ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A GAS COST ADJUSTMENT TO BE APPLICABLE IN THE MONTHS OF DECEMBER 2010, JANUARY 2011 and FEBRUARY 2011, PURSUANT TO IND. CODE § 8-1-2-42(g)	)	**CAUSE NO. 43629 GCA 16** **APPROVED:** NOV 3 0 2010

<u>**BY THE COMMISSION**</u>:
Carolene Mays, Commissioner
David E. Veleta, Administrative Law Judge

On September 27, 2010, in accordance with Indiana Code § 8-1-2-42, Northern Indiana Public Service Company ("Petitioner" or "NIPSCO") filed with the Indiana Utility Regulatory Commission ("Commission") its Petition in this Cause for approval of a Gas Cost Adjustment ("GCA") to be applicable during the billing cycles of December 2010 through February 2011. On October 27, 2010, Petitioner pre-filed the direct testimony and supporting exhibits of Katherine A. Cherven, Manager of Compliance, Rates Department; Roger A Huhn, Director of Resource Planning, Energy Supply and Trading; and Mitchell E. Hershberger, Controller. On November 15, 2010, in accordance with statute, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its statistical report and the direct testimony and exhibits of Lianne N. Lockhart, a Utility Analyst in the OUCC's Gas Division. On November 15, 2010, the OUCC also filed the testimony of Jerome D. Mierzwa, a Principal and Vice President of Exeter Associates, Inc.

Pursuant to notice, duly published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an evidentiary hearing was held in this Cause at 10:30 a.m. on November 18, 2010, in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC were present at the hearing. Petitioner and the OUCC presented their respective evidence without objection and waived cross-examination of each other's witnesses.

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

1. <u>**Statutory Notice and Commission Jurisdiction**</u>. Due, legal and timely notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner operates a public gas utility and as such, is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended. The provisions of said Act authorize the Commission to act in this proceeding. Therefore, this Commission has jurisdiction over the parties and the subject matter herein.

2. **Petitioner's Characteristics.** Petitioner is a public utility corporation organized and existing under the laws of the State of Indiana, with its principal office located at 801 East 86th Avenue, Merrillville, Indiana. It is engaged in rendering natural gas distribution service to the public in the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment used for the distribution and furnishing of such services.

3. **Source of Natural Gas.** Indiana Code § 8-1-2-42(g)(3)(A) requires Petitioner to make every reasonable effort to acquire long-term natural gas supplies in order to provide gas to its retail customers at the lowest gas cost reasonably possible.

Mr. Roger Huhn testified that NIPSCO meets this objective by managing a balanced and diversified gas supply portfolio comprised of a variety of commodity, transportation and storage resources. The commodity portfolio is balanced with a combination of fixed-price (physical and financial) and market-based purchases. The commodity portfolio diversification is achieved by acquiring gas from a number of suppliers through a competitive bidding process and utilizing a variety of pricing structures sourced from multiple locations. These gas supplies are delivered to NIPSCO through multiple long-term firm transportation arrangements with several different interstate gas pipelines, providing access to multiple supply basins. Mr. Huhn testified that NIPSCO also has several long-term firm contractual storage services as well as on-system storage capability to meet its gas customers' requirements. The storage portfolio is further diversified through a variety of storage service types in multiple locations in the market area, as well as in producing regions.

Mr. Huhn further testified that during the three-month recovery period beginning December 1, 2010, NIPSCO will purchase supply under firm arrangements on both a term and spot market basis. To achieve diversity of supply, he stated that NIPSCO has contracted with several pipelines permitting access to multiple supply basins. NIPSCO has long-term, firm transportation contracts with Natural Gas Pipeline Company of America ("Natural"), Panhandle Eastern Pipe Line Company ("Panhandle"), Trunkline Gas Company ("Trunkline"), ANR Pipeline Company ("ANR"), Vector Pipeline and Northern Border Pipeline. The long-term, firm long-haul transportation contracts with Natural, Panhandle, Trunkline, and ANR have an aggregate Maximum Daily Quantity ("MDQ") during the peak season of 370,000 Dth and an off-peak MDQ of 270,000 Dth. Generally speaking, he noted the winter season is defined as the peak season, and the summer season is defined as the off-peak season.

With regard to storage, Mr. Huhn testified that firm storage service contracts with Natural; Panhandle; ANR; Moss Bluff Hub Partners, L.P.; Kinder Morgan Texas Pipeline, L.P.; ENSTOR Operating Company; Washington 10 Storage Corporation and Egan Hub Partners, L.P. provide an annual storage capability of approximately 27,000,000 Dth, with maximum daily withdrawal capability of approximately 530,000 Dth to meet winter peaks.

The Commission has indicated that Indiana's gas utilities should make reasonable efforts to mitigate gas price volatility. This includes a program that works to mitigate gas price volatility and considers market conditions and the price of natural gas on a current and forward-looking basis. Based on the evidence offered, we find that Petitioner has demonstrated that it has and continues to follow a policy of securing natural gas supply at the lowest gas cost reasonably possible in order to meet anticipated customer requirements. Thus, the Commission finds that the requirement of this statutory provision has been fulfilled.

