	PEAK B			310,000		2.4045			745,395		745,395
7	Rockies Express Pipeline - TOR			620,000		2.1908			1,358,296		1,358,296
8	PEAK A			310,000		2.2770			705,870		705,870
9	Midwestern Gas Transmission Purchases			-		2.3613			-		-
10	Fixed Price Purchases										
11	Hedging Transaction Costs								85,303		85,303
12	Boil-off / Peaking purchase			42,263		2.6120			110,391		110,391
13	Net Demand Cost Charges - AMA							957,755	-		957,755
13a	REX Winter 2021 Demand Charges							-			-
14	Demand Cost Charges -IMGPA - Prepay	5,000			18.6404			93,202	-		93,202
15	Texas Gas - NNS - (Injections)/Withdrawls			(300,000)	0.3170	2.3874		(95,100)	(716,220)		(811,320)
16	Total			3,015,480				$955,857	$7,199,131	-	$8,154,988

Citizens Gas
Calculation of the Projected Average Pipeline Rates
Non-pipeline Supplies, Storage Injections, and Company Usage

Line No	Description	Mar 2021	Apr 2021	May 2021	Total
	Commodity Volumes (Dth)				
	Purchases for Retail:				
1	Panhandle TOR	0	744,071	984,907	1,728,978
2	IMGPA TOR	18,538	5,250	5,425	29,213
3	IMGPA Prepay	511,252	144,750	149,575	805,577
4	Midwestern Gas	0	0	0	0
5	Rockies Express TOR - Monthly	562,331	905,233	620,000	2,087,564
6	PEAK A	310,000	300,000	310,000	920,000
7	Fixed Price Purchases (Sch. 3)	0	0	0	0
8	Texas Gas TOR	0	241,655	651,655	893,310
9	TGT-Rex East	0	241,655	241,655	483,310
10	PEAK B	310,000	300,000	310,000	920,000
11	Texas Gas NNS	600,000	(100,000)	(300,000)	200,000
12	Boil-off/ Peaking purchases (Sch. 3)	42,263	42,263	42,263	126,789
	Total Retail Volumes				
13	(Ln1 through Ln12)	2,354,384	2,824,877	3,015,480	8,194,741
	Demand Rate				
14	Total Demand Costs (Sch. 3)	$2,332,628	$1,482,025	$955,857	$4,770,510
15	Demand Cost per Dth (Line 14 / Line 13)	$0.9908	$0.5246	$0.3170	$0.5821
	Commodity Rate				
16	Panhandle TOR	$2.4513	$2.4111	$2.4198	
17	IMGPA TOR	2.4513	2.4111	2.4198	
18	IMGPA Prepay	2.1197	2.0795	2.0882	
19	Annual Delivery Service - Midwestern Gas	2.4777	2.3780	2.3613	
20	Rockies Express TOR - Monthly	2.1116	2.2336	2.1908	
21	PEAK A	2.2620	2.2610	2.2770	
22	Fixed Price Purchases (Sch. 3)	0.0000	0.0000	0.0000	
23	Texas Gas TOR	2.4779	2.4750	2.4961	
24	TGT-Rex East	2.4451	2.3950	2.3784	
25	Texas Gas NNS	2.4912	2.3955	2.3874	
26	Boil-off/ Peaking purchases (Sch. 3)	2.5970	2.5960	2.6120	
27	PEAK B	2.3895	2.3885	2.4045	
	Commodity Costs				
28	PEPL (Ln 1 x Ln 16)	$0	$1,794,030	$2,383,278	$4,177,308
29	IMGPA - TOR (Ln 2 x Ln 17)	45,442	12,658	13,127	71,227
30	IMGPA - Authority Prepay (Ln 3 x Ln 18)	1,083,701	301,008	312,343	1,697,052
31	Midwestern (Ln 4 x Ln 19)	0	0	0	0
32	Rockies Express TOR (Ln 5 X Ln 20)	1,187,418	2,021,928	1,358,296	4,567,642
33	PEAK A (Ln 6 X Ln 21)	701,220	678,300	705,870	2,085,390
34	Fixed Price Purchases (Ln 7 x Ln 22)	0	0	0	0
35	Texas Gas (Ln 8 x Ln 23)	0	598,096	1,626,596	2,224,692
36	TGT-Rex East (Ln 9 x Ln 24)	0	578,764	574,752	1,153,516
37	Texas Gas -Unnominated Gas (Ln 11 x Ln 25)	1,494,720	(239,550)	(716,220)	538,950
38	Boil-off/ Peaking purchases (Ln 12 x Ln 26)	109,757	109,715	110,391	329,863
39	PEAK B (Ln 10 x Ln 27)	740,745	716,550	745,395	2,202,690
40	Hedging Transaction Costs (Sch 3)	73,555	195,419	85,303	354,277
41	Subtotal(Ln 28 through Ln 40)	$5,436,558	$6,766,918	$7,199,131	$19,402,607
	Commodity Cost per Dth				
42	(Line 41/Line 13)	$2.3091	$2.3955	$2.3874	$2.3677
	Total Average Rate per Dth				
43	(Line 15 + Line 42)	$3.2999	$2.9201	$2.7044	$2.9498

Citizens Gas
Projected Information
For Three Months Ending May 31, 2021

Line No.	A Mar 2021	B Volumes in Dths	C Commodity Cost per Dth	D % of Total	E Reference
1	Fixed Price Purchases	-	$ -	0.00%	Sch 3 pg 1 line 10
2	Monthly Spot Market - Index Purchases	1,712,121	$ 2.2382	43.51%	Sch 3 pg 1 (line 16 - line 10 - line 12 - line 15)
3	Boil off/Peaking Purchases	42,263	$ 2.5970	1.07%	Sch 3 pg 1 line 12
4	Unnominated Seasonal Gas Purchases	600,000	$ 2.4912	15.24%	Sch 3 pg 1 line 15
5	Storage Withdrawal - Net	1,581,934	$ 1.7776	40.18%	Sch 5 ln 3 col B - Sch 4pg 1 ln 22 Col E
6	Storage Injection - Gross	-	$ -	0.00%	Sch 5 ln 3 col A - Sch 4 pg 1 ln 20 Col E
7	Total Net Purchases	3,936,318		100.00%	

	Apr 2021	Volumes in Dths	Commodity Cost per Dth	% of Total	
8	Fixed Price Purchases	-	$ -	0.00%	Sch 3 pg 2 line 10
9	Monthly Spot Market - Index Purchases	2,882,614	$ 2.3925	106.11%	Sch 3 pg 2 (line 16 - line 10 - line 12 - line 15)
10	Boil off/Peaking Purchases	42,263	$ 2.5960	1.56%	Sch 3 pg 2 line 12
11	Unnominated Seasonal Gas Purchases	(100,000)	$ 2.3955	-3.68%	Sch 3 pg 2 line 15
12	Storage Withdrawal - Net	400,000	$ 1.9105	14.72%	Sch 5 line 6 col B - Sch 4pg 2 ln 22 Col E
13	Storage Injection - Gross	(508,308)	$ 2.3955	-18.71%	Sch 5 line 6 col A - Sch 4 pg 2 ln 20 Col E
14	Total Net Purchases	2,716,569		100.00%	

	May 2021	Volumes in Dths	Commodity Cost per Dth	% of Total	
15	Fixed Price Purchases	-	$ -	0.00%	Sch 3 pg 3 line 10
16	Monthly Spot Market - Index Purchases	3,273,217	$ 2.3845	251.47%	Sch 3 pg 3 (line 16 - line 10 - line 12 - line 15)
17	Boil off/Peaking Purchases	42,263	$ 2.6120	3.25%	Sch 3 pg 3 line 12
18	Unnominated Seasonal Gas Purchases	(300,000)	$ 2.3874	-23.05%	Sch 3 pg 3 line 15
19	Storage Withdrawal - Net	-	$ -	0.00%	Sch 5 line 9 col B - Sch 4pg 3 ln 22 Col E
20	Storage Injection - Gross	(1,713,847)	$ 2.3874	-131.67%	Sch 5 line 9 col A - Sch 4 pg 3 ln 20 Col E
21	Total Net Purchases	1,301,633		100.00%	

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
March 2021

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,953	$458,628	$1,979	$162,898	$0	-	$625,458
3	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	11,797	2,812,070	21,846	1,023,723	0	-	3,869,436
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.166	$0.163	$0.091	$0.159	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$136	$31,853	$137	$11,314	$0	-	$43,440
6	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	11,797	2,812,070	21,846	1,023,723	0	-	3,869,436
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.012	$0.011	$0.006	$0.011	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.178	$0.174	$0.097	$0.170	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 18)	$146	$34,691	$2,919	$20,537	$3,304	$262	$61,859
10	Est. monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	11,797	2,812,070	236,592	1,664,679	267,785	21,266	5,014,189
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.012	$0.012	$0.012	$0.012	$0.012	$0.012	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 18)	$10	$2,410	$203	$1,426	$229	$18	$4,296
13	Estimated monthly total throughput excl Basic- Dth (Sch 2C, ln 1)	11,797	2,812,070	236,592	1,664,679	267,785	21,266	5,014,189
14	Net monthly balancing variable costs per unit throughput (ln12 / ln13)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.013	$0.013	$0.013	$0.013	$0.013	$0.013	

Ln. No.	Calculation of Monthly Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$687,317
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$625,458
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$61,859

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	March 2021	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	0		0.0020			$0			$0
20	(100 - day firm) (Midpoint)	0		0.0094		0	0		$0	0
21	PEPL Withdrawals (Gross)		800,000		0.0020			1,600		1,600
22	(100 - day firm) (Net)		781,934		0.0094	18,066		7,350	38,786	46,136
23	Total (ln 19 + ln20 + ln21 + ln22)						$0	$8,950	$38,786	$47,736
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$43,440
25	PEPL Balancing Variable Costs (line 23* 9%) 1/									$4,296

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
April 2021

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,543	$362,389	$1,564	$128,715	$0	-	$494,211
3	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	8,201	1,968,698	41,575	651,976	0	-	2,670,450
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.188	$0.184	$0.038	$0.197	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$79	$18,507	$80	$6,573	$0	-	$25,239
6	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	8,201	1,968,698	41,575	651,976	0	-	2,670,450
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.010	$0.009	$0.002	$0.010	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.198	$0.193	$0.040	$0.207	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 19)	$114	$27,344	$3,237	$14,869	$3,047	$267	$48,878
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	8,201	1,968,698	233,055	1,070,536	219,403	19,200	3,519,093
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 19)	$6	$1,396	$165	$759	$156	$14	$2,496
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 2)	8,201	1,968,698	233,055	1,070,536	219,403	19,200	3,519,093
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.015	$0.015	$0.015	$0.015	$0.015	$0.015	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$543,089
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$494,211
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$48,878

		A	B	C	D	E	F	G	H	I
	Calculation of Monthly Variable Costs	Volumes		Storage Rates			Costs			
	April 2021	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	300,000		0.0020			$600			$600
20	(100 - day firm) (Midpoint)	305,842		0.0094		8,308	2,875		$24,260	27,135
21	PEPL Withdrawals (Gross)		0		0.0020			0		0
22	(100 - day firm) (Net)		0		0.0094	0		0	0	0
23	Total (ln 19 + ln20 + ln21 + ln22)						$3,475	$0	$24,260	$27,735
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$25,239
25	PEPL Balancing Variable Costs (line 23 * 9%) 1/									$2,496

