FILED
October 2, 2020
INDIANA UTILITY
REGULATORY COMMISSION

**CITIZENS GAS**

**Petition for Approval of Gas Cost Adjustments
To Be Applicable in the Months of
December 2020, January and February 2021**

**Cause No. 37399 – GCA 148**

**Prefiled Direct Testimony and Attachments**

**Korlon L. Kilpatrick II**

**Filed
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# 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 December 2020 and January and February 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 December 2020, January and February 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. October 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 December 2020, January and February 2021.

Schedules 6 through 12 of Attachment KLK-4 are the reconciliation of actual gas costs and recoveries for June, July and August 2020. Schedule 6 shows the actual gas costs and variance calculation of gas cost incurred versus recoveries in the reconciliation period of June, July and August 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 148 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 DECEMBER 2020, JANUARY AND FEBRUARY 2021?**

A11. The majority of the gas costs for December 2020, January and February 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 09/17/20 | |
|---|---|
| Dec. 2020 | $3.1200 |
| Jan. 2021 | $3.2490 |
| Feb. 2021 | $3.2100 |

**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 DECEMBER 2020, JANUARY AND FEBRUARY 2021?**

A13. Financially hedged transactions account for 28.24% of total purchases for the months of December 2020, January and February 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 148 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 DECEMBER 2020, JANUARY AND FEBRUARY 2021 ARE ACCURATE?**

A15. Yes, I do.

**RECONCILIATION PERIOD**

**Q16. HAVE YOU COMPARED PETITIONER'S ESTIMATED GAS COSTS FOR THE PERIOD OF JUNE, JULY AND AUGUST 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 148 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 June, July and August 2020 presented in the GCA reconciliation period are shown in Table 2:

**Table 2**

| Twelve Months Ending | Actual Gas Cost | Variance | % Variance |
|---|---|---|---|
| **June 2020** | $73,327,799 | ($6,883,201) | (9.39)% |
| **July 2020** | $73,134,188 | ($6,711,905) | (9.18)% |
| **August 2020** | $773,203,041 | ($6,640,665) | (9.07)% |

**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. As shown above in Table 2, the 12-month trailing averages for each month in the reconciliation period do not exceed the approved level of +/- 10%, as set by the Commission.

**Q19. DO THE PROPOSED RATES INCLUDE THE ANNUAL TRUE-UP FOR COST OF "(UAFG)"?**

A19. Yes. Pursuant to Commission approval in Cause No. 37399-GCA95, the proposed GCA rates to be effective December 2020, January and February 2021, include the effect of reconciling actual UAFG costs incurred for the twelve-month period of September 2019 through August 2020 to actual UAFG cost recoveries for the same period. The UAFG percentage established in Citizens Gas' last general rate case, Cause No. 43975, is 1.36%. The reconciliation of UAFG costs shown on Schedule 11A of Attachment KLK- 4 results in no refund to customers.

**Q20. DO THE PROPOSED GCA RATES INCLUDE A RECONCILIATION OF ACTUAL COSTS TO ACTUAL RECOVERIES FOR THE MONTHS OF JUNE, JULY AND AUGUST 2020?**

A20. Yes. The proposed GCA rates to be effective December 2020, January and February 2021 include the effect of reconciling actual gas costs incurred for the months of June, July and August 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** |
| **June 2020** | $1,345,954 | $2,021,621 | ($675,667) |
| **July 2020** | $1,382,709 | $1,720,706 | ($337,977) |
| **August 2020** | $1,647,779 | $1,747,044 | ($99,265) |
| **Total** | $4,376,442 | $5,489,371 | ($1,112,929) |

**Q21. WHAT PERCENTAGE OF TOTAL PURCHASES WAS MADE UP OF FINANCIALLY-HEDGED TRANSACTIONS FOR THE MONTHS OF JUNE, JULY AND AUGUST 2020?**

A21. Financially-hedged transactions accounted for 26.98% of total purchases for the months of June, July and August 2020.

**Q22. HAS PETITIONER RECEIVED ANY NEW REFUNDS THAT ARE INCLUDED IN THIS GCA?**

A22. No.

**MONTHLY PRICE UPDATE**

**Q23. PLEASE DESCRIBE THE HISTORY OF THE MONTHLY PRICE UPDATE MECHANISM.**

A23. 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.

**Q24. 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?**

A24. 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.

**Q25. PLEASE DESCRIBE THE MPU FILING.**

A25. 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.

**Q26. WHEN CITIZENS GAS FILES ITS MONTHLY PRICE UPDATE WITH THE COMMISSION, WHAT IS INCLUDED IN THE FILING?**

A26. 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.

**Q27. FOR PURPOSES OF IDENTIFYING THE BENCHMARK PRICES AS A REQUIREMENT OF THE MONTHLY PRICE UPDATE MECHANISM, WHAT ARE THE MONTHLY BENCHMARK PRICES FOR DECEMBER 2020, JANUARY AND FEBRUARY 2021?**

A27. Table 4 shows the Monthly Benchmark Prices as established by NYMEX +/- basis as of September 17, 2020 by pipeline for December 2020, January and February 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 |
| **Dec. 2020** | $2.9572 | $3.0048 | $3.1736 | $2.6249 | $2.9125 | $2.8203 | $2.7300 | $3.0439 |
| **Jan. 2021** | $3.1577 | $3.1692 | $3.4938 | $2.8255 | $3.0415 | $3.0110 | $2.8590 | $3.2537 |
| **Feb. 2021** | $3.0812 | $3.1425 | $3.4643 | $2.7489 | $3.0025 | $2.9835 | $2.8200 | $3.1992 |

**Q28. HAS PETITIONER PROPERLY APPLIED ITS GCA RATES SINCE ITS LAST GCA PROCEEDING IN CAUSE NO. 37399 GCA 147?**

A28. Yes.

**Q29. ARE PETITIONER'S BOOKS AND RECORDS UNDER REVIEW BEING KEPT ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS, AS PRESCRIBED BY THE COMMISSION?**

A29. Yes.

## GAS SUPPLY

### ASSET MANAGEMENT AGREEMENT

**Q30. PLEASE DESCRIBE THE ASSET MANAGEMENT AGREEMENT ("AMA") BETWEEN EXELON GENERATION COMPANY, LLC ("EXELON") AND CITIZENS GAS.**

A30. 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.

**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 | Total |
|---|---|---|---|---|---|
| **Dec. 2020** | 135,866 | 20,000 | 80,000 | 100,000 | 335,886 |
| **Jan. 2021** | 180,995 | 20,000 | 80,000 | 100,000 | 380,995 |
| **Feb. 2021** | 257,044 | 20,000 | 80,000 | 100,000 | 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 November 2021. 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 will remain for gas purchases through March 31, 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 DECEMBER 2020, JANUARY AND FEBRUARY 2021** | **) CAUSE NO. 37399-GCA 148** |

**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

**Request for Approval of Gas Cost Adjustments**
**to be Applicable During the Months of December 2020, January and February 2021**

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 December 2020, January and February 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 December 2020, January and February 2021, is estimated to total $47,672,270. 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 Eleventh Revised Page No. 501, One-Hundred Twelfth Revised Page No. 501, and One-Hundred Thirteenth Revised Page No. 501) and will be applied to all bills rendered by Petitioner during its December 2020, January and February 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 Eleventh Revised Page No. 501, One-Hundred Twelfth Revised Page No. 501, and One-Hundred Thirteenth 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 December 2020, January and February 2021 billing months;

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

DATED this 2nd day of October 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 2nd day of October 2020, I served a copy of the foregoing Petition upon the Office of Utility Consumer Counselor by electronic mail 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
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Michael E. Allen, (Attorney No. 20768-49)
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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 Eleventh Revised Page No. 501**
**Superseding Substitute One-Hundred Tenth 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 December 1, 2020

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

| | | | |
|---|---|---|---|
| Gas Rate No. D1 | Gas Supply Charge | **$** | **0.2863** |
| Gas Rate No. D2 | Gas Supply Charge | **$** | **0.3000** |
| Gas Rate No. D3 | Gas Supply Charge | **$** | **0.2775** |
| Gas Rate No. D4 | Gas Supply Charge | **$** | **0.2880** |
| Gas Rate No. D5 | Gas Supply Charge | **$** | **-** |
| Gas Rate No. D7 | Gas Supply Charge | **$** | **0.2736** |

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

| | | |
|---|---|---|
| Capacity | **$** | **0.0833** |
| Commodity | **$** | **0.2334** |
| Gas Supply Charge | **$** | **0.3167** |

**3. Balancing Charges: $ per Therm**

| | | | | | |
|---|---|---|---|---|---|
| Gas Rate No. D3 | **$** | **0.0010** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D4 | **$** | **0.0012** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D5 | **$** | **0.0020** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D7 | **$** | **0.0010** | | | |
| Gas Rate No. D9 | **$** | **0.0245** | **$** | **0.0012** | for Basic Delivery Service Option |

**Citizens Gas**
**2020 North Meridian Street**
**Indianapolis, IN 46202**

**One-Hundred Twelfth Revised Page No. 501**
**Superseding One-Hundred Eleventh 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 January 1, 2021

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

| | | | |
|---|---|---|---|
| Gas Rate No. D1 | Gas Supply Charge | **$** | **0.2819** |
| Gas Rate No. D2 | Gas Supply Charge | **$** | **0.2997** |
| Gas Rate No. D3 | Gas Supply Charge | **$** | **0.3147** |
| Gas Rate No. D4 | Gas Supply Charge | **$** | **0.2754** |
| Gas Rate No. D5 | Gas Supply Charge | **$** | **-** |
| Gas Rate No. D7 | Gas Supply Charge | **$** | **0.3103** |

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

| | | |
|---|---|---|
| Capacity | **$** | **0.0702** |
| Commodity | **$** | **0.2356** |
| Gas Supply Charge | **$** | **0.3058** |

### 3. Balancing Charges: $ per Therm

| | | | | | |
|---|---|---|---|---|---|
| Gas Rate No. D3 | **$** | **0.0009** | **$** | **-** | for Basic Delivery Service Option |
| Gas Rate No. D4 | **$** | **0.0011** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D5 | **$** | **0.0019** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D7 | **$** | **0.0009** | | | |
| Gas Rate No. D9 | **$** | **0.0245** | **$** | **0.0012** | for Basic Delivery Service Option |

**Current rates effective pursuant to**
**I.U.R.C. Order in Cause No. 43975**

**Effective: January 1, 2021**

**Citizens Gas**
**2020 North Meridian Street**
**Indianapolis, IN 46202**

**One-Hundred Thirteenth Revised Page No. 501**
**Superseding One-Hundred Twelfth 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 February 1, 2021

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

| | | | |
|---|---|---|---|
| Gas Rate No. D1 | Gas Supply Charge | **$** | **0.2873** |
| Gas Rate No. D2 | Gas Supply Charge | **$** | **0.2987** |
| Gas Rate No. D3 | Gas Supply Charge | **$** | **0.3499** |
| Gas Rate No. D4 | Gas Supply Charge | **$** | **0.2765** |
| Gas Rate No. D5 | Gas Supply Charge | **$** | **-** |
| Gas Rate No. D7 | Gas Supply Charge | **$** | **0.3450** |

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

| | | |
|---|---|---|
| Capacity | **$** | **0.0661** |
| Commodity | **$** | **0.2412** |
| Gas Supply Charge | **$** | **0.3073** |

**3. Balancing Charges: $ per Therm**

| | | | | | |
|---|---|---|---|---|---|
| Gas Rate No. D3 | **$** | **0.0007** | **$** | **-** | for Basic Delivery Service Option |
| Gas Rate No. D4 | **$** | **0.0009** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D5 | **$** | **0.0017** | **$** | **0.0001** | for Basic Delivery Service Option |
| Gas Rate No. D7 | **$** | **0.0007** | | | |
| Gas Rate No. D9 | **$** | **0.0242** | **$** | **0.0012** | for Basic Delivery Service Option |

**Current rates effective pursuant to**
**I.U.R.C. Order in Cause No. 43975**

**Effective: February 1, 2021**

# Tab 4

## CITIZENS GAS

**Impact Statement for Residential Heating Customers**

Proposed GCA Factor December 2020
vs.
Currently Approved GCA Factor October 2020

Table No. 1

| Consumption Dth | Bill At Proposed GCA Factor $3.0000 | Bill At Current GCA Factor $3.4910 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.15 | $45.61 | ($2.46) | (5.39)% |
| 10 | $69.81 | $74.72 | ($4.91) | (6.57)% |
| 15 | $96.46 | $103.83 | ($7.37) | (7.10)% |
| 20 | $123.12 | $132.94 | ($9.82) | (7.39)% |
| 25 | $149.77 | $162.05 | ($12.28) | (7.58)% |

Proposed GCA Factor December 2020
vs.
GCA Factor One Year Ago December 2019

Table No. 2

| Consumption Dth | Bill At Proposed GCA Factor $3.0000 | Bill At Prior Year's GCA Factor $2.9310 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.15 | $42.78 | $0.37 | 0.86 % |
| 10 | $69.81 | $69.07 | $0.74 | 1.07 % |
| 15 | $96.46 | $95.35 | $1.11 | 1.16 % |
| 20 | $123.12 | $121.64 | $1.48 | 1.22 % |
| 25 | $149.77 | $147.92 | $1.85 | 1.25 % |

**CITIZENS GAS**

**Impact Statement for Residential Heating Customers**

Proposed GCA Factor January 2021
vs.
Currently Approved GCA Factor October 2020

Table No. 1

| Consumption Dth | Bill At Proposed GCA Factor $2.9970 | Bill At Current GCA Factor $3.4910 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.14 | $45.61 | ($2.47) | (5.42)% |
| 10 | $69.78 | $74.72 | ($4.94) | (6.61)% |
| 15 | $96.42 | $103.83 | ($7.41) | (7.14)% |
| 20 | $123.06 | $132.94 | ($9.88) | (7.43)% |
| 25 | $149.70 | $162.05 | ($12.35) | (7.62)% |

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

Table No. 2

| Consumption Dth | Bill At Proposed GCA Factor $2.9970 | Bill At Prior Year's GCA Factor $2.9390 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.14 | $42.82 | $0.32 | 0.75 % |
| 10 | $69.78 | $69.15 | $0.63 | 0.91 % |
| 15 | $96.42 | $95.47 | $0.95 | 1.00 % |
| 20 | $123.06 | $121.80 | $1.26 | 1.03 % |
| 25 | $149.70 | $148.12 | $1.58 | 1.07 % |

# CITIZENS GAS

## Impact Statement for Residential Heating Customers

Proposed GCA Factor February 2021
vs.
Currently Approved GCA Factor October 2020

Table No. 1

| Consumption Dth | Bill At Proposed GCA Factor $2.9870 | Bill At Current GCA Factor $3.4910 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.09 | $45.61 | ($2.52) | (5.53)% |
| 10 | $69.68 | $74.72 | ($5.04) | (6.75)% |
| 15 | $96.27 | $103.83 | ($7.56) | (7.28)% |
| 20 | $122.86 | $132.94 | ($10.08) | (7.58)% |
| 25 | $149.45 | $162.05 | ($12.60) | (7.78)% |

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

Table No. 2

| Consumption Dth | Bill At Proposed GCA Factor $2.9870 | Bill At Prior Year's GCA Factor $2.7200 | Dollar Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| 5 | $43.09 | $41.73 | $1.36 | 3.26 % |
| 10 | $69.68 | $66.96 | $2.72 | 4.06 % |
| 15 | $96.27 | $92.19 | $4.08 | 4.43 % |
| 20 | $122.86 | $117.42 | $5.44 | 4.63 % |
| 25 | $149.45 | $142.65 | $6.80 | 4.77 % |

# Tab 5

**Citizens Gas**
**Determination of Gas Supply Charge with Demand Cost Allocated**
**Estimated For December 2020**

| Line No. | | A<br>Demand | B<br>Commodity and Other | C<br>Total |
|---|---|---|---|---|
| | Estimated Cost of Gas | | | |
| 1 | Purchased gas cost (Schedule 3, Page 1, ln 16) | $2,243,633 | $7,148,846 | $9,392,479 |
| 2 | PEPL Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col A + ln 23) | - | 752,185 | 752,185 |
| 3 | Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 3) | 1,220,630 | 4,352,770 | 5,573,400 |
| 4 | Total estimated gas cost (ln 1 through ln 3) | $3,464,263 | $12,253,801 | $15,718,064 |
| 5 | Total Gas Supply variance (Sch 1, December, total of ln 17) | - | (1,115,802) | (1,115,802) |
| 6 | Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28) | - | (21,336) | (21,336) |
| 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) | $3,464,263 | $11,116,663 | $14,580,926 |
| 9 | Net Write-Off Recovery Costs (ln 8 *1.10%) | | | $160,390 |
| 10 | Total cost to be recovered through GCA (ln. 8 + ln 9) | | | $14,741,316 |

**Citizens Gas**
**Determination of Gas Supply Charge with Demand Cost Allocated**
**Estimated For December 2020**
**To Be Applied To December 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 |
|---|---|---|---|---|---|---|
| | Calculation of Gas Supply Charge per Unit (Dth) | | | | | |
| 11 | Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22) | ($96) | ($14,632) | - | - | - |
| 12 | Throughput excluding Basic - Dth (Sch 2C, ln 1) | 17,096 | 3,708,819 | - | - | - |
| 13 | Total Balancing Demand Cost variance per unit of throughput (ln 11/ ln 12) | ($0.006) | ($0.004) | - | - | - |
| 14 | Retail demand cost per unit sales (Sch 1A, pg 1 ln 8) | 0.657 | 0.677 | 0.560 | 0.701 | - |
| 15 | Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 1, ln 11) | 0.006 | 0.006 | - | - | - |
| 16 | Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15) | $0.657 | $0.679 | $0.560 | $0.701 | $0.000 |
| 17 | Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 27) | (5,095) | (724,418) | (8,789) | (377,500) | 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) | 39,128 | 8,488,412 | 126,644 | 2,847,432 | 0 |
| 20 | Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19) | $34,033 | $7,763,994 | $117,855 | $2,469,932 | $0 |
| 21 | Sales subject to GCA - Dth (Schedule 2B, ln 1) | 17,096 | 3,708,819 | 55,332 | 1,244,118 | 0 |
| 22 | Total monthly non-demand costs per unit sales (ln 20 / ln 21) | $1.991 | $2.093 | $2.130 | $1.985 | $0.000 |
| 23 | Net Write-Off Recovery Cost (Sch 1C, pg 1, ln 4 ) | 0.039 | 0.039 | 0.007 | 0.011 | 0.000 |
| 24 | PEPL Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8) | 0.125 | 0.136 | 0.039 | 0.143 | 0.000 |
| 25 | PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15) | 0.011 | 0.011 | - | - | - |
| 26 | Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25) | $2.823 | $2.958 | $2.736 | $2.840 | $0.000 |
| 27 | Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%)) | $2.863 | $3.000 | $2.775 | $2.880 | $0.000 |

**Citizens Gas**
**Determination of Balancing Demand Charge per Unit (Dth)**
**Estimated for the Period December 2020**
**To Be Applied to the December 2020 Throughput**

| Line No. | | A<br>Gas Rate<br>No. D3/No. D7 | B<br>Gas Rate<br>No. D4 | C<br>Gas Rate<br>No. D5 | D<br>Gas Rate<br>No. D9 |
|---|---|---|---|---|---|
| | Calculation of Balancing Demand Charge per Unit (Dth) | | | | |
| 28 | Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22) | ($2,125) | ($10,591) | $862 | $5,246 |
| 29 | Throughput excluding Basic - Dth (Sch 2C, ln 1) | 292,646 | 2,101,516 | 310,062 | 23,312 |
| 30 | Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29) | ($0.0073) | ($0.0050) | $0.0028 | $0.2250 |
| 31 | Monthly balancing demand charge per unit of throughput (Sch 1A, pg 1, ln 11) | 0.006 | 0.006 | 0.006 | 0.006 |
| 32 | PEPL balancing demand charge per unit of throughput (Sch 4, pg 1, ln 15) | 0.0110 | 0.0110 | 0.0110 | 0.0110 |
| 33 | Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32) | 0.0097 | $0.0120 | $0.0198 | $0.2420 |
| 34 | Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%)) | $0.010 | $0.012 | $0.020 | $0.245 |

**Citizens Gas**
**Determination of Basic Balancing Charge**
**Estimated for December 2020**
**To Be Applied to December 2020**

| 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) | 0.0005 | 0.0006 | 0.0010 | 0.0121 |
| 36 | Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%)) | $0.001 | $0.001 | $0.001 | $0.012 |

**Citizens Gas**
**Determination of Back-up Gas Supply Charge**
**Estimated for December 2020**
**To Be Applied to December 2020**

| 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) | 902,615 |
| 39 | Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38) | $1,067,492 |
| 40 | Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 1) | 1,299,450 |
| 41 | Back-up supply capacity charge per unit (ln 39 / ln 40) | $0.821 |
| 42 | Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%)) | $0.833 |
| 43 | PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 5) | $15,561 |
| 44 | Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19) | 2,974,076 |
| 45 | Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44) | $2,989,637 |
| 46 | Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 1) | 1,299,450 |
| 47 | Back-up supply commodity charge per unit (ln 45 / ln 46) | $2.301 |
| 48 | Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%)) | $2.334 |
| 49 | Total Back-up Gas Supply Charge (ln 42 + ln 48) | $3.167 |

**Citizens Gas**
**Determination of Gas Supply Charge with Demand Cost Allocated**
**Estimated for January 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) | $2,243,634 | $8,034,842 | $10,278,476 |
| 2 | PEPL Unnominated Quantities cost (Schedule 4 pg 2, ln 16 col A + ln 23) | - | 768,403 | $768,403 |
| 3 | Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 6) | 1,469,100 | 5,205,300 | $6,674,400 |
| 4 | Total estimated gas cost (ln 1 through ln 3) | $3,712,734 | $14,008,545 | $17,721,279 |
| 5 | Total Gas Supply variance (Sch 1, January, total of ln 17) | - | (1,292,558) | ($1,292,558) |
| 6 | Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28) | | (24,665) | ($24,665) |
| 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) | $3,712,734 | $12,691,322 | $16,404,056 |
| 9 | Net Write-Off Recovery Costs (ln 8 * 1.10%) | | | $180,445 |
| 10 | Total cost to be recovered through GCA (ln. 8 + ln 9) | | | $16,584,501 |

