Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF WESTFIELD GAS, LLC, D/B/A CITIZENS GAS OF WESTFIELD FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES; (2) APPROVAL OF CERTAIN REVISIONS TO ITS TERMS AND CONDITIONS APPLICABLE TO GAS UTILITY SERVICE; AND (3) APPROVAL PURSUANT TO INDIANA CODE SECTION 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN UNDER WHICH IT WOULD CONTINUE ITS ENERGY EFFICIENCY PROGRAM PORTFOLIO AND ENERGY EFFICIENCY RIDER	)	**CAUSE NO. 45761** **APPROVED: APR 12 2023**

ORDER OF THE COMMISSION

Presiding Officers:
Sarah E. Freeman, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On August 26, 2022, Westfield Gas, LLC, d/b/a Citizens Gas of Westfield ("Westfield Gas" or "Petitioner") filed a Verified Petition with the Indiana Utility Regulatory Commission ("Commission" or "IURC") seeking authority to increase its rates and charges for gas utility service and approval of a new schedule of rates and charges, certain revisions to its terms and conditions for gas utility service, and pursuant to Ind. Code § 8-1-2.5-6, an alternative regulatory plan under which Petitioner will continue its energy efficiency ("EE") program portfolio and Energy Efficiency Rider ("EER").

On August 26, 2022, Petitioner also filed the direct testimony and attachments of the following witnesses in support of its Verified Petition:

- J.P. Ghio, Vice President of Energy Operations for Citizens Energy Group and President of Westfield Gas
- Craig Jackson, Senior Vice President and Chief Financial Officer of Citizens Energy Group
- Adrien M. McKenzie, Vice President of FINCAP, Inc.
- Camela Johnson, Senior Accounting Manager, Shared Services and Financial Planning of Citizens Energy Group
- Sabine E. Karner, Vice President and Controller of Citizens Energy Group

- Scott A. Miller, Certified Public Accountant and a partner with Baker Tilly Municipal Advisors, LLC ("BTMA") and
- Debi Bardhan-Akala, Director, Regulatory Affairs for Citizens Energy Group.

On December 2, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed consumer comments as well as the direct testimony and attachments of the following OUCC staff:

- Mark H. Grosskopf, Senior Utility Analyst
- Linda M. Devine, Utility Analyst II
- LeCresha N. Vaulx, Gas Utility Analyst II
- Mohab M. Noureldin, Utility Analyst II
- Leja D. Courter, Chief Technical Advisor and
- Brien R. Krieger, Utility Analyst II.

On December 19, 2022, Petitioner filed a motion for protection and nondisclosure of confidential and proprietary information in which Petitioner advised certain information (the "Confidential Information") the OUCC intended to submit, specifically BTMA's cost-of-service model, provided confidentially as part of Petitioner's case-in-chief, as modified by OUCC Krieger, is proprietary, competitively sensitive, and a trade secret in nature and should be exempt from public disclosure. Confidential treatment was approved on a preliminary basis in a docket entry dated December 30, 2022.

On January 3, 2023, Petitioner filed the rebuttal testimony and attachments of the following witnesses:

- J.P. Ghio
- Craig Jackson
- Adrien M. McKenzie
- Scott A. Miller and
- Debi Bardhan-Akala.

In a docket entry issued on January 13, 2023, Petitioner was asked to provide certain additional information. Petitioner filed a motion on January 18, 2023, notifying the Commission that Westfield Gas and the OUCC had reached a settlement in principle resolving the issues in this proceeding. In light of the settlement, Petitioner requested an extension of time to respond to the docket entry if responses remained desired. Petitioner's docket entry responses were filed on January 26, 2023, consistent with a docket entry dated January 20, 2023, confirming the responses should be filed. Given the text of Petitioner's response, an additional docket entry was issued on January 30, 2023, reminding Westfield Gas that the practice before the Commission is that docket entry responses be offered into evidence at the evidentiary hearing and the need for Westfield Gas to adhere to this practice.

On January 20, 2023, Petitioner and the OUCC (the "Settling Parties") jointly filed a notice of settlement and moved to modify the procedural schedule (the "Joint Notice"). In the Joint Notice, the Settling Parties sought to continue the evidentiary hearing so their agreement could be reduced to writing and filed with the Commission, along with supportive testimony.

On February 10, 2023, the Settling Parties filed their Stipulation and Settlement Agreement ("Settlement Agreement.") Also on February 10, 2023, Petitioner filed the settlement testimony of Craig Jackson and Debi Bardhan-Akala, and the OUCC filed the settlement testimony of Heather Poole. On March 2, 2023, Westfield Gas filed a correction to an attachment to Ms. Karner's testimony.

On March 3, 2023, the Commission held a settlement hearing at 10:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC appeared, by counsel, and participated in the hearing. The cases-in-chief of Petitioner and the OUCC were admitted into the record without objection along with Petitioner's rebuttal testimony, the Settlement Agreement, and the Settling Parties' settlement testimony.

Based upon the applicable law and the evidence presented, the Commission now finds:

1. <u>Legal Notice and Commission Jurisdiction</u>. Westfield Gas published notice of filing the Verified Petition in this Cause, as required by law. Due, legal, and timely notice of the public hearing was published by the Commission.

Petitioner is a public utility under the Indiana Public Service Commission Act, Ind. Code §§ 8-1-2-1 *et seq.*, an energy utility under Ind. Code § 8-1-2.5-2, and is subject to the jurisdiction of the Commission, and the Commission has subject matter jurisdiction with respect to the matters at issue. Additionally, in accordance with Ind. Code § 8-1-2.5-4, Petitioner elected to become subject to Ind. Code §§ 8-1-2.5-5 and -6.

2. <u>Petitioner's Organization and Business</u>. Petitioner owns, operates, manages, and controls plant, property, and equipment used and useful to provide gas utility service to approximately 6,100 customers in and around the City of Westfield, Indiana. Petitioner is an Indiana limited liability company with its principal office located at 2020 North Meridian Street, Indianapolis, Indiana. Petitioner's sole membership interest is owned by Citizens Westfield Utilities, LLC, which is a subsidiary of Citizens By-Products Coal Company d/b/a Citizens Resources. Citizens Energy Group owns the stock of Citizens Resources.

3. <u>Test Year</u>. Petitioner requested the calendar year ending December 31, 2021, be used as the test year, adjusted for changes that are fixed, known, and measurable and occur within the 12 months following the end of the test year. The Commission finds the December 31, 2021, test year, as adjusted, is sufficiently representative of Petitioner's normal utility operations to provide reliable data for ratemaking purposes.

4. <u>Background and Relief Requested</u>. The Commission approved Petitioner's current base rates and charges in Cause No. 44731 in an Order approved on April 26, 2017, (the "44731 Order") based on operating results for the test year ending December 31, 2015, and the fair value of Petitioner's used and useful utility property as of April 30, 2016. Following the 44731 Order, Westfield Gas filed compliance rates that went into effect on May 1, 2017. In addition, Petitioner sought and received approval to modify its rates to remove the Indiana Utility Receipts Tax via a 30-day filing (Filing No. 50536) with these revised rates effective July 1, 2022.

In its 44731 Order, the Commission authorized Petitioner, under Ind. Code ch. 8-1-2.5, to continue its EE program portfolio, as well as an EER designed to: (i) recover costs incurred to maintain a portfolio of EE programs through a mechanism known as the Energy Efficiency Funding Component ("EEFC"); and (ii) decouple Westfield Gas' fixed cost recovery from sales of natural gas to its residential and commercial customers through a mechanism known as the Sales Reconciliation Component ("SRC"). In its Order dated November 27, 2019, in Cause No. 45263, the Commission authorized extending Petitioner's gas EE program portfolio, as well as the EER, until Petitioner's next base rate order or until Indiana Gas Company, Inc. d/b/a Vectren (n/k/a CenterPoint Energy Indiana) North's EE programs are not approved, expire, or otherwise cease, in which case Petitioner's EE portfolio and EER are to be discontinued.

In this case, Petitioner requests approval of an increase in its rates and charges for gas utility service that will enable Westfield Gas to realize net operating income adequate to provide safe, reliable, efficient, and economical gas utility service and an opportunity to earn a fair return on the fair value of the utility properties used to provide such service. Petitioner also requests approval of a new schedule of rates and charges reflecting the proposed increase and approval of revisions to its terms and conditions for gas service. In addition, Petitioner seeks to extend its EE program portfolio and authority to continue both components of the EER (*i.e.*, the EEFC and SRC.)

5. Petitioner's Evidence

A. J.P. Ghio. Mr. Ghio described the infrastructure investments Westfield Gas has made to serve the City of Westfield since Petitioner's last rate case due to the community's growth. He testified these investments increased Petitioner's rate base by 79%, from $10.8 million to $19.3 million, since 2017. Mr. Ghio testified the rapid growth in Petitioner's rate base has been commensurate with corresponding development throughout Westfield, and these investments have enabled Petitioner to continue to provide Westfield's residents with reliable and affordable energy. As a result of these infrastructure investments, Petitioner has experienced increased incremental costs including operating and maintenance costs. Mr. Ghio stated the combined circumstances of increased operating costs and Petitioner's investment in the expanding Westfield gas system prompted the requested relief Petitioner seeks in this case.

Mr. Ghio advised that Westfield's population increased by 68.38% from 2010 to 2021, and residential housing units in Westfield increased by over 5,000 since 2017. Mr. Ghio stated that from January 2017 through December 2021, Westfield Gas added approximately 1,800 customers and 50 miles of mains. The design cold peak day demand for the winter of November 2016 through March 2017 was 7,634 dekatherms, as opposed to winter 2021-2022 where the design cold peak day demand was estimated to be 10,010 dekatherms, a growth in demand of more than 30% in five years.

Mr. Ghio testified Petitioner's requested rate relief is directly tied to the growth Westfield is experiencing. Because of Westfield's growth, Petitioner invested over $8.5 million in facilities and property. As Petitioner's system has grown, Mr. Ghio stated the costs to operate and maintain the system have also grown. As a result, Petitioner's investment returns have been decreasing and do not provide a fair return. Mr. Ghio testified Petitioner's rate of return stood below 3.5% in 2021, as reported in Petitioner's 2021 Annual Report filed with the Commission. Based on trends, Mr. Ghio projects Petitioner's return on equity for 2022 to likely be lower than 3.5%.

Mr. Ghio testified that Westfield Gas began assessing the possibility of filing a rate case in late 2019 but shifted its focus from rate case planning after the COVID-19 outbreak; however, having delayed filing for rate relief for over two years, Westfield Gas has reached a point where further delay will materially impact its financial integrity. Mr. Ghio testified Petitioner is requesting approval to increase its total annual revenues by $1.29 million based on normal weather, meaning for a typical residential heating customer consuming 735 therms per year, the annual increase will be approximately $165 or 18%.

B. Craig L. Jackson. Mr. Jackson testified regarding the fair value of Petitioner's utility property under Indiana law, Petitioner's capital structure, the proposed fair rate of return for Petitioner's investment, and the importance of Petitioner's financial integrity. Mr. Jackson stated Westfield Gas is requesting a rate increase as a result of Westfield's population growth since 2017 and the related required investments Westfield Gas has made in gas infrastructure to meet the City's and its residents' needs. Mr. Jackson identified increased operating costs as an additional reason for Petitioner's rate increase request. He stated that as rate base has grown and costs have increased, Petitioner's realized rate of return declined sharply to 3.41% for calendar year 2021, materially impacting Westfield Gas' financial integrity and leading to Petitioner's requested rate increase.

Mr. Jackson defined fair value as the true current worth of property, perhaps best measured by what a third-party market participant would be willing to pay for the property. In support of his definition of fair value, Mr. Jackson cited the Commission's Order in Cause No. 39314 (the "39314 Order") and the appellate decision in *Indianapolis Water Co. v. Public Serv. Comm'n of Indiana*, 484 N.E.2d 635 (Ind. Ct. App. 1985). He differentiated fair value from original cost and cited the Commission's Order on Remand in Cause No. 37612 for the proposition that original cost is one of the factors the Commission should consider in arriving at fair value, but it is not necessarily in and of itself an accurate reflection of the fair value of Petitioner's property.

Mr. Jackson testified the fair value of utility property directly relates to the fair rate of return for a utility, as a utility's rate of return must be sufficient to allow it an opportunity to earn a fair return on the fair value of its investment in utility plant. Mr. Jackson, again citing the 39314 Order and *Indianapolis Water Co.*, stated a utility is entitled to earn a fair rate of return on the fair value of its used and useful property, and a ratemaking agency's rate of return formula must be methodically consistent with rate base development. Under these holdings, Mr. Jackson testified if property value increases and exceeds original cost, Westfield Gas is entitled to benefit from the increase via a greater dollar return, and a fair rate of return should consider the effect of inflation.

Mr. Jackson testified that he calculated Westfield Gas' fair value rate base as $22,073,595. He stated the proposed rate base was calculated using the fair value of utility plant and adding the 13-month average of inventory. Mr. Jackson testified Petitioner's fair value rate base is $8,196,110 higher than its original cost rate base of $13,877,485, as shown on Attachment CLJ-1, and

Westfield Gas' fair rate of return is 8.426%, as shown on Attachment CLJ-1, resulting in a proposed fair return of $1,859,896.

Mr. Jackson stated Petitioner's investor-supplied capital structure consists of 24.8% long-term debt, 75% common equity, and 0.2% customer deposits. He explained that Westfield Gas' capital structure has an appropriate equity component to enable Petitioner to achieve financial integrity. Per Mr. Jackson, it is not financially responsible for a company of Petitioner's size to be leveraged at levels comparable to larger investor-owned utilities ("IOU"), but as Petitioner grows, its leverage position will continue transitioning to that of a traditional IOU.

Mr. Jackson also testified about the basis for the common equity rate of 10.9%, as shown on Attachment CLJ-1, and the adjustment made to the common equity rate of 10.9% by 2.3% to account for inflation, resulting in a cost of equity of 8.6% for the fair value increment.

C. Adrien M. McKenzie. Mr. McKenzie testified regarding his assessment of a reasonable cost of equity ("COE") for Petitioner's jurisdictional gas utility operations. Mr. McKenzie's analysis included a review of fair value ratemaking and the development of a reasonable estimate of expected inflation relevant to determining a fair rate of return on fair value for Westfield Gas. Mr. McKenzie testified to the importance of financial strength for public utilities, defining financial strength as a utility's ability to attract and retain the capital that is necessary to provide service at a reasonable cost. Additionally, Mr. McKenzie testified to the role of COE in setting a utility's rates, defining COE as the cost of attracting and retaining common equity investment in a utility's physical plant and assets. He stated this investment is necessary to finance the asset base needed to provide utility service. Mr. McKenzie opined that based upon the results of five methods – the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of the CAPM ("EPCAPM"), the risk premium approach, and the expected earnings approach, the COE range is 9.6% to 10.9%.

Mr. McKenzie stated 10.90% is a conservative estimate of investors' required COE for Petitioner. He explained his conclusion is based on several factors. The risks and prospects associated with Petitioner's jurisdictional utility operations led Mr. McKenzie to focus his analysis on a proxy group of firms with gas utility operations. Because investors' required return on equity ("ROE") is unobservable and no single method should be viewed in isolation, Mr. McKenzie stated he applied the DCF, CAPM, ECAPM, risk premium, and expected earnings methods to estimate a fair COE for Westfield Gas. Based on these analyses and giving less weight to extremes at the high and low ends of the range, he concluded the COE for a regulated gas utility is in the 9.6% to 10.9% range. Mr. McKenzie testified a COE from the upper end is warranted here because of the additional uncertainties associated with Petitioner's relatively small size. Also, because the proxy group utilities operate under a wide variety of adjustment mechanisms, including decoupling, the mitigation in risks associated with Petitioner's regulatory mechanisms is already reflected in the results of Mr. McKenzie's analysis, and no separate adjustment to the COE is necessary or warranted.

Mr. McKenzie explained that investors' expectations of future inflation are likely to fall in the range of 2.3% to 3.0%. He testified that considering the implications for common equity investors and the attrition impact associated with historical cost depreciation expense, if inflation is considered in evaluating the return on fair value, he recommended using the lower end of his inflation range, or 2.3%.

Finally, Mr. McKenzie concluded Petitioner's actual capital structure, consisting of 75.00% common equity, 24.82% debt, and 0.18% customer deposits, represents a reasonable basis on which to establish Petitioner's return. This compares with a capital structure consisting of 100% common equity that was used in the Commission's determination of the fair return for Westfield Gas in its last litigated rate case, Cause No. 43624.

D. Camela A. Johnson. Ms. Johnson summarized certain pro forma adjustments, including the test year amount incurred for property taxes, depreciation, amortization expense, and cloud computing, and she described the process she used to determine pro forma adjustments to the test year. Ms. Johnson sponsored a summary of pro forma adjustments she calculated to some of Petitioner's operating test year expenses, and she described her pro forma adjustments to property taxes and depreciation expense for plant in service. She established the annual amount of Petitioner's depreciation expense on depreciable utility plant in service as of December 31, 2021, and applied pro forma depreciation rates. Ms. Johnson also included Petitioner's share of Shared Services depreciation on plant in service as of December 31, 2021, leading to a pro forma decrease of $137,132.

Ms. Johnson stated Petitioner currently uses group depreciation rates that were approved in the 44731 Order. These are based on a 2009 depreciation study. She advised that in Cause No. 45039, Petitioner presented updated depreciation accrual rates from a depreciation study the Gannet Fleming consulting firm prepared dated 2016, and in the Order in Cause No. 45039 dated December 27, 2018, (the "45039 Order") the Commission approved new depreciation accrual rates for Petitioner but stipulated the new rates not take effect before approval of new base rates and charges in Petitioner's next general rate case. Ms. Johnson provided a table comparing Petitioner's depreciation rates currently in use and those approved in the 45039 Order as used for pro forma purposes.

Ms. Johnson testified Petitioner's original cost net plant in service balance is $12,808,842. She sponsored Attachment CAJ-4, which includes the calculation of Petitioner's portion of Shared Services net plant in service and Petitioner's original cost rate base as of December 31, 2021. Ms. Johnson stated Petitioner's portion of Shared Services net plant in service as of December 31, 2021, is $667,519, and Petitioner's original cost rate base as of December 31, 2021, is $13,877,485.

E. Sabine E. Karner. Ms. Karner sponsored the test year financial statements for Petitioner as Attachment SEK-1. She also sponsored the test year allocation of Shared Services costs to Petitioner and described how Shared Services are assigned among the various Citizens Energy Group business units and the process for their allocation. Ms. Karner testified Petitioner was allocated Shared Services at a rate of 1.18% or $1,232,322.

Ms. Karner also reviewed Petitioner's pro forma adjustments related to certain operating expenses, and she sponsored Attachment SEK-3, summarizing those adjustments during the test year. Ms. Karner discussed pro forma adjustments to line locate costs, wages and payroll taxes, certain other operation and maintenance expenses, and the pro forma adjustments Petitioner's witnesses Johnson and Bardhan-Akala made.

F. Scott A. Miller. Mr. Miller, a Certified Public Accountant and a partner at BTMA, testified regarding the fair value or true current worth of Petitioner's property as of December 31, 2021, and he sponsored a Special Purpose Accounting Report summarizing the results of his studies. Mr. Miller discussed fair value, explaining that it is the objective in a rate case to determine the actual current value of a utility's property as the basis for a fair value finding, so there is a rational basis for determining the return requirement. To this end, Mr. Miller stated there are a variety of methodologies available to the Commission to find the true current worth of the property being valued.

Mr. Miller testified that he employed the cost-based methodology to determine the fair value of Petitioner's assets, as reflected in the Special Purpose Accounting Report. The Special Purpose Accounting Report contains the calculations and analysis Mr. Miller used to arrive at his opinions upon the fair value of Petitioner's property. Mr. Miller stated that in his opinion, the fair value of Petitioner's utility assets is $21,672,471.

Mr. Miller also supported the fully allocated class cost-of-service study BTMA created based on Petitioner's embedded cost of providing gas service during the test year, adjusted for fixed, known, and measurable changes. He sponsored the Special Purpose Report that BTMA prepared on August 26, 2022, summarizing the results of the cost-of-service study performed for Westfield Gas (Attachment SAM-2). Mr. Miller generally described the purpose of a cost-of-service study, and he summarized the existing subsidy between Petitioner's rate classes and the reduction proposed in this subsidy.

Mr. Miller stated that overall, the proposed rates result in an 18.38% increase in revenue and a 40.11% increase in margin that are spread evenly on a percentage basis among Westfield Gas' customer classes. He described the proposed revisions to Petitioner's base rates for each customer class, breaking down the proposed changes to the customer charge and the volumetric delivery charge for each customer class. Mr. Miller opined that the rates proposed are fair, just, non-discriminatory, reasonable, and necessary to meet Petitioner's pro forma revenue requirements.

G. Debi Bardhan-Akala. Ms. Bardhan-Akala testified regarding Petitioner's revenue requirements, including the underlying adjustments to the financial results for the test year ended December 31, 2021. Ms. Bardhan-Akala sponsored Attachment DBA-1, which is a Summary of Pro Forma Revenue Requirement for the twelve months ending December 31, 2021, and the pro forma revenue requirements for Petitioner's operations. She stated Petitioner is seeking an 18.38% increase in total revenues.

Ms. Bardhan-Akala described how pro forma natural gas costs were determined, and she explained why the Indiana Utility Receipts Tax ("URT") on gas costs is reflected as a gas cost rather than in the taxes section of the revenue requirements. Ms. Bardhan-Akala testified that unaccounted for gas ("UAFG") is reflected in natural gas cost at 1.28% of natural gas cost and stated this percentage was determined by using a two-year average of historical levels and will be the UAFG percentage utilized in Westfield Gas' GCAs if approved in this case.

Ms. Bardhan-Akala testified that Petitioner's Attachment DBA-1, page 6, shows the computation of pro forma adjustments for other revenues. She explained what these other revenues include, and she advised a total pro forma decrease of $152,919 was made to include additions/reductions associated with the listed miscellaneous non-recuring charges. Ms. Bardhan-Akala further stated a decrease of $3,609 was made to adjust net write-off non-gas costs.

Ms. Bardhan-Akala also testified concerning Petitioner's proposed revenue increase of $1,295,861. She stated Petitioner offset the total net operating income figure of $1,859,896 that Mr. Jackson supported by pro forma at present rates net operating income of $569,171 to determine the increase in operating income. She stated the increase in operating income is $1,290,725 grossed up for the Public Utility Fee and net write-off non-gas cost to determine Petitioner's total revenue requirement increase of $1,295,861.