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
May 2021

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,580	$371,179	$1,602	$131,838	$0	-	$506,199
3	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	5,349	903,171	56,186	307,336	0	-	1,272,042
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.295	$0.411	$0.029	$0.429	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$123	$28,853	$124	$10,248	$0	-	$39,348
6	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	5,349	903,171	56,186	307,336	0	-	1,272,042
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.023	$0.032	$0.002	$0.033	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.318	$0.443	$0.031	$0.462	$0.000	-	
9	PEPL balancing demand costs (ln 18* Sch 2C, ln 20)	$140	$23,565	$6,048	$14,985	$4,863	$463	$50,064
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	5,349	903,171	231,810	574,308	186,379	17,732	1,918,749
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.026	$0.026	$0.026	$0.026	$0.026	$0.026	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 20)	$11	$1,832	$470	$1,165	$378	$36	$3,892
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 3)	5,349	903,171	231,810	574,308	186,379	17,732	1,918,749
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	
15	Total PEPL Balancing cost per unit sales (ln 11 + ln 14)	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$556,263
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$506,199
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$50,064

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	May 2021	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	500,000		0.0020			$1,000			$1,000
20	(100 - day firm) (Midpoint)	509,736		0.0094		13,847	4,792		$37,448	42,240
21	PEPL Withdrawals (Gross)		0		0.0020			0		0
22	(100 - day firm) (Net)		0		0.0094	0		0	0	0
23	Total (ln 19 + ln20 + ln21 + ln22)						$5,792	$0	$37,448	$43,240
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$39,348
25	PEPL & 3 Balancing Variable Costs (line 23 * 9%) 1/									$3,892

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Estimated Cost of Gas Injections and Withdrawals
For Three Months Ending May 31, 2021

		A	B	C	D	E	F	G	H	I
		Estimated Change		Estimated Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	March 2021									
1	Greene Co.	0	800,000	$0	$0	$369,200	$1,528,480	$369,200	$1,528,480	$1,897,680
2	PEPL WSS	0	800,000	0	0	401,840	1,315,680	401,840	1,315,680	1,717,520
3	Subtotal	0	1,600,000	0	0	771,040	2,844,160	771,040	2,844,160	3,615,200
	April 2021									
4	Greene Co.	200,000	400,000	104,920	479,100	184,640	764,200	79,720	285,100	364,820
5	PEPL WSS	300,000	0	157,380	718,650	0	0	(157,380)	(718,650)	(876,030)
6	Subtotal	500,000	400,000	262,300	1,197,750	184,640	764,200	(77,660)	(433,550)	(511,210)
	May 2021									
7	Greene Co.	1,200,000	0	380,400	2,864,880	0	0	(380,400)	(2,864,880)	(3,245,280)
8	PEPL WSS	500,000	0	158,500	1,193,700	0	0	(158,500)	(1,193,700)	(1,352,200)
9	Subtotal	1,700,000	0	538,900	4,058,580	0	0	(538,900)	(4,058,580)	(4,597,480)
10	Grand Total	2,200,000	2,000,000	$801,200	$5,256,330	$955,680	$3,608,360	$154,480	($1,647,970)	($1,493,490)

Citizens Gas
Demand Allocation of Injections and Withdrawals
Greene Co.
For Three Months Ending May 31, 2021

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Comm $/DTH
1	Beginning Balance @ March 2021	3,687,547	$1,701,864	$7,045,275	$8,747,139	$2.3721	$1.9106
2	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
3	Less: Gross withdrawals - avg. unit cost	(800,000)	(369,200)	(1,528,480)	(1,897,680)	2.3721	1.9106
4	Beginning Balance @ April 2021	2,887,547	1,332,664	5,516,795	6,849,459	2.3721	1.9105
5	Add: Net injections at cost	200,000	104,920	479,100	584,020	2.9201	2.3955
6	Less: Gross withdrawals - avg. unit cost	(400,000)	(184,640)	(764,200)	(948,840)	2.3721	1.9105
7	Beginning Balance @ May 2021	2,687,547	1,252,944	5,231,695	6,484,639	2.4128	1.9466
8	Add: Net injections at cost	1,200,000	380,400	2,864,880	3,245,280	2.7044	2.3874
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ May 31, 2021	3,887,547	$1,633,344	$8,096,575	$9,729,919	$2.5028	$2.0827

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL FS
For Three Months Ending May 31, 2021

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Comm $/DTH
1	Beginning Balance @ March 2021	1,632,177	$819,833	$2,684,297	$3,504,130	$2.1469	$1.6446
2	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
3	Less: Gross withdrawals - avg. unit cost	(800,000)	(401,840)	(1,315,680)	(1,717,520)	2.1469	1.6446
4	Beginning Balance @ April 2021	832,177	417,993	1,368,617	1,786,610	2.1469	1.6446
5	Add: Net injections at cost	300,000	157,380	718,650	876,030	2.9201	2.3955
6	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
7	Beginning Balance @ May 2021	1,132,177	575,373	2,087,267	2,662,640	2.3518	1.8436
8	Add: Net injections at cost	500,000	158,500	1,193,700	1,352,200	2.7044	2.3874
9	Less: Gross withdrawals - avg. unit cost	0	0	0	0	0.0000	0.0000
10	Ending balance @ May 31, 2021	1,632,177	$733,873	$3,280,967	$4,014,840	$2.4598	$2.0102

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
September 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1, ln 1 Col A)	$3,121	$697,805	$8,609	$242,300	$0	$951,835
6	Allocated other demand costs (ln 2 * (Schedule 7, pg. 1, ln 4 Col A)	(2,565)	(482,207)	(13,257)	(185,360)	0	(683,389)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, ln 3 Col B))	1,749	410,722	1,772	145,882	0	$560,125
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col B, ln 2 + ln 4) * (Sch. 6A, ln 30))	7,650	719,712	65,621	385,340	0	1,178,323
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$9,955	$1,346,032	$62,745	$588,162	$0	$2,006,894
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6A, ln 33)	$9,675	$1,342,299	$67,569	$633,330	$0	$2,052,873
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	9,540	1,323,507	66,623	624,463	0	2,024,133
12	Net - Write Off Recovered (Sch 12 C ln 3)	82	19,209	61	2,165	0	21,517
13	Variance from Cause No. 37399-GCA 147 Filing (Sch. 1, pg. 2 Sep., 2020 ln 17)	(1,214)	(64,726)	(6,879)	(42,004)	0	(114,823)
14	Refund from cause No. 37399- GCA 147 Filing (Sch. 1, pg. 2 Sep., 2020 ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	10,672	1,369,024	73,441	664,302	0	2,117,439
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($717)	($22,992)	($10,696)	($76,140)	$0	($110,545)

Citizens Gas
Calculation of Actual Gas Cost Variance
September 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, Col A ln 1 * ln 31)	$0	$0	$0	$0	$0	$0	$0
18	Allocated PEPL Balancing Demand & variable cost (Sch. 7, pg. 2, Col A ln 2 * ln 31)	120	11,284	6,725	13,797	7,466	16,005	55,397
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	120	11,284	6,725	13,797	7,466	16,005	55,397
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6A, ln 38)	$158	$15,502	$8,063	$17,939	$8,014	$19,482	$69,158
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	156	15,285	7,950	17,688	7,902	19,209	68,190
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 2 Sep., 2020 ln 11)	(26)	(1,455)					(1,481)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 3 Sep., 2020 ln 28)			(1,657)	(2,109)	300	9,326	5,860
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$182	$16,740	$9,607	$19,797	$7,602	$9,883	$63,811
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($62)	($5,456)	($2,882)	($6,000)	($136)	$6,122	($8,414)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
September 2020

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dths	3,582	337,007	30,727	180,436	-		551,752
27	Standard Delivery - Dths			166,613	227,058	149,908	19,605	563,184
28	Basic Delivery - Dths			3,488	4,543	73,042	458,355	539,428
29	Total Throughput - Dths (ln 26+ ln 27 + ln 28)	3,582	337,007	200,828	412,037	222,950	477,960	1,654,364
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.006492	0.610794	0.055690	0.327024	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29/ln 29, column G)	0.002165	0.203707	0.121393	0.249061	0.134765	0.288909	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 147 (D1 & D2 excludes balancing charges) per Dth	$2.701	$3.983	$2.199	$3.510	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$9,675	$1,342,299	$67,569	$633,330	$0	-	$2,052,873
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 147 Standard & Retail Customers (per Dth)	$0.044	$0.046	$0.041	$0.044	$0.052	$0.456	
35	Balancing GCA Charge Cause No. 37399 - GCA 147 Basic Delivery Customers (per Dth)			$0.002	$0.002	$0.003	$0.023	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$158	$15,502	$8,056	$17,930	$7,795	$8,940	$58,381
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)			$7	$9	$219	$10,542	$10,777
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$158	$15,502	$8,063	$17,939	$8,014	$19,482	$69,158

1/ Line 36 Column C calculation is (161,955 * 0.041) + (35,385 * 0.04)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
October 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1,Col C ln 1)	$5,405	$1,208,425	$14,909	$419,604	$0	$1,648,343
6	Allocated other demand costs (ln 2 * ((Schedule 7 pg. 1, Col C ln 4))	(1,871)	(351,751)	(9,670)	(135,212)	0	(498,504)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, Col D ln 3))	1,726	405,383	1,749	143,986	0	552,844
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col D, ln 2 + ln 4) * (Sch. 6B, ln 30))	17,370	2,386,494	79,785	830,662	0	3,314,311
9	Total actual cost of gas incurred (lns 5+6+7+8)	$22,630	$3,648,551	$86,773	$1,259,040	$0	$5,016,994
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6B, ln 33)	$24,294	$4,254,480	$81,937	$1,417,644	$0	$5,778,355
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	23,954	4,194,917	80,790	1,397,797	0	5,697,458
12	Net - Write Off Recovered (Sch 12 C ln 9)	270	59,296	83	5,160	0	64,809
13	Variance from Cause No. 37399-GCA 147 Filing (Sch. 1, pg. 2 Oct., 2020 ln 17)	(1,468)	(120,939)	(14,147)	(64,612)	0	(201,166)
14	Refund from cause No. 37399- GCA 147 Filing (Sch. 1, pg. 2 Oct., 2020 ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$25,152	$4,256,560	$94,854	$1,457,249	$0	$5,833,815
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($2,522)	($608,009)	($8,081)	($198,209)	$0	($816,821)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
October 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost ((Sch. 7, pg. 2, Col B ln 1 *) *ln 31)	$102	$14,079	$2,558	$8,509	$3,065	$5,869	$34,182
18	Allocated ADS2 Balancing Demand & variable cost ((Sch. 7, pg. 2, Col B ln 2) * ln 31)	164	22,518	4,092	13,611	4,903	9,389	54,677
19	Total actual Balancing Demand cost incurred (ln17 + ln 18)	$266	$36,597	$6,650	$22,120	$7,968	$15,258	$88,859
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6B, ln 38)	$405	$58,061	$9,209	$33,378	$9,613	$19,356	$130,022
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	399	57,248	9,080	32,911	9,478	19,085	128,201
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 2 Oct., 2020 ln 11)	(31)	(2,718)	-	-	-	-	(2,749)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 3 Oct., 2020 ln 28)	-	-	(2,189)	(3,398)	375	7,575	2,363
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 21 - ln 22 - ln 23)	$430	$59,966	$11,269	$36,309	$9,103	$11,510	$128,587
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($164)	($23,369)	($4,619)	($14,189)	($1,135)	$3,748	($39,728)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
October 2020