**Citizens Gas**
**Determination of Gas Supply Charge with Demand Cost Allocated**
**Estimated for January 2021**
**To Be Applied to January 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) | ($111) | ($16,070) | - | - | - |
| 12 | Throughput excluding Basic - Dth (Sch 2C, ln 2) | 19,809 | 4,073,269 | - | - | - |
| 13 | Total Balancing Demand Cost per unit of throughput (ln 11 /ln 12) | ($0.006) | ($0.004) | - | - | - |
| 14 | Retail demand cost per unit sales (Sch 1A, pg 2 ln 8) | 0.608 | 0.661 | 0.881 | 0.585 | - |
| 15 | Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 2, ln 11) | 0.006 | 0.006 | - | - | - |
| 16 | Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15) | $0.608 | $0.663 | $0.881 | $0.585 | $0.000 |
| 17 | Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 28) | (5,903) | (795,604) | (5,990) | (485,061) | 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) | 45,771 | 9,412,986 | 87,147 | 3,694,238 | 0 |
| 20 | Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19) | $39,868 | $8,617,382 | $81,157 | $3,209,177 | $0 |
| 21 | Sales subject to GCA - Dth (Schedule 2B, ln 2) | 19,809 | 4,073,269 | 37,712 | 1,598,601 | 0 |
| 22 | Total monthly non-demand costs per unit sales (ln 20 / ln 21) | $2.013 | $2.116 | $2.152 | $2.007 | $0.000 |
| 23 | Net Write-Off Recovery Cost (Sch 1C, pg 2, ln 4 ) | 0.038 | 0.040 | 0.012 | $0.009 | $0.000 |
| 24 | PEPL Unnominated Quantites Retail Cost (Sch 4, pg 2 ln 8) | 0.111 | 0.126 | 0.058 | 0.114 | 0.000 |
| 25 | PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 2, ln 15) | 0.010 | 0.010 | - | - | - |
| 26 | Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25) | $2.780 | $2.955 | $3.103 | $2.715 | $0.000 |
| 27 | Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%)) | $2.819 | $2.997 | $3.147 | $2.754 | $0.000 |

**Citizens Gas**
**Determination of Balancing Demand Charge per Unit (Dth)**
**Estimated for January 2021**
**To Be Applied to the January 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) | ($2,054) | ($12,751) | $907 | $5,414 |
| 29 | Throughput excluding Basic - Dth (Sch 2C, ln 2) | 282,776 | 2,530,151 | 326,182 | 24,056 |
| 30 | Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29) | ($0.0073) | ($0.0050) | $0.0028 | $0.2251 |
| 31 | Monthly balancing demand charge per unit of throughput (Sch 1A, pg 2, ln 11) | 0.006 | 0.006 | 0.006 | 0.006 |
| 32 | PEPL balancing demand charge per unit of throughput (Sch 4, pg 2, ln 15) | 0.0100 | 0.0100 | 0.0100 | 0.0100 |
| 33 | Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32) | $0.0087 | $0.0110 | $0.0188 | $0.2411 |
| 34 | Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%)) | $0.009 | $0.011 | $0.019 | $0.245 |

**Citizens Gas**
**Determination of Basic Balancing Charge**
**Estimated for January 2021**
**To Be Applied to January 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) | 0.0004 | 0.0006 | 0.0009 | 0.0121 |
| 36 | Basic balancing charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%)) | $0.000 | $0.001 | $0.001 | $0.012 |

**Citizens Gas**
**Determination of Back-up Gas Supply Charge**
**Estimated for January 2021**
**To Be Applied to January 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) | $164,877 |
| 38 | Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 2, ln 6) | 968,113 |
| 39 | Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38) | $1,132,990 |
| 40 | Estimated Monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 2) | 1,636,313 |
| 41 | Back-up supply capacity charge per unit (ln 39 / ln 40) | $0.692 |
| 42 | Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%)) | $0.702 |
| 43 | PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 5) | $19,451 |
| 44 | Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19) | 3,781,385 |
| 45 | Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44) | $3,800,836 |
| 46 | Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 2) | 1,636,313 |
| 47 | Back-up supply commodity charge per unit (ln 45 / ln 46) | $2.323 |
| 48 | Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%)) | $2.356 |
| 49 | Total Back-up Gas Supply Charge (ln 42 + ln 48) | $3.058 |

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

| Line No. | | A<br>Demand | B<br>Commodity and Other | C<br>Total |
|---|---|---|---|---|
| | Estimated Cost of Gas | | | |
| 1 | Purchased gas cost (Schedule 3, Page 3, ln 16) | $1,905,836 | $8,156,456 | $10,062,292 |
| 2 | PEPL Unnominated Quantities cost (Schedule 4 pg 3, ln 16 col A + ln 23) | - | 728,877 | 728,877 |
| 3 | Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 9) | 1,468,650 | 5,205,450 | 6,674,100 |
| 4 | Total estimated gas cost (ln 1 through ln 3) | $3,374,486 | $14,090,783 | $17,465,269 |
| 5 | Total Gas Supply variance (Sch 1, February, total of ln 17) | - | (1,272,852) | (1,272,852) |
| 6 | Total Balancing Demand variance (total of Sch 1 pg 2 ln 11 + Sch. 1, ln 28) | | (23,819) | (23,819) |
| 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) | $3,374,486 | $12,794,112 | $16,168,598 |
| 9 | Net Write-Off Recovery Costs (ln 8 * 1.10%) | | | $177,855 |
| 10 | Total cost to be recovered through GCA (ln. 8 + ln 9) | | | $16,346,453 |

**Citizens Gas**
**Determination of Gas Supply Charge with Demand Cost Allocated**
**Estimated for February 2021**
**To Be Applied to February 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) | ($103) | ($15,949) | - | - | - |
| 12 | Throughput excluding Basic - Dth (Sch 2C, ln 3) | 18,188 | 4,042,802 | - | - | - |
| 13 | Total Balancing Demand Cost per unit of throughput (ln 11/ln 12) | ($0.006) | ($0.004) | - | - | - |
| 14 | Retail demand cost per unit sales (Sch 1A, pg 3 ln 8) | $0.602 | $0.605 | $1.146 | $0.544 | - |
| 15 | Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 3, ln 11) | 0.005 | 0.005 | - | - | - |
| 16 | Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15) | $0.601 | $0.606 | $1.146 | $0.544 | $0.000 |
| 17 | Total variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 29) | (5,420) | (789,652) | (4,184) | (473,596) | 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) | 43,025 | 9,564,118 | 62,307 | 3,692,456 | 0 |
| 20 | Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19) | $37,605 | $8,774,466 | $58,123 | $3,218,860 | $0 |
| 21 | Sales subject to GCA - Dth (Schedule 2B, ln 3) | 18,188 | 4,042,802 | 26,336 | 1,560,817 | 0 |
| 22 | Total monthly non-demand costs per unit sales (ln 20 / ln 21) | $2.068 | $2.170 | $2.207 | $2.062 | $0.000 |
| 23 | Net Write-Off Recovery Cost (Sch 1C, pg 3 ln 4) | 0.041 | 0.040 | 0.017 | 0.010 | 0.000 |
| 24 | PEPL Unnominated Quantites Retail Cost (Sch 4, pg 3 ln 8) | 0.114 | 0.120 | 0.080 | 0.110 | 0.000 |
| 25 | PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 3, ln 15) | 0.009 | 0.009 | - | - | - |
| 26 | Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25) | $2.833 | $2.945 | $3.450 | $2.726 | $0.000 |
| 27 | Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%)) | $2.873 | $2.987 | $3.499 | $2.765 | $0.000 |

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

| Line No. | | A<br>Gas Rate<br>No. D3/No. D7 | B<br>Gas Rate<br>No. D4 | C<br>Gas Rate<br>No. D5 | D<br>Gas Rate<br>No. D9 |
|---|---|---|---|---|---|
| | Calculation of Balancing Demand Charge per Unit (Dth) | | | | |
| 28 | Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 24) | ($1,859) | ($11,817) | $818 | $5,091 |
| 29 | Throughput excluding Basic - Dth (Sch 2C, ln 3) | 255,952 | 2,344,761 | 294,056 | 22,624 |
| 30 | Total Balancing Demand Cost variance per unit of throughput (ln 28/ ln 29) | ($0.0073) | ($0.0050) | $0.0028 | $0.2250 |
| 31 | Monthly balancing demand charge per unit of throughput (Sch 1A, pg 3, ln 11) | 0.005 | 0.005 | 0.005 | 0.005 |
| 32 | PEPL balancing demand charge per unit of throughput (Sch 4, pg 3, ln 15) | 0.0090 | 0.0090 | 0.0090 | 0.0090 |
| 33 | Total balancing demand charge per unit of throughput (ln 30 + ln 31 + ln 32) | $0.0067 | $0.0090 | $0.0168 | $0.2390 |
| 34 | Total balancing demand charge modified for Indiana Utilities Receipts Tax (ln 33 / (1-1.40%)) | $0.007 | $0.009 | $0.017 | $0.242 |

**Citizens Gas**
**Determination of Basic Balancing Charge**
**Estimated for February 2021**
**To Be Applied to February 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) | 0.0003 | 0.0005 | 0.0008 | 0.0120 |
| 36 | Basic Balancing Charge modified for Indiana Utilities Receipts Tax (ln 35/ (1-1.40%)) | $0.000 | $0.001 | $0.001 | $0.012 |

**Citizens Gas**
**Determination of Back-up Gas Supply Charge**
**Estimated for February 2021**
**To Be Applied to February 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) | $155,396 |
| 38 | Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 3, ln 6) | 879,972 |
| 39 | Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 37 + ln 38) | $1,035,368 |
| 40 | Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 3) | 1,587,153 |
| 41 | Back-up supply capacity charge per unit (ln 39 / ln 40) | $0.652 |
| 42 | Back-up supply capacity charge modified for Indiana Utilities Receipts Tax (ln 41 / (1-1.40%)) | $0.661 |
| 43 | PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 5) | $19,450 |
| 44 | Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 18 + ln 19) | 3,754,763 |
| 45 | Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 43 + ln 44) | $3,774,213 |
| 46 | Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 3) | 1,587,153 |
| 47 | Back-up supply commodity charge per unit (ln 45 / ln 46) | $2.378 |
| 48 | Back-up supply commodity charge modified for Indiana Utilities Receipts Tax (ln 47 / (1-1.40%)) | $2.412 |
| 49 | Total Back-up Gas Supply Charge (ln 42 + ln 48) | $3.073 |

**Citizens Gas**
**Allocation of Monthly Demand Cost**
**December 2020**

| 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) | $10,042 | $2,245,281 | $27,702 | $779,634 | - | - | $3,062,659 |
| 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) | $11,227 | $2,510,261 | $30,971 | $871,644 | - | - | $3,424,103 |
| 7 | Estimated monthly retail sales- Dth (Sch 2B, ln 1) | 17,096 | 3,708,819 | 55,332 | 1,244,118 | - | - | 5,025,365 |
| 8 | Monthly retail demand cost per unit sales (ln 6 / ln 7) | $0.657 | $0.677 | $0.560 | $0.701 | - | - | $0.681 |
| 9 | Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 18) | 106 | 23,080 | 1,821 | 13,078 | 1,930 | 145 | 40,160 |
| 10 | Estimated monthly total throughput excl. Basic - Dth (Sch 2C, ln 1) | 17,096 | 3,708,819 | 292,646 | 2,101,516 | 310,062 | 23,312 | 6,453,451 |
| 11 | Monthly balancing demand cost per unit of throughput (ln 9 / ln 10) | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 |

| Line No. | Calculation of Monthly Demand Costs | Demand Cost |
|---|---|---|
| | Exelon Generation Company, LLC | |
| 12 | Nominated Demand Costs | $ 1,100,106 |
| 13 | TGT Unnominated Demand Costs | $ 401,604 |
| 14 | IMGPA Prepay Demand Costs | $ 318,563 |
| 15 | Demand Cost (Sch 3 ln 15 col G) | $ 423,360 |
| 16 | Demand Cost (Sch 5 ln 3 col G) | $ 1,220,630 |
| 17 | Monthly retail demand costs (ln 12 + sum( ln14 + ln15 + ln16)) | $ 3,062,659 |
| 18 | Unnominated Demand Costs (ln 13) | $401,604 |
| 19 | Total monthly demand costs ( ln 17 + ln 18) | $3,464,263 |

**Citizens Gas**
**Allocation of Monthly Demand Cost**
**January 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) | $10,857 | $2,427,439 | $29,949 | $842,885 | - | - | $3,311,130 |
| 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) | $12,042 | $2,692,419 | $33,218 | $934,895 | - | - | $3,672,574 |
| 7 | Estimated monthly retail sales- Dth (Sch 2B, ln 2) | 19,809 | 4,073,269 | 37,712 | 1,598,601 | - | - | 5,729,391 |
| 8 | Monthly retail demand cost per unit sales (ln 6 / ln 7) | $0.608 | $0.661 | $0.881 | $0.585 | - | - | $0.641 |
| 9 | Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 19) | 110 | 22,544 | 1,565 | 14,003 | 1,805 | 133 | 40,160 |
| 10 | Estimated monthly total throughput - Dth (Sch 2C, ln 2) | 19,809 | 4,073,269 | 282,776 | 2,530,151 | 326,182 | 24,056 | 7,256,243 |
| 11 | Monthly balancing demand cost per unit of throughput (ln 9 / ln 10) | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 | $0.006 |

| Line | Calculation of Monthly Demand Costs | Demand Cost |
|---|---|---|
| | Exelon Generation Company, LLC | |
| 12 | Nominated Demand Costs | $ 1,100,107 |
| 13 | TGT Unnominated Demand Costs | $ 401,604 |
| 14 | IMGPA Prepay Demand Costs | $ 318,563 |
| 15 | Demand Cost (Sch 3 ln 15 col G) | $ 423,360 |
| 16 | Demand Cost (Sch 5 Ln 6 Col G) | $ 1,469,100 |
| 17 | Monthly retail demand costs (ln 12 + sum( ln 14 + ln15 + ln16)) | $ 3,311,130 |
| 18 | Unnominated Demand Costs (ln 13) | $401,604 |
| 19 | Total Monthly demand costs ( ln 17 + ln 18) | $ 3,712,734 |

**Citizens Gas**
**Allocation of Monthly Demand Cost**
**February 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) | $9,876 | $2,207,957 | $27,241 | $766,673 | - | - | $3,011,747 |
| 5 | Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3) | 1,070 | 239,337 | 2,953 | 83,105 | - | - | 326,465 |
| 6 | Total monthly retail demand costs (ln 4 + ln 5) | $10,946 | $2,447,294 | $30,194 | $849,778 | - | - | $3,338,212 |
| 7 | Estimated monthly retail sales- Dth (Sch 2B, ln 3) | 18,188 | 4,042,802 | 26,336 | 1,560,817 | - | - | 5,648,143 |
| 8 | Monthly retail demand cost per unit sales (ln 6 / ln 7) | $0.602 | $0.605 | $1.146 | $0.544 | - | - | $0.591 |
| 9 | Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 20) | 95 | 21,014 | 1,330 | 12,188 | 1,529 | 118 | 36,274 |
| 10 | Estimated monthly total throughput - Dth (Sch 2C, ln 3) | 18,188 | 4,042,802 | 255,952 | 2,344,761 | 294,056 | 22,624 | 6,978,383 |
| 11 | Monthly balancing demand cost per unit of throughput (ln 9 / ln 10) | $0.005 | $0.005 | $0.005 | $0.005 | $0.005 | $0.005 | $0.005 |

| Line No. | Calculation of Monthly Demand Costs | Demand Cost |
|---|---|---|
| | Exelon Generation Company, LLC | |
| 12 | Nominated Demand Costs | $ 1,043,683 |
| 13 | TGT Unnominated Demand Costs | $ 362,739 |
| 14 | IMGPA Prepay Demand Costs | $ 287,734 |
| 15 | Demand Cost (Sch 3 ln 15 col G) | $ 211,680 |
| 16 | Demand Cost (Sch 5 Ln 9 Col G) | $ 1,468,650 |
| 17 | Monthly retail demand costs (ln 12 + sum( ln 14 + ln15 + ln16)) | $3,011,747 |
| 18 | Unnominated Demand Costs (ln 13) | $362,739 |
| 19 | Total Monthly demand costs ( ln 17 + ln 18) | $3,374,486 |

Citizens Gas
Determination of Gas Cost Adjustment (GCA)
Estimation Period December 1, 2020 through February 28, 2021
UAF Component in Rates ($/DTH)

| Line No. | | A December 2020 | B January 2021 | C February 2021 | D Total |
|---|---|---|---|---|---|
| 1 | Volume of pipeline gas purchases (Sch. 3) - Dths | 2,633,119 | 2,857,561 | 2,776,053 | 8,266,733 |
| 2 | Volume of Gas (injected into) withdrawn from storage (See Schedule 3B) - Dths | 2,475,641 | 2,969,551 | 2,969,551 | 8,414,743 |
| 3 | Total volume supplied - Dths | 5,108,760 | 5,827,112 | 5,745,604 | 16,681,476 |
| 4 | Less: Gas Division usage - Dths | (14,848) | (19,536) | (20,369) | (54,753) |
| 5 | Total volume of gas available for sale - Dths (ln 3 + ln 4) | 5,093,912 | 5,807,576 | 5,725,235 | 16,626,723 |
| 6 | UAF Percentage 1.360% | 1.360% | 1.360% | 1.360% | |
| 7 | UAF Volumes - Dths (ln 5 * ln 6) | 69,277 | 78,983 | 77,863 | 226,123 |
| 8 | Average Commodity Rate - Schedule 3A | $2.7150 | $2.8118 | $2.9381 | |
| 9 | UAF Costs (ln7 * ln8) | $188,087 | $222,084 | $228,769 | $638,940 |
| 10 | Schedule 2B Retail sales volumes | 5,025,365 | 5,729,391 | 5,648,143 | 16,402,899 |
| 11 | UAF Component in rates - $ per Dth (ln9 / ln10) 1/ | $0.0374 | $0.0388 | $0.0405 | |

1/ For informational purposes only.

**Citizens Gas**
**Allocation of Net Write-Off Recovery Cost**
**December 2020**

| 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 | $674 | $145,794 | $413 | $13,398 | $111 | $160,390 |
| 3 | Estimated retail sales- Dth (Sch 2B, ln 1) | 17,096 | 3,708,819 | 55,332 | 1,244,118 | 0 | 5,025,365 |
| 4 | Net Write-Off Recovery cost per unit sales (ln 2 / ln 3) | $0.039 | $0.039 | $0.007 | $0.011 | $0.000 | |

**Citizens Gas**
**Allocation of Net Write-Off Recovery Cost**
**January 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 | $758 | $164,023 | $465 | $15,074 | $125 | $180,445 |
| 3 | Estimated retail sales- Dth (Sch 2B, ln 2) | 19,809 | 4,073,269 | 37,712 | 1,598,601 | 0 | 5,729,391 |
| 4 | Net Write-Off Recovery cost per unit sales (ln 2 / ln 3) | $0.038 | $0.040 | $0.012 | $0.009 | $0.000 | |

**Citizens Gas**
**Allocation of Net Write-Off Recovery Cost**
**February 2021**

| Line No. | Calculation of Net Write-Off Recovery Cost per Unit (Dth) | A<br>Gas Rate<br>No. D1 | B<br>Gas Rate<br>No. D2 | C<br>Gas Rate<br>No. D3/No. D7 | D<br>Gas Rate<br>No. D4 | E<br>Gas Rate<br>No. D5 | F<br>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 | $747 | $161,669 | $458 | $14,857 | $124 | $177,855 |
| 3 | Estimated retail sales- Dth (Sch 2B, ln 3) | 18,188 | 4,042,802 | 26,336 | 1,560,817 | 0 | 5,648,143 |
| 4 | Net Write-Off Recovery cost per unit sales (ln 2 / ln 3) | $0.041 | $0.040 | $0.017 | $0.010 | $0.000 | |

**Citizens Gas**
**Estimated Total Throughput for Twelve Months Ending November 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 | F Gas Rate No. D9 | G Total Throughput Subject to GCA |
|---|---|---|---|---|---|---|---|---|
| | Estimated Total Throughput Volumes (Dth) for Twelve Months Ending November 2021 | | | | | | | |
| 1 | December 2020 | 17,096 | 3,708,819 | 309,076 | 2,108,646 | 456,196 | 841,650 | 7,441,483 |
| 2 | January 2021 | 19,809 | 4,073,269 | 299,330 | 2,537,653 | 480,438 | 344,286 | 7,754,785 |
| 3 | February 2021 | 18,188 | 4,042,802 | 272,304 | 2,351,537 | 432,096 | 324,856 | 7,441,783 |
| 4 | First Quarter | 55,093 | 11,824,890 | 880,710 | 6,997,836 | 1,368,730 | 1,510,792 | 22,638,051 |
| 5 | March 2021 | 11,797 | 2,812,070 | 252,774 | 1,670,817 | 390,049 | 541,694 | 5,679,201 |
| 6 | April 2021 | 8,201 | 1,968,698 | 248,895 | 1,075,576 | 317,203 | 755,760 | 4,374,333 |
| 7 | May 2021 | 5,349 | 903,171 | 247,434 | 578,648 | 267,475 | 751,812 | 2,753,889 |
| 8 | Second Quarter | 25,347 | 5,683,939 | 749,103 | 3,325,041 | 974,727 | 2,049,266 | 12,807,423 |
| 9 | June 2021 | 3,815 | 349,491 | 232,447 | 347,516 | 239,743 | 724,740 | 1,897,752 |
| 10 | July 2021 | 3,222 | 301,132 | 232,257 | 334,554 | 237,343 | 504,184 | 1,612,692 |
| 11 | August 2021 | 3,219 | 299,531 | 231,993 | 334,269 | 236,909 | 727,198 | 1,833,119 |
| 12 | Third Quarter | 10,256 | 950,154 | 696,697 | 1,016,339 | 713,995 | 1,956,122 | 5,343,563 |
| 13 | September 2021 | 4,333 | 355,340 | 234,167 | 408,924 | 252,043 | 717,720 | 1,972,527 |
| 14 | October 2021 | 4,966 | 677,949 | 262,287 | 635,075 | 302,808 | 786,222 | 2,669,307 |
| 15 | November 2021 | 9,461 | 1,886,703 | 275,265 | 1,171,871 | 371,100 | 540,480 | 4,254,880 |
| 16 | Fourth Quarter | 18,760 | 2,919,992 | 771,719 | 2,215,870 | 925,951 | 2,044,422 | 8,896,714 |
| 17 | Total Throughput - Dth | 109,456 | 21,378,975 | 3,098,229 | 13,555,086 | 3,983,403 | 7,560,602 | 49,685,751 |
| | Quarterly Allocation Factor | | | | | | | |
| 18 | First Quarter (line 4/line 17) | 0.503334 | 0.553109 | 0.284263 | 0.516253 | 0.343609 | 0.199824 | 0.455624 |
| 19 | Second Quarter (line 8/line 17) | 0.231573 | 0.265866 | 0.241784 | 0.245298 | 0.244697 | 0.271045 | 0.257769 |
| 20 | Third Quarter (line 12/line 17) | 0.093700 | 0.044443 | 0.224869 | 0.074978 | 0.179242 | 0.258726 | 0.107547 |
| 21 | Fourth Quarter (line 16/line 17) | 0.171393 | 0.136582 | 0.249084 | 0.163471 | 0.232452 | 0.270405 | 0.179060 |
| | Current Throughput Allocation Factor | | | | | | | |
| 22 | Allocation of December 2020 Estimated Throughput (line 1/line 1, column G) | 0.002297 | 0.498399 | 0.041534 | 0.283364 | 0.061304 | 0.113102 | 1.000000 |
| 23 | Allocation of January 2021 Estimated Throughput (line 2/line 2, column G) | 0.002554 | 0.525259 | 0.038599 | 0.327237 | 0.061954 | 0.044397 | 1.000000 |
| 24 | Allocation of February 2021 Estimated Throughput (line 3/line 3, column G) | 0.002444 | 0.543257 | 0.036591 | 0.315991 | 0.058064 | 0.043653 | 1.000000 |
| 25 | Allocation of Quarter Estimated Throughput (line 4/line 4, column G) | 0.002434 | 0.522346 | 0.038904 | 0.309118 | 0.060461 | 0.066737 | 1.000000 |
| | Monthly Allocation Factors | | | | | | | |
| 26 | December 2020 (line 1/line 4) | 0.310311 | 0.313645 | 0.350939 | 0.301328 | 0.333299 | 0.557092 | 0.328716 |
| 27 | January 2021 (line 2/line 4) | 0.359556 | 0.344466 | 0.339874 | 0.362634 | 0.351010 | 0.227884 | 0.342555 |
| 28 | February 2021 (line 3/line 4) | 0.330133 | 0.341889 | 0.309187 | 0.336038 | 0.315691 | 0.215024 | 0.328729 |
| 29 | Total Throughput Allocation Factor (line 17/line 17, col. G) | 0.002203 | 0.430285 | 0.062356 | 0.272816 | 0.080172 | 0.152168 | 1.000000 |

**Citizens Gas**
**Estimated Retail Sales Volume for Twelve Months Ending November 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 | F Total Retail Sales Subject to GCA |
|---|---|---|---|---|---|---|---|
| | Estimated Retail Sales Volumes (Dth) for Twelve Months Ending November 2021 | | | | | | |
| 1 | December 2020 | 17,096 | 3,708,819 | 55,332 | 1,244,118 | 0 | 5,025,365 |
| 2 | January 2021 | 19,809 | 4,073,269 | 37,712 | 1,598,601 | 0 | 5,729,391 |
| 3 | February 2021 | 18,188 | 4,042,802 | 26,336 | 1,560,817 | 0 | 5,648,143 |
| 4 | First Quarter | 55,093 | 11,824,890 | 119,380 | 4,403,536 | 0 | 16,402,899 |
| 5 | March 2021 | 11,797 | 2,812,070 | 21,846 | 1,023,723 | 0 | 3,869,436 |
| 6 | April 2021 | 8,201 | 1,968,698 | 41,575 | 651,976 | 0 | 2,670,450 |
| 7 | May 2021 | 5,349 | 903,171 | 56,186 | 307,336 | 0 | 1,272,042 |
| 8 | Second Quarter | 25,347 | 5,683,939 | 119,607 | 1,983,035 | 0 | 7,811,928 |
| 9 | June 2021 | 3,815 | 349,491 | 50,087 | 161,336 | 0 | 564,729 |
| 10 | July 2021 | 3,222 | 301,132 | 50,681 | 155,684 | 0 | 510,719 |
| 11 | August 2021 | 3,219 | 299,531 | 50,603 | 156,763 | 0 | 510,116 |
| 12 | Third Quarter | 10,256 | 950,154 | 151,371 | 473,783 | 0 | 1,585,564 |
| 13 | September 2021 | 4,333 | 355,340 | 47,787 | 184,824 | 0 | 592,284 |
| 14 | October 2021 | 4,966 | 677,949 | 53,638 | 221,284 | 0 | 957,837 |
| 15 | November 2021 | 9,461 | 1,886,703 | 44,029 | 538,133 | 0 | 2,478,326 |
| 16 | Fourth Quarter | 18,760 | 2,919,992 | 145,454 | 944,241 | 0 | 4,028,447 |
| 17 | Total Retail Sales - Dth | 109,456 | 21,378,975 | 535,812 | 7,804,595 | 0 | 29,828,838 |
| | Quarterly Retail Allocation Factor | | | | | | |
| 18 | First Quarter (line 4/line 17) | 0.503334 | 0.553109 | 0.222801 | 0.564223 | 0.000000 | 0.549901 |
| 19 | Second Quarter (line 8/line 17) | 0.231573 | 0.265866 | 0.223226 | 0.254086 | 0.000000 | 0.261892 |
| 20 | Third Quarter (line 12/line 17) | 0.093700 | 0.044443 | 0.282508 | 0.060706 | 0.000000 | 0.053155 |
| 21 | Fourth Quarter (line 16/line 17) | 0.171393 | 0.136582 | 0.271465 | 0.120985 | 0.000000 | 0.135052 |
| 22 | Annual (line 17 / line 17, Column F) | 0.003669 | 0.716722 | 0.017963 | 0.261646 | 0.000000 | 1.000000 |
| | Current Retail Sales Allocation Factor | | | | | | |
| 23 | Allocation of December 2020 Estimated Throughput (line 1/line 1, column F) | 0.003402 | 0.738019 | 0.011011 | 0.247568 | 0.000000 | 1.000000 |
| 24 | Allocation of January 2021 Estimated Throughput (line 2/line 2, column F) | 0.003457 | 0.710943 | 0.006582 | 0.279018 | 0.000000 | 1.000000 |
| 25 | Allocation of February 2021 Estimated Throughput (line 3/line 3, column F) | 0.003220 | 0.715775 | 0.004663 | 0.276342 | 0.000000 | 1.000000 |
| 26 | Allocation of Quarter Estimated Retail Sales (line 4/line 4, column F) | 0.003359 | 0.720902 | 0.007278 | 0.268461 | 0.000000 | 1.000000 |
| | Monthly Retail Allocation Factors | | | | | | |
| 27 | December 2020 (line 1/line 4) | 0.310311 | 0.313645 | 0.463495 | 0.282527 | 0.000000 | 0.306371 |
| 28 | January 2021 (line 2/line 4) | 0.359556 | 0.344466 | 0.315899 | 0.363027 | 0.000000 | 0.349291 |
| 29 | February 2021 (line 3/line 4) | 0.330133 | 0.341889 | 0.220606 | 0.354446 | 0.000000 | 0.344338 |

**Citizens Gas**
**Estimated Total Throughput Excluding Basic Volume (Dth) for Twelve Months Ending November 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 | F Gas Rate No. D9 | G Total Throughput Subject to GCA |
|---|---|---|---|---|---|---|---|---|---|
| | Estimated Total Throughput Excluding Basic Volumes (Dth) for Twelve Months Ending November 2021 | | | | | | | | |
| 1 | December 2020 | | 17,096 | 3,708,819 | 292,646 | 2,101,516 | 310,062 | 23,312 | 6,453,451 |
| 2 | January 2021 | | 19,809 | 4,073,269 | 282,776 | 2,530,151 | 326,182 | 24,056 | 7,256,243 |
| 3 | February 2021 | | 18,188 | 4,042,802 | 255,952 | 2,344,761 | 294,056 | 22,624 | 6,978,383 |
| 4 | First Quarter | | 55,093 | 11,824,890 | 831,374 | 6,976,428 | 930,300 | 69,992 | 20,688,077 |
| 5 | March 2021 | | 11,797 | 2,812,070 | 236,592 | 1,664,679 | 267,785 | 21,266 | 5,014,189 |
| 6 | April 2021 | | 8,201 | 1,968,698 | 233,055 | 1,070,536 | 219,403 | 19,200 | 3,519,093 |
| 7 | May 2021 | | 5,349 | 903,171 | 231,810 | 574,308 | 186,379 | 17,732 | 1,918,749 |
| 8 | Second Quarter | | 25,347 | 5,683,939 | 701,457 | 3,309,523 | 673,567 | 58,198 | 10,452,031 |
| 9 | June 2021 | | 3,815 | 349,491 | 216,907 | 343,556 | 167,983 | 16,920 | 1,098,672 |
| 10 | July 2021 | | 3,222 | 301,132 | 216,757 | 330,648 | 166,353 | 16,864 | 1,034,976 |
| 11 | August 2021 | | 3,219 | 299,531 | 216,493 | 330,363 | 166,105 | 16,864 | 1,032,575 |
| 12 | Third Quarter | | 10,256 | 950,154 | 650,157 | 1,004,567 | 500,441 | 50,648 | 3,166,223 |
| 13 | September 2021 | | 4,333 | 355,340 | 218,567 | 404,784 | 176,143 | 17,280 | 1,176,447 |
| 14 | October 2021 | | 4,966 | 677,949 | 246,240 | 630,177 | 208,196 | 18,910 | 1,786,438 |
| 15 | November 2021 | | 9,461 | 1,886,703 | 258,944 | 1,165,991 | 253,560 | 20,880 | 3,595,539 |
| 16 | Fourth Quarter | | 18,760 | 2,919,992 | 723,751 | 2,200,952 | 637,899 | 57,070 | 6,558,424 |
| 17 | Total Throughput excl. Basic - Dth | | 109,456 | 21,378,975 | 2,906,739 | 13,491,470 | 2,742,207 | 235,908 | 40,864,755 |
| | Current Throughput Excl. Basic Allocation Factor | | | | | | | | |
| 18 | Allocation of December 2020 Estimated Throughput (line 1/line 1, column G) | | 0.002649 | 0.574704 | 0.045347 | 0.325642 | 0.048046 | 0.003612 | 1.000000 |
| 19 | Allocation of January 2021 Estimated Throughput (line 2/line 2, column G) | | 0.002730 | 0.561347 | 0.038970 | 0.348686 | 0.044952 | 0.003315 | 1.000000 |
| 20 | Allocation of February 2021 Estimated Throughput (line 3/line 3, column G) | | 0.002606 | 0.579333 | 0.036678 | 0.336003 | 0.042138 | 0.003242 | 1.000000 |
| 21 | Total Throughput Excl. Basic Allocation Factor (line 17/line 17, col. G) | | 0.002678 | 0.523165 | 0.071131 | 0.330149 | 0.067104 | 0.005773 | 1.000000 |
| | Monthly Total Throughput less Basic | | | | | | | | |
| 22 | December 2020 | (line 1/line 4) | 0.310311 | 0.313645 | 0.352003 | 0.301231 | 0.333293 | 0.333067 | 0.311941 |
| 23 | January 2021 | (line 2/line 4) | 0.359556 | 0.344466 | 0.340131 | 0.362671 | 0.350620 | 0.343696 | 0.350745 |
| 24 | February 2021 | (line 3/line 4) | 0.330133 | 0.341889 | 0.307866 | 0.336098 | 0.316087 | 0.323237 | 0.337314 |

**Citizens Gas**
**Purchased Gas Cost - Estimated**
**December 2020**

| 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) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | December 2020 | | | | | | | | | | |
| | Exelon Generation Company, LLC | | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | | | - | | $2.9572 | | | - | | - |
| 2 | Texas Gas Transmission - TOR | | | - | | 3.0048 | | | - | | - |
| 3 | TGT-REX | | | - | | 3.0439 | | | - | | - |
| 4 | Indiana Municipal Gas Purchasing Authority - TOR | | | 19,592 | | 2.9572 | | | 57,937 | | 57,937 |
| 5 | Indiana Municipal Gas Purchasing Authority - Prepay | | | 510,198 | | 2.6249 | | | 1,339,219 | | 1,339,219 |
| 6 | PEAK B | | | 310,000 | | 2.9125 | | | 902,875 | | 902,875 |
| 7 | Rockies Express Pipeline - TOR | | | 241,066 | | 2.8203 | | | 679,878 | | 679,878 |
| 8 | PEAK A | | | 310,000 | | 2.7300 | | | 846,300 | | 846,300 |
| 9 | Midwestern Gas Transmission Purchases | | | - | | 3.1736 | | | - | | - |
| 10 | Fixed Price Purchases | | | | | | | | - | | - |
| 11 | Hedging Transaction Costs | | | | | | | | 81,456 | | 81,456 |
| 12 | Boil-off / Peaking purchase | | | 42,263 | | 3.1200 | | | 131,861 | | 131,861 |
| 13 | Net Demand Cost Charges - AMA | | | | | | | 1,501,710 | - | | 1,501,710 |
| 14 | Demand Cost Charges -IMGPA - Prepay | 17,090 | | | 18.6403 | | | 318,563 | - | | 318,563 |
| 15 | Texas Gas - NNS - (Injections)/Withdrawls | | | 1,200,000 | 0.3528 | 2.5911 | | 423,360 | 3,109,320 | | 3,532,680 |
| 16 | Total | | | 2,633,119 | | | | $2,243,633 | $7,148,846 | - | $9,392,479 |

**Citizens Gas**
**Purchased Gas Cost - Estimated**
**January 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) |
| | January 2021 | | | | | | | | | | |
| | Exelon Generation Company, LLC | | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | | | - | | $3.1577 | | | - | | - |
| 2 | Texas Gas Transmission - TOR | | | - | | 3.1692 | | | - | | - |
| 3 | TGT-REX | | | - | | 3.2537 | | | - | | - |
| 4 | Indiana Municipal Gas Purchasing Authority - TOR | | | 19,592 | | 3.1577 | | | 61,866 | | 61,866 |
| 5 | Indiana Municipal Gas Purchasing Authority - Prepay | | | 510,198 | | 2.8255 | | | 1,441,564 | | 1,441,564 |
| 6 | PEAK B | | | 309,999 | | 3.0415 | | | 942,862 | | 942,862 |
| 7 | Rockies Express Pipeline - TOR | | | 465,509 | | 3.0110 | | | 1,401,648 | | 1,401,648 |
| 8 | PEAK A | | | 310,000 | | 2.8590 | | | 886,290 | | 886,290 |
| 9 | Midwestern Gas Transmission Purchases | | | - | | 3.4938 | | | - | | - |
| 10 | Fixed Price Purchases | | | | | | | | - | | - |
| 11 | Hedging Transaction Costs | | | | | | | | 53,980 | | 53,980 |
| 12 | Boil-off / Peaking purchase | | | 42,263 | | 3.2490 | | | 137,312 | | 137,312 |
| 13 | Net Demand Cost Charges - AMA | | | | | | | 1,501,711 | - | | 1,501,711 |
| 14 | Demand Cost Charges -IMGPA - Prepay | 17,090 | | | 18.6403 | | | 318,563 | - | | 318,563 |
| 15 | Texas Gas - NNS - (Injections)/Withdrawls | | | 1,200,000 | 0.3528 | 2.5911 | | 423,360 | 3,109,320 | | 3,532,680 |
| 16 | Total | | | 2,857,561 | | | | $2,243,634 | $8,034,842 | - | $10,278,476 |

**Citizens Gas**
**Purchased Gas Cost - Estimated**
**February 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) |
| | February 2021 | | | | | | | | | | |
| Exelon Generation Company, LLC | | | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | | | 519,022 | | $3.0812 | | | $1,599,211 | | $1,599,211 |
| 2 | Texas Gas Transmission - TOR | | | - | | 3.1425 | | | - | | - |
| 3 | TGT-REX | | | - | | 3.1992 | | | - | | - |
| 4 | Indiana Municipal Gas Purchasing Authority - TOR | | | 17,696 | | 3.0812 | | | 54,525 | | 54,525 |
| 5 | Indiana Municipal Gas Purchasing Authority - Prepay | | | 460,824 | | 2.7489 | | | 1,266,759 | | 1,266,759 |
| 6 | PEAK B | | | 280,000 | | 3.0025 | | | 840,700 | | 840,700 |
| 7 | Rockies Express Pipeline - TOR | | | 576,248 | | 2.9835 | | | 1,719,236 | | 1,719,236 |
| 8 | PEAK A | | | 280,000 | | 2.8200 | | | 789,600 | | 789,600 |
| 9 | Midwestern Gas Transmission Purchases | | | - | | 3.4643 | | | - | | - |
| 10 | Fixed Price Purchases | | | | | | | | | | |
| 11 | Hedging Transaction Costs | | | | | | | | 196,101 | | 196,101 |
| 12 | Boil-off / Peaking purchase | | | 42,263 | | 3.2100 | | | 135,664 | | 135,664 |
| 13 | Net Demand Cost Charges - AMA | | | | | | | 1,406,422 | - | | 1,406,422 |
| 14 | Demand Cost Charges -IMGPA - Prepay | 17,090 | | | 16.8364 | | | 287,734 | - | | 287,734 |
| 15 | Texas Gas - NNS - (Injections)/Withdrawls | | | 600,000 | 0.3528 | 2.5911 | | 211,680 | 1,554,660 | | 1,766,340 |
| 16 | Total | | | 2,776,053 | | | | $1,905,836 | $8,156,456 | - | $10,062,292 |

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

| Line No | Description | Dec 2020 | Jan 2021 | Feb 2021 | Total |
|---|---|---|---|---|---|
| | Commodity Volumes (Dth) | | | | |
| | Purchases for Retail: | | | | |
| 1 | Panhandle TOR | 0 | 0 | 519,022 | 519,022 |
| 2 | IMGPA TOR | 19,592 | 19,592 | 17,696 | 56,880 |
| 3 | IMGPA Prepay | 510,198 | 510,198 | 460,824 | 1,481,220 |
| 4 | Midwestern Gas | 0 | 0 | 0 | 0 |
| 5 | Rockies Express TOR - Monthly | 241,066 | 465,509 | 576,248 | 1,282,823 |
| 6 | PEAK A | 310,000 | 310,000 | 280,000 | 900,000 |
| 7 | Fixed Price Purchases (Sch. 3) | 0 | 0 | 0 | 0 |
| 8 | Texas Gas TOR | 0 | 0 | 0 | 0 |
| 9 | TGT-Rex East | 0 | 0 | 0 | 0 |
| 10 | PEAK B | 310,000 | 309,999 | 280,000 | 899,999 |
| 11 | Texas Gas NNS | 1,200,000 | 1,200,000 | 600,000 | 3,000,000 |
| 12 | Boil-off/ Peaking purchases (Sch. 3) | 42,263 | 42,263 | 42,263 | 126,789 |
| | Total Retail Volumes | | | | |
| 13 | (Ln1 through Ln12) | 2,633,119 | 2,857,561 | 2,776,053 | 8,266,733 |
| | Demand Rate | | | | |
| 14 | Total Demand Costs (Sch. 3) | $2,243,633 | $2,243,634 | $1,905,836 | $6,393,103 |
| 15 | Demand Cost per Dth (Line 14 / Line 13) | $0.8521 | $0.7852 | $0.6865 | $0.7734 |
| | Commodity Rate | | | | |
| 16 | Panhandle TOR | $2.9572 | $3.1577 | $3.0812 | |
| 17 | IMGPA TOR | 2.9572 | 3.1577 | 3.0812 | |
| 18 | IMGPA Prepay | 2.6249 | 2.8255 | 2.7489 | |
| 19 | Annual Delivery Service - Midwestern Gas | 3.1736 | 3.4938 | 3.4643 | |
| 20 | Rockies Express TOR - Monthly | 2.8203 | 3.0110 | 2.9835 | |
| 21 | PEAK A | 2.7300 | 2.8590 | 2.8200 | |
| 22 | Fixed Price Purchases (Sch. 3) | 0.0000 | 0.0000 | 0.0000 | |
| 23 | Texas Gas TOR | 3.0048 | 3.1692 | 3.1425 | |
| 24 | TGT-Rex East | 3.0439 | 3.2537 | 3.1992 | |
| 25 | Texas Gas NNS | 2.5911 | 2.5911 | 2.5911 | |
| 26 | Boil-off/ Peaking purchases (Sch. 3) | 3.1200 | 3.2490 | 3.2100 | |
| 27 | PEAK B | 2.9125 | 3.0415 | 3.0025 | |
| | Commodity Costs | | | | |
| 28 | PEPL (Ln 1 x Ln 16) | $0 | $0 | $1,599,211 | $1,599,211 |
| 29 | IMGPA - TOR (Ln 2 x Ln 17) | 57,937 | 61,866 | 54,525 | 174,328 |
| 30 | IMGPA - Authority Prepay (Ln 3 x Ln 18) | 1,339,219 | 1,441,564 | 1,266,759 | 4,047,542 |
| 31 | Midwestern (Ln 4 x Ln 19) | 0 | 0 | 0 | 0 |
| 32 | Rockies Express TOR (Ln 5 X Ln 20) | 679,878 | 1,401,648 | 1,719,236 | 3,800,762 |
| 33 | PEAK A (Ln 6 X Ln 21) | 846,300 | 886,290 | 789,600 | 2,522,190 |
| 34 | Fixed Price Purchases ( Ln 7 x Ln 22) | 0 | 0 | 0 | 0 |
| 35 | Texas Gas (Ln 8 x Ln 23) | 0 | 0 | 0 | 0 |
| 36 | TGT-Rex East (Ln 9 x Ln 24) | 0 | 0 | 0 | 0 |
| 37 | Texas Gas -Unnominated Gas (Ln 11 x Ln 25) | 3,109,320 | 3,109,320 | 1,554,660 | 7,773,300 |
| 38 | Boil-off/ Peaking purchases (Ln 12 x Ln 26) | 131,861 | 137,312 | 135,664 | 404,837 |
| 39 | PEAK B (Ln 10 x Ln 27) | 902,875 | 942,862 | 840,700 | 2,686,437 |
| 40 | Hedging Transaction Costs (Sch 3) | 81,456 | 53,980 | 196,101 | 331,537 |
| 41 | Subtotal(Ln 28 through Ln 40) | $7,148,846 | $8,034,842 | $8,156,456 | $23,340,144 |
| | Commodity Cost per Dth | | | | |
| 42 | (Line 41/Line 13) | $2.7150 | $2.8118 | $2.9381 | $2.8234 |
| | Total Average Rate per Dth | | | | |
| 43 | (Line 15 + Line 42) | $3.5671 | $3.5970 | $3.6246 | $3.5968 |

Citizens Gas
Projected Information
For Three Months Ending February 28, 2021

| | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | Dec 2020 | Volumes in Dths | Commodity Cost per Dth | % of Total | Reference |
| 1 | Fixed Price Purchases | - | $ - | 0.00% | Sch 3 pg 1 line 10 |
| 2 | Monthly Spot Market - Index Purchases | 1,390,856 | $ 2.8095 | 27.22% | Sch 3 pg 1 (line 16 - line 10 - line 12 - line 15) |
| 3 | Boil off/Peaking Purchases | 42,263 | $ 3.1200 | 0.83% | Sch 3 pg 1 line 12 |
| 4 | Unnominated Seasonal Gas Purchases | 1,200,000 | $ 2.5911 | 23.49% | Sch 3 pg 1 line 15 |
| 5 | Storage Withdrawal - Net | 2,475,641 | $ 1.7411 | 48.46% | 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 | 5,108,760 | | 100.00% | |
| | Jan 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 | 1,615,298 | $ 2.9643 | 27.72% | Sch 3 pg 2 (line 16 - line 10 - line 12 - line 15) |
| 10 | Boil off/Peaking Purchases | 42,263 | $ 3.2490 | 0.73% | Sch 3 pg 2 line 12 |
| 11 | Unnominated Seasonal Gas Purchases | 1,200,000 | $ 2.5911 | 20.59% | Sch 3 pg 2 line 15 |
| 12 | Storage Withdrawal - Net | 2,969,551 | $ 1.7351 | 50.96% | Sch 5 line 6 col B - Sch 4pg 2 ln 22 Col E |
| 13 | Storage Injection - Gross | - | $ - | 0.00% | Sch 5 line 6 col A - Sch 4 pg 2 ln 20 Col E |
| 14 | Total Net Purchases | 5,827,112 | | 100.00% | |
| | Feb 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 | 2,133,790 | $ 3.0304 | 37.14% | Sch 3 pg 3 (line 16 - line 10 - line 12 - line 15) |
| 17 | Boil off/Peaking Purchases | 42,263 | $ 3.2100 | 0.74% | Sch 3 pg 3 line 12 |
| 18 | Unnominated Seasonal Gas Purchases | 600,000 | $ 2.5911 | 10.44% | Sch 3 pg 3 line 15 |
| 19 | Storage Withdrawal - Net | 2,969,551 | $ 1.7352 | 51.68% | Sch 5 line 9 col B - Sch 4pg 3 ln 22 Col E |
| 20 | Storage Injection - Gross | - | $ - | 0.00% | Sch 5 line 9 col A - Sch 4 pg 3 ln 20 Col E |
| 21 | Total Net Purchases | 5,745,604 | | 100.00% | |

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
December 2020

| 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) | 17,096 | 3,708,819 | 55,332 | 1,244,118 | 0 | - | 5,025,365 |
| 4 | Fixed cost per unit retail sales (ln 2 / ln 3) | $0.114 | $0.124 | $0.036 | $0.131 | $0.000 | - | |
| 5 | PEPL monthly retail variable costs (ln 24 * ln 1) | $184 | $43,285 | $187 | $15,374 | $0 | - | $59,030 |
| 6 | Estimated monthly retail sales- Dth (Sch 2B, ln 1) | 17,096 | 3,708,819 | 55,332 | 1,244,118 | 0 | - | 5,025,365 |
| 7 | Net monthly retail variable costs per unit sales (ln 5 / ln 6) | $0.011 | $0.012 | $0.003 | $0.012 | $0.000 | - | |
| 8 | Total PEPL cost per unit retail sales (ln 4 + ln 7) | $0.125 | $0.136 | $0.039 | $0.143 | $0.000 | - | |
| 9 | PEPL balancing demand costs (ln 18 * Sch 2C, ln 18) | $164 | $35,551 | $2,805 | $20,144 | $2,972 | $223 | $61,859 |
| 10 | Est. monthly total throughput excl. Basic - Dth (Sch 2C, ln 1) | 17,096 | 3,708,819 | 292,646 | 2,101,516 | 310,062 | 23,312 | 6,453,451 |
| 11 | Fixed balancing cost per unit throughput (ln 9 / ln 10) | $0.010 | $0.010 | $0.010 | $0.010 | $0.010 | $0.010 | |
| 12 | PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 18) | $15 | $3,356 | $265 | $1,901 | $280 | $21 | $5,838 |
| 13 | Estimated monthly total throughput excl Basic- Dth (Sch 2C, ln 1) | 17,096 | 3,708,819 | 292,646 | 2,101,516 | 310,062 | 23,312 | 6,453,451 |
| 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) | $0.011 | $0.011 | $0.011 | $0.011 | $0.011 | $0.011 | |

| 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 | | | |
| | December 2020 | 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) | | 1,200,000 | | 0.0020 | | | 2,400 | | 2,400 |
| 22 | (100 - day firm) (Net) | | 1,175,641 | | 0.0094 | 24,359 | | 11,051 | 51,417 | 62,468 |
| 23 | Total (ln 19 + ln20 + ln21 + ln22) | | | | | | $0 | $13,451 | $51,417 | $64,868 |
| 24 | PEPL Retail Variable Costs (line 23 * 91%) 1/ | | | | | | | | | $59,030 |
| 25 | PEPL Balancing Variable Costs (line 23* 9%) 1/ | | | | | | | | | $5,838 |

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

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
January 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 2) | 19,809 | 4,073,269 | 37,712 | 1,598,601 | 0 | - | 5,729,391 |
| 4 | Fixed cost per unit retail sales (ln 2 / ln 3) | $0.099 | $0.113 | $0.052 | $0.102 | $0.000 | - | |
| 5 | PEPL monthly retail variable costs (ln 24 * ln 1) | $230 | $54,107 | $233 | $19,218 | $0 | - | $73,788 |
| 6 | Estimated monthly retail sales - Dth (Sch 2B, ln 2) | 19,809 | 4,073,269 | 37,712 | 1,598,601 | 0 | - | 5,729,391 |
| 7 | Net monthly retail variable costs per unit sales (ln 5 / ln 6) | $0.012 | $0.013 | $0.006 | $0.012 | $0.000 | - | |
| 8 | Total PEPL cost per unit retail sales (ln 4 + ln 7) | $0.111 | $0.126 | $0.058 | $0.114 | $0.000 | - | |
| 9 | PEPL balancing demand costs (ln 18 * Sch 2C, ln 19) | $169 | $34,724 | $2,411 | $21,569 | $2,781 | $205 | $61,859 |
| 10 | Estimated monthly total throughput - Dth (Sch 2C, ln 2) | 19,809 | 4,073,269 | 282,776 | 2,530,151 | 326,182 | 24,056 | 7,256,243 |
| 11 | Fixed balancing cost per unit throughput (ln 9 / ln 10) | $0.009 | $0.009 | $0.009 | $0.009 | $0.009 | $0.009 | |
| 12 | PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 19) | $20 | $4,097 | $284 | $2,545 | $328 | $24 | $7,298 |
| 13 | Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 2) | 19,809 | 4,073,269 | 282,776 | 2,530,151 | 326,182 | 24,056 | 7,256,243 |
| 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) | $0.010 | $0.010 | $0.010 | $0.010 | $0.010 | $0.010 | |

| Ln. No. | Calculation of 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 | | | |
| | January 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) | | 1,500,000 | | 0.0020 | | | 3,000 | | 3,000 |
| 22 | (100 - day firm) (Net) | | 1,469,551 | | 0.0094 | 30,449 | | 13,814 | 64,272 | 78,086 |
| 23 | Total (ln 19 + ln20 + ln21 + ln22) | | | | | | $0 | $16,814 | $64,272 | $81,086 |
| 24 | PEPL Retail Variable Costs (line 23 * 91%) 1/ | | | | | | | | | $73,788 |
| 25 | PEPL Balancing Variable Costs (line 23 * 9%) 1/ | | | | | | | | | $7,298 |

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

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
February 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) | $1,840 | $432,257 | $1,865 | $153,531 | $0 | - | $589,493 |
| 3 | Estimated monthly retail sales- Dth (Sch 2B, ln 3) | 18,188 | 4,042,802 | 26,336 | 1,560,817 | 0 | - | 5,648,143 |
| 4 | Fixed cost per unit retail sales (ln 2 / ln 3) | $0.101 | $0.107 | $0.071 | $0.098 | $0.000 | - | |
| 5 | PEPL monthly retail variable costs (ln 24 * ln 1) | $230 | $54,106 | $233 | $19,217 | $0 | - | $73,786 |
| 6 | Estimated monthly retail sales- Dth (Sch 2B, ln 3) | 18,188 | 4,042,802 | 26,336 | 1,560,817 | 0 | - | 5,648,143 |
| 7 | Net monthly retail variable costs per unit sales (ln 5 / ln 6) | $0.013 | $0.013 | $0.009 | $0.012 | $0.000 | - | |
| 8 | Total PEPL cost per unit retail sales (ln 4 + ln 7) | $0.114 | $0.120 | $0.080 | $0.110 | $0.000 | - | |
| 9 | PEPL balancing demand costs (ln 18* Sch 2C, ln 20) | $152 | $33,776 | $2,138 | $19,589 | $2,457 | $189 | $58,301 |
| 10 | Estimated monthly total throughput - Dth (Sch 2C, ln 3) | 18,188 | 4,042,802 | 255,952 | 2,344,761 | 294,056 | 22,624 | 6,978,383 |
| 11 | Fixed balancing cost per unit throughput (ln 9 / ln 10) | $0.008 | $0.008 | $0.008 | $0.008 | $0.008 | $0.008 | |
| 12 | PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 20) | $19 | $4,227 | $268 | $2,452 | $307 | $24 | $7,297 |
| 13 | Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 3) | 18,188 | 4,042,802 | 255,952 | 2,344,761 | 294,056 | 22,624 | 6,978,383 |
| 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 sales (ln 11 + ln 14) | $0.009 | $0.009 | $0.009 | $0.009 | $0.009 | $0.009 | |

| | Calculation of Fixed Costs | A Monthly Fixed Costs |
|---|---|---|
| 16 | PEPL demand cost | $647,794 |
| 17 | PEPL Retail Demand Costs (line 16 * 91%) 1/ | $589,493 |
| 18 | PEPL Balancing Demand Costs (line 16 * 9%) 1/ | $58,301 |

| | Calculation of Monthly Variable Costs | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Volumes | | Storage Rates | | | Costs | | | |
| | February 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) | | 1,500,000 | | 0.0020 | | | 3,000 | | 3,000 |
| 22 | (100 - day firm) (Net) | | 1,469,551 | | 0.0094 | 30,449 | | 13,814 | 64,269 | 78,083 |
| 23 | Total (ln 19 + ln20 + ln21 + ln22) | | | | | | $0 | $16,814 | $64,269 | $81,083 |
| 24 | PEPL Retail Variable Costs (line 23 * 91%) 1/ | | | | | | | | | $73,786 |
| 25 | PEPL & 3 Balancing Variable Costs (line 23 * 9%) 1/ | | | | | | | | | $7,297 |

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 February 28, 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 |
| | December 2020 | | | | | | | | | |
| 1 | Greene Co. | 0 | 1,300,000 | $0 | $0 | $589,550 | $2,450,890 | $589,550 | $2,450,890 | $3,040,440 |
| 2 | PEPL WSS | 0 | 1,200,000 | 0 | 0 | 631,080 | 1,901,880 | 631,080 | 1,901,880 | 2,532,960 |
| 3 | Subtotal | 0 | 2,500,000 | 0 | 0 | 1,220,630 | 4,352,770 | 1,220,630 | 4,352,770 | 5,573,400 |
| | January 2021 | | | | | | | | | |
| 4 | Greene Co. | 0 | 1,500,000 | 0 | 0 | 680,250 | 2,827,950 | 680,250 | 2,827,950 | 3,508,200 |
| 5 | PEPL WSS | 0 | 1,500,000 | 0 | 0 | 788,850 | 2,377,350 | 788,850 | 2,377,350 | 3,166,200 |
| 6 | Subtotal | 0 | 3,000,000 | 0 | 0 | 1,469,100 | 5,205,300 | 1,469,100 | 5,205,300 | 6,674,400 |
| | February 2021 | | | | | | | | | |
| 7 | Greene Co. | 0 | 1,500,000 | 0 | 0 | 679,950 | 2,828,100 | 679,950 | 2,828,100 | 3,508,050 |
| 8 | PEPL WSS | 0 | 1,500,000 | 0 | 0 | 788,700 | 2,377,350 | 788,700 | 2,377,350 | 3,166,050 |
| 9 | Subtotal | 0 | 3,000,000 | 0 | 0 | 1,468,650 | 5,205,450 | 1,468,650 | 5,205,450 | 6,674,100 |
| 10 | Grand Total | 0 | 8,500,000 | $0 | $0 | $4,158,380 | $14,763,520 | $4,158,380 | $14,763,520 | $18,921,900 |

**Citizens Gas**
**Demand Allocation of Injections and Withdrawals**
**Greene Co.**
**For Three Months Ending February 28, 2021**

| Line No. | | A<br>Volume DTH | B<br>Demand Cost | C<br>Commodity Cost | D<br>Total Cost | E<br>Total $/DTH | F<br>Comm $/DTH |
|---|---|---|---|---|---|---|---|
| 1 | Beginning Balance @ December 2020 | 6,911,491 | $3,133,929 | $13,030,442 | $16,164,371 | $2.3388 | $1.8853 |
| 2 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 3 | Less: Gross withdrawals - avg. unit cost | (1,300,000) | (589,550) | (2,450,890) | (3,040,440) | 2.3388 | 1.8853 |
| 4 | Beginning Balance @ January 2021 | 5,611,491 | 2,544,379 | 10,579,552 | 13,123,931 | 2.3388 | 1.8853 |
| 5 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 6 | Less: Gross withdrawals - avg. unit cost | (1,500,000) | (680,250) | (2,827,950) | (3,508,200) | 2.3388 | 1.8853 |
| 7 | Beginning Balance @ February 2021 | 4,111,491 | 1,864,129 | 7,751,602 | 9,615,731 | 2.3387 | 1.8854 |
| 8 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 9 | Less: Gross withdrawals - avg. unit cost | (1,500,000) | (679,950) | (2,828,100) | (3,508,050) | 2.3387 | 1.8854 |
| 10 | Ending balance @ February 28, 2021 | 2,611,491 | $1,184,179 | $4,923,502 | $6,107,681 | $2.3388 | $1.8853 |

**Citizens Gas**
**Demand Allocation of Injections and Withdrawals**
**From PEPL FS**
**For Three Months Ending February 28, 2021**

| | | A | B | C | D | E | F |
|---|---|---|---|---|---|---|---|
| Line No. | | Volume DTH | Demand Cost | Commodity Cost | Total Cost | Total $/DTH | Comm $/DTH |
| 1 | Beginning Balance @ December 2020 | 5,844,783 | $3,073,485 | $9,263,477 | $12,336,962 | $2.1108 | $1.5849 |
| 2 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 3 | Less: Gross withdrawals - avg. unit cost | (1,200,000) | (631,080) | (1,901,880) | (2,532,960) | 2.1108 | 1.5849 |
| 4 | Beginning Balance @ January 2021 | 4,644,783 | 2,442,405 | 7,361,597 | 9,804,002 | 2.1108 | 1.5849 |
| 5 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 6 | Less: Gross withdrawals - avg. unit cost | (1,500,000) | (788,850) | (2,377,350) | (3,166,200) | 2.1108 | 1.5849 |
| 7 | Beginning Balance @ February 2021 | 3,144,783 | 1,653,555 | 4,984,247 | 6,637,802 | 2.1107 | 1.5849 |
| 8 | Add: Net injections at cost | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 |
| 9 | Less: Gross withdrawals - avg. unit cost | (1,500,000) | (788,700) | (2,377,350) | (3,166,050) | 2.1107 | 1.5849 |
| 10 | Ending balance @ February 28, 2021 | 1,644,783 | $864,855 | $2,606,897 | $3,471,752 | $2.1108 | $1.5849 |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**June 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<br>Cause No. 37399 - GCA 140 | 0.003153 | 0.740425 | 0.006293 | 0.250129 | 0.000000 | 1.000000 |
| 2 | Retail Throughput demand allocation factor<br>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<br>(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<br>Cause No. 37399 - GCA 140 | 0.003122 | 0.733268 | 0.003164 | 0.260446 | 0.000000 | 1.000000 |
| 5 | Actual net Demand cost allocated<br>(ln 3 * Schedule 7, pg. 1, ln 1 Col A) | $2,796 | $625,021 | $7,711 | $217,027 | $0 | $852,555 |
| 6 | Allocated other demand costs<br>(ln 2 * (Schedule 7, pg. 1, ln 4 Col A ) | (2,409) | (452,779) | (12,448) | (174,048) | 0 | (641,684) |
| 7 | Allocated contracted storage costs<br>(ln 4 * Schedule 7 pg. 1, ln 3 Col B)) | 1,647 | 386,829 | 1,669 | 137,396 | 0 | $527,541 |
| 8 | Actual other non-demand gas costs<br>(Sch. 7 pg. 1, Col B, ln 2 + ln 4 ) * (Sch. 6A, ln 30)) | 4,244 | 368,370 | 16,602 | 152,075 | 0 | 541,291 |
| 9 | Total actual cost of gas incurred<br>(ln 5 + ln 6 + ln 7 + ln 8) | $6,278 | $927,441 | $13,534 | $332,450 | $0 | $1,279,703 |
| 10 | Actual cost of gas billed including<br>Utility Gross Receipts Tax (Sch. 6A, ln 33) | $9,970 | $1,353,308 | $28,875 | $509,849 | $0 | $1,902,002 |
| 11 | Actual cost of gas billed excluding<br>Utility Gross Receipts Tax (ln 10 * (1 - 1.4%)) | 9,830 | 1,334,362 | 28,471 | 502,711 | 0 | 1,875,374 |
| 12 | Net - Write Off Recovered<br>(Sch 12 C ln 3) | 94 | 19,106 | 18 | 2,014 | 0 | 21,232 |
| 13 | Variance from Cause No. 37399-GCA 146 Filing<br>(Sch. 1, pg. 2 Jun., 2020 ln 17) | (900) | (39,270) | (7,042) | (33,970) | 0 | (81,182) |
| 14 | Refund from cause No. 37399- GCA 146 Filing<br>(Sch. 1, pg. 2 Jun., 2020 ln 18) | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Gas cost recovered to be reconciled with actual<br>cost of gas incurred (ln 11 - ln 12 - ln 13 + ln 14) | 10,636 | 1,354,526 | 35,495 | 534,667 | 0 | 1,935,324 |
| 16 | Gas cost variance (over)/underrecovery<br>(ln 9 - ln 15) | ($4,358) | ($427,085) | ($21,961) | ($202,217) | $0 | ($655,621) |

**Citizens Gas**
**Calculation of Actual Gas Cost Variance**
**June 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) | 145 | 12,619 | 6,609 | 10,837 | 6,659 | 15,305 | 52,174 |
| 19 | Total actual Balancing Demand cost incurred (ln 17 + ln 18) | 145 | 12,619 | 6,609 | 10,837 | 6,659 | 15,305 | 52,174 |
| 20 | Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6A, ln 38) | $211 | $19,106 | $8,377 | $15,882 | $7,844 | $17,118 | $68,538 |
| 21 | Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%)) | 208 | 18,839 | 8,260 | 15,660 | 7,734 | 16,878 | 67,579 |
| 22 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 2 Jun., 2020 ln 11) | (26) | (1,654) | | | | | (1,680) |
| 23 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 3 Jun., 2020 ln 28) | | | (1,721) | (1,991) | 153 | 7,753 | 4,194 |
| 24 | Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23) | $234 | $20,493 | $9,981 | $17,651 | $7,581 | $9,125 | $65,065 |
| 25 | Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24) | ($89) | ($7,874) | ($3,372) | ($6,814) | ($922) | $6,180 | ($12,891) |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**June 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 | 4,683 | 406,521 | 18,322 | 167,824 | - | | 597,350 |
| 27 | Standard Delivery - Dths | | | 176,536 | 177,263 | 143,992 | 19,508 | 517,299 |
| 28 | Basic Delivery - Dths | | | 18,039 | 4,032 | 70,525 | 473,541 | 566,137 |
| 29 | Total Throughput - Dths (ln 26+ ln 27 + ln 28) | 4,683 | 406,521 | 212,897 | 349,119 | 214,517 | 493,049 | 1,680,786 |
| 30 | Retail sales allocation factor (ln 26 / ln 26, col. G) | 0.007840 | 0.680540 | 0.030672 | 0.280948 | 0.000000 | 0.000000 | 1.000000 |
| 31 | Throughput subject to Balancing GCA allocation factor (ln 29/ln 29, column G) | 0.002786 | 0.241864 | 0.126665 | 0.207712 | 0.127629 | 0.293344 | 1.000000 |
| | Calculation of Gas Supply Charge Recovery | | | | | | | |
| 32 | Gas Supply Charge Cause No. 37399 - GCA 146 (D1 & D2 excludes balancing charges) per Dth | $2.129 | $3.329 | $1.576 | $3.038 | $0.000 | $0.000 | |
| 33 | Gas Supply Charge Recovery (ln 26 * ln 32) | $9,970 | $1,353,308 | $28,875 | $509,849 | $0 | - | $1,902,002 |
| | Calculation of Balancing Charge Recovery | | | | | | | |
| 34 | Balancing GCA Charge Cause No. 37399 - GCA 146 Standard & Retail Customers (per Dth) | $0.045 | $0.047 | $0.043 | $0.046 | $0.053 | $0.392 | |
| 35 | Balancing GCA Charge Cause No. 37399 - GCA 146 Basic Delivery Customers (per Dth) | | | $0.002 | $0.002 | $0.003 | $0.020 | |
| 36 | Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34) | $211 | $19,106 | $8,341 | $15,874 | $7,632 | $7,647 | $58,811 |
| 37 | Balancing Charge Recovery - Basic (ln 28 * ln 35) | | | $36 | $8 | $212 | $9,471 | $9,727 |
| 38 | Total Balancing Charge Recovery (ln 36 + ln 37) | $211 | $19,106 | $8,377 | $15,882 | $7,844 | $17,118 | $68,538 |

1/ Line 36 Column C calculation is (157,356 * 0.043) + (37,502 * 0.042)