Ms. Bardhan-Akala testified Petitioner's rate and rate design objectives are as follows: (1) to fully recover Petitioner's revenue requirements through its rates; (2) move towards straight fixed-variable rate design; and (3) design fair and equitable rates. She stated Westfield Gas adjusted the cost-of-service study because the residential customer class was being subsidized by the commercial, industrial, and large volume interruptible classes in the amount of $145,409. Ms. Bardhan-Akala stated Westfield Gas directed Petitioner's witness Miller to eliminate the residential subsidy in steps (25% in this case). She advised this step was intentional as Petitioner is committed to gradualism in rate design and establishing rates that are fair and equitable to all its customer classes. Ms. Bardhan-Akala stated the cost-of-service study was not modified, and the proposed rate design was not altered with respect to the fixed charge component of Petitioner's proposed rates.

Ms. Bardhan-Akala also discussed continuing the decoupling mechanism and EE programs. She stated Westfield Gas is seeking approval to continue utilizing a portfolio of EE programs and the EER. Ms. Bardhan-Akala provided an overview of Petitioner's existing EE portfolio and identified the EE programs offered to residential and commercial customers that Petitioner seeks to continue. She described the existing cost recovery mechanism introduced in Cause No. 43624 and reapproved and extended in Cause Nos. 44124, 44731, and 45263.

Ms. Bardhan-Akala testified the existing budget associated with the EE programs is $8,500, with $500 devoted to outreach efforts. Petitioner is not proposing to change the budgeted amount at this time, but Westfield Gas will monitor demand for the EE programs prospectively to better understand whether increased funding is warranted and will submit a 30-day filing request to adjust the EEFC amount if Petitioner concludes increased funding is needed.

Ms. Bardhan-Akala also summarized Petitioner's proposed changes to the Terms and Conditions for Gas Service.

6. OUCC's Evidence

A. Mark H. Grosskopf. Mr. Grosskopf addressed elements of Petitioner's requested rate increase, including Petitioner's revenue requirements, depreciation and amortization expense, the IURC fee, and taxes other than income tax, including property tax and URT. He testified the OUCC's review supports an increase in Petitioner's pro forma revenue requirement of $390,723, resulting in increased total revenues, net of gas costs, of 12.02%.

Mr. Grosskopf testified the OUCC does not dispute many of Petitioner's proposed revenue and expense adjustments. He confirmed the OUCC is not disputing Petitioner's updated depreciation and amortization expense based on the depreciation study and the settlement agreement the Commission approved in Cause No. 45039 on December 27, 2018. Mr. Grosskopf testified the OUCC also does not dispute Westfield Gas' methodology in calculating the IURC fee and made no adjustments to Petitioner's payroll taxes or pro forma adjustment to property taxes. Mr. Grosskopf testified Petitioner's revenue requirements were adjusted to remove URT in accordance with House Enrolled Act 1002, and the OUCC does not dispute Westfield Gas' pro forma adjustments to URT revenue or URT expense.

After citing Ind. Code § 8-1-2-0.5 as supporting the need to protect affordability when utilities invest in infrastructure, Mr. Grosskopf noted Petitioner is requesting a sizable rate increase because of its increased rate base investment. He expressed concern about the magnitude of Westfield Gas' current rate request, a $1,295,861 annual base rate revenue increase equating to 40.18% net of gas costs. Mr. Grosskopf testified that in Petitioner's prior rate case, Cause No. 44731, he calculated Petitioner's original cost rate base at $7,610,271 as of April 30, 2016. In this Cause, he calculated Westfield Gas' original cost rate base at $13,877,485 as of December 31, 2021, meaning that in just over five and one-half years, Westfield Gas has increased its investment in rate base by $6,267,214 or 82.4%.

Mr. Grosskopf testified that consistent with OUCC witnesses Vaulx and Courter, he used an original cost rate base to calculate revenue requirements in the schedules attached to his testimony. He stated the OUCC's proposed revenue requirements reflect a fair return on Westfield Gas' investment in rate base without inflating the value over Petitioner's original investment. Mr. Grosskopf opined that to be consistent with Ind. Code § 8-1-2-0.5, the Commission should only approve necessary and reasonable requests for Westfield Gas to provide quality gas service at reasonable prices and take steps to moderate the imposition of higher rates over time.

B. Linda M. Devine. Ms. Devine opposed Petitioner's adjustment to decrease Other Revenue by $152,919. She testified Petitioner used 2020 annual revenues to calculate proposed adjustments for three subcategories of Other Revenue: late payment charges, reconnection fees, and collection fees, but these are not representative of the future revenue amounts Petitioner will have due to the Commission's First and Second Interim Emergency Orders in Cause No. 45380. Ms. Devine also opposed Petitioner's proposed adjustment to eliminate imbalance premium revenues within the Other Revenue adjustment. She recommended an adjustment to decrease Petitioner's total Other Revenue by $127,027. In support of her positions, Ms. Devine sponsored Attachment LMD-1 related to late payment charges, Attachment LMD-2 related to reconnection fees and collection fees, Attachment LMD-3 related to imbalance premium revenue, and Attachment LMD-4 reflecting her overall adjustment to Other Revenue.

C. LaCresha N. Vaulx. In analyzing Petitioner's original cost rate base, Ms. Vaulx proposed Petitioner's rate case expense be reduced and the associated amortization period be increased. More specifically, Ms. Vaulx recommended approving Petitioner's original cost rate base of $13,877,485, as Westfield Gas proposed, but she recommended Petitioner's rate case expense be capped at $212,750 and amortized over five years for an annual amount of $42,550. She also recommended the 10% contingency Westfield Gas included for rate case expense be disallowed because Petitioner provided no testimony supporting this amount. In addition, Ms. Vaulx recommended Petitioner file a revised tariff if new rates have not gone into effect at the end of the five-year amortization period to remove the rate case expense from Petitioner's base rates. Ms. Vaulx testified that if new base rates go into effect for Westfield Gas before the five-year amortization period ends, remaining rate case expense not yet amortized at the time of Petitioner's next rate case order be included in that proceeding.

D. Mohab M. Noureldin. Mr. Noureldin addressed Petitioner's proposed net write off adjustment, which he viewed as high due to using a two-year average. He suggested using a ten-year UAFG average, instead, to smooth out high and low years and provide a more representative average of Petitioner's historical UAFG. Mr. Noureldin testified Petitioner's UAFG cap in the GCA should be reduced to 0.81%, and Petitioner's net write-off amount should be reduced by $7,479.

Mr. Noureldin recommended continuing Petitioner's decoupling mechanism and EE program until a final order is issued in Petitioner's next base rate case, with the authorizations approved in Cause No. 45263.

E. Leja D. Courter. Mr. Courter discussed Petitioner's COE, capital structure, fair value rate base, and fair return. He also discussed the OUCC's recommended COE, capital structure, fair value rate base, fair return, and rate case expense, recommending a 9.40% COE as reasonable and appropriate. Mr. Courter testified he reached his 9.40% estimate of Petitioner's COE through DCF and CAPM analyses that supported a COE range of 9.0 to 9.4%. He testified that given the current increase in interest rates, he is recommending a COE at the high end of this range. Mr. Courter testified a COE of 9.40% results in a weighted cost of capital of 7.94%.

Mr. Courter stated the differences between the OUCC's proposed COE of 9.40% and Petitioner's proposed COE of 10.9% can be attributed to Petitioner's use of the following: (1) an excessive market return as a result of using an inflated growth rate; (2) a CAPM size adjustment; (3) inflated DCF results; (4) an ECAPM; (5) a RPM using the historical relationship between long-term utility yields and authorized ROEs; and (6) a non-utility proxy group. Mr. Courter testified that Petitioner's use of these methods produced unreasonably high COE results, and he urged the Commission to disregard these results because data on bond yields, dividend yields, inflation, and economic growth do not support a projected 10.9% rate of return. Mr. Courter testified regulated public utilities tend to be less risky than the market and are not comparable to the companies in Petitioner's non-utility group. He noted Westfield Gas is the only Indiana gas utility in the last decade to request a return based on an inflated fair value rate base and advised that Petitioner's proposed 10.9% rate of return is higher than any COE awarded to a natural gas utility in Indiana in more than a decade.

Mr. Courter accepted Petitioner's proposed capital structure of 75% equity, 24.82% debt, and 0.18% customer deposits as reflected on Petitioner's Exhibit No. 5, Attachment SEK-1, page 1. He recommended a fair value rate base of $18,301,018 and fair cost of equity rate of 7.10%.

Mr. Courter testified Westfield Gas proposed an inflated $22,073,595 fair value rate base by adding an $8,196,110 fair value increment to the original cost rate base of $13,877,485. He revised Petitioner's fair value rate base by adjusting the accumulated depreciation for Petitioner's fair value plant. Mr. Courter testified the accumulated depreciation percentage should not change because the valuation method (original cost vs. fair value) of the utility plant in service changes. An asset that is 10% depreciated under original cost is still 10% depreciated under fair value. Mr. Courter stated Petitioner's reproduction cost new methodology will require its customers to pay a rate of return on part of Petitioner's rate base in which the investor capital used to invest in that rate base has already been returned to Westfield Gas and its investors via depreciation charges customers paid, and he testified after capital is returned to Petitioner and its investors, customers should not be obligated to pay a rate of return on that returned capital.

Mr. Courter applied an inflation adjustment to the equity and debt portions of Petitioner's capital structure. He disagreed with Petitioner's proposal to apply an inflation adjustment only to the equity portion of the capital structure, noting the Commission applied an inflation adjustment to the equity and debt portions of the capital structure in IPL's 2016 rate case order. *In re Indianapolis Power & Light Co*., Cause No. 44576, Order at p. 48 (IURC March 16, 2016).

Mr. Courter also opposed Petitioner's proposed rate case expenses of $425,500 and a 10% rate case expense contingency of $42,500. He deferred to OUCC witness Vaulx as describing why the 10% contingency should be disallowed, and Mr. Courter recommended the remaining rate case expenses of $425,500 be shared equally between Westfield Gas' shareholders and customers. Mr. Courter testified Westfield Gas' shareholder(s) receives the benefits of a rate case through an updated rate base and updated revenue requirements and also receives an updated and reasonable ROE that allows Westfield Gas to attract capital and provide shareholder dividends. Per Mr. Courter, the Commission is not prohibited by the Indiana Code from requiring a utility's shareholders to pay an equitable portion of the rate case expenses, and he opined that such sharing helps protect the affordability of utility services for Westfield Gas' present and future customers.

F. Brien R. Krieger. Mr. Krieger reviewed and analyzed Petitioner's cost-of-service study, proposed rate designs, tariffs, and monthly customer charges. He specifically addressed the application of Petitioner's revenue requirement to rate classes and Petitioner's proposed monthly customer charges.

Mr. Krieger stated fair value inflates revenue requirements by increasing rate base value from historical value to fair value. As a result, Mr. Krieger testified the OUCC is recommending an original cost ("Historical Cost") rate base and weighted average cost of capital based upon Historical Cost; however, Mr. Krieger stated he has no issues with Petitioner's cost-of-service study allocation process and the allocators unrelated to fair value.

Mr. Krieger disagreed with Petitioner's residential class monthly customer charge increase from $11.83 to $16.76. He recommended the residential monthly customer service charge become $14.00. Mr. Krieger testified that $14.00 better aligns with the average of Commission-approved residential customer charges for other small Indiana natural gas utilities before URT reductions, and an increase from $11.83 to $14.00 represents a portion of the percent margin increase (18.3%) but not the entirety of the proposed residential margin increase (41.7%). Additionally, Mr. Krieger testified his recommendation helps address affordability by placing more costs controlled by customer consumption into the volumetric rate portion of the block rate design.

Mr. Krieger confirmed the OUCC had no recommended changes to Petitioner's updated tariff language.

7. Petitioner's Rebuttal Evidence

A. J.P. Ghio. In his rebuttal testimony, Mr. Ghio expressed appreciation for the OUCC's agreement with the majority of Petitioner's operating revenues and expenses. He stated the primary divergence between the OUCC and Petitioner is with regard to the fair value of Petitioner's utility property and the rate of return that should be authorized. Mr. Ghio testified Petitioner believes the valuation and rate of return methodologies Westfield Gas presented are consistent with the Commission's findings in Petitioner's only litigated rate case since being acquired by Citizens Energy Group (Cause No. 43624) and are the only methodologies presented in this case that give effect to Indiana's fair value statute.

Mr. Ghio explained that while Petitioner's decision to increase its investment in rate base by $6,267,214 or 82.4% may appear unusual, it does not suggest Petitioner did not consider affordability. He testified Petitioner's investment in rate base is attributable to the following: (1) Petitioner's status as a relatively small utility, meaning investments in rate base have a larger percentage increase in the overall rate base; (2) the investments in rate base occurred over a long time period (five and one-half years); and (3) the investments were driven by substantial growth in Petitioner's service territory and supporting the growing needs of the Westfield community.

In responding to Mr. Grosskopf's recommendation to spread certain costs over longer periods of time, Mr. Ghio testified that delaying Petitioner's requested rate increase will deny Westfield Gas an opportunity to earn a fair return on its investments and recovery of operating and maintenance costs necessarily incurred to provide safe and reliable service.

B. Craig L. Jackson. Mr. Jackson responded in his rebuttal testimony to OUCC witness Courter's testimony regarding the proper application of the inflation adjustment when determining the fair rate of return and the proper interpretation of Indiana's fair value statute in calculating Petitioner's return. Mr. Jackson testified that Mr. Courter's application of an inflation adjustment to the cost of debt and the cost of equity is inappropriate.

Mr. Jackson also disagreed with Mr. Courter's proposed fair value rate base dollar amount of $18,301,018. He testified that Mr. Courter's conclusion that the return on the original cost rate base is higher than the return on Petitioner's fair value rate base (supported by Attachment LDC-

13, Fair Value Authorized NOI of $1,034,008; Original Cost Authorized NOI of $1,101,941) is fundamentally flawed. Per Mr. Jackson, if the property value increases and exceeds original cost, Petitioner is entitled to benefit from the increase; therefore, the dollar return should be greater. In support of his position, Mr. Jackson cited the Commission's Order in Cause No. 39314 at p. 44, *In re Indiana Mich. Power Co*., 1993 WL 602559 (IURC November 12, 1993).

Mr. Jackson reiterated that Petitioner proposed a fair value return of $1,859,896, which represents a fair rate of return of 8.426%. He provided an alternative approach to determine a proposed fair value return, but he testified the fair value return and fair rate of return included in his direct testimony provide the most complete and accurate representation of fair value.

C. Adrien M. McKenzie. Mr. McKenzie testified that Mr. Courter's COE recommendation of 9.40% falls below a fair and reasonable level for Petitioner's utility operations, falls below accepted benchmarks, and when adjusted for changes in bond yields, recently awarded COEs justify a significant increase in COE for Westfield Gas. Mr. McKenzie contended Mr. Courter's recommended COE is far too low because: (1) changes in Federal Reserve monetary policies and significantly higher bond yields document a substantial increase in long-term capital costs; (2) adjusting national average allowed ROEs for 2019-2020 to account for the rise recently in bond yields implies a current COE in the range of 10.23% to 10.96%; and (3) adjusting prior ROE Commission determinations for current bond yields implies a COE in the range of 10.28% to 11.18%.

Mr. McKenzie opined that several factors in Mr. Courter's DCF study led to a significant downward bias in his conclusions. Additionally, he testified Mr. Courter improperly ignored the implications of Westfield Gas' relative size in evaluating a fair COE and wrongly claims inflation should be subtracted from the WACC rather than from only the COE in evaluating an RFV. Mr. McKenzie testified that taken as a whole, these shortcomings ensure Mr. Courter's recommended COE for Westfield Gas falls well below a fair and reasonable level. Mr. McKenzie testified the OUCC's criticisms of his size adjustment, market return calculations, risk premium method, expected earnings approach, and non-utility DCF analysis are without merit.

D. Scott A. Miller. Mr. Miller also rebutted issues Mr. Courter raised regarding Petitioner's fair value rate base calculations and Mr. Krieger raised regarding Petitioner's cost-of-service study and rate design. Mr. Miller testified Mr. Courter's only objection to his fair value calculations related to the accumulated depreciation component of the calculation and not the actual reproduction cost figures. Mr. Miller disagreed with Mr. Courter's assessment of Petitioner's fair value rate base as well as the OUCC's failure to use its own fair value recommendations for ratemaking and, instead, revert to using original cost for rate base.

Mr. Miller testified that to provide service, Petitioner must be allowed to generate revenues that are sufficient to meet its requirements, including depreciation expense and a fair return on the fair value of its rate base. He testified the most appropriate estimate of the fair value of Petitioner's utility assets is the RCNLD value, which is $21,672,471. He stated that adding a 13-month average inventory balance of $401,124 results in a total fair value rate base of $22,073,595.

Mr. Miller disagreed with Mr. Krieger's proposal regarding the increase in the monthly residential customer charge and stated very few of Petitioner's expenses are truly variable or cyclical in nature. Mr. Miller testified Petitioner incurs significant cost simply to make gas service available to its customers, regardless of their level of usage, and needs to generate sufficient revenue to meet that need. He stated that comparing Petitioner's proposed monthly charge to other Indiana utilities has no plausible ratemaking function, and based on his experience, utilities with lower monthly residential customer charges will likely see increases in the near future that will bring their customer charge more in line with Westfield Gas' proposal.

Mr. Miller reiterated that the methodology employed in Petitioner's Exhibit 6, Attachment SAM-1, is the most appropriate for designing rates in this case and should be updated with the final determination of the fair value of Petitioner's rate base and the approved revenue requirement in order to calculate Petitioner's rates on a going forward basis.

E. Debi Bardhan-Akala. Ms. Bardhan-Akala addressed differences between Petitioner and the OUCC with respect to items in her direct testimony. In particular, Ms. Bardhan-Akala testified these disagreements primarily center around: (a) rate case expense; (b) pro forma adjustments for other revenues and net write-off non-gas cost; (c) the level of UAFG included in Petitioner's natural gas cost; and (d) the proposed residential class customer charge amount.

Ms. Bardhan-Akala testified the OUCC's assertion that rate case expenses should be shared with shareholders should not be accepted because this is an attempt to relitigate a proposition the Commission already rejected in *In re Kokomo Gas and Fuel Co.* (Cause No. 38096, July 29, 1987), *In re Community Nat. Gas Co. Inc.* (Cause No. 44768, March 22, 2017), and *Re Indiana Gas Co., Inc.* (Cause No. 38080, September 18, 1987).

Additionally, Ms. Bardhan-Akala testified the OUCC's position regarding pro forma adjustments for other revenues and net write-off non-gas cost and the OUCC's position upon the level of UAFG included in Petitioner's natural gas cost should not be accepted because the proposed pro forma adjustments and a UAFG cap do not reflect Petitioner's on-going experience in these areas. She testified the OUCC's proposed changes to the residential class customer charge amount should also not be accepted because they will lower the proposed residential class customer charge in a way that inconsistently applies the results of the cost-of-service study and is not in line with recently approved residential customer charges for other natural gas utilities.

8. Settlement Agreement. On February 10, 2023, the Settling Parties filed the Settlement Agreement resolving all the issues each raised in this proceeding. A copy of the Settlement Agreement is attached to this Order and incorporated by reference, and the terms of the Settlement Agreement are summarized below.

A. Test Year and Rate Base Cutoff. The Settling Parties agreed the period to be used for determining the revenues and expenses incurred by Petitioner to provide gas service should be the 12 months ended December 31, 2021, adjusted for charges that are fixed, known, and measurable for ratemaking purposes and occur within 12 months following the end of the test year.

B. Pro Forma Revenues, Expenses, and Net Operating Income at Present Rates. The Settling Parties agreed Petitioner's total pro forma operating revenues at present rates are $7,068,748, with certain adjustments specifically delineated in the Settlement Agreement. They further agreed Petitioner's total pro forma operating expenses at present rates are $6,417,537. The Settlement Agreement sets forth the Settling Parties agreements with respect to Petitioner's ongoing revenue requirement for certain operating expenses.

The Settling Parties agreed Petitioner's pro forma net operating income under present rates is $651,211, which is insufficient to cover Petitioner's necessary and reasonable operating expenses and provide Westfield Gas the opportunity to earn a fair return on its used and useful plant.

C. Fair Value Rate Base, Capital Structure, and Fair Return. The Settling Parties agreed the regulatory fair value rate base of Petitioner's utility properties used and useful for the provision of gas service to the public is $20,145,826. They also agreed Petitioner's authorized ROE should be 10.00%, adjusted for inflation. The Settling Parties further agreed that Petitioner's current cost of debt is 3.59%, as supported in Petitioner's Exhibit No. 2, Attachment CLJ-2, and an inflation adjustment should not be applied to the cost of debt or customer deposits. The resulting capital structure and weighted cost of capital are set forth in the table below:

Description	**Amount**	**Percent of Total**	**Cost**	**Inflation Adjustment**	**Fair Value Cost of Capital**	**Fair Value Weighted Cost of Capital**
Equity	$15,109,326	75.00%	10.00%	-1.923%	8.077%	6.058%
Debt	$5,000,000	24.82%	3.59%		3.59%	0.891%
Customer Deposits	$36,500	0.18%	0.50%		0.50%	0.001%
Total	$20,145,826	100.00%				6.950%

The Settling Parties agreed Westfield Gas should be authorized a fair rate of return of 6.950%, based upon a fair value rate base of $20,145,826, and that the foregoing fair rate of return will adequately and fairly compensate Petitioner for its investments while maintaining Petitioner's financial integrity. Applying a 6.950% fair rate of return to the regulatory fair value rate base of $20,145,826 generates for purposes of this proceeding a fair return of $1,400,063 for GCA earnings test purposes.

Fair Value Rate Base	$20,145,826
Rate of Return	6.950%
Net Operating Income Required	$1,400,063

D. Allowed Increase. The Settling Parties agreed Petitioner's current recurring monthly rates and charges should be increased to produce additional operating revenues of $751,832 from Petitioner's gas utility service, reflecting an approximately 10.64% increase in Westfield Gas' total operating revenues, inclusive of gas costs.