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dths	8,991	1,235,331	41,299	429,980	0	0	1,715,601
27	Standard Delivery - Dths		-	178,617	311,523	176,117	17,302	683,559
28	Basic Delivery - Dths	-	-	4,582	5,223	92,880	497,762	600,447
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	8,991	1,235,331	224,498	746,726	268,997	515,064	2,999,607
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.005241	0.720057	0.024073	0.250629	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / ln 29, column G)	0.002997	0.411833	0.074842	0.248941	0.089677	0.171710	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 147 (D1 & D2 excludes balancing charges) per Dth	$2.702	$3.444	$1.984	$3.297	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26* ln 32)	$24,294	$4,254,480	$ 81,937	$1,417,644	$0	$0	$5,778,355
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 147 Standard & Retail Customers (per Dth)	$0.045	$0.047	$0.042	$0.045	$0.053	$0.457	
35	Balancing GCA Charge Cause No. 37399 - GCA 147 Basic Delivery Customers (per Dth)	-	-	$0.002	$0.002	$0.003	$0.023	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$405	$58,061	$9,200	$33,368	$9,334	$7,907	$118,275
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$9	$10	$279	$11,449	$11,747
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$405	$58,061	$9,209	$33,378	$9,613	$19,356	$130,022

1/ Line 36 Column C calculation is (183,812 * 0.042) + (36,104 * 0.041)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
November 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7 pg. 1, Col E ln 1)	$6,564	$1,467,660	$18,108	$509,619	$0	$2,001,951
6	Allocated other demand costs (ln 2 * (Schedule 7 pg. 1, Col E, ln 4))	(104)	(19,609)	(539)	(7,537)	0	(27,789)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1,Col F ln 3)	1,957	459,596	1,983	163,242	0	626,778
8	Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4) * (Sch. 6C, ln 30))	22,906	3,935,863	52,549	1,537,646	0	5,548,964
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$31,323	$5,843,510	$72,101	$2,202,970	$0	$8,149,904
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6C, ln 33)	$35,548	$6,603,090	$67,970	$2,624,129	$0	$9,330,737
11	Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%))	35,050	6,510,648	67,018	2,587,391	0	9,200,107
12	Net - Write Off Recovered (Sch 12 C ln 15)	460	86,807	129	10,551	0	97,947
13	Variance from Cause No. 37399-GCA 147 Filing (Sch. 1, pg. 2 Nov, 2020, ln 17)	($2,797)	($336,583)	($11,925)	($152,481)	$0	(503,786)
14	Refund from cause No. 37399- GCA 147 Filing (Sch. 1, pg. 2 Nov, 2020, ln 18)	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14)	$37,387	$6,760,424	$78,814	$2,729,321	$0	$9,605,946
16	Gas cost variance (over)/underrecovery (ln 9 - ln 15)	($6,064)	($916,914)	($6,713)	($526,351)	$0	($1,456,042)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
November 2020

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
17	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, ln 1 * ln 31)	$101	$17,264	$1,942	$10,601	$2,600	$6,357	$38,865
18	Allocated ADS2 Balancing Demand cost (Sch. 7, pg. 2, ln 2 * ln 31)	$160	$27,537	$3,097	$16,908	$4,147	$10,140	$61,989
19	Total actual Balancing Demand cost incurred (ln 17 + ln 18)	$261	$44,801	$5,039	$27,509	$6,747	$16,497	$100,854
20	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (ln 38)	$258	$46,297	$4,055	$27,120	$5,631	$22,525	$105,886
21	Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%))	254	45,649	3,998	26,740	5,552	22,210	104,403
22	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 2 Nov, 2020 ln 11)	(59)	(7,563)	-	-	-	-	(7,622)
23	Balancing Demand Cost Variance from Cause No. 37399 - GCA 147 (Sch. 1, pg. 3 Nov, 2020 ln 28)	-	-	(2,303)	(6,287)	458	8,365	233
24	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23)	$313	$53,212	$6,301	$33,027	$5,094	$13,845	$111,792
25	Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24)	($52)	($8,411)	($1,262)	($5,518)	$1,653	$2,652	($10,938)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
November 2020

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
26	Retail gas sales - Dth	11,228	1,929,036	25,756	753,627	-	-	2,719,647
27	Standard Delivery - Dths	-	-	187,431	425,239	180,378	16,704	809,752
28	Basic Delivery - Dths	-	-	3,791	5,614	110,126	693,603	813,134
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	11,228	1,929,036	216,978	1,184,480	290,504	710,307	4,342,533
30	Retail sales allocation factor (ln 26 / ln 26, col. G)	0.004128	0.709297	0.009470	0.277105	0.000000	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 / 29, column G)	0.002586	0.444219	0.049966	0.272762	0.066897	0.163570	1.000000
	Calculation of Gas Supply Charge Recovery							
32	Gas Supply Charge Cause No. 37399 - GCA 147 (D1 & D2 excludes balancing charges) per Dth	$3.166	$3.423	$2.639	$3.482	$0.000	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$35,548	$6,603,090	$67,970	$2,624,129	-	-	$9,330,737
	Calculation of Balancing Charge Recovery							
34	Balancing GCA Charge Cause No. 37399 - GCA 147 Standard & Retail Customers (per Dth)	$0.023	$0.024	$0.019	$0.023	$0.030	$0.435	
35	Balancing GCA Charge Cause No. 37399 - GCA 147 Basic Delivery Customers (per Dth)	-	-	$0.001	$0.001	$0.002	$0.022	
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$258	$46,297	$4,051	$27,114	$5,411	$7,266	$90,397
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	-	-	$4	$6	$220	$15,259	$15,489
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$258	$46,297	$4,055	$27,120	$5,631	$22,525	$105,886

1/ Line 36 Column C calculation is (186,526 * 0.019) + (26,661 * 0.019)

Citizens Gas
Trailing Twelve Month Variance
For October 2019 through November 2020

Line No.			A October 2019	B November 2019	C December 2019	D January 2020	E February 2020	F March 2020	G April 2020	H May 2020	I June 2020	J July 2020	K August 2020	L September 2020	M October 2020	N November 2020
1	Actual Cost of Gas	Total Sch 6 pg 1 ln 9 + Sch 6 pg 2 ln 19	$3,940,195	$11,139,702	$12,187,945	$12,791,023	$12,620,659	$7,383,182	$4,317,200	$2,906,287	$1,331,877	$1,368,247	$1,630,453	$2,062,291	$5,105,853	$8,250,758
2	Variance	Total Sch 6 pg 1 ln 16 + Sch 6 pg 2 ln 25	($838,374)	($828,796)	($730,945)	($1,500,513)	($779,086)	($464,555)	($442,851)	$179,518	($668,512)	($334,647)	($98,921)	($118,959)	($856,549)	($1,466,980)
3										Gas Cost Trailing Twelve Months (ln 1, col A-L)				$73,679,061		
4										Variance Trailing Twelve Months (ln 2, col A-L)				($6,626,641)		
5										Total Trailing Twelve Months % Variance (ln 4 / ln 3)				-8.99%		
6										Gas Cost Trailing Twelve Months (ln 1, col B-M)					$74,844,719	
7										Variance Trailing Twelve Months (ln 2, col B-M)					($6,644,816)	
8										Total Trailing Twelve Months % Variance (ln 7 / ln 6)					-8.88%	
9										Gas Cost Trailing Twelve Months (ln 1, col C-N)						$71,955,775
10										Variance Trailing Twelve Months (ln 2, col C-N)						($7,283,000)
11										Total Trailing Twelve Months % Variance (ln 10 / ln 9)						-10.12%

Citizens Gas
Determination of Actual Retail Gas Costs
For Three Months Ending November 30, 2020

		A	B	C	D	E	F
		September 2020		October 2020		November 2020	
Line No.		Demand	Non-Demand	Demand	Non-Demand	Demand	Non-Demand
1	Demand gas costs (Sch. 8)	$951,835	-	$1,648,343	-	$2,001,951	-
2	Pipeline non-demand gas costs (Schedule 8)	-	4,179,128	-	4,694,673	-	5,365,184
3	PEPL Contracted storage and related transportation costs (Sch. 9)	-	560,125	-	552,844	-	626,778
4	Net cost of gas (injected into) withdrawn from storage (Schedule 10)	(683,389)	(3,000,805)	(498,504)	(1,380,362)	(27,789)	183,780
5	Total gas costs	$268,446	$1,738,448	$1,149,839	$3,867,155	$1,974,162	$6,175,742

Citizens Gas
Determination of Actual Balancing Costs
For Three Months Ending November 30, 2020

Line No.		A September 2020	B October 2020	C November 2020
1	Balancing Demand Costs (Schedule 8)	$0	$34,182	$38,865
2	PEPL Balancing Demand Costs (Sch. 9)	55,397	54,677	61,989
3	Total Balancing Costs	$55,397	$88,859	$100,854

Citizens Gas
Purchased Gas Cost - Per Books
September 2020

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual -August, 2020									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	679,582	$ 13.3194	$ 1.7177		$ 445,707	$ 1,167,344		$ 1,613,051
2	MGT Pipeline -	1,395,000	-	0.0620	-		86,504	681		87,185
3	Indiana Municipal Gas Purchasing Authority - TOR		5,735	-	1.7168			9,846		9,846
4	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	149,265	18.6192	1.3855		93,096	206,801		299,897
5	Texas Gas Transmission - Nominated Demand	974,113		0.3543	-		345,128			345,128
6	Texas Gas Transmission - Unnominated Demand	-		-	-		-			-
7	Texas Gas Transmission - Commodity - TOR		355,694	-	1.7332			616,472		616,472
8	Texas Gas Transmission - Unnominated Injection	(443,100)	(443,100)	0.5624	1.6062		(249,199)	(711,707)		(960,906)
9	Texas Gas Transmission - Unnominated Withdrawal	1,269	1,269	0.5626	1.6060		714	2,038		2,752
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		58,000	(1,700)		56,300
11	Rockies Express - Delivered Supply - (BP REX)		309,504	-	1.6466		-	509,640		509,640
12	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	1.4640		-	453,840		453,840
13	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
14	Intraday Purchases		-	-	-			-		-
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		-	-	-		-	-		-
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			32,744		32,744
19	Imbalance		1,960	-	1.6056			3,147		3,147
20	Utilization Fee			-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	Contract Services		-	-	-		-	-		-
23	Third Party Supplier Balancing Gas Costs		47,393	-			-	(21,704)		(21,704)
24	Boil-off / Peaking purchase		29,784	-	1.8540		-	55,220		55,220
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss	-	(314)	-	-		-			-
27	Backup Supply Sales		-		-			-		-
28	Subtotal		1,446,772				$870,783	$2,322,662	$0	$3,193,445
	Actual -August, 2020									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	679,582	$ 13.3194	$ 1.7177		$ 445,707	$ 1,167,344		$ 1,613,051
30	MGT Pipeline -	1,395,000	-	0.0620	-		86,504	681		87,185
31	Indiana Municipal Gas Purchasing Authority - TOR		5,735	-	1.7168			9,846		9,846
32	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	149,265	18.6192	1.3855		93,096	206,801		299,897
33	Texas Gas Transmission - Nominated Demand	974,113		0.3543	-		345,128			345,128
34	Texas Gas Transmission - Unnominated Demand	-		-	-		-			-
35	Texas Gas Transmission - Commodity - TOR		355,694	-	1.7332			616,472		616,472
36	Texas Gas Transmission - Unnominated Injection	(443,100)	(443,100)	0.5624	1.6063		(249,199)	(711,752)		(960,951)
37	Texas Gas Transmission - Unnominated Withdrawal	1,269	1,269	0.5626	1.6060		714	2,038		2,752
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		58,000	(1,700)		56,300
39	Rockies Express - Delivered Supply - (BP REX)		309,504	-	1.6466		-	509,640		509,640
40	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	1.4640		-	453,840		453,840
41	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
42	Intraday Purchases		-	-	-			-		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		-	-	-		-	-		-
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			32,744		32,744
47	Imbalance		1,960	-	1.6056			3,147		3,147
48	Utilization Fee			-	-		(243,750)	-		(243,750)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	Contract Services		-	-	-		-	-		-
51	Third Party Supplier Balancing Gas Costs		47,393	-				(21,704)		(21,704)
52	Boil-off / Peaking purchase		29,784	-	1.8540			55,220		55,220
53	MGT Cash Out Imbalance		181	-	2.2099			400		400
54	NSS Injection fuel loss	-	(314)							-
55	Backup Supply Sales		-	-	-		-	-		-
56	Subtotal		1,446,953				$870,783	$2,323,017	$0	$3,193,800

Citizens Gas
Purchased Gas Cost - Per Books
September 2020

		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - September, 2020									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	679,590	$ 13.2172	$ 2.3304		$ 442,288	$ 1,583,711		$ 2,025,999
58	MGT Gas Pipeline -	1,350,000	-	0.0641	-		86,504	1,274		87,778
59	Indiana Municipal Gas Purchasing Authority - TOR		5,550	-	2.3292			12,927		12,927
60	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	144,450	18.0258	1.9981		90,129	288,630		378,759
61	Texas Gas Transmission - Nominated Demand	942,690		0.3543	-		333,995			333,995
62	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
63	Texas Gas Transmission - Commodity - TOR		355,680	-	2.3621			840,154		840,154
64	Texas Gas Transmission - Unnominated Injection	(262,087)	(262,087)	0.4699	2.0842		(123,155)	(546,242)		(669,397)
65	Texas Gas Transmission - Unnominated Withdrawal	10,916	10,916	0.4699	2.0842		5,129	22,751		27,880
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		26,112	102,882		128,994
67	Rockies Express - Delivered Supply - (BP REX)		299,520	-	2.3728			710,700		710,700
68	Rockies Express - Delivered Supply - (BP PEAK)		300,000	-	2.1890			656,700		656,700
69	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
70	Intraday Purchases		-	-	-			-		-
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		285,550	-	0.8411			240,186		240,186
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			4,420		4,420
75	Imbalance		(13,923)	-	2.1366			(29,748)		(29,748)
76	Utilization Fee			-	-		(243,750)	-		(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Contract Services		-	-	-		-	-		-
79	Third Party Supplier Balancing Gas Costs		120,394	-				212,315		212,315
80	Boil-off / Peaking purchase		30,288	-	2.5790			78,113		78,113
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(83)	-	-		-			-
83	Backup Supply Sales		-		-			-		-
84	Subtotal		1,955,845				$ 951,835	$ 4,178,773	$ -	$ 5,130,608
85	Total Purchased Costs (line 84 + line 56 - line 28)		1,956,026				$ 951,835	$ 4,179,128	$ -	$ 5,130,963
86	Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						$ -			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		1,956,026				$ 951,835			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$ -			
89	Balancing Demand Cost (line 86 * 10%)						$ -			

Citizens Gas

Purchased Gas Cost - Per Books

October 2020

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - September, 2020									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	679,590	$ 13.2172	$ 2.3304		$ 442,288	$ 1,583,711		$ 2,025,999
2	MGT Gas Pipeline -	1,350,000	-	0.0641	-		86,504	1,274		87,778
3	Indiana Municipal Gas Purchasing Authority - TOR		5,550	-	2.3292			12,927		12,927
4	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	144,450	18.0258	1.9981		90,129	288,630		378,759
5	Texas Gas Transmission - Nominated Demand	942,690		0.3543	-		333,995			333,995
6	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
7	Texas Gas Transmission - Commodity - TOR		355,680	-	2.3621			840,154		840,154
8	Texas Gas Transmission - Unnominated Injection	(262,087)	(262,087)	0.4699	2.0842		(123,155)	(546,242)		(669,397)
9	Texas Gas Transmission - Unnominated Withdrawal	10,916	10,916	0.4699	2.0842		5,129	22,751		27,880
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		26,112	102,882		128,994
11	Rockies Express - Delivered Supply - (BP REX)		299,520	-	2.3728			710,700		710,700
12	Rockies Express - Delivered Supply - (BP PEAK)		300,000	-	2.1890			656,700		656,700
13	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
14	Intraday Purchases		-	-	-			-		-
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		285,550	-	0.8411			240,186		240,186
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			4,420		4,420
19	Imbalance		(13,923)	-	2.1366			(29,748)		(29,748)
20	Utilization Fee			-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	Contract Services		-	-	-		-	-		-
23	Third Party Supplier Balancing Gas Costs		120,394	-				212,315		212,315
24	Boil-off / Peaking purchase		30,288	-	2.5790			78,113		78,113
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss		(83)	-	-		-			-
27	Backup Supply Sales		-		-			-		-
28	Subtotal		1,955,845				$ 951,835	$ 4,178,773	$ -	$ 5,130,608
	Actual - September, 2020									
29	Panhandle Eastern Pipeline - TOR	33,463	679,590	$ 13.2172	2.3304		$ 442,288	$ 1,583,711		$ 2,025,999
30	MGT Gas Pipeline -	1,350,000	-	0.0641	-		86,504	1,274		87,778
31	Indiana Municipal Gas Purchasing Authority - TOR		5,550	-	2.3292			12,927		12,927
32	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	144,450	18.0258	1.9981		90,129	288,630		378,759
33	Texas Gas Transmission - Nominated Demand	942,690	-	0.3543	-		333,995			333,995
34	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
35	Texas Gas Transmission - Commodity - TOR		355,680	-	2.3621		-	840,153		840,153
36	Texas Gas Transmission - Unnominated Injection	(262,087)	(262,087)	0.4700	2.0842		(123,181)	(546,242)		(669,423)
37	Texas Gas Transmission - Unnominated Withdrawal	10,916	10,916	0.4700	2.0842		5,131	22,751		27,882
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		26,112	102,882		128,994
39	Rockies Express - Delivered Supply - (BP REX)		299,520	-	2.3728			710,700		710,700
40	Rockies Express - Delivered Supply - (BP PEAK)		300,000	-	2.1890			656,700		656,700
41	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
42	Intraday Purchases		-	-	-		-	-		-
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		285,550	-	0.8411			240,185		240,185
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-					-
46	Hedging Transaction Cost			-	-			4,420		4,420
47	Imbalance		(13,923)	-	2.1366			(29,748)		(29,748)
48	Utilization Fee		-	-	-		(243,750)	-		(243,750)
49	Net Demand Cost Charges - AMA			-	-		-	-		-
50	Contract Services		-	-	-		-	-		-
51	Third Party Supplier Balancing Gas Costs		120,394	-			-	212,315		212,315
52	Boil-off / Peaking purchase		30,288	-	2.5790		-	78,113		78,113
53	MGT Cash Out Imbalance		(137)	-	1.9854		-	(272)		(272)
54	NSS Injection fuel loss		(83)	-	-					-
55	Backup Supply Sales		-		-			-		-
56	Subtotal		1,955,708				$ 951,811	$ 4,178,499	$0	$ 5,130,310

Citizens Gas

Purchased Gas Cost - Per Books

October 2020

		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - October, 2020									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	679,582	$ 13.3194	$ 1.8941		$ 445,707	$ 1,287,174		$ 1,732,881
58	MGT Pipeline	1,395,000	-	0.0620	-		86,504	1,398		87,902
59	Indiana Municipal Gas Purchasing Authority - TOR		5,735	-	1.8931			10,857		10,857
60	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	149,265	18.6084	1.5618		93,042	233,121		326,163
61	Texas Gas Transmission - Nominated Demand	1,407,710		0.3543	-		498,752			498,752
62	Texas Gas Transmission - Unnominated Demand	964,782	-	0.3543	-		341,822			341,822
63	Texas Gas Transmission - Commodity - TOR	-	355,694	-	1.8858			670,768		670,768
64	Texas Gas Transmission - Unnominated Injection	(97,031)	(97,031)	0.6374	1.7848		(61,848)	(173,181)		(235,029)
65	Texas Gas Transmission - Unnominated Withdrawal	294,535	294,535	0.6374	1.7848		187,737	525,686		713,423
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP REX)	-	309,504	-	1.8940		-	586,210		586,210
68	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	1.7110			530,410		530,410
69	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
70	Intraday Purchases		30,000	-	2.4133			72,400		72,400
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		558,175	-	1.6527			922,490		922,490
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			61,893		61,893
75	Imbalance		(9,123)	-	1.7849			(16,284)		(16,284)
76	Utilization Fee			-	-		(243,750)			(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Contract Services		-	-	-		-	-		-
79	Third Party Supplier Balancing Gas Costs		15,641	-				(77,890)		(77,890)
80	Boil-off / Peaking purchase		28,508	-	2.1010			59,895		59,895
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(42)							-
83	Backup Supply Sales		-		-			-		-
84	Subtotal		2,630,443				$ 1,682,549	$ 4,694,947	$0	$6,377,496
85	Total Purchased Costs (line 84 + line 56 - line 28.)		2,630,306				$1,682,525	$4,694,673	$0	$6,377,198
86	Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						341,822			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		2,630,306				$1,340,703			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$307,640			
89	Balancing Demand Cost (line 86 * 10%)						$34,182			