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**July 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 ) | $2,236 | $499,897 | $6,168 | $173,580 | $0 | $681,881 |
| 6 | Allocated other demand costs (ln 2 * ((Schedule 7 pg. 1, Col C ln 4)) | (1,674) | (314,645) | (8,650) | (120,949) | 0 | (445,918) |
| 7 | Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, Col D ln 3)) | 1,688 | 396,531 | 1,711 | 140,842 | 0 | 540,772 |
| 8 | Actual other non-demand gas costs (Sch. 7 pg. 1, Col D, ln 2 + ln 4 ) * (Sch. 6B, ln 30)) | 4,821 | 346,212 | 18,464 | 168,532 | 0 | 538,029 |
| 9 | Total actual cost of gas incurred (lns 5+6+7+8) | $7,071 | $927,995 | $17,693 | $362,005 | $0 | $1,314,764 |
| 10 | Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6B, ln 33) | $9,459 | $1,106,758 | $24,956 | $463,385 | $0 | $1,604,558 |
| 11 | Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%)) | 9,327 | 1,091,262 | 24,607 | 456,898 | 0 | 1,582,094 |
| 12 | Net - Write Off Recovered (Sch 12 C ln 9) | 96 | 16,017 | 17 | 1,682 | 0 | 17,812 |
| 13 | Variance from Cause No. 37399-GCA 146 Filing (Sch. 1, pg. 2 Jul., 2020 ln 17) | (772) | (33,980) | (7,094) | (32,429) | 0 | (74,275) |
| 14 | Refund from cause No. 37399- GCA 146 Filing (Sch. 1, pg. 2 Jul., 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) | $10,003 | $1,109,225 | $31,684 | $487,645 | $0 | $1,638,557 |
| 16 | Gas cost variance (over)/underrecovery (ln 9 - ln 15) | ($2,932) | ($181,230) | ($13,991) | ($125,640) | $0 | ($323,793) |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**July 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) | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 18 | Allocated ADS2 Balancing Demand & variable cost ((Sch. 7, pg. 2, Col B ln 2 ) * ln 31) | 149 | 10,670 | 7,291 | 12,063 | 6,982 | 16,328 | 53,483 |
| 19 | Total actual Balancing Demand cost incurred (ln17 + ln 18) | $149 | $10,670 | $7,291 | $12,063 | $6,982 | $16,328 | $53,483 |
| 20 | Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6B, ln 38) | $214 | $16,017 | $9,593 | $17,557 | $8,128 | $16,591 | $68,100 |
| 21 | Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%)) | 211 | 15,793 | 9,459 | 17,311 | 8,014 | 16,359 | 67,147 |
| 22 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 2 Jul., 2020 ln 11) | (22) | (1,431) | - | - | - | - | (1,453) |
| 23 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 3 Jul., 2020 ln 28) | - | - | (1,719) | (1,910) | 151 | 7,741 | 4,263 |
| 24 | Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 21 - ln 22 - ln 23) | $233 | $17,224 | $11,178 | $19,221 | $7,863 | $8,618 | $64,337 |
| 25 | Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24) | ($84) | ($6,554) | ($3,887) | ($7,158) | ($881) | $7,710 | ($10,854) |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**July 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 | 4,373 | 314,063 | 16,749 | 152,882 | 0 | 0 | 488,067 |
| 27 | Standard Delivery - Dths | | - | 187,552 | 198,003 | 139,102 | 18,508 | 543,165 |
| 28 | Basic Delivery - Dths | - | - | 10,332 | 4,215 | 66,431 | 462,144 | 543,122 |
| 29 | Total Throughput - Dths (ln 26 + ln 27 + ln 28) | 4,373 | 314,063 | 214,633 | 355,100 | 205,533 | 480,652 | 1,574,354 |
| 30 | Retail sales allocation factor (ln 26 / ln 26, col. G) | 0.008960 | 0.643483 | 0.034317 | 0.313240 | 0.000000 | 0.000000 | 1.000000 |
| 31 | Throughput subject to Balancing GCA allocation factor (ln 29 / ln 29, column G) | 0.002778 | 0.199486 | 0.136331 | 0.225553 | 0.130551 | 0.305301 | 1.000000 |
| | Calculation of Gas Supply Charge Recovery | | | | | | | |
| 32 | Gas Supply Charge Cause No. 37399 - GCA 146 (D1 & D2 excludes balancing charges) per Dth | $2.163 | $3.524 | $1.490 | $3.031 | $0.000 | $0.000 | |
| 33 | Gas Supply Charge Recovery (ln 26* ln 32) | $9,459 | $1,106,758 | $ 24,956 | $463,385 | $0 | $0 | $1,604,558 |
| | Calculation of Balancing Charge Recovery | | | | | | | |
| 34 | Balancing GCA Charge Cause No. 37399 - GCA 146 Standard & Retail Customers (per Dth) | $0.049 | $0.051 | $0.047 | $0.050 | $0.057 | $0.397 | |
| 35 | Balancing GCA Charge Cause No. 37399 - GCA 146 Basic Delivery Customers (per Dth) | - | - | $0.002 | $0.003 | $0.003 | $0.020 | |
| 36 | Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34) | $214 | $16,017 | $9,572 | $17,544 | $7,929 | $7,348 | $58,624 |
| 37 | Balancing Charge Recovery - Basic (ln 28 * ln 35) | - | - | $21 | $13 | $199 | $9,243 | $9,476 |
| 38 | Total Balancing Charge Recovery (ln 36 + ln 37) | $214 | $16,017 | $9,593 | $17,557 | $8,128 | $16,591 | $68,100 |

1/ Line 36 Column C calculation is (173,800 * 0.047) + (30,501 * 0.046)

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**August 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) | $2,855 | $638,325 | $7,876 | $221,647 | $0 | $870,703 |
| 6 | Allocated other demand costs (ln 2 * (Schedule 7 pg. 1, Col E, ln 4)) | (2,231) | (419,290) | (11,527) | (161,175) | 0 | (594,223) |
| 7 | Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1,Col F ln 3) | 1,749 | 410,787 | 1,773 | 145,906 | 0 | 560,215 |
| 8 | Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4) * (Sch. 6C, ln 30)) | 3,779 | 462,860 | 32,349 | 239,364 | 0 | 738,352 |
| 9 | Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8) | $6,152 | $1,092,682 | $30,471 | $445,742 | $0 | $1,575,047 |
| 10 | Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6C, ln 33) | $5,633 | $1,102,129 | $34,039 | $489,436 | $0 | $1,631,237 |
| 11 | Actual cost of gas billed excluding Utility Gross Receipts Tax (ln 10 * (1 - 1.4%)) | 5,554 | 1,086,700 | 33,562 | 482,584 | 0 | 1,608,400 |
| 12 | Net - Write Off Recovered (Sch 12 C ln 15) | 56 | 15,749 | 21 | 1,844 | 0 | 17,670 |
| 13 | Variance from Cause No. 37399-GCA 146 Filing (Sch. 1, pg. 2 Aug, 2020, ln 17) | ($770) | ($33,798) | ($7,094) | ($32,702) | $0 | (74,364) |
| 14 | Refund from cause No. 37399- GCA 146 Filing (Sch. 1, pg. 2 Aug, 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) | $6,268 | $1,104,749 | $40,635 | $513,442 | $0 | $1,665,094 |
| 16 | Gas cost variance (over)/underrecovery (ln 9 - ln 15 ) | ($116) | ($12,067) | ($10,164) | ($67,700) | $0 | ($90,047) |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**August 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) | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 18 | Allocated ADS2 Balancing Demand cost (Sch. 7, pg. 2, ln 2 * ln 31) | $88 | $10,738 | $7,577 | $12,614 | $7,467 | $16,922 | $55,406 |
| 19 | Total actual Balancing Demand cost incurred (ln 17 + ln 18) | $88 | $10,738 | $7,577 | $12,614 | $7,467 | $16,922 | $55,406 |
| 20 | Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax ( ln 38 ) | $121 | $15,452 | $9,735 | $17,595 | $8,177 | $16,971 | $68,051 |
| 21 | Actual Balancing Demand Cost Billed excluding Utility Gross Receipts Tax (ln 20 * (1-1.4%)) | 119 | 15,236 | 9,599 | 17,349 | 8,063 | 16,733 | 67,099 |
| 22 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 2 Aug, 2020 ln 11) | (23) | (1,423) | - | - | - | - | (1,446) |
| 23 | Balancing Demand Cost Variance from Cause No. 37399 - GCA 146 (Sch. 1, pg. 3 Aug, 2020 ln 28) | - | - | (1,718) | (1,908) | 150 | 7,741 | 4,265 |
| 24 | Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln21 - ln22 - ln23) | $142 | $16,659 | $11,317 | $19,257 | $7,913 | $8,992 | $64,280 |
| 25 | Balancing Demand cost variance (over)/underrecovery (ln 19 - ln 24) | ($54) | ($5,921) | ($3,740) | ($6,643) | ($446) | $7,930 | ($8,874) |

**Citizens Gas**
**Calculation of Actual Gas Supply and Balancing Demand Cost Variance**
**August 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 | 2,426 | 297,150 | 20,768 | 153,669 | - | - | 474,013 |
| 27 | Standard Delivery - Dths | - | - | 182,607 | 191,080 | 137,392 | 20,173 | 531,252 |
| 28 | Basic Delivery - Dths | - | - | 6,302 | 4,313 | 69,242 | 448,115 | 527,972 |
| 29 | Total Throughput - Dths (ln 26 + ln 27 + ln 28) | 2,426 | 297,150 | 209,677 | 349,062 | 206,634 | 468,288 | 1,533,237 |
| 30 | Retail sales allocation factor (ln 26 / ln 26, col. G) | 0.005118 | 0.626882 | 0.043813 | 0.324187 | 0.000000 | 0.000000 | 1.000000 |
| 31 | Throughput subject to Balancing GCA allocation factor (ln 29 / 29, column G) | 0.001582 | 0.193807 | 0.136754 | 0.227663 | 0.134770 | 0.305424 | 1.000000 |
| | Calculation of Gas Supply Charge Recovery | | | | | | | |
| 32 | Gas Supply Charge Cause No. 37399 - GCA 146 (D1 & D2 excludes balancing charges) per Dth | $2.322 | $3.709 | $1.639 | $3.185 | $0.000 | $0.000 | |
| 33 | Gas Supply Charge Recovery (ln 26 * ln 32) | $5,633 | $1,102,129 | $34,039 | $489,436 | - | - | $1,631,237 |
| | Calculation of Balancing Charge Recovery | | | | | | | |
| 34 | Balancing GCA Charge Cause No. 37399 - GCA 146 Standard & Retail Customers (per Dth) | $0.050 | $0.052 | $0.048 | $0.051 | $0.058 | $0.397 | |
| 35 | Balancing GCA Charge Cause No. 37399 - GCA 146 Basic Delivery Customers (per Dth) | - | - | $0.002 | $0.003 | $0.003 | $0.020 | |
| 36 | Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34) | $121 | $15,452 | $9,722 | $17,582 | $7,969 | $8,009 | $58,855 |
| 37 | Balancing Charge Recovery - Basic (ln 28 * ln 35) | - | - | $13 | $13 | $208 | $8,962 | $9,196 |
| 38 | Total Balancing Charge Recovery (ln 36 + ln 37) | $121 | $15,452 | $9,735 | $17,595 | $8,177 | $16,971 | $68,051 |

1/ Line 36 Column C calculation is (163,015 * 0.048) + (40,360 * 0.047)

Citizens Gas
Trailing Twelve Month Variance
For July 2019 through August 2020

| Line No. | | | A July 2019 | B August 2019 | C September 2019 | D October 2019 | E November 2019 | F December 2019 | G January 2020 | H February 2020 | I March 2020 | J April 2020 | K May 2020 | L June 2020 | M July 2020 | N August 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Actual Cost of Gas | Total Sch 6 pg 1 ln 9 + Sch 6 pg 2 ln 19 | $1,561,858 | $1,561,600 | $1,586,271 | $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 | Variance | Total Sch 6 pg 1 ln 16 + Sch 6 pg 2 ln 25 | ($505,943) | ($170,161) | ($132,983) | ($838,374) | ($828,796) | ($730,945) | ($1,500,513) | ($779,086) | ($464,555) | ($442,851) | $179,518 | ($668,512) | ($334,647) | ($98,921) |
| 3 | | | | | | | | | | Gas Cost Trailing Twelve Months (ln 1, col A-L) | | | | $73,327,799 | | |
| 4 | | | | | | | | | | Variance Trailing Twelve Months (ln 2, col A-L) | | | | ($6,883,201) | | |
| 5 | | | | | | | | | | Total Trailing Twelve Months % Variance (ln 4 / ln 3) | | | | -9.39% | | |
| 6 | | | | | | | | | | Gas Cost Trailing Twelve Months (ln 1, col B-M) | | | | | $73,134,188 | |
| 7 | | | | | | | | | | Variance Trailing Twelve Months (ln 2, col B-M) | | | | | ($6,711,905) | |
| 8 | | | | | | | | | | Total Trailing Twelve Months % Variance (ln 7 / ln 6) | | | | | -9.18% | |
| 9 | | | | | | | | | | Gas Cost Trailing Twelve Months (ln 1, col C-N) | | | | | | $73,203,041 |
| 10 | | | | | | | | | | Variance Trailing Twelve Months (ln 2, col C-N) | | | | | | ($6,640,665) |
| 11 | | | | | | | | | | Total Trailing Twelve Months % Variance (ln 10 / ln 9) | | | | | | -9.07% |

**Citizens Gas**
**Determination of Actual Retail Gas Costs**
**For Three Months Ending August 31, 2020**

| | | A | B | C | D | E | F |
|---|---|---|---|---|---|---|---|
| | | June 2020 | | July 2020 | | August 2020 | |
| Line No. | | Demand | Non-Demand | Demand | Non-Demand | Demand | Non-Demand |
| 1 | Demand gas costs (Sch. 8) | $852,555 | - | $681,881 | - | $870,703 | - |
| 2 | Pipeline non-demand gas costs (Schedule 8) | - | 2,193,487 | - | 1,553,040 | - | 2,325,261 |
| 3 | PEPL Contracted storage and related transportation costs (Sch. 9) | - | 527,541 | - | 540,772 | - | 560,215 |
| 4 | Net cost of gas (injected into) withdrawn from storage (Schedule 10) | (641,684) | (1,652,196) | (445,918) | (1,015,011) | (594,223) | (1,586,909) |
| 5 | Total gas costs | $210,871 | $1,068,832 | $235,963 | $1,078,801 | $276,480 | $1,298,567 |

**Citizens Gas**
**Determination of Actual Balancing Costs**
**For Three Months Ending August 31, 2020**

| Line No. | | A June 2020 | B July 2020 | C August 2020 |
|---|---|---|---|---|
| 1 | Balancing Demand Costs (Schedule 8) | $0 | $0 | $0 |
| 2 | PEPL Balancing Demand Costs (Sch. 9) | 52,174 | 53,483 | 55,406 |
| 3 | Total Balancing Costs | $52,174 | $53,483 | $55,406 |

**Citizens Gas**
**Purchased Gas Cost - Per Books**
**June 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 -May, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | 33,463 | 1,009,298 | $ 13.3194 | $ 1.6451 | | $ 445,707 | $ 1,660,368 | | $ 2,106,075 |
| 2 | MGT Pipeline - | 1,395,000 | - | 0.0620 | - | | 86,504 | 2,043 | | 88,547 |
| 3 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,735 | - | 1.6441 | | | 9,429 | | 9,429 |
| 4 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.5502 | 1.3128 | | 92,751 | 195,951 | | 288,702 |
| 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 | - | 1.7245 | | | 613,399 | | 613,399 |
| 8 | Texas Gas Transmission - Unnominated Injection | (492,274) | (492,274) | 0.3474 | 1.6145 | | (171,016) | (794,776) | | (965,792) |
| 9 | Texas Gas Transmission - Unnominated Withdrawal | 41,291 | 41,291 | 0.3474 | 1.6145 | | 14,344 | 66,664 | | 81,008 |
| 10 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | (1,744) | 71,233 | | 69,489 |
| 11 | Rockies Express - Delivered Supply - (BP REX) | | 309,504 | - | 1.5865 | | - | 491,040 | | 491,040 |
| 12 | Rockies Express - Delivered Supply - (BP PEAK) | | 310,000 | - | 1.4040 | | - | 435,240 | | 435,240 |
| 13 | Rockies Express - EAST | 20,000 | 619,008 | 16.7292 | 1.5612 | | 334,583 | 966,394 | | 1,300,977 |
| 14 | Intraday Purchases | | 20,000 | - | 1.8500 | | | 37,000 | | 37,000 |
| 15 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 16 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 192,566 | - | 1.8080 | | - | 348,167 | | 348,167 |
| 17 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 18 | Hedging Transaction Cost | | | - | - | | | 66,617 | | 66,617 |
| 19 | Imbalance | | (22,897) | - | 1.6433 | | | (37,627) | | (37,627) |
| 20 | Utilization Fee | | | - | - | | (243,750) | - | | (243,750) |
| 21 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 22 | Contract Services | | - | - | - | | - | - | | - |
| 23 | Third Party Supplier Balancing Gas Costs | | 45,195 | - | | | - | 37,349 | | 37,349 |
| 24 | Boil-off / Peaking purchase | | 37,688 | - | 1.7940 | | - | 67,612 | | 67,612 |
| 25 | MGT Cash Out Imbalance | | - | - | - | | | - | | - |
| 26 | NSS Injection fuel loss | - | (2,195) | - | - | | - | | | - |
| 27 | Backup Supply Sales | | - | | - | | | - | | - |
| 28 | Subtotal | | 2,577,878 | | | | $902,507 | $4,236,103 | $0 | $5,138,610 |
| | Actual -May, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 29 | Panhandle Eastern Pipeline - TOR | 33,463 | 1,009,298 | $ 13.3194 | $ 1.6451 | | $ 445,707 | $ 1,660,368 | | $ 2,106,075 |
| 30 | MGT Pipeline - | 1,395,000 | - | 0.0620 | - | | 86,504 | 2,043 | | 88,547 |
| 31 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,735 | - | 1.6441 | | | 9,429 | | 9,429 |
| 32 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.5502 | 1.3128 | | 92,751 | 195,951 | | 288,702 |
| 33 | Texas Gas Transmission - Nominated Demand | 974,113 | | 0.3550 | - | | 345,816 | | | 345,816 |
| 34 | Texas Gas Transmission - Unnominated Demand | - | | - | - | | - | | | - |
| 35 | Texas Gas Transmission - Commodity - TOR | | 355,694 | - | 1.7245 | | | 613,399 | | 613,399 |
| 36 | Texas Gas Transmission - Unnominated Injection | (492,274) | (492,274) | 0.3475 | 1.6147 | | (171,065) | (794,875) | | (965,940) |
| 37 | Texas Gas Transmission - Unnominated Withdrawal | 41,291 | 41,291 | 0.3475 | 1.6147 | | 14,349 | 66,673 | | 81,022 |
| 38 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | (1,744) | 71,233 | | 69,489 |
| 39 | Rockies Express - Delivered Supply - (BP REX) | | 309,504 | - | 1.5865 | | - | 491,040 | | 491,040 |
| 40 | Rockies Express - Delivered Supply - (BP PEAK) | | 310,000 | - | 1.4040 | | - | 435,240 | | 435,240 |
| 41 | Rockies Express - EAST | 20,000 | 619,008 | 16.7292 | 1.5612 | | 334,583 | 966,394 | | 1,300,977 |
| 42 | Intraday Purchases | | 20,000 | - | 1.8500 | | | 37,000 | | 37,000 |
| 43 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 44 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 192,566 | - | 1.8080 | | - | 348,167 | | 348,167 |
| 45 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 46 | Hedging Transaction Cost | | | - | - | | | 66,617 | | 66,617 |
| 47 | Imbalance | | (22,897) | - | 1.6435 | | | (37,631) | | (37,631) |
| 48 | Utilization Fee | | | - | - | | (243,750) | - | | (243,750) |
| 49 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 50 | Contract Services | | - | - | - | | - | - | | - |
| 51 | Third Party Supplier Balancing Gas Costs | | 45,195 | - | | | | 37,349 | | 37,349 |
| 52 | Boil-off / Peaking purchase | | 37,688 | - | 1.7940 | | | 67,612 | | 67,612 |
| 53 | MGT Cash Out Imbalance | | (1,337) | - | 1.6926 | | | (2,263) | | (2,263) |
| 54 | NSS Injection fuel loss | - | (2,195) | | | | | | | - |
| 55 | Backup Supply Sales | | - | - | - | | - | - | | - |
| 56 | Subtotal | | 2,576,541 | | | | $903,151 | $4,233,746 | $0 | $5,136,897 |

**Citizens Gas**
**Purchased Gas Cost - Per Books**
**June 2020**

| Line | | 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 - June, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 57 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,590 | $ 13.2172 | $ 1.5827 | | $ 442,288 | $ 1,075,614 | | $ 1,517,902 |
| 58 | MGT Gas Pipeline - | 1,350,000 | - | 0.0641 | - | | 86,504 | 286 | | 86,790 |
| 59 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,550 | - | 1.5820 | | | 8,780 | | 8,780 |
| 60 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 144,450 | 18.0076 | 1.2505 | | 90,038 | 180,630 | | 270,668 |
| 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 | - | 1.6089 | | | 572,248 | | 572,248 |
| 64 | Texas Gas Transmission - Unnominated Injection | (527,383) | (527,383) | 0.4439 | 1.5111 | | (234,105) | (796,928) | | (1,031,033) |
| 65 | Texas Gas Transmission - Unnominated Withdrawal | 53,868 | 53,868 | 0.4439 | 1.5111 | | 23,912 | 81,400 | | 105,312 |
| 66 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 18,446 | (649,308) | | (630,862) |
| 67 | Rockies Express - Delivered Supply - (BP REX) | | 299,792 | - | 1.5130 | | | 453,600 | | 453,600 |
| 68 | Rockies Express - Delivered Supply - (BP PEAK) | | 300,000 | - | 1.3320 | | | 399,600 | | 399,600 |
| 69 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 70 | Intraday Purchases | | 26,000 | - | 1.7962 | | | 46,700 | | 46,700 |
| 71 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 72 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 463,428 | - | 1.4881 | | | 689,648 | | 689,648 |
| 73 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 74 | Hedging Transaction Cost | | | - | - | | | 30,394 | | 30,394 |
| 75 | Imbalance | | 6,481 | - | 1.1666 | | | 7,561 | | 7,561 |
| 76 | Utilization Fee | | | - | - | | (243,750) | - | | (243,750) |
| 77 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 78 | Contract Services | | - | - | - | | - | - | | - |
| 79 | Third Party Supplier Balancing Gas Costs | | 33,638 | - | | | | 21,313 | | 21,313 |
| 80 | Boil-off / Peaking purchase | | 43,151 | - | 1.7220 | | | 74,306 | | 74,306 |
| 81 | MGT Cash Out Imbalance | | - | - | - | | | - | | - |
| 82 | NSS Injection fuel loss | | (2,138) | - | - | | - | | | - |
| 83 | Backup Supply Sales | | - | | - | | | - | | - |
| 84 | Subtotal | | 1,882,107 | | | | $ 851,911 | $ 2,195,844 | $ - | $ 3,047,755 |
| 85 | Total Purchased Costs (line 84 + line 56 - line 28) | | 1,880,770 | | | | $ 852,555 | $ 2,193,487 | $ - | $ 3,046,042 |
| 86 | Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6) | | | | | | $ - | | | |
| 87 | Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86) | | 1,880,770 | | | | $ 852,555 | | | |
| 88 | TGT Unnominated Demand Cost - Retail (line 86 * 90%) | | | | | | $ - | | | |
| 89 | Balancing Demand Cost (line 86 * 10%) | | | | | | $ - | | | |