E. Increases to Monthly Customer Charges. The Settling Parties agreed the monthly customer charges should be revised as proposed in Petitioner's case-in-chief with the exception of the residential customer charge established under Gas Rate D20, which will increase from $11.83 to $15.00 per month. The stipulated customer charges, by rate class, are as follows:

Class	Customer Charge
Gas Rate No. D20	$15.00
Gas Rate No. D30	$152.20
Gas Rate No. D40	$50.56
Gas Rate No. D50	$1,442.69

F. Allocation of Agreed Increase in Operating Revenues. The Settling Parties stipulated the agreed increase in operating revenues should be applied based on the cost-of-service study filed in this Cause as Petitioner's Exhibit No. 6, Attachment SAM-6, without modifications aside from those necessary to reflect the agreed fair value rate base, WACC, revenue requirement, and change to the monthly residential customer charge. The Settling Parties included as Attachment 2 to the Settlement Agreement agreed rate schedules for each rate class setting forth the monthly customer charges and delivery charges.

G. Continuation of the EE Programs and EER. The Settling Parties agreed Westfield Gas shall continue offering EE programs, and the EER shall remain effective until a final Order is issued in Petitioner's next base rate case unless CenterPoint Energy Indiana North's EE programs are not approved, expire, or otherwise cease, in which case Westfield Gas' EE portfolio and EER will be wound down and discontinued. The Settling Parties agreed the EE program budget will continue to be $8,500 per year, $500 of which will be devoted to outreach efforts. For any year in which Petitioner spends less than the agreed amount, the difference between the actual amount spent and the budget will be carried forward and, therefore, increase the maximum permissible spend in future years.

The Settling Parties agreed the EEFC will continue to be used to recover costs associated with implementing the EE programs; consequently, the EEFC shall remain in place, unchanged, and continue to operate in the manner the Commission approved in Cause Nos. 43624, 44124, 44731, and 45263. In addition, the Settling Parties agreed the SRC should continue to be used to calculate and recover, as applicable, the differences between actual margins and adjusted order granted margins for the applicable rate schedules (*i.e.*, the order granted monthly margins for each applicable rate schedule, as approved in this proceeding, adjusted to reflect the change in number of end-use customers from the order approved end-use customer levels). In accordance with prior Orders, the Settling Parties agreed the residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year, and residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing or in a future rate case; provided, the total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

H. Changes to Petitioner's Terms and Conditions for Service. The Settling Parties agreed the miscellaneous revisions to Westfield Gas' General Terms and Conditions for Gas Service set forth in Petitioner's case-in-chief should be approved.

I. Rate Case Expense. The Settling Parties agreed upon total rate case expense of $375,000 amortized over four years. If Westfield Gas files a general rate case before the four-year amortization period expires, any unamortized portion is to be recoverable as part of Petitioner's revenue requirement in that new rate case. If not addressed by an intervening base rate case order before the stipulated amortization period expires, Westfield Gas agrees to file a revised tariff under this Cause to remove the annual rate case expense amortization (i.e., $93,750) from its base rates upon recovery of these expenses. If such an adjustment is required, Petitioner may adjust its rates and charges across-the-board.

J. Unaccounted for Gas Costs. The Settling Parties agreed to use a three-year average of 1.18% as a cap to UAFG in Petitioner's GCA.

9. Evidence Supporting Settlement Agreement.

A. Petitioner's Settlement Evidence. Petitioner's witness Jackson testified in support of the Settling Parties' agreements upon the fair value of Petitioner's used and useful utility properties, Petitioner's capital structure, including Petitioner's authorized return on equity and cost of debt, and the resulting return Westfield Gas should be authorized to earn for GCA earnings test purposes. Mr. Jackson stated the stipulated fair value of $20,145,826 is within the range of values Petitioner and the OUCC proposed which were $22,073,595 and $18,301,018, respectively. Mr. Jackson noted the Commission has discretion to consider a variety of evidence when making a fair value determination, and he testified the stipulated fair value of $20,145,826 is reasonable and supported by the evidence.

Mr. Jackson described the agreements the Settling Parties reached regarding capital structure and rate of return. These included an agreement that Petitioner be authorized a fair rate of return of 6.950%. Mr. Jackson explained that the agreed rate of return is based on a COE of 10.0% and cost of debt of 3.59%. He testified the Settling Parties further agreed that an inflation adjustment should be applied to the COE, reducing it to 8.077%. Mr. Jackson testified the agreed inflation-adjusted COE results in a weighted cost of capital of 6.95%; therefore, based on the foregoing, Petitioner's authorized return for GCA earnings test purposes should be $1,400,063.

Mr. Jackson testified the agreements described above are supported by the evidence. Specifically, he testified the Settling Parties' original positions presented COE recommendations ranging from 9.4% to 10.9%. The Settling Parties also proposed different methodologies for the inflation adjustment to be made to the authorized rate of return when applied to a fair value rate base. The authorized returns the OUCC and Petitioner proposed were $1,102,011 and $1,859,896, respectively. Given this range, Mr. Jackson testified the Settling Parties' authorized return of $1,400,063 is reasonable, will provide Westfield Gas an opportunity to earn a reasonable return on its utility properties and maintain its financial integrity, and ensures Petitioner has the resources necessary to continue meeting the needs of Westfield's growing community.

Mr. Jackson concluded the agreements comprising the Settlement Agreement are reasonable, supported by the evidence, and will allow Westfield Gas to continue serving Westfield's residents with safe, reliable, and affordable energy.

Petitioner's witness Bardhan-Akala testified the Settlement Agreement is the product of negotiations that began immediately after the OUCC filed its case-in-chief. She stated there were few accounting disagreements between Petitioner and the OUCC with respect to determining Petitioner's revenue requirement. The Settling Parties' limited disagreements centered around: (1) Petitioner's rate case expense; (2) the pro forma adjustments for other revenues and net write-off non-gas cost; (3) the level of UAFG included in Petitioner's natural gas cost; and (4) the proposed residential class customer charge amount. Ms. Bardhan-Akala stated each of these issues was resolved in the Settlement Agreement and is discussed in her settlement testimony.

Ms. Bardhan-Akala testified the Settling Parties agreed to use a three-year average of calendar years 2019, 2020, and 2021 data to determine the ongoing level of late payment and reconnect and collection fees. With respect to calculating miscellaneous supplier imbalance fees, she stated the Settling Parties compromised and agreed to use a three-year average of calendar years 2019, 2020, and 2021, which results in a ($4,514) decrease in pro forma revenue compared to Petitioner's originally proposed ($24,344) decrease in revenue and results in an adjustment of ($19,829) as compared to Petitioner's case-in-chief. Ms. Bardhan-Akala testified the Settling Parties' agreement with respect to the foregoing fees is a reasonable compromise.

Ms. Bardhan-Akala testified the Settling Parties also agreed Petitioner's rate case expenses will be $375,000, amortized over four years, for an annual revenue requirement of $93,750. She stated the Settling Parties' agreement upon rate case expenses is reasonable because it removes the contingency included in Petitioner's proposed rate case expense amount and, effectively, gives consideration to the Settling Parties having reached an agreement in principle rather than fully litigating this case. Additionally, Ms. Bardhan-Akala testified the Settling Parties' agreement that any adjustment removing the amortized portion of rate case expenses from Petitioner's rates if a rate case is not filed within four years on an across-the-board basis is in the public interest, as this allows Petitioner to potentially make this adjustment in house as opposed to needing to rerun the cost-of-service study.

Ms. Bardhan-Akala testified the Settling Parties agreed to use a three-year average of 1.18% as a cap to UAFG in Petitioner's GCA instead of the ten-year average of 0.81% the OUCC proposed or 1.28% as proposed in Petitioner's case-in-chief. She testified that using a three-year average is a fair compromise between the Settling Parties' respective positions and results in a reasonable cap, particularly since during the test year in this case the calculated UAFG was 1.72%.

Ms. Bardhan-Akala testified that, as indicated in Paragraph 5 of the Settlement Agreement, the Settling Parties agree Petitioner's monthly customer charges will be revised as proposed in Petitioner's case-in-chief with the exception of the residential customer charge established under Gas Rate D20, which will increase from $11.83 to $15.00 per month as opposed to $16.76 per month as Petitioner proposed. She provided a breakdown of the stipulated customer charges and testified the agreed rates and charges, including the monthly customer charges, are reasonable and just for Petitioner's service and represent a reasonable compromise between the Settling Parties' respective positions.

Ms. Bardhan-Akala described the Settling Parties' agreement that Petitioner continue offering EE programs and the EER remain in place until a final Order is issued in Petitioner's next base rate case. She testified continuation of the SRC, without modification, is critical for Petitioner. Ms. Bardhan-Akala testified decoupling provides a simple and effective means to remove a critical barrier to investment in EE programs, stabilizes customer bills, and reduces the overall level of business and financial risk to gas utilities for events beyond their control, such as declining usage. Ms. Bardhan-Akala testified that continuation of the EER and EE programs, as agreed in the Settlement Agreement, is in the public interest.

B. OUCC's Settlement Evidence. Heather R. Poole, Director of the OUCC's Natural Gas Division, also submitted testimony supporting the Settlement Agreement. Ms. Poole testified the Settlement Agreement is the product of arms-length negotiations between the Settling Parties. She stated the Settling Parties agreed Petitioner's base rates will be designed to produce a $1,400,063 return on rate base. Ms. Poole testified the agreed revenue requirement represents a $751,832 increase in Petitioner's revenue, which is $544,029 less than Westfield Gas originally requested. Ms. Poole testified the Settling Parties agreed to a fair value rate base of $20,145,826, which reflects a compromise between Petitioner's $22,073,595 fair value rate base and the OUCC's $18,301,018 fair value rate base recommendation.

Ms. Poole testified that Petitioner proposed a 10.90% COE, while the OUCC proposed a 9.40% COE. Per Ms. Poole, the Settling Parties agreed to a 10.00% COE, a result the OUCC considers fair and reasonable when combined with the other considerations and compromises the Settling Parties made in their agreement. Ms. Poole further testified that the Settling Parties agreed to apply an agreed-upon inflation factor to only the COE, resulting in a WACC of 6.95%.

Ms. Poole stated the OUCC considered the debt cost rate within the context of the settlement as a whole. She testified the debt cost rate and debt component in the capital structure, as proposed by Petitioner in its case-in-chief, accurately reflect Petitioner's current circumstances. Ms. Poole testified that after considering the litigation risk to ratepayers, as well as the benefits of a negotiated resolution, including the non-precedential nature of settlements, the OUCC concluded the agreed settlement is reasonable and serves the public interest when considering all concessions and gains, including the debt cost rate issue.

Ms. Poole testified the Settling Parties agreed Petitioner's pro forma revenues for late payments and reconnection/connection fees should be as stated in Petitioner's case-in-chief. She further testified the Settling Parties agreed to use a three-year average using calendar year ("CY") 2019, CY 2020, and CY 2021 data, which results in a $4,514 decrease in revenue for imbalance premium revenue. Ms. Poole testified these amounts result in a total other revenue adjustment of ($133,090). Ms. Poole testified the Settling Parties also agreed upon total rate case expense of $375,000, amortized over four years, for an annual expense of $93,750. She stated this is a reduction from what Westfield Gas proposed and recognizes the hearing in this matter will not be contested and a joint proposed order will be filed. Per Ms. Poole, the Settling Parties also agreed to a net write-off adjustment of ($1,449) and a public utility fee adjustment of $3,357, both of which are flow-through adjustments.

Ms. Poole also described the Settling Parties' agreement with respect to the EER. She advised the Settling Parties agreed to extend the EE programs, the EEFC, and the SRC of the EER through the final Order in Westfield Gas' next general rate case. Ms. Poole testified that continuing these programs and rate mechanisms is consistent with Petitioner's and the OUCC's case-in-chief positions.

Ms. Poole testified the Settling Parties agreed to lower the maximum annual UAFG percentage from 1.28%, as proposed in Petitioner's case-in-chief, to 1.18%, representing an increase from the OUCC's proposed 0.81%. Ms. Poole stated the Settling Parties agreed to use Petitioner's cost of service study, updated based on their agreed fair value rate base, WACC, revenue requirement, and change to the monthly residential customer charge. Ms. Poole described the Settling Parties' compromise upon the monthly customer service charge for residential customers, advising this charge will increase from $11.83 to $15.00 per month, an amount that falls between the OUCC's recommended $14.00 and Petitioner's proposed $16.83. Ms. Poole testified the decrease in the monthly customer charge for residential customers from Petitioner's original proposal will be made up in the volumetric charge for residential customers, thereby not impacting other rate classes.

Ms. Poole concluded the Settlement Agreement, in its entirety, serves the public interest and the ratepayers of Westfield Gas by guaranteeing ratepayer savings of $303,691 compared to Petitioner's rebuttal case and $544,029 compared to Petitioner's direct case.

10. Discussion and Findings.

A. Commission Review of Settlement Agreements. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co*., 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. v. PSI Energy, Inc*., 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal*., 664 N.E.2d at 406.

Any Commission decision, ruling, or order, including approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. v. Public Serv. Co.,* 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's procedural rules require settlements to be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the agreements are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that such agreements serve the public interest.

i. Revenue Requirement. The Settling Parties agreed Petitioner's current recurring monthly rates and charges should be increased to levels sufficient to produce additional operating revenues of $751,832 from gas utility service, reflecting an approximate 10.64% increase in Petitioner's total operating revenues, inclusive of gas costs. Joint Settlement

Exhibit No. 1, p. 5. This agreement is based on concurrence regarding Petitioner's fair value rate base, a fair rate of return, and operating revenue and expenses. As discussed more fully below, the Commission finds the Settling Parties' agreement upon Petitioner's revenue requirement was shown to be reasonable, is supported by the evidence, and should be approved to enable Westfield Gas to realize adequate utility operating income to render adequate and reliable gas service.

ii. Fair Value Rate Base. The Commission finds that Westfield Gas presented evidence, which was not disputed, demonstrating its utility properties, as included in its agreed fair value rate base, are used and useful and reasonably necessary for the convenience of the public and should be included in its fair value rate base. An initial step in determining revenue requirements requires the Commission to value all property used and useful for the convenience of the public at its fair value. Ind. Code § 8-1-2-6. The Settling Parties agreed that for purposes of establishing rates in this case, the fair value of Petitioner's rate base as of December 31, 2021, is $20,145,826. Joint Settlement Exhibit No. 1, p. 4. This agreed fair value rate base is supported by Petitioner's initial, rebuttal, and settlement testimony, as well as the OUCC's direct and settlement testimony. In Westfield Gas's case-in-chief, Mr. Jackson proposed a fair value rate base of $22,073,595, based primarily on the RCNLD analysis Mr. Miller conducted. In the OUCC's case-in-chief testimony, Mr. Courter recommended a fair value rate base of $18,301,018. We find the stipulated fair value amount of $20,145,826 is within the range of values Petitioner and the OUCC supported. Accordingly, the Commission further finds that Petitioner's fair value rate base as of December 31, 2021, for purposes of this proceeding, is $20,145,826 (including inventory), and this fair value rate base should be used for purposes of determining a fair return on the fair value of Petitioner's used and useful property.

iii. Fair Rate of Return. Having determined the fair value of Westfield Gas' used and useful property, we will determine the level of net operating income that represents a reasonable return on that property. The Commission is charged with providing utilities with the opportunity to earn a fair return on the fair value of their property. *See Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm 'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992) and *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). An accepted approach is to determine Petitioner's capital structure and determine the cost of the various components of its capital. The Settling Parties agreed for ratemaking purposes that Petitioner's capital structure as of December 31, 2021, consisted of 75.00% common equity, 24.82% debt, and 0.18% customer deposits.

The evidence established the cost of customer deposits was 0.50% (per IURC General Administrative Order 2015-02). In their respective cases, the Settling Parties disagreed upon the COE. The record contains a number of different methods of estimating Petitioner's COE. The Commission recognizes the COE cannot be precisely calculated and that estimating it requires the use of judgment and the consideration of more than one methodology. The testimony of the Settling Parties' witnesses reflected the initial views that Petitioner's COE was between 9.40% and 10.90%. The Settling Parties agreed Westfield Gas should be authorized a fair rate of return of 6.950%. Joint Settlement Exhibit No. 1, p. 4. This agreed rate of return is based on a cost of equity of 10.0% and cost of debt of 3.59%. *Id*.

The Commission finds Petitioner's cost of debt includes $4 million of new long-term debt Westfield Gas issued in July 2022 through a private placement offering ("Series 2022A") at a fixed rate of 4.05%. The debt was issued within 12 months of the test year, and the Commission approved this debt by Order dated June 28, 2022, in Cause No. 45668 finding "the proposed uses of the funds will serve the public interest and Petitioner's requested financing should be approved." *Re Westfield Gas*, Cause No. 45668 at p. 6 (June 28, 2022). OUCC witness Poole testified that by including the debt approved in Cause No. 45668 in determining the cost of debt, the Settlement Agreement accurately reflects Petitioner's actual debt structure as of the date of the Settlement Agreement.

Additionally, Ms. Poole testified that the OUCC considers the 10.00% COE a fair and reasonable result when combined with the other considerations and compromises made in the Settlement Agreement. She stated the Settling Parties agreed an inflation adjustment should be applied to the COE, reducing it to 8.077%. The agreed inflation-adjusted COE results in a weighted cost of capital of 6.95%. Joint Settlement Exhibit No. 1, p. 4. The Settling Parties concluded that applying a 6.950% fair rate of return to the agreed fair value rate base of $20,145,826 will provide Petitioner with the opportunity to earn a fair return of $1,400,063, and this amount should be used for Petitioner's GCA earnings test purposes.

Giving due consideration to this evidence, including the Settlement Agreement and the risks and challenges facing natural gas utilities generally, including Petitioner, the Commission finds the agreed fair rate of return to be applied to the agreed fair value falls within a reasonable range and within the range of fair rates of return Petitioner and the OUCC presented. This authorized fair return, for purposes of setting rates in this proceeding (and for purposes of Petitioner's GCA earnings test) is within the outcomes proposed and supported by the testimony. In sum, the respective authorized returns the OUCC and Petitioner proposed were $1,102,011, and $1,859,896. The Commission, therefore, finds that based on the evidence, the agreed fair rate of return of 6.950%, designed to produce a fair return of $1,400,063, is reasonable.

iv. Operating Results at Present Rates. The Settling Parties agreed total pro forma operating revenues at present rates for Westfield Gas are $7,068,748 for purposes of this proceeding. Joint Settlement Exhibit No. 1, p. 2. They further agreed the total pro forma operating expenses for purposes of this proceeding equal $6,417,537, which includes but is not limited to: (1) gas costs of $3,823,916; (2) depreciation expense of $506,642; (3) rate case expenses of $375,000 to be amortized over four years, subject to certain related agreements, for an annual revenue requirement of $93,750; (4) total net write off non-gas cost of $11,190; (5) taxes of $148,887; and (6) IURC fees of $9,040. *Id.* Thus, Petitioner's resulting proforma net operating income under present rates is $651,211. *Id.* at p. 3.

All proforma adjustments were identified in the testimony supporting the Settlement Agreement. In particular, the Settling Parties agreed to eliminate the contingency Petitioner included in rate case expense, thereby taking into account that the settlement was reached without fully litigating this matter and incurring the costs of preparing for and participating in a litigated proceeding. The Settling Parties also agreed to amortize Petitioner's rate case expenses over four years as opposed to the three years Petitioner proposed, which also mitigates the impact of the rate case expense. In addition, the Settling Parties agreed to use a three-year average using CY 2019, CY 2020, and CY 2021 data, resulting in a $4,514 decrease in revenue for imbalance premium revenue. Joint Settlement Exhibit No. 1, p. 3.

Given the parties' settlement agreements, as discussed above, the Commission finds all proforma adjustments and the resulting pro forma operating revenues at present rates agreed upon in the Settlement Agreement are reasonable and were supported by substantial evidence.

v. Allowed Increase. The Settling Parties agreed Petitioner's current recurring monthly rates and charges should be increased to produce additional operating revenues of $751,832, reflecting an approximately 10.64% increase in total operating revenues. Joint Settlement Exhibit No. 1, p. 5. The Settling Parties also agreed the allowed increase in additional revenues will provide Westfield Gas an opportunity to realize adequate utility operating income, enable Petitioner to maintain and support its credit and afford an opportunity to provide adequate financing, help assure market confidence in its financial soundness, allow Petitioner to earn a return equal to that available on other investments of comparable risk, and permit Westfield Gas to obtain reasonable additional capital so as to render adequate, reliable, and safe gas service to the public. The Commission finds the rates estimated to produce these results are just and fair and should allow Petitioner an opportunity to earn a reasonable return on its property dedicated to providing gas utility services.

vi. Special Terms Relating to Rate Case Expenses. As discussed above, the Settling Parties agreed to total rate case expense of $375,000, to be amortized over four years. Joint Settlement Exhibit No. 1, p. 9. Additionally, they agreed that if Westfield Gas files a general rate case before the four-year amortization expires, any unamortized portion will be recoverable as part of Petitioner's revenue requirement in the next rate case. If not addressed by an intervening base rate case order before the stipulated amortization period expires, Westfield Gas agreed to file a revised tariff to remove the annual amortization portion (i.e., $93,750) from its base rates. If such an adjustment is required, the Settling Parties agreed Petitioner may adjust its rates and charges on an across-the-board basis.

The Commission finds the Settling Parties' agreement that any adjustment to remove the amortized portion of Petitioner's rate case expenses, should a rate case not be filed within four years, may be done on an across-the-board basis is reasonable and in the public interest because this enables Petitioner to make an adjustment, should it become necessary, in house as opposed to having the cost-of-service study rerun and incurring additional costs. The Commission finds this resolution is reasonable in the context of the overall settlement and is in the public interest.

B. Cost-of-service and Rate Design. In *Re Westfield Gas*, Cause No. 44731, Petitioner and the OUCC entered into a settlement agreement providing that Petitioner would engage a consultant to conduct a cost-of-service study for presentation in its next general rate case and the reasonable costs of such a study may be recovered in that case as a rate case expense. 44731 Order at p. 23. In accordance with that agreement and the Commission's approval in the 44731 Order, Westfield Gas presented a cost-of-service study in this proceeding as Petitioner's Exhibit No. 6, Attachment SAM-6. Aside from recommended revisions to align the revenue recovery in the cost-of-service study with the OUCC's proposed revenue requirements, the OUCC did not oppose the methodology used in this cost-of-service study or propose changes to Petitioner's proposed subsidy reductions for the rate classes.