4. **Purchased Gas Cost Rates.** Indiana Code § 8-1-2-42(g)(3)(B) requires that Petitioner's pipeline suppliers have requested or filed, pursuant to the jurisdiction and procedures of a duly constituted regulatory authority the costs proposed to be included in the GCA factor. The evidence of record indicates that gas costs in this Petition include transportation rates that have been filed by Petitioner's pipeline suppliers in accordance with Federal Energy Regulatory Commission procedures. The Commission has reviewed the cost of gas included in the proposed gas cost adjustment charge and finds the costs to be reasonable. Accordingly, the Commission finds that the requirement of this statutory provision has been fulfilled.

5. **Return Earned.** Indiana Code § 8-1-2-42(g)(3)(C), in effect, prohibits approval of a GCA that results in the Petitioner earning a return in excess of the return authorized by the last Commission proceeding in which Petitioner's basic rates and charges were approved. The most recent proceeding in which Petitioner's basic rates and charges were approved is Cause No. 38380. The Commission's October 26, 1988 Order in that Cause authorized Petitioner to earn a net operating income of $63,182,056. The evidence of record indicates that for the twelve (12) months ending September 30, 2010, Petitioner's actual net operating income was $8,034,354. Therefore, the Commission finds that Petitioner is not earning in excess of that authorized in its last proceeding in which basic rates and charges were approved.

6. **Estimation of Purchased Gas Costs.** Indiana Code § 8-1-2-42(g)(3)(D) requires that Petitioner's estimate of its prospective average gas costs for each future recovery period be reasonable. The Commission has determined that this requires, in part, a comparison of prior estimates with the eventual actual costs. Petitioner's evidence indicates that its estimating techniques during the reconciliation period of June through August 2010 ("Reconciliation Period") yielded an under-estimated weighted average error of 18.15%. The differences between the estimated and actual costs is mainly attributable to actual sales being lower than estimated and the demand related costs which are estimated at the annualized demand factor. Actual demand costs will be higher than estimated in the summer months due to the lower summer usage on which the estimated demand dollars are based. Based upon Petitioner's historical accuracy in estimating the cost of gas, the Commission finds that Petitioner's estimating techniques for the reconciliation period are reasonable and Petitioner's average estimate of gas cost is reasonable.

7. **Reconciliation.** Indiana Code § 8-1-2-42(g)(3)(D) also requires that Petitioner reconcile its estimation for a previous recovery period with the actual purchased gas cost for that period.

The evidence presented in this current proceeding indicates that the variance for the Reconciliation Period is an under-collection of $6,279,503 from its customers. This amount should be included, based on estimated sales percentages, in this GCA and the next three GCAs. The amount of the Reconciliation Period variance to be included in this GCA as an increase in the estimated net cost of gas is $3,008,326. Also, included in this Reconciliation Period is a decrease to gas cost of $4,648,447 due to prior period adjustments related to the reconciliations of September 2008 through May 2010. The total amount of the Reconciliation Period variance to be included in this GCA as a decrease in the estimated net cost of gas is $1,640,121.

The variance from prior period recovery periods applicable to the current recovery period is an under-collection of $18,345,369. Combining this amount with the Reconciliation Period variance, results in a total under-collection of $16,705,248 to be applied in this GCA as an increase in the estimated net cost of gas.

Based upon the evidence presented, the Commission finds that Petitioner's proposed GCA properly reconciles the difference between the actual costs for the Reconciliation Period, and the gas costs recovered during that same period.

8. Refunds in GCA 16. GCA 16 includes three new refunds in the amount of $250,503, $19,007 and $1,563,804. The refund of $250,503 is from Tennessee Gas Pipeline Company. The $19,007 is a distribution related to Natural Gas Commodity Litigation. These refunds should be returned, based on estimated sales percentages, in this GCA and the next three GCAs. The $1,563,804 represent the Storage Service Credit to be passed back to GCA customers in December, January and February in accordance with Cause No. 38952, approved September 5, 1990. The total amount of the Reconciliation Period refunds to be returned in this GCA is $1,694,412.

Petitioner has refunds from prior periods applicable to the current recovery period of $1,280,307. Therefore, Petitioner has $2,974,719 in refunds to be applied as a decrease in the net cost of gas. Based upon the evidence presented, the Commission finds that Petitioner's proposed GCA properly reconciles the difference between the actual costs for the Reconciliation Period, and the gas costs recovered during that same period.