Citizens Gas
Purchased Gas Cost - Per Books
November 2020

		A	B	C	D	E	F	G	H	I
Line No.		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - October, 2020									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	33,463	679,582	$ 13.3194	$ 1.8941		$ 445,707	$ 1,287,174		$ 1,732,881
2	MGT Pipeline	1,395,000	-	$ 0.0620	-		86,504	1,398		87,902
3	Indiana Municipal Gas Purchasing Authority - TOR	-	5,735	-	1.8931		-	10,857		10,857
4	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	149,265	18.6084	1.5618		93,042	233,121		326,163
5	Texas Gas Transmission - Nominated Demand	1,407,710	-	0.3543	-		498,752			498,752
6	Texas Gas Transmission - Unnominated Demand	964,782	-	0.3543	-		341,822	-		341,822
7	Texas Gas Transmission - Commodity - TOR	-	355,694	-	1.8858			670,768		670,768
8	Texas Gas Transmission - Unnominated Injection	(97,031)	(97,031)	0.6374	1.7848		(61,848)	(173,181)		(235,029)
9	Texas Gas Transmission - Unnominated Withdrawal	294,535	294,535	0.6374	1.7848		187,737	525,686		713,423
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill	-	-	-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP REX)	-	309,504	-	1.8940		-	586,210		586,210
12	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	1.7110		-	530,410		530,410
13	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
14	Intraday Purchases	-	30,000	-	2.4133			72,400		72,400
15	Fuel Retention Volumes	-	-	-	-		-	-		-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)	-	558,175	-	1.6527		-	922,490		922,490
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)	-	-	-	-		-	-		-
18	Hedging Transaction Cost	-		-	-			61,893		61,893
19	Imbalance		(9,123)	-	1.7849			(16,284)		(16,284)
20	Utilization Fee	-	-	-	-		(243,750)	-		(243,750)
21	Net Demand Cost Charges - AMA	-	-	-	-		-			-
22	Contract Services		-	-	-		-	-		-
23	Third Party Supplier Balancing Gas Costs	-	15,641	-				(77,890)		(77,890)
24	Boil-off / Peaking purchase	-	28,508	-	2.1010		-	59,895		59,895
25	MGT Cash Out Imbalance	-	-	-	-		-	-		-
26	NSS Injection fuel loss		(42)							
27	Backup Supply Sales		-		-		-	-		-
28	Sub-total		2,630,443				$1,682,549	$4,694,947	$0	$6,377,496
	Actual - October, 2020									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	33,463	679,582	$ 13.3194	$ 1.8941		$ 445,707	$ 1,287,174		$ 1,732,881
30	MGT Pipeline	1,395,000	-	0.0620	-		86,504	1,398		87,902
31	Indiana Municipal Gas Purchasing Authority - TOR		5,735	-	1.8931			10,857		10,857
32	Indiana Municipal Gas Purchasing Authority - Prepay	5,000	149,265	18.6084	1.5618		93,042	233,121		326,163
33	Texas Gas Transmission - Nominated Demand	1,407,710		0.3543	-		498,752			498,752
34	Texas Gas Transmission - Unnominated Demand	964,782		0.3543	-		341,822			341,822
35	Texas Gas Transmission - Commodity - TOR		355,694	-	1.8858			670,768		670,768
36	Texas Gas Transmission - Unnominated Injection	(97,031)	(97,031)	0.7204	1.8235		(69,901)	(176,936)		(246,837)
37	Texas Gas Transmission - Unnominated Withdrawal	294,535	294,535	0.7204	1.8235		212,183	537,085		749,268
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP REX)	-	309,504	-	1.8940		-	586,210		586,210
40	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	1.7110		-	530,410		530,410
41	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
42	Intraday Purchases		30,000	-	2.4133			72,400		72,400
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		558,175	-	1.6527			922,490		922,490
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			61,893		61,893
47	Imbalance		(8,404)	-	1.8237			(15,326)		(15,326)
48	Utilization Fee			-	-		(243,750)			(243,750)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	Contract Services		-	-	-		-	-		-
51	Third Party Supplier Balancing Gas Costs		15,641	-				(77,890)		(77,890)
52	Boil-off / Peaking purchase		28,508	-	2.1010			59,895		59,895
53	MGT Cash Out Imbalance		(1,354)	-	2.0812			(2,818)		(2,818)
54	NSS Injection fuel loss		(42)							
55	Backup Supply Sales		(280,000)		1.4846			(415,700)		(415,700)
56	Sub-total		2,349,808				$ 1,698,942	$ 4,285,031	$ -	$ 5,983,973

Citizens Gas
Purchased Gas Cost - Per Books
November 2020

Line No.		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual -November, 2020									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	33,463	-	$ 13.2172	$ -		$ 442,288	$ -		$ 442,288
58	MGT Pipeline	1,350,000	-	0.0641	-		86,504	260		86,764
59	Indiana Municipal Gas Purchasing Authority - TOR		17,940	-	2.8347			50,854		50,854
60	Indiana Municipal Gas Purchasing Authority - Prepay	17,090	494,760	18.0374	2.5016		308,260	1,237,710		1,545,970
61	Texas Gas Transmission - Nominated Demand	1,303,050		0.3543	-		461,671			461,671
62	Texas Gas Transmission - Unnominated Demand	1,096,950		0.3543	-		388,649			388,649
63	Texas Gas Transmission - Commodity - TOR		-	-	-			-		-
64	Texas Gas Transmission - Unnominated Injection	(58,787)	(58,787)	0.7574	2.1870		(44,525)	(128,567)		(173,092)
65	Texas Gas Transmission - Unnominated Withdrawal	281,601	281,601	0.3802	2.6980		107,065	759,760		866,825
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
67	Rockies Express - Delivered Supply - (BP PEAK B)		294,118	-	2.7885		-	820,148		820,148
68	Rockies Express - Delivered Supply - (BP PEAK A)		299,888	-	2.6620		-	798,300		798,300
69	Rockies Express - EAST	20,000	-	16.7292	-		334,583	-		334,583
70	Intraday Purchases		-	-	-			-		-
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		693,259	-	1.6577			1,149,182		1,149,182
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			(54,911)		(54,911)
75	Imbalance		(2,656)	-	2.2428			(5,957)		(5,957)
76	Utilization Fee			-	-		(243,750)			(243,750)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	REX Winter Purchases	16,000	257,563	11.4799	1.8589		183,678	478,780		662,458
79	Third Party Supplier Balancing Gas Costs		299,368	-				663,679		663,679
80	Boil-off / Peaking purchase		40,121	-	2.9960			120,203		120,203
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(17)							-
83	Backup Supply Sales		(49,261)		2.3211			(114,341)		(114,341)
84	Sub-total		2,567,897				2,024,423	5,775,100	$ -	7,799,523
85	Total Purchased Costs (line 56 + line 84 - line 28)		2,287,262				$2,040,816	$5,365,184	$0	$7,406,000
86	Total TGT Unnominated Demand Cost (line 62+ line 34 - line 6)						388,649			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		2,287,262				$1,652,167			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$349,784			
89	Balancing Demand Cost (line 86 * 10%)						$38,865			

Citizens Gas
Actual Information
For Three Months Ending November 30, 2020

Line No.	A	B	C	D	E
	September 2020	Volumes in Dths	Commodity Cost per Dth	% of Total	Reference
1	Intraday Purchases	-	$ -	0.00%	Sch8A, lns 14, 42, 70
2	Index Purchases / Spot	1,784,790	$ 2.2939	84.53%	Sch8A, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
3	Swing Gas	285,550	$ 0.8411	13.52%	Sch8A, lns 16, 44, 72
4	Boil off/Peaking Purchases	30,288	$ 2.5790	1.43%	Sch8A, lns 24, 52, 80
5	Unnominated Seasonal Gas Purchases	-		0.00%	
6	Storage Withdrawal	10,916	$ 2.0842	0.52%	Sch8A, lns 9, 37, 65
7	Total Purchases	2,111,544		100.00%	
8	Contract Services	-			Sch8A, lns 22,50,78
9	Third Party	120,394			Sch8A, lns 23, 51, 79
10	Imbalance	(13,923)			Sch8A, lns 19, 47, 75
11	Fuel Retention	-			Sch8A, lns 15, 43, 71
12	MGT Cash Out Imbalance	181			Sch8A, lns 25, 53, 81
13	Unnominated Seasonal Gas Payback	-			
14	NNS Injection Loss	(83)			Sch8A, lns 26, 54, 82
15	Backup Supply Sales	-			Sch8A, lns 27, 55, 83
16	Storage Injection	(262,087)	$ 2.0844		Sch8A, lns 8, 36, 64
17	Net Purchases	1,956,026			
	October 2020	Volumes in Dths	Commodity Cost per Dth	% of Total	
18	Intraday Purchases	30,000	$ 2.4133	1.10%	Sch8B, lns 14, 42, 70
19	Index Purchases	1,809,780	$ 1.8344	66.52%	Sch8B, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
20	Swing Gas	558,175	$ 1.6527	20.51%	Sch8B, lns 16, 44, 72
21	Boil off/Peaking Purchases	28,508	$ 2.1010	1.05%	Sch8B, lns 24, 52, 80
22	Unnominated Seasonal Gas Purchases	-		0.00%	
23	Storage Withdrawal	294,535	$ 1.7848	10.82%	Sch8B, lns 9, 37, 65
24	Total Purchases	2,720,998		100.00%	
25	Contract Services	-			Sch8B, lns 22,50,78
26	Third Party	15,641			Sch8B, lns 23, 51, 79
27	Imbalance	(9,123)			Sch8B, lns 19, 47, 75
28	Fuel Retention	-			Sch8B, lns 15, 43, 71
29	MGT Cash Out Imbalance	(137)			Sch8B, lns 25, 53, 81
30	Unnominated Seasonal Gas Payback	-			
31	NNS Injection Loss	(42)			Sch8B, lns 26, 54, 82
32	Backup Supply Sales	-			Sch8B, lns 27, 55, 83
33	Storage Injection	(97,031)	$ 1.7848		Sch8B, lns 8, 36, 64
34	Net Purchases	2,630,306			
	November 2020	Volumes in Dths	Commodity Cost per Dth	% of Total	
35	Intraday Purchases	-	$ -	0.00%	Sch8C, lns 14, 42, 70
36	Index Purchases	1,106,706	$ 2.6270	52.17%	Sch8C, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
37	Swing Gas	693,259	$ 1.6577	32.67%	Sch8C, lns 16, 44, 72
38	Boil off/Peaking Purchases	40,121	$ 2.9960	1.89%	Sch8C, lns 24, 52, 80
39	Unnominated Seasonal Gas Purchases	-		0.00%	
40	Storage Withdrawal	281,601	$ 2.7385	13.27%	Sch8C, lns 9, 37, 65
41	Total Purchases	2,121,687		100.00%	
42	REX Winter Purchases	257,563			Sch8C, lns 22,50,78
43	Third Party	299,368			Sch8C, lns 23, 51, 79
44	Imbalance	(1,937)			Sch8C, lns 19, 47, 75
45	Fuel Retention	-			Sch8C, lns 15, 43, 71
46	MGT Cash Out Imbalance	(1,354)			Sch8C, lns 25, 53, 81
47	Unnominated Seasonal Gas Payback				
48	NNS Injection Loss	(17)			Sch8C, lns 26, 54, 82
49	Backup Supply Sales	(329,261)			Sch8C, lns 27, 55, 83
50	Storage Injection	(58,787)	$ 2.2509		Sch8C, lns 8, 36, 64
51	Net Purchases	2,287,262			

Citizens Gas
Calculation of the Average Accrual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