In the Settlement Agreement, the Settling Parties stipulate their agreed increase in operating revenues should be applied based on the cost-of-service study Petitioner filed in this

Cause. Joint Settlement Exhibit No. 1, p. 6. As discussed below, the Settling Parties' only change to the cost-of-service study was to update the study and rate design based on their agreed fair value rate base, weighted average cost of capital, revenue requirement, and the agreed change to the monthly residential customer charge.

Based on the Settlement Agreement and the testimony supporting the methodology used in the cost-of-service study, the Commission finds the Settling Parties' agreement that the increase in revenues approved in this Cause should be applied based on the cost-of-service study is reasonable and should be approved.

C. Customer Charges. In Petitioner's case-in-chief, Westfield Gas proposed to increase its customer charges consistent with the cost-of-service study. The resulting customer charge for residential customers was $16.76 per month. OUCC witness Krieger recommended the customer charge for residential customers be $14, but he did not oppose increasing the customer charges for Petitioner's other customer classes in accordance with the cost-of service-study. Mr. Krieger stated his "recommendation helps address the affordability issue of natural gas by placing more costs controlled by customer consumption into the volumetric rate portion of the block rate design." Public's Exhibit No. 6 at p. 18.

In their Settlement Agreement, the Settling Parties agreed the residential customer charge will increase to $15.00, as opposed to Petitioner's proposed $16.76 and the OUCC's recommended $14.00. Joint Settlement Exhibit No. 1, p. 5. The Settling Parties also agreed the customer charges for Petitioner's remaining customer classes will be the amounts Petitioner originally proposed.

The Settling Parties' agreement upon the increase in the residential customer charge represents a reasonable compromise between their initial positions. While the cost-of-service study supports a higher customer charge for residential customers (*i.e.*, $16.76), the Commission finds the Settlement Agreement represents a reasonable gradual step toward a cost-of-service-based rate and a modest move toward straight-fixed variable rate design. Notably, the agreed reduction in the residential customer charge from what Petitioner proposed will not impact the charges (fixed or volumetric) for other rate classes. Specifically, the reduction in fixed charge revenue from residential customers under the Settlement Agreement is being allocated to the residential variable charges for potential recovery from the residential rate class. In other words, Westfield Gas is assuming the risk of revenue recovery rather than transferring that by increasing the customer charges for the other rate classes, and as Mr. Krieger noted, this agreement gives residential customers a greater ability to control their costs by reducing usage.

The Commission finds the agreed change to the customer charge for Gas Rate D20 is within the scope of the evidence and in the public interest.

D. Unaccounted for Gas. Petitioner proposed an UAFG cap in its case-in-chief of 1.28%. The OUCC recommended lowering this cap to 0.81%, which is Petitioner's ten-year average UAFG. For purposes of settlement, the Settling Parties agreed to lower the maximum annual UAFG percentage to be used in Petitioner's GCA to a three-year average of 1.18%. Joint Settlement Exhibit No. 1, p. 9.

The Commission finds the agreed UAFG cap is reasonable and in the public interest. Use of a three-year average is a reasonable compromise between the Settling Parties' respective positions and results in a reasonable cap. Notably, the cap is lower than the UAFG percentage during the test year which the evidence reflects was 1.72%.

E. Terms and Conditions for Gas Service. The Settling Parties agreed the miscellaneous revisions proposed in Petitioner's General Terms and Conditions for Gas Service, as set forth in Petitioner's Exhibit No. 7, Attachments DBA-2 and DBA-3 and described in the direct testimony of Ms. Bardhan-Akala, should be approved. Joint Settlement Exhibit No. 1, p. 9. The suggested revisions were supported by OUCC witness Krieger. Given this support, the Commission finds the revisions to Petitioner's Terms and Conditions for Gas Service agreed upon in the Settlement Agreement are reasonable.

F. Continuation of the EE Programs and EER. In the March 10, 2010 Order in Cause No. 43624 (the "43624 Order"), the Commission authorized Petitioner, pursuant to Ind. Code ch. 8-1-2.5, to implement an EE program portfolio and the EER. The EER is designed: (1) to recover costs that are currently incurred to implement a portfolio of EE programs through the EEFC; and (2) to decouple fixed costs from the sales of natural gas to Petitioner's residential and commercial customers through the SRC cost recovery mechanism. Westfield Gas has been offering EE programs since the 43624 Order. To that end, in the 44731 Order in Petitioner's last rate case, the Commission authorized Petitioner to continue its EE program portfolio, as well as the EER. On November 27, 2019, in Cause No. 45263, the Commission also authorized extending Petitioner's gas EE program portfolio, as well as the EER, until Westfield Gas' next base rate order or until Indiana Gas Company, Inc. d/b/a Vectren (n/k/a CenterPoint Energy Indiana) North's EE programs are not approved, expire, or otherwise cease, in which case Petitioner's EE portfolio and EER are to be discontinued.

In this proceeding, OUCC witness Noureldin recommended the Commission approve "continuation of Petitioner's decoupling mechanism and EE programs until an order is issued in Petitioner's next rate case." Public's Exhibit No. 4, at p. 5. Mr. Noureldin testified that since Petitioner relies on CenterPoint Energy Indiana North's evaluation, measurement, and verification analyses, if CenterPoint Energy Indiana North's programs "are not approved, expire, or otherwise cease, then Petitioner's EE portfolio and energy efficiency rider should be discontinued and wound down" as provided in the Commission's Order in Cause No. 45263. *Id.* The Settlement Agreement incorporates Mr. Noureldin's recommendations. Joint Settlement Exhibit No. 1, pp. 6-8.

Specifically, the Settlement Agreement provides for the EE programs and the EER to continue until a final Order is issued in Petitioner's next base rate case, unless CenterPoint Energy Indiana North's EE programs are not approved, expire, or otherwise cease, in which case Westfield Gas's EE portfolio and EER are to be wound down and discontinued. Under the Settlement Agreement, the EE programs and EER will continue to operate as they have in the past, and on or before March 31st of each year, Westfield Gas will file an EE scorecard under this Cause showing the same information Petitioner has been filing with the Commission under Cause No. 44731. The Settlement Agreement also provides that Petitioner will convene a meeting once annually to collaborate with the OUCC to discuss the EE programs.

The Settling Parties also agreed the EER should continue for a commensurate time period. With respect to the SRC component of the EER, the Settlement Agreement preserves the caps the Commission previously approved. Specifically, the residential margin differences eligible for recovery in the SRC annually are capped at 8% of adjusted order granted residential margins applicable to the previous year. As approved in Cause No. 44124 and continued in Cause Nos. 44731 and 45263, any actual residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount subject to the 8% SRC cap, or in a future rate case.

Based on the evidence, the Commission finds the foregoing terms concerning Petitioner's EE programs and the EER to be reasonable and in the public interest. We note the Commission has found the provision of natural gas EE programs with accompanying funding to be appropriate and in the public interest for nearly every jurisdictional gas utility in Indiana. Natural gas EE programs reduce natural gas consumption by improving the EE of homes and businesses, space heating systems, water heating, and other gas appliances. This lowers the gas bills of consumers and businesses adopting these measures and provides broader societal benefits, including reducing natural gas imports, reducing the risk of gas shortages, and putting downward pressure on natural gas prices. Accordingly, the Commission finds Westfield Gas should continue offering its EE programs in accordance with the Settlement Agreement.

Based on the evidence, the Commission also approves continuation of the EER, which includes both the EEFC that has been used to recover the program costs and the SRC decoupling mechanism that allows Petitioner to recover its non-gas costs. The SRC was modeled after a similar mechanism the Commission approved for use by Vectren Energy in Consolidated Cause Nos. 42943 and 43046 (Order approved December 1, 2006). In that case, the Commission found:

> In the past, volumetric prices afforded gas utilities the opportunity to earn their authorized returns, even in the face of rising costs, because sales (and hence fixed cost recovery) were increasing. Today, volumetric pricing makes it difficult for an Indiana gas utility to earn its authorized return because usage per customer is declining. Under these conditions, this form of usage-based rate design has become an asymmetrical risk for the utilities.

Re Petition of Indiana Gas Co. and Southern Indiana Gas and Electric Co., Consolidated Cause Nos. 42943 and 43046 (December 1, 2006) at p. 39. Likewise, in our December 1, 2006 Order initiating an investigation into rate design alternatives and EE measures for natural gas utilities, the Commission expressed anticipation that "decoupling mechanisms will be an important element in promoting utility stability and benefits to customers." *In re the Investigation on the Commission's Own Motion into Rate Design Alternatives and Energy Efficiency Measures for Natural Gas Utilities*, Cause No. 43180 (December 1, 2006) at p. 1.

Based on the evidence, the Commission approves continued operation of the EER in the manner set forth in the Settlement Agreement. This is consistent with the Commission's Orders in Cause Nos. 43624, 44124, 44731, and most recently in 45263. With regard to the SRC, the residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year. Any actual residential margin differences in excess of the 8% SRC cap may be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% SRC cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million; consequently, the Commission finds the proposed EER is reasonable, in the public interest, and should be approved and implemented in accordance with the Settlement Agreement. We also find the EE programs and EER shall continue until a final Order is issued in Petitioner's next base rate case, unless CenterPoint Energy Indiana North's EE programs are not approved, expire, or otherwise cease, in which case Westfield Gas's EE portfolio and EER shall be wound down and discontinued.

11. Conclusion Regarding Settlement Agreement. Consistent with the foregoing findings, the Commission finds the Settlement Agreement is reasonable, was supported by the evidence, and is in the public interest; therefore, the Commission finds the Settlement Agreement should be approved.

12. Effect of Settlement Agreement. The Settling Parties agree the Settlement Agreement shall not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Accordingly, with regard to future citation of the Settlement Agreement or of this Order, the Commission finds our approval of the Settlement Agreement should be construed in a manner consistent with our finding in *Richmond Power & Light,* Cause No. 40434, 1997 WL 34889849 at 7-8 (IURC March 19, 1997).

13. Confidentiality. Westfield Gas filed a motion for protection and nondisclosure of confidential and proprietary information on December 19, 2022, that was supported by an affidavit showing certain documents and/or information to be submitted to the Commission contained confidential, proprietary, and/or trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and 24-2-3-2. A docket entry was issued on December 30, 2022, preliminarily finding the information that was the subject of Petitioner's motion is confidential, after which the information was submitted to the Commission under seal. The Commission finds all such information is confidential under Ind. Code §§ 5-14-3-4 and 24-2-3-2 and shall continue to be exempt from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement between Westfield Gas and the OUCC filed in this Cause on February 10, 2023, a copy of which is attached to this Order and incorporated by reference, is approved.

2. Westfield Gas is authorized to increase its rates and charges for natural gas service to levels sufficient to produce additional operating revenues of $751,832 from gas utility service, reflecting an approximate 10.64% increase Petitioner's total operating revenues, inclusive of gas costs.

3. Westfield Gas shall file a new schedule of rates and charges with the Commission's Energy Division in the form set forth in Attachment 2 to the Settlement Agreement and, upon approval by the Division, cancel Petitioner's existing schedules of recurring monthly rates and charges.

4. The proposed changes to Petitioner's Terms and Conditions for Gas Service, as shown in Petitioner's Attachments DBA-2 and DBA-3, are approved; therefore, Westfield Gas shall file with the Commission's Energy Division updated Terms and Conditions for Gas Service.

5. The extension of Petitioner's EE programs and rate mechanisms is approved consistent with the Settlement Agreement. On or before March 31st of each year, commencing in 2024, Westfield Gas shall file under this Cause an EE scorecard showing all the information Petitioner has been filing with the Commission under Cause No. 44731, and Petitioner shall convene a meeting at least once annually to collaborate with the OUCC to discuss the EE programs.

6. If not addressed by an intervening base rate case order before the Settling Parties' agreed amortization period for rate case expense expires, Westfield Gas shall promptly file a revised tariff removing the annual amortization portion (*i.e.*, $93,750) from Petitioner's approved base rates, and if such an adjustment is required, Petitioner may adjust its rates and charges on an across-the-board basis.

7. The information identified in Finding No. 13 above and preliminarily found to be confidential qualifies as confidential trade secret information under Ind. Code §§ 5-14-3-4(a)(4) and (9) and 24-2-3-2; therefore, this information is exempt from public access and disclosure under Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

8. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, VELETA, AND ZIEGNER CONCUR:

APPROVED: APR 12 2023

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco Date: 2023.04.12 10:13:26 -04'00'

Dana Kosco
Secretary of the Commission

FILED
February 10, 2023
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

OFFICIAL EXHIBITS

VERIFIED PETITION OF WESTFIELD GAS, LLC, D/B/A CITIZENS GAS OF WESTFIELD FOR (1) AUTHORITY TO INCREASE RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES; (2) APPROVAL OF CERTAIN REVISIONS TO ITS TERMS AND CONDITIONS APPLICABLE TO GAS UTILITY SERVICE; AND (3) APPROVAL PURSUANT TO INDIANA CODE SECTION 8-1-2.5-6 OF AN ALTERNATIVE REGULATORY PLAN UNDER WHICH IT WOULD CONTINUE ITS ENERGY EFFICIENCY PROGRAM PORTFOLIO AND ENERGY EFFICIENCY RIDER	**CAUSE NO. 45761**

IURC JOINT
EXHIBIT No. 1
3-3-23 AT
DATE REPORTER

STIPULATION AND SETTLEMENT AGREEMENT

On August 26, 2022, Westfield Gas, LLC, d/b/a Citizens Gas of Westfield ("Westfield Gas" or "Petitioner") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking: (i) authority to increase its rates and charges for gas utility service rendered by it and approval of a new schedule of rates and charges applicable thereto; (ii) approval of certain revisions to its terms and conditions for gas utility service; and (iii) approval pursuant to Ind. Code § 8-1-2.5-6 of an alternative regulatory plan under which it would continue its energy efficiency program portfolio and Energy Efficiency Rider. Petitioner also filed the testimony and exhibits constituting its case-in-chief on August 26, 2022. On December 2, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony and exhibits. Petitioner filed rebuttal testimony and exhibits on January 3, 2023.

In early December 2022, Petitioner and the OUCC (collectively the "Settling Parties") began discussions regarding potential resolution of the issues in this proceeding through a settlement agreement, subject to Commission approval. On January 18, 2023, the Settling

Parties notified the Commission that they had reached an agreement with respect to all of the issues before the Commission, subject to preparation and execution of a written definitive settlement agreement.

The Settling Parties, solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth in this Stipulation and Settlement Agreement ("Settlement Agreement") represent a fair, just and reasonable resolution of all matters raised in this proceeding, subject to their incorporation by the Commission into a final, non-appealable order without modification or further condition that may be unacceptable to either Settling Party ("Final Order").

I. INCREASE IN NET OPERATING INCOME.

1. **Test Year and Rate Base Cutoff**. The period used for determining the revenues and expenses incurred by Petitioner to provide gas service to the public was the twelve months ended December 31, 2021, adjusted for changes that are fixed, known, and measurable for ratemaking purposes and occur within 12 months following the end of the test year. The utility properties used and useful for the provision of gas service to the public by Petitioner are properly valued for purposes of this proceeding as of December 31, 2021.

2. **Pro Forma Revenues, Expenses and Net Operating Income at Present Rates**.

a. As shown on Attachment 1 hereto, the Settling Parties agree that Petitioner's total pro forma operating revenues at present rates are **$7,068,748** for purposes of this proceeding, which includes an adjustment for miscellaneous other revenues of ($133,090), as opposed to the adjustment proposed in Petitioner's case-in-chief of ($152,919). The agreed upon adjustment to miscellaneous other revenues of ($19,830) results from the Settling Parties' agreement to:

i. use of a three-year average of calendar years 2019, 2020 and 2021 to determine pro forma late payment fees as provided in Petitioner's case-in-chief;

ii. use of a three-year average of calendar years 2019, 2020 and 2021 to determine pro forma reconnection and collection fee revenue, as provided in Petitioner's case-in-chief; and

iii. use of a three-year average of calendar years 2019, 2020 and 2021 to determine pro forma imbalance premium revenue, which results in a ($4,514) decrease in revenue as compared to the ($24,344) decrease in revenue included in Petitioner's case in chief, which results in a ($19,830) adjustment.

b. Operating Expenses at Present Rates. As shown on Attachment 1 hereto, the Settling Parties agree Westfield Gas's present total operating expenses for purposes of this proceeding are **$6,417,537**, which includes without limitation:

i. gas costs of $3,823,916;

ii. depreciation expense in the amount of $506,642;

iii. pro forma rate case expenses of $375,000 to be amortized over four (4) years (subject to the agreements set forth in Section IV below) for an annual revenue requirement of $93,750 based on the Settling Parties having reached an agreement in principle on January 18, 2023, rather than fully litigating the case;

iv. total net write off non-gas cost of $11,190, based on an agreed upon pro forma adjustment to net write-off non-gas costs of ($1,448), as opposed to Petitioner's case-in-chief amount of $12,658;

v. taxes of $148,887; and

vi. public utility fees of $9,040.

c. Pro Forma Net Operating Income at Present Rates. The pro forma net operating income under present rates for purposes of this proceeding is **$651,211**. This net operating income amount is insufficient to cover Petitioner's necessary and reasonable operating expenses and provide Petitioner an opportunity to earn a fair return on the fair value of its utility properties as set forth below. Accordingly, the existing rates and charges are unjust and unreasonable and should be increased.

3. **Fair Value Rate Base, Capital Structure and Fair Return**.

a. Fair Value Rate Base. For purposes of this proceeding, the regulatory fair value rate base of the utility properties used and useful for the provision of gas service by Petitioner to the public is $20,145,826.

b. Capital Structure. The Settling Parties agree that Petitioner's authorized Return on Equity should be 10.00%, adjusted for inflation, as set forth below. The Settling Parties further agree that Petitioner's current cost of debt is 3.59%, as supported in Petitioner's Exhibit No. 2, Attachment CLJ-2, and that an inflation adjustment should not be applied to the cost of debt or customer deposits. The resulting capital structure and weighted cost of capital are set forth in the table below:

Description	Amount	Percent of Total	Cost	Inflation Adjustment	Fair Value Cost of Capital	Fair Value Weighted Cost of Capital
Equity	$15,109,326	75.00%	10.00%	-1.923%	8.077%	6.058%
Debt	$5,000,000	24.82%	3.59%		3.590%	0.891%
Customer Deposits	$36,500	0.18%	0.50%		0.500%	0.001%
Total	$20,145,826	100.00%				6.950%

c. Fair Return. The Settling Parties agree Petitioner should be authorized a fair rate of return of 6.950%, based upon a fair value rate base of $20,145,826. The foregoing fair rate of return will adequately and fairly compensate Petitioner for its investments, while maintaining the financial integrity of the gas utility. As shown on Attachment 1 hereto and in the table below, applying a 6.950% fair rate of return to the regulatory fair value rate base of $20,145,826 would generate for purposes of this proceeding a fair return of **$1,400,063** for GCA earnings test purposes.

Fair Value Rate Base	$20,145,826
Rate of Return	6.950%
Net Operating Income Required	$1,400,063

4. **Allowed Increase**. As shown on Attachment 1 hereto, the Settling Parties agree for purposes of settlement that Petitioner's current recurring monthly rates and charges should be increased to levels sufficient to produce additional operating revenues of **$751,832** from gas utility service, which reflects an approximately **10.64%** increase in total operating revenues, inclusive of gas costs. The agreed increase in additional revenues will provide Petitioner an opportunity to realize adequate utility operating income, enable Petitioner to maintain and support its credit and provide adequate financing, assure market confidence in its financial soundness, allow Petitioner to earn a return commensurate with returns available on other investments of comparable risk, and permit it to obtain reasonable additional capital to enable Petitioner to render adequate, reliable and safe gas service to the public.

5. **Increases to Monthly Customer Charges**. The Settling Parties agree the monthly Customer Charges will be revised as proposed in Petitioner's case-in-chief with the exception of the residential customer charge established under Gas Rate D20, which will be increased from $11.83 to $15.00 per Month as opposed to $16.76 per Month as proposed in Petitioner's case-in-chief. The stipulated Customer Charges, by rate class, are set forth below:

Class	Customer Charge
Gas Rate No. D20	$15.00
Gas Rate No. D30	$152.20
Gas Rate No. D40	$50.56
Gas Rate No. D50	$1,442.69

6. **Allocation of Agreed Upon Increase in Operating Revenues**. The Settling Parties stipulate that the agreed-upon increase in operating revenues should be applied based on the cost-of-service study filed by Petitioner in this Cause as Petitioner's Exhibit No. 6, Attachment SAM-6 without modification. Petitioner has updated the cost-of-service study and rate design based on the Settling Parties agreed-upon fair value rate base, weighted average cost of capital, revenue requirement and the agreed upon change to the monthly Residential Customer charges.

7. **Rate Schedules Implementing Agreed Upon Rate Increase**. Attachment 2 hereto includes red-line and clean copies of the agreed-upon rate schedules for each rate class setting forth the monthly Customer Charges and Delivery Charges for each customer class determined as described above.

II. CONTINUATION OF ENERGY EFFICIENCY PROGRAMS AND ENERGY EFFICIENCY RIDER

8. **Background**. In its Order in Cause No. 44731, the Commission authorized Petitioner, pursuant to Indiana Code ch. 8-1-2.5, to continue its energy efficiency program portfolio (which previously had been approved in Cause Nos. 43624 and 44124), as well as an Energy Efficiency Rider designed to both: (i) recover costs incurred to maintain a portfolio of energy efficiency programs through a mechanism known as the Energy Efficiency Funding Component ("EEFC"); and (ii) decouple Petitioner's fixed cost recovery from sales of natural gas to its residential and commercial customers through a mechanism known as the Sales Reconciliation Component ("SRC"). By Order dated November 27, 2019, in Cause No. 45263, the Commission authorized a further extension of Petitioner's gas energy efficiency program portfolio, as well as the EEFC and SRC until Petitioner's next base rate order, or until Indiana

Gas Company, Inc. n/k/a CenterPoint Energy Indiana North's energy efficiency programs are not approved, expire or otherwise cease. In this case, Petitioner sought an extension of its energy efficiency program portfolio, as well as authority to continue both components of the Energy Efficiency Rider.

9. **Energy Efficiency Programs**. The Settling Parties agree Petitioner shall continue offering energy efficiency programs. The energy efficiency program budget will continue to be $8,500 per year, $500 of which will be devoted to outreach efforts. For any year in which Petitioner spends less than the foregoing budgeted amount, the difference between the actual spend and the budget will be carried forward and increase the maximum permissible spend in future years. In order to minimize the cost of operating the programs, Petitioner will administer the programs "in-house," without using a third party administrator and will apply results from CenterPoint Energy Indiana North's most recent evaluation, measurement and verification ("EM&V") analyses to the same measures offered by Petitioner. On or before March 31st of each year, Petitioner will submit in this Cause an energy efficiency scorecard showing for the previous calendar year:

a. the deemed savings attributable to the energy efficiency programs;

b. the number of customers participating by measure;

c. incentive amount for each measure; the net-to-gross ratio, if any, by measure; and

d. a break out of the energy budget by sector and program on an annual basis.

Petitioner will convene a meeting once annually to collaborate with the OUCC to discuss the energy efficiency programs. Petitioner may modify the energy efficiency programs that it offers as a part of its portfolio at its sole discretion but may not offer any programs not offered by CenterPoint Energy Indiana North.

10. **Energy Efficiency Funding Component**. The EEFC shall continue to be used to recover costs associated with implementation of the energy efficiency programs. The EEFC shall remain in place unchanged and shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624, 44124, 44731 and 45263.

11. **Sales Reconciliation Component**. The SRC shall continue to be used to calculate and recover, as applicable, the differences between actual margins and adjusted order granted margins for the applicable rate schedules (*i.e.*, the order granted monthly margins for each Applicable Rate Schedule, as approved in this proceeding, as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels). The SRC shall continue to operate in the manner approved by the Commission's Orders in Cause Nos. 43624, 44124, 44731 and 45263. The residential margin differences eligible for recovery in the SRC annually will be capped at 8% of adjusted order granted residential margins applicable to the previous year. As approved in Cause No. 44124 and continued in Cause Nos. 44731 and 45263, any actual residential margin differences in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% SRC cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

12. **Term of Extension**. Petitioner shall continue offering energy efficiency programs, and the Energy Efficiency Rider shall remain effective, until a final Order is issued in Petitioner's next base rate case, unless CenterPoint Energy Indiana North's energy efficiency programs are not approved, expire, or otherwise cease, in which case Westfield Gas's energy efficiency portfolio and energy efficiency rider will be wound down and discontinued.

III. Terms and Conditions for Gas Service

13. The Settling Parties agree the miscellaneous revisions to Petitioner's General Conditions for Gas Service set forth in Petitioner's Exhibit No. 7, Attachments DBA-2 and DBA-3 and described in the direct testimony of Debi Bardhan-Akala should be approved by the Commission.

IV. Special Terms Regarding Rate Case Expenses

14. As set forth above, the Settling Parties agree to total rate case expense of $375,000 amortized over four (4) years. If Westfield Gas files a general rate case before the expiration of the amortization period of four (4) years, any unamortized portion will be recoverable as part of the revenue requirement in Westfield Gas's next rate case. If not already addressed by an intervening base rate case order before expiration of the stipulated amortization period, Westfield Gas agrees to file a revised tariff to remove the annual amortization portion (i.e., $93,750) from base rates. If such an adjustment is required, Petitioner may adjust its rates and charges on an across-the-board basis as opposed to re-running the cost-of-service study.

V. Unaccounted for Gas Costs

15. The Settling Parties agree to use a three-year average of 1.18% as a cap to unaccounted for gas in Petitioner's GCA.

VI. Agreed Upon Proposed Order

16. The Settling Parties have worked together to prepare an agreed upon proposed order (the "Proposed Order"), which will be submitted jointly by the Parties on or before February 13, 2023. As further set forth below, the Settling Parties will request the Commission adopt the findings in the Proposed Order accepting and approving this Settlement Agreement in its entirety, without any change or condition that is unacceptable to either Settling Party.

VII. SETTLEMENT AGREEMENT -- SCOPE AND APPROVAL

17. Neither the making of this Settlement Agreement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. The parties intend that neither the making of this Settlement Agreement, nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

18. This Settlement Agreement shall not constitute nor be deemed an admission by any Settling Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. This Settlement Agreement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceeding. Each of the Settling Parties has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses in this Cause. In accordance with the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Settlement Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues.

19. This Settlement Agreement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party. If the Settlement Agreement is not approved in its entirety by

the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Settlement Agreement is expressly predicated upon the Commission's approval of the Settlement Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Settlement Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by either Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Settlement Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

20. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Settlement Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. In addition, the Settling Parties shall offer settlement testimony supporting the Commission's approval of this Settlement Agreement. Such supportive testimony will be agreed-upon by the Settling Parties.

21. The direct, rebuttal and settlement testimony filed in this proceeding will be offered into evidence without objection. The Settling Parties agree that Public's Exhibit 5-S, Supplemental Testimony of OUCC Witness Leja D. Courter and Corrected Testimony of Leja D. Courter, filed by the OUCC on January 10, 2023, will not be offered into evidence. The Settling Parties hereby waive cross-examination of each other's witnesses.

22. The Settling Parties will support this Settlement Agreement before the Commission and request that the Commission accept and approve the Settlement Agreement. This Settlement Agreement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

23. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement Agreement in its entirety without changes or condition(s) unacceptable to any Party (or related orders to the extent such orders are specifically and exclusively implementing the provisions hereof) and shall not oppose this Settlement Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

24. The undersigned have represented and agreed that they are fully authorized to execute this Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

25. The communications and discussions during the negotiations and conferences have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are both inadmissible and privileged. All prior drafts of this Settlement Agreement and any settlement proposals and counterproposals also are or relate to offers of settlement and are both inadmissible and privileged.

Accepted and Agreed on this 10th day of February, 2023.

[signature page follows]

Westfield Gas, LLC d/b/a Citizens Gas of Westfield	Indiana Office of Utility Consumer Counselor
Michael E. Allen An Attorney for Citizens Gas of Westfield	Jeffrey Reed An Attorney for the Indiana Office of Utility Consumer Counselor

Westfield Gas, LLC
d/b/a Citizens Gas of Westfield
Cause No. 45761

Comparison of Petitioner's and the OUCC's Proposed Revenue Requirements
to Agreed Upon Revenue Requirements

Description	A Per Petitioner As Filed	B Per OUCC	C Settlement Agreement
Rate Base	22,073,595	13,877,485	20,145,826
Times: Rate Of Return	8.426%	7.941%	6.950%
Return on Rate Base	1,859,896	1,102,011	1,400,063
Less: Adjusted Net Operating Income	569,171	712,366	651,211
Increase In Net Operating Income	1,290,725	389,643	748,852
Divided by Revenue Conversion Factor	0.9960366	0.9972367	0.9960366
Recommended Revenue Increase (Decrease)	$1,295,861	$390,723	$751,832
Overall Percentage Increase (Decrease)	18.38%	5.52%	10.64%

WESTFIELD GAS, LLC
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro Forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro Forma Results Based on Proposed Rates	F Reference
	Operating Revenues						
1	Test Year Revenues	$5,671,284					Income Statement
2	IURT tax Reduction		($42,745)				page 5
3	Billing Exception Adjustment		4,394				page 4
4	Cancel Rebill Adjustment		(119)				page 4
5	New Customers Adjustment		141,674				page 4
6	WNA Weather Normalization Adjustment		90,528				page 4
7	Unbilled Non-Gas Revenue Adjustment		29,427				Income Statement
8	Gas Cost Adjustment		1,355,808				
9	Other Revenue Adjustment		(133,090)				page 6
10	NTA Removal		(47,351)				Income Statement
11	Special Contract Discount		(1,074)				page 5
12	Rounding		13				
13	Revenue Requirement Increase				$751,832		page 10
14	Total Operating Revenues	$5,671,284	$ 1,397,464	$7,068,748	$751,832	$7,820,580	
	Gas Cost						
15	Test Year Gas Costs	$2,404,341					Income Statement
16	Gas Price Adjustment		1,355,808				page 5
17	Miscellaneous		63,767				
18	Total Gas Costs	$2,404,341	$1,419,575	$3,823,916	$0	$3,823,916	
19	**Gross Margin**	$3,266,942	($22,110)	$3,244,832	$751,832	$3,996,664	
	Other Operating Expenses						
20	Test Year Other Operating Expenses	$1,640,499					Income Statement
21	Amortized Regulatory Expense		93,750				page 7
22	Net Write-Off Non-Gas Cost		(3,553)		2,105		page 7
23	Payroll		14,377				Attachment SEK-2
24	Payroll Taxes		1,398				Attachment SEK-2
25	Line Locate Costs		171,510				Attachment SEK-2
26	Normalization of Costs		11,104				Attachment SEK-2
27	Health Insurance		8,190				Attachment SEK-2
28	Out of Period Expenses		3,043				Attachment SEK-2
29	Non-Recurring Expenses		(4,664)				Attachment SEK-2
30	Non-Allowed Expenses		(943)				Attachment SEK-2
31	Cloud Computing Amortization		901				Attachment SEK-2
32	Public Utility Fee		2,482		875		page 8
33	Total Other Operating Expenses	$1,640,499	$297,594	$1,938,093	$2,980	$1,941,073	

WESTFIELD GAS, LLC
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro Forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro Forma Results Based on Proposed Rates	F Reference
	Depreciation & Amortization						
34	Test Year Depreciation & Amortization	$753,704					Income Statement
35	Depreciation & Amortization Adjustment		(247,063)				Attachment CAJ-2
36	Pro Forma Depreciation & Amortization	$753,704	($247,063)	$506,642	$0	$506,642	
	Taxes						
37	Test Year Taxes	$212,470					Income Statement
38	Pro Forma Change in IURT		($67,162)		$0		page 9
39	Pro Forma Change in Property Tax		3,582				Attachment CAJ-2
40	Proforma Non-Recurring Tax Expense		(4)				Attachment SEK-2
41	Pro Forma Taxes	$212,470	($63,584)	$148,887	$0	$148,887	
42	**Operating Income**	$660,269	($9,058)	$651,211	$748,852	$1,400,063	

GAS RATE NO. D20

RESIDENTIAL DELIVERY & SUPPLY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for residential domestic and residential space heating purposes by a Customer through one Meter supplying a single Premise, with no more than four (4) individual units.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D20, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$~~11.83~~15.00 per Meter per Month

DELIVERY CHARGE:

$0~~.3590~~ .4468 per Therm for the first 120 Therms delivered each Month

$0~~.2245~~.2792 per Therm for the next 380 Therms delivered each Month

$0~~.2082~~.2591 per Therm for all usage over 500 Therms delivered each Month

In addition, the Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

GAS SUPPLY CHARGE:

The currently applicable charge for all Gas supplied under this Gas Rate No. D20 is identified on Variable-Rate Gas Supply Service under Gas Rate No. S1.

GAS RATE NO. D30

INDUSTRIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for year-round industrial processing and incidental general purposes for a single Customer through one Meter supplying a single Premise. This rate is not available for industrial gas loads which are predominately space heating in character.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D30, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$~~109.18~~152.20 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0~~.3869~~.4324 per Therm for the first 500 Therms delivered each Month

$0~~.1834~~.2050 per Therm for all usage over 500 Therms delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D40

COMMERCIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for cooking and/or water heating, and/or other commercial use by a single Customer through one Meter supplying a single Premise.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D40, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$~~36.48~~50.56 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0~~.2940~~.3376 per Therm for the first 120 Therms delivered each Month

$0~~.2132~~.2448 per Therm for the next 380 Therms delivered each Month

$0~~.2020~~.2319 per Therm for all usage over 500 Therms delivered each Month

In addition, the applicable Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. ~~g~~Gas supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D50

LARGE VOLUME INTERRUPTIBLE DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for space heating and other gas service for a single Customer using in excess of 50,000 dekatherms (dths) per year through one Meter supplying a single Premise. A Customer served under this tariff is required at all times to have alternate fuel capabilities. Equipment must be maintained in operating condition on Customer's Premises to ensure the alternate fuel capability is available during the Curtailment period. From time to time, the Company shall have the right to observe the equipment on Customer's Premises to verify it is in good operating condition and that an inventory of alternate fuels is adequately maintained.

The Company may require, at its sole discretion, that Customers on this Gas Rate No. D50 have Automated Meter Reading Service, provided by the Company through Gas Rate No. A1.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D50, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$~~1,142.34~~1,442.69 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0~~.1602~~.1663 per Therm delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

GAS SUPPLY CHARGE:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. A1

MISCELLANEOUS CHARGES

AUTOMATED METER READING SERVICE:

The Company will provide Automated Meter Reading Service to 3rd Party Suppliers or to applicable Customers that have requested or are required to have Automated Meter Reading Service. The Automated Meter Reading Service includes installation of an Automated Meter Reading device and access to Meter reads. The following charge for Automated Meter Reading Service will be billed to applicable Customers or 3rd Party Suppliers:

$64 per Month for each Meter transmitting daily Meter readings

NON-PERFORMANCE CHARGE:

The Company shall charge monthly, a 3rd Party Supplier or applicable Customer~~s,~~ for any volumes ~~associated with Customers receiving Gas Delivery Service under Gas Rate Nos. D30, D40 and D50~~ that are considered daily Delivery Imbalances~~, or~~ unauthorized usage during a Curtailment period, or any usage during the first three (3) days of 3rd Party Supplier default. Charges are as follows:

The applicable gas supply charges or credits from Appendix B, plus $6~~.00~~ per Therm.

WAIVER OF CHARGE:

In its reasonable discretion, on a case-by-case basis, the Company may waive all or part of any Non-Performance Charge assessable to a Customer pursuant to this Gas Rate No. A1, provided, however, that the waiver of such Non-Performance Charge shall be exercised on a non-discriminating basis.

BILLING:

Non-Performance Charges will be calculated and billed at Month end to the applicable 3rd Party Supplier or applicable Customer. ~~Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.~~

Gas Rate No. A1 – Miscellaneous Charges (cont'd)

USAGE INFORMATION CHARGE:

The Company shall provide summaries of up to 24 months of Customer's usage by Meter to Customers, and/or 3rd Party Suppliers with the Customer's approval. The information will be provided to 3rd Party Suppliers for the sole purpose of arranging to provide gas supply services. The ~~folllowing~~following charges for those summaries will be billed to requesting 3rd Party Suppliers or Customers, per Meter.

$25 per Customer usage summary, per Meter.

SWITCHING CHARGE:

The Company shall bill a Customer for switching from Company Gas Supply Service, for any changes in the 3rd Party Supplier selected, or for returning to Company Gas Supply Service.

$25 per switch

The changes described above may occur only on the first day of the Customer's billing cycle or as otherwise specified by Company.

GAS RATE NO. A2

UNACCOUNTED-FOR GAS

APPLICABILITY:

This rate schedule is applicable to 3rd Party Suppliers of a Supplier Group in accordance with the Company's requirements.

DESCRIPTION:

1.18% of the quantities received by the Company from 3rd Party Suppliers of a Supplier Group at a point of receipt on the Company's distribution system shall be retained by the Company to compensate for Unaccounted-For Gas. The Unaccounted-For Gas percentage stated above shall be reviewed and adjusted annually by the Company, through updating of this Gas Rate after approval by the Indiana Utility Regulatory Commission, to reflect any changes in the system Unaccounted-For Gas percentage.

GAS RATE NO. A3

USAGE BALANCING SERVICE

APPLICABILITY:

The following provisions shall apply to 3rd Party Suppliers providing gas supply services to a Supplier Group of Customers in accordance with the Company's requirements.

USAGE IMBALANCES:

The Company shall cash out monthly a 3rd Party Supplier with positive or negative monthly net Usage Imbalances associated with a Supplier Group of Customers receiving Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

Negative monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed greater volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

Positive monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed lesser volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

~~In the event an Operational Flow Order is issued, all Usage Imbalances will be billed in accordance with Rate No. A1 Non-Performance Charges.~~ In all ~~Non-Operational Flow Order~~ periods, any net monthly Usage Imbalances will be administered in the following manner:

MONTHLY CASH-OUT:

1. Cash-out charges for net monthly negative Usage Imbalances are as follows (charges posted to bill):

    100% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including ~~2~~10%.

    110% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than ~~2~~10% up to and including 2~~5~~0%.

Gas Rate No. A3 – Usage Balancing Service – (cont'd)

120% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 2~~5~~0% up to and including 30%.

140% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 30%.

2. Cash-out credits for net monthly positive Usage Imbalances are as follows (Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.):

100% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including ~~2~~10%.

90% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than ~~2~~10% up to and including 2~~5~~0%.

80% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 2~~5~~0% up to and including 30%.

60% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 30%.

BILLING:

Charges and credits for Usage Balancing Service will be calculated monthly and billed at Month end to the applicable 3rd Party Supplier or as otherwise applicable to a Customer. Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.

GAS RATE NO. A4

SUPPLY ADMINISTRATION SERVICE

APPLICABILITY:

This rate is applicable to 3rd Party Suppliers providing gas supply services to Customers in accordance with the Company's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. A4, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

APPLICATION:

3rd Party Suppliers are required to apply for approval to provide gas supply services to Customers. ~~Only entities listed as approved bidders on CMS Panhandle Eastern Pipe Line Company or their successors are eligible to apply.~~ Applications must be accompanied by a nonrefundable $1,000 application fee.

SUPPLIER APPLICATIONS:

All 3rd Party Suppliers approved to provide gas supply service to Customers must submit a 3rd Party Supplier Application to Company and comply with Supplier Access Requirements, as defined in the Terms and Conditions for Gas Service. 3rd Party Suppliers are required to comply with all requirements of Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

ADMINISTRATIVE SERVICE FEES:

The Company shall bill 3rd Party Suppliers the following charges for Supply Administration Services which support Customer-specific supply transactions. Those services include, but are not limited to, nominations, confirmations, scheduling, daily requirements forecasting, imbalance administration, supplier compliance and contract administration. The charges reflect the character of the Customer accounts, and participation in Supplier Groups. Charges to 3rd Party Suppliers include:

$100 per Month per Supplier Group plus $5 per Month per Single Account electing Gas Delivery Service

Gas Rate No. A4 – Supply Administration Service – (cont'd)

BILLING

Charges are billed to 3rd Party Suppliers at Month end.

APPENDIX A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply Services for all Therms delivered on or after August 1, 2022.

Gas Supply Charge: $ Per Therm

Gas Rate D20	Gas Supply Charge	$1.0130
Gas Rate D30	Gas Supply Charge	$1.0130
Gas Rate D40	Gas Supply Charge	$1.0130
Gas Rate D50	Gas Supply Charge	$1.0130

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APPENDIX B

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply services for the month of March 2022.

1. Gas Rate No. A3 Usage Balancing Service ~~– Gas Rate No. A1 Non-Performance Charges – Non-OFO Period~~ (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers,~~ or~~ (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (3) the average daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.~~.~~)

Gas Supply Charge - Negative Imbalance $0.7~~537~~627

2. Gas Rate No. A3 Usage Balancing Service ~~– Gas Rate No. A1 Non-Performance Charges – Non-OFO Period~~ (Positive Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the lower of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers,~~ or~~ (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (3) the average daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Gas Supply Charge - Positive Imbalance ($0.3985)

3. Gas Rate No. A1 Non-Performance Charges ~~– Economic OFO, Non-Economic OFO,~~ Delivery Imbalances (Negative Imbalance), Interruption or Curtailment ~~Periods~~ Gas Rate No. S2 Supply of Last Resort (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (2) the daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Day 1	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 2	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 3	Capacity	$0.3101	Commodity	$0.4457	Gas Supply Charge	$0.7558
Day 4	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537

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Day 5	Capacity	$0.3101	Commodity	$0.4560	Gas Supply Charge	$0.7661
Day 6	Capacity	$0.3101	Commodity	$0.4560	Gas Supply Charge	$0.7661
Day 7	Capacity	$0.3101	Commodity	$0.4560	Gas Supply Charge	$0.7661

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

~~**Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Negative Imbalance): $ Per Therm**~~

Day 8	Capacity	$0.3101	Commodity	$0.4756	Gas Supply Charge	$0.7857
Day 9	Capacity	$0.3101	Commodity	$0.4550	Gas Supply Charge	$0.7651
Day 10	Capacity	$0.3101	Commodity	$0.4467	Gas Supply Charge	$0.7568
Day 11	Capacity	$0.3101	Commodity	$0.4580	Gas Supply Charge	$0.7681
Day 12	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 13	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 14	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 15	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 16	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 17	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 18	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 19	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 20	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 21	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 22	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 23	Capacity	$0.3101	Commodity	$0.4519	Gas Supply Charge	$0.7620
Day 24	Capacity	$0.3101	Commodity	$0.4751	Gas Supply Charge	$0.7852
Day 25	Capacity	$0.3101	Commodity	$0.4730	Gas Supply Charge	$0.7831
Day 26	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 27	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 28	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 29	Capacity	$0.3101	Commodity	$0.5018	Gas Supply Charge	$0.8119
Day 30	Capacity	$0.3101	Commodity	$0.4879	Gas Supply Charge	$0.7980
Day 31	Capacity	$0.3101	Commodity	$0.5116	Gas Supply Charge	$0.8217

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APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

~~**4. Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Positive Imbalance): $ Per Therm**~~

~~(The Gas Supply Charge is equal to the lower of: (1) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (2) the daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)~~

~~Day 1~~	~~Gas Supply Charge~~	~~$0.3869)~~
~~Day 2~~	~~Gas Supply Charge~~	~~$0.4132)~~
~~Day 3~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 4~~	~~Gas Supply Charge~~	~~$0.4282)~~
~~Day 5~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 6~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 7~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 8~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 9~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 10~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 11~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 12~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 13~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 14~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 15~~	~~Gas Supply Charge~~	~~$0.4148)~~
~~Day 16~~	~~Gas Supply Charge~~	~~$0.4008)~~
~~Day 17~~	~~Gas Supply Charge~~	~~$0.4148)~~
~~Day 18~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 19~~	~~Gas Supply Charge~~	~~$0.4271)~~
~~Day 20~~	~~Gas Supply Charge~~	~~$0.4271)~~
~~Day 21~~	~~Gas Supply Charge~~	~~$0.4271)~~
~~Day 22~~	~~Gas Supply Charge~~	~~$0.4163)~~
~~Day 23~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 24~~	~~Gas Supply Charge~~	~~$0.4436)~~
~~Day 25~~	~~Gas Supply Charge~~	~~$0.4436)~~

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

~~Gas Rate No. A1 Non-Performance Charges – Economic OFO, Non-Economic OFO, Interruption, or Curtailment Periods (Positive Imbalance): $ Per Therm~~

~~Day 26~~	~~Gas Supply Charge~~	~~($0.4436)~~
~~Day 27~~	~~Gas Supply Charge~~	~~($0.4436)~~
~~Day 28~~	~~Gas Supply Charge~~	~~($0.4436)~~
~~Day 29~~	~~Gas Supply Charge~~	~~($0.4436)~~
~~Day 30~~	~~Gas Supply Charge~~	~~($0.4436)~~
~~Day 31~~	~~Gas Supply Charge~~	~~($0.4436)~~

APPENDIX C

NON-RECURRING CHARGES

APPLICABILITY:

Pursuant to the Terms and Conditions, listed below are charges applicable to all Customers in the Company's service area.

CHARGES:

Bad Check Charge (from Section 5.5.3)	$11.00
Delinquent Account Trip Charge (from Section 5.5.2)	$14.00
Reconnect Charge (from Sections 6.9 and 6.10)	$44.00

APPENDIX D

NORMAL TEMPERATURE ADJUSTMENT

The billed amount for each Rate D20 and D40 Customer shall be subject to a Normal Temperature Adjustment ("NTA") for each bill rendered during the billing months of November through May inclusive.

The NTA adjusts each Customer's Monthly billed amount to reverse the impact on margin recovery caused by non-normal temperatures during the billing period, as measured by actual heating degree day variations from normal heating degree days.

NTA COMPUTATION:

The NTA for each Customer's monthly billing shall be computed as follows:

NTA = NTA Therms x NTA Margin

NTA THERMS:

The NTA Therms usage for each Customer to which the NTA Margin shall be applied is computed as follows:

$$\text{NTA Therms} = \frac{[\text{Actual Therms} - \text{Base Load Therms}]}{\text{Actual Degree Days}} \times [\text{Normal Degree Days} - \text{Actual Degree Days}]$$

NTA MARGIN:

The NTA Margin for Rate D20 shall be the margin (i.e., non-gas cost) component of the second block of the Delivery Charge. The NTA Margin for Rate D40 shall be the margin (i.e., non-gas cost) component of the tail block Delivery Charge.

BASE LOAD THERMS:

Base Load Therms shall be the Customer's average daily Therms usage for the previous summer months (July and August) multiplied by the number of days in the current billing period.

For Customers whose Base Load Therms cannot be accurately determined (e.g., new Customers without two months of summer usage history), estimated average daily Therms shall be used.

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL AND ACTUAL DEGREE DAYS:

Normal Degree Days for each Customer's billing period shall be as set forth in the tables on the following pages.

Actual Degree Days for each customer's billing period shall be taken from the actual heating degree days reported each day by the National Weather Service.

Normal Degree Days and Actual Degree Days are based on Heating Degree Days as reported for Indianapolis, Indiana.

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
NON-LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0~~0~~	Aug 22	0~~0~~	Oct 13	9~~10~~	Dec 4	28~~30~~	Jan 25	37~~37~~	Mar 18	22~~22~~	May 9	5~~6~~
Jul 2	0~~0~~	Aug 23	0~~0~~	Oct 14	9~~10~~	Dec 5	29~~30~~	Jan 26	37~~37~~	Mar 19	22~~22~~	May 10	5~~6~~
Jul 3	0~~0~~	Aug 24	0~~0~~	Oct 15	10~~10~~	Dec 6	29~~31~~	Jan 27	37~~37~~	Mar 20	21~~21~~	May 11	5~~5~~
Jul 4	0~~0~~	Aug 25	0~~0~~	Oct 16	10~~10~~	Dec 7	29~~31~~	Jan 28	36~~37~~	Mar 21	21~~21~~	May 12	5~~5~~
Jul 5	0~~0~~	Aug 26	0~~0~~	Oct 17	10~~11~~	Dec 8	30~~31~~	Jan 29	36~~37~~	Mar 22	21~~21~~	May 13	5~~5~~
Jul 6	0~~0~~	Aug 27	0~~0~~	Oct 18	11~~11~~	Dec 9	30~~32~~	Jan 30	36~~36~~	Mar 23	20~~20~~	May 14	5~~5~~
Jul 7	0~~0~~	Aug 28	0~~0~~	Oct 19	11~~11~~	Dec 10	30~~32~~	Jan 31	36~~36~~	Mar 24	20~~20~~	May 15	4~~5~~
Jul 8	0~~0~~	Aug 29	0~~0~~	Oct 20	11~~12~~	Dec 11	31~~32~~	Feb 1	36~~36~~	Mar 25	19~~19~~	May 16	4~~4~~
Jul 9	0~~0~~	Aug 30	0~~0~~	Oct 21	12~~12~~	Dec 12	31~~33~~	Feb 2	36~~36~~	Mar 26	19~~19~~	May 17	4~~4~~
Jul 10	0~~0~~	Aug 31	0~~0~~	Oct 22	12~~12~~	Dec 13	31~~33~~	Feb 3	35~~36~~	Mar 27	19~~19~~	May 18	4~~4~~
Jul 11	0~~0~~	Sep 1	0~~0~~	Oct 23	13~~12~~	Dec 14	31~~33~~	Feb 4	35~~36~~	Mar 28	18~~18~~	May 19	4~~4~~
Jul 12	0~~0~~	Sep 2	0~~0~~	Oct 24	13~~13~~	Dec 15	32~~34~~	Feb 5	35~~35~~	Mar 29	18~~18~~	May 20	4~~4~~
Jul 13	0~~0~~	Sep 3	0~~0~~	Oct 25	13~~13~~	Dec 16	32~~34~~	Feb 6	35~~35~~	Mar 30	18~~18~~	May 21	3~~4~~
Jul 14	0~~1~~	Sep 4	0~~0~~	Oct 26	14~~13~~	Dec 17	32~~34~~	Feb 7	35~~35~~	Mar 31	17~~17~~	May 22	3~~3~~
Jul 15	1~~1~~	Sep 5	0~~1~~	Oct 27	14~~14~~	Dec 18	32~~34~~	Feb 8	35~~35~~	Apr 1	16~~17~~	May 23	3~~3~~
Jul 16	0~~0~~	Sep 6	0~~1~~	Oct 28	14~~14~~	Dec 19	33~~35~~	Feb 9	34~~35~~	Apr 2	16~~17~~	May 24	3~~3~~
Jul 17	0~~0~~	Sep 7	1~~1~~	Oct 29	15~~14~~	Dec 20	33~~35~~	Feb 10	34~~34~~	Apr 3	16~~16~~	May 25	3~~3~~
Jul 18	0~~0~~	Sep 8	1~~1~~	Oct 30	15~~15~~	Dec 21	33~~35~~	Feb 11	34~~34~~	Apr 4	16~~16~~	May 26	3~~3~~
Jul 19	0~~0~~	Sep 9	1~~1~~	Oct 31	16~~15~~	Dec 22	33~~35~~	Feb 12	33~~34~~	Apr 5	15~~16~~	May 27	2~~3~~
Jul 20	0~~0~~	Sep 10	1~~1~~	Nov 1	16~~15~~	Dec 23	34~~35~~	Feb 13	33~~34~~	Apr 6	15~~15~~	May 28	2~~2~~
Jul 21	0~~0~~	Sep 11	1~~1~~	Nov 2	16~~16~~	Dec 24	34~~36~~	Feb 14	33~~33~~	Apr 7	15~~15~~	May 29	2~~2~~
Jul 22	0~~0~~	Sep 12	1~~1~~	Nov 3	16~~16~~	Dec 25	34~~36~~	Feb 15	33~~33~~	Apr 8	14~~15~~	May 30	2~~2~~
Jul 23	0~~0~~	Sep 13	1~~1~~	Nov 4	17~~16~~	Dec 26	34~~36~~	Feb 16	32~~33~~	Apr 9	14~~14~~	May 31	2~~2~~
Jul 24	0~~0~~	Sep 14	1~~2~~	Nov 5	18~~17~~	Dec 27	34~~36~~	Feb 17	32~~32~~	Apr 10	14~~14~~	Jun 1	2~~2~~
Jul 25	0~~0~~	Sep 15	2~~2~~	Nov 6	18~~17~~	Dec 28	35~~36~~	Feb 18	32~~32~~	Apr 11	13~~14~~	Jun 2	2~~2~~
Jul 26	0~~0~~	Sep 16	2~~2~~	Nov 7	18~~18~~	Dec 29	35~~36~~	Feb 19	31~~32~~	Apr 12	13~~13~~	Jun 3	2~~1~~
Jul 27	0~~0~~	Sep 17	2~~2~~	Nov 8	19~~18~~	Dec 30	35~~36~~	Feb 20	31~~32~~	Apr 13	13~~13~~	Jun 4	2~~1~~
Jul 28	0~~0~~	Sep 18	2~~2~~	Nov 9	19~~18~~	Dec 31	35~~36~~	Feb 21	31~~31~~	Apr 14	12~~13~~	Jun 5	1~~1~~
Jul 29	0~~0~~	Sep 19	2~~3~~	Nov 10	20~~19~~	Jan 1	35~~37~~	Feb 22	30~~31~~	Apr 15	12~~12~~	Jun 6	1~~1~~
Jul 30	0~~0~~	Sep 20	2~~3~~	Nov 11	20~~19~~	Jan 2	35~~37~~	Feb 23	30~~31~~	Apr 16	12~~12~~	Jun 7	1~~1~~
Jul 31	0~~0~~	Sep 21	3~~3~~	Nov 12	20~~20~~	Jan 3	35~~37~~	Feb 24	30~~30~~	Apr 17	11~~12~~	Jun 8	1~~1~~
Aug 1	0~~0~~	Sep 22	3~~3~~	Nov 13	21~~20~~	Jan 4	35~~37~~	Feb 25	29~~30~~	Apr 18	11~~12~~	Jun 9	1~~1~~
Aug 2	0~~0~~	Sep 23	3~~4~~	Nov 14	21~~20~~	Jan 5	36~~37~~	Feb 26	29~~29~~	Apr 19	11~~11~~	Jun 10	1~~1~~
Aug 3	0~~0~~	Sep 24	3~~4~~	Nov 15	22~~21~~	Jan 6	36~~37~~	Feb 27	29~~29~~	Apr 20	10~~11~~	Jun 11	0~~1~~
Aug 4	0~~0~~	Sep 25	4~~4~~	Nov 16	22~~21~~	Jan 7	36~~37~~	Feb 28	28~~29~~	Apr 21	10~~11~~	Jun 12	0~~0~~
Aug 5	0~~0~~	Sep 26	4~~5~~	Nov 17	22~~22~~	Jan 8	36~~37~~	Mar 1	28~~28~~	Apr 22	10~~10~~	Jun 13	0~~0~~
Aug 6	0~~0~~	Sep 27	4~~5~~	Nov 18	23~~22~~	Jan 9	37~~37~~	Mar 2	27~~28~~	Apr 23	9~~10~~	Jun 14	0~~0~~
Aug 7	0~~0~~	Sep 28	4~~5~~	Nov 19	23~~23~~	Jan 10	37~~37~~	Mar 3	27~~28~~	Apr 24	9~~10~~	Jun 15	0~~0~~
Aug 8	0~~0~~	Sep 29	5~~6~~	Nov 20	24~~23~~	Jan 11	37~~37~~	Mar 4	27~~27~~	Apr 25	9~~9~~	Jun 16	0~~0~~
Aug 9	0~~0~~	Sep 30	5~~6~~	Nov 21	24~~24~~	Jan 12	37~~37~~	Mar 5	27~~27~~	Apr 26	8~~9~~	Jun 17	0~~0~~
Aug 10	0~~0~~	Oct 1	5~~6~~	Nov 22	24~~24~~	Jan 13	37~~37~~	Mar 6	26~~27~~	Apr 27	8~~9~~	Jun 18	0~~0~~
Aug 11	0~~0~~	Oct 2	5~~7~~	Nov 23	25~~25~~	Jan 14	37~~37~~	Mar 7	26~~26~~	Apr 28	8~~8~~	Jun 19	0~~0~~
Aug 12	0~~0~~	Oct 3	6~~7~~	Nov 24	25~~25~~	Jan 15	37~~37~~	Mar 8	26~~26~~	Apr 29	8~~8~~	Jun 20	0~~0~~
Aug 13	0~~0~~	Oct 4	6~~7~~	Nov 25	25~~26~~	Jan 16	37~~37~~	Mar 9	25~~25~~	Apr 30	7~~8~~	Jun 21	0~~0~~
Aug 14	1~~0~~	Oct 5	6~~7~~	Nov 26	26~~26~~	Jan 17	37~~37~~	Mar 10	25~~25~~	May 1	7~~8~~	Jun 22	0~~0~~
Aug 15	1~~0~~	Oct 6	7~~8~~	Nov 27	26~~27~~	Jan 18	37~~37~~	Mar 11	24~~25~~	May 2	6~~7~~	Jun 23	0~~0~~
Aug 16	0~~0~~	Oct 7	7~~8~~	Nov 28	26~~27~~	Jan 19	37~~37~~	Mar 12	24~~24~~	May 3	6~~7~~	Jun 24	0~~0~~
Aug 17	0~~0~~	Oct 8	7~~8~~	Nov 29	27~~28~~	Jan 20	37~~37~~	Mar 13	24~~24~~	May 4	6~~7~~	Jun 25	0~~0~~
Aug 18	0~~0~~	Oct 9	8~~9~~	Nov 30	27~~28~~	Jan 21	37~~37~~	Mar 14	23~~23~~	May 5	6~~7~~	Jun 26	0~~0~~
Aug 19	0~~0~~	Oct 10	8~~9~~	Dec 1	28~~28~~	Jan 22	37~~37~~	Mar 15	23~~23~~	May 6	6~~6~~	Jun 27	0~~0~~
Aug 20	0~~0~~	Oct 11	8~~9~~	Dec 2	28~~29~~	Jan 23	37~~37~~	Mar 16	23~~23~~	May 7	6~~6~~	Jun 28	0~~0~~
Aug 21	0~~0~~	Oct 12	9~~9~~	Dec 3	28~~29~~	Jan 24	37~~37~~	Mar 17	22~~22~~	May 8	6~~6~~	Jun 29	0~~0~~
												Jun 30	0~~0~~

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0~~0~~	Aug 22	0~~0~~	Oct 13	9~~10~~	Dec 4	28~~30~~	Jan 25	37~~37~~	Mar 17	22~~22~~	May 8	6~~6~~
Jul 2	0~~0~~	Aug 23	0~~0~~	Oct 14	9~~10~~	Dec 5	29~~30~~	Jan 26	37~~37~~	Mar 18	22~~22~~	May 9	5~~6~~
Jul 3	0~~0~~	Aug 24	0~~0~~	Oct 15	10~~10~~	Dec 6	29~~31~~	Jan 27	37~~37~~	Mar 19	22~~22~~	May 10	5~~6~~
Jul 4	0~~0~~	Aug 25	0~~0~~	Oct 16	10~~10~~	Dec 7	29~~31~~	Jan 28	36~~37~~	Mar 20	21~~21~~	May 11	5~~5~~
Jul 5	0~~0~~	Aug 26	0~~0~~	Oct 17	10~~11~~	Dec 8	30~~31~~	Jan 29	36~~37~~	Mar 21	21~~21~~	May 12	5~~5~~
Jul 6	0~~0~~	Aug 27	0~~0~~	Oct 18	11~~11~~	Dec 9	30~~32~~	Jan 30	36~~36~~	Mar 22	21~~21~~	May 13	5~~5~~
Jul 7	0~~0~~	Aug 28	0~~0~~	Oct 19	11~~11~~	Dec 10	30~~32~~	Jan 31	36~~36~~	Mar 23	20~~20~~	May 14	5~~5~~
Jul 8	0~~0~~	Aug 29	0~~0~~	Oct 20	11~~12~~	Dec 11	31~~32~~	Feb 1	36~~36~~	Mar 24	20~~20~~	May 15	4~~5~~
Jul 9	0~~0~~	Aug 30	0~~0~~	Oct 21	12~~12~~	Dec 12	31~~33~~	Feb 2	36~~36~~	Mar 25	19~~19~~	May 16	4~~4~~
Jul 10	0~~0~~	Aug 31	0~~0~~	Oct 22	12~~12~~	Dec 13	31~~33~~	Feb 3	35~~36~~	Mar 26	19~~19~~	May 17	4~~4~~
Jul 11	0~~0~~	Sep 1	0~~0~~	Oct 23	13~~12~~	Dec 14	31~~33~~	Feb 4	35~~36~~	Mar 27	19~~19~~	May 18	4~~4~~
Jul 12	0~~0~~	Sep 2	0~~0~~	Oct 24	13~~13~~	Dec 15	32~~34~~	Feb 5	35~~35~~	Mar 28	18~~18~~	May 19	4~~4~~
Jul 13	0~~0~~	Sep 3	0~~0~~	Oct 25	13~~13~~	Dec 16	32~~34~~	Feb 6	35~~35~~	Mar 29	18~~18~~	May 20	4~~4~~
Jul 14	0~~1~~	Sep 4	0~~0~~	Oct 26	14~~13~~	Dec 17	32~~34~~	Feb 7	35~~35~~	Mar 30	18~~18~~	May 21	3~~4~~
Jul 15	1~~1~~	Sep 5	0~~1~~	Oct 27	14~~14~~	Dec 18	32~~34~~	Feb 8	35~~35~~	Mar 31	17~~17~~	May 22	3~~3~~
Jul 16	0~~0~~	Sep 6	0~~1~~	Oct 28	14~~14~~	Dec 19	33~~35~~	Feb 9	34~~35~~	Apr 1	16~~17~~	May 23	3~~3~~
Jul 17	0~~0~~	Sep 7	1~~1~~	Oct 29	15~~14~~	Dec 20	33~~35~~	Feb 10	34~~34~~	Apr 2	16~~17~~	May 24	3~~3~~
Jul 18	0~~0~~	Sep 8	1~~1~~	Oct 30	15~~15~~	Dec 21	33~~35~~	Feb 11	34~~34~~	Apr 3	16~~16~~	May 25	3~~3~~
Jul 19	0~~0~~	Sep 9	1~~1~~	Oct 31	16~~15~~	Dec 22	33~~35~~	Feb 12	33~~34~~	Apr 4	16~~16~~	May 26	3~~3~~
Jul 20	0~~0~~	Sep 10	1~~1~~	Nov 1	16~~15~~	Dec 23	34~~35~~	Feb 13	33~~34~~	Apr 5	15~~16~~	May 27	2~~3~~
Jul 21	0~~0~~	Sep 11	1~~1~~	Nov 2	16~~16~~	Dec 24	34~~36~~	Feb 14	33~~33~~	Apr 6	15~~15~~	May 28	2~~2~~
Jul 22	0~~0~~	Sep 12	1~~1~~	Nov 3	16~~16~~	Dec 25	34~~36~~	Feb 15	33~~33~~	Apr 7	15~~15~~	May 29	2~~2~~
Jul 23	0~~0~~	Sep 13	1~~1~~	Nov 4	17~~16~~	Dec 26	34~~36~~	Feb 16	32~~33~~	Apr 8	14~~15~~	May 30	2~~2~~
Jul 24	0~~0~~	Sep 14	1~~2~~	Nov 5	18~~17~~	Dec 27	34~~36~~	Feb 17	32~~32~~	Apr 9	14~~14~~	May 31	2~~2~~
Jul 25	0~~0~~	Sep 15	2~~2~~	Nov 6	18~~17~~	Dec 28	35~~36~~	Feb 18	32~~32~~	Apr 10	14~~14~~	Jun 1	2~~2~~
Jul 26	0~~0~~	Sep 16	2~~2~~	Nov 7	18~~18~~	Dec 29	35~~36~~	Feb 19	31~~32~~	Apr 11	13~~14~~	Jun 2	2~~2~~
Jul 27	0~~0~~	Sep 17	2~~2~~	Nov 8	19~~18~~	Dec 30	35~~36~~	Feb 20	31~~32~~	Apr 12	13~~13~~	Jun 3	2~~1~~
Jul 28	0~~0~~	Sep 18	2~~2~~	Nov 9	19~~18~~	Dec 31	35~~36~~	Feb 21	31~~31~~	Apr 13	13~~13~~	Jun 4	2~~1~~
Jul 29	0~~0~~	Sep 19	2~~3~~	Nov 10	20~~19~~	Jan 1	35~~37~~	Feb 22	30~~31~~	Apr 14	12~~13~~	Jun 5	1~~1~~
Jul 30	0~~0~~	Sep 20	2~~3~~	Nov 11	20~~19~~	Jan 2	35~~37~~	Feb 23	30~~31~~	Apr 15	12~~12~~	Jun 6	1~~1~~
Jul 31	0~~0~~	Sep 21	3~~3~~	Nov 12	20~~20~~	Jan 3	35~~37~~	Feb 24	30~~30~~	Apr 16	12~~12~~	Jun 7	1~~1~~
Aug 1	0~~0~~	Sep 22	3~~3~~	Nov 13	21~~20~~	Jan 4	35~~37~~	Feb 25	29~~30~~	Apr 17	11~~12~~	Jun 8	1~~1~~
Aug 2	0~~0~~	Sep 23	3~~4~~	Nov 14	21~~20~~	Jan 5	36~~37~~	Feb 26	29~~29~~	Apr 18	11~~12~~	Jun 9	1~~1~~
Aug 3	0~~0~~	Sep 24	3~~4~~	Nov 15	22~~21~~	Jan 6	36~~37~~	Feb 27	29~~29~~	Apr 19	11~~11~~	Jun 10	1~~1~~
Aug 4	0~~0~~	Sep 25	4~~4~~	Nov 16	22~~21~~	Jan 7	36~~37~~	Feb 28	28~~29~~	Apr 20	10~~11~~	Jun 11	0~~1~~
Aug 5	0~~0~~	Sep 26	4~~5~~	Nov 17	22~~22~~	Jan 8	36~~37~~	Feb 29	29~~29~~	Apr 21	10~~11~~	Jun 12	0~~0~~
Aug 6	0~~0~~	Sep 27	4~~5~~	Nov 18	23~~22~~	Jan 9	37~~37~~	Mar 1	28~~28~~	Apr 22	10~~10~~	Jun 13	0~~0~~
Aug 7	0~~0~~	Sep 28	4~~5~~	Nov 19	23~~23~~	Jan 10	37~~37~~	Mar 2	27~~28~~	Apr 23	9~~10~~	Jun 14	0~~0~~
Aug 8	0~~0~~	Sep 29	5~~6~~	Nov 20	24~~23~~	Jan 11	37~~37~~	Mar 3	27~~28~~	Apr 24	9~~10~~	Jun 15	0~~0~~
Aug 9	0~~0~~	Sep 30	5~~6~~	Nov 21	24~~24~~	Jan 12	37~~37~~	Mar 4	27~~27~~	Apr 25	9~~9~~	Jun 16	0~~0~~
Aug 10	0~~0~~	Oct 1	5~~6~~	Nov 22	24~~24~~	Jan 13	37~~37~~	Mar 5	27~~27~~	Apr 26	8~~9~~	Jun 17	0~~0~~
Aug 11	0~~0~~	Oct 2	5~~7~~	Nov 23	25~~25~~	Jan 14	37~~37~~	Mar 6	26~~27~~	Apr 27	8~~9~~	Jun 18	0~~0~~
Aug 12	0~~0~~	Oct 3	6~~7~~	Nov 24	25~~25~~	Jan 15	37~~37~~	Mar 7	26~~26~~	Apr 28	8~~8~~	Jun 19	0~~0~~
Aug 13	0~~0~~	Oct 4	6~~7~~	Nov 25	25~~26~~	Jan 16	37~~37~~	Mar 8	26~~26~~	Apr 29	8~~8~~	Jun 20	0~~0~~
Aug 14	1~~0~~	Oct 5	6~~7~~	Nov 26	26~~26~~	Jan 17	37~~37~~	Mar 9	25~~25~~	Apr 30	7~~8~~	Jun 21	0~~0~~
Aug 15	1~~0~~	Oct 6	7~~8~~	Nov 27	26~~27~~	Jan 18	37~~37~~	Mar 10	25~~25~~	May 1	7~~8~~	Jun 22	0~~0~~
Aug 16	0~~0~~	Oct 7	7~~8~~	Nov 28	26~~27~~	Jan 19	37~~37~~	Mar 11	24~~25~~	May 2	6~~7~~	Jun 23	0~~0~~
Aug 17	0~~0~~	Oct 8	7~~8~~	Nov 29	27~~28~~	Jan 20	37~~37~~	Mar 12	24~~24~~	May 3	6~~7~~	Jun 24	0~~0~~
Aug 18	0~~0~~	Oct 9	8~~9~~	Nov 30	27~~28~~	Jan 21	37~~37~~	Mar 13	24~~24~~	May 4	6~~7~~	Jun 25	0~~0~~
Aug 19	0~~0~~	Oct 10	8~~9~~	Dec 1	28~~28~~	Jan 22	37~~37~~	Mar 14	23~~23~~	May 5	6~~7~~	Jun 26	0~~0~~
Aug 20	0~~0~~	Oct 11	8~~9~~	Dec 2	28~~29~~	Jan 23	37~~37~~	Mar 15	23~~23~~	May 6	6~~6~~	Jun 27	0~~0~~
Aug 21	0~~0~~	Oct 12	9~~9~~	Dec 3	28~~29~~	Jan 24	37~~37~~	Mar 16	23~~23~~	May 7	6~~6~~	Jun 28	0~~0~~
												Jun 29	0~~0~~
												Jun 30	0~~0~~