**Citizens Gas**

**Purchased Gas Cost - Per Books**

**July 2020**

| Line No. | | A<br>Demand - Dth | B<br>Commodity Dth | C<br>Demand $/Unit | D<br>Commodity $/Dth | E<br>Other $/Unit | F<br>Demand (A x C) | G<br>Commodity (B x D) | H<br>Other | I<br>Total (F + G + H) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Accrual - June, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,590 | $ 13.2172 | $ 1.5827 | | $ 442,288 | $ 1,075,614 | | $ 1,517,902 |
| 2 | MGT Gas Pipeline - | 1,350,000 | - | 0.0641 | - | | 86,504 | 286 | | 86,790 |
| 3 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,550 | - | 1.5820 | | | 8,780 | | 8,780 |
| 4 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 144,450 | 18.0076 | 1.2505 | | 90,038 | 180,630 | | 270,668 |
| 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 | - | 1.6089 | | | 572,248 | | 572,248 |
| 8 | Texas Gas Transmission - Unnominated Injection | (527,383) | (527,383) | 0.4439 | 1.5111 | | (234,105) | (796,928) | | (1,031,033) |
| 9 | Texas Gas Transmission - Unnominated Withdrawal | 53,868 | 53,868 | 0.4439 | 1.5111 | | 23,912 | 81,400 | | 105,312 |
| 10 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 18,446 | (649,308) | | (630,862) |
| 11 | Rockies Express - Delivered Supply - (BP REX) | | 299,792 | - | 1.5130 | | | 453,600 | | 453,600 |
| 12 | Rockies Express - Delivered Supply - (BP PEAK) | | 300,000 | - | 1.3320 | | | 399,600 | | 399,600 |
| 13 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 14 | Intraday Purchases | | 26,000 | - | 1.7962 | | | 46,700 | | 46,700 |
| 15 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 16 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 463,428 | - | 1.4881 | | | 689,648 | | 689,648 |
| 17 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 18 | Hedging Transaction Cost | | | - | - | | | 30,394 | | 30,394 |
| 19 | Imbalance | | 6,481 | - | 1.1666 | | | 7,561 | | 7,561 |
| 20 | Utilization Fee | | | - | - | | (243,750) | - | | (243,750) |
| 21 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 22 | Contract Services | | - | - | - | | - | - | | - |
| 23 | Third Party Supplier Balancing Gas Costs | | 33,638 | - | | | | 21,313 | | 21,313 |
| 24 | Boil-off / Peaking purchase | | 43,151 | - | 1.7220 | | | 74,306 | | 74,306 |
| 25 | MGT Cash Out Imbalance | | - | - | - | | | - | | - |
| 26 | NSS Injection fuel loss | | (2,138) | - | - | | - | | | - |
| 27 | Backup Supply Sales | | - | | - | | | - | | - |
| 28 | Subtotal | | 1,882,107 | | | | $ 851,911 | $ 2,195,844 | $ - | $ 3,047,755 |
| | Actual - June, 2020 | | | | | | | | | |
| 29 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,590 | $ 13.2172 | 1.5827 | | $ 442,288 | $ 1,075,614 | | $ 1,517,902 |
| 30 | MGT Gas Pipeline - | 1,350,000 | - | 0.0641 | - | | 86,504 | 285 | | 86,789 |
| 31 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,550 | - | 1.5820 | | | 8,780 | | 8,780 |
| 32 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 144,450 | 18.0076 | 1.2505 | | 90,038 | 180,630 | | 270,668 |
| 33 | Texas Gas Transmission - Nominated Demand | 942,690 | - | 0.3556 | - | | 335,233 | | | 335,233 |
| 34 | Texas Gas Transmission - Unnominated Demand | - | - | - | - | | - | | | - |
| 35 | Texas Gas Transmission - Commodity - TOR | | 355,680 | - | 1.6089 | | - | 572,248 | | 572,248 |
| 36 | Texas Gas Transmission - Unnominated Injection | (527,383) | (527,383) | 0.4438 | 1.5118 | | (234,053) | (797,298) | | (1,031,351) |
| 37 | Texas Gas Transmission - Unnominated Withdrawal | 53,868 | 53,868 | 0.4438 | 1.5118 | | 23,907 | 81,438 | | 105,345 |
| 38 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 18,446 | (649,308) | | (630,862) |
| 39 | Rockies Express - Delivered Supply - (BP REX) | | 299,792 | - | 1.5130 | | | 453,600 | | 453,600 |
| 40 | Rockies Express - Delivered Supply - (BP PEAK) | | 300,000 | - | 1.3320 | | | 399,600 | | 399,600 |
| 41 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 42 | Intraday Purchases | | 26,000 | - | 1.8038 | | - | 46,900 | | 46,900 |
| 43 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 44 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 463,428 | - | 1.4881 | | | 689,648 | | 689,648 |
| 45 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | - | - | - | | | | | - |
| 46 | Hedging Transaction Cost | | | - | - | | | 30,394 | | 30,394 |
| 47 | Imbalance | | 6,481 | - | 1.1674 | | | 7,566 | | 7,566 |
| 48 | Utilization Fee | | - | - | - | | (243,750) | - | | (243,750) |
| 49 | Net Demand Cost Charges - AMA | | | - | - | | - | - | | - |
| 50 | Contract Services | | - | - | - | | - | - | | - |
| 51 | Third Party Supplier Balancing Gas Costs | | 33,638 | - | | | - | 21,313 | | 21,313 |
| 52 | Boil-off / Peaking purchase | | 43,151 | - | 1.7220 | | - | 74,306 | | 74,306 |
| 53 | MGT Cash Out Imbalance | | 552 | - | 1.5833 | | - | 874 | | 874 |
| 54 | NSS Injection fuel loss | | (2,138) | - | - | | | | | - |
| 55 | Backup Supply Sales | | - | | - | | | - | | - |
| 56 | Subtotal | | 1,882,659 | | | | $ 853,196 | $ 2,196,590 | $0 | $ 3,049,786 |

**Citizens Gas**

**Purchased Gas Cost - Per Books**

**July 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 - July, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 57 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,582 | $ 13.3194 | $ 1.4166 | | $ 445,707 | $ 962,696 | | $ 1,408,403 |
| 58 | MGT Pipeline | 1,395,000 | - | 0.0620 | - | | 86,504 | 879 | | 87,383 |
| 59 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,735 | - | 1.4159 | | | 8,120 | | 8,120 |
| 60 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.6014 | 1.0843 | | 93,007 | 161,851 | | 254,858 |
| 61 | Texas Gas Transmission - Nominated Demand | 974,113 | | 0.3543 | - | | 345,128 | | | 345,128 |
| 62 | Texas Gas Transmission - Unnominated Demand | - | - | - | - | | - | | | - |
| 63 | Texas Gas Transmission - Commodity - TOR | - | 355,694 | - | 1.3711 | | | 487,684 | | 487,684 |
| 64 | Texas Gas Transmission - Unnominated Injection | (810,843) | (810,843) | 0.5170 | 1.2897 | | (419,206) | (1,045,744) | | (1,464,950) |
| 65 | Texas Gas Transmission - Unnominated Withdrawal | 5,074 | 5,074 | 0.5169 | 1.2897 | | 2,623 | 6,544 | | 9,167 |
| 66 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 36,000 | (84,000) | | (48,000) |
| 67 | Rockies Express - Delivered Supply - (BP REX) | - | 309,504 | - | 1.2871 | | - | 398,350 | | 398,350 |
| 68 | Rockies Express - Delivered Supply - (BP PEAK) | | 310,000 | - | 1.1050 | | | 342,550 | | 342,550 |
| 69 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 70 | Intraday Purchases | | 25,000 | - | 1.6920 | | | 42,300 | | 42,300 |
| 71 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 72 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 147,556 | - | 1.4402 | | | 212,503 | | 212,503 |
| 73 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 74 | Hedging Transaction Cost | | | - | - | | | 31,406 | | 31,406 |
| 75 | Imbalance | | 22,961 | - | 1.2233 | | | 28,088 | | 28,088 |
| 76 | Utilization Fee | | | - | - | | (243,750) | | | (243,750) |
| 77 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 78 | Contract Services | | - | - | - | | - | - | | - |
| 79 | Third Party Supplier Balancing Gas Costs | | 32,866 | - | | | | (56,960) | | (56,960) |
| 80 | Boil-off / Peaking purchase | | 37,476 | - | 1.4950 | | | 56,027 | | 56,027 |
| 81 | MGT Cash Out Imbalance | | - | - | - | | | - | | - |
| 82 | NSS Injection fuel loss | | (970) | | | | | | | - |
| 83 | Backup Supply Sales | | - | | - | | | - | | - |
| 84 | Subtotal | | 1,268,900 | | | | $ 680,596 | $ 1,552,294 | $0 | $2,232,890 |
| 85 | Total Purchased Costs (line 84 + line 56 - line 28.) | | 1,269,452 | | | | $681,881 | $1,553,040 | $0 | $2,234,921 |
| 86 | Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6) | | | | | | 0 | | | |
| 87 | Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86) | | 1,269,452 | | | | $681,881 | | | |
| 88 | TGT Unnominated Demand Cost - Retail (line 86 * 90%) | | | | | | $0 | | | |
| 89 | Balancing Demand Cost (line 86 * 10%) | | | | | | $0 | | | |

**Citizens Gas**
**Purchased Gas Cost - Per Books**
**August 2020**

| Line No. | | A<br>Demand - Dth | B<br>Commodity Dth | C<br>Demand $/Unit | D<br>Commodity $/Dth | E<br>Other $/Unit | F<br>Demand (A x C) | G<br>Commodity (B x D) | H<br>Other | I<br>Total (F + G + H) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Accrual - July, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 1 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,582 | $ 13.3194 | $ 1.4166 | | $ 445,707 | $ 962,696 | | $ 1,408,403 |
| 2 | MGT Pipeline | 1,395,000 | - | $ 0.0620 | - | | 86,504 | 879 | | 87,383 |
| 3 | Indiana Municipal Gas Purchasing Authority - TOR | - | 5,735 | - | 1.4159 | | - | 8,120 | | 8,120 |
| 4 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.6014 | 1.0843 | | 93,007 | 161,851 | | 254,858 |
| 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 | - | 1.3711 | | | 487,684 | | 487,684 |
| 8 | Texas Gas Transmission - Unnominated Injection | (810,843) | (810,843) | 0.5170 | 1.2897 | | (419,206) | (1,045,744) | | (1,464,950) |
| 9 | Texas Gas Transmission - Unnominated Withdrawal | 5,074 | 5,074 | 0.5169 | 1.2897 | | 2,623 | 6,544 | | 9,167 |
| 10 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | - | - | - | - | | 36,000 | (84,000) | | (48,000) |
| 11 | Rockies Express - Delivered Supply - (BP REX) | - | 309,504 | - | 1.2871 | | - | 398,350 | | 398,350 |
| 12 | Rockies Express - Delivered Supply - (BP PEAK) | | 310,000 | - | 1.1050 | | - | 342,550 | | 342,550 |
| 13 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 14 | Intraday Purchases | - | 25,000 | - | 1.6920 | | | 42,300 | | 42,300 |
| 15 | Fuel Retention Volumes | - | - | - | - | | - | - | | - |
| 16 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | - | 147,556 | - | 1.4402 | | - | 212,503 | | 212,503 |
| 17 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | - | - | - | - | | - | - | | - |
| 18 | Hedging Transaction Cost | - | | - | - | | | 31,406 | | 31,406 |
| 19 | Imbalance | | 22,961 | - | 1.2233 | | | 28,088 | | 28,088 |
| 20 | Utilization Fee | - | - | - | - | | (243,750) | - | | (243,750) |
| 21 | Net Demand Cost Charges - AMA | - | - | - | - | | - | | | - |
| 22 | Contract Services | | - | - | - | | - | - | | - |
| 23 | Third Party Supplier Balancing Gas Costs | - | 32,866 | - | | | | (56,960) | | (56,960) |
| 24 | Boil-off / Peaking purchase | - | 37,476 | - | 1.4950 | | - | 56,027 | | 56,027 |
| 25 | MGT Cash Out Imbalance | - | - | - | - | | - | - | | - |
| 26 | NSS Injection fuel loss | | (970) | | | | | | | |
| 27 | Backup Supply Sales | | - | | - | | - | - | | - |
| 28 | Sub-total | | 1,268,900 | | | | $680,596 | $1,552,294 | $0 | $2,232,890 |
| | Actual - July, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 29 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,582 | $ 13.3194 | $ 1.4166 | | $ 445,707 | $ 962,696 | | $ 1,408,403 |
| 30 | MGT Pipeline | 1,395,000 | - | 0.0620 | - | | 86,504 | 879 | | 87,383 |
| 31 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,735 | - | 1.4159 | | | 8,120 | | 8,120 |
| 32 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.6014 | 1.0843 | | 93,007 | 161,851 | | 254,858 |
| 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 | - | 1.3711 | | | 487,684 | | 487,684 |
| 36 | Texas Gas Transmission - Unnominated Injection | (810,843) | (810,843) | 0.5171 | 1.2922 | | (419,287) | (1,047,771) | | (1,467,058) |
| 37 | Texas Gas Transmission - Unnominated Withdrawal | 5,074 | 5,074 | 0.5171 | 1.2923 | | 2,624 | 6,557 | | 9,181 |
| 38 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 36,000 | (84,000) | | (48,000) |
| 39 | Rockies Express - Delivered Supply - (BP REX) | - | 309,504 | - | 1.2871 | | - | 398,350 | | 398,350 |
| 40 | Rockies Express - Delivered Supply - (BP PEAK) | - | 310,000 | - | 1.1050 | | - | 342,550 | | 342,550 |
| 41 | Rockies Express - EAST | 20,000 | - | 16.7292 | - | | 334,583 | - | | 334,583 |
| 42 | Intraday Purchases | | 25,000 | - | 1.6920 | | | 42,300 | | 42,300 |
| 43 | Fuel Retention Volumes | | - | - | - | | | | | - |
| 44 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity) | | 147,556 | - | 1.4402 | | | 212,503 | | 212,503 |
| 45 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 46 | Hedging Transaction Cost | | | - | - | | | 31,406 | | 31,406 |
| 47 | Imbalance | | 22,961 | - | 1.2257 | | | 28,143 | | 28,143 |
| 48 | Utilization Fee | | | - | - | | (243,750) | | | (243,750) |
| 49 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 50 | Contract Services | | - | - | - | | - | - | | - |
| 51 | Third Party Supplier Balancing Gas Costs | | 32,866 | - | | | | (56,960) | | (56,960) |
| 52 | Boil-off / Peaking purchase | | 37,476 | - | 1.4950 | | | 56,027 | | 56,027 |
| 53 | MGT Cash Out Imbalance | | (324) | - | (14.0679) | | | 4,558 | | 4,558 |
| 54 | NSS Injection fuel loss | | (970) | | | | | | | |
| 55 | Backup Supply Sales | | - | | - | | | - | | - |
| 56 | Sub-total | | 1,268,576 | | | | $ 680,516 | $ 1,554,893 | $ - | $ 2,235,409 |

**Citizens Gas**
**Purchased Gas Cost - Per Books**
**August 2020**

| Line No. | | A<br>Demand - Dth | B<br>Commodity Dth | C<br>Demand $/Unit | D<br>Commodity $/Dth | E<br>Other $/Unit | F<br>Demand (A x C) | G<br>Commodity (B x D) | H<br>Other | I<br>Total (F + G + H) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Accrual -August, 2020 | | | | | | | | | |
| | Exelon Generation Company | | | | | | | | | |
| 57 | Panhandle Eastern Pipeline - TOR | 33,463 | 679,582 | $ 13.3194 | $ 1.7177 | | $ 445,707 | $ 1,167,344 | | $ 1,613,051 |
| 58 | MGT Pipeline | 1,395,000 | - | 0.0620 | - | | 86,504 | 681 | | 87,185 |
| 59 | Indiana Municipal Gas Purchasing Authority - TOR | | 5,735 | - | 1.7168 | | | 9,846 | | 9,846 |
| 60 | Indiana Municipal Gas Purchasing Authority - Prepay | 5,000 | 149,265 | 18.6192 | 1.3855 | | 93,096 | 206,801 | | 299,897 |
| 61 | Texas Gas Transmission - Nominated Demand | 974,113 | | 0.3543 | - | | 345,128 | | | 345,128 |
| 62 | Texas Gas Transmission - Unnominated Demand | - | | - | - | | - | | | - |
| 63 | Texas Gas Transmission - Commodity - TOR | | 355,694 | - | 1.7332 | | | 616,472 | | 616,472 |
| 64 | Texas Gas Transmission - Unnominated Injection | (443,100) | (443,100) | 0.5624 | 1.6062 | | (249,199) | (711,707) | | (960,906) |
| 65 | Texas Gas Transmission - Unnominated Withdrawal | 1,269 | 1,269 | 0.5626 | 1.6060 | | 714 | 2,038 | | 2,752 |
| 66 | Texas Gas Transmission - Unomminated Seasonal GasStorage Refill | | | - | - | | 58,000 | ($1,700) | | 56,300 |
| 67 | Rockies Express - Delivered Supply - (BP REX) | | 309,504 | - | 1.6466 | | - | 509,640 | | 509,640 |
| 68 | Rockies Express - Delivered Supply - (BP PEAK) | | 310,000 | - | 1.4640 | | - | 453,840 | | 453,840 |
| 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) | | - | - | - | | | - | | - |
| 73 | TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand) | | | - | - | | | | | - |
| 74 | Hedging Transaction Cost | | | - | - | | | 32,744 | | 32,744 |
| 75 | Imbalance | | 1,960 | - | 1.6056 | | | 3,147 | | 3,147 |
| 76 | Utilization Fee | | | - | - | | (243,750) | | | (243,750) |
| 77 | Net Demand Cost Charges - AMA | | | - | - | | - | | | - |
| 78 | Contract Services | | - | - | - | | | - | | - |
| 79 | Third Party Supplier Balancing Gas Costs | | 47,393 | - | | | | (21,704) | | (21,704) |
| 80 | Boil-off / Peaking purchase | | 29,784 | - | 1.8540 | | | 55,220 | | 55,220 |
| 81 | MGT Cash Out Imbalance | | - | - | - | | | - | | - |
| 82 | NSS Injection fuel loss | | (314) | | | | | | | - |
| 83 | Backup Supply Sales | | - | | - | | | - | | - |
| 84 | Sub-total | | 1,446,772 | | | | 870,783 | 2,322,662 | $ - | 3,193,445 |
| 85 | Total Purchased Costs (line 56 + line 84 - line 28) | | 1,446,448 | | | | $870,703 | $2,325,261 | $0 | $3,195,964 |
| 86 | Total TGT Unnominated Demand Cost (line 62+ line 34 - line 6) | | | | | | - | | | |
| 87 | Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86) | | 1,446,448 | | | | $870,703 | | | |
| 88 | TGT Unnominated Demand Cost - Retail (line 86 * 90%) | | | | | | $0 | | | |
| 89 | Balancing Demand Cost (line 86 * 10%) | | | | | | $0 | | | |

Citizens Gas
Actual Information
For Three Months Ending August 31, 2020

| | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | June 2020 | Volumes in Dths | Commodity Cost per Dth | % of Total | Reference |
| 1 | Intraday Purchases | 26,000 | $ 1.7962 | 1.10% | Sch8A, lns 14, 42, 70 |
| 2 | Index Purchases / Spot | 1,785,062 | $ 1.5074 | 75.27% | 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 | 463,428 | $ 1.4881 | 19.54% | Sch8A, lns 16, 44, 72 |
| 4 | Boil off/Peaking Purchases | 43,151 | $ 1.7220 | 1.82% | Sch8A, lns 24, 52, 80 |
| 5 | Unnominated Seasonal Gas Purchases | - | | 0.00% | |
| 6 | Storage Withdrawal | 53,868 | $ 1.5113 | 2.27% | Sch8A, lns 9, 37, 65 |
| 7 | Total Purchases | 2,371,509 | | 100.00% | |
| 8 | Contract Services | - | | | Sch8A, lns 22,50,78 |
| 9 | Third Party | 33,638 | | | Sch8A, lns 23, 51, 79 |
| 10 | Imbalance | 6,481 | | | Sch8A, lns 19, 47, 75 |
| 11 | Fuel Retention | - | | | Sch8A, lns 15, 43, 71 |
| 12 | MGT Cash Out Imbalance | (1,337) | | | Sch8A, lns 25, 53, 81 |
| 13 | Unnominated Seasonal Gas Payback | - | | | |
| 14 | NNS Injection Loss | (2,138) | | | Sch8A, lns 26, 54, 82 |
| 15 | Backup Supply Sales | - | | | Sch8A, lns 27, 55, 83 |
| 16 | Storage Injection | (527,383) | $ 1.5113 | | Sch8A, lns 8, 36, 64 |
| 17 | Net Purchases | 1,880,770 | | | |
| | July 2020 | Volumes in Dths | Commodity Cost per Dth | % of Total | |
| 18 | Intraday Purchases | 25,000 | $ 1.7000 | 1.23% | Sch8B, lns 14, 42, 70 |
| 19 | Index Purchases | 1,809,780 | $ 1.3052 | 89.38% | 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 | 147,556 | $ 1.4402 | 7.29% | Sch8B, lns 16, 44, 72 |
| 21 | Boil off/Peaking Purchases | 37,476 | $ 1.4950 | 1.85% | Sch8B, lns 24, 52, 80 |
| 22 | Unnominated Seasonal Gas Purchases | - | | 0.00% | |
| 23 | Storage Withdrawal | 5,074 | $ 1.2972 | 0.25% | Sch8B, lns 9, 37, 65 |
| 24 | Total Purchases | 2,024,886 | | 100.00% | |
| 25 | Contract Services | - | | | Sch8B, lns 22,50,78 |
| 26 | Third Party | 32,866 | | | Sch8B, lns 23, 51, 79 |
| 27 | Imbalance | 22,961 | | | Sch8B, lns 19, 47, 75 |
| 28 | Fuel Retention | - | | | Sch8B, lns 15, 43, 71 |
| 29 | MGT Cash Out Imbalance | 552 | | | Sch8B, lns 25, 53, 81 |
| 30 | Unnominated Seasonal Gas Payback | - | | | |
| 31 | NNS Injection Loss | (970) | | | Sch8B, lns 26, 54, 82 |
| 32 | Backup Supply Sales | - | | | Sch8B, lns 27, 55, 83 |
| 33 | Storage Injection | (810,843) | $ 1.2902 | | Sch8B, lns 8, 36, 64 |
| 34 | Net Purchases | 1,269,452 | | | |
| | August 2020 | Volumes in Dths | Commodity Cost per Dth | % of Total | |
| 35 | Intraday Purchases | - | $ - | 0.00% | Sch8C, lns 14, 42, 70 |
| 36 | Index Purchases | 1,809,780 | $ 1.6381 | 98.31% | 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 | - | $ - | 0.00% | Sch8C, lns 16, 44, 72 |
| 38 | Boil off/Peaking Purchases | 29,784 | $ 1.8540 | 1.62% | Sch8C, lns 24, 52, 80 |
| 39 | Unnominated Seasonal Gas Purchases | - | | 0.00% | |
| 40 | Storage Withdrawal | 1,269 | $ 1.6162 | 0.07% | Sch8C, lns 9, 37, 65 |
| 41 | Total Purchases | 1,840,833 | | 100.00% | |
| 42 | Contract Services | - | | | Sch8C, lns 22,50,78 |
| 43 | Third Party | 47,393 | | | Sch8C, lns 23, 51, 79 |
| 44 | Imbalance | 1,960 | | | Sch8C, lns 19, 47, 75 |
| 45 | Fuel Retention | - | | | Sch8C, lns 15, 43, 71 |
| 46 | MGT Cash Out Imbalance | (324) | | | Sch8C, lns 25, 53, 81 |
| 47 | Unnominated Seasonal Gas Payback | | | | |
| 48 | NNS Injection Loss | (314) | | | Sch8C, lns 26, 54, 82 |
| 49 | Backup Supply Sales | - | | | Sch8C, lns 27, 55, 83 |
| 50 | Storage Injection | (443,100) | $ 1.6108 | | Sch8C, lns 8, 36, 64 |
| 51 | Net Purchases | 1,446,448 | | | |