Line No.	Description	September 2020 Dth	September 2020 Rate	September 2020 Amount	October 2020 Dth	October 2020 Rate	October 2020 Amount	November 2020 Dth	November 2020 Rate	November 2020 Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 13.2172	$ 442,288	33,463	$ 13.3194	$ 445,707	33,463	$ 13.2172	$ 442,288
2	MGT Pipeline - Demand	1,350,000	0.0641	86,504	1,395,000	0.0620	86,504	1,350,000	0.0641	86,504
3	Indiana Municipal Gas Purchasing Authority - Demand	5,000	18.0258	90,129	5,000	18.6084	93,042	17,090	18.0374	308,260
4	Texas Gas Transmission - Nominated Demand	942,690	0.3820	360,107	1,407,710	0.3543	498,752	1,303,050	0.3543	461,671
5	Texas Gas Transmission - Unnominated Demand	-	-	-	964,782	0.3543	341,822	1,096,950	0.3543	388,649
6	Texas Gas Transmission - Unnominated Injections	(262,087)	0.4699	(123,155)	(97,031)	0.6374	(61,848)	(58,787)	0.7574	(44,525)
7	Texas Gas Transmission - Unnominated Withdrawal	10,916	0.4699	5,129	294,535	0.6374	187,737	281,601	0.3802	107,065
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST (Demand)	20,000	16.7292	334,583	20,000	16.7292	334,583	20,000	16.7292	334,583
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(243,750)	-	-	(243,750)	-	-	(243,750)
12	REX Winter Purchases	-	-	-	-	-	-	16,000	11.4799	183,678
13	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	679,590	2.3323	1,584,985	679,582	1.8961	1,288,572	-	-	260
14	Indiana Municipal Gas Purchasing Authority - Commodity	5,550	2.3292	12,927	5,735	1.8931	10,857	17,940	2.8347	50,854
15	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	144,450	1.9981	288,630	149,265	1.5618	233,121	494,760	2.5016	1,237,710
16	Texas Gas Transmission - Commodity	355,680	2.6514	943,036	355,694	1.8858	670,768	-	-	-
17	Texas Gas Transmission - Unnominated Injection - Commodity	(262,087)	2.0842	(546,242)	(97,031)	1.7848	(173,181)	(58,787)	2.1870	(128,567)
18	Texas Gas Transmission - Unnominated Withdrawal - Commodity	10,916	2.0842	22,751	294,535	1.7848	525,686	281,601	2.6980	759,760
19	Rockies Express - Delivered Supply - (BP REX)	299,520	2.3728	710,700	309,504	1.8940	586,210	294,118	2.7885	820,148
20	Rockies Express - Delivered Supply - (BP PEAK)	300,000	2.1890	656,700	310,000	1.7110	530,410	299,888	2.6620	798,300
21	Intra-DayPurchases	-	-	-	30,000	2.4133	72,400	-	-	-
22	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	285,550	0.8411	240,186	558,175	1.6527	922,490	693,259	1.6577	1,149,182
23	Hedging Transaction Cost	-	-	4,420	-	-	61,893	-	-	(54,911)
24	Imbalance	(13,923)	2.1366	(29,748)	(9,123)	1.7849	(16,284)	(2,656)	2.2428	(5,957)
25	REX Winter Purchases	-	-	-	-	-	-	257,563	1.8589	478,780
26	Third Party Supplier Balancing Gas Costs	120,394		212,315	15,641		(77,890)	299,368		663,679
27	Boil-off / Peaking purchase	30,288	2.5790	78,113	28,508	2.1010	59,895	40,121	2.9960	120,203
28	MGT Cash Out Imbalance	-	-	-	-	-	-	-	-	-
29	Fuel Retention Volumes	-	-		-	-		-	-	-
30	NSS Injection fuel loss	(83)		-	(42)			(17)		-
31	Backup Supply Sales	-	-	-	-	-	-	(49,261)	2.3211	(114,341)
32	Current Pipeline Rate Per Dth	1,955,845	$2.6232	$ 5,130,608	2,630,443	$2.4245	$ 6,377,496	2,567,897	$3.0373	$ 7,799,523
33	Current Commodity Rate Per Dth	1,955,845	$2.1366	$4,178,773	2,630,443	$1.7849	$4,694,947	2,567,897	$2.2490	5,775,100

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
Calculation of the Average Actual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

Line No.	Description	August 2020 Dth	August 2020 Rate	August 2020 Amount	September 2020 Dth	September 2020 Rate	September 2020 Amount	October 2020 Dth	October 2020 Rate	October 2020 Amount
1	Panhandle Eastern Pipeline - Demand	33,463	$ 13.3194	$ 445,707	33,463	$ 13.2172	$ 442,288	33,463	$ 13.3194	$ 445,707
2	MGT Pipeline - Demand	1,395,000	0.0620	86,504	1,350,000	0.0641	86,504	1,395,000	0.0620	86,504
3	Indiana Municipal Gas Purchasing Authority - Demand	5,000	18.6192	93,096	5,000	18.0258	90,129	5,000	18.6084	93,042
4	Texas Gas Transmission - Nominated Demand	974,113	0.4138	403,128	942,690	0.3820	360,107	1,407,710	0.3543	498,752
5	Texas Gas Transmission - Unnominated Demand	-	-	-	-	-	-	964,782	0.3543	341,822
6	Texas Gas Transmission - Unnominated Injections	(443,100)	0.5624	(249,199)	(262,087)	0.4700	(123,181)	(97,031)	0.7204	(69,901)
7	Texas Gas Transmission - Unnominated Withdrawal	1,269	0.5626	714	10,916	0.4700	5,131	294,535	0.7204	212,183
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST- (Demand)	20,000	16.7292	334,583	20,000	16.7292	334,583	20,000	16.7292	334,583
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(243,750)	-	-	(243,750)	-	-	(243,750)
12	REX Winter Purchases	-	-	-	-	-	-	-	-	-
13	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	679,582	1.7187	1,168,025	679,590	2.3323	1,584,985	679,582	1.8961	1,288,572
14	Indiana Municipal Gas Purchasing Authority - Commodity	5,735	1.7168	9,846	5,550	2.3292	12,927	5,735	1.8931	10,857
15	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	149,265	1.3855	206,801	144,450	1.9981	288,630	149,265	1.5618	233,121
16	Texas Gas Transmission - Commodity	355,694	1.7284	614,772	355,680	2.6514	943,035	355,694	1.8858	670,768
17	Texas Gas Transmission - Unnominated Injection - Commodity	(443,100)	1.6063	(711,752)	(262,087)	2.0842	(546,242)	(97,031)	1.8235	(176,936)
18	Texas Gas Transmission - Unnominated Withdrawal - Commodity	1,269	1.6060	2,038	10,916	2.0842	22,751	294,535	1.8235	537,085
19	Rockies Express - Delivered Supply - (BP REX)	309,504	1.6466	509,640	299,520	2.3728	710,700	309,504	1.8940	586,210
20	Rockies Express - Delivered Supply - (BP PEAK)	310,000	1.4640	453,840	300,000	2.1890	656,700	310,000	1.7110	530,410
21	Intra-DayPurchases	-	-	-	-	-	-	30,000	2.4133	72,400
22	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	-	-	-	285,550	0.8411	240,185	558,175	1.6527	922,490
23	Hedging Transaction Cost	-	-	32,744	-	-	4,420	-	-	61,893
24	Imbalance	1,960	1.6056	3,147	(13,923)	2.1366	(29,748)	(8,404)	1.8237	(15,326)
25	REX Winter Purchases	-	-	-	-	-	-	-	-	-
26	Third Party Supplier Balancing Gas Costs	47,393		(21,704)	120,394		212,315	15,641		(77,890)
27	Boil-off / Peaking purchase	29,784	1.8540	55,220	30,288	2.5790	78,113	28,508	2.1010	59,895
28	MGT Cash Out Imbalance	181	2.2099	400	(137)	1.9854	(272)	(1,354)	2.0812	(2,818)
29	Fuel Retention Volumes	-	-	-	-	-	-	-	-	-
30	NSS Injection fuel loss	(314)	-	-	(83)	-	-	(42)	-	-
31	Backup Supply Sales	-	-	-	-	-	-	(280,000)	1.4846	(415,700)
32	Current Pipeline Rate Per Dth	1,446,953	$2.2073	$ 3,193,800	1,955,708	$2.6232	$ 5,130,310	2,349,808	$2.5466	$ 5,983,973
33	Current Commodity Rate Per Dth	1,446,953	$1.6055	2,323,017	1,955,708	$2.1366	4,178,499	2,349,808	$1.8236	4,285,031

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
PEPL Unnominated Quantities Cost
September 2020

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual -August, 2020						
	PEPL						
1	Demand Cost		$556,263				$556,263
2	PEPL Injection fuel cost	22,483				49,627	49,627
3	PEPL Injection (Net)			837,293	$0.0020		1,675
4	(100-day Firm) (Midpoint)			852,555	0.0094		8,014
5	PEPL Withdrawal fuel cost	-				-	-
6	PEPL Withdrawal (Midpoint)			-	0.0020		-
7	(100-day Firm) (Net)			-	0.0094		-
8	PEPL - Sub Total		$556,263			$49,627	$615,579
	Actual -August, 2020						
	PEPL						
9	Demand Cost		$562,194				$562,194
10	PEPL Injection fuel cost	22,494				49,651	49,651
11	PEPL Injection (Net)			837,675	0.0020		1,675
12	(100-day Firm) (Midpoint)			852,944	0.0094		8,018
13	PEPL Withdrawal fuel cost	-				-	-
14	PEPL Withdrawal (Midpoint)			-	0.0020		-
15	(100-day Firm) (Net)			-	0.0094		-
16	PEPL - Sub Total		$562,194			$49,651	$621,538
	Accrual - September, 2020						
	PEPL						
17	Demand Cost		$543,089				$543,089
18	PEPL Injection fuel cost	21,765				57,094	57,094
19	PEPL Injection (Net)			810,606	0.0020		1,621
20	(100-day Firm) (Midpoint)			825,378	0.0094		7,759
21	PEPL Withdrawal fuel cost	-				-	-
22	PEPL Withdrawal (Midpoint)			-	0.0020		-
23	(100-day Firm) (Net)			-	0.0094		-
24	PEPL - Sub Total		$543,089			$57,094	$609,563
25	Total (line 24 + line 16 - line 8)		$549,020			$57,118	$615,522
26	PEPL - Balancing Costs (ln 25 * 9%)						$55,397
27	PEPL - Retail Costs (ln 25 * 91%)						$560,125

Citizens Gas
PEPL Unnominated Quantities Cost
October 2020

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - September, 2020						
	PEPL						
1	Demand Cost		$543,089				$543,089
2	PEPL Injection fuel cost	21,765				57,094	57,094
3	PEPL Injection (Net)			810,606	$0.0020		1,621
4	(100-day Firm) (Midpoint)			825,378	0.0094		7,759
5	PEPL Withdrawal fuel cost	-				-	-
6	PEPL Withdrawal (Midpoint)			-	0.0020		-
7	(100-day Firm) (Net)			-	0.0094		-
8	PEPL - Sub Total		$543,089			$57,094	$609,563
	Actual - September, 2020						
	PEPL						
9	Demand Cost		$547,590				$547,590
10	PEPL Injection fuel cost	21,760				57,081	57,081
11	PEPL Injection (Net)			810,444	0.0020		1,621
12	(100-day Firm) (Midpoint)			825,213	0.0094		7,757
13	PEPL Withdrawal fuel cost	-				-	-
14	PEPL Withdrawal (Midpoint)			-	0.0020		-
15	(100-day Firm) (Net)			-	0.0094		-
16	PEPL - Sub Total		$547,590			$57,081	$614,049
	Accrual - October, 2020						
	PEPL						
17	Demand Cost		$556,263				$556,263
18	PEPL Injection fuel cost	16,349				39,638	39,638
19	PEPL Injection (Net)			608,797	0.0020		1,218
20	(100-day Firm) (Midpoint)			619,894	0.0094		5,827
21	PEPL Withdrawal fuel cost	34				71	71
22	PEPL Withdrawal (Midpoint)			1,634	0.0020		3
23	(100-day Firm) (Net)			1,620	0.0094		15
24	PEPL - Sub Total		$556,263			$39,709	$603,035
25	Total (line 24+ line 16 - line 8)		$560,764			$39,696	$607,521
26	PEPL Balancing Costs (ln 25 * 9%)						$54,677
27	PEPL Retail Costs (ln 25 * 91%)						$552,844

Citizens Gas
PEPL Unnominated Quantities Cost
November 2020

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - October, 2020						
	PEPL						
1	Demand Cost		$556,263				$556,263
2	PEPL Injection Fuel Cost	16,349				39,638	39,638
3	PEPL Injection (Net)			608,797	$0.0020		1,218
4	(100-day Firm) (Midpoint)			619,894	0.0094		5,827
5	PEPL Withdrawal Fuel Cost	34				71	71
6	PEPL Withdrawal (Midpoint)			1,634	0.0020		3
7	(100-day Firm) (Net)			1,620	0.0094		15
8	PEPL Total		$556,263			$39,709	$603,035
	Actual - October, 2020						
	PEPL						
9	Demand Cost		$556,263				$556,263
10	PEPL Injection Fuel Cost	16,309				41,532	41,532
11	PEPL Injection (Net)			607,248	$0.0020		1,214
12	(100-day Firm) (Midpoint)			618,317	0.0094		5,812
13	PEPL Withdrawal Fuel Cost	34				71	71
14	PEPL Withdrawal (Midpoint)			1,636	0.0020		3
15	(100-day Firm) (Net)			1,622	0.0094		15
16	PEPL Total		$556,263			$41,603	$604,910
	Accrual -November, 2020						
	PEPL						
17	Demand Cost		$674,143				$674,143
18	PEPL Injection Fuel Cost	157				477	477
19	PEPL Injection (Net)			5,659	$0.0020		11
20	(100-day Firm) (Midpoint)			5,769	0.0094		54
21	PEPL Withdrawal fuel cost	4,624				9,923	9,923
22	PEPL Withdrawal (Midpoint)			201,673	0.0020		403
23	(100-day Firm) (Net)			200,059	0.0094		1,881
24	PEPL Total		$674,143			$10,400	$686,892
25	Total (line 24 + line 16 - line 8)		$674,143			$12,294	$688,767
26	PEPL Balancing Costs (ln 25 * 9%)						$61,989
27	PEPL Retail Costs (ln 25 * 91%)						$626,778

Citizens Gas
Cost of Gas Injections and Withdrawals
For the period September 1, 2020 - November 30, 2020

		A	B	C	D	E	F	G	H	I
		Estimated Change		Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	September 2020									
1	UGS	571,764	-	$278,207	$1,221,644	$0	$0	($278,207)	($1,221,644)	($1,499,851)
2	PEPL	832,764	-	405,182	1,779,161	-	-	(405,182)	(1,779,161)	(2,184,343)
3	Subtotal	1,404,528	-	$683,389	$3,000,805	$0	$0	($683,389)	($3,000,805)	($3,684,194)
	October 2020									
4	UGS	166,632	15,680	$106,578	$297,421	$7,062	$29,894	($99,516)	($267,527)	($367,043)
5	PEPL	624,979	1,620	399,762	1,115,466	774	2,631	(398,988)	(1,112,835)	(1,511,823)
6	Subtotal	791,611	17,300	506,340	1,412,887	7,836	32,525	(498,504)	(1,380,362)	(1,878,866)
	November 2020									
7	UGS	135,082	104,727	$120,383	$310,248	$47,756	$199,484	($72,627)	($110,764)	($183,391)
8	PEPL	4,227	200,061	55,573	34,376	100,411	328,920	44,838	294,544	339,382
9	Subtotal	139,309	304,788	175,956	344,624	148,167	528,404	(27,789)	183,780	155,991
10	Grand Total	2,335,448	322,088	$1,365,685	$4,758,316	$156,003	$560,929	$ (1,209,682)	$ (4,197,387)	$ (5,407,069)

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL
For Three Months Ending November 30, 2020

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Commodity $/DTH
1	Beginning balance @ September 2020	4,674,783	$2,224,772	$7,177,290	$9,402,062	$2.0112	$1.5353
2	Less: Net W/D @ avg. unit cost						
3	Prior mo. accrual reversal	-	-	-	-	-	-
4	Prior mo. actual	-	-	-	-	-	-
5	Current mo. accrual	-	-	-	-	-	-
6	Add: Gross Injections						
7	Prior mo. accrual reversal	(859,776)	(517,500)	(1,380,284)	(1,897,784)	2.2073	1.6054
8	Prior mo. actual	860,169	517,650	1,381,001	1,898,651	2.2073	1.6055
9	Current mo. accrual	832,371	405,032	1,778,444	2,183,476	2.6232	2.1366
10	Less: Compressor Fuel						
11	Prior mo. accrual reversal - W/D	-	-	-	-	-	-
12	Prior mo. accrual reversal - Injections	22,483	13,533	36,094	49,627	2.2073	1.6054
13	Prior mo. Actual - W/D	-	-	-	-	-	-
14	Prior mo. Actual - Injections	(22,494)	(13,537)	(36,114)	(49,651)	2.2073	1.6055
15	Current mo. Accrual -Inj	(21,765)	(10,591)	(46,503)	(57,094)	2.6232	2.1366
16	Current mo. Accrual-W/D	-	-	-	-	-	-
17	Beginning balance @ October 2020	5,485,771	2,619,359	8,909,928	11,529,287	2.1017	1.6242
18	Less: Net W/D @ avg. unit cost						
19	Prior mo. accrual reversal	-	-	-	-	-	-
20	Prior mo. actual	-	-	-	-	-	-
21	Current mo. accrual	(1,620)	(774)	(2,631)	(3,405)	2.1017	1.6242
22	Add: Gross Injections						
23	Prior mo. accrual reversal	(832,371)	(405,032)	(1,778,444)	(2,183,476)	2.6232	2.1366
24	Prior mo. actual	832,204	404,951	1,778,087	2,183,038	2.6232	2.1366
25	Current mo. accrual	625,146	399,843	1,115,823	1,515,666	2.4245	1.7849
26	Less: Compressor Fuel						
27	Prior mo. accrual reversal - W/D	-	-	-	-	-	-
28	Prior mo. accrual reversal - Inj	21,765	10,591	46,503	57,094	2.6232	2.1366
29	Prior mo. Actual - W/D	-	-	-	-	-	-
30	Prior mo. Actual - Injections	(21,760)	(10,589)	(46,492)	(57,081)	2.6232	2.1366
31	Current mo. accrual - Inj	(16,349)	(10,457)	(29,181)	(39,638)	2.4245	1.7849
32	Current mo. Accrual-W/D	(34)	(16)	(55)	(71)	2.1017	1.6242
33	Beginning balance @ November 2020	6,092,752	3,007,876	9,993,538	13,001,414	2.1339	1.6402
34	Less: Net W/D @ avg. unit cost						
35	Prior mo. accrual reversal	1,620	774	2,631	3,405	2.1017	1.6242
36	Prior mo. actual	(1,622)	(775)	(2,634)	(3,409)	2.1017	1.6242
37	Current mo. accrual	(200,059)	(100,410)	(328,917)	(429,327)	2.1460	1.6441
38	Add: Gross Injections						
39	Prior mo. accrual reversal	(625,146)	(399,843)	(1,115,823)	(1,515,666)	2.4245	1.7849
40	Prior mo. actual	623,557	450,831	1,137,119	1,587,950	2.5466	1.8236
41	Current mo. Accrual	5,816	4,585	13,080	17,665	3.0373	2.2490
42	Less: Compressor Fuel						
43	Prior mo. accrual reversal - W/D	34	16	55	71	2.1017	1.6242
44	Prior mo. accrual reversal - Inj	16,349	10,457	29,181	39,638	2.4245	1.7849
45	Prior mo. Actual - W/D	(34)	(16)	(55)	(71)	2.1017	1.6242
46	Prior mo. Actual - Injections	(16,309)	(11,791)	(29,741)	(41,532)	2.5466	1.8236
47	Current mo. accrual -Inj	(157)	(124)	(353)	(477)	3.0373	2.2490
48	Current mo. Accrual-W/D	(4,624)	(2,321)	(7,602)	(9,923)	2.1460	1.6441
49	Ending balance @ November 30, 2020	5,892,177	2,959,259	9,690,479	12,649,738	$2.1469	$1.6446

Citizens Gas
Demand Allocation of Injections and Withdrawals
From UGS
For Three Months Ending November 30, 2020

Line No.		A Volume	B Demand Cost	C Commodity Cost	D Total Cost	E Total $/Unit	F Commodity $/Unit
1	Beginning balance @ September 2020	7,338,457	$3,284,050	$13,859,368	$17,143,418	$2.3361	$1.8886
2	Add: Gross Injections						
3	Less: Prior mo. accrual	(127,466)	(76,722)	(204,634)	(281,356)	2.2073	1.6054
4	Add: Prior mo. actual	127,466	76,709	204,647	281,356	2.2073	1.6055
5	Add: Current mo. accrual	571,764	278,220	1,221,631	1,499,851	2.6232	2.1366
6	Less: Net Withdrawals						
7	Prior mo. accrual reversal	-	-	-	-	-	-
8	Prior mo. Actual	-	-	-	-	-	-
9	Current mo. accrual	-	-	-	-	-	-
10	Less: Blowoff						
11	Current mo. Blowoff	(2,859)	(1,279)	(5,400)	(6,679)	2.3361	1.8886
12	Beginning balance @ October 2020	7,907,362	3,560,978	15,075,612	18,636,590	2.3569	1.9065
13	Add: Gross Injections						
14	Less: Prior mo. accrual	(571,764)	(278,220)	(1,221,631)	(1,499,851)	2.6232	2.1366
15	Add: Prior mo. actual	571,764	278,220	1,221,631	1,499,851	2.6232	2.1366
16	Add: Current mo. accrual	166,632	106,578	297,421	403,999	2.4245	1.7849
17	Less: Net Withdrawals						
18	Prior mo. accrual reversal	-	-	-	-	-	-
19	Prior mo. actual	-	-	-	-	-	-
20	Current mo. accrual	(15,680)	(7,062)	(29,894)	(36,956)	2.3569	1.9065
21	Less: Blowoff						
22	Current mo. Blowoff	(755)	(340)	(1,439)	(1,779)	2.3569	1.9065
23	Beginning balance @ November 2020	8,057,559	3,660,154	15,341,700	19,001,854	2.3583	1.9040
24	Add: Injections						
25	Less: Prior mo. accrual	(166,632)	(106,578)	(297,421)	(403,999)	2.4245	1.7849
26	Prior mo. actual	166,632	120,475	303,870	424,345	2.5466	1.8236
27	Current mo. accrual	135,082	106,486	303,799	410,285	3.0373	2.2490
28	Less: Withdrawals						
29	Prior mo. accrual reversal	15,680	7,062	29,894	36,956	2.3569	1.9065
30	Prior mo. actual	(15,680)	(7,062)	(29,894)	(36,956)	2.3569	1.9065
31	Current mo. Accrual	(104,727)	(47,756)	(199,484)	(247,240)	2.3608	1.9048
32	Less: Blowoff						
33	Current mo. Blowoff	(367)	(167)	(699)	(866)	2.3608	1.9048
34	Ending balance @ November 30, 2020	8,087,547	3,732,614	15,451,765	19,184,379	$2.3721	$1.9106