APPENDIX E

ENERGY EFFICIENCY ADJUSTMENT

The Delivery Charges specified in Gas Rate Nos. D20 and D40 shall be adjusted from time to time in accordance with the Final Order of the Indiana Utility Regulatory Commission in Company's most recent general rate case to reflect an Energy Efficiency Funding Component and a Sales Reconciliation Component.

ENERGY EFFICIENCY FUNDING COMPONENT ("EEFC"):

The EEFC shall recover the costs of funding energy efficiency efforts throughout the Company's service area. These efforts may include, among others, energy efficiency programs, Customer education programs, and weatherization programs designed to benefit Customers under the applicable rate schedules.

The estimated annual costs, plus related revenue taxes, shall be divided by projected sales volumes to determine the applicable EEFC. The actual costs recoverable and the actual costs recovered under the EEFC shall be reconciled, with any under or over recovery being recovered or returned via the EEFC over a subsequent twelve Month period.

SALES RECONCILIATION COMPONENT ("SRC"):

The SRC shall recover the differences between Actual Margins and Adjusted Order Granted Margins for the applicable rate schedules.

Actual Margins are defined as Monthly margins for each rate schedule, prior to the SRC Adjustment. Adjusted Order Granted Margins are defined as the Order granted Monthly margins for each rate schedule, as approved in Company's most recent general rate case, as adjusted to reflect the change in number of Customers from the Order granted Customer levels. To reflect the change in number of Customers, Order granted margin per Customer is multiplied by the change in the number of Customers since the like Month during the test year, with the product being added to the Order granted margins for such Month.

The Company shall defer the calculated differences between Actual Margins and Adjusted Order Granted Margins for subsequent return or recovery via the SRC. Annually, the Company shall reflect in a revised SRC the accumulated Monthly margin differences. Beginning with the twelve-month period ending December 31, 2013, margin differences from Residential Customers

Appendix E – Energy Efficiency Adjustment (cont'd)

receiving Gas Delivery Service under Gas Rate No. D20 eligible for recovery in the SRC annually are capped at 8% of Adjusted Order Granted Margins attributable to Residential Customers applicable to the previous year. Any actual margin differences from Residential Customers in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

Appendix E – Energy Efficiency Adjustment

The accumulated Monthly margin differences for each rate schedule shall be divided by projected throughput volumes for each rate schedule to determine the applicable SRC. Projected and actual recoveries by rate schedule under the SRC are reconciled, with any under or over recovery being recovered or returned over a subsequent twelve Month period.

ENERGY EFFICIENCY ADJUSTMENT RATE: $ per Therm

The applicable Energy Efficiency Adjustment Rate (the sum of the EEFC and SRC) shall be applied to each Therm of metered Gas usage each Month.

Rate Schedule	A Energy Efficiency Funding Component	B Sales Reconciliation Component	A + B Energy Efficiency Adjustment Rate
Gas Rate D20	**$0.0013**	**$0.0424**	**$0.0437**
Gas Rate D40	**$0.0013**	**($0.0057)**	**($0.0044)**

APPENDIX F

REGULATORY ASSET AMORTIZATION

APPLICABILITY:

Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43600, issued, April 1, 2009, the Company was authorized to create a regulatory asset for the purpose of accumulating energy efficiency rebate costs. Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43624, issued March 10, 2010, the Company was authorized to recover the amortized cost of energy efficiency rebates previously authorized in Cause No. 43600 through this appendix. Appendix F is applicable to Gas Rate Nos. D20 and D40.

RATES AND CHARGES:

The appendix shall be applied to each Therm of metered gas usage each Month. The current charges are set forth below:

$0.0000 per Therm

GAS RATE NO. S1

VARIABLE-RATE GAS SUPPLY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas supplied in a Month or any portion thereof and delivered under Gas Rate Nos. D20, D30, D40, and D50 unless an eligible Customer has contracted with a 3rd Party Supplier for gas supply service.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. S1, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

GAS SUPPLY CHARGE:

The currently applicable charge for all gas supplied under this Gas Rate No. S1 is identified on Appendix A. The Gas Supply Charge is subject to change on a monthly basis.

3rd PARTY SUPPLIER:

Customers may select a 3rd Party Supplier to provide gas supply instead of the Company. Such selections shall be governed by the Company's requirements as described in the Terms and Conditions for Gas Service.

GAS RATE NO. S2

SUPPLY OF LAST RESORT

APPLICABILITY:

This rate schedule is applicable to Customers ~~who have chosen a~~and 3rd Party Suppliers in accordance with the Company's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. S2, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

GAS SUPPLY CHARGE:

For the first three days of default, ~~T~~the Non-Performance Charge (Gas Rate No. A1) will be applicable along with all other charges as ~~Gas Supply Charge for all negative imbalancesCustomer usage are~~ identified i~~o~~n Appendix B. The Gas Supply Charge will be applicable to 3rd Party Suppliers.

BILLING:

Beginning with the fourth day following default, until the end of the Customer's billing cycle, Customers who have chosen a 3rd Party Supplier, who has defaulted, by failing to nominate and/or deliver gas supply for three (3) consecutive days, will be billed Variable-Rate Gas Supply Service, under Gas Rate No. S1, for any volumes used. Volumes may be based on estimation or proration if daily usage is not available. ~~in excess of accumulated Daily Gas Supply Deliveries for the Month.~~

GAS RATE NO. D20

RESIDENTIAL DELIVERY & SUPPLY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for residential domestic and residential space heating purposes by a Customer through one Meter supplying a single Premise, with no more than four (4) individual units.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D20, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$15.00 per Meter per Month

DELIVERY CHARGE:

$0.4468 per Therm for the first 120 Therms delivered each Month

$0.2792 per Therm for the next 380 Therms delivered each Month

$0.2591 per Therm for all usage over 500 Therms delivered each Month

In addition, the Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

GAS SUPPLY CHARGE:

The currently applicable charge for all Gas supplied under this Gas Rate No. D20 is identified on Variable-Rate Gas Supply Service under Gas Rate No. S1.

GAS RATE NO. D30

INDUSTRIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for year-round industrial processing and incidental general purposes for a single Customer through one Meter supplying a single Premise. This rate is not available for industrial gas loads which are predominately space heating in character.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D30, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$152.20 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.4324 per Therm for the first 500 Therms delivered each Month

$0.2050 per Therm for all usage over 500 Therms delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D30 – Industrial Delivery Service (cont'd)

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D40

COMMERCIAL DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for cooking and/or water heating, and/or other commercial use by a single Customer through one Meter supplying a single Premise.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D40, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$50.56 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.3376 per Therm for the first 120 Therms delivered each Month

$0.2448 per Therm for the next 380 Therms delivered each Month

$0.2319 per Therm for all usage over 500 Therms delivered each Month

In addition, the applicable Normal Temperature Adjustment from Appendix D, Energy Efficiency Adjustment from Appendix E, and Regulatory Asset Amortization from Appendix F shall apply to all Therms delivered.

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D40 – Commercial Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. D50

LARGE VOLUME INTERRUPTIBLE DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for space heating and other gas service for a single Customer using in excess of 50,000 dekatherms (dths) per year through one Meter supplying a single Premise. A Customer served under this tariff is required at all times to have alternate fuel capabilities. Equipment must be maintained in operating condition on Customer's Premises to ensure the alternate fuel capability is available during the Curtailment period. From time to time, the Company shall have the right to observe the equipment on Customer's Premises to verify it is in good operating condition and that an inventory of alternate fuels is adequately maintained.

The Company may require, at its sole discretion, that Customers on this Gas Rate No. D50 have Automated Meter Reading Service, provided by the Company through Gas Rate No. A1.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D50, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

CUSTOMER CHARGE:

$1,442.69 per Meter per Month

The total Customer Charge will be the sum of all applicable per Meter charges.

DELIVERY CHARGE:

$0.1663 per Therm delivered each Month

Automated Meter Reading Service charges apply, in accordance with Gas Rate No. A1.

GAS SUPPLY CHARGE:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Company through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

When eligible under the Transportation Program, Customers may also choose to purchase gas supply from a 3rd Party Supplier.

Customers choosing not to make a gas supply selection, either from the Company or from a 3rd Party Supplier, will receive Variable-Rate Supply Service under Gas Rate No. S1.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

Customers may, when eligible under the Transportation Program, choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Company's requirements. It is the Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Company.

The Company also reserves the right to bill the Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, Customers may choose to purchase gas supply from the Company under Gas Rate No. S1, with the Company's approval.

Customers who switch from Company Gas Supply Service, switch 3rd Party Suppliers, or return to Company Gas Supply Service will be subject to Switching Charges, under Gas Rate No. A1.

GAS IMBALANCE PROVISIONS:

Delivery Imbalances for Supplier Groups, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries to the Company's gas system, will be monitored on a daily basis and accumulated monthly for all Customers of a 3rd Party Supplier, in a Supplier Group. Charges for all Delivery Imbalances will be billed, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of Gas consumed by Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A3.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at Month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A1.

SUPPLY OF LAST RESORT:

If the 3rd Party Supplier defaults, (as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days) beginning with the fourth day following default, Customers who have contracted for gas supply services from 3rd Party Suppliers, will have access to Supply of Last Resort Service from the Company, under Gas Rate No. S2 if available. Supply of Last Resort Service, if available, will be provided until the first day of the Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Company's discretion. If Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated. A Switching Charge will be assessed, pursuant to Gas Rate No. A1, on the first day of the next billing cycle.

NOMINATIONS:

3rd Party Suppliers of Customers in a Supplier Group, will be required to provide an estimate of Daily Gas Supply Nominations for the following Month to the Company by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the Month. 3rd Party Suppliers of Customers in a Supplier Group also will be required to provide Daily Gas Supply Nominations to the Company, as stated in the Terms and Conditions for Gas Service. The Company retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Company.

NON-ECONOMIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Non-Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

Gas Rate No. D50 – Large Volume Interruptible Delivery Service (cont'd)

ECOMONIC OPERATIONAL FLOW ORDER:

The Company, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Company will notify the affected 3rd Party Suppliers in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers who do not comply with the Economic Operational Flow Order, will be subject to Non-Performance Charges, under Gas Rate No. A1.

UNACCOUNTED-FOR GAS:

The Company will retain the allowance for Unaccounted-For Gas of the volumes tendered for delivery to the Customer for Company Use Gas as approved by the Indiana Utility Regulatory Commission in Gas Rate No. A2.

CURTAILMENT:

Service under this rate schedule, may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Company will notify Customers, and 3rd Party Suppliers, as soon as practical, but not less than 30 minutes prior to the effective time. Customers may be directed to restrict their Gas consumption on an hourly or daily basis. Customers who do not comply with the Company's request may be subject to Non-Performance Charges, under Gas Rate No. A1, for all Gas taken in excess of the Company's order.

GAS RATE NO. A1

MISCELLANEOUS CHARGES

AUTOMATED METER READING SERVICE:

The Company will provide Automated Meter Reading Service to 3rd Party Suppliers or to applicable Customers that have requested or are required to have Automated Meter Reading Service. The Automated Meter Reading Service includes installation of an Automated Meter Reading device and access to Meter reads. The following charge for Automated Meter Reading Service will be billed to applicable Customers or 3rd Party Suppliers:

$64 per Month for each Meter transmitting daily Meter readings

NON-PERFORMANCE CHARGE:

The Company shall charge monthly, a 3rd Party Supplier or applicable Customer for any volumes that are considered daily Delivery Imbalances, unauthorized usage during a Curtailment period, or any usage during the first three (3) days of 3rd Party Supplier default. Charges are as follows:

The applicable gas supply charges or credits from Appendix B, plus $6 per Therm.

WAIVER OF CHARGE:

In its reasonable discretion, on a case-by-case basis, the Company may waive all or part of any Non-Performance Charge assessable to a Customer pursuant to this Gas Rate No. A1, provided, however, that the waiver of such Non-Performance Charge shall be exercised on a non-discriminating basis.

BILLING:

Non-Performance Charges will be calculated and billed at Month end to the applicable 3rd Party Supplier or applicable Customer.

Gas Rate No. A1 – Miscellaneous Charges (cont'd)

USAGE INFORMATION CHARGE:

The Company shall provide summaries of up to 24 months of Customer's usage by Meter to Customers, and/or 3rd Party Suppliers with the Customer's approval. The information will be provided to 3rd Party Suppliers for the sole purpose of arranging to provide gas supply services. The following charges for those summaries will be billed to requesting 3rd Party Suppliers or Customers, per Meter.

$25 per Customer usage summary, per Meter.

SWITCHING CHARGE:

The Company shall bill a Customer for switching from Company Gas Supply Service, for any changes in the 3rd Party Supplier selected, or for returning to Company Gas Supply Service.

$25 per switch

The changes described above may occur only on the first day of the Customer's billing cycle or as otherwise specified by Company.

GAS RATE NO. A2

UNACCOUNTED-FOR GAS

APPLICABILITY:

This rate schedule is applicable to 3rd Party Suppliers of a Supplier Group in accordance with the Company's requirements.

DESCRIPTION:

1.18% of the quantities received by the Company from 3rd Party Suppliers of a Supplier Group at a point of receipt on the Company's distribution system shall be retained by the Company to compensate for Unaccounted-For Gas. The Unaccounted-For Gas percentage stated above shall be reviewed and adjusted annually by the Company, through updating of this Gas Rate after approval by the Indiana Utility Regulatory Commission, to reflect any changes in the system Unaccounted-For Gas percentage.

GAS RATE NO. A3

USAGE BALANCING SERVICE

APPLICABILITY:

The following provisions shall apply to 3rd Party Suppliers providing gas supply services to a Supplier Group of Customers in accordance with the Company's requirements.

USAGE IMBALANCES:

The Company shall cash out monthly a 3rd Party Supplier with positive or negative monthly net Usage Imbalances associated with a Supplier Group of Customers receiving Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

Negative monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed greater volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

Positive monthly net Usage Imbalances reflect situations where a Supplier Group of Customers consumed lesser volumes of Gas than accumulated Daily Gas Supply Deliveries for the Month.

In all periods, any net monthly Usage Imbalances will be administered in the following manner:

MONTHLY CASH-OUT:

1. Cash-out charges for net monthly negative Usage Imbalances are as follows (charges posted to bill):

   100% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including 10%.

   110% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 10% up to and including 20%.

Gas Rate No. A3 – Usage Balancing Service – (cont'd)

120% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 30%.

140% of applicable Gas Supply Charge from Appendix B (including capacity costs) for monthly net Usage Imbalances of greater than 30%.

2. Cash-out credits for net monthly positive Usage Imbalances are as follows (Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.):

100% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 0% up to and including 10%.

90% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 10% up to and including 20%.

80% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 30%.

60% of applicable Gas Supply Charge from Appendix B (excluding capacity costs) for monthly net Usage Imbalances of greater than 30%.

BILLING:

Charges and credits for Usage Balancing Service will be calculated monthly and billed at Month end to the applicable 3rd Party Supplier or as otherwise applicable to a Customer. Company will purchase amounts from a 3rd Party Supplier that are not offset by other charges.

GAS RATE NO. A4

SUPPLY ADMINISTRATION SERVICE

APPLICABILITY:

This rate is applicable to 3rd Party Suppliers providing gas supply services to Customers in accordance with the Company's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. A4, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

APPLICATION:

3rd Party Suppliers are required to apply for approval to provide gas supply services to Customers. Applications must be accompanied by a nonrefundable $1,000 application fee.

SUPPLIER APPLICATIONS:

All 3rd Party Suppliers approved to provide gas supply service to Customers must submit a 3rd Party Supplier Application to Company and comply with Supplier Access Requirements, as defined in the Terms and Conditions for Gas Service. 3rd Party Suppliers are required to comply with all requirements of Gas Delivery Service under Gas Rate Nos. D30, D40 and D50.

ADMINISTRATIVE SERVICE FEES:

The Company shall bill 3rd Party Suppliers the following charges for Supply Administration Services which support Customer-specific supply transactions. Those services include, but are not limited to, nominations, confirmations, scheduling, daily requirements forecasting, imbalance administration, supplier compliance and contract administration. The charges reflect the character of the Customer accounts, and participation in Supplier Groups. Charges to 3rd Party Suppliers include:

> **$100 per Month per Supplier Group plus $5 per Month per Single Account electing Gas Delivery Service**

Gas Rate No. A4 – Supply Administration Service – (cont'd)

BILLING

Charges are billed to 3rd Party Suppliers at Month end.

APPENDIX A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply Services for all Therms delivered on or after August 1, 2022.

Gas Supply Charge: $ Per Therm

Gas Rate D20	Gas Supply Charge	$1.0130
Gas Rate D30	Gas Supply Charge	$1.0130
Gas Rate D40	Gas Supply Charge	$1.0130
Gas Rate D50	Gas Supply Charge	$1.0130

For Illustrative Purposes Only

APPENDIX B

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Company's Gas Supply services for the month of March 2022.

1. Gas Rate No. A3 Usage Balancing Service (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers, (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (3) the average daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Gas Supply Charge - Negative Imbalance $0.7627

2. Gas Rate No. A3 Usage Balancing Service (Positive Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the lower of: (1) the month's average commodity cost per Therm for Commercial, Industrial, and Large Volume customers, (2) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (3) the average daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Gas Supply Charge - Positive Imbalance ($0.3985)

3. Gas Rate No. A1 Non-Performance Charges –Delivery Imbalances (Negative Imbalance), Interruption or Curtailment Gas Rate No. S2 Supply of Last Resort (Negative Imbalance): $ Per Therm

(The Gas Supply Charge is equal to the capacity cost, plus the higher of: (1) the first of the month index price of Panhandle adjusted for appropriate fuel, transportation, and basis, or (2) the daily index price of Panhandle adjusted for appropriate fuel, transportation, and basis.)

Day 1	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 2	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 3	Capacity	$0.3101	Commodity	$0.4457	Gas Supply Charge	$0.7558
Day 4	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 5	Capacity	For Illustrative Purposes Only			Supply Charge	$0.7661
Day 6	Capacity				Supply Charge	$0.7661
Day 7	Capacity	$0.3101	Commodity	$0.4560	Gas Supply Charge	$0.7661

APPENDIX B – CURRENT GAS SUPPLY CHARGES (Cont'd)

Day 8	Capacity	$0.3101	Commodity	$0.4756	Gas Supply Charge	$0.7857
Day 9	Capacity	$0.3101	Commodity	$0.4550	Gas Supply Charge	$0.7651
Day 10	Capacity	$0.3101	Commodity	$0.4467	Gas Supply Charge	$0.7568
Day 11	Capacity	$0.3101	Commodity	$0.4580	Gas Supply Charge	$0.7681
Day 12	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 13	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 14	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 15	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 16	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 17	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 18	Capacity	$0.3101	Commodity	$0.4477	Gas Supply Charge	$0.7578
Day 19	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 20	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 21	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 22	Capacity	$0.3101	Commodity	$0.4436	Gas Supply Charge	$0.7537
Day 23	Capacity	$0.3101	Commodity	$0.4519	Gas Supply Charge	$0.7620
Day 24	Capacity	$0.3101	Commodity	$0.4751	Gas Supply Charge	$0.7852
Day 25	Capacity	$0.3101	Commodity	$0.4730	Gas Supply Charge	$0.7831
Day 26	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 27	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 28	Capacity	$0.3101	Commodity	$0.5111	Gas Supply Charge	$0.8212
Day 29	Capacity	$0.3101	Commodity	$0.5018	Gas Supply Charge	$0.8119
Day 30	Capacity	$0.3101	Commodity	$0.4879	Gas Supply Charge	$0.7980
Day 31	Capacity	$0.3101	Commodity	$0.5116	Gas Supply Charge	$0.8217

For Illustrative Purposes Only

APPENDIX C

NON-RECURRING CHARGES

APPLICABILITY:

Pursuant to the Terms and Conditions, listed below are charges applicable to all Customers in the Company's service area.