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

| Line No. | Description | June 2020 Dth | June 2020 Rate | June 2020 Amount | July 2020 Dth | July 2020 Rate | July 2020 Amount | August 2020 Dth | August 2020 Rate | August 2020 Amount |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Panhandle Eastern Pipeline - Demand | 33,463 | $ 13.2172 | $ 442,288 | 33,463 | $ 13.3194 | $ 445,707 | 33,463 | $ 13.3194 | $ 445,707 |
| 2 | MGT Pipeline - Demand | 1,350,000 | 0.0641 | 86,504 | 1,395,000 | 0.0620 | 86,504 | 1,395,000 | 0.0620 | 86,504 |
| 3 | Indiana Municipal Gas Purchasing Authority - Demand | 5,000 | 18.0076 | 90,038 | 5,000 | 18.6014 | 93,007 | 5,000 | 18.6192 | 93,096 |
| 4 | Texas Gas Transmission - Nominated Demand | 942,690 | 0.3739 | 352,441 | 974,113 | 0.3913 | 381,128 | 974,113 | 0.4138 | 403,128 |
| 5 | Texas Gas Transmission - Unnominated Demand | - | - | - | - | - | - | - | - | - |
| 6 | Texas Gas Transmission - Unnominated Injections | (527,383) | 0.4439 | (234,105) | (810,843) | 0.5170 | (419,206) | (443,100) | 0.5624 | (249,199) |
| 7 | Texas Gas Transmission - Unnominated Withdrawal | 53,868 | 0.4439 | 23,912 | 5,074 | 0.5169 | 2,623 | 1,269 | 0.5626 | 714 |
| 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 | Contract Services Demand | - | - | - | - | - | - | - | - | - |
| 13 | Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity | 679,590 | 1.5832 | 1,075,900 | 679,582 | 1.4179 | 963,575 | 679,582 | 1.7187 | 1,168,025 |
| 14 | Indiana Municipal Gas Purchasing Authority - Commodity | 5,550 | 1.5820 | 8,780 | 5,735 | 1.4159 | 8,120 | 5,735 | 1.7168 | 9,846 |
| 15 | Indiana Municipal Gas Purchasing Authority - Prepay Commodity | 144,450 | 1.2505 | 180,630 | 149,265 | 1.0843 | 161,851 | 149,265 | 1.3855 | 206,801 |
| 16 | Texas Gas Transmission - Commodity | 355,680 | (0.2167) | (77,060) | 355,694 | 1.1349 | 403,684 | 355,694 | 1.7284 | 614,772 |
| 17 | Texas Gas Transmission - Unnominated Injection - Commodity | (527,383) | 1.5111 | (796,928) | (810,843) | 1.2897 | (1,045,744) | (443,100) | 1.6062 | (711,707) |
| 18 | Texas Gas Transmission - Unnominated Withdrawal - Commodity | 53,868 | 1.5111 | 81,400 | 5,074 | 1.2897 | 6,544 | 1,269 | 1.6060 | 2,038 |
| 19 | Rockies Express - Delivered Supply - (BP REX) | 299,792 | 1.5130 | 453,600 | 309,504 | 1.2871 | 398,350 | 309,504 | 1.6466 | 509,640 |
| 20 | Rockies Express - Delivered Supply - (BP PEAK) | 300,000 | 1.3320 | 399,600 | 310,000 | 1.1050 | 342,550 | 310,000 | 1.4640 | 453,840 |
| 21 | Intra-DayPurchases | 26,000 | 1.7962 | 46,700 | 25,000 | 1.6920 | 42,300 | - | - | - |
| 22 | TGT-PEPL-MGT-REX- Swing Gas (Commodity) | 463,428 | 1.4881 | 689,648 | 147,556 | 1.4402 | 212,503 | - | - | - |
| 23 | Hedging Transaction Cost | - | - | 30,394 | - | - | 31,406 | - | - | 32,744 |
| 24 | Imbalance | 6,481 | 1.1666 | 7,561 | 22,961 | 1.2233 | 28,088 | 1,960 | 1.6056 | 3,147 |
| 25 | Contract Services Commodity | - | - | - | - | - | - | - | - | - |
| 26 | Third Party Supplier Balancing Gas Costs | 33,638 | | 21,313 | 32,866 | | (56,960) | 47,393 | | (21,704) |
| 27 | Boil-off / Peaking purchase | 43,151 | 1.7220 | 74,306 | 37,476 | 1.4950 | 56,027 | 29,784 | 1.8540 | 55,220 |
| 28 | MGT Cash Out Imbalance | - | - | - | - | - | - | - | - | - |
| 29 | Fuel Retention Volumes | - | - | | - | - | | - | - | - |
| 30 | NSS Injection fuel loss | (2,138) | | - | (970) | | | (314) | | - |
| 31 | Backup Supply Sales | - | - | - | - | - | - | - | - | - |
| 32 | Current Pipeline Rate Per Dth | 1,882,107 | $1.6193 | $ 3,047,755 | 1,268,900 | $1.7597 | $ 2,232,890 | 1,446,772 | $2.2073 | $ 3,193,445 |
| 33 | Current Commodity Rate Per Dth | 1,882,107 | $1.1667 | $2,195,844 | 1,268,900 | $1.2233 | $1,552,294 | 1,446,772 | $1.6054 | 2,322,662 |

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 | May 2020 Dth | May 2020 Rate | May 2020 Amount | June 2020 Dth | June 2020 Rate | June 2020 Amount | July 2020 Dth | July 2020 Rate | July 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 | 18.5502 | 92,751 | 5,000 | 18.0076 | 90,038 | 5,000 | 18.6014 | 93,007 |
| 4 | Texas Gas Transmission - Nominated Demand | 974,113 | 0.3532 | 344,072 | 942,690 | 0.3752 | 353,679 | 974,113 | 0.3913 | 381,128 |
| 5 | Texas Gas Transmission - Unnominated Demand | - | - | - | - | - | - | - | - | - |
| 6 | Texas Gas Transmission - Unnominated Injections | (492,274) | 0.3475 | (171,065) | (527,383) | 0.4438 | (234,053) | (810,843) | 0.5171 | (419,287) |
| 7 | Texas Gas Transmission - Unnominated Withdrawal | 41,291 | 0.3475 | 14,349 | 53,868 | 0.4438 | 23,907 | 5,074 | 0.5171 | 2,624 |
| 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 | Contract Services Demand | - | - | - | - | - | - | - | - | - |
| 13 | Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity | 1,628,306 | 1.6144 | 2,628,805 | 679,590 | 1.5832 | 1,075,899 | 679,582 | 1.4179 | 963,575 |
| 14 | Indiana Municipal Gas Purchasing Authority - Commodity | 5,735 | 1.6441 | 9,429 | 5,550 | 1.5820 | 8,780 | 5,735 | 1.4159 | 8,120 |
| 15 | Indiana Municipal Gas Purchasing Authority - Prepay Commodity | 149,265 | 1.3128 | 195,951 | 144,450 | 1.2505 | 180,630 | 149,265 | 1.0843 | 161,851 |
| 16 | Texas Gas Transmission - Commodity | 355,694 | 1.9248 | 684,632 | 355,680 | (0.2167) | (77,060) | 355,694 | 1.1349 | 403,684 |
| 17 | Texas Gas Transmission - Unnominated Injection - Commodity | (492,274) | 1.6147 | (794,875) | (527,383) | 1.5118 | (797,298) | (810,843) | 1.2922 | (1,047,771) |
| 18 | Texas Gas Transmission - Unnominated Withdrawal - Commodity | 41,291 | 1.6147 | 66,673 | 53,868 | 1.5118 | 81,438 | 5,074 | 1.2923 | 6,557 |
| 19 | Rockies Express - Delivered Supply - (BP REX) | 309,504 | 1.5865 | 491,040 | 299,792 | 1.5130 | 453,600 | 309,504 | 1.2871 | 398,350 |
| 20 | Rockies Express - Delivered Supply - (BP PEAK) | 310,000 | 1.4040 | 435,240 | 300,000 | 1.3320 | 399,600 | 310,000 | 1.1050 | 342,550 |
| 21 | Intra-DayPurchases | 20,000 | 1.8500 | 37,000 | 26,000 | 1.8038 | 46,900 | 25,000 | 1.6920 | 42,300 |
| 22 | TGT-PEPL-MGT-REX- Swing Gas (Commodity) | 192,566 | 1.8080 | 348,167 | 463,428 | 1.4881 | 689,648 | 147,556 | 1.4402 | 212,503 |
| 23 | Hedging Transaction Cost | - | - | 66,617 | - | - | 30,394 | - | - | 31,406 |
| 24 | Imbalance | (22,897) | 1.6435 | (37,631) | 6,481 | 1.1674 | 7,566 | 22,961 | 1.2257 | 28,143 |
| 25 | Contract Services Commodity | - | - | - | - | - | - | - | - | - |
| 26 | Third Party Supplier Balancing Gas Costs | 45,195 | | 37,349 | 33,638 | | 21,313 | 32,866 | | (56,960) |
| 27 | Boil-off / Peaking purchase | 37,688 | 1.7940 | 67,612 | 43,151 | 1.7220 | 74,306 | 37,476 | 1.4950 | 56,027 |
| 28 | MGT Cash Out Imbalance | (1,337) | 1.6926 | (2,263) | 552 | 1.5833 | 874 | (324) | (14.0679) | 4,558 |
| 29 | Fuel Retention Volumes | - | - | - | - | - | - | - | - | - |
| 30 | NSS Injection fuel loss | (2,195) | - | - | (2,138) | - | - | (970) | - | - |
| 31 | Backup Supply Sales | - | - | - | - | - | - | - | - | - |
| 32 | Current Pipeline Rate Per Dth | 2,576,541 | $1.9937 | $ 5,136,897 | 1,882,659 | $1.6199 | $ 3,049,786 | 1,268,576 | $1.7621 | $ 2,235,409 |
| 33 | Current Commodity Rate Per Dth | 2,576,541 | $1.6432 | 4,233,746 | 1,882,659 | $1.1667 | 2,196,590 | 1,268,576 | $1.2257 | 1,554,893 |

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

**Citizens Gas**
**PEPL Unnominated Quantities Cost**
**June 2020**

| Line No. | | A Compres. Fuel-Dth | B Demand Costs | C Volumes | D Storage Rates | E Compres. Fuel | F Total |
|---|---|---|---|---|---|---|---|
| | Accrual -May, 2020 | | | | | | |
| | PEPL | | | | | | |
| 1 | Demand Cost | | $556,263 | | | | $556,263 |
| 2 | PEPL Injection fuel cost | 21,487 | | | | 42,830 | 42,830 |
| 3 | PEPL Injection (Net) | | | 800,365 | $0.0020 | | 1,601 |
| 4 | (100-day Firm) (Midpoint) | | | 814,952 | 0.0094 | | 7,661 |
| 5 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 6 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 7 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 8 | PEPL - Sub Total | | $556,263 | | | $42,830 | $608,355 |
| | Actual -May, 2020 | | | | | | |
| | PEPL | | | | | | |
| 9 | Demand Cost | | $556,263 | | | | $556,263 |
| 10 | PEPL Injection fuel cost | 21,490 | | | | 42,845 | 42,845 |
| 11 | PEPL Injection (Net) | | | 800,453 | 0.0020 | | 1,601 |
| 12 | (100-day Firm) (Midpoint) | | | 815,042 | 0.0094 | | 7,661 |
| 13 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 14 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 15 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 16 | PEPL - Sub Total | | $556,263 | | | $42,845 | $608,370 |
| | Accrual - June, 2020 | | | | | | |
| | PEPL | | | | | | |
| 17 | Demand Cost | | $543,089 | | | | $543,089 |
| 18 | PEPL Injection fuel cost | 17,857 | | | | 28,916 | 28,916 |
| 19 | PEPL Injection (Net) | | | 664,990 | 0.0020 | | 1,330 |
| 20 | (100-day Firm) (Midpoint) | | | 677,111 | 0.0094 | | 6,365 |
| 21 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 22 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 23 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 24 | PEPL - Sub Total | | $543,089 | | | $28,916 | $579,700 |
| 25 | Total ( line 24 + line 16 - line 8) | | $543,089 | | | $28,931 | $579,715 |
| 26 | PEPL - Balancing Costs (ln 25 * 9%) | | | | | | $52,174 |
| 27 | PEPL - Retail Costs (ln 25 * 91%) | | | | | | $527,541 |

**Citizens Gas**
**PEPL Unnominated Quantities Cost**
**July 2020**

| Line No. | | A Compres. Fuel-Dth | B Demand Costs | C Volumes | D Storage Rates | E Compres. Fuel | F Total |
|---|---|---|---|---|---|---|---|
| | Accrual - June, 2020 | | | | | | |
| | PEPL | | | | | | |
| 1 | Demand Cost | | $543,089 | | | | $543,089 |
| 2 | PEPL Injection fuel cost | 17,857 | | | | 28,916 | 28,916 |
| 3 | PEPL Injection (Net) | | | 664,990 | $0.0020 | | 1,330 |
| 4 | (100-day Firm) (Midpoint) | | | 677,111 | 0.0094 | | 6,365 |
| 5 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 6 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 7 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 8 | PEPL - Sub Total | | $543,089 | | | $28,916 | $579,700 |
| | Actual - June, 2020 | | | | | | |
| | PEPL | | | | | | |
| 9 | Demand Cost | | $543,089 | | | | $543,089 |
| 10 | PEPL Injection fuel cost | 17,857 | | | | 28,927 | 28,927 |
| 11 | PEPL Injection (Net) | | | 664,990 | 0.0020 | | 1,330 |
| 12 | (100-day Firm) (Midpoint) | | | 677,111 | 0.0094 | | 6,365 |
| 13 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 14 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 15 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 16 | PEPL - Sub Total | | $543,089 | | | $28,927 | $579,711 |
| | Accrual - July, 2020 | | | | | | |
| | PEPL | | | | | | |
| 17 | Demand Cost | | $556,263 | | | | $556,263 |
| 18 | PEPL Injection fuel cost | 17,337 | | | | 30,508 | 30,508 |
| 19 | PEPL Injection (Net) | | | 645,770 | 0.0020 | | 1,292 |
| 20 | (100-day Firm) (Midpoint) | | | 657,537 | 0.0094 | | 6,181 |
| 21 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 22 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 23 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 24 | PEPL - Sub Total | | $556,263 | | | $30,508 | $594,244 |
| 25 | Total ( line 24+ line 16 - line 8) | | $556,263 | | | $30,519 | $594,255 |
| 26 | PEPL Balancing Costs (ln 25 * 9%) | | | | | | $53,483 |
| 27 | PEPL Retail Costs (ln 25 * 91%) | | | | | | $540,772 |

**Citizens Gas**
**PEPL Unnominated Quantities Cost**
**August 2020**

| Line No. | | A<br>Compres. Fuel-Dth | B<br>Demand Costs | C<br>Volumes | D<br>Storage Rates | E<br>Compres. Fuel | F<br>Total |
|---|---|---|---|---|---|---|---|
| | Accrual - July, 2020 | | | | | | |
| | PEPL | | | | | | |
| 1 | Demand Cost | | $556,263 | | | | $556,263 |
| 2 | PEPL Injection Fuel Cost | 17,337 | | | | 30,508 | 30,508 |
| 3 | PEPL Injection (Net) | | | 645,770 | $0.0020 | | 1,292 |
| 4 | (100-day Firm) (Midpoint) | | | 657,537 | 0.0094 | | 6,181 |
| 5 | PEPL Withdrawal Fuel Cost | - | | | | - | - |
| 6 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 7 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 8 | PEPL Total | | $556,263 | | | $30,508 | $594,244 |
| | Actual - July, 2020 | | | | | | |
| | PEPL | | | | | | |
| 9 | Demand Cost | | $556,263 | | | | $556,263 |
| 10 | PEPL Injection Fuel Cost | 17,337 | | | | 30,550 | 30,550 |
| 11 | PEPL Injection (Net) | | | 645,770 | $0.0020 | | 1,292 |
| 12 | (100-day Firm) (Midpoint) | | | 657,537 | 0.0094 | | 6,181 |
| 13 | PEPL Withdrawal Fuel Cost | - | | | | - | - |
| 14 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 15 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 16 | PEPL Total | | $556,263 | | | $30,550 | $594,286 |
| | Accrual -August, 2020 | | | | | | |
| | PEPL | | | | | | |
| 17 | Demand Cost | | $556,263 | | | | $556,263 |
| 18 | PEPL Injection Fuel Cost | 22,483 | | | | 49,627 | 49,627 |
| 19 | PEPL Injection (Net) | | | 837,293 | $0.0020 | | 1,675 |
| 20 | (100-day Firm) (Midpoint) | | | 852,555 | 0.0094 | | 8,014 |
| 21 | PEPL Withdrawal fuel cost | - | | | | - | - |
| 22 | PEPL Withdrawal (Midpoint) | | | - | 0.0020 | | - |
| 23 | (100-day Firm) (Net) | | | - | 0.0094 | | - |
| 24 | PEPL Total | | $556,263 | | | $49,627 | $615,579 |
| 25 | Total ( line 24 + line 16 - line 8) | | $556,263 | | | $49,669 | $615,621 |
| 26 | PEPL Balancing Costs (ln 25 * 9%) | | | | | | $55,406 |
| 27 | PEPL Retail Costs (ln 25 * 91%) | | | | | | $560,215 |

**Citizens Gas**
**Cost of Gas Injections and Withdrawals**
**For the period June 1, 2020 - August 31, 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 |
| | June 2020 | | | | | | | | | |
| 1 | UGS | 733,274 | - | $332,186 | $855,450 | $0 | $0 | ($332,186) | ($855,450) | ($1,187,636) |
| 2 | PEPL | 682,938 | - | 309,498 | 796,746 | - | - | (309,498) | (796,746) | (1,106,244) |
| 3 | Subtotal | 1,416,212 | - | $641,684 | $1,652,196 | $0 | $0 | ($641,684) | ($1,652,196) | ($2,293,880) |
| | July 2020 | | | | | | | | | |
| 4 | UGS | 166,625 | - | $89,818 | $203,832 | $0 | $0 | ($89,818) | ($203,832) | ($293,650) |
| 5 | PEPL | 663,107 | - | 356,100 | 811,179 | - | - | (356,100) | (811,179) | (1,167,279) |
| 6 | Subtotal | 829,732 | - | 445,918 | 1,015,011 | - | - | (445,918) | (1,015,011) | (1,460,929) |
| | August 2020 | | | | | | | | | |
| 7 | UGS | 127,466 | - | $76,722 | $205,034 | $0 | $0 | ($76,722) | ($205,034) | ($281,756) |
| 8 | PEPL | 859,776 | - | 517,501 | 1,381,875 | - | - | (517,501) | (1,381,875) | (1,899,376) |
| 9 | Subtotal | 987,242 | - | 594,223 | 1,586,909 | - | - | (594,223) | (1,586,909) | (2,181,132) |
| 10 | Grand Total | 3,233,186 | - | $1,681,825 | $4,254,116 | $0 | $0 | $ (1,681,825) | $ (4,254,116) | $ (5,935,941) |