Citizens Gas
Determination of "Unaccounted For" Percentage and Manufacturing / Steam Division Costs
For Three Months Ending November 30, 2020

Line No.		A September 2020	B October 2020	C November 2020	D Total
1	Volume of pipeline gas purchases - Dths (See Schedule 8)	1,956,026	2,630,306	2,287,262	6,873,594
2	Gas (injected into) withdrawn from storage (See Schedule 10)	(1,404,528)	(774,311)	165,479	(2,013,360)
3	Transported gas received	1,263,094	1,313,446	1,904,999	4,481,539
4	Transported gas (injected into) withdrawn from storage	0	0	0	0
5	Reverse transport imbalance already on Sch 8	(120,394)	(15,641)	(299,368)	(435,403)
6	Total volume supplied	1,694,198	3,153,800	4,058,372	8,906,370
7	Less: Gas Division usage	(615)	(1,173)	(5,354)	(7,142)
8	Total volume available for sale	1,693,583	3,152,627	4,053,018	8,899,228
9	Retail Volume of gas sold - Dths (Schedule 6, Page 3, ln 26)	551,752	1,715,601	2,719,647	4,987,000
10	Total Transport Usage (Sch 6 , Page 3, ln 27 + ln 28)	1,102,612	1,284,006	1,622,886	4,009,504
11	"Unaccounted for" gas (ln 8- ln 9 - ln 10)	39,219	153,020	(289,515)	(97,276)
12	Percentage of "unaccounted for" gas (line 11 / line 8)	2.32%	4.85%	-7.14%	-1.09%

CITIZENS GAS
Initiation of Refund

Line No.	Refunds	
1	Supplier:	
2	Date received:	
3	Amount of refund:	$0
4	Reason for Refund:	
5	Docket Number:	
6	Total to be refunded	$0

Distribution of Refunds to GCA Quarters

Line No.	Quarter	A Sales % (All GCA Classes)		B Refund (line 6 * column A)
7	March 2021 - May 2021	26.2985%	(Sch. 2B, ln 18)	$0
8	June 2021 - August 2021	5.3377%	(Sch. 2B, ln 19)	$0
9	Sept., 2021 - Nov., 2021	13.5616%	(Sch. 2B, ln 20)	$0
10	Dec., 2021- Feb., 2022	54.8022%	(Sch. 2B, ln 21)	$0
11	Total			$0

Calculation of Refund to be Returned in this GCA

Line No.		
12	Refund from Cause No. 37399-GCA 146	$0
13	Refund from Cause No. 37399-GCA 147	0
14	Refund from Cause No. 37399-GCA 148	0
15	Refund from this Cause (line 7)	0
16	Total to be refunded in this Cause (Sum of lines 12 through 15)	$0

Citizens Gas
Allocation of Gas Supply Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/ No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Cost Variances
	Calculation of Total Gas Cost Variances						
1	Sep., 2020 Total Gas Supply Variance (Sch 6A, pg. 1,ln 16)	(717)	(22,992)	(10,696)	(76,140)	0	(110,545)
2	Oct., 2020 Total Gas Supply Variance (Sch 6B, pg. 1, ln 16)	(2,522)	(608,009)	(8,081)	(198,209)	0	(816,821)
3	Nov, 2020 Total Gas Supply Variance (Sch 6C, pg. 1, ln 16)	(6,064)	(916,914)	(6,713)	(526,351)	0	(1,456,042)
4	Total Net Write Off Gas Cost Variance (over)/under recover (Sch 12C, ln19)	(110)	(13,590)	157	(3,933)	115	(17,361)
5	Annual Unaccounted for over-recovery (Sch 11a, ln 18, col. D * Sch 2B, ln 22)	0	0	0	0	0	0
6	Sub-Total Gas Supply Variance (over)/underrecovery (ln 1 + ln 2 + ln 3 + ln 4 + ln 5)	($9,413)	($1,561,505)	($25,333)	($804,633)	$115	(2,400,769)
	Distribution of variances to quarters by rate class						
7	First quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 18)	($2,178)	($414,869)	($5,820)	($207,734)	$0	($630,601)
8	Second quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 19)	(881)	(69,351)	(7,365)	(49,631)	0	(127,228)
9	Third quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 20)	(1,612)	(213,128)	(7,077)	(98,914)	0	(320,731)
10	Fourth quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 21)	(4,742)	(864,157)	(5,071)	(448,354)	0	(1,322,324)
	Calculation of variances for this Cause						
11	Cause No. 37399 - GCA 146 Total Gas Supply Variance (Sch 12B pg 1, ln 10)	(2,894)	(564,937)	4,428	(231,941)	0	(795,344)
12	Cause No. 37399 - GCA 147 Total Gas Supply Variance (Sch 12B pg 1, ln 9)	(1,708)	(117,488)	(7,311)	(66,821)	0	(193,328)
13	Cause No. 37399 - GCA 148 Total Gas Supply Variance (Sch 12B pg 1, ln 8)	(1,727)	(167,379)	(10,280)	(100,940)	0	(280,326)
14	This Cause Total Gas Supply Variance (line 7)	(2,178)	(414,869)	(5,820)	(207,734)	0	($630,601)
15	Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (ln 11 + ln 12 + ln 13 + ln 14)	($8,507)	($1,264,673)	($18,983)	($607,436)	$0	($1,899,599)

Citizens Gas

Allocation of Balancing Demand Cost Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3 / No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Balancing Demand Cost Variance
	Calculation of Total Balancing Demand Cost Variances							
1	Sep., 2020 Total Balancing Demand Cost Variance (Sch 6A, pg. 2, ln 25)	($62)	($5,456)	($2,882)	($6,000)	($136)	$6,122	($8,414)
2	Oct., 2020 Total Balancing Demand Cost Variance (Sch 6B, pg. 2, ln 25)	($164)	($23,369)	($4,619)	($14,189)	($1,135)	$3,748	($39,728)
3	Nov, 2020 Total Balancing Demand Cost Variance (Sch 6C, pg. 2, ln 25)	($52)	($8,411)	($1,262)	($5,518)	$1,653	$2,652	($10,938)
4	Balancing Demand Cost Variance (Line 1 + Line 2 + Line 3)	($278)	($37,236)	($8,763)	($25,707)	$382	$12,522	($59,080)
	Distribution of variances to quarters by rate class							
5	First quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 18)	($64)	($9,893)	($2,118)	($6,303)	$94	$3,301	($14,983)
6	Second quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 19)	($26)	($1,654)	($1,969)	($1,927)	$68	$3,151	($2,357)
7	Third quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 20)	($48)	($5,082)	($2,181)	($4,201)	$89	$3,293	($8,130)
8	Fourth quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 21)	($140)	($20,607)	($2,495)	($13,276)	$131	$2,777	($33,610)
	Calculation of variances for this Cause							
9	Cause No. 37399 - GCA 146 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 8)	($1)	($138)	$260	($1,227)	$1,569	$3,834	$4,297
10	Cause No. 37399 - GCA 147 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 7)	($4)	($2,564)	$26	($1,201)	$1,327	$6,310	$3,894
11	Cause No. 37399 - GCA 148 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 6)	($53)	($5,410)	($2,659)	($5,057)	($550)	$5,914	($7,815)
12	This Cause Total Current Balancing Demand Cost Variance (line 5)	($64)	($9,893)	($2,118)	($6,303)	$94	$3,301	($14,983)
13	Total Balancing Demand Cost Variance to be included in GCA (Over)/Underrecovery (ln 9 + ln 10 + ln 11 + ln 12)	($122)	($18,005)	($4,491)	($13,788)	$2,440	$19,359	($14,607)

CITIZENS GAS
SCHEDULE 12C
DETERMINATION OF NET WRITE-OFF GAS COST RECOVERIES

Line No.		A	B	C	D	E	F
	September 2020						
		D1	**D2**	**D3**	**D4**	**D5**	**Total**
1	Actual Retail Sales in Dth (Sch 6A, line 26)	3,582	337,007	30,727	180,436	-	551,752
2	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 147, MPU Sch 1 pg 2, ln 23	$0.0230	$0.0570	$0.0020	$0.0120	$0.0000	
3	Actual Net Write Off Gas Cost Recovery (ln 1 * ln 2)	$82	$19,209	$61	$2,165	$0	$21,517
4	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
5	Recoverable Net-Write Off Gas Costs (Sch 6A, ln 9, Total * 1.10% * ln 4)	$93	$20,067	$57	$1,844	$15	$22,076
6	Net Write Off Gas Cost Variance (over)/under recovery (ln 5 - ln 3)	**$11**	**$858**	**($4)**	**($321)**	**$15**	**$559**
	October 2020						
7	Actual Retail Sales in Dth (Sch 6B, line 26)	8,991	1,235,331	41,299	429,980	-	1,715,601
8	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 147, MPU Sch 1 pg 2, ln 23	$0.0300	$0.0480	$0.0020	$0.0120	$0.0000	
9	Actual Net Write Off Gas Cost Recovery (ln 7 * ln 8)	$270	$59,296	$83	$5,160	$0	$64,809
10	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
11	Recoverable Net-Write Off Gas Costs (Sch 6B, ln 9, Total * 1.10% * ln 10)	$232	$50,165	$142	$4,610	$38	$55,187
12	Net Write Off Gas Cost Variance (over)/under recovery (ln 11 - ln 9)	**($38)**	**($9,131)**	**$59**	**($550)**	**$38**	**($9,622)**
	November 2020						
13	Actual Retail Sales in Dth (Sch 6C, line 26)	11,228	1,929,036	25,756	753,627	-	2,719,647
14	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 147, MPU Sch 1 pg 2, ln 23	$0.0410	$0.0450	$0.0050	$0.0140	$0.0000	
15	Actual Net Write Off Gas Cost Recovery (ln 13 * ln 14)	$460	$86,807	$129	$10,551	$0	$97,947
16	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
17	Recoverable Net-Write Off Gas Costs (Sch 6C, ln 9, Total * 1.10% * ln 16)	$377	$81,490	$231	$7,489	$62	$89,649
18	Net Write Off Gas Cost Variance (over)/under recovery (ln 17 - ln 15)	**($83)**	**($5,317)**	**$102**	**($3,062)**	**$62**	**($8,298)**
19	Total Net Write Off Gas Cost Variance (over)/under recovery (ln 6 + ln 12 + ln 18)	($110)	($13,590)	$157	($3,933)	115	($17,361)