CHARGES:

Bad Check Charge (from Section 5.5.3)	$11.00
Delinquent Account Trip Charge (from Section 5.5.2)	$14.00
Reconnect Charge (from Sections 6.9 and 6.10)	$44.00

APPENDIX D

NORMAL TEMPERATURE ADJUSTMENT

The billed amount for each Rate D20 and D40 Customer shall be subject to a Normal Temperature Adjustment ("NTA") for each bill rendered during the billing months of November through May inclusive.

The NTA adjusts each Customer's Monthly billed amount to reverse the impact on margin recovery caused by non-normal temperatures during the billing period, as measured by actual heating degree day variations from normal heating degree days.

NTA COMPUTATION:

The NTA for each Customer's monthly billing shall be computed as follows:

$$\text{NTA} = \text{NTA Therms} \times \text{NTA Margin}$$

NTA THERMS:

The NTA Therms usage for each Customer to which the NTA Margin shall be applied is computed as follows:

$$\text{NTA Therms} = \frac{[\text{Actual Therms} - \text{Base Load Therms}]}{\text{Actual Degree Days}} \times [\text{Normal Degree Days} - \text{Actual Degree Days}]$$

NTA MARGIN:

The NTA Margin for Rate D20 shall be the margin (i.e., non-gas cost) component of the second block of the Delivery Charge. The NTA Margin for Rate D40 shall be the margin (i.e., non-gas cost) component of the tail block Delivery Charge.

BASE LOAD THERMS:

Base Load Therms shall be the Customer's average daily Therms usage for the previous summer months (July and August) multiplied by the number of days in the current billing period.

For Customers whose Base Load Therms cannot be accurately determined (e.g., new Customers without two months of summer usage history), estimated average daily Therms shall be used.

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL AND ACTUAL DEGREE DAYS:

Normal Degree Days for each Customer's billing period shall be as set forth in the tables on the following pages.

Actual Degree Days for each customer's billing period shall be taken from the actual heating degree days reported each day by the National Weather Service.

Normal Degree Days and Actual Degree Days are based on Heating Degree Days as reported for Indianapolis, Indiana.

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
NON-LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0	Aug 22	0	Oct 13	9	Dec 4	28	Jan 25	37	Mar 18	22	May 9	5
Jul 2	0	Aug 23	0	Oct 14	9	Dec 5	29	Jan 26	37	Mar 19	22	May 10	5
Jul 3	0	Aug 24	0	Oct 15	10	Dec 6	29	Jan 27	37	Mar 20	21	May 11	5
Jul 4	0	Aug 25	0	Oct 16	10	Dec 7	29	Jan 28	36	Mar 21	21	May 12	5
Jul 5	0	Aug 26	0	Oct 17	10	Dec 8	30	Jan 29	36	Mar 22	21	May 13	5
Jul 6	0	Aug 27	0	Oct 18	11	Dec 9	30	Jan 30	36	Mar 23	20	May 14	5
Jul 7	0	Aug 28	0	Oct 19	11	Dec 10	30	Jan 31	36	Mar 24	20	May 15	4
Jul 8	0	Aug 29	0	Oct 20	11	Dec 11	31	Feb 1	36	Mar 25	19	May 16	4
Jul 9	0	Aug 30	0	Oct 21	12	Dec 12	31	Feb 2	36	Mar 26	19	May 17	4
Jul 10	0	Aug 31	0	Oct 22	12	Dec 13	31	Feb 3	35	Mar 27	19	May 18	4
Jul 11	0	Sep 1	0	Oct 23	13	Dec 14	31	Feb 4	35	Mar 28	18	May 19	4
Jul 12	0	Sep 2	0	Oct 24	13	Dec 15	32	Feb 5	35	Mar 29	18	May 20	4
Jul 13	0	Sep 3	0	Oct 25	13	Dec 16	32	Feb 6	35	Mar 30	18	May 21	3
Jul 14	0	Sep 4	0	Oct 26	14	Dec 17	32	Feb 7	35	Mar 31	17	May 22	3
Jul 15	1	Sep 5	0	Oct 27	14	Dec 18	32	Feb 8	35	Apr 1	16	May 23	3
Jul 16	0	Sep 6	0	Oct 28	14	Dec 19	33	Feb 9	34	Apr 2	16	May 24	3
Jul 17	0	Sep 7	1	Oct 29	15	Dec 20	33	Feb 10	34	Apr 3	16	May 25	3
Jul 18	0	Sep 8	1	Oct 30	15	Dec 21	33	Feb 11	34	Apr 4	16	May 26	3
Jul 19	0	Sep 9	1	Oct 31	16	Dec 22	33	Feb 12	33	Apr 5	15	May 27	2
Jul 20	0	Sep 10	1	Nov 1	16	Dec 23	34	Feb 13	33	Apr 6	15	May 28	2
Jul 21	0	Sep 11	1	Nov 2	16	Dec 24	34	Feb 14	33	Apr 7	15	May 29	2
Jul 22	0	Sep 12	1	Nov 3	16	Dec 25	34	Feb 15	33	Apr 8	14	May 30	2
Jul 23	0	Sep 13	1	Nov 4	17	Dec 26	34	Feb 16	32	Apr 9	14	May 31	2
Jul 24	0	Sep 14	1	Nov 5	18	Dec 27	34	Feb 17	32	Apr 10	14	Jun 1	2
Jul 25	0	Sep 15	2	Nov 6	18	Dec 28	35	Feb 18	32	Apr 11	13	Jun 2	2
Jul 26	0	Sep 16	2	Nov 7	18	Dec 29	35	Feb 19	31	Apr 12	13	Jun 3	2
Jul 27	0	Sep 17	2	Nov 8	19	Dec 30	35	Feb 20	31	Apr 13	13	Jun 4	2
Jul 28	0	Sep 18	2	Nov 9	19	Dec 31	35	Feb 21	31	Apr 14	12	Jun 5	1
Jul 29	0	Sep 19	2	Nov 10	20	Jan 1	35	Feb 22	30	Apr 15	12	Jun 6	1
Jul 30	0	Sep 20	2	Nov 11	20	Jan 2	35	Feb 23	30	Apr 16	12	Jun 7	1
Jul 31	0	Sep 21	3	Nov 12	20	Jan 3	35	Feb 24	30	Apr 17	11	Jun 8	1
Aug 1	0	Sep 22	3	Nov 13	21	Jan 4	35	Feb 25	29	Apr 18	11	Jun 9	1
Aug 2	0	Sep 23	3	Nov 14	21	Jan 5	36	Feb 26	29	Apr 19	11	Jun 10	1
Aug 3	0	Sep 24	3	Nov 15	22	Jan 6	36	Feb 27	29	Apr 20	10	Jun 11	0
Aug 4	0	Sep 25	4	Nov 16	22	Jan 7	36	Feb 28	28	Apr 21	10	Jun 12	0
Aug 5	0	Sep 26	4	Nov 17	22	Jan 8	36	Mar 1	28	Apr 22	10	Jun 13	0
Aug 6	0	Sep 27	4	Nov 18	23	Jan 9	37	Mar 2	27	Apr 23	9	Jun 14	0
Aug 7	0	Sep 28	4	Nov 19	23	Jan 10	37	Mar 3	27	Apr 24	9	Jun 15	0
Aug 8	0	Sep 29	5	Nov 20	24	Jan 11	37	Mar 4	27	Apr 25	9	Jun 16	0
Aug 9	0	Sep 30	5	Nov 21	24	Jan 12	37	Mar 5	27	Apr 26	8	Jun 17	0
Aug 10	0	Oct 1	5	Nov 22	24	Jan 13	37	Mar 6	26	Apr 27	8	Jun 18	0
Aug 11	0	Oct 2	5	Nov 23	25	Jan 14	37	Mar 7	26	Apr 28	8	Jun 19	0
Aug 12	0	Oct 3	6	Nov 24	25	Jan 15	37	Mar 8	26	Apr 29	8	Jun 20	0
Aug 13	0	Oct 4	6	Nov 25	25	Jan 16	37	Mar 9	25	Apr 30	7	Jun 21	0
Aug 14	1	Oct 5	6	Nov 26	26	Jan 17	37	Mar 10	25	May 1	7	Jun 22	0
Aug 15	1	Oct 6	7	Nov 27	26	Jan 18	37	Mar 11	24	May 2	6	Jun 23	0
Aug 16	0	Oct 7	7	Nov 28	26	Jan 19	37	Mar 12	24	May 3	6	Jun 24	0
Aug 17	0	Oct 8	7	Nov 29	27	Jan 20	37	Mar 13	24	May 4	6	Jun 25	0
Aug 18	0	Oct 9	8	Nov 30	27	Jan 21	37	Mar 14	23	May 5	6	Jun 26	0
Aug 19	0	Oct 10	8	Dec 1	28	Jan 22	37	Mar 15	23	May 6	6	Jun 27	0
Aug 20	0	Oct 11	8	Dec 2	28	Jan 23	37	Mar 16	23	May 7	6	Jun 28	0
Aug 21	0	Oct 12	9	Dec 3	28	Jan 24	37	Mar 17	22	May 8	6	Jun 29	0
												Jun 30	0

Appendix D – Normal Temperature Adjustment (cont'd)

NORMAL DEGREE DAYS (NDD)
LEAP YEAR

Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD	Date	NDD
Jul 1	0	Aug 22	0	Oct 13	9	Dec 4	28	Jan 25	37	Mar 17	22	May 8	6
Jul 2	0	Aug 23	0	Oct 14	9	Dec 5	29	Jan 26	37	Mar 18	22	May 9	5
Jul 3	0	Aug 24	0	Oct 15	10	Dec 6	29	Jan 27	37	Mar 19	22	May 10	5
Jul 4	0	Aug 25	0	Oct 16	10	Dec 7	29	Jan 28	36	Mar 20	21	May 11	5
Jul 5	0	Aug 26	0	Oct 17	10	Dec 8	30	Jan 29	36	Mar 21	21	May 12	5
Jul 6	0	Aug 27	0	Oct 18	11	Dec 9	30	Jan 30	36	Mar 22	21	May 13	5
Jul 7	0	Aug 28	0	Oct 19	11	Dec 10	30	Jan 31	36	Mar 23	20	May 14	5
Jul 8	0	Aug 29	0	Oct 20	11	Dec 11	31	Feb 1	36	Mar 24	20	May 15	4
Jul 9	0	Aug 30	0	Oct 21	12	Dec 12	31	Feb 2	36	Mar 25	19	May 16	4
Jul 10	0	Aug 31	0	Oct 22	12	Dec 13	31	Feb 3	35	Mar 26	19	May 17	4
Jul 11	0	Sep 1	0	Oct 23	13	Dec 14	31	Feb 4	35	Mar 27	19	May 18	4
Jul 12	0	Sep 2	0	Oct 24	13	Dec 15	32	Feb 5	35	Mar 28	18	May 19	4
Jul 13	0	Sep 3	0	Oct 25	13	Dec 16	32	Feb 6	35	Mar 29	18	May 20	4
Jul 14	0	Sep 4	0	Oct 26	14	Dec 17	32	Feb 7	35	Mar 30	18	May 21	3
Jul 15	1	Sep 5	0	Oct 27	14	Dec 18	32	Feb 8	35	Mar 31	17	May 22	3
Jul 16	0	Sep 6	0	Oct 28	14	Dec 19	33	Feb 9	34	Apr 1	16	May 23	3
Jul 17	0	Sep 7	1	Oct 29	15	Dec 20	33	Feb 10	34	Apr 2	16	May 24	3
Jul 18	0	Sep 8	1	Oct 30	15	Dec 21	33	Feb 11	34	Apr 3	16	May 25	3
Jul 19	0	Sep 9	1	Oct 31	16	Dec 22	33	Feb 12	33	Apr 4	16	May 26	3
Jul 20	0	Sep 10	1	Nov 1	16	Dec 23	34	Feb 13	33	Apr 5	15	May 27	2
Jul 21	0	Sep 11	1	Nov 2	16	Dec 24	34	Feb 14	33	Apr 6	15	May 28	2
Jul 22	0	Sep 12	1	Nov 3	16	Dec 25	34	Feb 15	33	Apr 7	15	May 29	2
Jul 23	0	Sep 13	1	Nov 4	17	Dec 26	34	Feb 16	32	Apr 8	14	May 30	2
Jul 24	0	Sep 14	1	Nov 5	18	Dec 27	34	Feb 17	32	Apr 9	14	May 31	2
Jul 25	0	Sep 15	2	Nov 6	18	Dec 28	35	Feb 18	32	Apr 10	14	Jun 1	2
Jul 26	0	Sep 16	2	Nov 7	18	Dec 29	35	Feb 19	31	Apr 11	13	Jun 2	2
Jul 27	0	Sep 17	2	Nov 8	19	Dec 30	35	Feb 20	31	Apr 12	13	Jun 3	2
Jul 28	0	Sep 18	2	Nov 9	19	Dec 31	35	Feb 21	31	Apr 13	13	Jun 4	2
Jul 29	0	Sep 19	2	Nov 10	20	Jan 1	35	Feb 22	30	Apr 14	12	Jun 5	1
Jul 30	0	Sep 20	2	Nov 11	20	Jan 2	35	Feb 23	30	Apr 15	12	Jun 6	1
Jul 31	0	Sep 21	3	Nov 12	20	Jan 3	35	Feb 24	30	Apr 16	12	Jun 7	1
Aug 1	0	Sep 22	3	Nov 13	21	Jan 4	35	Feb 25	29	Apr 17	11	Jun 8	1
Aug 2	0	Sep 23	3	Nov 14	21	Jan 5	36	Feb 26	29	Apr 18	11	Jun 9	1
Aug 3	0	Sep 24	3	Nov 15	22	Jan 6	36	Feb 27	29	Apr 19	11	Jun 10	1
Aug 4	0	Sep 25	4	Nov 16	22	Jan 7	36	Feb 28	28	Apr 20	10	Jun 11	0
Aug 5	0	Sep 26	4	Nov 17	22	Jan 8	36	Feb 29	29	Apr 21	10	Jun 12	0
Aug 6	0	Sep 27	4	Nov 18	23	Jan 9	37	Mar 1	28	Apr 22	10	Jun 13	0
Aug 7	0	Sep 28	4	Nov 19	23	Jan 10	37	Mar 2	27	Apr 23	9	Jun 14	0
Aug 8	0	Sep 29	5	Nov 20	24	Jan 11	37	Mar 3	27	Apr 24	9	Jun 15	0
Aug 9	0	Sep 30	5	Nov 21	24	Jan 12	37	Mar 4	27	Apr 25	9	Jun 16	0
Aug 10	0	Oct 1	5	Nov 22	24	Jan 13	37	Mar 5	27	Apr 26	8	Jun 17	0
Aug 11	0	Oct 2	5	Nov 23	25	Jan 14	37	Mar 6	26	Apr 27	8	Jun 18	0
Aug 12	0	Oct 3	6	Nov 24	25	Jan 15	37	Mar 7	26	Apr 28	8	Jun 19	0
Aug 13	0	Oct 4	6	Nov 25	25	Jan 16	37	Mar 8	26	Apr 29	8	Jun 20	0
Aug 14	1	Oct 5	6	Nov 26	26	Jan 17	37	Mar 9	25	Apr 30	7	Jun 21	0
Aug 15	1	Oct 6	7	Nov 27	26	Jan 18	37	Mar 10	25	May 1	7	Jun 22	0
Aug 16	0	Oct 7	7	Nov 28	26	Jan 19	37	Mar 11	24	May 2	6	Jun 23	0
Aug 17	0	Oct 8	7	Nov 29	27	Jan 20	37	Mar 12	24	May 3	6	Jun 24	0
Aug 18	0	Oct 9	8	Nov 30	27	Jan 21	37	Mar 13	24	May 4	6	Jun 25	0
Aug 19	0	Oct 10	8	Dec 1	28	Jan 22	37	Mar 14	23	May 5	6	Jun 26	0
Aug 20	0	Oct 11	8	Dec 2	28	Jan 23	37	Mar 15	23	May 6	6	Jun 27	0
Aug 21	0	Oct 12	9	Dec 3	28	Jan 24	37	Mar 16	23	May 7	6	Jun 28	0
												Jun 29	0
												Jun 30	0

APPENDIX E

ENERGY EFFICIENCY ADJUSTMENT

The Delivery Charges specified in Gas Rate Nos. D20 and D40 shall be adjusted from time to time in accordance with the Final Order of the Indiana Utility Regulatory Commission in Company's most recent general rate case to reflect an Energy Efficiency Funding Component and a Sales Reconciliation Component.

ENERGY EFFICIENCY FUNDING COMPONENT ("EEFC"):

The EEFC shall recover the costs of funding energy efficiency efforts throughout the Company's service area. These efforts may include, among others, energy efficiency programs, Customer education programs, and weatherization programs designed to benefit Customers under the applicable rate schedules.

The estimated annual costs, plus related revenue taxes, shall be divided by projected sales volumes to determine the applicable EEFC. The actual costs recoverable and the actual costs recovered under the EEFC shall be reconciled, with any under or over recovery being recovered or returned via the EEFC over a subsequent twelve Month period.

SALES RECONCILIATION COMPONENT ("SRC"):

The SRC shall recover the differences between Actual Margins and Adjusted Order Granted Margins for the applicable rate schedules.

Actual Margins are defined as Monthly margins for each rate schedule, prior to the SRC Adjustment. Adjusted Order Granted Margins are defined as the Order granted Monthly margins for each rate schedule, as approved in Company's most recent general rate case, as adjusted to reflect the change in number of Customers from the Order granted Customer levels. To reflect the change in number of Customers, Order granted margin per Customer is multiplied by the change in the number of Customers since the like Month during the test year, with the product being added to the Order granted margins for such Month.

The Company shall defer the calculated differences between Actual Margins and Adjusted Order Granted Margins for subsequent return or recovery via the SRC. Annually, the Company shall reflect in a revised SRC the accumulated Monthly margin differences. Beginning with the twelve-month period ending December 31, 2013, margin differences from Residential Customers

Appendix E – Energy Efficiency Adjustment (cont'd)

receiving Gas Delivery Service under Gas Rate No. D20 eligible for recovery in the SRC annually are capped at 8% of Adjusted Order Granted Margins attributable to Residential Customers applicable to the previous year. Any actual margin differences from Residential Customers in excess of the 8% SRC cap will be deferred for future recovery either in a future SRC filing, with the annual residential SRC amount still subject to the 8% cap, or in a future rate case. The total amount that may be deferred for recovery in a future rate case may not exceed $1 million.

Appendix E – Energy Efficiency Adjustment

The accumulated Monthly margin differences for each rate schedule shall be divided by projected throughput volumes for each rate schedule to determine the applicable SRC. Projected and actual recoveries by rate schedule under the SRC are reconciled, with any under or over recovery being recovered or returned over a subsequent twelve Month period.

ENERGY EFFICIENCY ADJUSTMENT RATE: $ per Therm

The applicable Energy Efficiency Adjustment Rate (the sum of the EEFC and SRC) shall be applied to each Therm of metered Gas usage each Month.

Rate Schedule	A Energy Efficiency Funding Component	B Sales Reconciliation Component	A + B Energy Efficiency Adjustment Rate
Gas Rate D20	**$0.0013**	**$0.0424**	**$0.0437**
Gas Rate D40	**$0.0013**	**($0.0057)**	**($0.0044)**

APPENDIX F

REGULATORY ASSET AMORTIZATION

APPLICABILITY:

Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43600, issued, April 1, 2009, the Company was authorized to create a regulatory asset for the purpose of accumulating energy efficiency rebate costs. Pursuant to Indiana Utility Regulatory Commission Order in Cause No. 43624, issued March 10, 2010, the Company was authorized to recover the amortized cost of energy efficiency rebates previously authorized in Cause No. 43600 through this appendix. Appendix F is applicable to Gas Rate Nos. D20 and D40.

RATES AND CHARGES:

The appendix shall be applied to each Therm of metered gas usage each Month. The current charges are set forth below:

$0.0000 per Therm

GAS RATE NO. S1

VARIABLE-RATE GAS SUPPLY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas supplied in a Month or any portion thereof and delivered under Gas Rate Nos. D20, D30, D40, and D50 unless an eligible Customer has contracted with a 3rd Party Supplier for gas supply service.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. S1, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

GAS SUPPLY CHARGE:

The currently applicable charge for all gas supplied under this Gas Rate No. S1 is identified on Appendix A. The Gas Supply Charge is subject to change on a monthly basis.

3rd PARTY SUPPLIER:

Customers may select a 3rd Party Supplier to provide gas supply instead of the Company. Such selections shall be governed by the Company's requirements as described in the Terms and Conditions for Gas Service.

GAS RATE NO. S2

SUPPLY OF LAST RESORT

APPLICABILITY:

This rate schedule is applicable to Customers and 3rd Party Suppliers in accordance with the Company's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. S2, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

GAS SUPPLY CHARGE:

For the first three days of default, the Non-Performance Charge (Gas Rate No. A1) will be applicable along with all other charges as identified in Appendix B. The Gas Supply Charge will be applicable to 3rd Party Suppliers.

BILLING:

Beginning with the fourth day following default, until the end of the Customer's billing cycle, Customers who have chosen a 3rd Party Supplier, who has defaulted, by failing to nominate and/or deliver gas supply for three (3) consecutive days, will be billed Variable-Rate Gas Supply Service, under Gas Rate No. S1, for any volumes used. Volumes may be based on estimation or proration if daily usage is not available.