**Citizens Gas**
**Demand Allocation of Injections and Withdrawals**
**From PEPL**
**For Three Months Ending August 31, 2020**

| Line No. | | A Volume DTH | B Demand Cost | C Commodity Cost | D Total Cost | E Total $/DTH | F Commodity $/DTH |
|---|---|---|---|---|---|---|---|
| 1 | Beginning balance @ June 2020 | 2,526,642 | $1,072,612 | $4,265,670 | $5,338,282 | $2.1128 | $1.6883 |
| 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 | (821,852) | (287,649) | (1,350,549) | (1,638,198) | 1.9933 | 1.6433 |
| 8 | Prior mo. actual | 821,943 | 288,091 | 1,350,617 | 1,638,708 | 1.9937 | 1.6432 |
| 9 | Current mo. accrual | 682,847 | 309,056 | 796,678 | 1,105,734 | 1.6193 | 1.1667 |
| 10 | Less: Compressor Fuel | | | | | | |
| 11 | Prior mo. accrual reversal - W/D | - | - | - | - | - | - |
| 12 | Prior mo. accrual reversal - Injections | 21,487 | 7,520 | 35,310 | 42,830 | 1.9933 | 1.6433 |
| 13 | Prior mo. Actual - W/D | - | - | - | - | - | - |
| 14 | Prior mo. Actual - Injections | (21,490) | (7,533) | (35,312) | (42,845) | 1.9937 | 1.6432 |
| 15 | Current mo. Accrual -Inj | (17,857) | (8,082) | (20,834) | (28,916) | 1.6193 | 1.1667 |
| 16 | Current mo. Accrual-W/D | - | - | - | - | - | - |
| 17 | Beginning balance @ July 2020 | 3,191,720 | 1,374,015 | 5,041,580 | 6,415,595 | 2.0101 | 1.5796 |
| 18 | Less: Net W/D @ avg. unit cost | | | | | | |
| 19 | Prior mo. accrual reversal | - | - | - | - | - | - |
| 20 | Prior mo. actual | - | - | - | - | - | - |
| 21 | Current mo. accrual | - | - | - | - | - | - |
| 22 | Add: Gross Injections | | | | | | |
| 23 | Prior mo. accrual reversal | (682,847) | (309,056) | (796,678) | (1,105,734) | 1.6193 | 1.1667 |
| 24 | Prior mo. actual | 682,847 | 309,466 | 796,678 | 1,106,144 | 1.6199 | 1.1667 |
| 25 | Current mo. accrual | 663,107 | 355,690 | 811,179 | 1,166,869 | 1.7597 | 1.2233 |
| 26 | Less: Compressor Fuel | | | | | | |
| 27 | Prior mo. accrual reversal - W/D | - | - | - | - | - | - |
| 28 | Prior mo. accrual reversal - Inj | 17,857 | 8,082 | 20,834 | 28,916 | 1.6193 | 1.1667 |
| 29 | Prior mo. Actual - W/D | - | - | - | - | - | - |
| 30 | Prior mo. Actual - Injections | (17,857) | (8,093) | (20,834) | (28,927) | 1.6199 | 1.1667 |
| 31 | Current mo. accrual - Inj | (17,337) | (9,300) | (21,208) | (30,508) | 1.7597 | 1.2233 |
| 32 | Current mo. Accrual-W/D | - | - | - | - | - | - |
| 33 | Beginning balance @ August 2020 | 3,837,490 | 1,720,804 | 5,831,551 | 7,552,355 | 1.9680 | 1.5196 |
| 34 | Less: Net W/D @ avg. unit cost | | | | | | |
| 35 | Prior mo. accrual reversal | - | - | - | - | - | - |
| 36 | Prior mo. actual | - | - | - | - | - | - |
| 37 | Current mo. accrual | - | - | - | - | - | - |
| 38 | Add: Gross Injections | | | | | | |
| 39 | Prior mo. accrual reversal | (663,107) | (355,690) | (811,179) | (1,166,869) | 1.7597 | 1.2233 |
| 40 | Prior mo. actual | 663,107 | 355,691 | 812,770 | 1,168,461 | 1.7621 | 1.2257 |
| 41 | Current mo. Accrual | 859,776 | 517,500 | 1,380,284 | 1,897,784 | 2.2073 | 1.6054 |
| 42 | Less: Compressor Fuel | | | | | | |
| 43 | Prior mo. accrual reversal - W/D | - | - | - | - | - | - |
| 44 | Prior mo. accrual reversal - Inj | 17,337 | 9,300 | 21,208 | 30,508 | 1.7597 | 1.2233 |
| 45 | Prior mo. Actual - W/D | - | - | - | - | - | - |
| 46 | Prior mo. Actual - Injections | (17,337) | (9,300) | (21,250) | (30,550) | 1.7621 | 1.2257 |
| 47 | Current mo. accrual -Inj | (22,483) | (13,533) | (36,094) | (49,627) | 2.2073 | 1.6054 |
| 48 | Current mo. Accrual-W/D | - | - | - | - | - | - |
| 49 | Ending balance @ August 31, 2020 | 4,674,783 | 2,224,772 | 7,177,290 | 9,402,062 | $2.0112 | $1.5353 |

**Citizens Gas**
**Demand Allocation of Injections and Withdrawals**
**From UGS**
**For Three Months Ending August 31, 2020**

| Line No. | | A<br>Volume | B<br>Demand Cost | C<br>Commodity Cost | D<br>Total Cost | E<br>Total $/Unit | F<br>Commodity $/Unit |
|---|---|---|---|---|---|---|---|
| 1 | Beginning balance @ June 2020 | 6,316,228 | $2,787,595 | $12,605,164 | $15,392,759 | $2.4370 | $1.9957 |
| 2 | Add: Gross Injections | | | | | | |
| 3 | Less: Prior mo. accrual | (611,025) | (213,859) | (1,004,097) | (1,217,956) | 1.9933 | 1.6433 |
| 4 | Add: Prior mo. actual | 611,025 | 214,165 | 1,004,036 | 1,218,201 | 1.9937 | 1.6432 |
| 5 | Add: Current mo. accrual | 733,274 | 331,880 | 855,511 | 1,187,391 | 1.6193 | 1.1667 |
| 6 | Less: Net Withdrawals | | | | | | |
| 7 | Prior mo. accrual reversal | 2,662 | 1,201 | 5,413 | 6,614 | 2.4845 | 2.0334 |
| 8 | Prior mo. Actual | (2,662) | (1,201) | (5,413) | (6,614) | 2.4845 | 2.0334 |
| 9 | Current mo. accrual | - | - | - | - | - | - |
| 10 | Less: Blowoff | | | | | | |
| 11 | Current mo. Blowoff | (3,666) | (1,618) | (7,316) | (8,934) | 2.4371 | 1.9957 |
| 12 | Beginning balance @ July 2020 | 7,045,836 | 3,118,163 | 13,453,298 | 16,571,461 | 2.3520 | 1.9094 |
| 13 | Add: Gross Injections | | | | | | |
| 14 | Less: Prior mo. accrual | (733,274) | (331,880) | (855,511) | (1,187,391) | 1.6193 | 1.1667 |
| 15 | Add: Prior mo. actual | 733,274 | 332,320 | 855,511 | 1,187,831 | 1.6199 | 1.1667 |
| 16 | Add: Current mo. accrual | 166,625 | 89,378 | 203,832 | 293,210 | 1.7597 | 1.2233 |
| 17 | Less: Net Withdrawals | | | | | | |
| 18 | Prior mo. accrual reversal | - | - | - | - | - | - |
| 19 | Prior mo. actual | - | - | - | - | - | - |
| 20 | Current mo. accrual | - | - | - | - | - | - |
| 21 | Less: Blowoff | | | | | | |
| 22 | Current mo. Blowoff | (834) | (370) | (1,592) | (1,962) | 2.3520 | 1.9094 |
| 23 | Beginning balance @ August 2020 | 7,211,627 | 3,207,611 | 13,655,538 | 16,863,149 | 2.3383 | 1.8935 |
| 24 | Add: Injections | | | | | | |
| 25 | Less: Prior mo. accrual | (166,625) | (89,378) | (203,832) | (293,210) | 1.7597 | 1.2233 |
| 26 | Prior mo. actual | 166,625 | 89,378 | 204,232 | 293,610 | 1.7621 | 1.2257 |
| 27 | Current mo. accrual | 127,466 | 76,722 | 204,634 | 281,356 | 2.2073 | 1.6054 |
| 28 | Less: Withdrawals | | | | | | |
| 29 | Prior mo. accrual reversal | - | - | - | - | - | - |
| 30 | Prior mo. actual | - | - | - | - | - | - |
| 31 | Current mo. Accrual | - | - | - | - | - | - |
| 32 | Less: Blowoff | | | | | | |
| 33 | Current mo. Blowoff | (636) | (283) | (1,204) | (1,487) | 2.3384 | 1.8936 |
| 34 | Ending balance @ August 31, 2020 | 7,338,457 | 3,284,050 | 13,859,368 | 17,143,418 | $2.3361 | $1.8886 |

**Citizens Gas**
**Determination of "Unaccounted For" Percentage and Manufacturing / Steam Division Costs**
**For Three Months Ending August 31, 2020**

| Line No. | | A June 2020 | B July 2020 | C August 2020 | D Total |
|---|---|---|---|---|---|
| 1 | Volume of pipeline gas purchases - Dths (See Schedule 8) | 1,880,770 | 1,269,452 | 1,446,448 | 4,596,670 |
| 2 | Gas (injected into) withdrawn from storage (See Schedule 10) | (1,416,212) | (829,732) | (987,242) | (3,233,186) |
| 3 | Transported gas received | 1,144,712 | 1,081,994 | 1,053,787 | 3,280,493 |
| 4 | Transported gas (injected into) withdrawn from storage | 0 | 0 | 0 | 0 |
| 5 | Reverse transport imbalance already on Sch 8 | (33,638) | (32,866) | (47,393) | (113,897) |
| 6 | Total volume supplied | 1,575,632 | 1,488,848 | 1,465,600 | 4,530,080 |
| 7 | Less:  Gas Division usage | (4,260) | (939) | (444) | (5,643) |
| 8 | Total volume available for sale | 1,571,372 | 1,487,909 | 1,465,156 | 4,524,437 |
| 9 | Retail Volume of gas sold - Dths (Schedule 6, Page 3, ln 26) | 597,350 | 488,067 | 474,013 | 1,559,430 |
| 10 | Total Transport Usage (Sch 6 , Page 3, ln 27 + ln 28) | 1,083,436 | 1,086,287 | 1,059,224 | 3,228,947 |
| 11 | "Unaccounted for" gas (ln 8- ln 9 - ln 10) | (109,414) | (86,445) | (68,081) | (263,940) |
| 12 | Percentage of "unaccounted for" gas (line 11 / line 8) | -6.96% | -5.81% | -4.65% | -5.83% |

**Citizens Gas**
**Annual True-Up for Cost of Unaccounted for (UAF) Gas**
**For the Period of September 2019 To August 2020**

| | | A | B | C | D | E |
|---|---|---|---|---|---|---|
| | | Volume of Gas Available (Dth) | Volume of Gas Delivered To Customers (Dth) | Volume of UAF Gas (Dth) | Percent of UAF Gas | Actual Commodity Costs |
| | | Sch 11, ln 8 | Sch 11, ln 9 & ln 10 | col. A - col. B | col. C / col. A | Sch 7 pg 1, ln 5 - ln 3 |
| 1 | September '19 | 1,779,395 | 1,770,926 | 8,469 | 0.48% | $770,276 |
| 2 | October | 2,870,475 | 2,864,996 | 5,479 | 0.19% | 2,596,844 |
| 3 | November | 5,669,675 | 5,624,165 | 45,510 | 0.80% | 8,350,810 |
| 4 | December | 6,616,953 | 6,511,243 | 105,710 | 1.60% | 8,997,951 |
| 5 | January '20 | 7,161,237 | 7,062,668 | 98,569 | 1.38% | 9,011,168 |
| 6 | February | 7,033,714 | 6,959,322 | 74,392 | 1.06% | 9,198,404 |
| 7 | March | 4,816,353 | 4,774,191 | 42,162 | 0.88% | 4,778,821 |
| 8 | April | 3,331,615 | 3,293,398 | 38,217 | 1.15% | 2,661,216 |
| 9 | May | 2,357,188 | 2,290,180 | 67,008 | 2.84% | 1,885,191 |
| 10 | June | 1,571,372 | 1,680,786 | (109,414) | -6.96% | 541,291 |
| 11 | July | 1,487,909 | 1,574,354 | (86,445) | -5.81% | 538,029 |
| 12 | August | 1,465,156 | 1,533,237 | (68,081) | -4.65% | 738,352 |
| 13 | 12-month total | 46,161,042 | 45,939,466 | 221,576 | 0.4800% | $50,068,353 |

| | | | | |
|---|---|---|---|---|
| 14 | Actual UAF % - 12 Months Ended (ln. 13, col. D) | | | 0.4800% |
| 15 | Maximum UAF % collected in GCA rate - | | | 1.3600% |
| 16 | UAF % Adjustment (0 if actual < maximum) | 1/ | | 0.0000% |
| 17 | Actual Commodity Costs (ln. 13, col. E) | | $ | 50,068,353 |
| 18 | UAF Refund - (ln. 16 X ln. 17) | | $ | - |

1/ If actual UAF % is less than the maximum UAF % no adjustment is necessary.
If actual UAF % exceeds the maximum UAF %, then a refund is necessary for the difference between maximum UAF% and the actual UAF%.

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

| | Quarter | A<br>Sales %<br>(All GCA Classes) | B<br>Refund<br>(line 6 * column A) |
|---|---|---|---|
| 7 | Dec., 2020- Feb., 2021 | 54.9901% (Sch. 2B, ln 18) | $0 |
| 8 | March 2021 - May 2021 | 26.1892% (Sch. 2B, ln 19) | $0 |
| 9 | June 2021 - August 2021 | 5.3155% (Sch. 2B, ln 20) | $0 |
| 10 | Sept., 2021 - Nov., 2021 | 13.5052% (Sch. 2B, ln 21) | $0 |
| 11 | Total | | $0 |

Calculation of Refund to be Returned in this GCA

| | | |
|---|---|---|
| 12 | Refund from Cause No. 37399-GCA 145 | $0 |
| 13 | Refund from Cause No. 37399-GCA 146 | 0 |
| 14 | Refund from Cause No. 37399-GCA 147 | 0 |
| 15 | Refund from this Cause (line 7) | 0 |
| 16 | Total to be refunded in this Cause<br>(Sum of lines 12 through 15) | $0 |

**Citizens Gas**
**Allocation of Gas Supply Variance**

| Line No. | | A<br>Gas Rate No. D1 | B<br>Gas Rate No. D2 | C<br>Gas Rate No. D3/ No. D7 | D<br>Gas Rate No. D4 | E<br>Gas Rate No. D5 | F<br>Gas Cost Variances |
|---|---|---|---|---|---|---|---|
| | Calculation of Total Gas Cost Variances | | | | | | |
| 1 | Jun., 2020 Total Gas Supply Variance (Sch 6A, pg. 1,ln 16 ) | (4,358) | (427,085) | (21,961) | (202,217) | 0 | (655,621) |
| 2 | Jul., 2020 Total Gas Supply Variance (Sch 6B, pg. 1, ln 16) | (2,932) | (181,230) | (13,991) | (125,640) | 0 | (323,793) |
| 3 | Aug, 2020 Total Gas Supply Variance (Sch 6C, pg. 1, ln 16 ) | (116) | (12,067) | (10,164) | (67,700) | 0 | (90,047) |
| 4 | Total Net Write Off Gas Cost Variance (over)/under recover (Sch 12C, ln19) | (53) | (9,181) | 62 | (1,709) | 32 | (10,849) |
| 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) | ($7,459) | ($629,563) | ($46,054) | ($397,266) | $32 | (1,080,310) |
| | Distribution of variances to quarters by rate class | | | | | | |
| 7 | First quarter<br>Total Gas Supply Variance (ln 6 * Sch 2B, ln 18) | ($3,755) | ($348,217) | ($10,261) | ($224,147) | $0 | ($586,380) |
| 8 | Second quarter<br>Total Gas Supply Variance (ln 6 * Sch 2B, ln 19) | (1,727) | (167,379) | (10,280) | (100,940) | 0 | (280,326) |
| 9 | Third quarter<br>Total Gas Supply Variance (ln 6 * Sch 2B, ln 20) | (699) | (27,980) | (13,011) | (24,116) | 0 | (65,806) |
| 10 | Fourth quarter<br>Total Gas Supply Variance (ln 6 * Sch 2B, ln 21) | (1,278) | (85,987) | (12,502) | (48,063) | 0 | (147,830) |
| | Calculation of variances for this Cause | | | | | | |
| 11 | Cause No. 37399 - GCA 145<br>Total Gas Supply Variance (Sch 12B pg 1, ln 10) | (2,574) | (525,422) | (9,078) | (434,226) | 0 | (971,300) |
| 12 | Cause No. 37399 - GCA 146<br>Total Gas Supply Variance (Sch 12B pg 1, ln 9) | (6,377) | (1,191,612) | 7,167 | (529,402) | 0 | (1,720,224) |
| 13 | Cause No. 37399 - GCA 147<br>Total Gas Supply Variance (Sch 12B pg 1, ln 8) | (3,712) | (244,423) | (6,791) | (148,382) | 0 | (403,308) |
| 14 | This Cause<br>Total Gas Supply Variance (line 7) | (3,755) | (348,217) | (10,261) | (224,147) | 0 | ($586,380) |
| 15 | Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (ln 11 + ln 12 + ln 13 + ln 14) | ($16,418) | ($2,309,674) | ($18,963) | ($1,336,157) | $0 | ($3,681,212) |

**Citizens Gas**
**Allocation of Balancing Demand Cost Variance**

| Line No. | | A<br>Gas Rate No. D1 | B<br>Gas Rate No. D2 | C<br>Gas Rate No. D3 / No. D7 | D<br>Gas Rate No. D4 | E<br>Gas Rate No. D5 | F<br>Gas Rate No. D9 | G<br>Balancing Demand Cost Variance |
|---|---|---|---|---|---|---|---|---|
| | Calculation of Total Balancing Demand Cost Variances | | | | | | | |
| 1 | Jun., 2020 Total Balancing Demand Cost Variance (Sch 6A, pg. 2, ln 25) | ($89) | ($7,874) | ($3,372) | ($6,814) | ($922) | $6,180 | ($12,891) |
| 2 | Jul., 2020 Total Balancing Demand Cost Variance (Sch 6B, pg. 2, ln 25) | ($84) | ($6,554) | ($3,887) | ($7,158) | ($881) | $7,710 | ($10,854) |
| 3 | Aug, 2020 Total Balancing Demand Cost Variance (Sch 6C, pg. 2, ln 25) | ($54) | ($5,921) | ($3,740) | ($6,643) | ($446) | $7,930 | ($8,874) |
| 4 | Balancing Demand Cost Variance (Line 1 + Line 2 + Line 3 ) | ($227) | ($20,349) | ($10,999) | ($20,615) | ($2,249) | $21,820 | ($32,619) |
| | Distribution of variances to quarters by rate class | | | | | | | |
| 5 | First quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 18) | ($114) | ($11,256) | ($3,127) | ($10,642) | ($773) | $4,361 | ($21,551) |
| 6 | Second quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 19) | ($53) | ($5,410) | ($2,659) | ($5,057) | ($550) | $5,914 | ($7,815) |
| 7 | Third quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 20) | ($21) | ($904) | ($2,473) | ($1,546) | ($403) | $5,645 | $298 |
| 8 | Fourth quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 21) | ($39) | ($2,779) | ($2,740) | ($3,370) | ($523) | $5,900 | ($3,551) |
| | Calculation of variances for this Cause | | | | | | | |
| 9 | Cause No. 37399 - GCA 145 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 8) | ($185) | ($29,770) | ($3,261) | ($19,392) | ($781) | $4,240 | ($49,149) |
| 10 | Cause No. 37399 - GCA 146 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 7) | ($2) | ($292) | $320 | ($2,598) | $2,278 | $2,498 | $2,204 |
| 11 | Cause No. 37399 - GCA 147 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 6) | ($9) | ($5,333) | $30 | ($2,527) | $1,863 | $4,652 | ($1,324) |
| 12 | This Cause Total Current Balancing Demand Cost Variance (line 5) | ($114) | ($11,256) | ($3,127) | ($10,642) | ($773) | $4,361 | ($21,551) |
| 13 | Total Balancing Demand Cost Variance to be included in GCA (Over)/Underrecovery (ln 9 + ln 10 + ln 11 + ln 12) | ($310) | ($46,651) | ($6,038) | ($35,159) | $2,587 | $15,751 | ($69,820) |

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

| Line No. | | A | B | C | D | E | F |
|---|---|---|---|---|---|---|---|
| | **June 2020** | | | | | | |
| | | **D1** | **D2** | **D3** | **D4** | **D5** | **Total** |
| 1 | Actual Retail Sales in Dth (Sch 6A, line 26) | 4,683 | 406,521 | 18,322 | 167,824 | - | 597,350 |
| 2 | Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 146, MPU Sch 1 pg 2, ln 23 | $0.0200 | $0.0470 | $0.0010 | $0.0120 | $0.0000 | |
| 3 | Actual Net Write Off Gas Cost Recovery (ln 1 * ln 2) | $94 | $19,106 | $18 | $2,014 | $0 | $21,232 |
| 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) | $59 | $12,796 | $36 | $1,176 | $10 | $14,077 |
| 6 | Net Write Off Gas Cost Variance (over)/under recovery (ln 5 - ln 3) | **($35)** | **($6,310)** | **$18** | **($838)** | **$10** | **($7,155)** |
| | **July 2020** | | | | | | |
| 7 | Actual Retail Sales in Dth (Sch 6B, line 26) | 4,373 | 314,063 | 16,749 | 152,882 | - | 488,067 |
| 8 | Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 146, MPU Sch 1 pg 2, ln 23 | $0.0220 | $0.0510 | $0.0010 | $0.0110 | $0.0000 | |
| 9 | Actual Net Write Off Gas Cost Recovery (ln 7 * ln 8) | $96 | $16,017 | $17 | $1,682 | $0 | $17,812 |
| 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) | $61 | $13,146 | $37 | $1,208 | $10 | $14,462 |
| 12 | Net Write Off Gas Cost Variance (over)/under recovery (ln 11 - ln 9) | **($35)** | **($2,871)** | **$20** | **($474)** | **$10** | **($3,350)** |
| | **August 2020** | | | | | | |
| 13 | Actual Retail Sales in Dth (Sch 6C, line 26) | 2,426 | 297,150 | 20,768 | 153,669 | - | 474,013 |
| 14 | Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 146, MPU Sch 1 pg 2, ln 23 | $0.0230 | $0.0530 | $0.0010 | $0.0120 | $0.0000 | |
| 15 | Actual Net Write Off Gas Cost Recovery (ln 13 * ln 14) | $56 | $15,749 | $21 | $1,844 | $0 | $17,670 |
| 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) | $73 | $15,749 | $45 | $1,447 | $12 | $17,326 |
| 18 | Net Write Off Gas Cost Variance (over)/under recovery (ln 17 - ln 15) | **$17** | **$0** | **$24** | **($397)** | **$12** | **($344)** |
| 19 | Total Net Write Off Gas Cost Variance (over)/under recovery (ln 6 + ln 12 + ln 18) | ($53) | ($9,181) | $62 | ($1,709) | 32 | ($10,849) |