9. Resulting Gas Cost Adjustment Factor. The estimated net commodity cost of gas to be recovered during the application periods of December 2010, January 2011 and February 2011 are $51,330,874, $57,785,467 and $47,216,322, respectively. Adjusting this total for the variance and refunds, yields gas costs to be recovered through the GCA of $170,063,192. After dividing that amount by estimated sales and adjusting for Indiana Utility Receipts Tax, Petitioner's recommended GCA factors are:

Estimated GCA per Therm

Rate Class	December 2010	January 2011	February 2011
Residential	$0.5702	$0.5812	$0.5956
General Service	$0.5651	$0.5779	$0.5916

10. Effects on Residential Customers. The December 2010 GCA factor of $5.702/Dth represents an increase of $0.244/Dth from the current November 2010 GCA factor of $5.458/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 1:

Table 1 Proposed GCA Factor for December 2010 vs. Currently Approved GCA Factor for November 2010				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Currently Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$ 45.53	$ 44.31	$1.22	2.75%
10	$ 80.04	$ 77.60	$2.44	3.14%
15	$114.57	$110.91	$3.66	3.30%
20	$149.09	$144.21	$4.88	3.38%
25	$183.61	$177.52	$6.09	3.43%

The January 2011 GCA factor of $5.812/Dth represents an increase of $0.354/Dth from the current November 2010 GCA factor of $5.458/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 2:

Table 2 Proposed GCA Factor for January 2011 vs. Currently Approved GCA Factor for November 2010				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Currently Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$46.08	$44.31	$1.77	3.99%
10	$81.14	$77.60	$3.54	4.56%
15	$116.22	$110.91	$5.31	4.79%
20	$151.29	$144.21	$7.08	4.91%
25	$186.36	$177.52	$8.84	4.98%

The February 2011 GCA factor of $5.956/Dth represents an increase of $0.498/Dth from the current November 2010 GCA factor of $5.458/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 3:

Table 3 **Proposed GCA Factor for February 2011** **vs.** **Currently Approved GCA Factor for November 2010**				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Currently Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$46.80	$44.31	$2.49	5.62%
10	$82.58	$77.60	$4.98	6.42%
15	$118.38	$110.91	$7.47	6.74%
20	$154.17	$144.21	$9.96	6.91%
25	$189.96	$177.52	$12.44	7.01%

The December 2010 GCA factor of $5.702/Dth represents an increase of $6.890/Dth from the GCA factor billed one year ago of $(1.188)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 4:

Table 4 **Proposed GCA Factor for December 2010** **vs.** **GCA Factor Prior Year for December 2009**				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Prior Year Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$45.53	$25.70	$19.83	77.16%
10	$80.04	$45.04	$35.00	77.71%
15	$114.57	$64.38	$50.19	77.96%
20	$149.09	$83.72	$65.37	78.08%
25	$183.61	$110.82	$72.79	65.68%

The January 2011 GCA factor of $5.812/Dth represents an increase of $7.512/Dth from the GCA factor billed one year ago of $(1.700)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 5:

Table 5 Proposed GCA Factor for January 2011 vs. GCA Factor Prior Year for January 2010				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Prior Year Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$46.08	$23.14	$22.94	99.14%
10	$81.14	$39.92	$41.22	103.26%
15	$116.22	$56.70	$59.52	104.97%
20	$151.29	$73.48	$77.81	105.89%
25	$186.36	$98.02	$88.34	90.12%

The February 2011 GCA factor of $5.956/Dth represents an increase of $7.110/Dth from the GCA factor billed one year ago of $(1.154)/Dth. The effects of this change for various consumption levels of residential customer bills are shown in Table 6:

Table 6 Proposed GCA Factor for February 2011 vs. GCA Factor Prior Year for February 2010				
Monthly Consumption Mcf or Dth	**Bill at Proposed GCA Factor**	**Bill at Prior Year Approved GCA Factor**	**Dollar Change**	**Percent Change**
5	$46.80	$25.87	$20.93	80.90%
10	$82.58	$45.38	$37.20	81.97%
15	$118.38	$64.89	$53.49	82.43%
20	$154.17	$84.40	$69.77	82.67%
25	$189.96	$111.67	$78.29	70.11%

11. **Interim Rates.** The Commission is unable to determine whether Petitioner will earn an excess return while this GCA is in effect. Accordingly, the Commission has authorized that the approved rates herein should be interim rates subject to refund pending reconciliation in the event an excess return is earned.

12. **Monthly Flex Mechanism.** Petitioner utilizes a flex mechanism each month to adjust the GCA for the subsequent month. The flex applies only to estimated pricing of estimated market purchases (the initial market price) in the GCA. The flex is to be filed no less than three (3) days before the beginning of each calendar month during the GCA quarter. Market purchases in the flex are to be priced at NYMEX prices on a day no more than six (6) business days prior to the beginning of said calendar month. Changes in the market price included in the flex is limited to a maximum adjustment (up or down) of $1.00 from the initial market price.

This Commission has indicated in prior orders that Indiana's gas utilities should make reasonable efforts to mitigate gas price volatility. Petitioner's monthly flex mechanism is designed to address the Commission's concerns. Therefore, Petitioner may utilize a monthly flex mechanism.

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

1. The Petition of Northern Indiana Public Service Company for the gas cost adjustment for natural gas service, as set forth in Finding Paragraph No. 9, shall be and hereby is approved, subject to refund in accordance with Finding Paragraph No. 11.

2. Northern Indiana Public Service Company shall file with the Commission under this Cause, prior to placing in effect the gas cost adjustment factors approved herein, or any future flexed factor, separate amendments to its rate schedules with reasonable references thereon reflecting that such charges are applicable to the rate schedule on these amendments.

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

ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: NOV 30 2010

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission